**CW-YECL-1**

**Issue:** Completeness of Application

**Reference:** YECL Rate Application Schedules

**Preamble:** CW wishes to gain a better understanding of the Application

**Request:**

Please provide an electronic copy of the Rate Schedules and revised rate schedules in the original Excel format. Please include the Excel format versions of the schedules in the Foster Associates report.

**Response:**

Please refer to CW-YECL-1 Attachment 1, 2 and 3.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Utility Revenue Requirement**
**( 000s)**

**Schedule 1.1**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Revenues** | | | | | |
| 2 | Retail revenues | S.2.1 L.45 | 39,115 | 40,177 | 45,850 | 47,075 |
| 3 | Other revenue | S.2.2 L.6 | 760 | 784 | 810 | 827 |
| 4 | **Total Revenues** | | 39,875 | 40,961 | 46,660 | 47,902 |
| 5 | | | | | | |
| 6 | **Costs** | | | | | |
| 7 | Purchase power | S.3.1 L.13 | 23,239 | 23,647 | 23,846 | 23,494 |
| 8 | Diesel Fuel | S.4.1 L.6 | 2,026 | 2,054 | 5,715 | 5,299 |
| 9 | Operations and maintenance | S.5.1 L.49 | 6,969 | 7,290 | 8,758 | 9,317 |
| 11 | Property Taxes | Page 6-1 | 230 | 235 | 249 | 261 |
| 12 | Depreciation | S.7.1 L.4 | 3,901 | 4,171 | 4,365 | 4,837 |
| 13 | Amortization of contributions | S.8.11 L.8 | (1,008) | (1,092) | (963) | (1,028) |
| 14 | Amortization of deferred costs credits | S.8.8 L.7 | - | 187 | 652 | 652 |
| 15 | Return on rate base | S.8.1 L.5, 10, 15, 20 | 3,484 | 3,614 | 3,618 | 4,026 |
| 16 | Income taxes | S.10.1 L.30 | 1,034 | 855 | 421 | 1,044 |
| 17 | **Total Costs** | | 39,875 | 40,961 | 46,660 | 47,902 |

**Yukon Electrical Company Limited** **Schedule 2.1**
**2008 - 2009 General Rate Application**
**Summary of Customers, Energy Sales and Revenue**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 Existing | Test Period 2008 Proposed | Test Period 2009 Existing | Test Period 2009 Proposed |
|---|---|---|---|---|---|---|---|---|
| 1 | **Residential** | | | | | | | |
| 2 | Customers (average during year) | | 12,196 | 12,452 | 12,693 | | 12,836 | |
| 3 | Sales in MWh | | 122,151 | 122,334 | 123,961 | | 125,337 | |
| 4 | MWh sales per customer | | 10.0 | 9.8 | 9.8 | | 9.8 | |
| 5 | Revenue ( 000s) | | 14,001 | 14,088 | 14,279 | | 14,435 | |
| 6 | Cents per KWh | | 11.46 | 11.52 | 11.52 | | 11.52 | |
| 7 | **Commercial** | | | | | | | |
| 8 | Customers (average during year) | | 2,515 | 2,570 | 2,599 | | 2,629 | |
| 9 | Sales in MWh | | 137,080 | 141,351 | 141,869 | | 142,564 | |
| 10 | MWh sales per customer | | 54.5 | 55.0 | 54.6 | | 54.2 | |
| 11 | Revenue ( 000s) | | 17,999 | 18,729 | 18,549 | | 18,641 | |
| 12 | Cents per KWh | | 13.13 | 13.25 | 13.07 | | 13.08 | |
| 13 | **Street lights** | | | | | | | |
| 14 | Sales in MWh | | 3,263 | 3,374 | 3,445 | | 3,522 | |
| 15 | Revenue ( 000s) | | 679 | 703 | 716 | | 729 | |
| 16 | Cents per KWh | | 20.81 | 20.83 | 20.78 | | 20.70 | |
| 17 | **Sentinel lights** | | | | | | | |
| 18 | Sales in MWh | | 644 | 639 | 638 | | 631 | |
| 19 | Revenue ( 000s) | | 135 | 134 | 134 | | 132 | |
| 20 | Cents per KWh | | 20.95 | 20.96 | 20.95 | | 20.95 | |
| 21 | **Total Company - Retail - Primary** | | | | | | | |
| 22 | Customers | | 14,711 | 15,022 | 15,293 | | 15,465 | |
| 23 | Sales in MWh | | 263,137 | 267,698 | 269,913 | | 272,054 | |
| 24 | Revenue ( 000s) | | 32,814 | 33,654 | 33,677 | | 33,937 | |
| 25 | Cents KWh | | 12.47 | 12.57 | 12.48 | | 12.47 | |
| 26 | **Secondary Sales** | | | | | | | |
| 27 | Customers (average during year) | | 22 | 22 | 22 | | 23 | |
| 28 | Sales in MWh | | 21,555 | 23,566 | 16,853 | | 6,954 | |
| 29 | MWh sales per customer | | 979.8 | 1,071.2 | 754.6 | | 302.4 | |
| 30 | Revenue ( 000s) | | 1,367 | 1,453 | 1,213 | | 501 | |
| 31 | Cents per KWh | | 6.34 | 6.17 | 7.20 | | 7.20 | |
| 32 | **Wholesale Sales** | | | | | | | |
| 33 | Customers (average during year) | | 2 | 2 | 2 | | 2 | |
| 34 | Sales in MWh | | 513 | 488 | 489 | | 489 | |
| 35 | MWh sales per customer | | 256.5 | 244.0 | 244.4 | | 244.4 | |
| 36 | Revenue ( 000s) | | 52 | 53 | 52 | | 52 | |
| 37 | Cents per KWh | | 10.14 | 10.86 | 10.60 | | 10.60 | |
| 38 | **Total Company** | | | | | | | |
| 39 | Customers | | 14,735 | 15,046 | 15,317 | | 15,490 | |
| 40 | Sales in MWh | S.3.2 L.2 | 285,205 | 291,752 | 287,255 | | 279,497 | |
| 41 | Revenue ( 000s) | | 34,233 | 35,160 | 34,942 | | 34,490 | |
| 42 | Cents KWh | | 12.00 | 12.05 | 12.16 | | 12.34 | |
| 43 | Retail Revenues | | 34,233 | 35,160 | 34,942 | | 34,490 | |
| 44 | **YEC Revenue Shortfall (Rider J)** | | 4,882 | 5,017 | 5,028 | | 5,067 | |
| 45 | **TOTAL REVENUES** | S.1.1 L.2 | 39,115 | 40,177 | 39,970 | 45,850 | 39,557 | 47,075 |
| 46 | Rate Increase from Existing Rates | | | | | 5,881 | | 7,518 |
| 47 | Less: Impact of higher fuel costs recovered through Rider F | | | | | (3,661) | | (3,388) |
| 48 | **Net Rate Increase ( 000s)** | L.46 - L.47 | | | | 2,220 | | 4,130 |
| 49 | **Rate Increase over Existing Rates** | | | | | | | |
| 50 | YECL Primary Retail Revenue | L.24 | | | 33,677 | | 33,937 | |
| 51 | YEC Primary Retail Revenue | S11.2 L.14, L.27 | | | 3,795 | | 3,750 | |
| 52 | Total YEC YECL Retail Revenue Primary Rates ( 00 | L.50 L.51 | | | 37,471 | | 37,687 | |
| 53 | **Rate increase over existing Rates** | L.48 L.52 | | | | 5.9 | | 11.0 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Miscellaneous Revenue**

**Schedule 2.2**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | Reconnect Revenue | | 83 | 75 | 80 | 80 |
| 2 | Joint Use | | 426 | 447 | 464 | 480 |
| 3 | Services to Outside Parties | | 102 | 99 | 100 | 100 |
| 4 | Other | | 149 | 163 | 166 | 167 |
| 5 | | | | | | |
| 6 | Total | S.1.1 L.3 | 760 | 784 | 810 | 827 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Purchase Power**

**Schedule 3.1**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Purchases (MWh)** | | | | | |
| 2 | Primary Energy | | 251,861 | 254,914 | 260,093 | 263,202 |
| 3 | Secondary Sales | | 21,555 | 23,566 | 16,853 | 6,954 |
| 4 | | S.3.2 L.10 | 273,416 | 278,480 | 276,946 | 270,156 |
| 5 | **Purchase Power Rates** | | | | | |
| 6 | Primary Energy Charge ( per KWh) | | 0.0684 | 0.0684 | 0.0684 | 0.0684 |
| 7 | Secondary Sales ( per KWh) | | 0.0524 | 0.0507 | 0.061 | 0.061 |
| 8 | Shortfall Rider J | | 14.93 | 14.93 | 14.93 | 14.93 |
| 9 | **Purchase Power Expense ( 000s)** | | | | | |
| 10 | Primary Energy Expense | L.2 x L.6 | 17,227 | 17,436 | 17,790 | 18,003 |
| 11 | Secondary Energy Expense | L.3 x L.7 | 1,130 | 1,194 | 1,028 | 424 |
| 12 | Shortfall Rider J | S.2.1 L.44 | 4,882 | 5,017 | 5,028 | 5,067 |
| 13 | Total Purchase Power Expense | S.1.1 L.7 | 23,239 | 23,647 | 23,846 | 23,494 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Energy Losses**
**(MW.h )**

**Schedule 3.2**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Sales and Losses** | | | | | |
| 2 | Total energy sales (MWh) | S.2.1 L.39 | 285,205 | 291,752 | 287,255 | 279,497 |
| 3 | Losses and company used - (MWh) | | 18,591 | 18,087 | 17,810 | 17,329 |
| 4 | Losses - | | 6.5 | 6.2 | 6.2 | 6.2 |
| 5 | Total generation and purchases (MWh) | | 303,796 | 309,839 | 305,065 | 296,826 |
| 6 | **Sources - MWh** | | | | | |
| 7 | Hydro generation | | 8,216 | 9,025 | 6,192 | 6,192 |
| 8 | Hydro grid standby diesel generation | S.4.1 L.1 | 39 | 131 | 44 | 44 |
| 9 | Diesel generation | S.4.1 L.1 | 22,125 | 22,203 | 21,883 | 20,433 |
| 10 | Purchases | S.3.1 L.4 | 273,416 | 278,480 | 276,946 | 270,156 |
| 11 | | | 303,796 | 309,839 | 305,065 | 296,826 |
| 12 | **Sources -** | | | | | |
| 13 | Hydro generation | | 2.7 | 2.9 | 2.0 | 2.1 |
| 14 | Diesel generation | | 7.3 | 7.2 | 7.2 | 6.9 |
| 15 | Purchases | | 90.0 | 89.9 | 90.8 | 91.0 |
| | | | 100.0 | 100.0 | 100.0 | 100.0 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Diesel Generation and Fuel Summary**
**( 000s)**

**Schedule 4.1**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | Total Diesel Generation (MWh) | S.3.2 L.8 & 9 | 22,164 | 22,334 | 21,927 | 20,477 |
| 2 | Fuel heat rate (KWh per litre) | | 3.69 | 3.67 | 3.71 | 3.71 |
| 3 | Litres of fuel (000s) | | 6,007 | 6,088 | 5,915 | 5,516 |
| 4 | Fuel costs ( 000s) | | 4,886 | 5,226 | 5,715 | 5,299 |
| 5 | Fuel Variance | | (2,860) | (3,172) | - | - |
| 6 | Fuel Expense | S.1.1 L.8 | 2,026 | 2,054 | 5,715 | 5,299 |
| 7 | Average cost (cents per litre) | L.3 L.4 | 81.34 | 85.84 | 96.61 | 96.07 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Diesel Information**

**Schedule 4.2**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| | Average Cost (in cents per litre) | | | | | |
| 1 | Watson Lake | | 74.62 | 78.16 | 87.48 | 87.48 |
| 2 | Beaver Creek | | 70.86 | 75.51 | 81.52 | 81.52 |
| 3 | Destruction Bay | | 72.43 | 77.75 | 83.13 | 83.13 |
| 4 | Old Crow | | 157.36 | 167.16 | 193.41 | 193.41 |
| 5 | Pelly Crossing | | 76.50 | 85.48 | 89.33 | 89.33 |
| 6 | Swift River | | 80.65 | 83.58 | 92.44 | 92.44 |
| 7 | Standby | | 50.42 | 66.40 | 70.00 | 70.00 |
| | Generation (MWh) | | | | | |
| 8 | Watson Lake | | 14,116 | 14,124 | 14,148 | 14,322 |
| 9 | Beaver Creek | | 2,034 | 1,957 | 2,021 | 2,041 |
| 10 | Destruction Bay | | 1,636 | 1,720 | 1,722 | 1,741 |
| 11 | Old Crow | | 1,811 | 1,853 | 1,967 | 1,993 |
| 12 | Pelly Crossing | | 2,250 | 2,272 | 1,746 | 11 |
| 13 | Swift River | | 276 | 277 | 278 | 326 |
| 14 | Standby | | 40 | 131 | 44 | 44 |
| 15 | | S.4.1 L.1 | 22,164 | 22,334 | 21,927 | 20,477 |
| 16 | Net Heat Rate (KWh litre) | | | | | |
| 17 | Watson Lake | | 3.84 | 3.80 | 3.82 | 3.82 |
| 18 | Beaver Creek | | 3.60 | 3.53 | 3.56 | 3.56 |
| 19 | Destruction Bay | | 3.30 | 3.34 | 3.41 | 3.41 |
| 20 | Old Crow | | 3.64 | 3.52 | 3.56 | 3.56 |
| 21 | Pelly Crossing | | 3.70 | 3.39 | 3.62 | 3.62 |
| 22 | Swift River | | 2.99 | 3.04 | 2.99 | 2.99 |
| 23 | Standby | | 3.00 | 3.00 | 3.50 | 3.50 |
| 24 | Litres Consumed (000s) | | | | | |
| 25 | Watson Lake | | 3,696 | 3,707 | 3,704 | 3,749 |
| 26 | Beaver Creek | | 564 | 551 | 567 | 573 |
| 27 | Destruction Bay | | 479 | 501 | 505 | 510 |
| 28 | Old Crow | | 514 | 528 | 552 | 559 |
| 29 | Pelly Crossing | | 633 | 654 | 482 | 3 |
| 30 | Swift River | | 91 | 91 | 93 | 109 |
| 31 | Standby | | 30 | 55 | 13 | 13 |
| | | S.4.1 L.3 | 6,007 | 6,088 | 5,915 | 5,516 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Operations and Maintenance Expenses**
**( 000s)**

**Schedule 5.1**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Production** | | | | | |
| 2 | 62600 - Hydro Generation | S.5.2 L.3 | 87 | 99 | 96 | 129 |
| 3 | 64000 - Supervision and Engineering Diesel | S.5.2 L.12 | 44 | 53 | 58 | 64 |
| 4 | 64600 - Diesel Generation | S.5.2 L.23 | 271 | 312 | 394 | 423 |
| 5 | 82600 - Hydro Maintenance | S.5.2 L.34 | 8 | 37 | 31 | 33 |
| 6 | 84600 - Diesel Maintenance | S.5.2 L.41 | 785 | 810 | 1,016 | 951 |
| 7 | | | 1,196 | 1,311 | 1,594 | 1,600 |
| 8 | **Distribution** | | | | | |
| 9 | 87000 - Supervision | S.5.2 L.54 | 188 | 230 | 229 | 250 |
| 10 | 87100 - Brushing | S.5.2 L.62 | 238 | 297 | 341 | 359 |
| 11 | 87200 - Vehicle Depreciation | | (84) | (94) | (100) | (105) |
| 12 | 87300 - Maintenance | S.5.2 L.73 | 927 | 936 | 1,386 | 1,514 |
| 13 | 87310 - Service to Outside Parties | | 96 | 101 | 106 | 112 |
| 14 | 87400 - Underground line maintenance | S.5.2 L.84 | 104 | 91 | 122 | 131 |
| 15 | 87500 - Meter and Meter Testing | S.5.2 L.93 | 145 | 108 | 115 | 75 |
| 16 | 87700 - Transformer Repair and Replacement | S.5.2 L.101 | 20 | 34 | 28 | 30 |
| 17 | 87800 - Street Light Maintenance | S.5.2 L.107 | 148 | 186 | 226 | 241 |
| 18 | | | 1,781 | 1,890 | 2,453 | 2,606 |
| 19 | **General** | | | | | |
| 20 | 88400 - Communication | | 11 | 8 | 13 | 14 |
| 21 | 88800 - Maintenance Company-owned Houses | | 28 | 29 | 33 | 34 |
| 22 | 88900 - Maintenance Warehouse and Office | S.5.2 L.118 | 97 | 110 | 118 | 125 |
| 23 | | | 136 | 147 | 164 | 173 |
| 24 | **Public information** | | | | | |
| 25 | 70100 - Public Information Administration | S.5.2 L.126 | 101 | 64 | 100 | 106 |
| 26 | 70200 - General Public Information | S.5.2 L.134 | 54 | 29 | 28 | 30 |
| 27 | | | 155 | 93 | 128 | 135 |
| 28 | **Customer accounting** | | | | | |
| 29 | 71000 - Supervision | S.5.2 L.138 | 34 | 31 | 35 | 49 |
| 30 | 71100 - Customer Applications and Service Orders | S.5.2 L.145 | 283 | 335 | 407 | 450 |
| 31 | 71200 - Meter Reading | S.5.2 L.155 | 391 | 464 | 436 | 471 |
| 32 | 71300 - Customer Billing and Accounting | S.5.2 L.167 | 474 | 513 | 572 | 646 |
| 33 | 71400 - Revenue Collections | S.5.2 L.177 | 167 | 181 | 162 | 258 |
| 34 | 71500 - Collection of Delinquent Accounts | S.5.2 L.188 | 121 | 124 | 142 | 158 |
| 35 | 71800 - Provision for Uncollectible Accounts | | 36 | 36 | 36 | 36 |
| 36 | | | 1,506 | 1,683 | 1,791 | 2,067 |
| 37 | **Administration and general** | | | | | |
| 38 | 72100 - Administrative | S.5.2 L.196 | 1,149 | 1,176 | 1,331 | 1,399 |
| 39 | 72200 - Administrative Corporate | S.5.2 L.203 | 27 | 14 | 30 | 32 |
| 40 | 72300 - Insurance | S.5.2 L.210 | 194 | 190 | 231 | 244 |
| 41 | 72400 - Injuries & Damages | | 75 | 75 | 86 | 86 |
| 42 | 72500 - Employee Expenses | S.5.2 L.214 | 208 | 229 | 222 | 312 |
| 43 | 72600 - Training and Safety | S.5.2 L.220 | 247 | 297 | 449 | 484 |
| 44 | 72700 - Relocation | S.5.2 L.233 | 190 | 93 | 182 | 77 |
| 45 | 72800 - Miscellaneous General | | 2 | 3 | 2 | 3 |
| 46 | 72900 - Audit Legal Fees & Special Studies | S.5.2 L.242 | 106 | 88 | 95 | 100 |
| 47 | | | 2,196 | 2,165 | 2,628 | 2,736 |
| 48 | | | | | | |
| 49 | **Total operations and maintenance expenses** | S.1.1 L.9 | 6,969 | 7,290 | 8,758 | 9,317 |

| Line No. | Description | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|
| 1 | **Production** | | | | |
| 2 | | | | | |
| 3 | 62600 - Hydro Generation | 87 | 99 | 96 | 129 |
| 4 | | | | | |
| 5 | Costs increase from 2006 to 2007 mainly due to increased Fish Lake inspection and maintenance costs due to water | | | | |
| 6 | re-licensing ( 39). This increase is offset by a one-time catch-up in 2006 of 1998 to 2006 water license fees to the | | | | |
| 7 | government ( 27). | | | | |
| 8 | | | | | |
| 9 | Costs increased from 2008 to 2009 mainly due to additional inspection and reporting to meet the requirements | | | | |
| 10 | of the new water license. | | | | |
| 11 | | | | | |
| 12 | 64000 - Supervision and Engineering Diesel | 44 | 53 | 58 | 64 |
| 13 | | | | | |
| 14 | Costs increase from 2006 to 2007 mainly due to fringe benefit defined benefit pension funding ( 5) and labour inflation ( 4). | | | | |
| 15 | The fringe benefit increase relates to increases for the defined benefit pension plan. This is due to the fact that contributions | | | | |
| 16 | of 27 of pensionable earnings are now required as a result of the actuarial valuation that was completed for the years | | | | |
| 17 | 2007-2009. | | | | |
| 18 | | | | | |
| 19 | Costs increase from 2007 to 2008 mainly due to inflation. | | | | |
| 20 | | | | | |
| 21 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | |
| 22 | | | | | |
| 23 | 64600 - Diesel Generation | 271 | 312 | 394 | 423 |
| 24 | | | | | |
| 25 | Costs increase from 2006 to 2007 mainly due to an increase in fringe benefits ( 23) and labour ( 18). | | | | |
| 26 | For an explanation of the fringe increase please refer to Account 64000. | | | | |
| 27 | | | | | |
| 28 | Cost increased from 2007 to 2008 mainly due to reduction in vacancies from employees returning off sick leave | | | | |
| 29 | and apprentice training ( 30), inflation ( 25), as well as new attraction and retention pay ( 15), fringe benefits ( 8), | | | | |
| 30 | and non-labour inflation ( 4). | | | | |
| 31 | | | | | |
| 32 | Costs increased from 2008 to 2009 mainly due to labour inflation ( 22), other inflation ( 4), and fringe benefits ( 3). | | | | |
| 33 | | | | | |
| 34 | 82600 - Hydro Maintenance | 8 | 37 | 31 | 33 |
| 35 | | | | | |
| 36 | Costs increase from 2006 to 2007 mainly due to inspection and reporting relating to Fish Lake. | | | | |
| 37 | | | | | |
| 38 | Costs decrease from 2007 to 2008 mainly due to lower labour ( 13) and fringe benefits ( 4) for inspection and reporting | | | | |
| 39 | of turbines 1 and 2, offset by non-labour inflation and an increase for property maintenance and upkeep ( 11). | | | | |
| 40 | | | | | |
| 41 | 84600 - Diesel Maintenance | 785 | 810 | 1,016 | 951 |
| 42 | | | | | |
| 43 | Costs increase from 2006 to 2007 mainly due to an increase in fringe benefits ( 25). | | | | |
| 44 | For an explanation of the fringe increase please refer to Account 64000. | | | | |
| 45 | | | | | |
| 46 | Costs increase from 2007 to 2008 mainly due to scheduled diesel overhaul costs ( 167). These costs are determined by | | | | |
| 47 | scheduled overhauls as prescribed by manufacturer's specifications that vary by type of unit and hours operated. | | | | |
| 48 | This increase is also due to new attraction and retention pay ( 25), and labour inflation ( 14). | | | | |
| 49 | | | | | |
| 50 | Costs decrease from 2008 to 2009 mainly due to varying costs for scheduled overhauls as prescribed by | | | | |
| 51 | manufacturer's specifications that are determined by type of unit and hours operated. | | | | |

| Line No. | Description | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|
| 52 | **Distribution** | | | | |
| 53 | | | | | |
| 54 | 87000 - Supervision | 188 | 230 | 229 | 250 |
| 55 | | | | | |
| 56 | Costs increase from 2006 to 2007 mainly due an increase in fringe benefits ( 24). For an explanation of this increase | | | | |
| 57 | please refer to Account 64000. This increase is also due to costs associated with after hours telephone answering | | | | |
| 58 | service ( 14), and labour inflation ( 4). | | | | |
| 59 | | | | | |
| 60 | Costs increase from 2008 to 2009 mainly due to labour inflation ( 13), attraction and retention pay ( 6) and fringe benefits ( 2). | | | | |
| 61 | | | | | |
| 62 | 87100 - Brushing | 238 | 297 | 341 | 359 |
| 63 | | | | | |
| 64 | Costs increase from 2006 to 2007 mainly due to an enhanced brushing program ( 40), labour cost increase due | | | | |
| 65 | to increased brushing activity ( 11), and increase in fringe benefits ( 8). For an explanation of this fringe | | | | |
| 66 | increase please refer to Account 64000. | | | | |
| 67 | | | | | |
| 68 | Costs increase from 2007 to 2008 due to increases to the labour compliment and labour inflation ( 24), non-labour | | | | |
| 69 | inflation ( 12), fringe benefits ( 4), and new attraction and retention pay ( 4). | | | | |
| 70 | | | | | |
| 71 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | |
| 72 | | | | | |
| 73 | 87300 - Maintenance | 927 | 936 | 1,386 | 1,514 |
| 74 | | | | | |
| 75 | Costs increase from 2007 to 2008 due mainly to additional labor as a result of new hires ( 136), vacancy reductions ( 120), | | | | |
| 76 | new attraction and retention pay ( 75), fringe benefits ( 59), annual labour inflation ( 46), and non-labour inflation ( 14). | | | | |
| 77 | The cost increases are for new and more extensive programs. These programs relate to Core certification and environmental | | | | |
| 78 | requirements. Many of these programs are mandated by outside agencies or are a result of changes to | | | | |
| 79 | industry standard. The increases also relate to enhanced patrols of lines and the introduction of planned maintenance programs | | | | |
| 80 | designed to support system performance. | | | | |
| 81 | | | | | |
| 82 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | |
| 83 | | | | | |
| 84 | 87400 - Underground Line Maintenance | 104 | 91 | 122 | 131 |
| 85 | | | | | |
| 86 | Costs decrease from 2006 to 2007 mainly due to a comprehensive inspection done in 2006. | | | | |
| 87 | | | | | |
| 88 | Costs increase from 2007 to 2008 mainly due to annual labour inflation ( 14), new attraction and retention pay ( 7), | | | | |
| 89 | non-labour inflation ( 6), and fringe benefits ( 4) | | | | |
| 90 | | | | | |
| 91 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | |
| 92 | | | | | |
| 93 | 87500 - Meter and Meter Testing | 145 | 108 | 115 | 75 |
| 94 | | | | | |
| 95 | Costs decrease from 2006 to 2007 mainly due to less one-time costs related to Automated Metering | | | | |
| 96 | Reading (AMR) feasibility study ( 19) and less miscellaneous material issues and payables ( 18). | | | | |
| 97 | | | | | |
| 98 | Costs increase from 2007 to 2008 mainly due to inflation. | | | | |
| 99 | | | | | |
| 100 | Costs decrease from 2008 to 2009 mainly due to savings from AMR. | | | | |

| Line No. | Description | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|
| 101 | 87700 - Transformer Repair and Replacement | 20 | 34 | 28 | 30 |
| 102 | | | | | |
| 103 | Costs increase from 2006 to 2007 mainly due to higher unplanned repairs to failed transformers. | | | | |
| 104 | | | | | |
| 105 | Costs decrease from 2007 to 2008 mainly due to normalization in allowance for unplanned repairs to failed transformers. | | | | |
| 106 | | | | | |
| 107 | 87800 - Street Light Maintenance | 148 | 186 | 226 | 241 |
| 108 | | | | | |
| 109 | Costs increase from 2006 to 2007 mainly due to increases in number of lights and age of street light infrastructure | | | | |
| 110 | as well as maintenance for new types of lights such as waterfront decorative lighting ( 31), and increase in fringe benefits ( 7). | | | | |
| 111 | For an explanation of the fringe increase please refer to Account 64000. | | | | |
| 112 | | | | | |
| 113 | Costs increase from 2007 to 2008 mainly due to annual labour inflation as increased maintenance requirements ( 19), | | | | |
| 114 | new attraction and retention pay ( 9), non-labour inflation ( 8), and fringe benefits ( 4). | | | | |
| 115 | | | | | |
| 116 | **General** | | | | |
| 117 | | | | | |
| 118 | 88900 - Maintenance Warehouse and Office | 97 | 110 | 118 | 125 |
| 119 | | | | | |
| 120 | Costs increase from 2006 to 2007 mainly due to heating fuel cost inflation. | | | | |
| 121 | | | | | |
| 122 | Costs increase from 2007 to 2008 mainly due to heating fuel cost inflation ( 5) and labour inflation ( 3). | | | | |
| 123 | | | | | |
| 124 | **Public Information** | | | | |
| 125 | | | | | |
| 126 | 70100 - Public Information Administration | 101 | 64 | 100 | 106 |
| 127 | | | | | |
| 128 | Costs decrease for 2006 to 2007 mainly due to decrease labour due to a vacancy in the marketing and communications | | | | |
| 129 | manager position. | | | | |
| 130 | | | | | |
| 131 | Costs increase from 2007 to 2008 mainly due to increased outsourcing costs for website development maintenance and | | | | |
| 132 | other communications costs. | | | | |
| 133 | | | | | |
| 134 | 70200 - General Public Information | 54 | 29 | 28 | 30 |
| 135 | | | | | |
| 136 | Costs decrease from 2006 to 2007 due to one-time commitments for 2007 Canada Winter Games funding in 2006. | | | | |
| 137 | | | | | |
| 138 | 71000 - Supervision | 34 | 31 | 35 | 49 |
| 139 | | | | | |
| 140 | Costs increase from 2008 to 2009 due to the return to normal staffing levels after billing system implementation complete ( 12) | | | | |
| 141 | as well as labour inflation ( 2). | | | | |
| 142 | | | | | |

| Line No. | Description | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|
| 143 | **Customer accounting** | | | | |
| 144 | | | | | |
| 145 | 71100 - Customer Applications and Service Orders | 283 | 335 | 407 | 450 |
| 146 | | | | | |
| 147 | Costs increase from 2006 to 2007 mainly due to an increase in fringe benefits ( 32). For an explanation of this fringe increase | | | | |
| 148 | please refer to Account 64000. This increase is also due to labour inflation ( 15), and non-labour inflation ( 5). | | | | |
| 149 | | | | | |
| 150 | Costs increase from 2007 to 2008 mainly due to labour inflation ( 41), new attraction and retention pay ( 23), fringe | | | | |
| 151 | benefits ( 5) and other inflation ( 3) | | | | |
| 152 | | | | | |
| 153 | Costs increase from 2008 to 2009 mainly due to labour inflation. | | | | |
| 154 | | | | | |
| 155 | 71200 - Meter Reading | 391 | 464 | 436 | 471 |
| 156 | | | | | |
| 157 | Costs increase from 2006 to 2007 mainly due to increase in fringe benefits ( 38). For an explanation of this fringe increase | | | | |
| 158 | please refer to Account 64000. This increase is also due to higher labour costs ( 23), annual labour inflation ( 10), | | | | |
| 159 | and non-labour inflation ( 2). | | | | |
| 160 | | | | | |
| 161 | Costs decrease from 2007 to 2008 mainly due to utilization of non-journeyman labour for meter reading services | | | | |
| 162 | as an additional Field Service Representative was added to the labour compliment ( 40) and related fringe benefits | | | | |
| 163 | decrease ( 14). This is offset by labour inflation ( 11), new attraction and retention pay ( 9) and other dollar inflation ( 6). | | | | |
| 164 | | | | | |
| 165 | Costs increase from 2008-2009 mainly due to inflation. | | | | |
| 166 | | | | | |
| 167 | 71300 - Customer Billing & Accounting | 474 | 513 | 572 | 646 |
| 168 | | | | | |
| 169 | Costs increase from 2006 to 2007 mainly due to inflation ( 24) and an increase in fringe benefits ( 15). For an explanation | | | | |
| 170 | of the fringe increase please refer to Account 64000. | | | | |
| 171 | | | | | |
| 172 | Costs increase from 2007 to 2008 due to implementing the new ATCO-CIS billing system. The new system conversion | | | | |
| 173 | is planned to be completed by July 2008. | | | | |
| 174 | | | | | |
| 175 | Costs increase from 2008 to 2009 due to full year impact of the new ATCO-CIS billing system costs. | | | | |
| 176 | | | | | |
| 177 | 71400 - Revenue Collections | 167 | 181 | 162 | 258 |
| 178 | | | | | |
| 179 | Costs increase from 2006 to 2007 mainly due to an increase in fringe benefits ( 18). For an explanation of this fringe increase | | | | |
| 180 | please refer to Account 64000. This increase is also due to labour inflation ( 5) offset by decreased payment agent costs | | | | |
| 181 | from closure of payment agents in some communities outside Whitehorse ( 9). | | | | |
| 182 | | | | | |
| 183 | Costs decrease from 2007 to 2008 mainly due to decreased labour and fringe as we migrate off of taking payments at | | | | |
| 184 | our service building in Watson Lake. | | | | |
| 185 | | | | | |
| 186 | Costs increase from 2008 to 2009 due to the commencement of accepting credit cards for customer payments. | | | | |
| 187 | | | | | |
| 188 | 71500 - Collection of Delinquent Accounts | 121 | 124 | 142 | 158 |
| 189 | | | | | |
| 190 | Costs increase from 2007 to 2008 due to labour inflation ( 14) and non-labour inflation ( 4). | | | | |
| 191 | | | | | |
| 192 | Costs increase from 2008 to 2009 due to labour inflation. | | | | |
| 193 | | | | | |

| Line No. | Description | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|
| 194 | **Administration and general** | | | | |
| 195 | | | | | |
| 196 | 72100 - Administrative | 1,149 | 1,176 | 1,331 | 1,399 |
| 197 | | | | | |
| 198 | Costs increase from 2007 to 2008 mainly due increased head office support for phase I & II GRA filings that are forecast on a levelized | | | | |
| 199 | basis as well as increased financial reporting requirements ( 80). The increase is also due to other inflation ( 50), and labour inflation ( 25). | | | | |
| 200 | | | | | |
| 201 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | |
| 202 | | | | | |
| 203 | 72200 - Administration Corporate | 27 | 14 | 30 | 32 |
| 204 | | | | | |
| 205 | Costs decrease from 2006 to 2007 due to a decrease in regulatory costs and costs awards credited in 2007 from | | | | |
| 206 | previous year. | | | | |
| 207 | | | | | |
| 208 | Cost increase from 2007 to 2008 is mainly due to the absence of any credits for regulatory cost awards from YUB. | | | | |
| 209 | | | | | |
| 210 | 72300 - Insurance | 194 | 190 | 231 | 244 |
| 211 | | | | | |
| 212 | Cost increase from 2007 to 2008 mainly due to an updated Comprehensive General Liability (CGL) corporate allocation methodology. | | | | |
| 213 | | | | | |
| 214 | 72500 - Employee Expenses | 208 | 229 | 222 | 312 |
| 215 | | | | | |
| 216 | Costs increase from 2006 to 2007 mainly due to labour from employee illness. | | | | |
| 217 | | | | | |
| 218 | Costs increase from 2008 to 2009 mainly due to employee northern travel benefits increasing for attraction and retention. | | | | |
| 219 | | | | | |
| 220 | 72600 - Training and Safety | 247 | 297 | 449 | 484 |
| 221 | | | | | |
| 222 | Costs increased from 2006 to 2007 mainly due an increase in fringe benefits ( 25). For an explanation of this fringe increase | | | | |
| 223 | please refer to Account 64000. This increase is also due to labour from increased apprenticeship training ( 13), | | | | |
| 224 | and increased other costs for driver training and other programs ( 12). | | | | |
| 225 | | | | | |
| 226 | Costs increase from 2007 to 2008 mainly due to increased labour for HS&E management position and other staff | | | | |
| 227 | labour ( 102), other dollar escalations for safety and training programs ( 30), and fringe benefits ( 20). | | | | |
| 228 | New training initiatives include: continuation of apprenticeship training for two apprentices; new core certification compliance | | | | |
| 229 | training (per revised Government occupational health and safety Act); new national transport safety compliance training; | | | | |
| 230 | management of environmental affairs with increased rigor around environmental policy issues; journeyman | | | | |
| 231 | certification refresher training; transportation of dangerous goods by air; WHIMS; and advanced driver training. | | | | |
| 232 | | | | | |
| 233 | 72700 - Relocation | 190 | 93 | 182 | 77 |
| 234 | | | | | |
| 235 | Costs decrease from 2006 to 2007 mainly due to lower costs due to unfilled vacancies. | | | | |
| 236 | | | | | |
| 237 | Costs increase from 2007 to 2008 mainly due to higher costs because of out of Yukon hires requiring moving | | | | |
| 238 | and relocation expenses. | | | | |
| 239 | | | | | |
| 240 | Costs decrease from 2008 to 2009 due to lower staff turnover anticipated. | | | | |
| 241 | | | | | |
| 242 | 72900 - Audit Legal Fees & Special Studies | 106 | 88 | 95 | 100 |
| 243 | | | | | |
| 244 | Costs decrease from 2006 to 2007 mainly due to decreased legal costs in 2006. | | | | |
| 245 | | | | | |
| 246 | Costs increase from 2007 to 2008 mainly due to an increase in audit fees. | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Affiliate Charges included in Operations and Maintenance**
**( 000s)**

**Schedule 5.3**

| Line No. | O M Category | Affiliate Company | Services Provided | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|
| 1 | Details of Affiliate Costs in Operations and Maintenance | | | | | | | |
| 2 | 87500 - Meters and Meter Testing | ATCO Electric | Metering Services | | 37 | 32 | 40 | 42 |
| 3 | | | | | | | | |
| 4 | 72100 - Administrative | ATCO Electric | After Hours Answering | | - | 28 | 26 | 26 |
| 5 | 71200 - Meter Reading | ATCO Gas | Meter Services | | 34 | 37 | 39 | 41 |
| 6 | | | | | | | | |
| 7 | 72100 - Administrative Expenses | ATCO Gas | Office Services | | 8 | 14 | 15 | 16 |
| 8 | | | | | | | | |
| 9 | 72100 - Administrative Expenses | ATCO I-Tek | Information Technology | Note 1 | 311 | 331 | 353 | 370 |
| 10 | | | | | | | | |
| 11 | 71300 - Customer Billing and Accounting | ATCO I-Tek Business Services | Billing System Services | Note 1 | 354 | 366 | 434 | 484 |
| 12 | | | | | | | | |
| 13 | | | | | | | | |
| 14 | Details of Head Office Costs | | | | | | | |
| 15 | 72100 - Administrative Expenses | ATCO Electric | Governance | | 22 | 22 | 24 | 25 |
| 16 | 72100 - Administrative Expenses | | Human Resources | | 67 | 67 | 87 | 90 |
| 17 | 72100 - Administrative Expenses | | Health and Safety | | 18 | 19 | - | - |
| 18 | 72100 - Administrative Expenses | | Regulatory Phase II | | - | - | 12 | 3 |
| 19 | 72100 - Administrative Expenses | | Financial Reporting and Regulatory Phase I | | 25 | 26 | 87 | 73 |
| 20 | 72100 - Administrative Expenses | | Payroll | | 7 | 6 | 9 | 10 |
| 21 | 72100 - Administrative Expenses | | Use of Systems | | 10 | 8 | 5 | 6 |
| 22 | 72100 - Administrative Expenses | | information Technology | | 3 | 3 | 2 | 3 |
| 23 | | | Total Head Office Fees | | 152 | 151 | 226 | 210 |
| 24 | | | | | | | | |
| 25 | 72100 - Administrative Expenses | ATCO Electric | Material Management | | 12 | 9 | - | - |
| 26 | | | | | | | | |
| 27 | | | | | | | | |
| 28 | | | | | | | | |
| 29 | | | | | | | | |
| 30 | Total Affiliate Costs included in Operations and Maintenance | | | | 908 | 968 | 1,133 | 1,189 |

31 Note 1 - The test period forecast costs are placeholders pending the completion of a benchmarking study. Please refer to Affiliate Costs write-up on Pages 5-3 & 5-4.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Depreciation Expense**

**Schedule 7.1**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | General Provision | S. 7.2, 7.3 L.50 | 4,062 | 4,335 | 4,580 | 5,052 |
| 2 | Amortization of Differences | S.7.5 L. 50 | (140) | (140) | (191) | (191) |
| 3 | Vehicle Depreciation Capitalized | | (21) | (24) | (24) | (24) |
| 4 | Total Depreciation Expense | S.8.6 L.11 | 3,901 | 4,171 | 4,365 | 4,837 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Calculation of Depreciation Expense 2008**

**Schedule 7.2**

| Line No. | Acct. | Description | Cross Ref. | 2008 Opening PPE | Depreciation Rate | Depreciation on Opening Balance | Capital Additions | Depreciation on Capital Additions | 2008 Total Deprecation |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | Production - Hydro | | | | | | | |
| 2 | | | | | | | | | - |
| 3 | 422 00 | Hydro Structures | | 259 | 3.70 | 10 | 449 | 8 | 18 |
| 4 | 423 00 | Hydro Resv, Dams & Waterways | | 757 | 3.70 | 28 | - | - | 28 |
| 5 | 425 00 | Hydro Generators | | 273 | 3.70 | 10 | - | - | 10 |
| 6 | 426 00 | Hydro Accessory Electrical Equip | | 105 | 3.70 | 4 | - | - | 4 |
| 7 | 427 00 | Hydro Misc Equip | | 24 | 3.70 | 1 | - | - | 1 |
| 8 | | Total Production - Hydro | | 1,418 | | 53 | 449 | 8 | 61 |
| 9 | | | | | | | | | |
| 10 | | Production - Diesel | | | | | | | |
| 11 | 442 00 | Structures and improvement - Other | | 1,498 | 2.74 | 41 | - | - | 41 |
| 12 | 444 00 | Fuel Holders, Proucers, & Acc. Equipment - Other | | 2,137 | 3.90 | 83 | 87 | 2 | 85 |
| 13 | 445 00 | Generating Equipment & Prime Mover - Other | | 8,444 | 4.06 | 343 | 347 | 7 | 350 |
| 14 | 446 00 | Accessory Electric Equipment - Other | | 2,142 | 3.00 | 64 | 91 | 1 | 65 |
| 15 | 447 00 | Misc. Power Plant Equipment - Other | | 643 | 3.31 | 21 | 27 | - | 21 |
| 16 | | Total Production - Diesel | | 14,864 | | 552 | 552 | 10 | 562 |
| 17 | | | | | | | | | |
| 18 | | Transmission | | | | | | | |
| 19 | 457 00 | Substation Equipment | | 1,401 | 2.55 | 36 | - | - | 36 |
| 20 | | Total Transmission | | 1,401 | | 36 | - | - | 36 |
| 21 | | | | | | | | | |
| 22 | | Distribution Plant | | | | | | | |
| 23 | 471 00 | Land Rights | | 929 | 1.52 | 14 | - | - | 14 |
| 24 | 473 00 | Poles, Towers & Fixtures | | 22,740 | 4.27 | 971 | 1,689 | 36 | 1,007 |
| 25 | 474 00 | Overhead Conductor | | 15,092 | 4.57 | 690 | 1,186 | 27 | 717 |
| 26 | 474 10 | Services - Overhead | | 2,306 | 2.62 | 60 | 183 | 2 | 62 |
| 27 | 475 00 | Underground Conductor | | 17,426 | 2.22 | 387 | 1,385 | 15 | 402 |
| 28 | 475 10 | Services - Underground | | 2,547 | 2.63 | 67 | 202 | 3 | 70 |
| 29 | 476 10 | Meters | | 1,263 | 9.00 | 114 | (82) | - | 114 |
| 30 | 476 30 | AMR - Meters | | 8 | 4.54 | - | 330 | 7 | 7 |
| 31 | 477 10 | Substation Equipment | | 3,132 | 2.92 | 91 | - | - | 91 |
| 32 | 478 10 | Street Lighting | | 7,699 | 4.54 | 350 | 498 | 11 | 361 |
| 33 | 478 20 | Sentinel Lights | | 285 | 3.03 | 9 | | - | 9 |
| 34 | 479 10 | Line Transformers | | 17,596 | 3.19 | 561 | 1,311 | 21 | 582 |
| 35 | | Total Distribution Plant | | 91,023 | | 3,314 | 6,702 | 122 | 3,436 |
| 36 | | | | | | | | | |
| 37 | | General Plant | | | | | | | |
| 38 | 482 00 | Structures & Improvements | | 3,184 | 3.03 | 96 | 199 | 3 | 99 |
| 39 | 483 00 | Office Furniture & Equipment | | 220 | 4.49 | 10 | (25) | - | 10 |
| 40 | 483.20 | Computer Equipment | | 37 | 20.00 | 7 | 0 | - | 7 |
| 41 | 484 00 | Transportation & Mobile Equipment | | 2,207 | 8.66 | 191 | 147 | 6 | 197 |
| 42 | 485 00 | Tool & Work Equipment | | 501 | 6.54 | 33 | (9) | - | 33 |
| 43 | 486 00 | Communication Structures & Equipment | | 491 | 5.79 | 28 | 102 | 3 | 31 |
| 44 | 488 20 | Company Housing | | 388 | 2.47 | 10 | 19 | - | 10 |
| 45 | 491 00 | Franchise & Consent | | 1 | 0.00 | - | - | - | - |
| 46 | 496 xx | New ATCO-CIS | | - | 10.00 | - | 1,488 | 74 | 74 |
| 47 | 496 05 | Oracle Financials | | 235 | 10.00 | 24 | | - | 24 |
| 48 | | Total General Plant | | 7,266 | | 399 | 1,921 | 86 | 485 |
| 49 | | | | | | | | | |
| 50 | | Plant Studied | | 115,972 | | 4,354 | 9,624 | 226 | 4,580 |
| 51 | | Plant Not Studied - Land | | 479 | | | | | |
| 52 | | Total Plant | S.8.6 L.6 | 116,451 | | | | | |
| 53 | | | | | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Calculation of Depreciation Expense 2009**

**Schedule 7.3**

| Line No. | Acct. | Description | Cross Ref. | 2009 Opening PPE | Depreciation Rate | Depreciation on Opening Balance | Capital Additions | Depreciation on Capital Additions | 2009 Total Deprecation |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | Production - Hydro | | | | | | | |
| 2 | | | | | | | | | |
| 3 | 422 00 | Hydro Structures | | 259 | 3.70 | 10 | - | - | 10 |
| 4 | 423 00 | Hydro Resv, Dams & Waterways | | 1,206 | 3.70 | 45 | 687 | 13 | 58 |
| 5 | 425 00 | Hydro Generators | | 273 | 3.70 | 10 | - | - | 10 |
| 6 | 426 00 | Hydro Accessory Electrical Equip | | 105 | 3.70 | 4 | - | - | 4 |
| 7 | 427 00 | Hydro Misc Equip | | 24 | 3.70 | 1 | - | - | 1 |
| 8 | | Total Production - Hydro | | 1,867 | | 70 | 687 | 13 | 83 |
| 9 | | | | | | | | | |
| 10 | | Production - Diesel | | | | | | | |
| 11 | 442 00 | Structures and improvement - Other | | 1,498 | 2.74 | 41 | - | - | 41 |
| 12 | 444 00 | Fuel Holders, Proucers, & Acc. Equipment - Other | | 2,223 | 3.90 | 87 | 386 | 8 | 95 |
| 13 | 445 00 | Generating Equipment & Prime Mover - Other | | 8,792 | 4.06 | 357 | 1,530 | 31 | 388 |
| 14 | 446 00 | Accessory Electric Equipment - Other | | 2,232 | 3.00 | 67 | 390 | 6 | 73 |
| 15 | 447 00 | Misc. Power Plant Equipment - Other | | 670 | 3.31 | 22 | 117 | 2 | 24 |
| 16 | | Total Production - Diesel | | 15,416 | | 574 | 2,424 | 47 | 621 |
| 17 | | | | | | | | | |
| 18 | | Transmission | | | | | | | |
| 19 | 457 00 | Substation Equipment | | 1,401 | 2.55 | 36 | - | - | 36 |
| 20 | | Total Transmission | | 1,401 | | 36 | - | - | 36 |
| 21 | | | | | | | | | |
| 22 | | Distribution Plant | | | | | | | |
| 23 | 471 00 | Land Rights | | 929 | 1.52 | 14 | - | - | 14 |
| 24 | 473 00 | Poles, Towers & Fixtures | | 24,430 | 4.27 | 1,043 | 1,612 | 34 | 1,077 |
| 25 | 474 00 | Overhead Conductor | | 16,278 | 4.57 | 744 | 1,065 | 24 | 768 |
| 26 | 474 10 | Services - Overhead | | 2,489 | 2.62 | 65 | 165 | 2 | 67 |
| 27 | 475 00 | Underground Conductor | | 18,811 | 2.22 | 418 | 1,246 | 14 | 432 |
| 28 | 475 10 | Services - Underground | | 2,749 | 2.63 | 72 | 182 | 2 | 74 |
| 29 | 476 10 | Meters | | 1,181 | 9.00 | 106 | (341) | - | 106 |
| 30 | 476 30 | AMR - Meters | | 338 | 4.54 | 15 | 2,720 | 62 | 77 |
| 31 | 477 10 | Substation Equipment | | 3,132 | 2.92 | 91 | 580 | 8 | 99 |
| 32 | 478 10 | Street Lighting | | 8,197 | 4.54 | 372 | 487 | 11 | 383 |
| 33 | 478 20 | Sentinel Lights | | 285 | 3.03 | 9 | - | - | 9 |
| 34 | 479 10 | Line Transformers | | 18,907 | 3.19 | 603 | 1,178 | 19 | 622 |
| 35 | | Total Distribution Plant | | 97,725 | | 3,552 | 8,893 | 176 | 3,728 |
| 36 | | | | | | | | | |
| 37 | | General Plant | | | | | | | |
| 38 | 482 00 | Structures & Improvements | | 3,383 | 3.03 | 103 | 161 | 2 | 105 |
| 39 | 483 00 | Office Furniture & Equipment | | 194 | 4.49 | 9 | (28) | - | 9 |
| 40 | 483.20 | Computer Equipment | | 38 | 20.00 | 8 | (1) | - | 8 |
| 41 | 484 00 | Transportation & Mobile Equipment | | 2,354 | 8.66 | 204 | 172 | 7 | 211 |
| 42 | 485 00 | Tool & Work Equipment | | 492 | 6.54 | 32 | (2) | - | 32 |
| 43 | 486 00 | Communication Structures & Equipment | | 593 | 5.79 | 34 | 54 | 2 | 36 |
| 44 | 488 20 | Company Housing | | 407 | 2.47 | 10 | 19 | - | 10 |
| 45 | 491 00 | Franchise & Consent | | 1 | 0.00 | - | - | - | - |
| 46 | 496 xx | New ATCO-CIS | | 1,488 | 10.00 | 149 | - | - | 149 |
| 47 | 496 05 | Oracle Financials | | 235 | 10.00 | 24 | - | - | 24 |
| 48 | | Total General Plant | | 9,187 | | 573 | 375 | 11 | 584 |
| 49 | | | | | | | | | |
| 50 | | Plant Studied | | 125,597 | | 4,805 | 12,379 | 247 | 5,052 |
| 51 | | Plant Not Studied -Land | | 479 | | | | | |
| 52 | | Total Plant | S.8.6 L.6 | 126,076 | | | | | |
| 53 | | | | | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Amortization of Differences**

**Schedule 7.4**

| Line No. | Acct. | Description | Cross Ref. | YFR Curve | Life | Net Salvage | Depn. Rates | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Production - Hydro | | | | | | | | | |
| 2 | | | | | | | | | | | |
| 3 | 422 00 | Hydro Structures | | R3 | 30 | -10 | 3.70 | (11) | (11) | (17) | (17) |
| 4 | 423 00 | Hydro Resv, Dams & Waterways | | R3 | 30 | -10 | 3.70 | - | - | - | - |
| 5 | 425 00 | Hydro Generators | | R3 | 30 | -10 | 3.70 | - | - | - | - |
| 6 | 426 00 | Hydro Accessory Electrical Equip | | R3 | 30 | -10 | 3.70 | - | - | - | - |
| 7 | 427 00 | Hydro Misc Equip | | R3 | 30 | -10 | 3.70 | - | - | - | - |
| 8 | | Total Production - Hydro | | | | | | (11) | (11) | (17) | (17) |
| 9 | | | | | | | | | | | |
| 10 | | Production - Diesel | | | | | | | | | |
| 11 | 442 00 | Structures and improvement - Other | | R2.5 | 40 | 0 | 2.74 | - | - | (2) | (2) |
| 12 | 444 00 | Fuel Holders, Proucers, & Acc. Equipment - Other | | R4 | 35 | -30 | 3.90 | (1) | (1) | (3) | (3) |
| 13 | 445 00 | Generating Equipment & Prime Mover - Other | | R2.5 | 27 | -10 | 4.06 | (28) | (28) | (24) | (24) |
| 14 | 446 00 | Accessory Electric Equipment - Other | | R3 | 35 | 0 | 3.00 | (7) | (7) | (16) | (16) |
| 15 | 447 00 | Misc. Power Plant Equipment - Other | | R3 | 35 | -5 | 3.31 | (1) | (1) | (2) | (2) |
| 16 | | Total Production - Diesel | | | | | | (37) | (37) | (47) | (47) |
| 17 | | | | | | | | | | | |
| 18 | | Transmission | | | | | | | | | |
| 19 | 457 00 | Substation Equipment | | R4 | 40 | 0 | 2.55 | (2) | (2) | (4) | (4) |
| 20 | | Total Transmission | | | | | | (2) | (2) | (4) | (4) |
| 21 | | | | | | | | | | | |
| 22 | | Distribution Plant | | | | | | | | | |
| 23 | 471 00 | Land Rights | | R3 | 75 | 0 | 1.52 | (0) | (0) | - | - |
| 24 | 473 00 | Poles, Towers & Fixtures | | R3 | 40 | -60 | 4.27 | 3 | 3 | (47) | (47) |
| 25 | 474 00 | Overhead Conductor | | R3 | 40 | -70 | 4.57 | (8) | (8) | 19 | 19 |
| 26 | 474 10 | Services - Overhead | | R3 | 40 | 0 | 2.62 | (5) | (5) | (10) | (10) |
| 27 | 475 00 | Underground Conductor | | R4 | 50 | -5 | 2.22 | (5) | (5) | 1 | 1 |
| 28 | 475 10 | Services - Underground | | R4 | 40 | 0 | 2.63 | - | - | (6) | (6) |
| 29 | 476 10 | Meters | | n a | 0 | 0 | 9.00 | 24 | 24 | - | - |
| 30 | 476 30 | AMR - Meters | | S2 | 25 | 0 | 4.54 | | | | |
| 31 | 477 10 | Substation Equipment | | R3 | 35 | 0 | 2.92 | (5) | (5) | - | - |
| 32 | 478 10 | Street Lighting | | R3 | 25 | -10 | 4.54 | (15) | (15) | (25) | (25) |
| 33 | 478 20 | Sentinel Lights | | R2 | 23 | 10 | 3.03 | (11) | (11) | - | - |
| 34 | 479 10 | Line Transformers | | R3 | 35 | -5 | 3.19 | (25) | (25) | (69) | (69) |
| 35 | | Total Distribution Plant | | | | | | (47) | (47) | (137) | (137) |
| 36 | | | | | | | | | | | |
| 37 | | General Plant | | | | | | | | | |
| 38 | 482 00 | Structures & Improvements | | R4 | 32 | 5 | 3.03 | (3) | (3) | 3 | 3 |
| 39 | 483 00 | Office Furniture & Equipment | | SQ | 15 | 0 | 4.49 | - | - | 3 | 3 |
| 40 | 483.20 | Computer Hardware Software | | SQ | 5 | 0 | 20.00 | (14) | (14) | - | - |
| 41 | 484 00 | Transportation & Mobile Equipment | | R0.5 | 10 | 20 | 8.66 | (33) | (33) | - | - |
| 42 | 485 00 | Tool & Work Equipment | | SQ | 15 | 0 | 6.54 | 6 | 6 | (3) | (3) |
| 43 | 486 00 | Communication Structures & Equipment | | SQ | 15 | 0 | 5.79 | 1 | 1 | 11 | 11 |
| 44 | 488 20 | Company Housing | | R3 | 40 | 10 | 2.47 | | | | |
| 45 | 491 00 | Franchise & Consent | | | | | 0.00 | - | - | - | - |
| 46 | 496 xx | New ATCO-CIS | | | | | 10.00 | | | | |
| 47 | 496 05 | Oracle Financials | | S3 | 10 | 0 | 10.00 | - | - | - | - |
| 48 | | Total General Plant | | | | | | (43) | (43) | 14 | 14 |
| 49 | | | | | | | | | | | |
| 50 | | Total Amortization of Differences | S. 7.1 L 2 | | | | | (140) | (140) | (191) | (191) |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Return on Rate Base**
**( 000s)**

**Schedule 8.1**

| Line No. | Description | Cross Ref. | Mid Year Balance | Ratio | Mid Year Rate Base | Mid Year Cost Rate | Return |
|---|---|---|---|---|---|---|---|
| 1 | **2006 Actuals** | | | | | | |
| 2 | Long-term debt | S.8.2 L.18 | 22,475 | 57.18 | 23,424 | 7.14 | 1,673 |
| 3 | Common stock | | 16,280 | 41.42 | 16,967 | 10.67 | 1,811 |
| 4 | No Cost Capital | S.8.4 L.8 | 549 | 1.40 | 572 | 0.00 | - |
| 5 | Total | S.8.5 L.21<br>S.1.1 L.15 | 39,304 | 100 | 40,963 | 8.51 | 3,484 |
| 6 | **2007 Actual** | | | | | | |
| 7 | Long-term debt | S.8.2 L.36 | 23,800 | 57.60 | 25,117 | 7.03 | 1,766 |
| 8 | Common stock | | 16,890 | 40.87 | 17,825 | 10.37 | 1,848 |
| 9 | No Cost Capital | S.8.4 L.8 | 632 | 1.53 | 666 | 0.00 | - |
| 10 | Total | S.8.5 L.21<br>S.1.1 L.15 | 41,322 | 100 | 43,608 | 8.29 | 3,614 |
| 11 | **2008 Test Period** | | | | | | |
| 12 | Long-term debt | S.8.3 L.19 | 24,575 | 54.23 | 24,838 | 7.01 | 1,741 |
| 13 | Common stock | | 20,071 | 44.29 | 20,286 | 9.25 | 1,877 |
| 14 | No Cost Capital | S.8.4 L.8 | 669 | 1.48 | 676 | 0.00 | - |
| 15 | Total | S.8.5 L.21<br>S.1.1 L.15 | 45,315 | 100 | 45,800 | 7.90 | 3,618 |
| 16 | **2009 Test Period** | | | | | | |
| 17 | Long-term debt | S.8.3 L.38 | 26,950 | 51.81 | 26,498 | 6.83 | 1,810 |
| 18 | Common stock | | 24,376 | 46.86 | 23,967 | 9.25 | 2,216 |
| 19 | No Cost Capital | S.8.4 L.8 | 695 | 1.34 | 683 | 0.00 | - |
| 20 | Total | S.8.5 L.21<br>S.1.1 L.15 | 52,021 | 100 | 51,149 | 7.87 | 4,026 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Debt Capital Employed and Embedded Cost**
**( 000's)**

**Schedule 8.2**

| Line No. | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **2006 Actuals** | | | | | | **Net Capital Employed** | | | | | |
| 2 | | | | | | Principal | | Per 100 of | | Principal | | Average |
| 3 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | Outstanding | Carrying | Embedded |
| 4 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | **31-Dec-06** | **Cost** | **Cost Rate** |
| 5 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 6 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 7 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 8 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 9 | | L | 06-02-2000 | 7.00 | 2008 | 600 | 600 | 100.00 | 7.05 | 600 | 42 | |
| 10 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 11 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 12 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 13 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 14 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 15 | Total | | | | | 23,800 | | | | 23,800 | 1,673 | 7.03 |
| 16 | Prior Year | | | | | | | | | 21,150 | 1,538 | 7.27 |
| 17 | Total | | | | | | | | | 44,950 | 3,211 | |
| 18 | Mid Year | | | | | | | | | 22,475 | 1,606 | 7.14 |
| 19 | **2007 Actual** | | | | | | **Net Capital Employed** | | | | | |
| 20 | | | | | | Principal | | Per 100 of | | Principal | | Average |
| 21 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | Outstanding | Carrying | Embedded |
| 22 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | **31-Dec-07** | **Cost** | **Cost Rate** |
| 23 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 24 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 25 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 26 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 27 | | L | 06-02-2000 | 7.00 | 2008 | 600 | 600 | 100.00 | 7.05 | 600 | 42 | |
| 28 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 29 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 30 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 31 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 32 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 33 | Total | | | | | 23,800 | | | | 23,800 | 1,673 | 7.03 |
| 34 | Prior Year | | | | | | | | | 23,800 | 1,673 | 7.03 |
| 35 | Total | | | | | | | | | 47,600 | 3,346 | |
| 36 | Mid Year | | | | | | | | | 23,800 | 1,673 | 7.03 |

**Schedule 8.3**

**Yukon Electrical Limited**
**2008 - 2009 General Rate Application**
**Schedule of Debt Capital Employed and Embedded Cost**
**( 000's)**

| Line No. | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **2008 Test Period** | | | | | | **Net Capital Employed** | | | | | |
| 2 | | | | | | Principal | | Per 100 of | | Principal | | Average |
| 3 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | Outstanding | Carrying | Embedded |
| 4 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | **31-Dec-08** | **Cost** | **Cost Rate** |
| 5 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 6 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 7 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 8 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 9 | | L | 06-02-2000 | 7.00 | 2008 | 0 | 0 | | 7.05 | 0 | 0 | |
| 10 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 11 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 12 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 13 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 14 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 15 | | T | 11-20-2008 | 6.55 | 2038 | 2,150 | 2,150 | 100.00 | 6.60 | 2,150 | 142 | |
| 16 | Total | | | | | 25,350 | | | | 25,350 | 1,773 | 6.99 |
| 17 | Prior Year | | | | | | | | | 23,800 | 1,673 | 7.03 |
| 18 | Total | | | | | | | | | 49,150 | 3,446 | |
| 19 | Mid Year | | | | | | | | | 24,575 | 1,723 | 7.01 |
| 20 | **2009 Test Period** | | | | | | **Net Capital Employed** | | | | | |
| 21 | | | | | | Principal | | Per 100 of | | Principal | | Average |
| 22 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | Outstanding | Carrying | Embedded |
| 23 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | **31-Dec-09** | **Cost** | **Cost Rate** |
| 24 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 25 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 26 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 27 | | L | 06-02-2000 | 7.00 | 2008 | 0 | 0 | | 7.05 | 0 | 0 | |
| 28 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 29 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 30 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 31 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 32 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 33 | | T | 11-20-2008 | 6.55 | 2038 | 2,150 | 2,150 | 100.00 | 6.60 | 2,150 | 142 | |
| 34 | | U | 11-20-2009 | 6.55 | 2039 | 5,200 | 5,200 | 100.00 | 6.60 | 5,200 | 343 | |
| 35 | Total | | | | | 28,550 | | | | 28,550 | 1,909 | 6.69 |
| 36 | Prior Year | | | | | | | | | 25,350 | 1,773 | 6.99 |
| 37 | Total | | | | | | | | | 53,900 | 3,682 | |
| 38 | Mid Year | | | | | | | | | 26,950 | 1,841 | 6.83 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Continuity Schedule of No Cost Capital**
**( 000s)**

**Schedule 8.4**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **No Cost Capital** | | | | | |
| 2 | **Deferred Pension and Regulatory Asset Liability** | | | | | |
| 3 | | | | | | |
| 4 | **Mid-Year Balance Summary** | | | | | |
| 5 | Defined Benefit Pension | L.16 | 443 | 514 | 537 | 537 |
| 6 | Other Post Employment Benefits (OPEB) | L.23 | 172 | 171 | 171 | 171 |
| 7 | Injuries & Damages | L.30 | (66) | (53) | (39) | (13) |
| 8 | **Total No Cost Capital Mid-Year Balance** | S.8.1 L.4,9,14,19 | 549 | 632 | 669 | 695 |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | **Other Post Employment Benefits (OPEB)** | | | | | |
| 12 | Balance at beginning of year | | 395 | 490 | 537 | 537 |
| 13 | Add: Charges | | 123 | 103 | 60 | 60 |
| 14 | Less: Cash Payments | | (28) | (56) | (60) | (60) |
| 15 | Balance at end of year | | 490 | 537 | 537 | 537 |
| 16 | Mid-Year balance | (L.12 L.15) 2 | 443 | 514 | 537 | 537 |
| 17 | | | | | | |
| 18 | **Defined Benefit Pension** | | | | | |
| 19 | Balance at beginning of year | | 173 | 171 | 171 | 171 |
| 20 | Add: Charges | | 9 | 520 | 579 | 629 |
| 21 | Less: Cash Payments | | (11) | (520) | (579) | (629) |
| 22 | Balance at end of year | | 171 | 171 | 171 | 171 |
| 23 | Mid-Year balance | (L.19 L.22) 2 | 172 | 171 | 171 | 171 |
| 24 | | | | | | |
| 25 | **Injuries Damages** | | | | | |
| 26 | Balance at beginning of year | | (78) | (54) | (52) | (26) |
| 27 | Add: Write-off | S.10.1 L.8 | 75 | 75 | 86 | 86 |
| 28 | Less: Costs | S.10.1 L.17 | (51) | (73) | (60) | (60) |
| 29 | Balance at end of year | | (54) | (52) | (26) | 0 |
| 30 | Mid-Year balance | (L.26 L.29) 2 | (66) | (53) | (39) | (13) |
| 31 | | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Computation of Rate Base**
**( 000s)**

**Schedule 8.5**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Property, Plant and Equipment** | | | | | |
| 2 | Year end balance | S.8.6 L.8 | 110,103 | 117,486 | 126,696 | 139,035 |
| 3 | Deduct: | | | | | |
| 4 | Accumulated depreciation | S.8.6 L.14 | 49,959 | 53,768 | 57,693 | 61,314 |
| 5 | Construction-in-progress | S.9.1 L.26 | 871 | 1,035 | 620 | 580 |
| 6 | Total deductions | | 50,830 | 54,803 | 58,313 | 61,894 |
| 7 | **Net plant in Service** | | | | | |
| 8 | Current year-end balance | | 59,273 | 62,683 | 68,382 | 77,140 |
| 9 | Previous year-end balance | | 56,140 | 59,273 | 62,683 | 68,382 |
| 10 | Total | | 115,413 | 121,956 | 131,066 | 145,522 |
| 11 | Mid-year balance | | 57,707 | 60,978 | 65,533 | 72,761 |
| 12 | Mid-year rate deferred charges credits | S.8.8 L.13 | 0 | 309 | 757 | 570 |
| 13 | Working capital | S.8.9 L.29 | 3,683 | 4,078 | 2,805 | 2,650 |
| 14 | **Gross Rate Base** | | 61,390 | 65,365 | 69,095 | 75,981 |
| 15 | Deduct: | | | | | |
| 16 | **Contributions for extensions** | | | | | |
| 17 | Current year-end balance | S.8.11 L.11 | 21,017 | 22,496 | 24,093 | 25,571 |
| 18 | Previous year-end balance | | 19,837 | 21,017 | 22,496 | 24,093 |
| 19 | Total | | 40,854 | 43,513 | 46,589 | 49,664 |
| 20 | Mid-year balance | | 20,427 | 21,757 | 23,295 | 24,832 |
| 21 | **Net Rate Base** | S.8.1 L.5,10,15,20 | 40,963 | 43,608 | 45,800 | 51,149 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Property, Plant and Equipment**
**( 000)**

**Schedule 8.6**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Property, Plant and Equipment** | | | | | |
| 2 | Balance at beginning of year | | 102,602 | 109,232 | 116,451 | 126,076 |
| 3 | Additions | S.9.1 L.25 | 6,872 | 7,645 | 9,975 | 13,544 |
| 4 | Retirement and disposals | S.8.7 L.20 | (242) | (426) | (351) | (1,165) |
| 5 | | S.7.2, 7.3 L.50 | 6,630 | 7,219 | 9,624 | 12,379 |
| 6 | Balance at end of year | S.7.2, 7.3 L.52 | 109,232 | 116,451 | 126,076 | 138,455 |
| 7 | Construction-in-progress | S.9.1 L.26 | 871 | 1,035 | 620 | 580 |
| 8 | Total Property, Plant and Equipment | S.8.5 L.2 | 110,103 | 117,486 | 126,696 | 139,035 |
| 9 | **Accumulated Depreciation** | | | | | |
| 10 | Balance at beginning of year | | 46,441 | 49,959 | 53,768 | 57,693 |
| 11 | Depreciation expense | S.7.1 L.4 | 3,901 | 4,171 | 4,365 | 4,837 |
| 12 | Depreciation capitalized | | 21 | 24 | 24 | 24 |
| 13 | Retirements and dismantling | | (404) | (386) | (464) | (1,240) |
| 14 | Balance at end of year | S.8.5 L.4 | 49,959 | 53,768 | 57,693 | 61,314 |
| 15 | Net Property, Plant and Equipment | | 60,144 | 63,718 | 69,002 | 77,720 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Capital Retirements by Function**
**( 000)**

**Schedule 8.7**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Generation** | | | | | |
| 2 | Other retirements less than 20,000 | | - | (3) | (14) | (14) |
| 3 | Total Generation Retirements | | - | (3) | (14) | (14) |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | **Distribution** | | | | | |
| 7 | Poles, Towers & Fixtures | | (66) | (11) | (68) | (68) |
| 8 | Line transformers | | (18) | (3) | (18) | (18) |
| 9 | Meters | | (49) | (15) | (82) | (896) |
| 10 | Other retirements less than 20,000 | | (7) | (4) | (8) | (8) |
| 11 | Total Distribution Retirements | | (140) | (33) | (176) | (990) |
| 12 | | | | | | |
| 13 | **General Plant** | | | | | |
| 14 | Office Furniture & Equipment | | (42) | (39) | (44) | (44) |
| 15 | Vehicles | | - | (289) | (57) | (57) |
| 16 | Tool & Work Equipment | | (59) | (61) | (59) | (59) |
| 17 | Other retirements less than 20,000 | | (1) | (2) | (1) | (1) |
| 18 | Total General Plant Retirements | | (102) | (390) | (161) | (161) |
| 19 | | | | | | |
| 20 | **Total Capital Retirements** | S.8.6 L.4 | (242) | (426) | (351) | (1,165) |

**Yukon Electrical Company Limited** **Schedule 8.8**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Deferred Charges Credits**
**( 000s)**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Total Deferred Charges Credits Summary** | | | | | |
| 2 | | | | | | |
| 3 | **Write-off Summary** | | | | | |
| 4 | Rate Case Costs | | - | - | (375) | (375) |
| 5 | Diesel Plant Major Overhaul Costs | | - | (108) | (123) | (123) |
| 6 | Fish Lake License Renewal Costs | | - | (79) | (154) | (154) |
| 7 | **Total Write-off** | S.1.1 L.14 | - | (187) | (652) | (652) |
| 8 | | | | | | |
| 9 | **Deferred Credits Mid-Year Balance Summary** | | | | | |
| 10 | Rate Case Reserve | | - | 15 | 203 | 188 |
| 11 | Diesel Plant Major Overhaul Costs | | - | 215 | 399 | 306 |
| 12 | Fish Lake Licence Reserve | | | 79 | 156 | 77 |
| 13 | **Total Deferred Credits Mid-Year Balance** | S.8.5 L.12 | - | 309 | 757 | 570 |
| 14 | | | | | | |
| 15 | Rate Case Costs | | | | | |
| 16 | Balance at beginning of year | | - | - | 30 | 375 |
| 17 | Add: Rate Case Costs | | - | 30 | 720 | - |
| 18 | Less: Rate Case Write-off | | - | - | (375) | (375) |
| 19 | Balance at end of year | | - | 30 | 375 | - |
| 20 | | | | | | |
| 21 | Mid-Year balance | (L.16 L.19) 2 | - | 15 | 203 | 188 |
| 22 | | | | | | |
| 23 | Diesel Plant Major Overhaul Costs | | | | | |
| 24 | Balance at beginning of year | | - | - | 430 | 367 |
| 25 | Add: Watson Lake plant overhaul costs | | - | 538 | 60 | - |
| 26 | Less; Watson Lake plant overhaul Write-off | | - | (108) | (123) | (123) |
| 27 | Balance at end of year | | - | 430 | 367 | 244 |
| 28 | | | | | | |
| 29 | Mid-Year balance | (L.24 L.27) 2 | - | 215 | 399 | 306 |
| 30 | | | | | | |
| 31 | | | | | | |
| 32 | Fish Lake License Renewal Costs | | | | | |
| 33 | Balance at beginning of year | | - | - | 158 | 154 |
| 34 | Add: Fish Lake Costs | | - | 237 | 150 | - |
| 35 | Less: Fish Lake Write-off | | - | (79) | (154) | (154) |
| 36 | Balance at end of year | | - | 158 | 154 | - |
| 37 | | | | | | |
| 38 | Mid-Year balance | (L.33 L.36) 2 | - | 79 | 156 | 77 |
| 39 | | | | | | |

**Yukon Electrical Company Limited** **Schedule 8.9**
**2008 - 2010 General Rate Application**
**Computation of Allowance for Working Capital**
**( 000s)**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | Operating and maintenance | S.1.1 L.9 | 6,969 | 7,290 | 8,758 | 9,317 |
| 2 | Purchased Power | S.1.1 L.7 | 23,239 | 23,647 | 23,846 | 23,494 |
| 3 | Diesel Fuel | S.1.1 L.8 | 2,026 | 2,054 | 5,715 | 5,299 |
| 5 | Property Taxes | S.1.1 L.11 | 230 | 235 | 249 | 261 |
| 6 | Net O&M | | 32,464 | 33,226 | 38,567 | 38,371 |
| 7 | O&M Lag Days | | 19 | 19 | 5 | 5 |
| 8 | Operating Expenses Working Capital | | 1,690 | 1,730 | 573 | 570 |
| 9 | Tax installments | | 1,045 | 1,140 | 422 | 500 |
| 10 | Income Tax Installment Lag Days | | 25 | 25 | 22 | 22 |
| 11 | Tax Installments Working Capital | | 72 | 78 | 25 | 30 |
| 12 | Income taxes receivable (payable) | | 11 | 285 | 0 | (544) |
| 13 | Tax Receivable Lag Days | | 206 | 206 | 204 | 204 |
| 14 | Taxes Payable Working Capital | | 6 | 161 | 0 | (304) |
| 15 | Inventory (Three year average) | | 1,516 | 1,702 | 1,858 | 1,942 |
| 16 | GST Impact on working capital | S.8.10 L.38 | 146 | 141 | 108 | 117 |
| 17 | Return - Long Term Debt | | 1,673 | 1,766 | 1,741 | 1,810 |
| 18 | Combined Long Term Debt Lag Days | | (46) | (46) | (52) | (52) |
| 19 | Long Term Debt Working Capital | | (212) | (224) | (248) | (258) |
| 20 | Return - 50 of Common Equity | | 906 | 924 | 939 | 1,108 |
| 21 | Dividend Lag Days | | (1) | (1) | (4) | (4) |
| 22 | Common Equity (Dividend) Working Capital | | (2) | (3) | (10) | (12) |
| 23 | Return - 50 of Common Equity | | 906 | 924 | 939 | 1,108 |
| 24 | Depreciation Lag Days | | 45 | 45 | 42 | 42 |
| 25 | Common Equity (Retained Earnings) Working Capital | | 112 | 114 | 108 | 127 |
| 26 | Net Depreciation | | 2,893 | 3,079 | 3,402 | 3,809 |
| 27 | Depreciation Lag Days | | 45 | 45 | 42 | 42 |
| 28 | Depreciation Working Capital | | 357 | 380 | 391 | 438 |
| 29 | Working capital | S.8.5 L.13 | 3,683 | 4,078 | 2,805 | 2,650 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Effect of GST on Working Capital**
**( 000s)**

Schedule 8.10

| Line No. | Description | Cross Ref. | | Actual 2006 | Forecast 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | REVENUE: | | | | | | |
| 2 | Total Operating Revenue Subject to GST | S.2.1 L.45 | | 34,233 | 35,160 | 45,850 | 47,075 |
| 3 | GST Rate | | | 6.50 | 6.00 | 5.00 | 5.00 |
| 4 | GST Billable | | (a) | 2,225 | 2,110 | 2,293 | 2,354 |
| 5 | | | | | | | |
| 6 | Day Factor - Revenues | | | 45.0 | 45.0 | 41.9 | 41.9 |
| 7 | Day Factor - Remittance Lag | | | 56.6 | 56.6 | 56.6 | 56.6 |
| 8 | | | (b) | (11.6) | (11.6) | (14.7) | (14.7) |
| 9 | | | | | | | |
| 10 | GST Impact on Working Capital Increase (Decrease) | | (a) (b) 365 | (71) | (67) | (93) | (95) |
| 11 | | | | | | | |
| 12 | EXPENSES: | | | | | | |
| 13 | Total Utility Expenses | | | 39,875 | 40,961 | 46,660 | 47,902 |
| 14 | Taxes other than Income | | | (230) | (235) | (249) | (261) |
| 15 | Labour and Fringe | | | (3,296) | (3,826) | (4,629) | (5,072) |
| 16 | Depreciation | | | (3,901) | (4,171) | (4,365) | (4,837) |
| 17 | Amortization of contributions | | | 1,008 | 1,092 | 963 | 1,028 |
| 18 | Income Tax | | | (1,034) | (855) | (421) | (1,044) |
| 19 | Fish Lake Costs | | | - | 237 | 150 | - |
| 20 | Fish Lake Amortization | | | - | (79) | (154) | (154) |
| 21 | Plant Maintenance Reserve Costs | | | - | 538 | 60 | - |
| 22 | Plant Maintenance Reserve Amortization | | | - | (108) | (123) | (123) |
| 23 | Injuries & Damages Costs | | | (51) | (73) | (60) | (60) |
| 24 | Injuries & Damages Write-off | | | 75 | 75 | 86 | 86 |
| 25 | Rate Case Costs | | | - | 30 | 720 | - |
| 26 | Rate Case Write-off | | | - | - | (375) | (375) |
| 27 | Capital Expenditures | | | 7,316 | 7,809 | 9,560 | 13,504 |
| 28 | Net Costs Subject to GST | | | 39,762 | 41,396 | 47,824 | 50,595 |
| 29 | GST Rate | | | 6.50 | 6.00 | 5.00 | 5.00 |
| 30 | GST Refundable | | ( c) | 2,585 | 2,484 | 2,391 | 2,530 |
| 31 | | | | | | | |
| 32 | Day Factor - Expense (Including Capital) | | | 26.0 | 26.0 | 26.0 | 26.0 |
| 33 | Day Factor - Remittance Lag | | | 56.6 | 56.6 | 56.6 | 56.6 |
| 34 | | | (d) | 30.6 | 30.6 | 30.6 | 30.6 |
| 35 | | | | | | | |
| 36 | GST Impact on Working Capital Increase (Decrease) | | ( c) (d) 365 | 217 | 208 | 200 | 212 |
| 37 | | | | | | | |
| 38 | Net Impact of GST on Working Capital | | S.8.9 L.16 | 146 | 141 | 108 | 117 |

**Yukon Electrical Company Limited** **Schedule 8.11**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Contributions in Aid of Construction**
**( 000)**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Contributions in Aid of Construction** | | | | | |
| 2 | Prior Year Gross Contributions | | 31,445 | 33,634 | 36,205 | 38,765 |
| 3 | Additions to property | | 2,189 | 2,571 | 2,560 | 2,506 |
| 4 | Retirements | | - | - | - | - |
| 5 | Current Year Gross Contributions | | 33,634 | 36,205 | 38,765 | 41,271 |
| 6 | **Accumulated Amortization** | | | | | |
| 7 | Prior Year Accumulated Amortization | | 11,609 | 12,617 | 13,709 | 14,672 |
| 8 | Gross Amortization | S.1 L.13 | 1,008 | 1,092 | 963 | 1,028 |
| 9 | Retirements | | - | - | - | - |
| 10 | Current Year Accumulated Amortization | | 12,617 | 13,709 | 14,672 | 15,700 |
| 11 | **Net Contributions in Aid of Construction** | S.8.5 L.17 | 21,017 | 22,496 | 24,093 | 25,571 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Plant Additions**
**( 000s)**

**Schedule 9**

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | Work in progress, beginning of year | | 427 | 871 | 1,035 | 620 |
| 2 | **Generation:** | | | | | |
| 3 | Generating Plants | | 638 | 476 | 1,014 | 3,124 |
| 4 | | | 638 | 476 | 1,014 | 3,124 |
| 5 | **Billing:** | | | | | |
| 6 | New N60 Billing Systems | | - | 480 | 1,008 | - |
| 7 | | | - | 480 | 1,008 | - |
| 8 | **Distribution:** | | | | | |
| 9 | New Extensions | | 2,433 | 3,106 | 3,141 | 2,962 |
| 10 | Distribution Improvements | | 2,858 | 2,070 | 2,967 | 2,532 |
| 11 | Street and Sentinel Lights | | 943 | 908 | 506 | 495 |
| 12 | Meters | | 77 | 37 | 330 | 3,855 |
| 13 | Transformers and Regulators | | - | 20 | | |
| 14 | | | 6,311 | 6,141 | 6,943 | 9,843 |
| 15 | **General property and equipment:** | | | | | |
| 16 | Tools, Instruments & Equipment | | 55 | 48 | 50 | 57 |
| 17 | Office Furniture & Equipment | | 6 | 10 | 13 | 10 |
| 18 | Office Computer Equipment | | 3 | 0 | 6 | 5 |
| 19 | Communication Equipment | | 9 | 57 | 102 | 54 |
| 20 | Transportation Equipment | | 158 | 513 | 205 | 230 |
| 21 | Land and Buildings | | 136 | 84 | 219 | 181 |
| 22 | | | 367 | 712 | 595 | 537 |
| 23 | Miscellaneous Other | | - | - | - | - |
| 24 | **Total capital expenditures** | | 7,316 | 7,809 | 9,560 | 13,504 |
| 25 | Less: Transfers to rate base | S.8.6 L.3 | (6,872) | (7,645) | (9,975) | (13,544) |
| 26 | Work in progress, end of year | S.8.5 L.5 | 871 | 1,035 | 620 | 580 |

**Schedule 10.1**

# Yukon Electrical Company Limited
## 2008 - 2009 General Rate Application
## Income Tax Expense
## ( 000s)

| Line No. | Description | Cross Ref. | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | Utility earnings before tax | | 2,845 | 2,703 | 2,298 | 3,260 |
| 2 | **Add:** | | | | | |
| 3 | Depreciation | S.1.1 L.12 | 3,901 | 4,171 | 4,365 | 4,837 |
| 4 | Amortization of contributions | S.1.1 L.13 | (1,008) | (1,092) | (963) | (1,028) |
| 5 | Non-allowable expenses | | 18 | 18 | 18 | 18 |
| 6 | Plant Maintenance write-off | S.8.8 L.26 | - | 108 | 123 | 123 |
| 7 | Rate case write-off | S.8.8 L.18 | - | - | 375 | 375 |
| 8 | Injuries & Damages write-off | S.8.4 L27 | 75 | 75 | 86 | 86 |
| 9 | Fish Lake Water License write-off | S.8.8 L.35 | - | 79 | 154 | 154 |
| 10 | Charges to deferred pension & OPEB | S.8.4 L.13 L.20 | 132 | 623 | 639 | 689 |
| 11 | Sub-total | | 3,118 | 3,982 | 4,797 | 5,253 |
| 12 | | | | | | |
| 13 | **Deduct:** | | | | | |
| 14 | CCA | | 2,259 | 2,518 | 3,528 | 3,960 |
| 15 | Plant Maintenance Reserve Charges | S.8.8 L.25 | - | 538 | 60 | - |
| 16 | Rate Case Expenditure | S.8.8 L.17 | - | 30 | 720 | - |
| 17 | Injuries & Damages Costs | S.8.4 L28 | 51 | 73 | 60 | 60 |
| 18 | Fish Lake Water License Costs | S.8.8 L.34 | - | 237 | 150 | - |
| 19 | Pension & OPEB payments | S.8.4 L.14 L.21 | 39 | 576 | 639 | 689 |
| 20 | Inventory Pool Costs Capitalized | | - | - | 358 | 376 |
| 21 | Cumulative Eligible Captial | | 12 | 11 | 10 | 9 |
| 22 | ES&G | | 348 | 334 | 350 | 350 |
| 23 | Sub-total | | 2,709 | 4,317 | 5,875 | 5,444 |
| 24 | | | | | | |
| 25 | Taxable income | | 3,254 | 2,368 | 1,220 | 3,070 |
| 26 | Tax rate | | 36.00 | 36.00 | 34.50 | 34.00 |
| 27 | Income tax | | 1,171 | 852 | 421 | 1,044 |
| 28 | Surtax | | 36 | 27 | - | - |
| 29 | Prior & current years' book to filing overprovision | | (174) | (24) | - | - |
| 30 | Total current provision | S.1.1 L.16 | 1,034 | 855 | 421 | 1,044 |
| 31 | | | | | | |

**Yukon Electrical Company Limited (YECL)** **Schedule 11.1**
**2008 - 2009 General Rate Application**
**Interim Rates (Rider R) Revenue Shortfall (Rider G) Calculations**

| Line No. | Description | Cross Ref. | |
|---|---|---|---|
| 1 | **Revenues** | | |
| 2 | 2008 Retail revenues on Existing Rates ( 000's) | S.2.1 L.45 | 39,970 |
| 3 | Less: Fuel Cost in Existing base rates ( 000s) | | 2,054 |
| 4 | Sub-total ( 000s) | (2)-(3) | 37,916 |
| 5 | | | |
| 6 | 2008 Retail revenues on Proposed Rates ( 000's) | S.2.1 L.45 | 45,850 |
| 7 | Less: Fuel Cost ( 000s) | S.4.1 L.4 | 5,715 |
| 8 | Sub-total ( 000s) | (6)-(7) | 40,135 |
| 9 | | | |
| 10 | **Non-Fuel Revenue Shortfall ( 000's)** | (8)-(4) | 2,220 |
| 11 | | | |
| 12 | YECL 2008 Retail revenues on Existing Primary Rates ( 000s) | S.2.1 L.24 | 33,677 |
| 13 | YEC 2008 Retail revenues on Existing Primary Rates ( 000s) [1] | S.11.2 L.14 | 3,795 |
| 14 | **Total 2008 Retail revenues on Existing Primary Rates ( 000s)** | (12) (13) | 37,471 |
| 15 | **2008 Rider R ( ) Interim Rate Rider** | (10) (14) 100 | 5.924 |
| 16 | | | |
| 17 | | | |
| 18 | **2008 Retail Revenues on Existing Primary Rates ( 000s)** | | |
| 19 | YECL - Jan to Jun | | 17,101 |
| 20 | YEC - Jan to Jun [1] | S.11.2 L.2-7 | 1,864 |
| 21 | **Total Retail Revenues on Existing Primary Rates ( 000s)** | (19) (20) | 18,964 |
| 22 | **Interim Rider Shortfall Revenue ( 000's) - Jan to Jun 2008** | (21) (15) | 1,123 |
| 23 | | | |
| 24 | **Retail Revenues on Existing Primary Rates ( 000s)** | | |
| 25 | YECL 2008 Revenue ( 000's) - Jul to Dec | | 16,576 |
| 26 | YECL 2009 Revenue ( 000's) - Jan to Jun | | 17,236 |
| 27 | YEC 2008 Revenue ( 000's) - Jul to Dec [1] | S.11.2 L.8-13 | 1,931 |
| 28 | YEC 2009 Revenue ( 000's) - Jan to Jun [1] | S.11.2 L.15-20 | 1,871 |
| 29 | **Retail Revenues for period which shortfall revenue is to be collected** | (25) (26) (27) (28) | 37,613 |
| 30 | | | |
| 31 | **2008 Rider G ( ) Revenue Shortfall Rider** | (22) (29) 100 | 2.987 |

32 [(1)] Excludes revenues from Rate Schedule 39 (Industrial Primary) based on provision of Yukon Territorial Government Order-In-Council (OIC) 2007 94

**Schedule 11.2**

# Yukon Energy Corporation (YEC)
## 2008 - 2009 Firm Retail Sales and Revenue Forecast (Excluding Rate 39)

| Line No. | Description | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | Month Yr | Firm Retail Sales (MWh) | YEC Rate 39 (Minto) MWh | Firm less Rate 39 MWh | Revenue 000s | YEC Rate 39 (Minto) 000s | Firm less Rate 39 000s |
| 2 | **Jan-08** | 2,665 | - | 2,665 | 343 | 0 | 343 |
| 3 | **Feb-08** | 2,415 | - | 2,415 | 312 | 0 | 312 |
| 4 | **Mar-08** | 2,371 | - | 2,371 | 307 | 0 | 307 |
| 5 | **Apr-08** | 2,259 | - | 2,259 | 293 | 0 | 293 |
| 6 | **May-08** | 2,124 | - | 2,124 | 277 | 0 | 277 |
| 7 | **Jun-08** | 2,540 | - | 2,540 | 333 | 0 | 333 |
| 8 | **Jul-08** | 2,797 | - | 2,797 | 368 | 0 | 368 |
| 9 | **Aug-08** | 2,694 | - | 2,694 | 354 | 0 | 354 |
| 10 | **Sep-08** | 2,541 | - | 2,541 | 333 | 0 | 333 |
| 11 | **Oct-08** | 5,126 | 3,000 | 2,126 | 576 | 300 | 276 |
| 12 | **Nov-08** | 4,687 | 2,500 | 2,187 | 533 | 250 | 283 |
| 13 | **Dec-08** | 4,960 | 2,500 | 2,460 | 567 | 250 | 317 |
| 14 | **Total 2008** | 37,179 | 8,000 | 29,179 | 4,595 | 800 | 3,795 |
| 15 | **Jan-09** | 4,704 | 2,000 | 2,704 | 548 | 200 | 348 |
| 16 | **Feb-09** | 4,413 | 2,000 | 2,413 | 511 | 200 | 311 |
| 17 | **Mar-09** | 5,438 | 3,000 | 2,438 | 615 | 300 | 315 |
| 18 | **Apr-09** | 5,281 | 3,000 | 2,281 | 595 | 300 | 295 |
| 19 | **May-09** | 5,159 | 3,000 | 2,159 | 581 | 300 | 281 |
| 20 | **Jun-09** | 5,448 | 3,000 | 2,448 | 620 | 300 | 320 |
| 21 | **Jul-09** | 5,532 | 3,000 | 2,532 | 632 | 300 | 332 |
| 22 | **Aug-09** | 5,422 | 3,000 | 2,422 | 618 | 300 | 318 |
| 23 | **Sep-09** | 5,578 | 3,000 | 2,578 | 638 | 300 | 338 |
| 24 | **Oct-09** | 5,157 | 3,000 | 2,157 | 580 | 300 | 280 |
| 25 | **Nov-09** | 4,212 | 2,000 | 2,212 | 486 | 200 | 286 |
| 26 | **Dec-09** | 4,530 | 2,000 | 2,530 | 526 | 200 | 326 |
| 27 | **Total 2009** | 60,874 | 32,000 | 28,874 | 6,950 | 3,200 | 3,750 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Utility Revenue Requirement**
**( 000s)**

**Schedule 1.1**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Revenues** | | | | | | | | |
| 2 | Retail revenues | S.2.1 L.45 | 35,163 | 36,221 | 37,109 | 39,115 | 40,177 | 45,850 | 47,075 |
| 3 | Other revenue | S.2.2 L.6 | 692 | 696 | 757 | 760 | 784 | 810 | 827 |
| 4 | **Total Revenues** | | 35,855 | 36,917 | 37,866 | 39,875 | 40,961 | 46,660 | 47,902 |
| 5 | | | | | | | | | |
| 6 | **Costs** | | | | | | | | |
| 7 | Purchase power | S.3.1 L.13 | 20,562 | 21,111 | 21,681 | 23,239 | 23,647 | 23,846 | 23,494 |
| 8 | Diesel Fuel | S.4.1 L.6 | 1,942 | 2,030 | 2,014 | 2,026 | 2,054 | 5,715 | 5,299 |
| 9 | Operations and maintenance | S.5.1 L.49 | 6,008 | 6,469 | 6,755 | 6,969 | 7,290 | 8,758 | 9,317 |
| 11 | Property Taxes | Page 6-1 | 223 | 226 | 230 | 230 | 235 | 249 | 261 |
| 12 | Depreciation | S.7.1 L.4 | 3,355 | 3,481 | 3,727 | 3,901 | 4,171 | 4,365 | 4,837 |
| 13 | Amortization of contributions | S.8.11 L.8 | (847) | (901) | (962) | (1,008) | (1,092) | (963) | (1,028) |
| 14 | Amortization of deferred costs credits | S.8.8 L.7 | 75 | 75 | - | - | 187 | 652 | 652 |
| 15 | Return on rate base | S.8.1 L.5,10,15,20,25,30 | 3,180 | 3,186 | 3,093 | 3,484 | 3,614 | 3,618 | 4,026 |
| 16 | Income taxes | S.10.1 L.30 | 1,357 | 1,240 | 1,328 | 1,034 | 855 | 421 | 1,044 |
| 17 | **Total Costs** | | 35,855 | 36,917 | 37,866 | 39,875 | 40,961 | 46,660 | 47,902 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Summary of Customers, Energy Sales and Revenue**

**Schedule 2.1**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 Existing | Test Period 2008 Proposed | Test Period 2009 Existing | Test Period 2009 Proposed |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Residential** | | | | | | | | | | |
| 2 | Customers (average during year) | | 11,550 | 11,741 | 11,976 | 12,196 | 12,452 | 12,693 | | 12,836 | |
| 3 | Sales in MWh | | 110,499 | 111,283 | 113,651 | 122,151 | 122,334 | 123,961 | | 125,337 | |
| 4 | MWh sales per customer | | 9.6 | 9.5 | 9.5 | 10.0 | 9.8 | 9.8 | | 9.8 | |
| 5 | Revenue ( 000s) | | 12,705 | 12,893 | 13,167 | 14,001 | 14,088 | 14,279 | | 14,435 | |
| 6 | Cents per KWh | | 11.50 | 11.59 | 11.59 | 11.46 | 11.52 | 11.52 | | 11.52 | |
| 7 | **Commercial** | | | | | | | | | | |
| 8 | Customers (average during year) | | 2,432 | 2,459 | 2,489 | 2,515 | 2,570 | 2,599 | | 2,629 | |
| 9 | Sales in MWh | | 126,962 | 130,976 | 131,678 | 137,080 | 141,351 | 141,869 | | 142,564 | |
| 10 | MWh sales per customer | | 52.2 | 53.3 | 52.9 | 54.5 | 55.0 | 54.6 | | 54.2 | |
| 11 | Revenue ( 000s) | | 16,667 | 17,342 | 17,432 | 17,999 | 18,729 | 18,549 | | 18,641 | |
| 12 | Cents per KWh | | 13.13 | 13.24 | 13.24 | 13.13 | 13.25 | 13.07 | | 13.08 | |
| 13 | **Street lights** | | | | | | | | | | |
| 14 | Sales in MWh | | 3,030 | 3,193 | 3,294 | 3,263 | 3,374 | 3,445 | | 3,522 | |
| 15 | Revenue ( 000s) | | 632 | 654 | 681 | 679 | 703 | 716 | | 729 | |
| 16 | Cents per KWh | | 20.86 | 20.48 | 20.67 | 20.81 | 20.83 | 20.78 | | 20.70 | |
| 17 | **Sentinel lights** | | | | | | | | | | |
| 18 | Sales in MWh | | 674 | 664 | 654 | 644 | 639 | 638 | | 631 | |
| 19 | Revenue ( 000s) | | 141 | 146 | 137 | 135 | 134 | 134 | | 132 | |
| 20 | Cents per KWh | | 20.92 | 21.99 | 20.95 | 20.95 | 20.96 | 20.95 | | 20.95 | |
| 21 | **Total Company - Retail - Primary** | | | | | | | | | | |
| 22 | Customers | | 13,982 | 14,200 | 14,465 | 14,711 | 15,022 | 15,293 | | 15,465 | |
| 23 | Sales in MWh | | 241,165 | 246,116 | 249,277 | 263,137 | 267,698 | 269,913 | | 272,054 | |
| 24 | Revenue ( 000s) | | 30,145 | 31,035 | 31,417 | 32,814 | 33,654 | 33,677 | | 33,937 | |
| 25 | Cents KWh | | 12.50 | 12.61 | 12.60 | 12.47 | 12.57 | 12.48 | | 12.47 | |
| 26 | **Secondary Sales** | | | | | | | | | | |
| 27 | Customers (average during year) | | 17 | 18 | 21 | 22 | 22 | 22 | | 23 | |
| 28 | Sales in MWh | | 13,039 | 15,998 | 18,363 | 21,555 | 23,566 | 16,853 | | 6,954 | |
| 29 | MWh sales per customer | | 767.0 | 888.8 | 874.4 | 979.8 | 1,071.2 | 754.6 | | 302.4 | |
| 30 | Revenue ( 000s) | | 430 | 528 | 958 | 1,367 | 1,453 | 1,213 | | 501 | |
| 31 | Cents per KWh | | 3.30 | 3.30 | 5.22 | 6.34 | 6.17 | 7.20 | | 7.20 | |
| 32 | **Wholesale Sales** | | | | | | | | | | |
| 33 | Customers (average during year) | | 2 | 2 | 2 | 2 | 2 | 2 | | 2 | |
| 34 | Sales in MWh | | 431 | 369 | 465 | 513 | 488 | 489 | | 489 | |
| 35 | MWh sales per customer | | 215.5 | 184.5 | 232.5 | 256.5 | 244.0 | 244.4 | | 244.4 | |
| 36 | Revenue ( 000s) | | 43 | 40 | 48 | 52 | 53 | 52 | | 52 | |
| 37 | Cents per KWh | | 9.98 | 10.84 | 10.32 | 10.14 | 10.86 | 10.60 | | 10.60 | |
| 38 | **Total Company** | | | | | | | | | | |
| 39 | Customers | | 14,000 | 14,219 | 14,487 | 14,735 | 15,046 | 15,317 | | 15,490 | |
| 40 | Sales in MWh | S.3.2 L.2 | 254,635 | 262,483 | 268,105 | 285,205 | 291,752 | 287,255 | | 279,497 | |
| 41 | Revenue ( 000s) | | 30,618 | 31,603 | 32,423 | 34,233 | 35,160 | 34,942 | | 34,490 | |
| 42 | Cents KWh | | 12.02 | 12.04 | 12.09 | 12.00 | 12.05 | 12.16 | | 12.34 | |
| 43 | Retail Revenues | | 30,618 | 31,603 | 32,423 | 34,233 | 35,160 | 34,942 | | 34,490 | |
| 44 | **YEC Revenue Shortfall (Rider J)** | | 4,545 | 4,618 | 4,686 | 4,882 | 5,017 | 5,028 | | 5,067 | |
| 45 | **TOTAL REVENUES** | S.1.1 L.2 | 35,163 | 36,221 | 37,109 | 39,115 | 40,177 | 39,970 | 45,850 | 39,557 | 47,075 |
| 46 | Rate Increase from Existing Rates | | | | | | | | 5,881 | | 7,518 |
| 47 | Less: Impact of higher fuel costs recovered through Rider F | | | | | | | | (3,661) | | (3,388) |
| 48 | **Net Rate Increase ( 000s)** | L.46 - L.47 | | | | | | | 2,220 | | 4,130 |
| 49 | **Rate Increase over Existing Rates** | | | | | | | | | | |
| 50 | YECL Primary Retail Revenue | L.24 | | | | | | 33,677 | | 33,937 | |
| 51 | YEC Primary Retail Revenue | S11.2 L.14, L.27 | | | | | | 3,795 | | 3,750 | |
| 52 | Total YEC YECL Retail Revenue Primary Rates ( 00 | L.50 L.51 | | | | | | 37,471 | | 37,687 | |
| 53 | **Rate increase over existing Rates** | L.48 L.52 | | | | | | | 5.9 | | 11.0 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Miscellaneous Revenue**

**Schedule 2.2**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | Reconnect Revenue | | 85 | 83 | 75 | 80 | 80 |
| 2 | Joint Use | | 455 | 426 | 447 | 464 | 480 |
| 3 | Services to Outside Parties | | 70 | 102 | 99 | 100 | 100 |
| 4 | Other | | 147 | 149 | 163 | 166 | 167 |
| 5 | | | | | | | |
| 6 | Total | S.1.1 L.3 | 757 | 760 | 784 | 810 | 827 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Purchase Power**

**Schedule 3.1**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Purchases (MWh)** | | | | | | | | |
| 2 | Primary Energy | | 229,971 | 235,982 | 237,419 | 251,861 | 254,914 | 260,093 | 263,202 |
| 3 | Secondary Sales | | 13,039 | 15,998 | 18,363 | 21,555 | 23,566 | 16,853 | 6,954 |
| 4 | | S.3.2 L.10 | 243,010 | 251,980 | 255,782 | 273,416 | 278,480 | 276,946 | 270,156 |
| 5 | **Purchase Power Rates** | | | | | | | | |
| 6 | Primary Energy Charge ( per KWh) | | 0.0684 | 0.0684 | 0.0684 | 0.0684 | 0.0684 | 0.0684 | 0.0684 |
| 7 | Secondary Sales ( per KWh) | | 0.0220 | 0.0220 | 0.0412 | 0.0524 | 0.0507 | 0.061 | 0.061 |
| 8 | Shortfall Rider J [1] | | 14.93 | 14.93 | 14.93 | 14.93 | 14.93 | 14.93 | 14.93 |
| 9 | **Purchase Power Expense ( 000s)** | | | | | | | | |
| 10 | Primary Energy Expense | L.2 x L.6 | 15,730 | 16,141 | 16,239 | 17,227 | 17,436 | 17,790 | 18,003 |
| 11 | Secondary Energy Expense | L.3 x L.7 | 287 | 352 | 756 | 1,130 | 1,194 | 1,028 | 424 |
| 12 | Shortfall Rider J | S.2.1 L.44 | 4,545 | 4,618 | 4,686 | 4,882 | 5,017 | 5,028 | 5,067 |
| 13 | Total Purchase Power Expense | S.1.1 L.7 | 20,562 | 21,111 | 21,681 | 23,239 | 23,647 | 23,846 | 23,494 |

14 (1) In March 2003 the Shortfall Rider J changed from 18.74 to 14.93 .

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Energy Losses**
**(MW.h )**

**Schedule 3.2**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Sales and Losses** | | | | | | | | |
| 2 | Total energy sales (MWh) | S.2.1 L.39 | 254,635 | 262,483 | 268,105 | 285,205 | 291,752 | 287,255 | 279,497 |
| 3 | Losses and company used - (MWh) | | 14,836 | 17,284 | 15,723 | 18,591 | 18,087 | 17,810 | 17,329 |
| 4 | Losses - | | 5.8 | 6.6 | 5.9 | 6.5 | 6.2 | 6.2 | 6.2 |
| 5 | Total generation and purchases (MWh) | | 269,471 | 279,767 | 283,828 | 303,796 | 309,839 | 305,065 | 296,826 |
| 6 | **Sources - MWh** | | | | | | | | |
| 7 | Hydro generation | | 4,948 | 5,799 | 6,239 | 8,216 | 9,025 | 6,192 | 6,192 |
| 8 | Hydro grid standby diesel generation | S.4.1 L.1 | 27 | 14 | 8 | 39 | 131 | 44 | 44 |
| 9 | Diesel generation | S.4.1 L.1 | 21,486 | 21,974 | 21,799 | 22,125 | 22,203 | 21,883 | 20,433 |
| 10 | Purchases | S.3.1 L.4 | 243,010 | 251,980 | 255,782 | 273,416 | 278,480 | 276,946 | 270,156 |
| 11 | | | 269,471 | 279,767 | 283,828 | 303,796 | 309,839 | 305,065 | 296,826 |
| 12 | **Sources -** | | | | | | | | |
| 13 | Hydro generation | | 1.8 | 2.1 | 2.2 | 2.7 | 2.9 | 2.0 | 2.1 |
| 14 | Diesel generation | | 8.0 | 7.9 | 7.7 | 7.3 | 7.2 | 7.2 | 6.9 |
| 15 | Purchases | | 90.2 | 90.1 | 90.1 | 90.0 | 89.9 | 90.8 | 91.0 |
| | | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Diesel Generation and Fuel Summary**
**( 000s)**

**Schedule 4.1**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Total Diesel Generation (MWh) | S.3.2 L.8 & 9 | 21,513 | 21,988 | 21,807 | 22,164 | 22,334 | 21,927 | 20,477 |
| 2 | Fuel heat rate (KWh per litre) | | 3.69 | 3.66 | 3.66 | 3.69 | 3.67 | 3.71 | 3.71 |
| 3 | Litres of fuel (000s) | | 5,828 | 6,004 | 5,956 | 6,007 | 6,088 | 5,915 | 5,516 |
| 4 | Fuel costs ( 000s) | | 2,848 | 3,284 | 4,403 | 4,886 | 5,226 | 5,715 | 5,299 |
| 5 | Fuel Variance | | (906) | (1,254) | (2,389) | (2,860) | (3,172) | - | - |
| 6 | Fuel Expense | S.1.1 L.8 | 1,942 | 2,030 | 2,014 | 2,026 | 2,054 | 5,715 | 5,299 |
| 7 | Average cost (cents per litre) | L.4 L.3 | 48.87 | 54.70 | 73.93 | 81.34 | 85.84 | 96.61 | 96.07 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Diesel Information**

**Schedule 4.2**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| | Average Cost (in cents per litre) | | | | | | | | |
| 1 | Watson Lake | | 42.04 | 47.65 | 66.56 | 74.62 | 78.16 | 87.48 | 87.48 |
| 2 | Beaver Creek | | 42.53 | 48.34 | 64.20 | 70.86 | 75.51 | 81.52 | 81.52 |
| 3 | Destruction Bay | | 42.56 | 49.77 | 65.12 | 72.43 | 77.75 | 83.13 | 83.13 |
| 4 | Old Crow | | 116.37 | 122.11 | 140.99 | 157.36 | 167.16 | 193.41 | 193.41 |
| 4.1 | Stewart Crossing | | 50.91 | 50.06 | 65.57 | | | | |
| 5 | Pelly Crossing | | 46.08 | 44.37 | 73.51 | 76.50 | 85.48 | 89.33 | 89.33 |
| 6 | Swift River | | 45.48 | 65.99 | 70.18 | 80.65 | 83.58 | 92.44 | 92.44 |
| 7 | Standby | | 31.92 | 50.61 | 39.62 | 50.42 | 66.40 | 70.00 | 70.00 |
| | Generation (MWh) | | | | | | | | |
| 8 | Watson Lake | | 13,505 | 13,738 | 13,642 | 14,116 | 14,124 | 14,148 | 14,322 |
| 9 | Beaver Creek | | 1,926 | 2,067 | 1,988 | 2,034 | 1,957 | 2,021 | 2,041 |
| 10 | Destruction Bay | | 1,601 | 1,563 | 1,419 | 1,636 | 1,720 | 1,722 | 1,741 |
| 11 | Old Crow | | 1,690 | 1,771 | 1,962 | 1,811 | 1,853 | 1,967 | 1,993 |
| 11.1 | Stewart Crossing | | 437 | 433 | 351 | | | | |
| 12 | Pelly Crossing | | 2,017 | 2,132 | 2,168 | 2,250 | 2,272 | 1,746 | 11 |
| 13 | Swift River | | 309 | 271 | 269 | 276 | 277 | 278 | 326 |
| 14 | Standby | | 27 | 14 | 8 | 40 | 131 | 44 | 44 |
| 15 | | S.4.1 L.1 | 21,513 | 21,988 | 21,807 | 22,164 | 22,334 | 21,927 | 20,477 |
| 16 | Net Heat Rate (KWh litre) | | | | | | | | |
| 17 | Watson Lake | | 3.83 | 3.83 | 3.79 | 3.84 | 3.80 | 3.82 | 3.82 |
| 18 | Beaver Creek | | 3.52 | 3.58 | 3.58 | 3.60 | 3.53 | 3.56 | 3.56 |
| 19 | Destruction Bay | | 3.45 | 3.41 | 3.55 | 3.30 | 3.34 | 3.41 | 3.41 |
| 20 | Old Crow | | 3.60 | 3.50 | 3.56 | 3.64 | 3.52 | 3.56 | 3.56 |
| 20.1 | Stewart Crossing | | 3.04 | 2.72 | 3.06 | | | | |
| 21 | Pelly Crossing | | 3.72 | 3.67 | 3.64 | 3.70 | 3.39 | 3.62 | 3.62 |
| 22 | Swift River | | 3.00 | 3.00 | 2.93 | 2.99 | 3.04 | 2.99 | 2.99 |
| 23 | Standby | | 3.00 | 3.00 | 3.00 | 3.00 | 3.00 | 3.50 | 3.50 |
| 24 | Litres Consumed (000s) | | | | | | | | |
| 25 | Watson Lake | | 3,518 | 3,585 | 3,596 | 3,696 | 3,707 | 3,704 | 3,749 |
| 26 | Beaver Creek | | 548 | 579 | 565 | 564 | 551 | 567 | 573 |
| 27 | Destruction Bay | | 475 | 462 | 423 | 479 | 501 | 505 | 510 |
| 28 | Old Crow | | 479 | 520 | 558 | 514 | 528 | 552 | 559 |
| 28.1 | Stewart Crossing | | 148 | 159 | 113 | | | | |
| 29 | Pelly Crossing | | 544 | 598 | 605 | 633 | 654 | 482 | 3 |
| 30 | Swift River | | 99 | 88 | 91 | 91 | 91 | 93 | 109 |
| 31 | Standby | | 19 | 13 | 6 | 30 | 55 | 13 | 13 |
| | | S.4.1 L.3 | 5,828 | 6,004 | 5,956 | 6,007 | 6,088 | 5,915 | 5,516 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Operations and Maintenance Expenses**
**( 000s)**

**Schedule 5.1**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Production** | | | | | | | | |
| 2 | 62600 - Hydro Generation | S.5.2 L.3 | 57 | 59 | 65 | 87 | 99 | 96 | 129 |
| 3 | 64000 - Supervision and Engineering Diesel | S.5.2 L.14 | 31 | 33 | 37 | 44 | 53 | 58 | 64 |
| 4 | 64600 - Diesel Generation | S.5.2 L.25 | 298 | 252 | 260 | 271 | 312 | 394 | 423 |
| 5 | 82600 - Hydro Maintenance | S.5.2 L.36 | 23 | 17 | 20 | 8 | 37 | 31 | 33 |
| 6 | 84600 - Diesel Maintenance | S.5.2 L.43 | 794 | 862 | 799 | 785 | 810 | 1,016 | 951 |
| 7 | | | 1,203 | 1,223 | 1,181 | 1,196 | 1,311 | 1,594 | 1,600 |
| 8 | **Distribution** | | | | | | | | |
| 9 | 87000 - Supervision | S.5.2 L.56 | 150 | 159 | 171 | 188 | 230 | 229 | 250 |
| 10 | 87100 - Brushing | S.5.2 L.64 | 114 | 151 | 163 | 238 | 297 | 341 | 359 |
| 11 | 87200 - Vehicle Depreciation | | (93) | (82) | (87) | (84) | (94) | (100) | (105) |
| 12 | 87300 - Maintenance | S.5.2 L.78 | 848 | 1,044 | 819 | 927 | 936 | 1,386 | 1,514 |
| 13 | 87310 - Service to Outside Parties | | 78 | 61 | 102 | 96 | 101 | 106 | 112 |
| 14 | 87400 - Underground line maintenance | S.5.2 L.91 | 111 | 94 | 81 | 104 | 91 | 122 | 131 |
| 15 | 87500 - Meter and Meter Testing | S.5.2 L.102 | 58 | 81 | 170 | 145 | 108 | 115 | 75 |
| 16 | 87700 - Transformer Repair and Replacement | S.5.2 L.112 | 1 | 0 | 4 | 20 | 34 | 28 | 30 |
| 17 | 87800 - Street Light Maintenance | S.5.2 L.120 | 145 | 147 | 139 | 148 | 186 | 226 | 241 |
| 18 | | | 1,412 | 1,654 | 1,563 | 1,781 | 1,890 | 2,453 | 2,606 |
| 19 | **General** | | | | | | | | |
| 20 | 88400 - Communication | | 6 | 10 | 9 | 11 | 8 | 13 | 14 |
| 21 | 88800 - Maintenance Company-owned Houses | | 10 | 16 | 15 | 28 | 29 | 33 | 34 |
| 22 | 88900 - Maintenance Warehouse and Office | S.5.2 L.131 | 97 | 97 | 109 | 97 | 110 | 118 | 125 |
| 23 | | | 113 | 123 | 134 | 136 | 147 | 164 | 173 |
| 24 | **Public information** | | | | | | | | |
| 25 | 70100 - Public Information Administration | S.5.2 L.141 | 115 | 139 | 109 | 101 | 64 | 100 | 106 |
| 26 | 70200 - General Public Information | S.5.2 L.149 | 15 | 19 | 21 | 54 | 29 | 28 | 30 |
| 27 | | | 130 | 158 | 129 | 155 | 93 | 128 | 135 |
| 28 | **Customer accounting** | | | | | | | | |
| 29 | 71000 - Supervision | S.5.2 L.155 | 29 | 35 | 36 | 34 | 31 | 35 | 49 |
| 30 | 71100 - Customer Applications and Service Orders | S.5.2 L.162 | 289 | 280 | 337 | 283 | 335 | 407 | 450 |
| 31 | 71200 - Meter Reading | S.5.2 L.174 | 369 | 382 | 373 | 391 | 464 | 436 | 471 |
| 32 | 71300 - Customer Billing and Accounting | S.5.2 L.186 | 398 | 438 | 441 | 474 | 513 | 572 | 646 |
| 33 | 71400 - Revenue Collections | S.5.2 L.196 | 196 | 182 | 178 | 167 | 181 | 162 | 258 |
| 34 | 71500 - Collection of Delinquent Accounts | S.5.2 L.207 | 124 | 137 | 141 | 121 | 124 | 142 | 158 |
| 35 | 71800 - Provision for Uncollectible Accounts | | 36 | 36 | 36 | 36 | 36 | 36 | 36 |
| 36 | | | 1,441 | 1,490 | 1,540 | 1,506 | 1,683 | 1,791 | 2,067 |
| 37 | **Administration and general** | | | | | | | | |
| 38 | 72100 - Administrative | S.5.2 L.215 | 952 | 1,001 | 1,101 | 1,149 | 1,176 | 1,331 | 1,399 |
| 39 | 72200 - Administrative Corporate | S.5.2 L.223 | 153 | 19 | 104 | 27 | 14 | 30 | 32 |
| 40 | 72300 - Insurance | S.5.2 L.232 | 131 | 168 | 202 | 194 | 190 | 231 | 244 |
| 41 | 72400 - Injuries & Damages | | 75 | 75 | 75 | 75 | 75 | 86 | 86 |
| 42 | 72500 - Employee Expenses | S.5.2 L.236 | 107 | 170 | 176 | 208 | 229 | 222 | 312 |
| 43 | 72600 - Training and Safety | S.5.2 L.242 | 153 | 149 | 174 | 247 | 297 | 449 | 484 |
| 44 | 72700 - Relocation | S.5.2 L.257 | 87 | 153 | 311 | 190 | 93 | 182 | 77 |
| 45 | 72800 - Miscellaneous General | | 10 | 3 | 3 | 2 | 3 | 2 | 3 |
| 46 | 72900 - Audit Legal Fees & Special Studies | S.5.2 L.268 | 41 | 84 | 62 | 106 | 88 | 95 | 100 |
| 47 | | | 1,709 | 1,821 | 2,208 | 2,196 | 2,165 | 2,628 | 2,736 |
| 48 | | | | | | | | | |
| 49 | **Total operations and maintenance expenses** | S.1.1 L.9 | 6,008 | 6,469 | 6,755 | 6,969 | 7,290 | 8,758 | 9,317 |

| Line No. | Description | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 1 | **Production** | | | | | |
| 2 | | | | | | |
| 3 | 62600 - Hydro Generation | 65 | 87 | 99 | 96 | 129 |
| 4 | | | | | | |
| 5 | Costs increase from 2005 to 2006 mainly due to a one-time catch-up of 1998-2006 water license fees. | | | | | |
| 6 | | | | | | |
| 7 | Costs increase from 2006 to 2007 mainly due to increased Fish Lake inspection and maintenance costs due to water | | | | | |
| 8 | re-licensing ( 39). This increase is offset by a one-time catch-up in 2006 of 1998 to 2006 water license fees to the | | | | | |
| 9 | government ( 27). | | | | | |
| 10 | | | | | | |
| 11 | Costs increased from 2008 to 2009 mainly due to additional inspection and reporting to meet the requirements | | | | | |
| 12 | of the new water license. | | | | | |
| 13 | | | | | | |
| 14 | 64000 - Supervision and Engineering Diesel | 37 | 44 | 53 | 58 | 64 |
| 15 | | | | | | |
| 16 | Costs increase from 2006 to 2007 mainly due to fringe benefit defined benefit pension funding ( 5) and labour inflation ( 4). | | | | | |
| 17 | The fringe benefit increase relates to increases for the defined benefit pension plan. This is due to the fact that contributions | | | | | |
| 18 | of 27 of pensionable earnings are now required as a result of the actuarial valuation that was completed for the years | | | | | |
| 19 | 2007-2009. | | | | | |
| 20 | | | | | | |
| 21 | Costs increase from 2007 to 2008 mainly due to inflation. | | | | | |
| 22 | | | | | | |
| 23 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | | |
| 24 | | | | | | |
| 25 | 64600 - Diesel Generation | 260 | 271 | 312 | 394 | 423 |
| 26 | | | | | | |
| 27 | Costs increase from 2006 to 2007 mainly due to an increase in fringe benefits ( 23) and labour ( 18). | | | | | |
| 28 | For an explanation of the fringe increase please refer to Account 64000. | | | | | |
| 29 | | | | | | |
| 30 | Cost increased from 2007 to 2008 mainly due to reduction in vacancies from employees returning off sick leave | | | | | |
| 31 | and apprentice training ( 30), inflation ( 25), as well as new attraction and retention pay ( 15), fringe benefits ( 8), | | | | | |
| 32 | and non-labour inflation ( 4). | | | | | |
| 33 | | | | | | |
| 34 | Costs increased from 2008 to 2009 mainly due to labour inflation ( 22), other inflation ( 4), and fringe benefits ( 3). | | | | | |
| 35 | | | | | | |
| 36 | 82600 - Hydro Maintenance | 20 | 8 | 37 | 31 | 33 |
| 37 | | | | | | |
| 38 | Costs increase from 2006 to 2007 mainly due to inspection and reporting relating to Fish Lake. | | | | | |
| 39 | | | | | | |
| 40 | Costs decrease from 2007 to 2008 mainly due to lower labour ( 13) and fringe benefits ( 4) for inspection and reporting | | | | | |
| 41 | of turbines 1 and 2, offset by non-labour inflation and an increase for property maintenance and upkeep ( 11). | | | | | |
| 42 | | | | | | |
| 43 | 84600 - Diesel Maintenance | 799 | 785 | 810 | 1,016 | 951 |
| 44 | | | | | | |
| 45 | Costs increase from 2006 to 2007 mainly due to an increase in fringe benefits ( 25). | | | | | |
| 46 | For an explanation of the fringe increase please refer to Account 64000. | | | | | |
| 47 | | | | | | |
| 48 | Costs increase from 2007 to 2008 mainly due to scheduled diesel overhaul costs ( 167). These costs are determined by | | | | | |
| 49 | scheduled overhauls as prescribed by manufacturer's specifications that vary by type of unit and hours operated. | | | | | |
| 50 | This increase is also due to new attraction and retention pay ( 25), and labour inflation ( 14). | | | | | |
| 51 | | | | | | |
| 52 | Costs decrease from 2008 to 2009 mainly due to varying costs for scheduled overhauls as prescribed by | | | | | |
| 53 | manufacturer's specifications that are determined by type of unit and hours operated. | | | | | |

| Line No. | Description | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 54 | **Distribution** | | | | | |
| 55 | | | | | | |
| 56 | 87000 - Supervision | 171 | 188 | 230 | 229 | 250 |
| 57 | | | | | | |
| 58 | Costs increase from 2006 to 2007 mainly due an increase in fringe benefits ( 24). For an explanation of this increase | | | | | |
| 59 | please refer to Account 64000. This increase is also due to costs associated with after hours telephone answering | | | | | |
| 60 | service ( 14), and labour inflation ( 4). | | | | | |
| 61 | | | | | | |
| 62 | Costs increase from 2008 to 2009 mainly due to labour inflation ( 13), attraction and retention pay ( 6) and fringe benefits ( 2). | | | | | |
| 63 | | | | | | |
| 64 | 87100 - Brushing | 163 | 238 | 297 | 341 | 359 |
| 65 | | | | | | |
| 66 | Costs increase from 2005 to 2006 due to additional brushing activity ( 56) and labour cost increases due to | | | | | |
| 67 | increased brushing activity ( 19). | | | | | |
| 68 | | | | | | |
| 69 | Costs increase from 2006 to 2007 mainly due to an enhanced brushing program ( 40), labour cost increase due | | | | | |
| 70 | to increased brushing activity ( 11), and increase in fringe benefits ( 8). For an explanation of this fringe | | | | | |
| 71 | increase please refer to Account 64000. | | | | | |
| 72 | | | | | | |
| 73 | Costs increase from 2007 to 2008 due to increases to the labour compliment and labour inflation ( 24), non-labour | | | | | |
| 74 | inflation ( 12), fringe benefits ( 4), and new attraction and retention pay ( 4). | | | | | |
| 75 | | | | | | |
| 76 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | | |
| 77 | | | | | | |
| 78 | 87300 - Maintenance | 819 | 927 | 936 | 1,386 | 1,514 |
| 79 | | | | | | |
| 80 | Costs increase from 2005 to 2006 mainly due to filling vacancies in 2006 and labour allocation to 71100 in 2005. | | | | | |
| 81 | | | | | | |
| 82 | Costs increase from 2007 to 2008 due mainly to additional labor as a result of new hires ( 136), vacancy reductions ( 120), | | | | | |
| 83 | new attraction and retention pay ( 75), fringe benefits ( 59), annual labour inflation ( 46), and non-labour inflation ( 14). | | | | | |
| 84 | The cost increases are for new and more extensive programs. These programs relate to Core certification and environmental | | | | | |
| 85 | requirements. Many of these programs are mandated by outside agencies or are a result of changes to | | | | | |
| 86 | industry standard. The increases also relate to enhanced patrols of lines and the introduction of planned maintenance programs | | | | | |
| 87 | designed to support system performance. | | | | | |
| 88 | | | | | | |
| 89 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | | |
| 90 | | | | | | |
| 91 | 87400 - Underground Line Maintenance | 81 | 104 | 91 | 122 | 131 |
| 92 | | | | | | |
| 93 | Costs increase from 2005 to 2006 due to a comprehensive inspection done in 2006. | | | | | |
| 94 | | | | | | |
| 95 | Costs decrease from 2006 to 2007 mainly due to a comprehensive inspection done in 2006. | | | | | |
| 96 | | | | | | |
| 97 | Costs increase from 2007 to 2008 mainly due to annual labour inflation ( 14), new attraction and retention pay ( 7), | | | | | |
| 98 | non-labour inflation ( 6), and fringe benefits ( 4) | | | | | |
| 99 | | | | | | |
| 100 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | | |
| 101 | | | | | | |
| 102 | 87500 - Meter and Meter Testing | 170 | 145 | 108 | 115 | 75 |
| 103 | | | | | | |
| 104 | Costs decrease from 2005 to 2006 due to high number of meters scheduled for changeout in 2005 versus 2006. | | | | | |
| 105 | | | | | | |
| 106 | Costs decrease from 2006 to 2007 mainly due to less one-time costs related to Automated Metering | | | | | |
| 107 | Reading (AMR) feasibility study ( 19) and less miscellaneous material issues and payables ( 18). | | | | | |
| 108 | | | | | | |
| 109 | Costs increase from 2007 to 2008 mainly due to inflation. | | | | | |
| 110 | | | | | | |
| 111 | Costs decrease from 2008 to 2009 mainly due to savings from AMR. | | | | | |

| Line No. | Description | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 112 | 87700 - Transformer Repair and Replacement | 4 | 20 | 34 | 28 | 30 |
| 113 | | | | | | |
| 114 | Costs increase from 2005 to 2006 mainly due to higher unplanned repairs to failed transformers. | | | | | |
| 115 | | | | | | |
| 116 | Costs increase from 2006 to 2007 mainly due to higher unplanned repairs to failed transformers. | | | | | |
| 117 | | | | | | |
| 118 | Costs decrease from 2007 to 2008 mainly due to normalization in allowance for unplanned repairs to failed transformers. | | | | | |
| 119 | | | | | | |
| 120 | 87800 - Street Light Maintenance | 139 | 148 | 186 | 226 | 241 |
| 121 | | | | | | |
| 122 | Costs increase from 2006 to 2007 mainly due to increases in number of lights and age of street light infrastructure | | | | | |
| 123 | as well as maintenance for new types of lights such as waterfront decorative lighting ( 31), and increase in fringe benefits ( 7). | | | | | |
| 124 | For an explanation of the fringe increase please refer to Account 64000. | | | | | |
| 125 | | | | | | |
| 126 | Costs increase from 2007 to 2008 mainly due to annual labour inflation as increased maintenance requirements ( 19), | | | | | |
| 127 | new attraction and retention pay ( 9), non-labour inflation ( 8), and fringe benefits ( 4). | | | | | |
| 128 | | | | | | |
| 129 | **General** | | | | | |
| 130 | | | | | | |
| 131 | 88900 - Maintenance Warehouse and Office | 109 | 97 | 110 | 118 | 125 |
| 132 | | | | | | |
| 133 | Costs decrease from 2005 to 2006 mainly due to less HVAC and house repairs. | | | | | |
| 134 | | | | | | |
| 135 | Costs increase from 2006 to 2007 mainly due to heating fuel cost inflation. | | | | | |
| 136 | | | | | | |
| 137 | Costs increase from 2007 to 2008 mainly due to heating fuel cost inflation ( 5) and labour inflation ( 3). | | | | | |
| 138 | | | | | | |
| 139 | **Public Information** | | | | | |
| 140 | | | | | | |
| 141 | 70100 - Public Information Administration | 109 | 101 | 64 | 100 | 106 |
| 142 | | | | | | |
| 143 | Costs decrease for 2006 to 2007 mainly due to decrease labour due to a vacancy in the marketing and communications | | | | | |
| 144 | manager position. | | | | | |
| 145 | | | | | | |
| 146 | Costs increase from 2007 to 2008 mainly due to increased outsourcing costs for website development maintenance and | | | | | |
| 147 | other communications costs. | | | | | |
| 148 | | | | | | |
| 149 | 70200 - General Public Information | 21 | 54 | 29 | 28 | 30 |
| 150 | | | | | | |
| 151 | Costs increase from 2005 to 2006 due to one-time commitments for 2007 Canada Winter Games funding in 2006. | | | | | |
| 152 | | | | | | |
| 153 | Costs decrease from 2006 to 2007 due to one-time commitments for 2007 Canada Winter Games funding in 2006. | | | | | |
| 154 | | | | | | |
| 155 | 71000 - Supervision | 36 | 34 | 31 | 35 | 49 |
| 156 | | | | | | |
| 157 | Costs increase from 2008 to 2009 due to the return to normal staffing levels after billing system implementation complete ( 12) | | | | | |
| 158 | as well as labour inflation ( 2). | | | | | |
| 159 | | | | | | |

| Line No. | Description | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 160 | **Customer accounting** | | | | | |
| 161 | | | | | | |
| 162 | 71100 - Customer Applications and Service Orders | 337 | 283 | 335 | 407 | 450 |
| 163 | | | | | | |
| 164 | Costs decrease from 2005 to 2006 mainly due to labour allocation from 87300 in 2005. | | | | | |
| 165 | | | | | | |
| 166 | Costs increase from 2006 to 2007 mainly due to an increase in fringe benefits ( 32). For an explanation of this fringe increase | | | | | |
| 167 | please refer to Account 64000. This increase is also due to labour inflation ( 15), and non-labour inflation ( 5). | | | | | |
| 168 | | | | | | |
| 169 | Costs increase from 2007 to 2008 mainly due to labour inflation ( 41), new attraction and retention pay ( 23), fringe | | | | | |
| 170 | benefits ( 5) and other inflation ( 3) | | | | | |
| 171 | | | | | | |
| 172 | Costs increase from 2008 to 2009 mainly due to labour inflation. | | | | | |
| 173 | | | | | | |
| 174 | 71200 - Meter Reading | 373 | 391 | 464 | 436 | 471 |
| 175 | | | | | | |
| 176 | Costs increase from 2006 to 2007 mainly due to increase in fringe benefits ( 38). For an explanation of this fringe increase | | | | | |
| 177 | please refer to Account 64000. This increase is also due to higher labour costs ( 23), annual labour inflation ( 10), | | | | | |
| 178 | and non-labour inflation ( 2). | | | | | |
| 179 | | | | | | |
| 180 | Costs decrease from 2007 to 2008 mainly due to utilization of non-journeyman labour for meter reading services | | | | | |
| 181 | as an additional Field Service Representative was added to the labour compliment ( 40) and related fringe benefits | | | | | |
| 182 | decrease ( 14). This is offset by labour inflation ( 11), new attraction and retention pay ( 9) and other dollar inflation ( 6). | | | | | |
| 183 | | | | | | |
| 184 | Costs increase from 2008-2009 mainly due to inflation. | | | | | |
| 185 | | | | | | |
| 186 | 71300 - Customer Billing & Accounting | 441 | 474 | 513 | 572 | 646 |
| 187 | | | | | | |
| 188 | Costs increase from 2006 to 2007 mainly due to inflation ( 24) and an increase in fringe benefits ( 15). For an explanation | | | | | |
| 189 | of the fringe increase please refer to Account 64000. | | | | | |
| 190 | | | | | | |
| 191 | Costs increase from 2007 to 2008 due to implementing the new ATCO-CIS billing system. The new system conversion | | | | | |
| 192 | is planned to be completed by July 2008. | | | | | |
| 193 | | | | | | |
| 194 | Costs increase from 2008 to 2009 due to full year impact of the new ATCO-CIS billing system costs. | | | | | |
| 195 | | | | | | |
| 196 | 71400 - Revenue Collections | 178 | 167 | 181 | 162 | 258 |
| 197 | | | | | | |
| 198 | Costs increase from 2006 to 2007 mainly due to an increase in fringe benefits ( 18). For an explanation of this fringe increase | | | | | |
| 199 | please refer to Account 64000. This increase is also due to labour inflation ( 5) offset by decreased payment agent costs | | | | | |
| 200 | from closure of payment agents in some communities outside Whitehorse ( 9). | | | | | |
| 201 | | | | | | |
| 202 | Costs decrease from 2007 to 2008 mainly due to decreased labour and fringe as we migrate off of taking payments at | | | | | |
| 203 | our service building in Watson Lake. | | | | | |
| 204 | | | | | | |
| 205 | Costs increase from 2008 to 2009 due to the commencement of accepting credit cards for customer payments. | | | | | |
| 206 | | | | | | |
| 207 | 71500 - Collection of Delinquent Accounts | 141 | 121 | 124 | 142 | 158 |
| 208 | | | | | | |
| 209 | Costs increase from 2007 to 2008 due to labour inflation ( 14) and non-labour inflation ( 4). | | | | | |
| 210 | | | | | | |
| 211 | Costs increase from 2008 to 2009 due to labour inflation. | | | | | |
| 212 | | | | | | |

| Line No. | Description | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|
| 213 | **Administration and general** | | | | | |
| 214 | | | | | | |
| 215 | 72100 - Administrative | 1,101 | 1,149 | 1,176 | 1,331 | 1,399 |
| 216 | | | | | | |
| 217 | Costs increase from 2007 to 2008 mainly due increased head office support for phase I & II GRA filings that are forecast | | | | | |
| 218 | on a levelized basis as well as increased financial reporting requirements ( 80). The increase is also due to other inflation ( 50), | | | | | |
| 219 | and labour inflation ( 25). | | | | | |
| 220 | | | | | | |
| 221 | Costs increase from 2008 to 2009 mainly due to inflation. | | | | | |
| 222 | | | | | | |
| 223 | 72200 - Administration Corporate | 104 | 27 | 14 | 30 | 32 |
| 224 | | | | | | |
| 225 | Costs decrease from 2005 to 2006 due to one-time costs for Regulatory intervention. | | | | | |
| 226 | | | | | | |
| 227 | Costs decrease from 2006 to 2007 due to a decrease in regulatory costs and costs awards credited in 2007 from | | | | | |
| 228 | previous year. | | | | | |
| 229 | | | | | | |
| 230 | Cost increase from 2007 to 2008 is mainly due to the absence of any credits for regulatory cost awards from YUB. | | | | | |
| 231 | | | | | | |
| 232 | 72300 - Insurance | 202 | 194 | 190 | 231 | 244 |
| 233 | | | | | | |
| 234 | Cost increase from 2007 to 2008 mainly due to an updated Comprehensive General Liability (CGL) corporate allocation methodology. | | | | | |
| 235 | | | | | | |
| 236 | 72500 - Employee Expenses | 176 | 208 | 229 | 222 | 312 |
| 237 | | | | | | |
| 238 | Costs increase from 2006 to 2007 mainly due to labour from employee illness. | | | | | |
| 239 | | | | | | |
| 240 | Costs increase from 2008 to 2009 mainly due to employee northern travel benefits increasing for attraction and retention. | | | | | |
| 241 | | | | | | |
| 242 | 72600 - Training and Safety | 174 | 247 | 297 | 449 | 484 |
| 243 | | | | | | |
| 244 | Costs increase from 2005 to 2006 mainly due to an increase in labour costs allocated to training. | | | | | |
| 245 | | | | | | |
| 246 | Costs increased from 2006 to 2007 mainly due an increase in fringe benefits ( 25). For an explanation of this fringe increase | | | | | |
| 247 | please refer to Account 64000. This increase is also due to labour from increased apprenticeship training ( 13), | | | | | |
| 248 | and increased other costs for driver training and other programs ( 12). | | | | | |
| 249 | | | | | | |
| 250 | Costs increase from 2007 to 2008 mainly due to increased labour for HS&E management position and other staff | | | | | |
| 251 | labour ( 102), other dollar escalations for safety and training programs ( 30), and fringe benefits ( 20). | | | | | |
| 252 | New training initiatives include: continuation of apprenticeship training for two apprentices; new core certification compliance | | | | | |
| 253 | training (per revised Government occupational health and safety Act); new national transport safety compliance training; | | | | | |
| 254 | management of environmental affairs with increased rigor around environmental policy issues; journeyman | | | | | |
| 255 | certification refresher training; transportation of dangerous goods by air; WHIMS; and advanced driver training. | | | | | |
| 256 | | | | | | |
| 257 | 72700 - Relocation | 311 | 190 | 93 | 182 | 77 |
| 258 | | | | | | |
| 259 | Costs decrease from 2005 to 2006 due to less one-time moving and relocation expenses for employees. | | | | | |
| 260 | | | | | | |
| 261 | Costs decrease from 2006 to 2007 mainly due to lower costs due to unfilled vacancies. | | | | | |
| 262 | | | | | | |
| 263 | Costs increase from 2007 to 2008 mainly due to higher costs because of out of Yukon hires requiring moving | | | | | |
| 264 | and relocation expenses. | | | | | |
| 265 | | | | | | |
| 266 | Costs decrease from 2008 to 2009 due to lower staff turnover anticipated. | | | | | |
| 267 | | | | | | |
| 268 | 72900 - Audit Legal Fees & Special Studies | 62 | 106 | 88 | 95 | 100 |
| 269 | | | | | | |
| 270 | Costs increase from 2005 to 2006 mainly due to employee association bargaining costs and other one-time costs. | | | | | |
| 271 | | | | | | |
| 272 | Costs decrease from 2006 to 2007 mainly due to decreased legal costs in 2006. | | | | | |
| 273 | | | | | | |
| 274 | Costs increase from 2007 to 2008 mainly due to an increase in audit fees. | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Affiliate Charges included in Operations and Maintenance**
**( 000s)**

**Schedule 5.3**

| Line No. | O M Category | Affiliate Company | Services Provided | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Details of Affiliate Costs in Operations and Maintenance | | | | | | | | | | |
| 2 | 87500 - Meters and Meter Testing | ATCO Electric | Metering Services | | 41 | 34 | 37 | 37 | 32 | 40 | 42 |
| 3 | | | | | | | | | | | |
| 4 | 72100 - Administrative | ATCO Electric | After Hours Answering | | | | | - | 28 | 26 | 26 |
| 5 | 71200 - Meter Reading | ATCO Gas | Meter Services | | 41 | 41 | 34 | 34 | 37 | 39 | 41 |
| 6 | | | | | | | | | | | |
| 7 | 72100 - Administrative Expenses | ATCO Gas | Office Services | | 5 | 11 | 7 | 8 | 14 | 15 | 16 |
| 8 | | | | | | | | | | | |
| 9 | 72100 - Administrative Expenses | ATCO I-Tek | Information Technology | Note 1 | 228 | 270 | 306 | 311 | 331 | 353 | 370 |
| 10 | | | | | | | | | | | |
| 11 | 71300 - Customer Billing and Accounting | ATCO I-Tek Business Services | Billing System Services | Note 1 | 310 | 322 | 339 | 354 | 366 | 434 | 484 |
| 12 | | | | | | | | | | | |
| 13 | | | | | | | | | | | |
| 14 | Details of Head Office Costs | | | | | | | | | | |
| 15 | 72100 - Administrative Expenses | ATCO Electric | Governance | | 16 | 15 | 22 | 22 | 22 | 24 | 25 |
| 16 | 72100 - Administrative Expenses | | Human Resources | | 58 | 59 | 67 | 67 | 67 | 87 | 90 |
| 17 | 72100 - Administrative Expenses | | Health and Safety | | 22 | 25 | 18 | 18 | 19 | - | - |
| 18 | 72100 - Administrative Expenses | | Regulatory Phase II | | | | | - | - | 12 | 3 |
| 19 | 72100 - Administrative Expenses | | Financial Reporting and Regulatory Phase I | | 30 | 32 | 25 | 25 | 26 | 87 | 73 |
| 20 | 72100 - Administrative Expenses | | Payroll | | 7 | 7 | 7 | 7 | 6 | 9 | 10 |
| 21 | 72100 - Administrative Expenses | | Use of Systems | | 71 | 56 | 12 | 10 | 8 | 5 | 6 |
| 22 | 72100 - Administrative Expenses | | information Technology | | 3 | 3 | 3 | 3 | 3 | 2 | 3 |
| 23 | | | Total Head Office Fees | | 207 | 197 | 154 | 152 | 151 | 226 | 210 |
| 24 | | | | | | | | | | | |
| 25 | | | | | | | | | | | |
| 26 | | | | | | | | | | | |
| 27 | 72100 - Administrative Expenses | ATCO Electric | Material Management | | 10 | 10 | 10 | 12 | 9 | - | - |
| 28 | | | | | | | | | | | |
| 29 | | | | | | | | | | | |
| 30 | | | | | | | | | | | |
| 31 | | | | | | | | | | | |
| 32 | Total Affiliate Costs included in Operations and Maintenance | | | | 842 | 885 | 887 | 908 | 968 | 1,133 | 1,189 |

33 Note 1 - The test period forecast costs are placeholders pending the completion of a benchmarking study. Please refer to Affiliate Costs write-up on Pages 5-3 & 5-4.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Depreciation Expense**

**Schedule 7.1**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | General Provision | S. 7.2, 7.3 L.50 | 3,836 | 4,062 | 4,335 | 4,580 | 5,052 |
| 2 | Amortization of Differences | S.7.4 L. 50 | (83) | (140) | (140) | (191) | (191) |
| 3 | Vehicle Depreciation Capitalized | | (26) | (21) | (24) | (24) | (24) |
| 4 | Total Depreciation Expense | S.8.6 L.11 | 3,727 | 3,901 | 4,171 | 4,365 | 4,837 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Calculation of Depreciation Expense 2008**

**Schedule 7.2**

| Line No. | Acct. | Description | Cross Ref. | 2008 Opening PPE | Depreciation Rate | Depreciation on Opening Balance | Capital Additions | Depreciation on Capital Additions | 2008 Total Deprecation |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | Production - Hydro | | | | | | | |
| 2 | | | | | | | | | - |
| 3 | 422 00 | Hydro Structures | | 259 | 3.70 | 10 | 449 | 8 | 18 |
| 4 | 423 00 | Hydro Resv, Dams & Waterways | | 757 | 3.70 | 28 | - | - | 28 |
| 5 | 425 00 | Hydro Generators | | 273 | 3.70 | 10 | - | - | 10 |
| 6 | 426 00 | Hydro Accessory Electrical Equip | | 105 | 3.70 | 4 | - | - | 4 |
| 7 | 427 00 | Hydro Misc Equip | | 24 | 3.70 | 1 | - | - | 1 |
| 8 | | Total Production - Hydro | | 1,418 | | 53 | 449 | 8 | 61 |
| 9 | | | | | | | | | |
| 10 | | Production - Diesel | | | | | | | |
| 11 | 442 00 | Structures and improvement - Other | | 1,498 | 2.74 | 41 | - | - | 41 |
| 12 | 444 00 | Fuel Holders, Proucers, & Acc. Equipment - Other | | 2,137 | 3.90 | 83 | 87 | 2 | 85 |
| 13 | 445 00 | Generating Equipment & Prime Mover - Other | | 8,444 | 4.06 | 343 | 347 | 7 | 350 |
| 14 | 446 00 | Accessory Electric Equipment - Other | | 2,142 | 3.00 | 64 | 91 | 1 | 65 |
| 15 | 447 00 | Misc. Power Plant Equipment - Other | | 643 | 3.31 | 21 | 27 | - | 21 |
| 16 | | Total Production - Diesel | | 14,864 | | 552 | 552 | 10 | 562 |
| 17 | | | | | | | | | |
| 18 | | Transmission | | | | | | | |
| 19 | 457 00 | Substation Equipment | | 1,401 | 2.55 | 36 | - | - | 36 |
| 20 | | Total Transmission | | 1,401 | | 36 | - | - | 36 |
| 21 | | | | | | | | | |
| 22 | | Distribution Plant | | | | | | | |
| 23 | 471 00 | Land Rights | | 929 | 1.52 | 14 | - | - | 14 |
| 24 | 473 00 | Poles, Towers & Fixtures | | 22,740 | 4.27 | 971 | 1,689 | 36 | 1,007 |
| 25 | 474 00 | Overhead Conductor | | 15,092 | 4.57 | 690 | 1,186 | 27 | 717 |
| 26 | 474 10 | Services - Overhead | | 2,306 | 2.62 | 60 | 183 | 2 | 62 |
| 27 | 475 00 | Underground Conductor | | 17,426 | 2.22 | 387 | 1,385 | 15 | 402 |
| 28 | 475 10 | Services - Underground | | 2,547 | 2.63 | 67 | 202 | 3 | 70 |
| 29 | 476 10 | Meters | | 1,263 | 9.00 | 114 | (82) | - | 114 |
| 30 | 476 30 | AMR - Meters | | 8 | 4.54 | - | 330 | 7 | 7 |
| 31 | 477 10 | Substation Equipment | | 3,132 | 2.92 | 91 | - | - | 91 |
| 32 | 478 10 | Street Lighting | | 7,699 | 4.54 | 350 | 498 | 11 | 361 |
| 33 | 478 20 | Sentinel Lights | | 285 | 3.03 | 9 | | - | 9 |
| 34 | 479 10 | Line Transformers | | 17,596 | 3.19 | 561 | 1,311 | 21 | 582 |
| 35 | | Total Distribution Plant | | 91,023 | | 3,314 | 6,702 | 122 | 3,436 |
| 36 | | | | | | | | | |
| 37 | | General Plant | | | | | | | |
| 38 | 482 00 | Structures & Improvements | | 3,184 | 3.03 | 96 | 199 | 3 | 99 |
| 39 | 483 00 | Office Furniture & Equipment | | 220 | 4.49 | 10 | (25) | - | 10 |
| 40 | 483.20 | Computer Equipment | | 37 | 20.00 | 7 | 0 | - | 7 |
| 41 | 484 00 | Transportation & Mobile Equipment | | 2,207 | 8.66 | 191 | 147 | 6 | 197 |
| 42 | 485 00 | Tool & Work Equipment | | 501 | 6.54 | 33 | (9) | - | 33 |
| 43 | 486 00 | Communication Structures & Equipment | | 491 | 5.79 | 28 | 102 | 3 | 31 |
| 44 | 488 20 | Company Housing | | 388 | 2.47 | 10 | 19 | - | 10 |
| 45 | 491 00 | Franchise & Consent | | 1 | 0.00 | - | - | - | - |
| 46 | 496 xx | New ATCO-CIS | | - | 10.00 | - | 1,488 | 74 | 74 |
| 47 | 496 05 | Oracle Financials | | 235 | 10.00 | 24 | | - | 24 |
| 48 | | Total General Plant | | 7,266 | | 399 | 1,921 | 86 | 485 |
| 49 | | | | | | | | | |
| 50 | | Plant Studied | | 115,972 | | 4,354 | 9,624 | 226 | 4,580 |
| 51 | | Plant Not Studied - Land | | 479 | | | | | |
| 52 | | Total Plant | S.8.6 L.6 | 116,451 | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Calculation of Depreciation Expense 2009**

**Schedule 7.3**

| Line No. | Acct. | Description | Cross Ref. | 2009 Opening PPE | Depreciation Rate | Depreciation on Opening Balance | Capital Additions | Depreciation on Capital Additions | 2009 Total Deprecation |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | Production - Hydro | | | | | | | |
| 2 | | | | | | | | | |
| 3 | 422 00 | Hydro Structures | | 259 | 3.70 | 10 | - | - | 10 |
| 4 | 423 00 | Hydro Resv, Dams & Waterways | | 1,206 | 3.70 | 45 | 687 | 13 | 58 |
| 5 | 425 00 | Hydro Generators | | 273 | 3.70 | 10 | - | - | 10 |
| 6 | 426 00 | Hydro Accessory Electrical Equip | | 105 | 3.70 | 4 | - | - | 4 |
| 7 | 427 00 | Hydro Misc Equip | | 24 | 3.70 | 1 | - | - | 1 |
| 8 | | Total Production - Hydro | | 1,867 | | 70 | 687 | 13 | 83 |
| 9 | | | | | | | | | |
| 10 | | Production - Diesel | | | | | | | |
| 11 | 442 00 | Structures and improvement - Other | | 1,498 | 2.74 | 41 | - | - | 41 |
| 12 | 444 00 | Fuel Holders, Proucers, & Acc. Equipment - Other | | 2,223 | 3.90 | 87 | 386 | 8 | 95 |
| 13 | 445 00 | Generating Equipment & Prime Mover - Other | | 8,792 | 4.06 | 357 | 1,530 | 31 | 388 |
| 14 | 446 00 | Accessory Electric Equipment - Other | | 2,232 | 3.00 | 67 | 390 | 6 | 73 |
| 15 | 447 00 | Misc. Power Plant Equipment - Other | | 670 | 3.31 | 22 | 117 | 2 | 24 |
| 16 | | Total Production - Diesel | | 15,416 | | 574 | 2,424 | 47 | 621 |
| 17 | | | | | | | | | |
| 18 | | Transmission | | | | | | | |
| 19 | 457 00 | Substation Equipment | | 1,401 | 2.55 | 36 | - | - | 36 |
| 20 | | Total Transmission | | 1,401 | | 36 | - | - | 36 |
| 21 | | | | | | | | | |
| 22 | | Distribution Plant | | | | | | | |
| 23 | 471 00 | Land Rights | | 929 | 1.52 | 14 | - | - | 14 |
| 24 | 473 00 | Poles, Towers & Fixtures | | 24,430 | 4.27 | 1,043 | 1,612 | 34 | 1,077 |
| 25 | 474 00 | Overhead Conductor | | 16,278 | 4.57 | 744 | 1,065 | 24 | 768 |
| 26 | 474 10 | Services - Overhead | | 2,489 | 2.62 | 65 | 165 | 2 | 67 |
| 27 | 475 00 | Underground Conductor | | 18,811 | 2.22 | 418 | 1,246 | 14 | 432 |
| 28 | 475 10 | Services - Underground | | 2,749 | 2.63 | 72 | 182 | 2 | 74 |
| 29 | 476 10 | Meters | | 1,181 | 9.00 | 106 | (341) | - | 106 |
| 30 | 476 30 | AMR - Meters | | 338 | 4.54 | 15 | 2,720 | 62 | 77 |
| 31 | 477 10 | Substation Equipment | | 3,132 | 2.92 | 91 | 580 | 8 | 99 |
| 32 | 478 10 | Street Lighting | | 8,197 | 4.54 | 372 | 487 | 11 | 383 |
| 33 | 478 20 | Sentinel Lights | | 285 | 3.03 | 9 | - | - | 9 |
| 34 | 479 10 | Line Transformers | | 18,907 | 3.19 | 603 | 1,178 | 19 | 622 |
| 35 | | Total Distribution Plant | | 97,725 | | 3,552 | 8,893 | 176 | 3,728 |
| 36 | | | | | | | | | |
| 37 | | General Plant | | | | | | | |
| 38 | 482 00 | Structures & Improvements | | 3,383 | 3.03 | 103 | 161 | 2 | 105 |
| 39 | 483 00 | Office Furniture & Equipment | | 194 | 4.49 | 9 | (28) | - | 9 |
| 40 | 483.20 | Computer Equipment | | 38 | 20.00 | 8 | (1) | - | 8 |
| 41 | 484 00 | Transportation & Mobile Equipment | | 2,354 | 8.66 | 204 | 172 | 7 | 211 |
| 42 | 485 00 | Tool & Work Equipment | | 492 | 6.54 | 32 | (2) | - | 32 |
| 43 | 486 00 | Communication Structures & Equipment | | 593 | 5.79 | 34 | 54 | 2 | 36 |
| 44 | 488 20 | Company Housing | | 407 | 2.47 | 10 | 19 | - | 10 |
| 45 | 491 00 | Franchise & Consent | | 1 | 0.00 | - | - | - | - |
| 46 | 496 xx | New ATCO-CIS | | 1,488 | 10.00 | 149 | - | - | 149 |
| 47 | 496 05 | Oracle Financials | | 235 | 10.00 | 24 | - | - | 24 |
| 48 | | Total General Plant | | 9,187 | | 573 | 375 | 11 | 584 |
| 49 | | | | | | | | | |
| 50 | | Plant Studied | | 125,597 | | 4,805 | 12,379 | 247 | 5,052 |
| 51 | | Plant Not Studied -Land | | 479 | | | | | |
| 52 | | Total Plant | S.8.6 L.6 | 126,076 | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Amortization of Differences**

**Schedule 7.4**

| Line No. | Acct. | Description | Cross Ref. | YFR Curve | Life | Net Salvage | Depn. Rates | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Production - Hydro | | | | | | | | | | |
| 2 | | | | | | | | | | | | |
| 3 | 422 00 | Hydro Structures | | R3 | 30 | -10 | 3.70 | (11) | (11) | (11) | (17) | (17) |
| 4 | 423 00 | Hydro Resv, Dams & Waterways | | R3 | 30 | -10 | 3.70 | - | - | - | - | - |
| 5 | 425 00 | Hydro Generators | | R3 | 30 | -10 | 3.70 | - | - | - | - | - |
| 6 | 426 00 | Hydro Accessory Electrical Equip | | R3 | 30 | -10 | 3.70 | - | - | - | - | - |
| 7 | 427 00 | Hydro Misc Equip | | R3 | 30 | -10 | 3.70 | - | - | - | - | - |
| 8 | | Total Production - Hydro | | | | | | (11) | (11) | (11) | (17) | (17) |
| 9 | | | | | | | | | | | | |
| 10 | | Production - Diesel | | | | | | | | | | |
| 11 | 442 00 | Structures and improvement - Other | | R2.5 | 40 | 0 | 2.74 | - | - | - | (2) | (2) |
| 12 | 444 00 | Fuel Holders, Proucers, & Acc. Equipment - Other | | R4 | 35 | -30 | 3.90 | (2) | (1) | (1) | (3) | (3) |
| 13 | 445 00 | Generating Equipment & Prime Mover - Other | | R2.5 | 27 | -10 | 4.06 | (24) | (28) | (28) | (24) | (24) |
| 14 | 446 00 | Accessory Electric Equipment - Other | | R3 | 35 | 0 | 3.00 | (5) | (7) | (7) | (16) | (16) |
| 15 | 447 00 | Misc. Power Plant Equipment - Other | | R3 | 35 | -5 | 3.31 | (1) | (1) | (1) | (2) | (2) |
| 16 | | Total Production - Diesel | | | | | | (32) | (37) | (37) | (47) | (47) |
| 17 | | | | | | | | | | | | |
| 18 | | Transmission | | | | | | | | | | |
| 19 | 457 00 | Substation Equipment | | R4 | 40 | 0 | 2.55 | (2) | (2) | (2) | (4) | (4) |
| 20 | | Total Transmission | | | | | | (2) | (2) | (2) | (4) | (4) |
| 21 | | | | | | | | | | | | |
| 22 | | Distribution Plant | | | | | | | | | | |
| 23 | 471 00 | Land Rights | | R3 | 75 | 0 | 1.52 | - | (0) | (0) | - | - |
| 24 | 473 00 | Poles, Towers & Fixtures | | R3 | 40 | -60 | 4.27 | 7 | 3 | 3 | (47) | (47) |
| 25 | 474 00 | Overhead Conductor | | R3 | 40 | -70 | 4.57 | (7) | (8) | (8) | 19 | 19 |
| 26 | 474 10 | Services - Overhead | | R3 | 40 | 0 | 2.62 | (4) | (5) | (5) | (10) | (10) |
| 27 | 475 00 | Underground Conductor | | R4 | 50 | -5 | 2.22 | (5) | (5) | (5) | 1 | 1 |
| 28 | 475 10 | Services - Underground | | R4 | 40 | 0 | 2.63 | 0 | - | - | (6) | (6) |
| 29 | 476 10 | Meters | | n a | 0 | 0 | 9.00 | 24 | 24 | 24 | - | - |
| 30 | 476 30 | AMR - Meters | | S2 | 25 | 0 | 4.54 | | | | | |
| 31 | 477 10 | Substation Equipment | | R3 | 35 | 0 | 2.92 | (9) | (5) | (5) | - | - |
| 32 | 478 10 | Street Lighting | | R3 | 25 | -10 | 4.54 | 3 | (15) | (15) | (25) | (25) |
| 33 | 478 20 | Sentinel Lights | | R2 | 23 | 10 | 3.03 | (8) | (11) | (11) | - | - |
| 34 | 479 10 | Line Transformers | | R3 | 35 | -5 | 3.19 | (21) | (25) | (25) | (69) | (69) |
| 35 | | Total Distribution Plant | | | | | | (20) | (47) | (47) | (137) | (137) |
| 36 | | | | | | | | | | | | |
| 37 | | General Plant | | | | | | | | | | |
| 38 | 482 00 | Structures & Improvements | | R4 | 32 | 5 | 3.03 | (2) | (3) | (3) | 3 | 3 |
| 39 | 483 00 | Office Furniture & Equipment | | SQ | 15 | 0 | 4.49 | 2 | - | - | 3 | 3 |
| 40 | 483.20 | Computer Hardware Software | | SQ | 5 | 0 | 20.00 | 2 | (14) | (14) | - | - |
| 41 | 484 00 | Transportation & Mobile Equipment | | R0.5 | 10 | 20 | 8.66 | (27) | (33) | (33) | - | - |
| 42 | 485 00 | Tool & Work Equipment | | SQ | 15 | 0 | 6.54 | 6 | 6 | 6 | (3) | (3) |
| 43 | 486 00 | Communication Structures & Equipment | | SQ | 15 | 0 | 5.79 | 1 | 1 | 1 | 11 | 11 |
| 44 | 488 20 | Company Housing | | R3 | 40 | 10 | 2.47 | | | | | |
| 45 | 491 00 | Franchise & Consent | | | | | 0.00 | - | - | - | - | - |
| 46 | 496 xx | New ATCO-CIS | | | | | 10.00 | | | | | |
| 47 | 496 05 | Oracle Financials | | S3 | 10 | 0 | 10.00 | - | - | - | - | - |
| 48 | | Total General Plant | | | | | | (18) | (43) | (43) | 14 | 14 |
| 49 | | | | | | | | | | | | |
| 50 | | Total Amortization of Differences | S. 7.1 L 2 | | | | | (83) | (140) | (140) | (191) | (191) |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Return on Rate Base**
**( 000s)**



| Line No. | Description | Cross Ref. | Mid Year Balance | Ratio | Mid Year Rate Base | Mid Year Cost Rate | Return |
|---|---|---|---|---|---|---|---|
| 1 | **2003 Actuals** | | | | | | |
| 2 | Long-term debt | S.8.2 L.16 | 19,600 | 55.88 | 19,922 | 7.51 | 1,497 |
| 3 | Common stock | | 15,032 | 42.86 | 15,279 | 11.02 | 1,683 |
| 4 | No Cost Capital | S.8.4 L.8 | 443 | 1.26 | 450 | 0.00 | - |
| 5 | Total | S.8.5 L.21 | 35,075 | 100 | 35,652 | 8.92 | 3,180 |
| | | S.1.1 L.15 | | | | | |
| 6 | **2004 Actuals** | | | | | | |
| 7 | Long-term debt | S.8.2 L.19 | 20,100 | 56.23 | 20,452 | 7.37 | 1,508 |
| 8 | Common stock | | 15,253 | 42.67 | 15,520 | 10.81 | 1,678 |
| 9 | No Cost Capital | S.8.4 L.8 | 392 | 1.10 | 399 | 0.00 | - |
| 10 | Total | S.8.5 L.21 | 35,745 | 100 | 36,372 | 8.76 | 3,186 |
| | | S.1.1 L.15 | | | | | |
| 11 | **2005 Actual** | | | | | | |
| 12 | Long-term debt | S.8.2 L.37 | 21,000 | 56.28 | 21,554 | 7.54 | 1,626 |
| 13 | Common stock | | 15,905 | 42.63 | 16,324 | 8.99 | 1,467 |
| 14 | No Cost Capital | S.8.4 L.8 | 406 | 1.09 | 417 | 0.00 | - |
| 15 | Total | S.8.5 L.21 | 37,311 | 100 | 38,295 | 8.08 | 3,093 |
| | | S.1.1 L.15 | | | | | |
| 16 | **2006 Actuals** | | | | | | |
| 17 | Long-term debt | S.8.2 L.55 | 22,475 | 57.18 | 23,430 | 7.14 | 1,674 |
| 18 | Common stock | | 16,280 | 41.42 | 16,972 | 10.66 | 1,810 |
| 19 | No Cost Capital | S.8.4 L.8 | 549 | 1.40 | 572 | 0.00 | - |
| 20 | Total | S.8.5 L.21 | 39,304 | 100 | 40,973 | 8.50 | 3,484 |
| | | S.1.1 L.15 | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Return on Rate Base**
**( 000s)**



| Line No. | Description | Cross Ref. | Mid Year Balance | Ratio | Mid Year Rate Base | Mid Year Cost Rate | Return |
|---|---|---|---|---|---|---|---|
| 21 | **2007 Actual** | | | | | | |
| 22 | Long-term debt | S.8.3 L.19 | 23,800 | 57.60 | 25,117 | 7.03 | 1,766 |
| 23 | Common stock | | 16,890 | 40.87 | 17,825 | 10.37 | 1,848 |
| 24 | No Cost Capital | S.8.4 L.8 | 632 | 1.53 | 666 | 0.00 | - |
| 25 | Total | S.8.5 L.21<br>S.1.1 L.15 | 41,322 | 100 | 43,608 | 8.29 | 3,614 |
| 26 | **2008 Test Period** | | | | | | |
| 27 | Long-term debt | S.8.3 L.38 | 24,575 | 54.23 | 24,838 | 7.01 | 1,741 |
| 28 | Common stock | | 20,071 | 44.29 | 20,286 | 9.25 | 1,877 |
| 29 | No Cost Capital | S.8.4 L.8 | 669 | 1.48 | 676 | 0.00 | - |
| 30 | Total | S.8.5 L.21<br>S.1.1 L.15 | 45,315 | 100 | 45,800 | 7.90 | 3,618 |
| 31 | **2009 Test Period** | | | | | | |
| 32 | Long-term debt | S.8.2 L.111 | 26,950 | 51.81 | 26,498 | 6.83 | 1,810 |
| 33 | Common stock | | 24,376 | 46.86 | 23,967 | 9.25 | 2,216 |
| 34 | No Cost Capital | S.8.4 L.8 | 695 | 1.34 | 683 | 0.00 | - |
| 35 | Total | S.8.5 L.21<br>S.1.1 L.15 | 52,021 | 100 | 51,149 | 7.87 | 4,026 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Debt Capital Employed and Embedded Cost**
**( 000's)**

**2003 Actuals** — **Net Capital Employed**

| Line | Description | Series | Issue Date | Coupon Rate | Maturity Date | Principal Amount Offered | Total Amount | Per 100 of Principal Amount | Effective Cost Rate | Principal Outstanding 31-Dec-03 | Carrying Cost | Average Embedded Cost Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 6 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 7 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 8 | | G | 06-01-1995 | 8.51 | 2005 | 4,000 | 4,000 | 100.00 | 8.56 | 4,000 | 342 | |
| 9 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 10 | | L | 06-02-2000 | 7.00 | 2008 | 600 | 600 | 100.00 | 7.05 | 600 | 42 | |
| 11 | | M | 11-06-2001 | 4.90 | 2006 | 350 | 350 | 100.00 | 4.95 | 350 | 17 | |
| 12 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 13 | Total | | | | | 19,350 | | | | 19,350 | 1,333 | 6.89 |
| 14 | Prior Year | | | | | | | | | 19,850 | 1,612 | 8.12 |
| 15 | Total | | | | | | | | | 39,200 | 2,945 | |
| 16 | Mid Year | | | | | | | | | 19,600 | 1,473 | 7.51 |

**2004 Actuals** — **Net Capital Employed**

| Line | Description | Series | Issue Date | Coupon Rate | Maturity Date | Principal Amount Offered | Total Amount | Per 100 of Principal Amount | Effective Cost Rate | Principal Outstanding 31-Dec-04 | Carrying Cost | Average Embedded Cost Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 21 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 22 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 23 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 24 | | G | 06-01-1995 | 8.51 | 2005 | 4,000 | 4,000 | 100.00 | 8.56 | 4,000 | 342 | |
| 25 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 26 | | L | 06-02-2000 | 7.00 | 2008 | 600 | 600 | 100.00 | 7.05 | 600 | 42 | |
| 27 | | M | 11-06-2001 | 4.90 | 2006 | 350 | 350 | 100.00 | 4.95 | 350 | 17 | |
| 28 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 13 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 14 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 16 | Total | | | | | 20,850 | | | | 20,850 | 1,630 | 7.82 |
| 17 | Prior Year | | | | | | | | | 19,350 | 1,333 | 6.89 |
| 18 | Total | | | | | | | | | 40,200 | 2,963 | |
| 19 | Mid Year | | | | | | | | | 20,100 | 1,482 | 7.37 |

**Yukon Electrical Limited**
**2008 - 2009 General Rate Application**
**Schedule of Debt Capital Employed and Embedded Cost**
**( 000's)**

**2005 Actuals** — **Net Capital Employed**

| Line No. | Description | Series | Issue Date | Coupon Rate | Maturity Date | Principal Amount Offered | Total Amount | Per 100 of Principal Amount | Effective Cost Rate | Principal Outstanding 31-Dec-05 | Carrying Cost | Average Embedded Cost Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 25 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 26 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 27 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 28 | | L | 06-02-2000 | 7.00 | 2008 | 600 | 600 | 100.00 | 7.05 | 600 | 42 | |
| 29 | | M | 11-06-2001 | 4.90 | 2006 | 350 | 350 | 100.00 | 4.95 | 350 | 17 | |
| 30 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 31 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 32 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 33 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 34 | Total | | | | | 21,150 | | | | 21,150 | 1,538 | 7.27 |
| 35 | Prior Year | | | | | | | | | 20,850 | 1,630 | 7.82 |
| 36 | Total | | | | | | | | | 42,000 | 3,169 | |
| 37 | Mid Year | | | | | | | | | 21,000 | 1,584 | 7.54 |

**2006 Actuals** — **Net Capital Employed**

| Line No. | Description | Series | Issue Date | Coupon Rate | Maturity Date | Principal Amount Offered | Total Amount | Per 100 of Principal Amount | Effective Cost Rate | Principal Outstanding 31-Dec-06 | Carrying Cost | Average Embedded Cost Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 42 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 43 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 44 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 45 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 46 | | L | 06-02-2000 | 7.00 | 2008 | 600 | 600 | 100.00 | 7.05 | 600 | 42 | |
| 47 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 48 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 49 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 50 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 51 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 52 | Total | | | | | 23,800 | | | | 23,800 | 1,673 | 7.03 |
| 53 | Prior Year | | | | | | | | | 21,150 | 1,538 | 7.27 |
| 54 | Total | | | | | | | | | 44,950 | 3,211 | |
| 55 | Mid Year | | | | | | | | | 22,475 | 1,606 | 7.14 |

**Yukon Electrical Limited**
**2008 - 2009 General Rate Application**
**Schedule of Debt Capital Employed and Embedded Cost**
**( 000's)**

| Line No. | | | | | | | Net Capital Employed | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 56 | **2007 Actual** | | | | | | | | | | | |
| 57 | | | | | | Principal | | Per 100 of | | Principal | | Average |
| 58 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | Outstanding | Carrying | Embedded |
| 59 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | **31-Dec-07** | **Cost** | **Cost Rate** |
| 60 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 61 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 62 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 63 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 64 | | L | 06-02-2000 | 7.00 | 2008 | 600 | 600 | 100.00 | 7.05 | 600 | 42 | |
| 65 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 66 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 67 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 68 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 69 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 70 | Total | | | | | 23,800 | | | | 23,800 | 1,673 | 7.03 |
| 71 | Prior Year | | | | | | | | | 23,800 | 1,673 | 7.03 |
| 72 | Total | | | | | | | | | 47,600 | 3,346 | |
| 73 | Mid Year | | | | | | | | | 23,800 | 1,673 | 7.03 |

**Yukon Electrical Limited**
**2008 - 2009 General Rate Application**
**Schedule of Debt Capital Employed and Embedded Cost**
**( 000's)**

| Line No. | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **2008 Test Period** | | | | | | | **Net Capital Employed** | | | | |
| 2 | | | | | | Principal | | Per 100 of | | | Principal | | Average |
| 3 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | | Outstanding | Carrying | Embedded |
| 4 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | | **31-Dec-08** | **Cost** | **Cost Rate** |
| 5 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | | 2,000 | 207 | |
| 6 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | | 1,500 | 179 | |
| 7 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | | 2,500 | 238 | |
| 8 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | | 4,500 | 308 | |
| 9 | | L | 06-02-2000 | 7.00 | 2008 | 0 | 0 | | 7.05 | | 0 | 0 | |
| 10 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | | 3,900 | 242 | |
| 11 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | | 1,000 | 55 | |
| 12 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | | 500 | 26 | |
| 13 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | | 4,300 | 225 | |
| 14 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | | 3,000 | 152 | |
| 15 | | T | 11-20-2008 | 6.55 | 2038 | 2,150 | 2,150 | 100.00 | 6.60 | | 2,150 | 142 | |
| 16 | Total | | | | | 25,350 | | | | | 25,350 | 1,773 | 6.99 |
| 17 | Prior Year | | | | | | | | | | 23,800 | 1,673 | 7.03 |
| 18 | Total | | | | | | | | | | 49,150 | 3,446 | |
| 19 | Mid Year | | | | | | | | | | 24,575 | 1,723 | 7.01 |

| Line No. | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20 | **2009 Test Period** | | | | | | | **Net Capital Employed** | | | | |
| 21 | | | | | | Principal | | Per 100 of | | | Principal | | Average |
| 22 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | | Outstanding | Carrying | Embedded |
| 23 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | | **31-Dec-09** | **Cost** | **Cost Rate** |
| 24 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | | 1,500 | 179 | |
| 25 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | | 2,500 | 238 | |
| 26 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | | 4,500 | 308 | |
| 27 | | L | 06-02-2000 | 7.00 | 2008 | 0 | 0 | | 7.05 | | 0 | 0 | |
| 28 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | | 3,900 | 242 | |
| 29 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | | 1,000 | 55 | |
| 30 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | | 500 | 26 | |
| 31 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | | 4,300 | 225 | |
| 32 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | | 3,000 | 152 | |
| 33 | | T | 11-20-2008 | 6.55 | 2038 | 2,150 | 2,150 | 100.00 | 6.60 | | 2,150 | 142 | |
| 34 | | U | 11-20-2009 | 6.55 | 2039 | 5,200 | 5,200 | 100.00 | 6.60 | | 5,200 | 343 | |
| 35 | Total | | | | | 28,550 | | | | | 28,550 | 1,909 | 6.69 |
| 36 | Prior Year | | | | | | | | | | 25,350 | 1,773 | 6.99 |
| 37 | Total | | | | | | | | | | 53,900 | 3,682 | |
| 38 | Mid Year | | | | | | | | | | 26,950 | 1,841 | 6.83 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Continuity Schedule of No Cost Capital**
**( 000s)**

**Schedule 8.4**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **No Cost Capital** | | | | | | | | |
| 2 | **Deferred Pension and Regulatory Asset Liability** | | | | | | | | |
| 3 | | | | | | | | | |
| 4 | **Mid-Year Balance Summary** | | | | | | | | |
| 5 | Defined Benefit Pension | L.16 | 190 | 267 | 351 | 443 | 514 | 537 | 537 |
| 6 | Other Post Employment Benefits (OPEB) | L.23 | 133 | 153 | 174 | 172 | 171 | 171 | 171 |
| 7 | Injuries & Damages | L.30 | 121 | (28) | (118) | (66) | (53) | (39) | (13) |
| 8 | **Total No Cost Capital Mid-Year Balance** | S.8.1 L.4,9,14,19 | 443 | 392 | 406 | 549 | 632 | 669 | 695 |
| 9 | | | | | | | | | |
| 10 | | | | | | | | | |
| 11 | **Other Post Employment Benefits (OPEB)** | | | | | | | | |
| 12 | Balance at beginning of year | | 151 | 228 | 306 | 395 | 490 | 537 | 537 |
| 13 | Add: Charges | | 104 | 103 | 117 | 123 | 103 | 60 | 60 |
| 14 | Less: Cash Payments | | (27) | (25) | (28) | (28) | (56) | (60) | (60) |
| 15 | Balance at end of year | | 228 | 306 | 395 | 490 | 537 | 537 | 537 |
| 16 | Mid-Year balance | (L.12 L.15) 2 | 190 | 267 | 351 | 443 | 514 | 537 | 537 |
| 17 | | | | | | | | | |
| 18 | **Defined Benefit Pension** | | | | | | | | |
| 19 | Balance at beginning of year | | 133 | 132 | 174 | 173 | 171 | 171 | 171 |
| 20 | Add: Charges | | 9 | 52 | 9 | 9 | 520 | 579 | 629 |
| 21 | Less: Cash Payments | | (10) | (10) | (10) | (11) | (520) | (579) | (629) |
| 22 | Balance at end of year | | 132 | 174 | 173 | 171 | 171 | 171 | 171 |
| 23 | Mid-Year balance | (L.19 L.22) 2 | 133 | 153 | 174 | 172 | 171 | 171 | 171 |
| 24 | | | | | | | | | |
| 25 | **Injuries Damages** | | | | | | | | |
| 26 | Balance at beginning of year | | 140 | 102 | (158) | (78) | (54) | (52) | (26) |
| 27 | Add: Write-off | S.10.1 L.8 | 75 | 75 | 75 | 75 | 75 | 86 | 86 |
| 28 | Less: Costs | S.10.1 L.17 | (113) | (335) | 5 | (51) | (73) | (60) | (60) |
| 29 | Balance at end of year | | 102 | (158) | (78) | (54) | (52) | (26) | 0 |
| 30 | Mid-Year balance | (L.26 L.29) 2 | 121 | (28) | (118) | (66) | (53) | (39) | (13) |
| 31 | | | | | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Computation of Rate Base**
**( 000s)**

**Schedule 8.5**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Property, Plant and Equipment** | | | | | | | | |
| 2 | Year end balance | S.8.6 L.8 | 91,872 | 97,216 | 103,029 | 110,103 | 117,486 | 126,696 | 139,035 |
| 3 | Deduct: | | | | | | | | |
| 4 | Accumulated depreciation | S.8.6 L.14 | 40,001 | 43,126 | 46,441 | 49,959 | 53,768 | 57,693 | 61,314 |
| 5 | Construction-in-progress | S.9.1 L.26 | 609 | 934 | 427 | 871 | 1,035 | 620 | 580 |
| 6 | Total deductions | | 40,610 | 44,060 | 46,868 | 50,830 | 54,803 | 58,313 | 61,894 |
| 7 | **Net plant in Service** | | | | | | | | |
| 8 | Current year-end balance | | 51,262 | 53,156 | 56,161 | 59,273 | 62,683 | 68,382 | 77,140 |
| 9 | Previous year-end balance | | 49,709 | 51,262 | 53,156 | 56,161 | 59,273 | 62,683 | 68,382 |
| 10 | Total | | 100,971 | 104,418 | 109,317 | 115,434 | 121,956 | 131,066 | 145,522 |
| 11 | Mid-year balance | | 50,486 | 52,209 | 54,659 | 57,717 | 60,978 | 65,533 | 72,761 |
| 12 | Mid-year rate deferred charges credits | S.8.8 L.13 | (316) | (391) | (214) | 0 | 309 | 757 | 570 |
| 13 | Working capital | S.8.9 L.29 | 3,025 | 3,127 | 3,240 | 3,683 | 4,078 | 2,805 | 2,650 |
| 14 | **Gross Rate Base** | | 53,196 | 54,946 | 57,685 | 61,400 | 65,365 | 69,095 | 75,981 |
| 15 | Deduct: | | | | | | | | |
| 16 | **Contributions for extensions** | | | | | | | | |
| 17 | Current year-end balance | S.8.11 L.11 | 18,205 | 18,943 | 19,836 | 21,017 | 22,496 | 24,093 | 25,571 |
| 18 | Previous year-end balance | | 16,882 | 18,205 | 18,943 | 19,837 | 21,017 | 22,496 | 24,093 |
| 19 | Total | | 35,087 | 37,148 | 38,779 | 40,854 | 43,513 | 46,589 | 49,664 |
| 20 | Mid-year balance | | 17,544 | 18,574 | 19,390 | 20,427 | 21,757 | 23,295 | 24,832 |
| 21 | **Net Rate Base** | S.8.1 L.5,10,15,20 | 35,652 | 36,372 | 38,295 | 40,973 | 43,608 | 45,800 | 51,149 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Property, Plant and Equipment**
**( 000)**

**Schedule 8.6**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Property, Plant and Equipment** | | | | | | | | |
| 2 | Balance at beginning of year | | 87,141 | 91,263 | 96,282 | 102,602 | 109,232 | 116,451 | 126,076 |
| 3 | Additions | S.9.1 L.25 | 4,603 | 5,358 | 6,623 | 6,872 | 7,645 | 9,975 | 13,544 |
| 4 | Retirement and disposals | S.8.7 L.20 | (481) | (339) | (303) | (242) | (426) | (351) | (1,165) |
| 5 | | S.7.2, 7.3 L.50 | 4,122 | 5,019 | 6,320 | 6,630 | 7,219 | 9,624 | 12,379 |
| 6 | Balance at end of year | S.7.2, 7.3 L.52 | 91,263 | 96,282 | 102,602 | 109,232 | 116,451 | 126,076 | 138,455 |
| 7 | Construction-in-progress | S.9.1 L.26 | 609 | 934 | 427 | 871 | 1,035 | 620 | 580 |
| 8 | Total Property, Plant and Equipment | S.8.5 L.2 | 91,872 | 97,216 | 103,029 | 110,103 | 117,486 | 126,696 | 139,035 |
| 9 | **Accumulated Depreciation** | | | | | | | | |
| 10 | Balance at beginning of year | | 37,432 | 40,001 | 43,126 | 46,441 | 49,959 | 53,768 | 57,693 |
| 11 | Depreciation expense | S.7.1 L.4 | 3,355 | 3,481 | 3,727 | 3,901 | 4,171 | 4,365 | 4,837 |
| 12 | Depreciation capitalized | | 20 | 18 | 26 | 21 | 24 | 24 | 24 |
| 13 | Retirements and dismantling | | (806) | (374) | (438) | (404) | (386) | (464) | (1,240) |
| 14 | Balance at end of year | S.8.5 L.4 | 40,001 | 43,126 | 46,441 | 49,959 | 53,768 | 57,693 | 61,314 |
| 15 | Net Property, Plant and Equipment | | 51,871 | 54,090 | 56,588 | 60,144 | 63,718 | 69,002 | 77,720 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Capital Retirements by Function**
**( 000)**

**Schedule 8.7**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | **Generation** | | | | | | |
| 2 | Other retirements less than 20,000 | | - | - | (3) | (14) | (14) |
| 3 | Total Generation Retirements | | - | - | (3) | (14) | (14) |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | **Distribution** | | | | | | |
| 7 | Poles, Towers & Fixtures | | (76) | (66) | (11) | (68) | (68) |
| 8 | Line transformers | | (15) | (18) | (3) | (18) | (18) |
| 9 | Meters | | (101) | (49) | (15) | (82) | (896) |
| 10 | Other retirements less than 20,000 | | (5) | (7) | (4) | (8) | (8) |
| 11 | Total Distribution Retirements | | (197) | (140) | (33) | (176) | (990) |
| 12 | | | | | | | |
| 13 | **General Plant** | | | | | | |
| 14 | Office Furniture & Equipment | | (45) | (42) | (39) | (44) | (44) |
| 15 | Vehicles | | | - | (289) | (57) | (57) |
| 16 | Tool & Work Equipment | | (61) | (59) | (61) | (59) | (59) |
| 17 | Other retirements less than 20,000 | | | (1) | (2) | (1) | (1) |
| 18 | Total General Plant Retirements | | (106) | (102) | (390) | (161) | (161) |
| 19 | | | | | | | |
| 20 | **Total Capital Retirements** | S.8.6 L.4 | (303) | (242) | (426) | (351) | (1,165) |

**Yukon Electrical Company Limited** **Schedule 8.8**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Deferred Charges Credits**
**( 000s)**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | **Total Deferred Charges Credits Summary** | | | | | | |
| 2 | | | | | | | |
| 3 | **Write-off Summary** | | | | | | |
| 4 | Rate Case Costs | | - | - | - | (375) | (375) |
| 5 | Diesel Plant Major Overhaul Costs | | - | - | (108) | (123) | (123) |
| 6 | Fish Lake License Renewal Costs | | - | - | (79) | (154) | (154) |
| 7 | **Total Write-off** | S.1.1 L.14 | - | - | (187) | (652) | (652) |
| 8 | | | | | | | |
| 9 | **Deferred Credits Mid-Year Balance Summary** | | | | | | |
| 10 | Rate Case Reserve | | (214) | - | 15 | 203 | 188 |
| 11 | Diesel Plant Major Overhaul Costs | | - | - | 215 | 399 | 306 |
| 12 | Fish Lake Licence Reserve | | - | | 79 | 156 | 77 |
| 13 | **Total Deferred Credits Mid-Year Balance** | S.8.5 L.12 | (214) | - | 309 | 757 | 570 |
| 14 | | | | | | | |
| 15 | Rate Case Costs | | | | | | |
| 16 | Balance at beginning of year | | (428) | - | - | 30 | 375 |
| 17 | Add: Rate Case Costs | | | - | 30 | 720 | - |
| 18 | Less: Rate Case Write-off | | 428 | - | - | (375) | (375) |
| 19 | Balance at end of year | | - | - | 30 | 375 | - |
| 20 | | | | | | | |
| 21 | Mid-Year balance | (L.16 L.19) 2 | (214) | - | 15 | 203 | 188 |
| 22 | | | | | | | |
| 23 | Diesel Plant Major Overhaul Costs | | | | | | |
| 24 | Balance at beginning of year | | - | - | - | 430 | 367 |
| 25 | Add: Watson Lake plant overhaul costs | | - | - | 538 | 60 | - |
| 26 | Less; Watson Lake plant overhaul Write-off | | - | - | (108) | (123) | (123) |
| 27 | Balance at end of year | | - | - | 430 | 367 | 244 |
| 28 | | | | | | | |
| 29 | Mid-Year balance | (L.24 L.27) 2 | - | - | 215 | 399 | 306 |
| 30 | | | | | | | |
| 31 | | | | | | | |
| 32 | Fish Lake License Renewal Costs | | | | | | |
| 33 | Balance at beginning of year | | - | - | - | 158 | 154 |
| 34 | Add: Fish Lake Costs | | - | - | 237 | 150 | - |
| 35 | Less: Fish Lake Write-off | | - | - | (79) | (154) | (154) |
| 36 | Balance at end of year | | - | - | 158 | 154 | - |
| 37 | | | | | | | |
| 38 | Mid-Year balance | (L.33 L.36) 2 | - | - | 79 | 156 | 77 |
| 39 | | | | | | | |

**Yukon Electrical Company Limited**
**2008 - 2010 General Rate Application**
**Computation of Allowance for Working Capital**
**( 000s)**

**Schedule 8.9**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | Operating and maintenance | S.1.1 L.9 | 6,755 | 6,969 | 7,290 | 8,758 | 9,317 |
| 2 | Purchased Power | S.1.1 L.7 | 21,681 | 23,239 | 23,647 | 23,846 | 23,494 |
| 3 | Diesel Fuel | S.1.1 L.8 | 2,014 | 2,026 | 2,054 | 5,715 | 5,299 |
| 5 | Property Taxes | S.1.1 L.11 | 230 | 230 | 235 | 249 | 261 |
| 6 | Net O&M | | 30,680 | 32,464 | 33,226 | 38,567 | 38,371 |
| 7 | O&M Lag Days | | 19 | 19 | 19 | 5 | 5 |
| 8 | Operating Expenses Working Capital | | 1,597 | 1,690 | 1,730 | 573 | 570 |
| 9 | Tax installments | | 1,320 | 1,045 | 1,140 | 422 | 500 |
| 10 | Income Tax Installment Lag Days | | 25 | 25 | 25 | 22 | 22 |
| 11 | Tax Installments Working Capital | | 90 | 72 | 78 | 25 | 30 |
| 12 | Income taxes receivable (payable) | | (175) | 11 | 285 | 0 | (544) |
| 13 | Tax Receivable Lag Days | | 204 | 206 | 206 | 204 | 204 |
| 14 | Taxes Payable Working Capital | | (98) | 6 | 161 | 0 | (304) |
| 15 | Inventory (Three year average) | | 1,285 | 1,516 | 1,702 | 1,858 | 1,942 |
| 16 | GST Impact on working capital | S.8.10 L.38 | 142 | 146 | 141 | 108 | 117 |
| 17 | Return - Long Term Debt | | 1,626 | 1,674 | 1,766 | 1,741 | 1,810 |
| 18 | Combined Long Term Debt Lag Days | | (46) | (46) | (46) | (52) | (52) |
| 19 | Long Term Debt Working Capital | | (207) | (213) | (224) | (248) | (258) |
| 20 | Return - 50 of Common Equity | | 734 | 905 | 924 | 939 | 1,108 |
| 21 | Dividend Lag Days | | (1) | (1) | (1) | (4) | (4) |
| 22 | Common Equity (Dividend) Working Capital | | (2) | (2) | (3) | (10) | (12) |
| 23 | Return - 50 of Common Equity | | 734 | 905 | 924 | 939 | 1,108 |
| 24 | Depreciation Lag Days | | 45 | 45 | 45 | 42 | 42 |
| 25 | Common Equity (Retained Earnings) Working Capital | | 90 | 112 | 114 | 108 | 127 |
| 26 | Net Depreciation | | 2,765 | 2,893 | 3,079 | 3,402 | 3,809 |
| 27 | Depreciation Lag Days | | 45 | 45 | 45 | 42 | 42 |
| 28 | Depreciation Working Capital | | 341 | 357 | 380 | 391 | 438 |
| 29 | Working capital | S.8.5 L.13 | 3,240 | 3,683 | 4,078 | 2,805 | 2,650 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Effect of GST on Working Capital**
**( 000s)**

**Schedule 8.10**

| Line No. | Description | Cross Ref. | | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|
| 1 | REVENUE: | | | | | | | |
| 2 | Total Operating Revenue Subject to GST | S.2.1 L.45 | | 32,423 | 34,233 | 35,160 | 45,850 | 47,075 |
| 3 | GST Rate | | | 7.00 | 6.50 | 6.00 | 5.00 | 5.00 |
| 4 | GST Billable | | (a) | 2,270 | 2,225 | 2,110 | 2,293 | 2,354 |
| 5 | | | | | | | | |
| 6 | Day Factor - Revenues | | | 45.0 | 45.0 | 45.0 | 41.9 | 41.9 |
| 7 | Day Factor - Remittance Lag | | | 56.6 | 56.6 | 56.6 | 56.6 | 56.6 |
| 8 | | | (b) | (11.6) | (11.6) | (11.6) | (14.7) | (14.7) |
| 9 | | | | | | | | |
| 10 | GST Impact on Working Capital Increase (Decrease) | | (a) (b) 365 | (72) | (71) | (67) | (93) | (95) |
| 11 | | | | | | | | |
| 12 | EXPENSES: | | | | | | | |
| 13 | Total Utility Expenses | | | 37,866 | 39,875 | 40,961 | 46,660 | 47,902 |
| 14 | Taxes other than Income | | | (230) | (230) | (235) | (249) | (261) |
| 15 | Labour and Fringe | | | (3,227) | (3,296) | (3,826) | (4,629) | (5,072) |
| 16 | Depreciation | | | (3,727) | (3,901) | (4,171) | (4,365) | (4,837) |
| 17 | Amortization of contributions | | | 962 | 1,008 | 1,092 | 963 | 1,028 |
| 18 | Income Tax | | | (1,328) | (1,034) | (855) | (421) | (1,044) |
| 19 | Fish Lake Costs | | | - | - | 237 | 150 | - |
| 20 | Fish Lake Amortization | | | - | - | (79) | (154) | (154) |
| 21 | Plant Maintenance Reserve Costs | | | - | - | 538 | 60 | - |
| 22 | Plant Maintenance Reserve Amortization | | | - | - | (108) | (123) | (123) |
| 23 | Injuries & Damages Costs | | | 5 | (51) | (73) | (60) | (60) |
| 24 | Injuries & Damages Write-off | | | 75 | 75 | 75 | 86 | 86 |
| 25 | Rate Case Costs | | | - | - | 30 | 720 | - |
| 26 | Rate Case Write-off | | | - | - | - | (375) | (375) |
| 27 | Capital Expenditures | | | 6,116 | 7,316 | 7,809 | 9,560 | 13,504 |
| 28 | Net Costs Subject to GST | | | 36,512 | 39,762 | 41,396 | 47,824 | 50,595 |
| 29 | GST Rate | | | 7.00 | 6.50 | 6.00 | 5.00 | 5.00 |
| 30 | GST Refundable | | ( c) | 2,556 | 2,585 | 2,484 | 2,391 | 2,530 |
| 31 | | | | | | | | |
| 32 | Day Factor - Expense (Including Capital) | | | 26.0 | 26.0 | 26.0 | 26.0 | 26.0 |
| 33 | Day Factor - Remittance Lag | | | 56.6 | 56.6 | 56.6 | 56.6 | 56.6 |
| 34 | | | (d) | 30.6 | 30.6 | 30.6 | 30.6 | 30.6 |
| 35 | | | | | | | | |
| 36 | GST Impact on Working Capital Increase (Decrease) | | ( c) (d) 365 | 214 | 217 | 208 | 200 | 212 |
| 37 | | | | | | | | |
| 38 | Net Impact of GST on Working Capital | | S.8.9 L.16 | 142 | 146 | 141 | 108 | 117 |

**Yukon Electrical Company Limited** **Schedule 8.11**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Contributions in Aid of Construction**
**( 000)**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | **Contributions in Aid of Construction** | | | | | | |
| 2 | Prior Year Gross Contributions | | 29,590 | 31,445 | 33,634 | 36,205 | 38,765 |
| 3 | Additions to property | | 1,855 | 2,189 | 2,571 | 2,560 | 2,506 |
| 4 | Retirements | | - | - | - | - | - |
| 5 | Current Year Gross Contributions | | 31,445 | 33,634 | 36,205 | 38,765 | 41,271 |
| 6 | **Accumulated Amortization** | | | | | | |
| 7 | Prior Year Accumulated Amortization | | 10,647 | 11,609 | 12,617 | 13,709 | 14,672 |
| 8 | Gross Amortization | S.1 L.13 | 962 | 1,008 | 1,092 | 963 | 1,028 |
| 9 | Retirements | | | - | - | - | - |
| 10 | Current Year Accumulated Amortization | | 11,609 | 12,617 | 13,709 | 14,672 | 15,700 |
| 11 | **Net Contributions in Aid of Construction** | S.8.5 L.17 | 19,836 | 21,017 | 22,496 | 24,093 | 25,571 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Plant Additions**
**( 000s)**

**Schedule 9.1**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | Work in progress, beginning of year | | 934 | 427 | 871 | 1,035 | 620 |
| 2 | **Generation:** | | | | | | |
| 3 | Generating Plants | | 825 | 638 | 476 | 1,014 | 3,124 |
| 4 | | | 825 | 638 | 476 | 1,014 | 3,124 |
| 5 | **Billing:** | | | | | | |
| 6 | New N60 Billing Systems | | - | - | 480 | 1,008 | - |
| 7 | | | - | - | 480 | 1,008 | - |
| 8 | **Distribution:** | | | | | | |
| 9 | New Extensions | | 1,923 | 2,433 | 3,106 | 3,141 | 2,962 |
| 10 | Distribution Improvements | | 2,899 | 2,858 | 2,070 | 2,967 | 2,532 |
| 11 | Street and Sentinel Lights | | 172 | 943 | 908 | 506 | 495 |
| 12 | Meters | | 17 | 77 | 37 | 330 | 3,855 |
| 13 | Transformers and Regulators | | 7 | - | 20 | | |
| 14 | | | 5,018 | 6,311 | 6,141 | 6,943 | 9,843 |
| 15 | **General property and equipment:** | | | | | | |
| 16 | Tools, Instruments & Equipment | | 59 | 55 | 48 | 50 | 57 |
| 17 | Office Furniture & Equipment | | 12 | 6 | 10 | 13 | 10 |
| 18 | Office Computer Equipment | | 5 | 3 | 0 | 6 | 5 |
| 19 | Communication Equipment | | 7 | 9 | 57 | 102 | 54 |
| 20 | Transportation Equipment | | 160 | 158 | 513 | 205 | 230 |
| 21 | Land and Buildings | | 30 | 136 | 84 | 219 | 181 |
| 22 | | | 273 | 367 | 712 | 595 | 537 |
| 23 | Miscellaneous Other | | | - | - | - | - |
| 24 | **Total capital expenditures** | | 6,116 | 7,316 | 7,809 | 9,560 | 13,504 |
| 25 | Less: Transfers to rate base | S.8.6 L.3 | (6,623) | (6,872) | (7,645) | (9,975) | (13,544) |
| 26 | Work in progress, end of year | S.8.5 L.5 | 427 | 871 | 1,035 | 620 | 580 |

**Yukon Electrical Company Limited** **Schedule 10.1**

**2008 - 2009 General Rate Application**

**Income Tax Expense**

**( 000s)**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| 1 | Utility earnings before tax | | 2,795 | 2,845 | 2,703 | 2,298 | 3,260 |
| 2 | **Add:** | | | | | | |
| 3 | Depreciation | S.1.1 L.12 | 3,727 | 3,901 | 4,171 | 4,365 | 4,837 |
| 4 | Amortization of contributions | S.1.1 L.13 | (962) | (1,008) | (1,092) | (963) | (1,028) |
| 5 | Non-allowable expenses | | 18 | 18 | 18 | 18 | 18 |
| 6 | Plant Maintenance write-off | S.8.8 L.26 | | - | 108 | 123 | 123 |
| 7 | Rate case write-off | S.8.8 L.18 | - | - | - | 375 | 375 |
| 8 | Injuries & Damages write-off | S.8.4 L27 | 75 | 75 | 75 | 86 | 86 |
| 9 | Fish Lake Water License write-off | S.8.8 L.35 | - | - | 79 | 154 | 154 |
| 10 | Charges to deferred pension & OPEB | S.8.4 L.13 L.20 | 126 | 132 | 623 | 639 | 689 |
| 11 | Sub-total | | 2,984 | 3,118 | 3,982 | 4,797 | 5,253 |
| 12 | | | | | | | |
| 13 | **Deduct:** | | | | | | |
| 14 | CCA | | 2,056 | 2,259 | 2,518 | 3,528 | 3,960 |
| 15 | Plant Maintenance Reserve Charges | S.8.8 L.25 | - | - | 538 | 60 | - |
| 16 | Rate Case Expenditure | S.8.8 L.17 | - | - | 30 | 720 | - |
| 17 | Injuries & Damages Costs | S.8.4 L28 | (5) | 51 | 73 | 60 | 60 |
| 18 | Fish Lake Water License Costs | S.8.8 L.34 | - | - | 237 | 150 | - |
| 19 | Pension & OPEB payments | S.8.4 L.14 L.21 | 38 | 39 | 576 | 639 | 689 |
| 20 | Inventory Pool Costs Capitalized | | | - | - | 358 | 376 |
| 21 | Cumulative Eligible Captial | | 12 | 12 | 11 | 10 | 9 |
| | Donated Land | | - | | | | |
| 22 | ES&G | | 306 | 348 | 334 | 350 | 350 |
| 23 | Sub-total | | 2,407 | 2,709 | 4,317 | 5,875 | 5,444 |
| 24 | | | | | | | |
| 25 | Taxable income | | 3,372 | 3,254 | 2,368 | 1,220 | 3,070 |
| 26 | Tax rate | | 36.00 | 36.00 | 36.00 | 34.50 | 34.00 |
| 27 | Income tax | | 1,214 | 1,171 | 852 | 421 | 1,044 |
| 28 | Surtax | | 38 | 36 | 27 | - | - |
| 29 | Prior & current years' book to filing (over) under provision | | 76 | (174) | (24) | - | - |
| 30 | Total current provision | S.1.1 L.16 | 1,328 | 1,034 | 855 | 421 | 1,044 |

**Yukon Electrical Company Limited (YECL)** **Schedule 11.1**
**2008 - 2009 General Rate Application**
**Interim Rates (Rider R) Revenue Shortfall (Rider G) Calculations**

| Line No. | Description | Cross Ref. | |
|---|---|---|---|
| 1 | **Revenues** | | |
| 2 | 2008 Retail revenues on Existing Rates ( 000's) | S.2.1 L.45 | 39,970 |
| 3 | Less: Fuel Cost in Existing base rates ( 000s) | | 2,054 |
| 4 | Sub-total ( 000s) | (2)-(3) | 37,916 |
| 5 | | | |
| 6 | 2008 Retail revenues on Proposed Rates ( 000's) | S.2.1 L.45 | 45,850 |
| 7 | Less: Fuel Cost ( 000s) | S.4.1 L.4 | 5,715 |
| 8 | Sub-total ( 000s) | (6)-(7) | 40,135 |
| 9 | | | |
| 10 | **Non-Fuel Revenue Shortfall ( 000's)** | (8)-(4) | 2,220 |
| 11 | | | |
| 12 | YECL 2008 Retail revenues on Existing Primary Rates ( 000s) | S.2.1 L.24 | 33,677 |
| 13 | YEC 2008 Retail revenues on Existing Primary Rates ( 000s) [1] | S.11.2 L.14 | 3,795 |
| 14 | **Total 2008 Retail revenues on Existing Primary Rates ( 000s)** | (12) (13) | 37,471 |
| 15 | **2008 Rider R ( ) Interim Rate Rider** | (10) (14) 100 | 5.924 |
| 16 | | | |
| 17 | | | |
| 18 | **2008 Retail Revenues on Existing Primary Rates ( 000s)** | | |
| 19 | YECL - Jan to Jun | | 17,101 |
| 20 | YEC - Jan to Jun [1] | S.11.2 L.2-7 | 1,864 |
| 21 | **Total Retail Revenues on Existing Primary Rates ( 000s)** | (19) (20) | 18,964 |
| 22 | **Interim Rider Shortfall Revenue ( 000's) - Jan to Jun 2008** | (21) (15) | 1,123 |
| 23 | | | |
| 24 | **Retail Revenues on Existing Primary Rates ( 000s)** | | |
| 25 | YECL 2008 Revenue ( 000's) - Jul to Dec | | 16,576 |
| 26 | YECL 2009 Revenue ( 000's) - Jan to Jun | | 17,236 |
| 27 | YEC 2008 Revenue ( 000's) - Jul to Dec [1] | S.11.2 L.8-13 | 1,931 |
| 28 | YEC 2009 Revenue ( 000's) - Jan to Jun [1] | S.11.2 L.15-20 | 1,871 |
| 29 | **Retail Revenues for period which shortfall revenue is to be collected** | (25) (26) (27) (28) | 37,613 |
| 30 | | | |
| 31 | **2008 Rider G ( ) Revenue Shortfall Rider** | (22) (29) 100 | 2.987 |

32 [(1)] Excludes revenues from Rate Schedule 39 (Industrial Primary) based on provision of Yukon Territorial Government Order-In-Council (OIC) 2007 94

**Schedule 11.2**

# Yukon Energy Corporation (YEC)
## 2008 - 2009 Firm Retail Sales and Revenue Forecast (Excluding Rate 39)

| Line No. | Description | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | Month Yr | Firm Retail Sales (MWh) | YEC Rate 39 (Minto) MWh | Firm less Rate 39 MWh | Revenue 000s | YEC Rate 39 (Minto) 000s | Firm less Rate 39 000s |
| 2 | **Jan-08** | 2,665 | - | 2,665 | 343 | 0 | 343 |
| 3 | **Feb-08** | 2,415 | - | 2,415 | 312 | 0 | 312 |
| 4 | **Mar-08** | 2,371 | - | 2,371 | 307 | 0 | 307 |
| 5 | **Apr-08** | 2,259 | - | 2,259 | 293 | 0 | 293 |
| 6 | **May-08** | 2,124 | - | 2,124 | 277 | 0 | 277 |
| 7 | **Jun-08** | 2,540 | - | 2,540 | 333 | 0 | 333 |
| 8 | **Jul-08** | 2,797 | - | 2,797 | 368 | 0 | 368 |
| 9 | **Aug-08** | 2,694 | - | 2,694 | 354 | 0 | 354 |
| 10 | **Sep-08** | 2,541 | - | 2,541 | 333 | 0 | 333 |
| 11 | **Oct-08** | 5,126 | 3,000 | 2,126 | 576 | 300 | 276 |
| 12 | **Nov-08** | 4,687 | 2,500 | 2,187 | 533 | 250 | 283 |
| 13 | **Dec-08** | 4,960 | 2,500 | 2,460 | 567 | 250 | 317 |
| 14 | **Total 2008** | 37,179 | 8,000 | 29,179 | 4,595 | 800 | 3,795 |
| 15 | **Jan-09** | 4,704 | 2,000 | 2,704 | 548 | 200 | 348 |
| 16 | **Feb-09** | 4,413 | 2,000 | 2,413 | 511 | 200 | 311 |
| 17 | **Mar-09** | 5,438 | 3,000 | 2,438 | 615 | 300 | 315 |
| 18 | **Apr-09** | 5,281 | 3,000 | 2,281 | 595 | 300 | 295 |
| 19 | **May-09** | 5,159 | 3,000 | 2,159 | 581 | 300 | 281 |
| 20 | **Jun-09** | 5,448 | 3,000 | 2,448 | 620 | 300 | 320 |
| 21 | **Jul-09** | 5,532 | 3,000 | 2,532 | 632 | 300 | 332 |
| 22 | **Aug-09** | 5,422 | 3,000 | 2,422 | 618 | 300 | 318 |
| 23 | **Sep-09** | 5,578 | 3,000 | 2,578 | 638 | 300 | 338 |
| 24 | **Oct-09** | 5,157 | 3,000 | 2,157 | 580 | 300 | 280 |
| 25 | **Nov-09** | 4,212 | 2,000 | 2,212 | 486 | 200 | 286 |
| 26 | **Dec-09** | 4,530 | 2,000 | 2,530 | 526 | 200 | 326 |
| 27 | **Total 2009** | 60,874 | 32,000 | 28,874 | 6,950 | 3,200 | 3,750 |

**Current Ratings and New Issue Indicated Spreads**
**Relative to the Benchmark 30 Year Government of Canada Bond for Selected Canadian Utilities**

| | Current Ratings April 1, 2007 | | 4-10-06 | 6-12-06 | 9-5-06 | 11-6-06 | 1-2-07 | 2006 Average | 4-2-07 | 7-3-07 | 10-9-07 | 11-26-07 | 2007 Average | 4-1-08 | 2007-2008Q1 Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | DBRS | S P | | | | | | | | | | | | | |
| **A Rated** | | | | | | | | | | | | | | | |
| CU Inc. | A(high) | A | 90 | 94 | 97 | 93 | 92 | **93** | 90 | 95 | 115 | 130 | **108** | 157 | **117** |
| Enbridge Gas | A | A- | 100 | 105 | 100 | 96 | 95 | **99** | 98 | 110 | 115 | 130 | **113** | 170 | **125** |
| Enbridge Pipelines | A(high) | A- | 100 | 105 | 100 | 96 | 95 | **99** | 98 | 105 | 115 | 130 | **112** | 170 | **124** |
| Gaz Metro | A | A | 89 | 94 | 99 | 95 | 97 | **95** | 94 | 92 | 115 | 135 | **109** | 172 | **122** |
| Terasen Gas [1] | A | A | na | na | na | na | na | **na** | na | 122 | 135 | 145 | **134** | 168 | **143** |
| TransCanada PipeLines | A | A- | 117 | 120 | 120 | 116 | 115 | **118** | 115 | 130 | 140 | 160 | **136** | 215 | **152** |
| **Average** | **A** | **A-** | **99** | **104** | **103** | **99** | **99** | **101** | **99** | **109** | **123** | **138** | **117** | **175** | **130** |
| **Median** | **A** | **A-** | **100** | **105** | **100** | **96** | **95** | **99** | **98** | **108** | **115** | **133** | **113** | **170** | **124** |
| **Split Rated A BBB** | | | | | | | | | | | | | | | |
| EPCOR Utilities | A(low) | BBB | 129 | 132 | 133 | 130 | 135 | **132** | 130 | 136 | 170 | 185 | **155** | 255 | **175** |
| Nova Scotia Power | A(low) | BBB | 135 | 140 | 142 | 140 | 138 | **139** | 132 | 136 | 145 | 170 | **146** | 205 | **158** |
| Terasen Gas [1] | A | A | 129 | 145 | 142 | 130 | 130 | **135** | 119 | na | na | na | **119** | na | **119** |
| Union Gas | A | BBB | 118 | 123 | 120 | 114 | 107 | **116** | 109 | 109 | 120 | 150 | **122** | 185 | **135** |
| Westcoast Energy | A(low) | BBB | 123 | 128 | 125 | 120 | 118 | **123** | 119 | 119 | 125 | 155 | **130** | 185 | **141** |
| **Average** | **A(low)** | **BBB** | **127** | **134** | **132** | **127** | **126** | **129** | **122** | **125** | **140** | **165** | **138** | **208** | **145** |
| **Median** | **A(low)** | **BBB** | **129** | **132** | **133** | **130** | **130** | **131** | **119** | **128** | **135** | **163** | **136** | **195** | **141** |
| **BBB Rated** | | | | | | | | | | | | | | | |
| TransAlta | BBB | BBB | 162 | 168 | 168 | 162 | 170 | **166** | 170 | 205 | 300 | 325 | **250** | 390 | **278** |

[1] Terasen Gas was upgraded to A by S&P in June 2007 following Terasen's acquisition by Fortis Inc .
Source: RBC Capital Markets

**FINANCIAL METRICS**
**FOR CANADIAN UTILITIES**
**2004-2006**

| Company | EBIT Coverage | FFO Total Debt | FFO Coverage [1] |
|---|---|---|---|
| **Electric Utilities** | | | |
| AltaLink L.P. | 1.8 | 11.4 | 3.1 |
| CU Inc. | 2.7 | 18.7 | 3.6 |
| Enersource | 2.1 | 16.7 | 3.8 |
| ENMAX Corp. | 6.4 | 46.3 | 8.1 |
| EPCOR Utilities Inc. | 3.0 | 23.4 | 4.2 |
| FortisAlberta Inc.[2] | 2.3 | 17.5 | 3.0 |
| FortisBC Inc.[2] | 2.2 | 10.9 | 2.8 |
| Hamilton Utilities | 3.4 | 32.0 | 4.7 |
| Hydro One Inc. | 3.2 | 20.0 | 4.4 |
| Hydro Ottawa Holding Inc. | 2.8 | 26.1 | 5.7 |
| Maritime Electric | 2.5 | 12.9 | 2.6 |
| Newfoundland Power [2] | 2.4 | 14.0 | 2.9 |
| Nova Scotia Power | 2.4 | 14.2 | 3.3 |
| Toronto Hydro | 2.7 | 17.5 | 3.4 |
| **Gas Distributors** | | | |
| Enbridge Gas Distribution | 2.1 | 12.5 | 3.0 |
| Gaz Metropolitain | 2.5 | 24.0 | 4.6 |
| Pacific Northern Gas [4] | 2.4 | 26.4 | 3.2 |
| Terasen Gas | 2.0 | 9.7 | 2.4 |
| Union Gas [3] | 2.1 | 12.8 | 2.8 |
| **Pipelines** | | | |
| Enbridge Pipelines [3] | 3.3 | 17.2 | 3.1 |
| Nova Gas Transmission Ltd.[3] | 2.4 | 18.5 | 2.8 |
| TransCanada PipeLines Ltd.[3] | 2.6 | 15.7 | 2.8 |
| Westcoast Energy Inc. | 2.1 | 16.4 | 3.1 |
| **Medians** | | | |
| **Electric T D** | **2.7** | **17.5** | **3.8** |
| **Electric Integrated** | **2.5** | **14.2** | **3.3** |
| **All Electric** | **2.6** | **17.5** | **3.5** |
| **Gas Distributors** | **2.1** | **12.8** | **3.0** |
| **All Companies** | **2.4** | **17.2** | **3.1** |

[1] S&P defines Funds from Operations as follows:
FFO (income from continuing operations depreciation & amortization deferred income taxes AFUDC).

[2] EBIT, EBITDA and Cashflow to total debt for 2004-2006 from DBRS, FFO data for 2003-2005

[3] FFO Coverage for 2003-2005

[4] All data for 2004-2006 from annual report

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

## DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

| Name | S&P Debt Rating | S&P Business Profile | Average 2004-2006 Debt Ratio | Average 2004-2006 EBIT Coverage | Average 2004-2006 FFO/Debt | Average 2004-2006 FFO Coverage | Average ROE 2004-2006 |
|---|---|---|---|---|---|---|---|
| Alabama Power Co. | A | 4 | 54.3 | 4.3 | 22.8 | 5.6 | 13.5 |
| Central Hudson Gas & Electric Corp. | A | 3 | 66.3 | 4.7 | 16.7 | 4.3 | 12.2 |
| Consolidated Edison Co. of New York Inc. | A | 2 | 54.8 | 2.8 | 18.7 | 3.9 | 10.0 |
| Consolidated Edison Inc. | A | 2 | 57.2 | 2.6 | 16.7 | 3.7 | 9.2 |
| Duke Energy Carolinas LLC | A- | 4 | 48.0 | 4.0 | 28.8 | 14.9 | NA |
| Duke Energy Corp. | A- | 5 | 48.7 | 3.2 | 19.8 | 3.9 | 9.9 |
| Duke Energy Indiana Inc. | A- | 4 | 56.7 | 3.1 | 17.6 | 4.6 | 8.8 |
| Duke Energy Ohio Inc. | A- | 5 | 38.7 | 4.5 | 23.2 | 5.6 | 11.0 |
| Florida Power & Light Co. | A | 4 | 41.1 | 5.9 | 34.1 | 7.7 | 11.7 |
| FPL Group Inc. | A | 5 | 51.8 | 2.7 | 22.3 | 4.5 | 12.4 |
| Georgia Power Co. | A | 4 | 56.0 | 4.6 | 22.0 | 6.1 | 14.1 |
| Gulf Power Co. | A | 4 | 54.5 | 3.7 | 20.9 | 4.6 | 12.2 |
| Integrys Energy Group Inc. | A- | 5 | 58.6 | 3.4 | 13.8 | 4.1 | 12.5 |
| KeySpan Corp. | A- | 3 | 61.8 | 3.5 | 16.2 | 3.9 | 10.4 |
| Madison Gas & Electric Co. | AA- | 4 | 52.4 | 4.5 | 20.4 | 5.1 | 10.6 |
| MidAmerican Energy Co. | A- | 5 | 52.4 | 4.4 | 26.0 | 5.8 | 14.2 |
| MidAmerican Energy Holdings Co. | A- | 4 | 74.9 | 1.9 | 11.1 | 2.5 | 13.2 |
| Mississippi Power Co. | A | 4 | 63.0 | 4.2 | 22.8 | 10.8 | 13.9 |
| NSTAR | A+ | 1 | 65.4 | 3.5 | 22.6 | 4.9 | 13.3 |
| NSTAR Electric Co. | A+ | 1 | 49.7 | 5.7 | 39.4 | 8.1 | 13.8 |
| Orange and Rockland Utilities Inc. | A | 2 | 70.8 | 3.6 | 16.9 | 3.9 | NA |
| PacifiCorp | A- | 5 | 59.0 | 2.5 | 15.0 | 3.7 | 7.0 |
| PPL Electric Utilities Corp. | A- | 3 | 51.0 | 3.1 | 26.2 | 4.9 | NA |
| San Diego Gas & Electric Co. | A | 5 | 54.8 | 5.0 | 25.9 | 6.7 | 16.3 |
| SCANA Corp. | A- | 4 | 57.6 | 2.5 | 22.5 | 4.2 | 11.4 |
| South Carolina Electric & Gas Co. | A- | 4 | 50.1 | 2.6 | 25.6 | 5.1 | 10.3 |
| Southern Co. | A | 4 | 57.0 | 3.8 | 22.3 | 5.3 | 14.9 |
| Vectren Corp. | A- | 4 | 60.4 | 2.7 | 15.9 | 3.9 | 10.5 |
| Wisconsin Electric Power Co. | A- | 4 | 52.5 | 4.8 | 25.0 | 6.8 | 11.8 |
| Wisconsin Power & Light Co. | A- | 4 | 48.1 | 3.6 | 31.1 | 5.9 | 9.9 |
| Wisconsin Public Service Corp. | A | 4 | 52.3 | 4.0 | 22.3 | 5.4 | 10.1 |
| **Mean** | **A** | **4** | **55.5** | **3.7** | **22.1** | **5.5** | **11.8** |
| **Median** | **A** | **4** | **54.8** | **3.6** | **22.3** | **4.9** | **11.8** |

Source: All from S&P: Research Insight; *Issuer Ranking: U.S. Integrated Electric Utility Companies, Strongest to Weakest,* November 1, 2007;
*Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest,* November 9, 2007; and *Credit Stats,* September 2007.

**DEBT AND COMMON STOCK QUALITY RATINGS**
**OF CANADIAN UTILITIES**

| Company | Debt Rated | DBRS Bond Rating | Moody's Bond Rating | S P Bond Rating | CBS Stock Ranking |
|---|---|---|---|---|---|
| **Electric Utilities** | | | | | |
| AltaLink L.P. | Senior Secured | A | | A- | |
| CU Inc. | Senior Unsecured | A(high) | | A | Very conservative |
| Enersource | Issuer | A | | | |
| ENMAX | Unsecured Debentures (DBRS) | A | | A- | |
| | Issuer (S&P) | | | | |
| EPCOR Utilities Inc | Senior Unsecured | A(low) | Baa2 | BBB | |
| FortisAlberta Inc. | Senior Unsecured | A(low) | Baa1 | | Very conservative |
| FortisBC Inc | Secured Debentures | BBB(high) | Baa2 | | Very conservative |
| Hamilton Utilities | Senior Unsecured | | | A | |
| Hydro One | Senior Unsecured | A(high) | Aa3 | A | |
| Hydro Ottawa Holding Inc. | Senior Unsecured | A (low) | | A- | |
| Maritime Electric | Senior Secured | | | A- | Very conservative |
| Newfoundland Power | Senior Secured | A | Baa1 | NR [1] | Very conservative |
| Nova Scotia Power | Senior Unsecured | A(low) | Baa1 | BBB | Very conservative |
| Toronto Hydro | Senior Unsecured | A | | A- | |
| **Gas Distributors** | | | | | |
| Enbridge Gas Distribution | Senior Unsecured | A | | A- | Very conservative |
| Gaz Metropolitain | Senior Secured | A | | A | |
| Pacific Northern Gas | Senior Secured | BBB(low) | | NR [2] | Average |
| Terasen Gas | Senior Secured | A | A2 | AA- | Very conservative |
| | Senior Unsecured | A | A3 | A | |
| Union Gas Limited | Senior Unsecured | A | | BBB | Very conservative |
| **Pipelines** | | | | | |
| Enbridge Pipelines | Senior Unsecured | A(high) | | A- | Very conservative |
| NOVA Gas Transmission | Senior Unsecured | A | A2 | A- | Very conservative |
| TransCanada PipeLines | Senior Secured | A | | A | Very conservative |
| | Senior Unsecured | A | A2 | A- | |
| Westcoast Energy | Senior Unsecured | A(low) | | BBB | Very conservative |
| **Medians** | | | | | |
| **Electric T D** | | **A** | **Baa1** | **A-** | **Very conservative** |
| **Electric Integrated** | | **A(low)** | **Baa2** | **BBB** | **Very conservative** |
| **All Electric** | | **A** | **Baa1** | **A-** | **Very conservative** |
| **Gas Distributors** | | **A** | **A3** | **A** | **Very conservative** |
| **All Companies** | | **A** | **Baa1** | **A-** | **Very conservative** |

[1] Withdrawn by company; BBB prior to withdrawal.
[2] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

**CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES
(2006)**

| Company | Long-term Debt [1] | Short-Term Debt | Preferred Stock [2] | Common Stock Equity [3] |
|---|---|---|---|---|
| **Electric Utilities** | | | | |
| AltaLink L.P. | 62.2 | 0.0 | 0.0 | 37.8 |
| CU Inc. | 55.2 | 2.3 | 6.2 | 36.3 |
| Enersource | 58.1 | 0.0 | 0.0 | 48.9 |
| ENMAX Corp. | 20.1 | 2.8 | 0.0 | 77.1 |
| EPCOR Utilities Inc. | 43.7 | 4.3 | 6.9 | 45.0 |
| FortisAlberta Inc. | 60.6 | 0.7 | 0.0 | 38.7 |
| FortisBC Inc. | 59.5 | 0.0 | 0.0 | 40.5 |
| Hamilton Utilities | 36.7 | 0.0 | 0.0 | 63.3 |
| Hydro One Inc. | 52.1 | 0.3 | 3.2 | 44.5 |
| Hydro Ottawa Holding Inc. | 47.2 | 0.0 | 0.0 | 52.8 |
| Maritime Electric | 38.0 | 21.2 | 0.0 | 40.8 |
| Newfoundland Power | 54.5 | 0.1 | 1.2 | 44.2 |
| Nova Scotia Power | 50.6 | 0.1 | 9.4 | 39.9 |
| Toronto Hydro | 57.5 | 0.0 | 0.0 | 42.5 |
| **Gas Distributors** | | | | |
| Enbridge Gas Distribution | 47.1 | 17.3 | 2.1 | 33.5 |
| Gaz Metropolitain | 59.2 | 1.6 | 0.0 | 39.2 |
| Pacific Northern Gas | 46.0 | 3.0 | 3.0 | 47.9 |
| Terasen Gas | 54.7 | 8.8 | 0.0 | 36.5 |
| Union Gas | 63.8 | 0.0 | 2.9 | 33.3 |
| **Pipelines** | | | | |
| Enbridge Pipelines | 39.3 | 13.9 | 0.0 | 46.7 |
| Nova Gas Transmission Ltd. | 57.5 | 2.5 | 0.0 | 39.9 |
| TransCanada PipeLines Ltd.[4] | 58.7 | 2.3 | 1.9 | 37.1 |
| Westcoast Energy Inc. | 54.5 | 0.0 | 5.0 | 40.5 |
| **Medians** | | | | |
| **Electric T D** | **54.5** | **0.0** | **0.0** | **44.5** |
| **Electric Integrated** | **50.6** | **2.3** | **6.2** | **40.5** |
| **All Electric** | **53.3** | **0.1** | **0.0** | **43.4** |
| **Gas Distributors** | **54.7** | **3.0** | **2.1** | **36.5** |
| **All Companies** | **54.5** | **0.7** | **0.0** | **40.5** |

1 Includes current portion of long-term debt and preferred securities classified as debt.

2 Includes minority interest in preferred shares of subsidiary companies and preferred securities.

3 Includes minority interest in common shares of subsidiary companies.

4 Excludes non-recourse debt

Source: Reports to Shareholders

**EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES**
**(Percentages)**

| | Decision Date | Regulator | Order File Number | Debt | Preferred Stock | Common Stock Equity | Equity Return | Forecast 30-Year Bond Yield | |
|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | |
| **Electric Utilities** | | | | | | | | | |
| AltaLink | 7 04; 11 07 | EUB | 2004-052; U2007-347 | 67.00 | 0.00 | 33.00 | 8.75 | 4.55 | |
| ATCO Electric | | EUB | | | | | | | |
| Transmission | 7 04; 11 07 | | 2004-052; U2007-347 | 61.00 | 6.00 | 33.00 | 8.75 | 4.55 | |
| Distribution | 7 04; 11 07 | | 2004-052; U2007-347 | 56.10 | 6.90 | 37.00 | 8.75 | 4.55 | |
| EPCOR | | EUB | | | | | | | |
| Transmission | 7 04; 11 07 | | 2004-052; U2007-347 | 65.00 | 0.00 | 35.00 | 8.75 | 4.55 | |
| Distribution | 7 04; 11 07 | | 2004-052; U2007-347 | 61.00 | 0.00 | 39.00 | 8.75 | 4.55 | |
| FortisAlberta Inc. | 7 04; 11 07 | EUB | 2004-052; U2007-347 | 63.00 | 0.00 | 37.00 | 8.75 | 4.55 | |
| FortisBC Inc. | 3 06; 11 07 | BCUC | G-14-06; L-93-07 | 60.00 | 0.00 | 40.00 | 9.02 | 4.55 | |
| Hydro One Transmission | 8 07 | OEB | EB-2006-0501 | 60.00 | 0.00 | 40.00 | 8.35 | 4.16 | |
| Maritime Electric | 1 08 | IRAC | UE20937 | 57.31 | 0.00 | 42.69 | 10.00 | na | |
| Newfoundland Power | 12 07 | NLPub | PU32 (2007) | 54.01 | 1.15 | 44.84 | 8.95 | 4.60 | [1] |
| Nova Scotia Power | 1 05;2 07 | UARB | 2005 NSUARB 27; 2007 NSUARB 8 | 53.30 | 9.20 | 37.50 | 9.55 | na | [2] |
| Northwest Territories Power Corp. | 8 07 | PUB of NWT | Decision 13-2007 | 52.26 | 0.00 | 48.59 [3] | 9.25 | 4.60 | |
| Ontario Electricity Distributors | 12 06 | OEB | Report of the Board | 60.00 | 0.00 | 40.00 | 8.57 | 4.46 | [4] |
| Yukon Energy | 10 05 | YUB | OIC 1998 32; Order 2005-12, BCUC G-55-07 | 60.00 | 0.00 | 40.00 | 9.15 | 4.55 | [5] |
| **Gas Distributors** | | | | | | | | | |
| ATCO Gas | 7 04; 11 07 | EUB | 2004-052; U2007-347 | 55.10 | 6.90 | 38.00 | 8.75 | 4.55 | |
| Enbridge Gas Distribution Inc | 1 04; 1 07; 2 08 | OEB | RP-2002-0158; EB-2006-0034; EB-2007-0615 | 61.33 | 2.67 | 36.00 | 8.39 | 4.23 | |
| Gaz Metropolitain | 10 07 | R gie | D-2007-116 | 54.00 | 7.50 | 38.50 | 9.05 | 4.78 | |
| Pacific Northern Gas | 11 07; 5 07 | BCUC | L-93-07; G-55-07 | 56.20 | 3.80 | 40.00 | 9.27 | 4.55 | |
| Terasen Gas | 3 06; 11 07 | BCUC | G-14-06; L-93-07 | 65.00 | 0.00 | 35.00 | 8.62 | 4.55 | |
| Union Gas | 1 04; 3 04; 5 06 | OEB | RP-2002-0158; RP-2003-0063; EB-2005-0520 | 60.60 | 3.40 | 36.00 | 8.54 | 4.23 | |
| **Gas Pipelines** | | | | | | | | | |
| Alberta Natural Gas | 11 07; 2 06 | NEB | RH-2-94;TG-02-2006 | 64.00 | 0.00 | 36.00 | 8.72 | 4.55 | |
| Foothills Pipe Lines (Yukon) Ltd. | 11 07; 12 05 | NEB | RH-2-94;TG-08-2005 | 64.00 | 0.00 | 36.00 | 8.72 | 4.55 | |
| TransCanada PipeLines | 11 07; 5 07 | NEB | RH-2-94 RH-2-2004 TG-06-2007 | 60.00 | 0.00 | 40.00 | 8.72 | 4.55 | |
| Trans Quebec & Maritimes Pipeline | 11 07 | NEB | RH-2-94 | 70.00 | 0.00 | 30.00 | 8.72 | 4.55 | |
| Westcoast Energy | 11 07; 12 06 | NEB | RH-2-94;TG-05-2006 | 64.00 | 0.00 | 36.00 | 8.72 | 4.55 | |

[1] The settlement agreement specifying ROE and capital structure was approved by the PUB.

[2] A negotiated settlement to be filed with the UARB would implement a fuel adjustment clause and reduce the return on equity to 9.35 if approved.

[3] The capital structure of NTPC includes no cost capital (-.85 ).

[4] The 8.57 ROE is for rates to be in effect as of May 2008. As per the 12 06 Report of the Board, the ROE is to be based on the January 2008 *Consensus Forecasts* and the January 2008 spread.

[5] The YUB set YEC's risk premium at the mid-point of the FortisBC risk premium (40bp) and that of PNG (65bp) as established by BCUC G-55-07. By Order in Council, YEC's ROE is then reduced from the "fair return on common equity" by 0.50 .

Source: Board Decisions.

**RATES OF RETURN ON COMMON EQUITY ADOPTED BY**
**REGULATORY BOARDS FOR CANADIAN UTILITIES**

| | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Electric Utilities** | | | | | | | | | | | | | | | | | | | |
| AltaLink | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 9.40 | 9.60 | 9.50 | 8.93 | 8.51 | 8.75 |
| ATCO Electric | 13.50 | 13.50 | 13.25 | 11.88 | NA | NA | 11.25 | [1] | [1] | [1] | [1] | [1] | [1] | 9.40 | 9.60 | 9.50 | 8.93 | 8.51 | 8.75 |
| FortisAlberta Inc. | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 9.50 | 9.50 | 9.60 | 9.50 | 8.93 | 8.51 | 8.75 |
| FortisBC Inc. | 13.50 | NA | 11.75 | 11.50 | 11.00 | 12.25 | 11.25 | 10.50 | 10.25 | 9.50 | 10.00 | 9.75 | 9.53 | 9.82 | 9.55 | 9.43 | 9.20 | 8.77 | 9.02 |
| Newfoundland Power | 13.95 | 13.25 | NA | NA | NA | NA | 11.00 | NA | 9.25 | 9.25 | 9.59 | 9.59 | 9.05 | 9.75 | 9.75 | 9.24 | 9.24 | 8.60 | 8.95 |
| Nova Scotia Power | NA | NA | NA | 11.75 | NA | NA | 10.75 | NA | NA | NA | NA | NA | 10.15 | NA | NA | 9.55 | 9.55 | 9.55 | na |
| Ontario Electricity Distributors | NA | NA | NA | NA | NA | NA | NA | NA | NA | 9.35 | 9.88 | 9.88 | 9.88 | 9.88 | 9.88 | 9.88 | 9.00 | 9.00 | 8.57 |
| TransAlta Utilities | 13.50 | 13.50 | 13.25 | 11.88 | NA | 12.25 | 11.25 | [1] | [2] | 9.25 | 9.25 | NA | 9.40 | NA | NA | NA | NA | NA | na |
| **Mean of Electric Utilities** | **13.61** | **13.42** | **12.75** | **11.75** | **11.00** | **12.25** | **11.10** | **10.50** | **9.75** | **9.34** | **9.68** | **9.74** | **9.59** | **9.63** | **9.66** | **9.51** | **9.11** | **8.78** | **8.80** |
| **Gas Distributors** | | | | | | | | | | | | | | | | | | | |
| ATCO Gas | 13.25 | 13.25 | 12.25 | 12.25 | NA | NA | NA | 10.50 | 9.38 | NA | NA | 9.75 | 9.75 | 9.50 | 9.50 | 9.50 | 8.93 | 8.51 | 8.75 |
| Enbridge Gas Distribution | 13.25 | 13.13 | 13.13 | 12.30 | 11.60 | 11.65 | 11.88 | 11.50 | 10.30 | 9.51 | 9.73 | 9.54 | 9.66 | 9.69 | NA | 9.57 | 8.74 | 8.39 | 8.39 |
| Gaz Metro | 14.25 | 14.25 | 14.00 | 12.50 | 12.00 | 12.00 | 12.00 | 11.50 | 10.75 | 9.64 | 9.72 | 9.60 | 9.67 | 9.89 | 9.45 | 9.69 | 8.95 | 8.73 | 9.05 |
| Pacific Northern Gas | 15.00 | 14.00 | 13.25 | NA | 11.50 | 12.75 | 11.75 | 11.00 | 10.75 | 10.00 | 10.25 | 10.00 | 9.88 | 10.17 | 9.80 | 9.68 | 9.45 | 9.02 | 9.27 |
| Terasen Gas | NA | NA | 12.25 | NA | 10.65 | 12.00 | 11.00 | 10.25 | 10.00 | 9.25 | 9.50 | 9.25 | 9.13 | 9.42 | 9.15 | 9.03 | 8.80 | 8.37 | 8.62 |
| Union Gas | 13.75 | 13.50 | 13.50 | 13.00 | 12.50 | 11.75 | 11.75 | 11.00 | 10.44 | 9.61 | 9.95 | 9.95 | 9.95 | 9.95 | 9.62 | 9.62 | 9.62 | 8.54 | 8.54 |
| **Mean of Gas Distributors** | **13.90** | **13.63** | **13.06** | **12.51** | **11.65** | **12.03** | **11.68** | **10.96** | **10.27** | **9.60** | **9.83** | **9.68** | **9.67** | **9.77** | **9.50** | **9.52** | **9.08** | **8.59** | **8.77** |
| **Gas Pipelines (NEB)** | | | | | | | | | | | | | | | | | | | |
| TransCanada PipeLines | 13.25 | 13.50 | 13.25 | 12.25 | 11.25 | 12.25 | 11.25 | 10.67 | 10.21 | 9.58 | 9.90 | 9.61 | 9.53 | 9.79 | 9.56 | 9.46 | 8.88 | 8.46 | 8.72 |
| Westcoast Energy | 13.25 | 13.75 | 12.50 | 12.25 | 11.50 | 12.25 | 11.25 | 10.67 | 10.21 | 9.58 | 9.90 | 9.61 | 9.53 | 9.79 | 9.56 | 9.46 | 8.88 | 8.46 | 8.72 |
| **Mean of Gas Pipelines** | **13.25** | **13.63** | **12.88** | **12.25** | **11.38** | **12.25** | **11.25** | **10.67** | **10.21** | **9.58** | **9.90** | **9.61** | **9.53** | **9.79** | **9.56** | **9.46** | **8.88** | **8.46** | **8.72** |
| **Mean of All Companies** | **13.68** | **13.56** | **12.94** | **12.16** | **11.50** | **12.13** | **11.36** | **10.84** | **10.15** | **9.50** | **9.79** | **9.68** | **9.62** | **9.71** | **9.59** | **9.51** | **9.07** | **8.66** | **8.78** |

[1] Negotiated settlement, details not available.
[2] Negotiated settlement, implicit ROE made public is 10.5 .

Source: Regulatory Decisions

**COMPARISON BETWEEN ALLOWED RETURNS ON EQUITY**
**FOR CANADIAN AND U.S. UTILITIES**

| | Canadian Utilities | | | U.S. Utilities | | |
|---|---|---|---|---|---|---|
| Year | Allowed ROE [1] | Average Long Canada Yield | Equity Risk Premium | Allowed ROE | Average Long Treasury Yield | Equity Risk Premium |
| 1990 | 13.68 | 10.69 | 2.99 | 12.69 | 8.61 | 4.08 |
| 1991 | 13.56 | 9.72 | 3.84 | 12.51 | 8.14 | 4.37 |
| 1992 | 12.94 | 8.68 | 4.26 | 12.06 | 7.67 | 4.39 |
| 1993 | 12.16 | 7.86 | 4.30 | 11.37 | 6.59 | 4.78 |
| 1994 | 11.50 | 8.69 | 2.81 | 11.34 | 7.39 | 3.95 |
| 1995 | 12.13 | 8.41 | 3.72 | 11.51 | 6.85 | 4.66 |
| 1996 | 11.36 | 7.75 | 3.61 | 11.29 | 6.73 | 4.56 |
| 1997 | 10.84 | 6.66 | 4.18 | 11.34 | 6.58 | 4.76 |
| 1998 | 10.15 | 5.59 | 4.56 | 11.59 | 5.54 | 6.05 |
| 1999 | 9.50 | 5.72 | 3.78 | 10.74 | 5.91 | 4.83 |
| 2000 | 9.79 | 5.71 | 4.08 | 11.41 | 5.88 | 5.53 |
| 2001 | 9.68 | 5.77 | 3.91 | 11.04 | 5.50 | 5.54 |
| 2002 | 9.62 | 5.67 | 3.95 | 11.10 | 5.41 | 5.69 |
| 2003 | 9.71 | 5.31 | 4.40 | 10.98 | 5.03 | 5.95 |
| 2004 | 9.59 | 5.11 | 4.48 | 10.73 | 5.08 | 5.65 |
| 2005 | 9.51 | 4.38 | 5.13 | 10.50 | 4.52 | 5.98 |
| 2006 | 9.07 | 4.33 | 4.74 | 10.39 | 4.93 | 5.46 |
| 2007 | 8.66 | 4.30 | 4.36 | 10.30 | 4.80 | 5.50 |
| 2008q1 | 8.78 | 4.10 | 4.68 | 10.37 | 4.35 | 6.02 |
| **Means:** | | | | | | |
| **1990-1993** | **13.08** | **9.24** | **3.85** | **12.16** | **7.75** | **4.41** |
| **1994-1998** | **11.20** | **7.42** | **3.78** | **11.41** | **6.62** | **4.80** |
| **1999-2007** | **9.46** | **5.14** | **4.31** | **10.80** | **5.23** | **5.57** |

[1] 2008 ROE represents results for the full year.

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; Various Canadian Regulatory Decisions; Bank of Canada; www.federalreserve.gov; www.ustreas.gov.

**CW-YECL-2**

**Issue:** Map of System

**Reference:** General

**Preamble:** CW wishes to better understand the proposed capital additions and system operation.

**Request:**

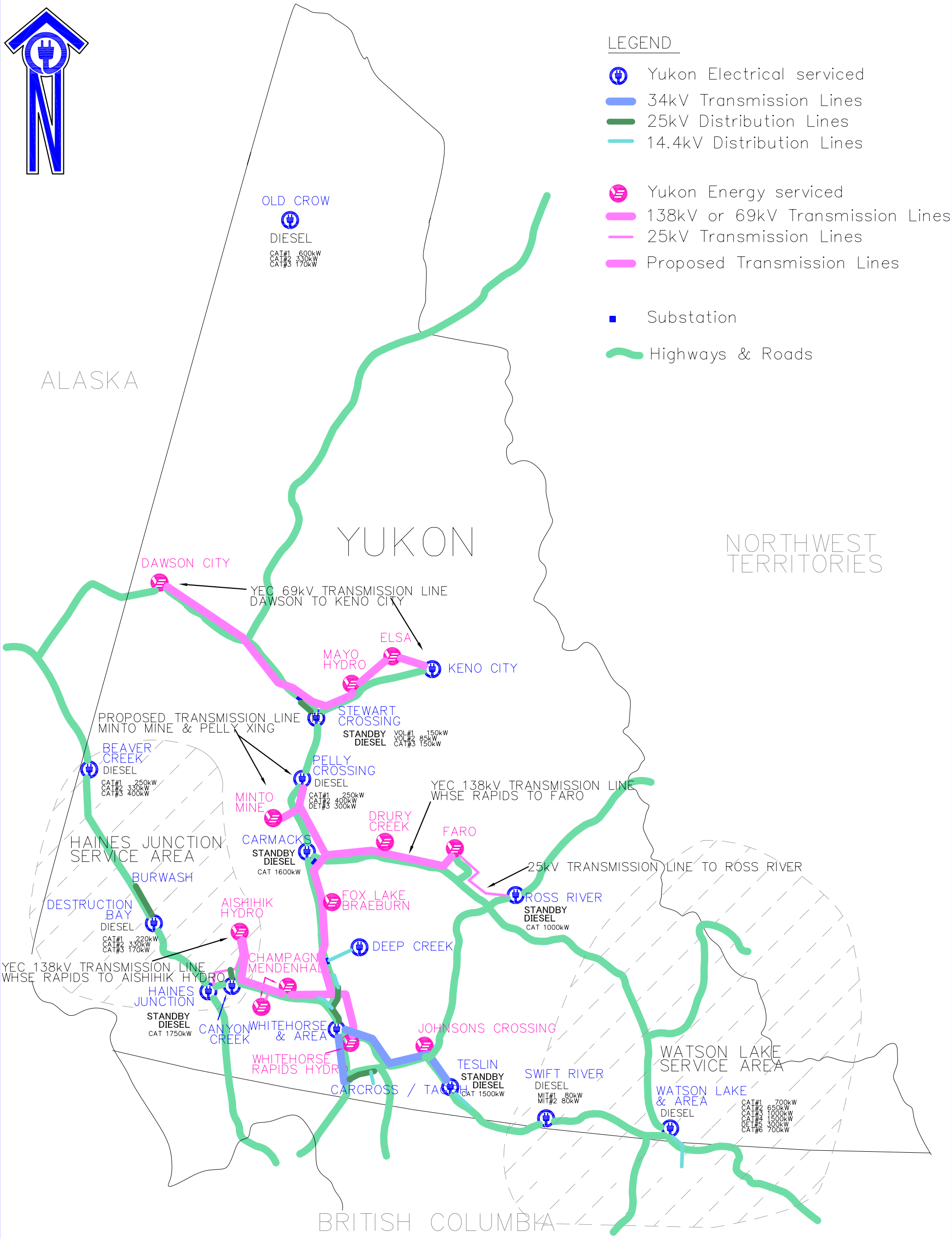
(a) Please provide an apposite system map or maps showing the locations of each of the communities, transmission facilities by number and generating units (size of units) at each location

(b) Please provide a system map to scale for the City of Whitehorse distribution system including all interconnected facilities

**Response:**

(a) Please refer to CW-YECL-02 (a) Attachment 1

(b) Please refer to CW-YECL-02 (b) Attachment 1




# YUKON POWERLINE SERVICE AREAS & FACILITIES

Yukon Powerlines.dgn

CW-YECL-02 (b)
Attachment 1
1 of 1

# WHITEHORSE & AREA

SCALE 1:40 000

YEC OWNED 138kV TRANSMISSION LINE

YEC OWNED 138kV TRANSMISSION LINE

YEC OWNED 138kV TRANSMISSION LINE

S146 FARO 138kV/25kV

YEC OWNED 25kV LINE

ROSS RIVER SUBSTATION #19 25kV/25kV

S163 CARMACKS 138kV/25kV

S164 TAKHINI SWITCHING STATION #

S167 AISHIHIK HYDRO 138kV/25kV

YEC OWNED 25kV LINE

HAINES JUNCTION SUBSTATION #20 25kV/25kV

RIVERDALE SUBDIVISION

RIVERDALE SUBSTATION #3 34kV/12kV

SWATCKA LAKE

LEWES BLVD. SUBSTATION #2 34kV/12kV

LEWES BLVD.

S171 RIVERSIDE SWITCH STATION

YEC WHSE RAPIDS HYDRO

YEC SUB S150

YUKON RIVER

ROBERT SERVICE WAY

SHIPYARDS SUBSTATION 34kV/12kV

DOWNTOWN WHITEHORSE

TO MACRAE SUBSTATION #1 34kV/25kV

SERVICES SUBSTATION #5 34kV/12kV

QUARTZ ROAD

AIRPORT

ALASKA HWY.

MARWELL

2 MILE HILL

ARKELL SUBSTATION #29 34kV/25kV

TAKHINI

VALLEYVIEW

HILLCREST

HAMILTON BLVD.

McINTYRE

GRANGER

COPPERIDGE

ARKELL

KOPPER KING

MOUNTAINVIEW DRIVE

MOUNTAIN VIEW SUBSTATION #28 34kV/12kV

SANDPIPER DR.

LOGAN

LOGAN SUBSTATION #35 34kV/25kV

PORTERCREEK SUBDIVISION

PORTER CREEK SUBSTATION #6 34kV/12kV

HOLLY STREET

McINTYRE YEC SUBSTATION S170 YECL SUBSTATION #17 138kV/34kV

ALASKA HWY.

FISH LAKE ROAD

FISH LAKE HYDRO #2 2.4kV/12kV

LABERGE SUBSTATION #21 34kV/25kV

LABERGE ROAD

ALASKA HWY

KULAN INDUSTRIAL

CRESTVIEW SUBDIVISION

FISH LAKE HYDRO #1 2.4kV/12kV

TO YEC OWNED HEAKEL HILL WIND TURBINES 408V/12kV

SUBSTATIONS

138kV YEC

34.5kV

34.5kV UG

25kV

25kV UG

14.4kV

14.4kV UG

12.5kV

12kV UG

7.2kV

2.4kV

**CW-YECL-3**

**Issue:** **Audited Financial Statements**

**Reference:** **General**

**Preamble:** CW requires audited financial statements to review and assess the application and to reconcile utility and non-utility items.

**Request:**

(a) Please provide Audited Financial Statements for the years ended December 31, 2005, 2006 and 2007.

(b) Please provide Pro-Forma Financial Statements for the years 2008 and 2009, including a statement of Earnings and Retained Earnings, Balance Sheet and Cash Flows.

**Response:**

(a) Please refer to CW-YECL-4 (a) Attachments 1-5

(b) .

**Yukon Electrical Company Limited**
**2008-2009 General Rate Application**
**Pro forma Income Statement**
**000's**

| Line No. | Description | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|
| 1 | **Revenues** | 40,219 | 41,420 | 47,026 | 48,239 |
| 2 | **Costs and Expenses** | | | | |
| 3 | Fuel | 2,157 | 2,191 | 5,865 | 5,459 |
| 4 | Purchased Power | 23,239 | 23,647 | 23,846 | 23,494 |
| 5 | Operations and Maintenance | 7,446 | 7,980 | 9,853 | 10,424 |
| 6 | Depreciation and amorization | 2,893 | 3,079 | 3,404 | 3,807 |
| 7 | Interest | 1,580 | 1,666 | 1,750 | 1,815 |
| | | 37,316 | 38,563 | 44,719 | 45,000 |
| | | 2,903 | 2,857 | 2,307 | 3,240 |
| 8 | **Interest and other income** | 25 | 137 | 44 | 43 |
| 9 | **Earnings before income taxes** | 2,928 | 2,994 | 2,351 | 3,282 |
| 10 | **Income taxes** | 1,001 | 900 | 431 | 1,043 |
| 11 | **Earnings attributable to Class A and Class B shares** | 1,926 | 2,093 | 1,920 | 2,239 |
| 12 | **Retained Earnings at beginning of year** | 8,998 | 9,524 | 10,217 | 12,137 |
| | | 10,924 | 11,617 | 12,137 | 14,376 |
| 13 | Dividends on Class A and Class B shares | 1,400 | 1,400 | - | - |
| 14 | **Retained Earnings at end of year** | 9,524 | 10,217 | 12,137 | 14,376 |

**Yukon Electrical Company Limited**
**2008-2009 General Rate Application**
**Pro Forma Balance Sheet**
**( 000's)**

| | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|
| **ASSETS** | | | | |
| **Current assets** | | | | |
| Cash and short term investments | - | - | - | - |
| Short term advances to affiliated corporations | - | - | - | - |
| Accounts receivable | 5,507 | 5,244 | 5,979 | 6,176 |
| Inventories | 1,784 | 1,849 | 1,940 | 2,036 |
| Income taxes recoverable | - | - | - | - |
| Prepaid expenses | 103 | 110 | 116 | 122 |
| | 7,394 | 7,203 | 8,035 | 8,334 |
| **Property, plant and equipment** | 39,126 | 41,222 | 44,907 | 52,149 |
| **Regulatory assets** | - | - | - | - |
| **Other assets** | 156 | 786 | 1,034 | 370 |
| | 46,676 | 49,212 | 53,976 | 60,853 |
| **LIABILITIES AND SHARE OWNER'S EQUITY** | | | | |
| **Current liabilities** | | | | |
| Bank indebtedness | 607 | 874 | 171 | 126 |
| Short term advances from parent and affiliated corporations | 1,000 | 2,200 | 300 | 400 |
| Accounts payable and accrued liabilities | 3,560 | 4,276 | 4,108 | 4,134 |
| Owing to parent and affiliated corporations | 560 | 499 | 489 | 557 |
| Income taxes payable | (1) | (328) | (29) | 534 |
| | 5,726 | 7,521 | 5,040 | 5,751 |
| **Regulatory Liabilities** | (54) | (52) | (26) | (0) |
| **Pension and other post employment benefits** | 661 | 707 | 707 | 707 |
| **Long term debt** | 23,800 | 23,800 | 25,350 | 28,550 |
| **Class A and Class B share owner's equity** | | | | |
| Class A and Class B shares | 7,019 | 7,019 | 10,769 | 11,469 |
| Retained earnings | 9,524 | 10,217 | 12,137 | 14,377 |
| Accumulated other comprehensive income | - | - | - | |
| | 16,543 | 17,236 | 22,906 | 25,846 |
| | 46,676 | 49,212 | 53,976 | 60,853 |

**Yukon Electrical Company Limited**
**2008-2009 General Rate Application**
**Pro forma Statement of Cash Flows**
**000's**

| Line No. | Description | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|
| 1 | **Operating activities** | | | | |
| 2 | Earnings attributable to Class A and Class B shares | 1,926 | 2,093 | 1,920 | 2,239 |
| 3 | Adjustments for: | | | | |
| 4 | Depreciation and Amortization | 2,893 | 3,079 | 3,404 | 3,807 |
| 5 | Other | 117 | 47 | (474) | 26 |
| 6 | Cash flow from operations | 4,937 | 5,220 | 4,850 | 6,073 |
| 7 | Changes in non-cash working capital | (453) | 331 | (145) | 393 |
| | | 4,483 | 5,551 | 4,705 | 6,465 |
| 8 | **Investing Activities** | | | | |
| 9 | Purchase of property, plant and equipment | (7,295) | (7,785) | (9,536) | (13,480) |
| 10 | Proceeds on disposal of property, plant and equipment | (163) | 40 | (113) | (75) |
| 11 | Contributions by utility customers for extensions to plant | 2,188 | 2,571 | 2,560 | 2,506 |
| 12 | Changes in non-cash working capital | (258) | 187 | (66) | (35) |
| 13 | Other | (83) | (631) | (248) | 664 |
| | | (5,611) | (5,618) | (7,402) | (10,420) |
| 14 | **Financing activities** | | | | |
| 15 | Issue of long term debt | 3,000 | - | 2,150 | 5,200 |
| 16 | repayment of long term debt | (350) | - | (600) | (2,000) |
| 17 | Issue of common shares | - | - | 3,750 | 700 |
| 18 | Dividends paid to the Class A and Class B share owner | (1,400) | (1,400) | - | - |
| 19 | Other | - | - | - | - |
| | | 1,250 | (1,400) | 5,300 | 3,900 |
| 20 | **Cash Position** | | | | |
| 21 | Increase (decrease) | 122 | (1,467) | 2,603 | (54) |
| 22 | Beginning of year | (1,729) | (1,607) | (3,074) | (471) |
| 23 | **End of Year** | (1,607) | (3,074) | (471) | (526) |

**CW-YECL-4**

**Issue:** 2006-2007 Variance Between Forecast and Actual Results

**Reference:** General

**Preamble:** CW would like to assess the variances between forecast and actual results for the years 2003 through 2007.

**Request:**

(a) Please provide copies of the 2003, 2004, 2005, 2006 and 2007 Reports on Finances as filed with the Board.

(b) To the extent not included in a), please provide explanations for the material variances between forecast and actual results for the years referenced in a).

**Response:**

(a) Please refer to CW-YECL 4 (a) Attachments 1 to 5 for a copy of the Annual Filings to the Yukon Utilities Board.

(b) No explanations of variances of actuals to forecast are required as 2003 2007 were not test years and there were no approved forecasts for these periods.

The Yukon Electrical Company Limited
An ATCO Company

March 31, 2004

Yukon Utilities Board
P.O. Box 6070
Whitehorse, Yukon
Y1A 5L7

Attention: Mr. Brian Morris, Chair

Dear Sir:

Re: Annual Filings - The Yukon Electrical Company Limited

In accordance with Section 25 and 84 of the Public Utilities Act, attached please find the following information:

a) 2003 Audited Financial Statements
b) Utility Income and Rate of Return
c) Computation of Net Rate Base
d) Schedule of Allowance for Working Capital
e) Analysis of Depreciation Reserve
f) Reconciliation of Utility Income to Net Earnings
g) Cost of Debt Capital Employed
h) Property, Plant & Equipment
i) List of Officers and Directors
j) Affidavit.

Yours truly,

THE YUKON ELECTRICAL COMPANY LIMITED

Paul Gogueh,
General Manager

Encl.



100, 1100 First Avenue, Whitehorse, YT Y1A 3T4 tel: 867.633.7000 or 1.800.661.0513 fax: 867.668.3965

# THE YUKON ELECTRICAL COMPANY LIMITED

## FINANCIAL STATEMENTS

## DECEMBER 31, 2003

PRICEWATERHOUSECOOPERS

**PricewaterhouseCoopers LLP**
**Chartered Accountants**
Suite 1501, TD Tower
10088 - 102 Avenue
Edmonton, Alberta
Canada T5J 3N5
Telephone +1 (780) 441 6700
Facsimile +1 (780) 441 6776

February 4, 2004

## Auditors' Report

**To the Shareholder of**
**The Yukon Electrical Company Limited**

We have audited the balance sheet of **The Yukon Electrical Company Limited** as at December 31, 2003 and the statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2003 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

**Chartered Accountants**

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF EARNINGS AND RETAINED EARNINGS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2003 | 2002 |
|---|---|---|---|
| **Revenues** | | $ 36,077 | $ 36,538 |
| **Costs and expenses** | | | |
| Purchased power | | 20,562 | 20,874 |
| Operation and maintenance | | 5,462 | 5,579 |
| Selling and administrative | | 3,055 | 2,919 |
| Depreciation and amortization | | 2,508 | 2,434 |
| Interest | 6 | 1,605 | 1,575 |
| | | 33,192 | 33,381 |
| | | 2,885 | 3,157 |
| **Interest and other income** | 2 | 88 | 77 |
| **Earnings before income taxes** | | 2,973 | 3,234 |
| **Income taxes** | 3 | 1,354 | 1,597 |
| **Earnings attributable to Class A and Class B shares** | | 1,619 | 1,637 |
| **Retained earnings at beginning of year** | | 7,903 | 7,666 |
| | | 9,522 | 9,303 |
| Dividends on Class A and Class B shares | | 1,400 | 1,400 |
| **Retained earnings at end of year** | | $ 8,122 | $ 7,903 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## BALANCE SHEET

*(Thousands of Canadian Dollars)*

| | Note | December 31 2003 | December 31 2002 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Cash and short term investments | | $ - | $ 500 |
| Accounts receivable | | 4,875 | 4,573 |
| Inventories | | 1,091 | 1,074 |
| Prepaid expenses | | 71 | 66 |
| | | 6,037 | 6,213 |
| **Property, plant and equipment** | 4 | 33,665 | 33,189 |
| **Other assets** | | 67 | 77 |
| | | $ 39,769 | $ 39,479 |
| **LIABILITIES AND SHARE OWNER'S EQUITY** | | | |
| **Current liabilities** | | | |
| Bank indebtedness | | $ 157 | $ 294 |
| Short term advance from parent corporation | | 500 | - |
| Accounts payable and accrued liabilities | | 3,373 | 3,152 |
| Income and other taxes payable | | 25 | 115 |
| Owing to parent and affiliated corporations | | 408 | 443 |
| | | 4,463 | 4,004 |
| **Deferred credits** | 5 | 815 | 703 |
| **Long term debt** | 6 | 19,350 | 19,850 |
| **Class A and Class B share owner's equity** | | | |
| Class A and Class B shares | 7 | 7,019 | 7,019 |
| Retained earnings | | 8,122 | 7,903 |
| | | 15,141 | 14,922 |
| | | $ 39,769 | $ 39,479 |

Director

Director

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF CASH FLOWS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2003 | 2002 |
|---|---|---|---|
| **Operating activities** | | | |
| Earnings attributable to Class A and Class B shares | | $ 1,619 | $ 1,637 |
| Adjustments for: | | | |
| Depreciation and amortization | | 2,508 | 2,434 |
| Other | | 112 | 197 |
| Cash flow from operations | | 4,239 | 4,268 |
| Changes in non-cash working capital | 8 | (257) | 291 |
| | | 3,982 | 4,559 |
| **Investing activities** | | | |
| Purchase of property, plant and equipment | | (5,157) | (4,189) |
| Proceeds on disposal of property, plant and equipment | | 3 | 32 |
| Contributions by utility customers for extensions to plant | | 2,170 | 1,215 |
| Changes in non-cash working capital | 8 | 29 | (34) |
| Other | | 10 | 10 |
| | | (2,945) | (2,966) |
| **Financing activities** | | | |
| Issue of long term debt | | - | 3,900 |
| Repayment of long term debt | | (500) | (3,400) |
| Dividends paid to the Class A and Class B share owner | | (1,400) | (1,400) |
| Other | | - | (29) |
| | | (1,900) | (929) |
| **Cash Position**[1] | | | |
| (Decrease) increase | | (863) | 664 |
| Beginning of year | | 206 | (458) |
| **End of year** | | $ (657) | $ 206 |

[1] Cash position includes cash and short term investments, bank indebtedness and short term advance from parent corporation.

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

## December 31, 2003

(tabular amounts in thousands of Canadian dollars)

## 1. Summary of significant accounting policies

### *Financial Statement Presentation*

The accompanying financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The Yukon Electrical Company Limited (the "Corporation") is engaged in the generation, transmission, distribution and sale of electric energy.

Certain comparative figures have been reclassified to conform to the current presentation.

### *Regulation*

The Corporation is regulated primarily by the Yukon Utilities Board (the "Board"), which administers acts and regulations covering such matters as rates, financing, accounting, construction and operation and service area. The Board may approve interim rates, subject to final determination.

### *Use of Estimates*

The preparation of the Corporation's financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates.

### *Revenue Recognition*

Revenues are recorded on the basis of regular meter readings and include an estimate of services provided but not yet billed.

### *Purchased Power*

Purchased power expense is based on the actual cost of electricity purchased.

### *Income Taxes*

The Corporation utilizes the flow through method to account for income taxes. In accordance with the Board, future income taxes have not been recorded to the extent that the income tax component of rates

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2003

(tabular amounts in thousands of Canadian dollars)

***Income Taxes*** (continued)

approved by the Board was not designed to recover those taxes. Accordingly, the customer in future years will bear an additional charge as these unrecorded future income taxes are reversed.

***Inventories***

Inventories include materials and supplies and are valued at the lower of average cost or net realizable value.

***Property, Plant and Equipment***

The Corporation includes in property, plant and equipment an allowance for funds used during construction at rates approved by the Board for debt and equity capital.

Certain additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate. Property, plant and equipment is disclosed net of unamortized contributions.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates are approved by the Board. These depreciation rates include a provision for future removal or site restoration costs. On retirement of depreciable utility assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

***Long Term Debt Due Within One Year***

All of the long term debt is held by the parent corporation, ATCO Electric Ltd. When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on ATCO Electric Ltd.'s behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

***Employee Future Benefits***

The Corporation, together with its ultimate parent corporation, Canadian Utilities Limited and affiliate corporations, participates in a group defined benefit pension plan ("the Group Plan"). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid.

The Corporation accrues for its obligations under other post employment benefit and certain other defined benefit pension plans. These plans are administered on a combined basis with the Corporation's parent and affiliate corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for the plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2003

(tabular amounts in thousands of Canadian dollars)

***Employee Future Benefits*** (Continued)

Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of wage and salary increases, age at retirement and expected health care costs. Experience gains and losses and the effect of changes in assumptions in excess of 10% of the accrued benefit obligations, together with adjustments resulting from plan amendments, are amortized over the estimated average remaining service life of employees.

The Corporation expenses contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred.

## 2. Interest and other income

| | 2003 | 2002 |
|---|---|---|
| Allowance for funds used during construction | $ 44 | $ 23 |
| Interest | 41 | 50 |
| Other | 3 | 4 |
| | $ 88 | $ 77 |

Interest received in 2003 amounted to $41,000 (2002 - $46,000).

## 3. Income taxes

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

| | 2003 | | 2002 | |
|---|---|---|---|---|
| Earnings before income taxes | $ 2,973 | % | $ 3,234 | % |
| Income taxes, at statutory rate | 1,162 | 39.1 | 1,329 | 41.1 |
| Unrecorded future income taxes | 239 | 8.0 | 206 | 6.3 |
| Large corporations tax | 43 | 1.4 | 36 | 1.1 |
| Other | (90) | (3.0) | 26 | 0.8 |
| Income taxes | $ 1,354 | 45.5 | $ 1,597 | 49.3 |

Unrecorded future income taxes receivable increased by $239,000 (net of future tax rate reductions of $93,000) to $1,997,000 at December 31, 2003.

Income taxes paid in 2003 amounted to $1,470,000 (2002 - $1,581,000).

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

### December 31, 2003

(tabular amounts in thousands of Canadian dollars)

## 4. Property, plant and equipment

| | Composite Depreciation Rates | 2003 Cost | 2003 Accumulated Depreciation | 2002 Cost | 2002 Accumulated Depreciated |
|---|---|---|---|---|---|
| Generation | 3.88% | $ 13,590 | $ 6,944 | $ 13,184 | $ 6,490 |
| Distribution | 3.86% | 71,126 | 30,077 | 67,425 | 28,174 |
| Other | 4.70% | 6,197 | 2,980 | 6,183 | 2,768 |
| Land | | 349 | - | 349 | - |
| Construction work in progress | | 609 | - | 363 | - |
| | 3.94% | $ 91,871 | $ 40,001 | $ 87,504 | $ 37,432 |
| Property, plant and equipment less accumulated depreciation | | | $ 51,870 | | $ 50,072 |
| Unamortized contributions by utility customers for extensions to plant | | | 18,205 | | 16,883 |
| | | | $ 33,665 | | $ 33,189 |

Accumulated depreciation includes an amount provided for future removal and site restoration costs, net of salvage value, of $2,682,000 (2002 - $2,530,000).

## 5. Deferred credits

Deferred credits are as follows:

| | 2003 | 2002 |
|---|---|---|
| Pension plan | $ 360 | $ 284 |
| Regulatory hearing costs | 353 | 278 |
| Reserve for injuries and damages | 102 | 141 |
| | $ 815 | $ 703 |

## 6. Long term debt

| | 2003 | 2002 |
|---|---|---|
| Debentures | | |
| 1993 Series 7.36% due September 2003 | $ - | $ 500 |

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2003

(tabular amounts in thousands of Canadian dollars)

6. **Long term debt** (continued)

| | | |
|---|---|---|
| 1995 Series 8.56% due June 2005 | 4,000 | 4,000 |
| 2001 Series 4.95% due November 2006 | 350 | 350 |
| 2000 Series 7.05% due June 2008 | 600 | 600 |
| 1989 Series 10.33% due November 2009 | 2,000 | 2,000 |
| 2002 Series 6.21% due November 2017 | 3,900 | 3,900 |
| 1999 Series 6.85% due August 2019 | 4,500 | 4,500 |
| 1990 Series 11.91% due November 2020 | 1,500 | 1,500 |
| 1992 Series 9.51% due May 2023 | 2,500 | 2,500 |
| | $ 19,350 | $ 19,850 |

The minimum annual repayments of long term debt for each of the next five years are as follows:

| 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|
| $ - | $ 4,000 | $ 350 | $ - | $ 600 |

***Interest expense***

Interest on debt is as follows:

| | 2003 | 2002 |
|---|---|---|
| Long term debt | $ 1,602 | $ 1,567 |
| Customer deposit | 3 | 8 |
| | $ 1,605 | $ 1,575 |

Interest paid in 2003 amounted to $1,612,265 (2002 - $1,559,000).

***Fair values***

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are $22,515,000 (2002 - $23,376,000). Where market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

**December 31, 2003**

(tabular amounts in thousands of Canadian dollars)

## 7. Class A and Class B shares

***Authorized and issued***

| | Class A Non-Voting | | Class B Common | | Total | |
|---|---|---|---|---|---|---|
| | Shares | Consideration | Shares | Consideration | Shares | Consideration |
| *Authorized:* | Unlimited | | Unlimited | | | |
| *Issued and Outstanding:* | | | | | | |
| December 31, 2002 | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |
| **December 31, 2003** | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |

## 8. Changes in non-cash working capital

| | **2003** | 2002 |
|---|---|---|
| *Operating activities, changes related to:* | | |
| Accounts receivable | $ (302) | $ 440 |
| Inventories | (7) | 12 |
| Prepaid expenses | (5) | (51) |
| Accounts payable and accrued liabilities | 182 | (404) |
| Income taxes and other taxes payable | (90) | 260 |
| Owing to parent and affiliated corporations | (35) | 34 |
| | $ (257) | $ 291 |
| *Investing activities, changes related to:* | | |
| Inventories | (10) | 49 |
| Accounts payable and accrued liabilities | 39 | (83) |
| | $ 29 | $ (34) |

## 9. Related party transactions

| Entity | Relationship | Transaction | Recorded as | **2003** | 2002 |
|---|---|---|---|---|---|
| ATCO Electric Ltd. | Parent | Administration, financial management, meter reading, and computer services | Operation and maintenance | $ 196 | $ 139 |
| Northland Utilities (Yellowknife) Limited | Affiliate | Administration and financial management | Revenue | 37 | 30 |

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2003

(tabular amounts in thousands of Canadian dollars)

## 9. Related party transactions (continued)

| Entity | Relationship | Transaction | Recorded as | 2003 | 2002 |
|---|---|---|---|---|---|
| Northland Utilities (NWT) Limited | Affiliate | Administration and financial management | Revenue | 28 | 27 |
| ATCO Frontec Corp. | Affiliate | Building Rent | Revenue | 26 | 20 |
| Canadian Utilities Limited/ATCO Ltd. | Ultimate Parent | Administration, information systems, aircraft | Selling and administrative | 336 | 311 |
| ATCO I-Tek Business Services Ltd. | Affiliate | Billing and call centre services | Selling and administrative | 310 | 292 |

These transactions are considered to be in the normal course of business and are measured at the exchange amount being the amount of consideration established and agreed to by the related parties. The amounts owing to the parent and affiliated corporations are subject to commercial terms and conditions.

## 10. Employee future benefits

The Corporation, together with its parent and affiliate corporations, maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants.

Contributions to a group defined benefit pension plan, which is accounted for as a defined contribution plan, are expensed as paid. Other post employment benefit and certain other defined benefit pension plans, which the Corporation funds out of general revenues, are administered on a combined basis with the Corporation's parent and affiliate corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for each plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. The Corporation expenses contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred.

Information about the benefit plans is as follows:

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2003

(tabular amounts in thousands of Canadian dollars)

## 10. Employee future benefits (continued)

| | 2003 | | 2002 | |
|---|---|---|---|---|
| | Pension Benefit Plans | Other Post Employment Benefit Plans | Pension Benefit Plans | Other Post Employment Benefit Plans |
| **Benefit plan expense** | | | | |
| Benefit plans expense | $ 9 | $ 104 | $ 9 | $ 82 |
| Less: Capitalized | 2 | 21 | 2 | 15 |
| Benefit plan expense | $ 7 | $ 83 | $ 7 | $ 67 |
| **Benefit plan liabilities** | | | | |
| Accrued liability at beginning of year | $ (133) | $ (151) | $ (134) | $ (93) |
| Total benefit plans expense | (9) | (104) | (9) | (82) |
| Benefit payments | 10 | 27 | 10 | 24 |
| Accrued liability at end of year | $ (132) | $ ( 228) | $ (133) | $ (151) |

## 11. Risk management and financial instruments

In conducting its business, the Corporation uses various instruments to manage the risks arising from fluctuations in interest rates.

### *Fair value of financial assets and liabilities*

The fair value of cash and short term investments, accounts receivable, income taxes recoverable, and current liabilities approximate their carrying amounts in the financial statements due to the relatively short period to maturity of these instruments.

### *Interest rate risk*

The Corporation's long term debt has fixed interest rates. The Corporation is exposed to variable interest rates related to the amount owing to parent and affiliated corporations.

## 12. Commitments

The Corporation has contractual obligations in the normal course of business and in respect of long term operating leases for office equipment. Future minimum operating lease payments are as follows:

| 2004 | 2005 | 2006 | 2007 | 2008 | Total of All Subsequent Years |
|---|---|---|---|---|---|
| $ 13 | $ 13 | $ 14 | $ 15 | $ 16 | $ 128 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## UTILITY INCOME AND RATE OF RETURN
## For The Year Ended December 31, 2003
## ($000s)

| | | |
|---|---|---|
| UTILITY REVENUE | | 35,849 |
| UTILITY EXPENSE | | |
| Operation and Maintenance | | 28,505 |
| Less: | Non Allowables | 5 |
| | Non Utility Income Taxes | (10) |
| | Non Utility Depreciation | 1 |
| Add: | Depreciation | 3,355 |
| | Other Taxes | 223 |
| | Income Taxes | 1,354 |
| | Amortization of Contribution for Extensions | (847) |
| | Amortization of Deferred Study and Rate Case Costs | 75 |
| | Amortization of Deferred Gain on Land | 0 |
| TOTAL | | 32,669 |
| UTILITY INCOME | | 3,180 |
| NET RATE BASE | | 35,189 |
| RATE OF RETURN | | 9.038% |

# THE YUKON ELECTRICAL COMPANY LIMITED
## COMPUTATION OF NET RATE BASE
## For The Year Ended December 31, 2003
## ($000s)

| | | |
|---|---|---|
| PROPERTY PLANT AND EQUIPMENT | | |
| BALANCE AT DECEMBER 31, 2002 | | 91,872 |
| Add: | Deferred Study Costs | |
| Less: | Accumulated Depreciation | 40,001 |
| | Non-regulated Assets | 20 |
| | Construction Work-in-Progress | 609 |
| | Deferred Gain on Land | 0 |
| | | 40,630 |
| NET BALANCE AT YEAR END | | 51,242 |
| Add: | Previous Year's Balance | 49,687 |
| TOTAL | | 100,929 |
| MID-YEAR BALANCE | | 50,465 |
| Add: | Allowance for Working Capital | 2,584 |
| | Mid-Year Rate Case Expense | (316) |
| Less: | Mid-Year Contribution for Extensions | 17,545 |
| NET RATE BASE | | 35,189 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## SCHEDULE OF ALLOWANCE FOR WORKING CAPITAL
## For The Year Ended December 31, 2003
## ($000s)

| | |
|---|---|
| Operation & Maintenance | 28,505 |
| Add: Other Taxes | 223 |
| Less: Non Allowables | 5 |
| Allowable Operating Expense | 28,723 |
| Utility Income Tax (Previous Year) | 1,580 |
| Current Year Income Taxes (Payable) Receivable | (37) |
| Allowance: Operating Expense<br>19/365 * Allowable Operating Expense | 1,495 |
| Allowance: Income Tax<br>30/365 * Income Tax (Previous Year) | 129 |
| Allowance: Final Tax Payment<br>196/365 * Income Taxes Payable | (19) |
| Three Year Average Inventory | 1,100 |
| GST Impact | (121) |
| TOTAL WORKING CAPITAL | 2,584 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## ANALYSIS OF DEPRECIATION RESERVE
## For The Year Ended December 31, 2003
## ($000s)

| | | |
|---|---|---|
| BALANCE - DECEMBER 31, 2003 | | 37432 |
| Add: | Depreciation - Operating Expense | 3355 |
| | Depreciation - Other | 21 |
| | | 40,808 |
| Less: | Retirements | 481 |
| | Sale and Salvage Proceeds | (3) |
| | Dismantling Expense | 329 |
| BALANCE - DECEMBER 31, 2002 | | 40,001 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## RECONCILIATION OF UTILITY INCOME TO NET EARNINGS
## For The Year Ended December 31, 2003
## ($000s)

| | |
|---|---|
| UTILITY INCOME | 3,180 |
| Add Non Utility Income: | |
| Allowance for Funds Used During Construction | 44 |
| Non Regulated Revenues | 228 |
| Short Term Interest From Parent | 20 |
| Gain on sale of land | 0 |
| Non Utility Income | 4 |
| Other Interest | 19 |
| | 315 |
| Sub-Total | 3,495 |
| Less Non Utility Expenses: | |
| Interest to Parent | 1602 |
| Non Regulated Expenses | 275 |
| Non Regulated Depreciation | 1 |
| Preferred Dividends to Parent | 0 |
| Other Interest | 3 |
| Non Allowables | 5 |
| | 1,886 |
| Sub-Total | 1,609 |
| Add Income Tax Adjustment: | |
| Tax on Net Non Utility Income | 10 |
| NET EARNINGS | 1,619 |

# YUKON ELECTRICAL COMPANY LIMITED
## COST OF CAPITAL CALCULATION
## For The Year Ended December 31, 2003
## (%)

| | CAPITAL RATIO | COST | RETURN COMPONENT |
|---|---|---|---|
| LONG TERM DEBT | 55.88 | 8.086 | 4.518 |
| PREFERRED SHARES | 0.00 | 0.00 | 0.000 |
| COMMON SHARES AND RETAINED EARNINGS | 42.86 | 10.55 | 4.520 |
| NO COST CAPITAL | 1.26 | | |
| | 100.00 | | 9.038 |

FA-A-417
RUN TYPE: ADHOC

COMPANY 05
FIXED ASSETS - ACCOUNT WORKSHEET
AS OF December 31, 2003


04-01-15 18:36:19
PGM: FIPF417R

| F.A. ACCOUNT | DESCRIPTION | BALANCE JAN 1, 03 | ADDITIONS | RETIRE TO ACCUM DEPN | RETIRE NON DEPRECIABLE | RETIRE TO O&M & CAP | GAIN/(LOSS) ON SALE | TRANSFERS | BALANCE DEC 31, 03 |
|---|---|---|---|---|---|---|---|---|---|
| HYDRO PRODUCTION | | | | | | | | | |
| 42000 | HYDRO-LAND | 20,912.46 | | | | | | | 20,912.46 |
| 42200 | HYDRO-STRUCTURES AND IMPROVEMENTS | 147,548.11 | | | | | | | 147,548.11 |
| 42300 | HYDRO-RESERVOIRS, DAMS AND WATERWAY | 712,096.18 | 2,788.31 | | | | | | 714,884.49 |
| 42500 | HYDRO-WATERWHEELS, TURBINES & GENER | 272,629.36 | | | | | | | 272,629.36 |
| 42600 | HYDRO-ACCESSORY ELECTRIC EQUIPMENT | 105,192.21 | | | | | | | 105,192.21 |
| 42700 | HYDRO-MISC POWER PLANT EQUIP | 23,984.46 | | | | | | | 23,984.46 |
| TOTAL HYDRO PRODUCTION | | 1,282,362.78 | 2,788.31 | | | | | | 1,285,151.09 |
| DIESEL PRODUCTION | | | | | | | | | |
| 44000 | DIESEL-LAND | 7,130.15 | | | | | | | 7,130.15 |
| 44200 | DIESEL-STRUCTURE AND IMPROVEMENTS | 920,193.57 | | | | | | | 920,193.57 |
| 44400 | DIESEL-FUEL HOLDERS AND ACCESSORIES | 1,234,049.51 | 74,195.05 | 10,000.00- | | | | | 1,298,244.56 |
| 44500 | DIESEL-GENERATING EQUIPMENT | 7,618,614.20 | 172,163.64 | | | | | | 7,790,777.84 |
| 44600 | DIESEL-ACCESSORY ELECTRIC EQUIPMENT | 1,872,613.52 | 129,841.31 | | | | | | 2,002,454.83 |
| 44700 | DIESEL-MISC POWER PLANT EQUIP | 276,619.99 | 37,097.53 | | | | | | 313,717.52 |
| TOTAL DIESEL PRODUCTION | | 11,929,220.94 | 413,297.53 | 10,000.00- | | | | | 12,332,518.47 |
| TRANSMISSION | | | | | | | | | |
| 45000 | TRANS-LAND | 11,550.51 | | | | | | | 11,550.51 |
| 45710 | TRANS-SUBSTATION EQUIPMENT | 1,401,497.52 | | | | | | | 1,401,497.52 |
| TOTAL TRANSMISSION | | 1,413,048.03 | | | | | | | 1,413,048.03 |
| DISTRIBUTION | | | | | | | | | |
| 47000 | DIST-LAND | 7,669.98 | | | | | | | 7,669.98 |
| 47100 | DIST-LAND RIGHTS | 485,766.31 | 61,972.64 | | | | | | 547,738.95 |
| 47300 | DIST-POLES AND FIXTURES | 17,499,383.85 | 779,295.60 | 105,813.87- | | | | | 18,172,865.58 |
| 47400 | DIST-OVERHEAD CONDUCTORS | 10,451,494.62 | 476,359.79 | 59,842.50- | | | | | 10,868,011.91 |
| 47410 | DIST-OVERHEAD SERVICES | 1,779,445.14 | 58,618.71 | | | | | | 1,838,063.85 |
| 47500 | DIST-UNDERGROUND CONDUIT AND DEVICE | 12,982,194.51 | 1,156,926.64 | | | | | | 14,138,596.53 |
| 47510 | DIST-UNDERGROUND SERVICES | 1,714,064.68 | 77,294.57 | 524.62- | | | | | 1,791,359.25 |
| 47610 | DIST-METERS | 633,118.37 | 37,326.60 | 140,305.79- | | | | | 530,139.18 |
| 47620 | DIST-METER EQUIPMENT | 596,759.27 | 94,230.62 | | | | | | 690,989.89 |
| 47710 | DIST-SUBSTATION EQUIPMENT | 2,604,868.74 | | | | | | | 2,604,868.74 |
| 47720 | DIST-SUBSTATION BUILDINGS | 12,601.29 | | | | | | | 12,601.29 |
| 47810 | DIST-STREET LIGHTS | 5,182,449.38 | 588,972.07 | 15,079.66- | | | | | 5,756,341.79 |
| 47820 | DIST-SENTINEL LIGHTS | 284,738.28 | | | | | | | 284,738.28 |
| 47910 | DIST-LINE TRANSFORMERS | 11,797,307.83 | 741,723.31 | 50,174.21- | | | | | 12,488,856.93 |
| TOTAL DISTRIBUTION | | 66,031,862.25 | 4,072,720.55 | 371,740.65- | | | | | 69,732,842.15 |
| GENERAL PROPERTY | | | | | | | | | |
| 48000 | GP-LAND | 300,311.31 | | | | | | | 300,311.31 |
| 48110 | GP-SURVEY | 395.00 | | | | | | | 395.00 |
| 48200 | GP-BUILDINGS AND IMPROVEMENTS | 2,971,441.30 | 46,885.37 | | | | | | 3,018,326.67 |
| 48300 | GP-OFFICE FURNITURE | 342,181.87 | 836.28 | 32,094.23- | | | | | 310,923.92 |
| 48320 | GP-COMPUTER HARDWARE | 46,181.32 | 11,582.80 | 8,271.70- | | | | | 49,492.42 |
| 48330 | GP-COMPUTER SOFTWARE | | | | | | | | |
| 48400 | VEHICLE-DEPRECIATION | 353.48 | | | | | | 353.48- | |
| 48410 | VEHICLE-SEDANS AND WAGONS | 28,209.00 | | | | | | | 28,209.00 |
| 48420 | VEHICLE-TRUCK AND POLE TRAILERS | 207,057.35 | | | | | | | 207,057.35 |
| 48430 | VEHICLE-TRAILERS > 10000 POUNDS | 48,864.48 | | | | | | | 48,864.48 |
| 48440 | VEHICLE-TRUCKS 3/4 TO 2 TON | 769,436.70 | 8,923.42 | | | | | | 778,713.60 |
| 48450 | VEHICLE-TRUCKS >2 TON <3 TON | 399,937.91 | 16,195.05 | | | | | | 416,132.96 |
| 48460 | VEHICLE-POLE CATS | 156,818.41 | | | | | | 353.48 | 156,818.41 |
| 48480 | VEHICLE-TRACTOR | 23,722.23 | | | | | | | 23,722.23 |
| 48490 | VEHICLE-FOREMOST ASSET CONTROL ACCT | | | | | | | | |
| 48500 | GP-TOOLS AND INSTRUMENTS | 543,486.40 | 24,603.39 | 58,843.99- | | | | | 509,245.80 |
| 48600 | GP-COMMUNICATION EQUIPMENT | 381,125.68 | 649.95 | | | | | | 381,775.63 |
| 48810 | GP-HOUSES (LAND) | 603.60 | | | | | | | 603.60 |
| 48820 | GP-HOUSES (BUILDING) | 262,520.63 | 3,969.00 | | | | | | 266,489.63 |
| TOTAL GENERAL PROPERTY | | 6,482,646.67 | 113,645.26 | 99,209.92- | | | | | 6,497,082.01 |
| OTHER | | | | | | | | | |
| 49100 | OTH-FRANCHISE AND CONSENTS | 1,493.00 | | | | | | | 1,493.00 |

| E.A. ACCOUNT | DESCRIPTION | BALANCE JAN 1, 03 | ADDITIONS | RETIRE TO ACCUM DEPN | RETIRE NON DEPRECIABLE | RETIRE TO O&M & CAP | GAIN/(LOSS) ON SALE | TRANSFERS | BALANCE DEC 31, 03 |
|---|---|---|---|---|---|---|---|---|---|
| 49999 | DEFAULT ACCOUNT | | | | | | | | |
| TOTAL OTHER | | 1,493.00 | | | | | | | 1,493.00 |
| | COMPANY TOTAL | 87,140,633.67 | 4,602,451.65 | 480,950.57- | | | | | 91,262,134.75 |

THE YUKON ELECTRICAL COMPANY LIMITED

100 – 1100 1st Avenue, Whitehorse, Yukon, Y1A 3T4

**DIRECTORS**

William L. Britton

James A. Campbell

Basil K. French

Nancy C. Southern

Ronald D. Southern

**OFFICERS**

Ronald D. Southern . . . . . Chairman of the Board

William L. Britton . . . . . Vice-Chairman of the Board

Nancy C. Southern . . . . . Chief Executive Officer

Richard H. Walthall . . . . . President

Owen G. Edmondson . . . . . Vice President and Controller

Dale R. Cawsey . . . . . Secretary

Pat Spruin . . . . . Assistant Secretary

# STATUTORY DECLARATION

IN THE MATTER OF A REPORT REQUIRED BY
SECTION 84 OF THE YUKON PUBLIC UTILITIES ACT
BY R.H. WALTHALL, PRESIDENT, AND D.R. CAWSEY, VICE PRESIDENT,
CORPORATE SECRETARY
OF
THE YUKON ELECTRICAL COMPANY LIMITED (the "Corporation")
(in thousands of dollars)

WE SOLEMNLY DECLARE THAT:

1. For 2003, the Net Rate Base for the Corporation was $35,189

2. As of December 31, 2003, the total capitalization of the Corporation was $34,491 with a weighted average cost of 9.038%.

3. The revenues for the Corporation for the period from January 1, 2003 to December 31, 2003 were as follows:

| | |
|---|---|
| Retail Sales | $ 35,120 |
| Sales to other Utilities | 43 |
| Other Revenue | 914 |
| TOTAL | $ 36,077 |

4. The dividends paid by the Corporation for the period January 1, 2003 to December 31, 2003 were as follows:

| | |
|---|---|
| Common Shares | $ 1,400 |

5. The operating and maintenance costs of the Corporation for the period from January 1, 2003 to December 31, 2003 were $6,482

6. The Corporation estimates the following costs for new works, extensions and improvements during the current year:

| | |
|---|---|
| Distribution Projects | $ 3,713 |
| General Property & Equipment | 306 |
| Generating Plants | 900 |
| TOTAL | $ 4,919 |

WE MAKE THIS SOLEMN DECLARATION CONSCIENTIOUSLY BELIEVING IT TO BE TRUE AND KNOWING THAT IT IS OF THE SAME FORCE AND EFFECT AS IF MADE UNDER OATH.

Severally declared before me )
at the City of Calgary )
in the Province of Alberta )
this 25 day of March, 2004. )

R.H. Walthall

D.R. Cawsey

PATRICIA SPRUIN
A NOTARY PUBLIC
IN AND FOR THE PROVINCE OF ALBERTA
WHOSE COMMISSION EXPIRES DECEMBER 31, 2006

**The Yukon Electrical Company Limited**
An ***ATCO*** Company

March 31, 2005

Yukon Utilities Board
P.O. Box 6070
Whitehorse, Yukon
Y1A 5L7

Attention: Mr. Brian Morris, Chair

Dear Sir:

Re: Annual Filings - The Yukon Electrical Company Limited

In accordance with Section 25 and 84 of the Public Utilities Act, attached please find the following information:

a) 2004 Audited Financial Statements
b) Utility Income and Rate of Return
c) Computation of Net Rate Base
d) Schedule of Allowance for Working Capital
e) Analysis of Depreciation Reserve
f) Reconciliation of Utility Income to Net Earnings
g) Cost of Debt Capital Employed
h) Property, Plant & Equipment
i) List of Officers and Directors
j) Affidavit.

Yours truly,

THE YUKON ELECTRICAL COMPANY LIMITED

Doug Tenney,
General Manager

Encl.

# THE YUKON ELECTRICAL COMPANY LIMITED

## FINANCIAL STATEMENTS

## DECEMBER 31, 2004

PRICEWATERHOUSECOOPERS

**PricewaterhouseCoopers LLP**
**Chartered Accountants**
Suite 1501, TD Tower
10088 – 102 Avenue
Edmonton, Alberta
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February 7, 2005

## Auditors' Report

**To the Shareholder of**
**The Yukon Electrical Company Limited**

We have audited the balance sheet of **The Yukon Electrical Company Limited** as at December 31, 2004 and the statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2004 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

**Chartered Accountants**

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF EARNINGS AND RETAINED EARNINGS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2004 | 2003 |
|---|---|---|---|
| **Revenues** | | $ 37,204 | $ 36,077 |
| **Costs and expenses** | | | |
| Purchased power | | 21,112 | 20,562 |
| Operation and maintenance | | 5,876 | 5,462 |
| Selling and administrative | | 3,207 | 3,055 |
| Depreciation and amortization | | 2,580 | 2,508 |
| Interest | 7 | 1,631 | 1,605 |
| | | 34,406 | 33,192 |
| | | 2,798 | 2,885 |
| **Interest and other income** | 3 | 88 | 88 |
| **Earnings before income taxes** | | 2,886 | 2,973 |
| **Income taxes** | 4 | 1,262 | 1,354 |
| **Earnings attributable to Class A and Class B shares** | | 1,624 | 1,619 |
| **Retained earnings at beginning of year** | | 8,122 | 7,903 |
| | | 9,746 | 9,522 |
| Dividends on Class A and Class B shares | | 1,400 | 1,400 |
| **Retained earnings at end of year** | | $ 8,346 | $ 8,122 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## BALANCE SHEET

*(Thousands of Canadian Dollars)*

| | Note | December 31 2004 | December 31 2003 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Accounts receivable | | $ 4,781 | $ 4,875 |
| Inventories | | 1,289 | 1,091 |
| Prepaid expenses | | 110 | 71 |
| | | 6,180 | 6,037 |
| **Property, plant and equipment** | 5 | 35,146 | 33,665 |
| **Other assets** | | 92 | 67 |
| | | $ 41,418 | $ 39,769 |
| **LIABILITIES AND SHARE OWNER'S EQUITY** | | | |
| **Current liabilities** | | | |
| Bank indebtedness | | $ 314 | $ 157 |
| Short term advance from parent corporation | | - | 500 |
| Accounts payable and accrued liabilities | | 3,357 | 3,373 |
| Owing to parent and affiliated corporations | | 751 | 408 |
| Income and other taxes payable | | 31 | 25 |
| | | 4,453 | 4,463 |
| **Deferred credits** | 6 | 750 | 815 |
| **Long term debt** | 7 | 20,850 | 19,350 |
| **Class A and Class B share owner's equity** | | | |
| Class A and Class B shares | 8 | 7,019 | 7,019 |
| Retained earnings | | 8,346 | 8,122 |
| | | 15,365 | 15,141 |
| | | $ 41,418 | $ 39,769 |

M.C. South Director

D.K. Fjordbotten Director

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF CASH FLOWS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2004 | 2003 |
|---|---|---|---|
| **Operating activities** | | | |
| Earnings attributable to Class A and Class B shares | | $ 1,624 | $ 1,619 |
| Adjustments for: | | | |
| Depreciation and amortization | | 2,580 | 2,508 |
| Other | | (65) | 112 |
| Cash flow from operations | | 4,139 | 4,239 |
| Changes in non-cash working capital | 9 | 303 | (257) |
| | | 4,442 | 3,982 |
| **Investing activities** | | | |
| Purchase of property, plant and equipment | | (5,706) | (5,157) |
| Proceeds on disposal of property, plant and equipment | | 6 | 3 |
| Contributions by utility customers for extensions to plant | | 1,639 | 2,170 |
| Changes in non-cash working capital | 9 | (113) | 29 |
| Other | | (25) | 10 |
| | | (4,199) | (2,945) |
| **Financing activities** | | | |
| Issue of long term debt | | 1,500 | - |
| Repayment of long term debt | | - | (500) |
| Dividends paid to the Class A and Class B share owner | | (1,400) | (1,400) |
| | | 100 | (1,900) |
| **Cash Position**[1] | | | |
| Increase (decrease) | | 343 | (863) |
| Beginning of year | | (657) | 206 |
| **End of year** | | $ (314) | $ (657) |

[1] Cash position includes cash and short term investments, bank indebtedness and short term advance from parent corporation.

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

## December 31, 2004

(tabular amounts in thousands of Canadian dollars)

## 1. Summary of significant accounting policies

### *Financial Statement Presentation*

The accompanying financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The Yukon Electrical Company Limited (the "Corporation") is engaged in the generation, transmission, distribution and sale of electric energy.

Certain comparative figures have been reclassified to conform to the current presentation.

### *Rate Regulation*

The Corporation is regulated primarily by the Yukon Utilities Board ("the Board") which administers acts and regulations covering such matters as rates, financing, accounting, construction and operation and service area. The Board may approve interim rates, subject to final determination.

Accounting for regulated operations is described in Note 2.

### *Use of Estimates*

The preparation of the Corporation's financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

### *Revenue Recognition*

Revenues from sales of electricity are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of services provided but not yet billed.

### *Purchased Power*

Purchased power expense is based on the actual cost of electricity purchased.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2004

(tabular amounts in thousands of Canadian dollars)

### *Income Taxes*

The Corporation utilizes the flow through method to account for income taxes. In accordance with the Board future income taxes have not been recorded to the extent that the income tax component of rates approved by the Board was not designed to recover those taxes. Accordingly, the customer in future years will bear an additional charge as these unrecorded future income taxes are reversed.

### *Inventories*

Inventories include materials and supplies and are valued at the lower of average cost or net realizable value.

### *Property, Plant and Equipment*

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant. The Corporation includes in property, plant and equipment an allowance for funds used during construction at rates approved by the Board for debt and equity capital. Certain additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates are approved by the Board. These depreciation rates include a provision for future removal or site restoration costs. On retirement of depreciable utility assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. The impairment loss may be deferred by the Corporation if there is reasonable assurance that the loss will be included in future rates to customers. The adoption of this recommendation had no effect on earnings for the year ended December 31, 2004.

### *Asset Retirement Obligations*

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for asset retirement obligations. The CICA recommendations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. An asset retirement obligation is recorded as a liability, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2004

(tabular amounts in thousands of Canadian dollars)

***Asset Retirement Obligations*** (Continued)

The Corporation has determined that it has tangible long lived assets where there is a legal liability regarding asset retirement. For these tangible long lived assets, asset retirement obligations have not been recorded as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time.

***Long Term Debt Due Within One Year***

All of the long term debt is held by the parent corporation, ATCO Electric Ltd. When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on ATCO Electric Ltd.'s behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

***Employee Future Benefits***

The Corporation, together with its ultimate parent corporation, Canadian Utilities Limited and affiliate corporations, participates in a group defined benefit pension plan ("the Group Plan"). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid.

The Corporation accrues for its obligations under other post employment benefit and certain other defined benefit pension plans. These plans are administered on a combined basis with the Corporation's parent and affiliate corporations.

For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for the plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans.

Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of wage and salary increases, age at retirement and expected health care costs. Experience gains and losses and the effect of changes in assumptions in excess of 10% of the accrued benefit obligations, together with adjustments resulting from plan amendments, are amortized over the estimated average remaining service life of employees.

The Corporation expenses contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred.

## 2. Accounting for regulated operations

While CICA recommendations encourage the application of the primary sources of GAAP to all operations, the recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2004

(tabular amounts in thousands of Canadian dollars)

## 2. Accounting for regulated operations (Continued)

Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities in the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the regulator renders a subsequent decision. The Corporation anticipates that there would be no material differences between the amounts approved by the regulator for collection or refund and the amounts included in assets or liabilities on the balance sheet.

The Corporation has chosen to retain the following existing accounting policies, as permitted by CICA recommendations that define the primary sources of GAAP, pertaining to regulatory decisions that give rise to deferred assets and liabilities:

a) *Future removal and site restoration costs* – Depreciation rates for regulated assets include a provision for future removal costs and site restoration costs. On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

b) Certain costs as required or permitted by the Board are deferred for recovery through future rates.

## 3. Interest and other income

| | 2004 | 2003 |
|---|---|---|
| Allowance for funds used during construction | $ 51 | $ 44 |
| Interest | 32 | 41 |
| Other | 5 | 3 |
| | $ 88 | $ 88 |

Interest received in 2004 amounted to $32,000 (2003 - $41,000).

## 4. Income taxes

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

| | 2004 | | 2003 | |
|---|---|---|---|---|
| Earnings before income taxes | $ 2,886 | % | $ 2,973 | % |
| Income taxes, at statutory rate | 1,106 | 38.3 | 1,162 | 39.1 |
| Unrecorded future income taxes | 141 | 4.9 | 239 | 8.0 |
| Large corporations tax | 40 | 1.4 | 43 | 1.4 |
| Other | (25) | (0.9) | (90) | (3.0) |
| Income taxes | $ 1,262 | 43.7 | $ 1,354 | 45.5 |

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2004

(tabular amounts in thousands of Canadian dollars)

## 4. Income taxes (Continued)

Unrecorded future income taxes receivable increased by $1,000 (net of future tax rate reductions of $140,000) to $1,998,000) at December 31, 2004.

Income taxes paid in 2004 amounted to $1,320,000 (2003 - $1,470,000).

## 5. Property, plant and equipment

| | Composite Depreciation Rates | 2004 Cost | 2004 Accumulated Depreciation | 2003 Cost | 2003 Accumulated Depreciated |
|---|---|---|---|---|---|
| Generation | 3.84% | $ 14,437 | $ 7,336 | $ 13,590 | $ 6,944 |
| Distribution | 3.82% | 75,199 | 32,621 | 71,126 | 30,077 |
| Other | 4.80% | 6,292 | 3,169 | 6,197 | 2,980 |
| Land | | 354 | - | 349 | - |
| Construction work in progress | | 934 | - | 609 | - |
| | 3.87% | $ 97,216 | $ 43,126 | $ 91,871 | $ 40,001 |
| Property, plant and equipment less accumulated depreciation | | | $ 54,090 | | $ 51,870 |
| Unamortized contributions by utility customers for extensions to plant | | | 18,944 | | 18,205 |
| | | | $ 35,146 | | $ 33,665 |

Accumulated depreciation includes an amount provided for future removal and site restoration costs, net of salvage value, of $3,167,000 (2003 - $2,682,000).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost.

## 6. Deferred credits

Deferred credits are as follows:

| | 2004 | 2003 |
|---|---|---|
| Pension plan | $ 480 | $ 360 |
| Regulatory hearing costs | 428 | 353 |
| Reserve for injuries and damages | (158) | 102 |
| | $ 750 | $ 815 |

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2004

(tabular amounts in thousands of Canadian dollars)

## 7. Long term debt

| | 2004 | 2003 |
|---|---|---|
| Debentures | | |
| 1995 Series 8.56% due June 2005 | $ 4,000 | $ 4,000 |
| 2001 Series 4.95% due November 2006 | 350 | 350 |
| 2000 Series 7.05% due June 2008 | 600 | 600 |
| 1989 Series 10.33% due November 2009 | 2,000 | 2,000 |
| 2004 Series 5.16% due November 2014 | 500 | - |
| 2002 Series 6.21% due November 2017 | 3,900 | 3,900 |
| 2004 Series 5.47% due January 2019 | 1,000 | - |
| 1999 Series 6.85% due August 2019 | 4,500 | 4,500 |
| 1990 Series 11.91% due November 2020 | 1,500 | 1,500 |
| 1992 Series 9.51% due May 2023 | 2,500 | 2,500 |
| | $ 20,850 | $ 19,350 |

The minimum annual repayments of long term debt for each of the next five years are as follows:

| 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|
| $ 4,000 | $ 350 | $ - | $ 600 | $ 2,000 |

The $4 million due in 2005 will be refinanced with ATCO Electric Ltd on a long term basis and therefore is excluded from long term debt due within one year on the balance sheet.

### *Interest expense*

Interest on debt is as follows:

| | 2004 | 2003 |
|---|---|---|
| Long term debt | $ 1,630 | $ 1,602 |
| Customer deposit | 1 | 3 |
| | $ 1,631 | $ 1,605 |

Interest paid in 2004 amounted to $1,603,815 (2003 - $1,612,265).

### *Fair values*

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are $25,031,000 (2003 - $22,515,000). Where market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

**December 31, 2004**

(tabular amounts in thousands of Canadian dollars)

## 8. Class A and Class B shares

***Authorized and issued***

| | Class A Non-Voting | | Class B Common | | Total | |
|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Shares | Amount |
| *Authorized:* | Unlimited | | Unlimited | | | |
| *Issued and Outstanding:* | | | | | | |
| December 31, 2003 | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |
| **December 31, 2004** | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |

## 9. Changes in non-cash working capital

| | **2004** | 2003 |
|---|---|---|
| *Operating activities, changes related to:* | | |
| Accounts receivable | $ 94 | $ (302) |
| Inventories | (77) | (7) |
| Prepaid expenses | (39) | (5) |
| Accounts payable and accrued liabilities | (24) | 182 |
| Income taxes and other taxes payable | 6 | (90) |
| Owing to parent and affiliated corporations | 343 | (35) |
| | $ 303 | $ (257) |
| *Investing activities, changes related to:* | | |
| Inventories | (121) | (10) |
| Accounts payable and accrued liabilities | 8 | 39 |
| | $ (113) | $ 29 |

## 10. Related party transactions

| Entity | Relationship | Transaction | Recorded as | **2004** | 2003 |
|---|---|---|---|---|---|
| ATCO Electric Ltd. | Parent | Administration, financial management, meter reading, and computer services | Operation and maintenance | $ 253 | $ 196 |

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2004

(tabular amounts in thousands of Canadian dollars)

**10. Related party transactions** (Continued)

| Entity | Relationship | Transaction | Recorded as | 2004 | 2003 |
|---|---|---|---|---|---|
| Northland Utilities (Yellowknife) Limited | Affiliate | Administration and financial management | Revenue | 40 | 37 |
| Northland Utilities (NWT) Limited | Affiliate | Administration and financial management | Revenue | 30 | 28 |
| ATCO Frontec Corp. | Affiliate | Building Rent | Revenue | 42 | 26 |
| Canadian Utilities Limited/ATCO Ltd. | Ultimate Parent | Administration, information systems, aircraft | Selling and administrative | 270 | 336 |
| ATCO I-Tek Business Services Ltd. | Affiliate | Billing and call centre services | Selling and administrative | 322 | 310 |
| ATCO Gas | Affiliate | Meter services | Operation and maintenance | 41 | - |

These transactions are considered to be in the normal course of business and are measured at the exchange amount being the amount of consideration established and agreed to by the related parties. The amounts owing to the parent and affiliated corporations are subject to commercial terms and conditions.

**11. Employee future benefits**

The Corporation, together with its parent and affiliate corporations, maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants.

Contributions to a group defined benefit pension plan, which is accounted for as a defined contribution plan, are expensed as paid. Other post employment benefit and certain other defined benefit pension plans, which the Corporation funds out of general revenues, are administered on a combined basis with the Corporation's parent and affiliate corporations.

For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for each plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2004

(tabular amounts in thousands of Canadian dollars)

## 11. Employee future benefits (Continued)

The Corporation expenses contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred.

Information about the benefit plans is as follows:

| | 2004 | | 2003 | |
|---|---|---|---|---|
| | **Pension Benefit Plans** | **Other Post Employment Benefit Plans** | Pension Benefit Plans | Other Post Employment Benefit Plans |
| **Benefit plan expense** | | | | |
| Benefit plans expense | $ 51 | $ 103 | $ 9 | $ 104 |
| Less: Capitalized | - | 21 | 2 | 21 |
| Benefit plan expense | $ 51 | $ 82 | $ 7 | $ 83 |
| **Benefit plan liabilities** | | | | |
| Accrued liability at beginning of year | $ (133) | $ (228) | $ (133) | $ (151) |
| Total benefit plans expense | (51) | (103) | (9) | (104) |
| Benefit payments | 9 | 25 | 10 | 27 |
| Accrued liability at end of year | $ 174 | $ 306 | $ (132) | $ ( 228) |

## 12. Risk management and financial instruments

***Fair value of financial assets and liabilities***

The fair value of accounts receivables and current liabilities approximate their carrying amounts in the financial statements due to the relatively short period to maturity of these instruments.

***Interest rate risk***

The Corporation is not exposed to significant interest rate risk due to its long term debt having fixed interest rate.

## 13. Commitments

The Corporation has contractual obligations in the normal course of business and in respect of long term operating leases for office equipment. Future minimum operating lease payments are as follows:

| 2005 | 2006 | 2007 | 2008 | 2009 | Total of All Subsequent Years |
|---|---|---|---|---|---|
| $ 8 | $ 8 | $ 9 | $ 9 | $ 9 | $ 100 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## UTILITY INCOME AND RATE OF RETURN
## For The Year Ended December 31, 2004
### ($000s)

| | | |
|---|---|---|
| UTILITY REVENUE | | 36,984 |
| UTILITY EXPENSE | | |
| Operation and Maintenance | | 29,677 |
| Less: | Non Allowables | 4 |
| | Non Utility Income Taxes | 17 |
| | Non Utility Depreciation | 1 |
| Add: | Depreciation | 3,481 |
| | Other Taxes | 226 |
| | Income Taxes | 1,262 |
| | Amortization of Contribution for Extensions | (901) |
| | Amortization of Deferred Study and Rate Case Cost | 75 |
| TOTAL | | 33,798 |
| UTILITY INCOME | | 3,186 |
| NET RATE BASE | | 35,902 |
| RATE OF RETURN | | 8.873% |

# THE YUKON ELECTRICAL COMPANY LIMITED
## COMPUTATION OF NET RATE BASE
## For The Year Ended December 31, 2004
**($000s)**

| | |
|---|---|
| PROPERTY PLANT AND EQUIPMENT | |
| BALANCE AT DECEMBER 31, 2004 | 97,216 |
| Add: Deferred Study Costs | |
| Less: Accumulated Depreciation | 43,126 |
| Non-regulated Assets | |
| Construction Work-in-Progress | 935 |
| | 44,061 |
| NET BALANCE AT YEAR END | 53,155 |
| Add: Previous Year's Balance | 51,242 |
| TOTAL | 104,397 |
| MID-YEAR BALANCE | 52,199 |
| Add: Allowance for Working Capital | 2,669 |
| Mid-Year Rate Case Expense | (391) |
| Less: Mid-Year Contribution for Extensions | 18,575 |
| NET RATE BASE | 35,902 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## SCHEDULE OF ALLOWANCE FOR WORKING CAPITAL
## For The Year Ended December 31, 2004
**($000s)**

| | |
|---|---|
| Operation & Maintenance | 29,677 |
| Add: Other Taxes | 226 |
| Less: Non Allowables | 4 |
| Allowable Operating Expense | 29,899 |
| Utility Income Tax (Previous Year) | 1,354 |
| Current Year Income Taxes (Payable) Receivable | (54) |
| Allowance: Operating Expense<br>19/365 * Allowable Operating Expense | 1,556 |
| Allowance: Income Tax<br>30/365 * Income Tax (Previous Year) | 111 |
| Allowance: Final Tax Payment<br>196/365 * Income Taxes Payable | (28) |
| Three Year Average Inventory | 1,151 |
| GST Impact | (121) |
| TOTAL WORKING CAPITAL | 2,669 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## ANALYSIS OF DEPRECIATION RESERVE
## For The Year Ended December 31, 2004
### ($000s)

| | | |
|---|---|---|
| BALANCE - DECEMBER 31, 2003 | | 40,001 |
| Add: | Depreciation - Operating Expense | 3,481 |
| | Depreciation - Other | 18 |
| | | 43,500 |
| Less: | Retirements | 339 |
| | Sale and Salvage Proceeds | (5) |
| | Dismantling Expense | 40 |
| BALANCE - DECEMBER 31, 2004 | | 43,126 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## RECONCILIATION OF UTILITY INCOME TO NET EARNINGS
## For The Year Ended December 31, 2004
($000s)

| | |
|---|---|
| UTILITY INCOME | 3,186 |
| Add Non Utility Income: | |
| Allowance for Funds Used During Construction | 51 |
| Non Regulated Revenues | 220 |
| Short Term Interest From Parent | 18 |
| Non Utility Income | 5 |
| Other Interest | 14 |
| | 308 |
| Sub-Total | 3,494 |
| Less Non Utility Expenses: | |
| Interest to Parent | 1,630 |
| Non Regulated Expenses | 214 |
| Non Regulated Depreciation | 1 |
| Preferred Dividends to Parent | - |
| Other Interest | 4 |
| Non Allowables | 4 |
| | 1,853 |
| Sub-Total | 1,641 |
| Add Income Tax Adjustment: | |
| Tax on Net Non Utility Income | (17) |
| NET EARNINGS | 1,624 |

# YUKON ELECTRICAL COMPANY LIMITED
## COST OF CAPITAL CALCULATION
## For The Year Ended December 31, 2004
(%)

| | CAPITAL RATIO | COST | RETURN COMPONENT |
|---|---|---|---|
| LONG TERM DEBT | 56.23 | 8.041 | 4.52 |
| PREFERRED SHARES | 0.00 | 0.00 | - |
| COMMON SHARES AND RETAINED EARNINGS | 42.67 | 10.20 | 4.35 |
| NO COST CAPITAL | 1.10 | | |
| | 100.00 | | 8.873 |

## (FA-420A) PPE by Fiscal Year Book Type Code: YECL CORP Period Name: DEC-2004

| Function | Major Acc | Major Description | Minor Account | Minor Description | Sub Category | Subcategory Description | Fiscal Year Beginning Balance | Additions | Retirements | Ending Period Balance |
|---|---|---|---|---|---|---|---|---|---|---|
| Corporate | CGPE | **(EL) Corporate GP&E** | 48000 | Land | 48000 | Land | 300,311 | 4,917 | | 305,229 |
| | | | 48200 | Buildings and Structures | 48100 | Land Rights | - | 19,148 | | 19,148 |
| | | | 48200 | Buildings and Structures | 48200 | Buildings and Structures | 3,018,722 | 29,522 | | 3,048,243 |
| | | | 48300 | Office Furniture | 48300 | Office Furniture | 310,924 | 41,364 | (33,788) | 318,499 |
| | | | 48320 | Computer Equipment | 48320 | Computer Equipment | 49,492 | 39,055 | (17,221) | 71,326 |
| | | | 48401 | Vehicles Category 1 | 48410 | Cars | 28,209 | | | 28,209 |
| | | | 48401 | Vehicles Category 1 | 48420 | Light Trucks and Pole Trailers | 207,057 | | | 207,057 |
| | | | 48401 | Vehicles Category 1 | 48430 | Pole Trailers > 10,000 lbs | 48,864 | | | 48,864 |
| | | | 48401 | Vehicles Category 1 | 48440 | 3/4 to 2 Ton Trucks | 778,714 | 1,623 | | 780,336 |
| | | | 48401 | Vehicles Category 1 | 48450 | Trucks > 2 Tons < 3 Tons | 416,133 | | | 416,133 |
| | | | 48401 | Vehicles Category 1 | 48460 | Pole Cats | 156,818 | | | 156,818 |
| | | | 48401 | Vehicles Category 1 | 48480 | Tractors | 23,722 | | | 23,722 |
| | | | 48500 | Loose Tools | 48500 | Loose Tools | 509,246 | 64,024 | (54,261) | 519,009 |
| | | | 48600 | Communication Equipment | 48600 | Communication Equipment | 381,776 | 4,711 | | 386,487 |
| | | | 48810 | Houses Land | 48810 | Houses Land | 604 | | | 604 |
| | | | 48820 | Houses | 48820 | Houses | 266,490 | | | 266,490 |
| | | | 49100 | Franchise and Consent | 49100 | Franchise and Consent | 1,493 | | | 1,493 |
| | Total for CGPE: | | | | | | 6,498,575 | 204,363 | (105,271) | 6,597,667 |
| Distributior | DPRM | **(EL) Dist Primary** | 47000 | Land | 47000 | Land | 7,670 | | | 7,670 |
| | | | 47100 | Land Rights | 47100 | Land Rights | 547,739 | 59,886 | | 607,625 |
| | | | 47300 | Poles and Fixtures | 47300 | Poles and Fixtures | 18,172,866 | 1,001,333 | (15,779) | 19,158,420 |
| | | | 47400 | Overhead Conductor | 47400 | Overhead Conductor | 10,868,012 | 650,915 | (4,049) | 11,514,878 |
| | | | 47410 | Overhead Services | 47410 | Overhead Services | 1,838,064 | 73,588 | | 1,911,652 |
| | | | 47500 | Underground Conduit | 47500 | Underground Conduit | 14,138,597 | 873,312 | (2,120) | 15,009,789 |
| | | | 47510 | Underground Services | 47510 | Underground Services | 1,791,359 | 207,282 | | 1,998,641 |
| | | | 47610 | Meters | 47610 | Meters | 530,139 | 12,350 | (106,016) | 436,473 |
| | | | 47610 | Meters | 47620 | Metering Equipment | 690,990 | 113,905 | | 804,894 |
| | | | 47710 | Distribution Substation | 47710 | Non-Fenced Distr Sub Equip | 2,604,869 | | | 2,604,869 |
| | | | 47710 | Distribution Substation | 47720 | Distr Substation Buildings | 12,601 | | | 12,601 |
| | | | 47810 | Street Lights | 47810 | Street Lights | 5,756,342 | 477,246 | (11,382) | 6,222,206 |
| | | | 47820 | Sentinel Lights | 47820 | Sentinel Lights | 284,738 | | | 284,738 |
| | | | 47910 | Transformers | 47910 | Line Transformers | 12,488,857 | (101,671) | (2,646) | 12,384,540 |
| | | | 47910 | Transformers | 47910INV | Inventory Reclass Transformers | | 846,518 | | 846,518 |
| | Total for Distribution: | | | | | | 69,732,842 | 4,214,664 | (141,991) | 73,805,516 |
| Generation | GHYD | **(EL) Gen Hydro** | 42000 | Hydro Land | 42000 | Hydro Land | 20,912 | - | | 20,912 |
| | | | 42500 | Hydro Equipment | 42200 | Hydro Structures | 147,548 | | | 147,548 |
| | | | 42500 | Hydro Equipment | 42300 | Hydro Resv, Dams & Waterways | 714,884 | 42,199 | | 757,083 |
| | | | 42500 | Hydro Equipment | 42500 | Hydro Generators | 272,629 | | | 272,629 |
| | | | 42500 | Hydro Equipment | 42600 | Hydro Accessory Electrical Equip | 105,192 | | | 105,192 |
| | | | 42500 | Hydro Equipment | 42700 | Hydro Misc Equip | 23,984 | | | 23,984 |
| | Total for GHYD: | | | | | | 1,285,151 | 42,199 | - | 1,327,350 |
| | GOTH | **(EL) Gen Other Productic** | 44000 | Int Combust Land | 44000 | Int Combust Land | 7,130 | | | 7,130 |
| | | | 44200 | Int Combust Structures | 44200 | Int Combust Structures | 920,194 | | (3,290) | 916,904 |
| | | | 44400 | Int Combust Fuel Holders | 44400 | Int Combust Fuel Holders | 1,298,245 | 38,348 | (9,322) | 1,327,270 |
| | | | 44500 | Int Combust Generators | 44500 | Int Combust Generators | 7,790,778 | 761,291 | (79,009) | 8,473,060 |
| | | | 44600 | Int Combust Access Elect Eq | 44600 | Int Combust Access Elect Equip | 2,002,455 | 35,377 | | 2,037,832 |
| | | | 44700 | Int Combust Misc Equip | 44700 | Int Combust Misc Equip | 313,718 | 61,572 | | 375,290 |
| | Total for GOTH: | | | | | | 12,332,518 | 896,588 | (91,621) | 13,137,486 |
| Total for Generation: | | | | | | | 13,617,670 | 938,787 | (91,621) | 14,464,836 |
| Transmissi | TPRM | **(EL) Trans Primary** | 45000 | Land | 45000 | Land | 11,551 | | | 11,551 |
| | | | 45700 | Transmission Substation | 45710 | Substation Misc Equip & Install | 1,401,498 | | | 1,401,498 |
| | Total for Transmission: | | | | | | 1,413,048 | | | 1,413,048 |
| Grand Total: | | | | | | | 91,262,134.75 | 5,357,814.38 | (338,882.72) | 96,281,066.77 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## 100 – 1100 1st Avenue, Whitehorse, YT, Y1A 3T4

### DIRECTORS

William L. Britton

Basil K. French

Nancy C. Southern

Ronald D. Southern

Karen M. Watson

### OFFICERS

Ronald D. Southern . . . . . Chairman of the Board

William L. Britton . . . . . Vice-Chairman of the Board

Nancy C. Southern . . . . . Chief Executive Officer

Siegfried W. Kiefer . . . . . Managing Director, Utilities

Sett F. Policicchio . . . . . President

Owen G. Edmondson . . . . . Senior Vice President, Controller, Utilities Group

Dennis A. DeChamplain . . . Vice President, Controller

Patricia Spruin . . . . . Secretary

# STATUTORY DECLARATION

IN THE MATTER OF A REPORT REQUIRED BY
SECTION 84 OF THE YUKON PUBLIC UTILITIES ACT
BY S.F. POLICICCHIO, PRESIDENT, AND P. SPRUIN,
CORPORATE SECRETARY
OF
THE YUKON ELECTRICAL COMPANY LIMITED (the "Corporation")
(in thousands of dollars)

WE SOLEMNLY DECLARE THAT:

1. For 2004, the Net Rate Base for the Corporation was $35,902

2. As of December 31, 2004, the total capitalization of the Corporation was $36,215 with a weighted average cost of 8.873%.

3. The revenues for the Corporation for the period from January 1, 2004 to December 31, 2004 were as follows:

| | |
|---|---|
| Retail Sales | $ 36,181 |
| Sales to other Utilities | 40 |
| Other Revenue | 983 |
| TOTAL | $ 37,204 |

4. The dividends paid by the Corporation for the period January 1, 2004 to December 31, 2004 were as follows:

| | |
|---|---|
| Common Shares | $ 1,400 |

5. The operating and maintenance costs of the Corporation for the period from January 1, 2004 to December 31, 2004 were $6,980

6. The Corporation estimates the following costs for new works, extensions and improvements during the current year:

| | |
|---|---|
| Distribution Projects | $ 3,982 |
| General Property & Equipment | 243 |
| Generating Plants | 1,215 |
| TOTAL | $ 5,440 |

WE MAKE THIS SOLEMN DECLARATION CONSCIENTIOUSLY BELIEVING IT TO BE TRUE AND KNOWING THAT IT IS OF THE SAME FORCE AND EFFECT AS IF MADE UNDER OATH.

Severally declared before me )
at the City of Edmonton )
in the Province of Alberta )
this 30 day of March, 2005. )

S. Policicchio
Sett F. Policicchio

J Bassendale

~~Severally~~ declared before me )
at the City of Calgary )
in the Province of Alberta )

this 24th day of March, 2005. )

P Spruin
Patricia Spruin

PERRY SPITZNAGEL
NOTARY PUBLIC FOR THE
PROVINCE OF ALBERTA
EXPIRES UPON DEATH OR
DISHONOUR

**The Yukon Electrical Company Limited**
An ***ATCO*** Company

March 31, 2006

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 6L3

Attention: Mr. Brian Morris , Chair

Dear Sir:

RE: Annual Filings – The Yukon Electrical Company Limited

In accordance with Section 25 and 84 of the Public Utilities Act, attached please find the following information:

a) 2005 Audited Financial Statements
b) Utility Income and Rate of Return
c) Computation of Net Rate Base
d) Schedule of Allowance for Working Capital
e) Analysis of Depreciation Reserve
f) Reconciliation of Utility Income to Net Earnings
g) Cost of Debt Capital Employed
h) Property, Plant and Equipment
i) List of Officers and Directors
j) Affidavit.

Yours truly,

THE YUKON ELECTRICAL COMPANY LIMITED

Doug Tenney,
General Manager

Encl.

PRICEWATERHOUSECOOPERS

**PricewaterhouseCoopers LLP**
**Chartered Accountants**
Suite 1501, TD Tower
10088 – 102 Avenue
Edmonton, Alberta
Canada T5J 3N5
Telephone +1 (780) 441 6700
Facsimile +1 (780) 441 6776

February 3, 2006

## Auditors' Report

**To the Shareholder of**
**The Yukon Electrical Company Limited**

We have audited the balance sheet of **The Yukon Electrical Company Limited** as at December 31, 2005 and the statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2005 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

**Chartered Accountants**

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

# THE YUKON ELECTRICAL COMPANY LIMITED

## FINANCIAL STATEMENTS

## DECEMBER 31, 2005

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF EARNINGS AND RETAINED EARNINGS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 | |
|---|---|---|---|
| | | **2005** | 2004 (Restated Notes 1,3) |
| **Revenues** | | $ 38,164 | $ 37,204 |
| **Costs and expenses** | | | |
| Purchased power | | 21,682 | 21,112 |
| Operation and maintenance | | 5,739 | 5,876 |
| Selling and administrative | | 3,587 | 3,132 |
| Depreciation and amortization | | 2,765 | 2,580 |
| Interest | 8 | 1,527 | 1,631 |
| | | 35,300 | 34,331 |
| | | 2,864 | 2,873 |
| **Interest and other income** | 4 | 66 | 88 |
| **Earnings before income taxes** | | 2,930 | 2,961 |
| **Income taxes** | 5 | 1,306 | 1,262 |
| **Earnings attributable to Class A and Class B shares** | | 1,624 | 1,699 |
| **Retained earnings at beginning of year** | | 8,774 | 8,475 |
| | | 10,398 | 10,174 |
| Dividends on Class A and Class B shares | | 1,400 | 1,400 |
| **Retained earnings at end of year** | | $ 8,998 | $ 8,774 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## BALANCE SHEET

*(Thousands of Canadian Dollars)*

| | Note | December 31 2005 | December 31 2004 (Restated Notes 1,3) |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Accounts receivable | | $ 5,428 | $ 4,781 |
| Inventories | | 1,474 | 1,289 |
| Prepaid expenses | | 104 | 110 |
| | | 7,006 | 6,180 |
| **Property, plant and equipment** | 6 | 36,751 | 35,146 |
| **Regulatory assets** | 2 | 78 | 158 |
| **Other assets** | | 72 | 92 |
| | | $ 43,907 | $ 41,576 |
| **LIABILITIES AND SHARE OWNER'S EQUITY** | | | |
| **Current liabilities** | | | |
| Bank indebtedness | 7 | $ 729 | $ 314 |
| Short term advance from parent corporation | 8 | 1,000 | - |
| Accounts payable and accrued liabilities | | 3,782 | 3,357 |
| Owing to parent and affiliated corporations | | 486 | 751 |
| Income and other taxes payable | | 175 | 31 |
| | | 6,172 | 4,453 |
| **Pension and other post employment benefits** | 12 | 568 | 480 |
| **Long term debt** | 8 | 21,150 | 20,850 |
| **Class A and Class B share owner's equity** | | | |
| Class A and Class B shares | 9 | 7,019 | 7,019 |
| Retained earnings | | 8,998 | 8,774 |
| | | 16,017 | 15,793 |
| | | $ 43,907 | $ 41,576 |

Director

Director

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF CASH FLOWS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2005 | 2004 (Restated Notes 1,3) |
|---|---|---|---|
| **Operating activities** | | | |
| Earnings attributable to Class A and Class B shares | | $ 1,624 | $ 1,699 |
| Adjustments for: | | | |
| Depreciation and amortization | | 2,765 | 2,580 |
| Other | | 142 | (140) |
| Cash flow from operations | | 4,531 | 4,139 |
| Changes in non-cash working capital | 10 | (447) | 303 |
| | | 4,084 | 4,442 |
| **Investing activities** | | | |
| Purchase of property, plant and equipment | | (6,090) | (5,706) |
| Proceeds (costs) on disposal of property, plant and equipment | | (135) | 6 |
| Contributions by utility customers for extensions to plant | | 1,855 | 1,639 |
| Changes in non-cash working capital | 10 | (75) | (113) |
| Other | | 46 | (25) |
| | | (4,399) | (4,199) |
| **Financing activities** | | | |
| Issue of long term debt | | 4,300 | 1,500 |
| Repayment of long term debt | | (4,000) | - |
| Dividends paid to the Class A and Class B share owner | | (1,400) | (1,400) |
| | | (1,100) | 100 |
| **Cash Position**[1] | | | |
| Increase (decrease) | | (1,415) | 343 |
| Beginning of year | | (314) | (657) |
| **End of year** | | $ (1,729) | $ (314) |

[1] Cash position includes bank indebtedness and short term advance from parent corporation.

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

## December 31, 2005

(tabular amounts in thousands of Canadian dollars)

### 1. Summary of significant accounting policies

*Financial Statement Presentation*

The accompanying financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The Yukon Electrical Company Limited (the "Corporation") is engaged in the generation, transmission, distribution and sale of electric energy.

Effective January 1, 2005, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") guideline pertaining to the consolidation of variable interest entities. The guideline requires the Corporation to identify variable interest entities in which it has an interest, determine whether it is the primary beneficiary of such entities, and, if so, to consolidate them. This change in accounting had no effect on the financial statements for the year ended December 31, 2005.

Effective January 1, 2005, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") guideline pertaining to lease arrangements. The guideline requires the Corporation to identify arrangements that do not take the legal form of a lease but convey a right to use a tangible asset in return for a payment or series of payments, and, if so, to account for them as leases. This change in accounting had no effect on the financial statements for the year ended December 31, 2005.

Certain comparative figures have been reclassified to conform to the current presentation.

*Rate Regulation*

The Corporation is regulated primarily by the Yukon Utilities Board ("Board") which administers acts and regulations covering such matters as rates, financing, accounting, construction and operation and service area.

Effective December 31, 2005, the Corporation retroactively adopted the CICA guideline pertaining to the disclosure and presentation of information by entities subject to rate regulation. Accounting for regulated operations is described in Note 2.

The prior year's financial statements have been restated to be consistent with a Board Order described in Note 3.

*Use of Estimates*

The preparation of the Corporation's financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

**December 31, 2005**

(tabular amounts in thousands of Canadian dollars)

## 1. Summary of significant accounting policies (continued)

### *Revenue Recognition*

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the Board.

Revenues from sales of electricity are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of services provided but not yet billed.

### *Purchased Power*

Purchased power expense is based on the actual cost of electricity purchased.

### *Income Taxes*

The Corporation utilizes the flow through method to account for income taxes. In accordance with the Board, future income taxes have not been recorded to the extent that the income tax component of rates approved by the Board was not designed to recover those taxes. Accordingly, the customer in future years will bear an additional charge as these unrecorded future income taxes are reversed.

### *Inventories*

Inventories include materials and supplies and are valued at the lower of average cost or net realizable value.

### *Property, Plant and Equipment*

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant. The Corporation includes in property, plant and equipment an allowance for funds used during construction at rates approved by the Board for debt and equity capital. Certain additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates are approved by the Board. These depreciation rates include a provision for future removal and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of depreciable utility assets, the accumulated depreciation is charged with the cost of the retired unit, net of disposal costs and site restoration costs.

An impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

**December 31, 2005**

(tabular amounts in thousands of Canadian dollars)

**1. Summary of significant accounting policies** (continued)

***Asset Retirement Obligations***

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

The Corporation has determined that it has tangible long lived assets where there is a legal liability regarding asset retirement. For these tangible long lived assets, asset retirement obligations have not been recorded as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time.

***Long Term Debt Due Within One Year***

All of the long term debt is held by the parent corporation, ATCO Electric Ltd. When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on ATCO Electric Ltd.'s behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

***Employee Future Benefits***

The Corporation, together with its ultimate parent corporation, Canadian Utilities Limited and affiliate corporations, participates in a group defined benefit pension plan ("the Group Plan"). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid.

The Corporation accrues for its obligations under other post employment benefit and certain other defined benefit pension plans. These plans are administered on a combined basis with the Corporation's parent and affiliate corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for the plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of wage and salary increases, age at retirement and expected health care costs. Experience gains and losses and the effect of changes in assumptions in excess of 10% of the accrued benefit obligations, together with adjustments resulting from plan amendments, are amortized over the estimated average remaining service life of employees.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

**December 31, 2005**

(tabular amounts in thousands of Canadian dollars)

## 2. Accounting for regulated operations

### *Nature and economic effects of rate regulation*

The Corporation is subject to a cost of service regulatory mechanism under which the Board establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base is the aggregate of the Board approved investment in property, plant and equipment, less accumulated depreciation, plus an allowance for working capital. Rate base also excludes no-cost capital, which consists of unamortized contributions by utility customers for extensions to plant. The Corporation earns a return on rate base intended to meet the cost of the debt and to provide the share owner with a fair return on the common equity component of rate base.

The Board approves rates of return for the debt and common equity component of rate base based on the actual or forecast weighted average cost of the Corporation's debt and common equity.

Under the cost of service methodology, the Corporation seeks approval for it's revenue requirement through submission of a general rate application to the Board. The Board may approve interim rates, subject to final determination.

### *Financial statement effects of rate regulation*

Certain items in these financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities on the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the Board renders a subsequent decision.

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

The regulatory assets comprise the following:

| | **2005** | 2004 |
|---|---|---|
| Reserve for injuries and damages | $ 78 | $ 158 |

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2005

(tabular amounts in thousands of Canadian dollars)

## 2. Accounting for regulated operations (continued)

*Reserves for injuries and damages*

The Board has approved the use of a reserve for injuries and damages by the Corporation as a means of self-insurance. The reserve for injuries and damages is established based on annual amounts approved by the Board to be expensed by the Corporation and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general tariff application or until a specific application is made to the Board requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses for 2005 would have been $80,000 lower (2004 – $260,000 higher) in the absence of rate regulation.

*Other items affected by rate regulation*

The Board permits an allowance for funds used ("AFU"), based on the Corporation's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes a common equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The Corporation follows the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 5).

## 3. Regulatory matters

On April 18, 1996, the Board issued Board Order 1996-6 regarding a joint GRA by the Corporation and Yukon Energy Corporation ("YEC") for the 1996 and 1997 test periods. In Board Order 1996-6, the Board established, among other things, the amount the Corporation and YEC were collectively entitled to record for purposes of their respective hearing cost reserves relating to the 1996 and 1997 test periods. As directed in Board Order 1996-6, the Corporation has expensed $75,000 of hearing costs in each of 1996 and 1997. Since the Corporation has not filed a GRA with the Board subsequent to the 1996 and 1997 test periods, the Corporation has continued to expense $75,000 of hearing costs each year from 1998 to 2004.

On October 18, 2005, the Board issued Board Order 2005-12 regarding the Yukon Energy Corporation's ("YEC") 2005 revenue requirement. In Board Order 2005-12, the Board approved, among other things, YEC's method of accounting for rate hearing costs in which it expensed hearing costs in each of 1996 and 1997, as directed by the Board in Board Order 1996-6, but did not continue to expense any hearing costs from 1998 to 2004.

To be consistent with the direction provided by the Board in Board Order 2005-12, the Corporation has reversed hearing costs previously expensed from 1998 to 2004 and is not expensing hearing costs in 2005. The prior year's financial statements have been restated for the impact of this adjustment. In the Statement of Earnings and Retained Earnings for 2004, Selling and administrative costs have been reduced by $75,000, Earnings attributable to Class A and Class B shares have been increased by

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2005

(tabular amounts in thousands of Canadian dollars)

**3. Regulatory matters** (continued)

$75,000, Retained earnings at beginning of year have been increased by $353,000, and Retained earnings at end of year have been increased by $428,000. In the Balance Sheet as at December 31, 2004, Deferred credits have been reduced by $428,000 and Retained Earnings have been increased by $428,000.

**4. Interest and other income**

| | 2005 | 2004 |
|---|---|---|
| Allowance for funds used during construction | $ 54 | $ 51 |
| Interest | 15 | 32 |
| Other | (3) | 5 |
| | $ 66 | $ 88 |

Interest received in 2005 amounted to $15,000 (2004 - $32,000).

**5. Income taxes**

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

| | 2005 | | 2004 | |
|---|---|---|---|---|
| Earnings before income taxes | $ 2,930 | % | $ 2,886 | % |
| Income taxes, at statutory rate | 1,088 | 37.1 | 1,106 | 38.3 |
| Unrecorded future income taxes | 186 | 6.4 | 141 | 4.9 |
| Large corporations tax | 31 | 1.1 | 40 | 1.4 |
| Other | 1 | 0.0 | (25) | (0.9) |
| Income taxes | $ 1,306 | 44.6 | $ 1,262 | 43.7 |

Unrecorded future income taxes receivable increased by $186,000 to $2,184,000 at December 31, 2005.

Income taxes paid in 2005 amounted to $1,320,000 (2004 - $1,320,000).

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2005

(tabular amounts in thousands of Canadian dollars)

## 6. Property, plant and equipment

| | Composite Depreciation Rates | 2005 Cost | 2005 Accumulated Depreciation | 2004 Cost | 2004 Accumulated Depreciated |
|---|---|---|---|---|---|
| Generation | 3.90% | $ 15,374 | $ 7,837 | $ 14,437 | $ 7,336 |
| Distribution | 3.81% | 80,226 | 35,214 | 75,199 | 32,621 |
| Other | 4.64% | 6,648 | 3,390 | 6,292 | 3,169 |
| Land | | 354 | - | 354 | - |
| Construction work in progress | | 427 | - | 934 | - |
| | 3.86% | $ 103,029 | $ 46,441 | $ 97,216 | $ 43,126 |
| Property, plant and equipment less accumulated depreciation | | | $ 56,588 | | $ 54,090 |
| Unamortized contributions by utility customers for extensions to plant | | | 19,837 | | 18,944 |
| | | | $ 36,751 | | $ 35,146 |

Accumulated depreciation includes an amount provided for future removal and site restoration costs, net of salvage value, of $3,641,000 (2004 - $3,167,000).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding non-depreciable assets and construction work in progress.

## 7. Bank indebtedness and credit lines

The Corporation has an operating credit line totaling $1,000,000 (2004 – $1,000,000) which is available on an uncommitted basis. The credit line enables the Corporation to obtain financing for general business purposes. At December 31, 2005, $990,000 (2004 – $1,000,000) of the credit line was still available.

## 8. Long term debt

| | 2005 | 2004 |
|---|---|---|
| Debentures | | |
| 1995 Series 8.56% due June 2005 | $ - | $ 4,000 |
| 2001 Series 4.95% due November 2006 | 350 | 350 |
| 2000 Series 7.05% due June 2008 | 600 | 600 |
| 1989 Series 10.33% due November 2009 | 2,000 | 2,000 |
| 2004 Series 5.16% due November 2014 | 500 | 500 |
| 2002 Series 6.21% due November 2017 | 3,900 | 3,900 |
| 2004 Series 5.47% due January 2019 | 1,000 | 1,000 |
| 1999 Series 6.85% due August 2019 | 4,500 | 4,500 |
| 1990 Series 11.91% due November 2020 | 1,500 | 1,500 |
| 1992 Series 9.51% due May 2023 | 2,500 | 2,500 |
| 2005 Series 5.23% due November 2030 | 4,300 | - |
| | $ 21,150 | $ 20,850 |

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2005

(tabular amounts in thousands of Canadian dollars)

**8. Long term debt** (continued)

The minimum annual repayments of long term debt for each of the next five years are as follows:

| 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|
| $ 350 | $ - | $ 600 | $ 2,000 | $ - |

The $350,000 due in 2006 will be refinanced with ATCO Electric Ltd on a long term basis and therefore is excluded from long term debt due within one year on the balance sheet.

***Interest expense***

Interest on debt is as follows:

| | 2005 | 2004 |
|---|---|---|
| Long term debt | $ 1,481 | $ 1,630 |
| Interest on Short term financing | 46 | - |
| Other | - | 1 |
| | $ 1,527 | $ 1,631 |

Interest paid in 2005 amounted to $1,484,765 (2004 - $1,603,815).

***Fair values***

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are $26,021,000 (2004 - $25,031,000). Where market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

***Short term advances from parent and affiliated corporations***

Short term advances from parent are payable upon demand and bear interest based on short term Bankers' Acceptance rates.

**9. Class A and Class B shares**

***Authorized and issued***

| | Class A Non-Voting | | Class B Common | | Total | |
|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Shares | Amount |
| *Authorized:* | Unlimited | | Unlimited | | | |
| *Issued and Outstanding:* | | | | | | |
| December 31, 2004 | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |
| **December 31, 2005** | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

**December 31, 2005**

(tabular amounts in thousands of Canadian dollars)

### 10. Changes in non-cash working capital

| | 2005 | 2004 |
|---|---|---|
| *Operating activities, changes related to:* | | |
| Accounts receivable | $ (647) | $ 94 |
| Inventories | (37) | (77) |
| Prepaid expenses | 6 | (39) |
| Accounts payable and accrued liabilities | 352 | (24) |
| Income taxes and other taxes payable | 144 | 6 |
| Owing to parent and affiliated corporations | (265) | 343 |
| | $ (447) | $ 303 |
| *Investing activities, changes related to:* | | |
| Inventories | (148) | (121) |
| Accounts payable and accrued liabilities | 73 | 8 |
| | $ (75) | $ (113) |

### 11. Related party transactions

| Entity | Relationship | Transaction | Recorded as | 2005 | 2004 |
|---|---|---|---|---|---|
| Northland Utilities (Yellowknife) Limited | Affiliate | Administration and financial management | Revenue | $ 34 | $ 40 |
| Northland Utilities (NWT) Limited | Affiliate | Administration and financial management | Revenue | 28 | 30 |
| ATCO Frontec Corp. | Affiliate | Building Rent | Revenue | 43 | 42 |
| ATCO I-Tek Business Services Ltd. | Affiliate | Information system services | Selling and administrative | 306 | 270 |
| ATCO I-Tek Business Services Ltd. | Affiliate | Billing services | Selling and administrative | 339 | 322 |
| ATCO Gas | Affiliate | Meter services | Operation and maintenance | 34 | 41 |
| ATCO Electric Ltd. | Parent | Administration and management support | Revenue | 47 | - |
| | | Administration, financial management, meter reading, computer services and equipment rent | Operation and maintenance | 315 | 308 |

These transactions are considered to be in the normal course of business and are measured at the exchange amount being the amount of consideration established and agreed to by the related parties. The amounts owing to the parent and affiliated corporations are subject to commercial terms and conditions.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

**December 31, 2005**

(tabular amounts in thousands of Canadian dollars)

## 12. Employee future benefits

The Corporation, together with its parent and affiliate corporations, maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants.

Contributions to a group defined benefit pension plan, which is accounted for as a defined contribution plan, are expensed as paid. Other post employment benefit and certain other defined benefit pension plans, which the Corporation funds out of general revenues, are administered on a combined basis with the Corporation's ultimate parent and affiliated corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for the plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans.

Information about the benefit plans is as follows:

| | 2005 | | 2004 | |
|---|---|---|---|---|
| | **Pension Benefit Plans** | **Other Post Employment Benefit Plans** | Pension Benefit Plans | Other Post Employment Benefit Plans |
| **Benefit plan expense** | | | | |
| Benefit plans expense | $ 9 | $ 117 | $ 51 | $ 103 |
| Less: Capitalized | - | 23 | - | 21 |
| Benefit plan expense | $ 9 | $ 94 | $ 51 | $ 82 |
| **Benefit plan liabilities** | | | | |
| Accrued liability at beginning of year | $ (174) | $ (306) | $ (132) | $ (228) |
| Total benefit plans expense | (9) | (117) | (51) | (103) |
| Benefit payments | 10 | 28 | 9 | 25 |
| Accrued liability at end of year | $ (173) | $ (395) | $ (174) | $ (306) |

## 13. Risk management and financial instruments

### *Fair value of financial assets and liabilities*

The fair value of accounts receivables and current liabilities approximate their carrying amounts in the financial statements due to the relatively short period to maturity of these instruments.

### *Interest rate risk*

The Corporation is not exposed to significant interest rate risk due to its long term debt having fixed interest rate.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

**December 31, 2005**

(tabular amounts in thousands of Canadian dollars)

## 14. Commitments & Contingencies

### *Commitments*

The Corporation has contractual obligations in the normal course of business and in respect of long term operating leases for office equipment. Future minimum operating lease payments are as follows:

| 2006 | 2007 | 2008 | 2009 | 2010 | Total of All Subsequent Years |
|---|---|---|---|---|---|
| $ 8 | $ 9 | $ 9 | $ 9 | $ 9 | $ 100 |

### *Contingencies*

Measurement inaccuracies occur from time to time with respect to the Corporation's metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the Board.

As a result of decisions of the Supreme Court of Canada in Garland vs.Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

# THE YUKON ELECTRICAL COMPANY LIMITED
## UTILITY INCOME AND RATE OF RETURN
## For The Year Ended December 31, 2005
**($000s)**

| | | |
|---|---|---|
| UTILITY REVENUE | | 37,927 |
| UTILITY EXPENSE | | |
| Operation and Maintenance | | 30,530 |
| Less: | Non Allowables | 19 |
| | Non Utility Income Taxes | (23) |
| | Non Utility Depreciation | 1 |
| Add: | Depreciation | 3,728 |
| | Other Taxes | 229 |
| | Income Taxes | 1,306 |
| | Amortization of Contribution for Extensions | (962) |
| | Amortization of Deferred Study and Rate Case Costs | - |
| TOTAL | | 34,834 |
| UTILITY INCOME | | 3,093 |
| NET RATE BASE | | 38,029 |
| RATE OF RETURN | | 8.134% |

# THE YUKON ELECTRICAL COMPANY LIMITED
## COMPUTATION OF NET RATE BASE
## For The Year Ended December 31, 2005
**($000s)**

| | | |
|---|---|---|
| PROPERTY PLANT AND EQUIPMENT | | |
| BALANCE AT DECEMBER 31, 2005 | | 103,029 |
| Add: | Deferred Study Costs | - |
| Less: | Accumulated Depreciation | 46,441 |
| | Non-regulated Assets | 18 |
| | Construction Work-in-Progress | 427 |
| | | 46,886 |
| NET BALANCE AT YEAR END | | 56,143 |
| Add: | Previous Year's Balance | 53,155 |
| TOTAL | | 109,298 |
| MID-YEAR BALANCE | | 54,649 |
| Add: | Allowance for Working Capital | 2,771 |
| | Mid-Year Rate Case Expense | - |
| Less: | Mid-Year Contribution for Extensions | 19,391 |
| NET RATE BASE | | 38,029 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## SCHEDULE OF ALLOWANCE FOR WORKING CAPITAL
## For The Year Ended December 31, 2005
**($000s)**

| | |
|---|---|
| Operation & Maintenance | 30,530 |
| Add: Other Taxes | 229 |
| Less: Non Allowables | 19 |
| Allowable Operating Expense | 30,741 |
| Utility Income Tax (Previous Year) | 1,245 |
| Current Year Income Taxes (Payable) Receivable | (175) |
| Allowance: Operating Expense<br>19/365 * Allowable Operating Expense | 1,600 |
| Allowance: Income Tax<br>30/365 * Income Tax (Previous Year) | 102 |
| Allowance: Final Tax Payment<br>196/365 * Income Taxes Payable | (93) |
| Three Year Average Inventory | 1,285 |
| GST Impact | (123) |
| TOTAL WORKING CAPITAL | 2,771 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## ANALYSIS OF DEPRECIATION RESERVE
## For The Year Ended December 31, 2005
**($000s)**

| | | |
|---|---|---|
| BALANCE - DECEMBER 31, 2004 | | 43,126 |
| Add: | Depreciation - Operating Expense | 3,728 |
| | Depreciation - Other | 26 |
| | | 46,880 |
| Less: | Retirements | 303 |
| | Sale and Salvage Proceeds | (13) |
| | Dismantling Expense | 149 |
| BALANCE - DECEMBER 31, 2005 | | 46,441 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## RECONCILIATION OF UTILITY INCOME TO NET EARNINGS
## For The Year Ended December 31, 2005
**($000s)**

| | |
|---|---|
| UTILITY INCOME | 3,093 |
| Add Non Utility Income: | |
| Allowance for Funds Used During Construction | 54 |
| Non Regulated Revenues | 232 |
| Short Term Interest From Parent | - |
| Non Utility Income | 5 |
| Other Interest | 20 |
| | 311 |
| Sub-Total | 3,404 |
| Less Non Utility Expenses: | |
| Interest to Parent | 1,481 |
| Short Term Interest To Parent | 46 |
| Non Regulated Expenses | 248 |
| Non Regulated Depreciation | 1 |
| Preferred Dividends to Parent | - |
| Other Interest | 7 |
| Non Allowables | 19 |
| | 1,803 |
| Sub-Total | 1,601 |
| Add Income Tax Adjustment: | |
| Tax on Net Non Utility Income | 23 |
| NET EARNINGS | 1,624 |

# YUKON ELECTRICAL COMPANY LIMITED
## COST OF CAPITAL CALCULATION
## For The Year Ended December 31, 2005
(%)

| | CAPITAL RATIO | COST | RETURN COMPONENT |
|---|---|---|---|
| LONG TERM DEBT | 56.28 | 7.606 | 4.281 |
| PREFERRED SHARES | - | - | - |
| COMMON SHARES AND RETAINED EARNINGS | 42.63 | 9.040 | 3.853 |
| NO COST CAPITAL | 1.09 | | |
| | 100.00 | | 8.134 |

(FA-420A) PPE by Fiscal Year Book Type Code: YECL CORP Period Name: DEC-2005

| Function | Major Account | Minor Account | Minor Description | Sub Category | Subcategory Description | Jan 1/05 | Additions | Retirements | Dec 31/05 |
|---|---|---|---|---|---|---|---|---|---|
| Corporate | CGPE | 48000 | Land | 48000 | Land | 305,228.63 | 0.00 | 0.00 | 305,228.63 |
| | | 48200 | Buildings and Structures | 48100 | Land Rights | 19,148.27 | 0.00 | 0.00 | 19,148.27 |
| | | 48200 | Buildings and Structures | 48200 | Buildings and Structures | 3,048,243.02 | 4,861.53 | 0.00 | 3,053,104.55 |
| | | 48300 | Office Furniture | 48300 | Office Furniture | 318,499.14 | 10,922.40 | -44,720.28 | 284,701.26 |
| | | 48320 | Computer Equipment | 48320 | Computer Equipment | 71,325.67 | 201,559.40 | -180.45 | 272,704.62 |
| | | 48401 | Vehicles Category 1 | 48410 | Cars | 28,209.00 | 0.00 | 0.00 | 28,209.00 |
| | | 48401 | Vehicles Category 1 | 48420 | Light Trucks and Pole Trailers | 207,057.35 | 0.00 | 0.00 | 207,057.35 |
| | | 48401 | Vehicles Category 1 | 48430 | Pole Trailers > 10,000 lbs | 48,864.48 | 0.00 | 0.00 | 48,864.48 |
| | | 48401 | Vehicles Category 1 | 48440 | 3/4 to 2 Ton Trucks | 780,336.25 | 159,789.00 | 0.00 | 940,125.25 |
| | | 48401 | Vehicles Category 1 | 48450 | Trucks > 2 Tons < 3 Tons | 416,132.96 | 0.00 | 0.00 | 416,132.96 |
| | | 48401 | Vehicles Category 1 | 48460 | Pole Cats | 156,818.41 | 0.00 | 0.00 | 156,818.41 |
| | | 48401 | Vehicles Category 1 | 48480 | Tractors | 23,722.23 | 0.00 | 0.00 | 23,722.23 |
| | | 48500 | Loose Tools | 48500 | Loose Tools | 519,008.57 | 58,628.39 | -60,771.35 | 516,865.61 |
| | | 48600 | Communication Equipment | 48600 | Communication Equipment | 386,486.63 | 6,820.90 | 0.00 | 393,307.53 |
| | | 48810 | Houses Land | 48810 | Houses Land | 603.60 | 0.00 | 0.00 | 603.60 |
| | | 48820 | Houses | 48820 | Houses | 266,489.63 | 19,559.47 | 0.00 | 286,049.10 |
| | | 49100 | Franchise and Consent | 49100 | Franchise and Consent | 1,493.00 | 0.00 | 0.00 | 1,493.00 |
| | Total for CGPE: | | | | | 6,597,666.84 | 462,141.09 | -105,672.08 | 6,954,135.85 |
| Total for Corporate: | | | | | | 6,597,666.84 | 462,141.09 | -105,672.08 | 6,954,135.85 |
| Distribution | DPRM | 47000 | Land | 47000 | Land | 7,669.98 | 0.00 | -196.00 | 7,473.98 |
| | | 47100 | Land Rights | 47100 | Land Rights | 607,625.41 | 200,406.29 | 0.00 | 808,031.70 |
| | | 47300 | Poles and Fixtures | 47300 | Poles and Fixtures | 19,158,420.35 | 1,211,441.53 | -72,803.13 | 20,297,058.75 |
| | | 47400 | Overhead Conductor | 47400 | Overhead Conductor | 11,514,878.15 | 879,119.42 | -2,976.02 | 12,391,021.55 |
| | | 47410 | Overhead Services | 47410 | Overhead Services | 1,911,652.08 | 64,612.17 | 0.00 | 1,976,264.25 |
| | | 47500 | Underground Conduit | 47500 | Underground Conduit | 15,009,788.81 | 849,831.40 | 0.00 | 15,859,620.21 |
| | | 47510 | Underground Services | 47510 | Underground Services | 1,998,641.13 | 152,138.13 | 0.00 | 2,150,779.26 |
| | | 47610 | Meters | 47610 | Meters | 436,473.41 | 0.00 | -100,471.06 | 336,002.35 |
| | | 47610 | Meters | 47620 | Metering Equipment | 804,894.44 | 13,350.62 | 0.00 | 818,245.06 |
| | | 47710 | Distribution Substation | 47710 | Non-Fenced Distr Sub Equip | 2,604,868.74 | 0.00 | 0.00 | 2,604,868.74 |
| | | 47710 | Distribution Substation | 47720 | Distr Substation Buildings | 12,601.29 | 464,466.06 | 0.00 | 477,067.35 |
| | | 47810 | Street Lights | 47810 | Street Lights | 6,222,205.71 | 127,554.93 | -5,109.99 | 6,344,650.65 |
| | | 47820 | Sentinel Lights | 47820 | Sentinel Lights | 284,738.28 | 0.00 | 0.00 | 284,738.28 |
| | | 47910 | Transformers | 47910 | Line Transformers | 12,384,539.89 | 1,359,261.41 | -15,096.40 | 13,728,704.90 |
| | | 47910 | Transformers | 47910INV | Inventory Reclass Transformers | 846,518.24 | -98,393.61 | 0.00 | 748,124.63 |
| | Total for DPRM: | | | | | 73,805,515.91 | 5,223,788.35 | -196,652.60 | 78,832,651.66 |
| Total for Distribution: | | | | | | 73,805,515.91 | 5,223,788.35 | -196,652.60 | 78,832,651.66 |
| Generation | GHYD | 42000 | Hydro Land | 42000 | Hydro Land | 20,912.46 | 0.00 | 0.00 | 20,912.46 |
| | | 42500 | Hydro Equipment | 42200 | Hydro Structures | 147,548.11 | 111,863.49 | 0.00 | 259,411.60 |
| | | 42500 | Hydro Equipment | 42300 | Hydro Resv, Dams & Waterways | 757,083.44 | 0.00 | 0.00 | 757,083.44 |
| | | 42500 | Hydro Equipment | 42500 | Hydro Generators | 272,629.36 | 0.00 | 0.00 | 272,629.36 |
| | | 42500 | Hydro Equipment | 42600 | Hydro Accessory Electrical Equip | 105,192.21 | 0.00 | 0.00 | 105,192.21 |
| | | 42500 | Hydro Equipment | 42700 | Hydro Misc Equip | 23,984.46 | 0.00 | 0.00 | 23,984.46 |
| | Total for GHYD: | | | | | 1,327,350.04 | 111,863.49 | 0.00 | 1,439,213.53 |
| | GOTH | 44000 | Int Combust Land | 44000 | Int Combust Land | 7,130.15 | 0.00 | 0.00 | 7,130.15 |
| | | 44200 | Int Combust Structures | 44200 | Int Combust Structures | 916,904.06 | 242,318.11 | 0.00 | 1,159,222.17 |
| | | 44400 | Int Combust Fuel Holders | 44400 | Int Combust Fuel Holders | 1,327,270.25 | 553,708.65 | 0.00 | 1,880,978.90 |
| | | 44500 | Int Combust Generators | 44500 | Int Combust Generators | 8,473,060.04 | 5,873.22 | 0.00 | 8,478,933.26 |
| | | 44600 | Int Combust Access Elect Equip | 44600 | Int Combust Access Elect Equip | 2,037,831.53 | 4,960.69 | 0.00 | 2,042,792.22 |
| | | 44700 | Int Combust Misc Equip | 44700 | Int Combust Misc Equip | 375,289.92 | 18,356.25 | 0.00 | 393,646.17 |
| | Total for GOTH: | | | | | 13,137,485.95 | 825,216.92 | 0.00 | 13,962,702.87 |
| Total for Generation: | | | | | | 14,464,835.99 | 937,080.41 | 0.00 | 15,401,916.40 |
| Transmission | TPRM | 45000 | Land | 45000 | Land | 11,550.51 | 0.00 | 0.00 | 11,550.51 |
| | | 45700 | Transmission Substation | 45710 | Substation Misc Equip & Install | 1,401,497.52 | 0.00 | 0.00 | 1,401,497.52 |
| | Total for TPRM: | | | | | 1,413,048.03 | 0.00 | 0.00 | 1,413,048.03 |
| Total for Transmission: | | | | | | 1,413,048.03 | 0.00 | 0.00 | 1,413,048.03 |
| Grand Total: | | | | | | 96,281,066.77 | 6,623,009.85 | -302,324.68 | 102,601,751.94 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## 100 - 1100 1ST Avenue, Whitehorse, YT, Y1A 3T4

**DIRECTORS:**

William L.Britton

Basil K. French

Nancy C. Southern

Rondald D.Southern

Karen M. Watson

**OFFICERS:**

Ronald D. Southern ..... Chariman of the Board

Willaim L. Britton ..... Vice-Chairman of the Board

Nancy C. Southern ..... Chief Executive Officer

Siegfried W. Kiefer ..... Managing Director, Utilities

Sett F. Policicchio ..... President

Owen G. Edmondson ..... Senior Vice President, Controller, Utilities Group

Dennis A. DeChamplain ..... Vice President, Controller

Patrica Spruin .....Secrectary

# STATUTORY DECLARATION

IN THE MATTER OF A REPORT REQUIRED BY
SECTION 84 OF THE YUKON PUBLIC UTILITIES ACT
BY S.F. POLICICCHIO, PRESIDENT, AND P. SPRUIN,
CORPORATE SECRETARY,
OF
THE YUKON ELECTRICAL COMPANY LIMITED (the "Corporation")
(in thousands of dollars)

WE SOLEMNLY DECLARE THAT:

1. For 2005, the Net Rate Base for the Corporation was $38,029.

2. As of December 31, 2005, the total capitalization of the Corporation was $36,167 with a weighted average cost of 8.134%.

3. The revenues for the Corporation for the period from January 1, 2005 to December 31, 2005 were as follows:

| | |
|---|---|
| Retail Sales | $ 37,061 |
| Sales to other Utilities | 48 |
| Other Revenue | 1,055 |
| TOTAL | $ 38,164 |

4. The dividends paid by the Corporation for the period January 1, 2005 to December 31, 2005 were as follows:

| | |
|---|---|
| Common Shares | $ 1,400 |

5. The operating and maintenance costs of the Corporation for the period from January 1, 2005 to December 31, 2005 were $7,185

6. The Corporation estimates the following costs for new works, extensions and improvements during the current year:

| | |
|---|---|
| Distribution Projects | $ 3,950 |
| General Property & Equipment | 398 |
| Generating Plants | 830 |
| TOTAL | $ 5,178 |

WE MAKE THIS SOLEMN DECLARATION CONSCIENTIOUSLY BELIEVING IT TO BE TRUE AND KNOWING THAT IT IS OF THE SAME FORCE AND EFFECT AS IF MADE UNDER OATH.

Severally declared before me )
at the City of Edmonton )
in the Province of Alberta )
this 30 day of March, 2006. )

Sett F. Policicchio

INGRID D. DUNN
A Commissioner for Oaths
in and for the Province of Alberta
My Commission expires Dec. 2, 2007

Severally declared before me )
at the City of Calgary )
in the Province of Alberta )
this 30 day of March, 2006. )

Patricia Spruin

INGRID D. DUNN
A Commissioner for Oaths
in and for the Province of Alberta
My Commission expires Dec. 2, 2007

The Yukon Electrical Company Limited
An ATCO Company

March 31, 2007

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 6L3

Attention: Ms. Wendy Shanks, Acting Chair

Dear Madam:

RE: Annual Filings – The Yukon Electrical Company Limited

In accordance with Section 25 and 84 of the Public Utilities Act, attached please find the following information:

a) 2006 Audited Financial Statements
b) Utility Income and Rate of Return
c) Computation of Net Rate Base
d) Schedule of Allowance for Working Capital
e) Analysis of Depreciation Reserve
f) Reconciliation of Utility Income to Net Earnings
g) Cost of Debt Capital Employed
h) Property, Plant and Equipment
i) List of Officers and Directors
j) Affidavit.

Yours truly,

THE YUKON ELECTRICAL COMPANY LIMITED

Doug Tenney,
Vice President and General Manager

Encl.

WHITEHORSE 2007
JEUX DU CANADA GAMES
FFICIAL SUPPLIER -
URNISSEUR OFFICIEL



WHITEHORSE 2007

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
Suite 1501, TD Tower
10088 - 102 Avenue NW
Edmonton, Alberta
Canada T5J 3N5
Telephone +1 (780) 441 6700
Facsimile +1 (780) 441 6776

February 21, 2007

## Auditors' Report

**To the Shareholder of**
**The Yukon Electrical Company Limited**

We have audited the balance sheet of **The Yukon Electrical Company Limited** as at December 31, 2006 and the statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

**Chartered Accountants**

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF EARNINGS AND RETAINED EARNINGS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2006 | 2005 |
|---|---|---|---|
| **Revenues** | | $ 40,219 | $ 38,164 |
| **Costs and expenses** | | | |
| Purchased power | | 23,239 | 21,682 |
| Operation and maintenance | | 6,025 | 5,739 |
| Selling and administrative | | 3,579 | 3,587 |
| Depreciation and amortization | | 2,893 | 2,765 |
| Interest | 7 | 1,609 | 1,527 |
| | | 37,345 | 35,300 |
| **Interest and other income** | 3 | 2,874<br>53 | 2,864<br>66 |
| **Earnings before income taxes** | | 2,927 | 2,930 |
| **Income taxes** | 4 | 1,001 | 1,306 |
| **Earnings attributable to Class A and Class B shares** | | 1,926 | 1,624 |
| **Retained earnings at beginning of year** | | 8,998 | 8,774 |
| | | 10,924 | 10,398 |
| Dividends on Class A and Class B shares | | 1,400 | 1,400 |
| **Retained earnings at end of year** | | $ 9,524 | $ 8,998 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## BALANCE SHEET

*(Thousands of Canadian Dollars)*

| | Note | December 31 2006 | December 31 2005 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Accounts receivable | | $ 5,497 | $ 5,428 |
| Inventories | | 1,784 | 1,474 |
| Prepaid expenses | | 103 | 104 |
| | | 7,384 | 7,006 |
| **Property, plant and equipment** | 5 | 39,127 | 36,751 |
| **Regulatory assets** | 2 | 54 | 78 |
| **Other assets** | | 156 | 72 |
| | | $ 46,721 | $ 43,907 |
| **LIABILITIES AND SHARE OWNER'S EQUITY** | | | |
| **Current liabilities** | | | |
| Bank indebtedness | 6 | $ 607 | $ 729 |
| Short term advances from parent and affiliated corporations | 7 | 1,000 | 1,000 |
| Accounts payable and accrued liabilities | | 3,392 | 3,782 |
| Owing to parent and affiliated corporations | | 729 | 486 |
| Income and other taxes payable | | (11) | 175 |
| | | 5,717 | 6,172 |
| **Pension and other post employment benefits** | 11 | 661 | 568 |
| **Long term debt** | 7 | 23,800 | 21,150 |
| **Class A and Class B share owner's equity** | | | |
| Class A and Class B shares | 8 | 7,019 | 7,019 |
| Retained earnings | | 9,524 | 8,998 |
| | | 16,543 | 16,017 |
| | | $ 46,721 | $ 43,907 |

Director

Director

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF CASH FLOWS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2006 | 2005 |
|---|---|---|---|
| **Operating activities** | | | |
| Earnings attributable to Class A and Class B shares | | $ 1,926 | $ 1,624 |
| Adjustments for: | | | |
| Depreciation and amortization | | 2,893 | 2,765 |
| Other | | 145 | 142 |
| Funds generated by operations | | 4,964 | 4,531 |
| Changes in non-cash working capital | 9 | (411) | (447) |
| Cash flow from operations | | 4,553 | 4,084 |
| **Investing activities** | | | |
| Purchase of property, plant and equipment | | (7,294) | (6,090) |
| Costs on disposal of property, plant and equipment | | (163) | (135) |
| Contributions by utility customers for extensions to plant | | 2,188 | 1,855 |
| Changes in non-cash working capital | 9 | (300) | (75) |
| Other | | 40 | 46 |
| | | (5,529) | (4,399) |
| **Financing activities** | | | |
| Issue of long term debt | | 3,000 | 4,300 |
| Repayment of long term debt | | (350) | (4,000) |
| Dividends paid to the Class A and Class B share owner | | (1,400) | (1,400) |
| Other | | (152) | - |
| | | 1,098 | (1,100) |
| **Cash Position**[1] | | | |
| Increase (decrease) | | 122 | (1,415) |
| Beginning of year | | (1,729) | (314) |
| **End of year** | | $ 1,607 | $ (1,729) |

[1] Cash position includes bank indebtedness and short term advances from parent and affiliated corporations.

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

## December 31, 2006

(tabular amounts in thousands of Canadian dollars)

## 1. Summary of significant accounting policies

### *Financial Statement Presentation*

The accompanying financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The Yukon Electrical Company Limited (the "Corporation") is engaged in the generation, transmission, distribution and sale of electric energy.

Certain comparative figures have been reclassified to conform to the current presentation.

### *Rate Regulation*

The Corporation is regulated primarily by the Yukon Utilities Board ("Board") which administers acts and regulations covering such matters as rates, financing, accounting, construction and operation and service area. Accounting for rate regulated operations is described in Note 2.

### *Use of Estimates*

The preparation of the Corporation's financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

### *Revenue Recognition*

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the Board.

Revenues from sales of electricity are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of services provided but not yet billed.

### *Purchased Power*

Purchased power expense is based on the actual cost of electricity purchased.

### *Income Taxes*

The Corporation utilizes the flow through method to account for income taxes. In accordance with the Board, future income taxes have not been recorded to the extent that the income tax component of rates approved by the Board was not designed to recover those taxes. Accordingly, the customer in future years will bear an additional charge as these unrecorded future income taxes are reversed.

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

**December 31, 2006**

(tabular amounts in thousands of Canadian dollars)

## 1. Summary of significant accounting policies (continued)

### *Inventories*

Inventories include materials and supplies and are valued at the lower of average cost or net realizable value.

### *Property, Plant and Equipment*

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant. The Corporation includes in property, plant and equipment an allowance for funds used during construction at rates approved by the Board for debt and equity capital. Certain additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates are approved by the Board and include a provision for future removal and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net of disposal costs and site restoration costs.

An impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques.

### *Asset Retirement Obligations*

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

The Corporation has determined that it has tangible long lived assets where there is a legal liability regarding asset retirement. For these tangible long lived assets, asset retirement obligations have not been recorded as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time.

Effective January 1, 2006, the Corporation retroactively adopted the Canadian Institute of Chartered Accountant's ("CICA") Emerging Issues Abstract regarding conditional asset retirement obligations. This Abstract requires an entity to record a liability for an asset retirement obligation even if the obligation is conditional upon the occurrence of a future event that may or may not be within the control of the entity.

**THE YUKON ELECTRICAL COMPANY LIMITED**

**NOTES TO FINANCIAL STATEMENTS**

**December 31, 2006**

(tabular amounts in thousands of Canadian dollars)

## 1. Summary of significant accounting policies (continued)

Adoption of this Abstract had no effect on the financial statements for the year ended December 31, 2006.

### *Long Term Debt Due Within One Year*

All of the long term debt is held by the parent corporation, ATCO Electric Ltd. When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on ATCO Electric Ltd.'s behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

### *Employee Future Benefits*

The Corporation, together with its ultimate parent corporation, Canadian Utilities Limited and affiliate corporations, participates in a group defined benefit pension plan ("the Group Plan"). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid.

The Corporation accrues for its obligations under other post employment benefit and certain other defined benefit pension plans. These plans are administered on a combined basis with the Corporation's parent and affiliate corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for the plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of wage and salary increases, age at retirement and expected health care costs. Experience gains and losses and the effect of changes in assumptions in excess of 10% of the accrued benefit obligations, together with adjustments resulting from plan amendments, are amortized over the estimated average remaining service life of employees.

## 2. Accounting for regulated operations

### *Nature and economic effects of rate regulation*

The Corporation is subject to a cost of service regulatory mechanism under which the Board establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base is the aggregate of the Board approved investment in property, plant and equipment less accumulated depreciation and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The Corporation earns a return on rate base intended to meet the cost of the debt and to provide the share owner with a fair return on the common equity component of rate base.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2006

(tabular amounts in thousands of Canadian dollars)

2. **Accounting for regulated operations** (continued)

The Board approves rates of return for the debt and common equity component of rate base based on the actual or forecast weighted average cost of the Corporation's debt and common equity.

Under the cost of service methodology, the Corporation seeks approval for it's revenue requirement through submission of a general rate application to the Board. The Board may approve interim rates, subject to final determination.

***Financial statement effects of rate regulation***

Certain items in these financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities on the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the Board renders a subsequent decision.

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

The regulatory assets comprise the following:

| | 2006 | 2005 |
|---|---|---|
| Reserve for injuries and damages | $ 54 | $ 78 |

***Reserves for injuries and damages***

The Board has approved the use of a reserve for injuries and damages by the Corporation as a means of self-insurance. The reserve for injuries and damages is established based on annual amounts approved by the Board to be expensed by the Corporation and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general tariff application or until a specific application is made to the Board requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses for 2006 would have been $24,000 lower (2005 – $80,000 lower) in the absence of rate regulation.

**THE YUKON ELECTRICAL COMPANY LIMITED**

**NOTES TO FINANCIAL STATEMENTS**

**December 31, 2006**

(tabular amounts in thousands of Canadian dollars)

## 2. Accounting for regulated operations (continued)

***Other items affected by rate regulation***

The Board permits an allowance for funds used ("AFU"), based on the Corporation's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes a common equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The Corporation follows the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 4).

## 3. Interest and other income

| | 2006 | 2005 |
|---|---|---|
| Allowance for funds used during construction | $ 54 | $ 54 |
| Interest | 0 | 15 |
| Other | (1) | (3) |
| | $ 53 | $ 66 |

Interest received in 2006 amounted to $0 (2005 - $15,000).

## 4. Income taxes

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

| | 2006 | | 2005 | |
|---|---|---|---|---|
| Earnings before income taxes | $ 2,927 | % | $ 2,930 | % |
| Income taxes, at statutory rate | 1,087 | 37.1 | 1,088 | 37.1 |
| Unrecorded future income taxes | 123 | 4.2 | 186 | 6.4 |
| Large corporations tax | 0 | 0.0 | 31 | 1.1 |
| Other | (209) | (7.1) | 1 | 0.0 |
| Income taxes | $ 1,001 | 34.2 | $ 1,306 | 44.6 |

Unrecorded future income taxes receivable decreased by $242,000 to $1,942,000 at December 31, 2006.

Income taxes paid in 2006 amounted to $1,240,000 (2005 - $1,320,000).

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

**December 31, 2006**

(tabular amounts in thousands of Canadian dollars)

## 5. Property, plant and equipment

| | Composite Depreciation Rates | 2006 Cost | 2006 Accumulated Depreciation | 2005 Cost | 2005 Accumulated Depreciated |
|---|---|---|---|---|---|
| Generation | 3.87% | $ 15,794 | $ 8,392 | $ 15,374 | $ 7,837 |
| Distribution | 3.80% | 86,186 | 37,967 | 80,226 | 35,214 |
| Other | 4.83% | 6,881 | 3,600 | 6,648 | 3,390 |
| Land | - | 371 | - | 354 | - |
| Construction work in progress | - | 871 | - | 427 | - |
| | 3.87% | $ 110,103 | $ 49,959 | $ 103,029 | $ 46,441 |
| Property, plant and equipment less accumulated depreciation | | | $ 60,144 | | $ 56,588 |
| Unamortized contributions by utility customers for extensions to plant | | | 21,017 | | 19,837 |
| | | | $ 39,127 | | $ 36,751 |

Accumulated depreciation includes an amount provided for future removal and site restoration costs, net of salvage value, of $4,050,000 (2005 - $3,641,000).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding non-depreciable assets and construction work in progress.

## 6. Bank indebtedness and credit lines

The Corporation has an operating credit line totaling $1,000,000 (2005 – $1,000,000) which is available on an uncommitted basis. The credit line enables the Corporation to obtain financing for general business purposes. At December 31, 2006, $1,000,000 (2005 – $990,000) of the credit line was still available.

## 7. Long term debt

| Debentures | 2006 | 2005 |
|---|---|---|
| 2001 Series 4.95% due November 2006 | $ - | $ 350 |
| 2000 Series 7.05% due June 2008 | 600 | 600 |
| 1989 Series 10.33% due November 2009 | 2,000 | 2,000 |
| 2004 Series 5.16% due November 2014 | 500 | 500 |
| 2002 Series 6.21% due November 2017 | 3,900 | 3,900 |
| 2004 Series 5.47% due January 2019 | 1,000 | 1,000 |
| 1999 Series 6.85% due August 2019 | 4,500 | 4,500 |
| 1990 Series 11.91% due November 2020 | 1,500 | 1,500 |
| 1992 Series 9.51% due May 2023 | 2,500 | 2,500 |
| 2005 Series 5.23% due November 2030 | 4,300 | 4,300 |
| 2006 Series 5.07% due November 2036 | 3,000 | - |
| | $ 23,800 | $ 21,150 |

**THE YUKON ELECTRICAL COMPANY LIMITED**

**NOTES TO FINANCIAL STATEMENTS**

**December 31, 2006**

(tabular amounts in thousands of Canadian dollars)

## 7. Long term debt (continued)

The minimum annual repayments of long term debt for each of the next five years are as follows:

| 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|
| $ - | $ 600 | $ 2,000 | $ - | $ - |

***Interest expense***

Interest on debt is as follows:

| | 2006 | 2005 |
|---|---|---|
| Long term debt | $ 1,553 | $ 1,481 |
| Interest on Short term financing | 56 | 46 |
| Other | | - |
| | $ 1,609 | $ 1,527 |

Interest paid in 2006 amounted to $1,538,455 (2005 - $1,484,765).

***Fair values***

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are $28,083,000 (2005 - $26,021,000). Where market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

***Short term advances from parent and affiliated corporations***

Short term advances from parent are payable upon demand and bear interest based on short term Bankers' Acceptance rates.

## 8. Class A and Class B shares

***Authorized and issued***

| | Class A Non-Voting | | Class B Common | | Total | |
|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Shares | Amount |
| *Authorized:* | Unlimited | | Unlimited | | | |
| *Issued and Outstanding:* | | | | | | |
| December 31, 2005 | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |
| **December 31, 2006** | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

**December 31, 2006**

(tabular amounts in thousands of Canadian dollars)

## 9. Changes in non-cash working capital

| | 2006 | 2005 |
|---|---|---|
| *Operating activities, changes related to:* | | |
| Accounts receivable | $ (69) | $ (647) |
| Inventories | (62) | (37) |
| Prepaid expenses | 1 | 6 |
| Accounts payable and accrued liabilities | (338) | 352 |
| Income taxes and other taxes payable | (186) | 144 |
| Owing to parent and affiliated corporations | 243 | (265) |
| | $ (411) | $ (447) |
| *Investing activities, changes related to:* | | |
| Inventories | (248) | (148) |
| Accounts payable and accrued liabilities | (52) | 73 |
| | $ (300) | $ (75) |

## 10. Related party transactions

| Entity | Relationship | Transaction | Recorded as | 2006 | 2005 |
|---|---|---|---|---|---|
| Northland Utilities Enterprises | Affiliate | Administration and financial management | Revenue | 74 | 62 |
| ATCO Frontec Corp. | Affiliate | Building Rent | Revenue | 43 | 43 |
| ATCO I-Tek Business Services Ltd. | Affiliate | Information system services | Selling and administrative | 311 | 306 |
| ATCO I-Tek Business Services Ltd. | Affiliate | Billing services | Selling and administrative | 434 | 339 |
| ATCO Gas | Affiliate | Meter services | Operation and maintenance | 34 | 34 |
| ATCO Electric Ltd. | Parent | Administration and management support | Revenue | - | 47 |
| | | Administration, financial management, meter reading, computer services and equipment rent | Operation and maintenance | 299 | 315 |

These transactions are considered to be in the normal course of business and are measured at the exchange amount being the amount of consideration established and agreed to by the related parties. The amounts owing to the parent and affiliated corporations are subject to commercial terms and conditions.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2006

(tabular amounts in thousands of Canadian dollars)

## 11. Employee future benefits

The Corporation, together with its parent and affiliate corporations, maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants.

Contributions to a group defined benefit pension plan, which is accounted for as a defined contribution plan, are expensed as paid. Other post employment benefit and certain other defined benefit pension plans, which the Corporation funds out of general revenues, are administered on a combined basis with the Corporation's ultimate parent and affiliated corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for the plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans.

Information about the benefit plans is as follows:

| | 2006 | | 2005 | |
|---|---|---|---|---|
| | **Pension Benefit Plans** | **Other Post Employment Benefit Plans** | Pension Benefit Plans | Other Post Employment Benefit Plans |
| **Benefit plan expense** | | | | |
| Total benefit plans expense | $ 9 | $ 123 | $ 9 | $ 17 |
| Less: Capitalized | - | 25 | - | 23 |
| Benefit plan expense | $ 9 | $ 98 | $ 9 | $ 94 |
| **Benefit plan liabilities** | | | | |
| Accrued liability at beginning of year | $ (173) | $ (395) | $ (174) | $ (306) |
| Total benefit plans expense | (9) | (123) | (9) | (117) |
| Benefit payments | 11 | 28 | 10 | 28 |
| Accrued liability at end of year | $ (171) | $ (490) | $ (173) | $ (395) |

## 12. Risk management and financial instruments

### *Fair value of financial assets and liabilities*

The fair value of accounts receivables, bank indebtedness, short term advances from parent and affiliated corporations, accounts payable and accrued liabilities, and owing to parent and affiliated corporations approximate their carrying amounts in the financial statements due to the relatively short period to maturity of these instruments.

### *Interest rate risk*

The Corporation is not exposed to significant interest rate risk due to its long term debt having fixed interest rate.

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

**December 31, 2006**

(tabular amounts in thousands of Canadian dollars)

## 13. Commitments & Contingencies

### *Commitments*

The Corporation has contractual obligations in the normal course of business.

### *Contingencies*

Measurement inaccuracies occur from time to time with respect to the Corporation's metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the Board.

As a result of decisions of the Supreme Court of Canada in Garland vs.Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

# THE YUKON ELECTRICAL COMPANY LIMITED
## UTILITY INCOME AND RATE OF RETURN
## For The Year Ended December 31, 2006
### ($000s)

| | | |
|---|---|---|
| UTILITY REVENUE | | 39,944 |
| UTILITY EXPENSE | | |
| Operation and Maintenance | | 32,341 |
| Less: | Non Allowables | 37 |
| | Non Utility Income Taxes | (33) |
| | Non Utility Depreciation | 1 |
| Add: | Depreciation | 3,902 |
| | Other Taxes | 229 |
| | Income Taxes | 1,001 |
| | Amortization of Contribution for Extensions | (1,008) |
| | Amortization of Deferred Study and Rate Case Cost | - |
| TOTAL | | 36,460 |
| UTILITY INCOME | | 3,484 |
| NET RATE BASE | | 40,930 |
| RATE OF RETURN | | 8.512% |

# THE YUKON ELECTRICAL COMPANY LIMITED
## COMPUTATION OF NET RATE BASE
## For The Year Ended December 31, 2006
### ($000s)

| | | |
|---|---|---|
| PROPERTY PLANT AND EQUIPMENT | | |
| BALANCE AT DECEMBER 31, 2005 | | 110,103 |
| Add: | Deferred Study Costs | - |
| Less: | Accumulated Depreciation | 49,959 |
| | Non-regulated Assets | 14 |
| | Construction Work-in-Progress | 871 |
| | | 50,844 |
| NET BALANCE AT YEAR END | | 59,259 |
| Add: | Previous Year's Balance | 56,143 |
| TOTAL | | 115,402 |
| MID-YEAR BALANCE | | 57,701 |
| Add: | Allowance for Working Capital | 3,210 |
| | Mid-Year Rate Case Expense | - |
| Less: | Mid-Year Contribution for Extensions | 19,981 |
| NET RATE BASE | | 40,930 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## SCHEDULE OF ALLOWANCE FOR WORKING CAPITAL
## For The Year Ended December 31, 2006
**($000s)**

| | |
|---|---|
| Operation & Maintenance | 32,341 |
| Add: Other Taxes | 229 |
| Less: Non Allowables | 37 |
| Allowable Operating Expense | 32,533 |
| Utility Income Tax (Previous Year) | 1,283 |
| Current Year Income Taxes (Payable) Receivable | 11 |
| Allowance: Operating Expense<br>19/365 * Allowable Operating Expense | 1,693 |
| Allowance: Income Tax<br>30/365 * Income Tax (Previous Year) | 105 |
| Allowance: Final Tax Payment<br>196/365 * Income Taxes Payable | 5 |
| Three Year Average Inventory | 1,516 |
| GST Impact | (109) |
| TOTAL WORKING CAPITAL | 3,210 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## ANALYSIS OF DEPRECIATION RESERVE
## For The Year Ended December 31, 2006
### ($000s)

| | | |
|---|---|---|
| BALANCE - DECEMBER 31, 2005 | | 46,441 |
| Add: | Depreciation - Operating Expense | 3,902 |
| | Depreciation - Other | 21 |
| | | 50,364 |
| Less: | Retirements | 242 |
| | Sale and Salvage Proceeds | (12) |
| | Dismantling Expense | 175 |
| BALANCE - DECEMBER 31, 2006 | | 49,959 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## RECONCILIATION OF UTILITY INCOME TO NET EARNINGS
## For The Year Ended December 31, 2006
### ($000s)

| | |
|---|---|
| UTILITY INCOME | 3,484 |
| Add Non Utility Income: | |
| Allowance for Funds Used During Construction | 54 |
| Non Regulated Revenues | 270 |
| Short Term Interest From Parent | - |
| Non Utility Income | 5 |
| Other Interest | 7 |
| | 336 |
| Sub-Total | 3,821 |
| Less Non Utility Expenses: | |
| Interest to Parent | 1,553 |
| Short Term Interest To Parent | 56 |
| Non Regulated Expenses | 273 |
| Non Regulated Depreciation | 1 |
| Preferred Dividends to Parent | - |
| Other Interest | 8 |
| Non Allowables | 37 |
| | 1,927 |
| Sub-Total | 1,893 |
| Add Income Tax Adjustment: | |
| Tax on Net Non Utility Income | 33 |
| NET EARNINGS | 1,927 |

# YUKON ELECTRICAL COMPANY LIMITED
## COST OF CAPITAL CALCULATION
## For The Year Ended December 31, 2006
(%)

| | CAPITAL RATIO | COST | RETURN COMPONENT |
|---|---|---|---|
| LONG TERM DEBT | 57.18 | 7.145 | 4.086 |
| PREFERRED SHARES | - | - | - |
| COMMON SHARES AND RETAINED EARNINGS | 41.42 | 10.690 | 4.427 |
| NO COST CAPITAL | 1.40 | | |
| | 100.00 | | 8.512 |

## (FA-420A) PPE by Fiscal Year Book Type Code: YECL CORP Period Name: DEC-2006

| Function | Minor Account | Minor Description | Sub Category | Subcategory Description | Fiscal Year Beginning Balance | Additions | Transfers | Retirements | Ending Period Balance |
|---|---|---|---|---|---|---|---|---|---|
| Generation | 42000 | Hydro Land | 42000 | Hydro Land | 20,912 | 0 | 0 | 0 | 20,912 |
| Generation | 42500 | Hydro Equipment | 42700 | Hydro Misc Equip | 23,984 | 0 | 0 | 0 | 23,984 |
| Generation | 42500 | Hydro Equipment | 42600 | Hydro Accessory Electrical Equip | 105,192 | 0 | 0 | 0 | 105,192 |
| Generation | 42500 | Hydro Equipment | 42500 | Hydro Generators | 272,629 | 0 | 0 | 0 | 272,629 |
| Generation | 42500 | Hydro Equipment | 42300 | Hydro Resv, Dams & Waterways | 757,083 | 0 | 0 | 0 | 757,083 |
| Generation | 42500 | Hydro Equipment | 42200 | Hydro Structures | 259,412 | 0 | 0 | 0 | 259,412 |
| Generation | 44000 | Int Combust Land | 44000 | Int Combust Land | 7,130 | 0 | 0 | 0 | 7,130 |
| Generation | 44200 | Int Combust Structures | 44200 | Int Combust Structures | 1,159,222 | 222,022 | 0 | 0 | 1,381,244 |
| Generation | 44400 | Int Combust Fuel Holders | 44400 | Int Combust Fuel Holders | 1,880,979 | 176,396 | 0 | 0 | 2,057,375 |
| Generation | 44500 | Int Combust Generators | 44500 | Int Combust Generators | 8,478,933 | (34,460) | 0 | 0 | 8,444,473 |
| Generation | 44600 | Int Combust Access Elect Equip | 44600 | Int Combust Access Elect Equip | 2,042,792 | 28,873 | 0 | 0 | 2,071,665 |
| Generation | 44700 | Int Combust Misc Equip | 44700 | Int Combust Misc Equip | 393,646 | 27,068 | 0 | 0 | 420,714 |
| Transmission | 45000 | Land | 45000 | Land | 11,551 | 0 | 0 | 0 | 11,551 |
| Transmission | 45700 | Transmission Substation | 45710 | Substation Misc Equip & Install | 1,401,498 | 0 | 0 | 0 | 1,401,498 |
| Distribution | 47000 | Land | 47000 | Land | 7,474 | 15,899 | 0 | 0 | 23,373 |
| Distribution | 47100 | Land Rights | 47100 | Land Rights | 808,032 | 50,793 | 0 | 0 | 858,825 |
| Distribution | 47300 | Poles and Fixtures | 47300 | Poles and Fixtures | 20,297,059 | 1,406,873 | 0 | (65,718) | 21,638,214 |
| Distribution | 47400 | Overhead Conductor | 47400 | Overhead Conductor | 12,391,022 | 1,195,519 | 0 | (974) | 13,585,566 |
| Distribution | 47410 | Overhead Services | 47410 | Overhead Services | 1,976,264 | 97,983 | 0 | 0 | 2,074,247 |
| Distribution | 47500 | Underground Conduit | 47500 | Underground Conduit | 15,859,620 | 714,912 | 0 | (967) | 16,573,565 |
| Distribution | 47510 | Underground Services | 47510 | Underground Services | 2,150,779 | 232,525 | 0 | (25) | 2,383,279 |
| Distribution | 47610 | Meters | 47620 | Metering Equipment | 818,245 | 12,000 | 0 | 0 | 830,245 |
| Distribution | 47610 | Meters | 47610 | Meters | 336,002 | 77,090 | 0 | (48,626) | 364,467 |
| Distribution | 47710 | Distribution Substation | 47720 | Distr Substation Buildings | 477,067 | 0 | 0 | 0 | 477,067 |
| Distribution | 47710 | Distribution Substation | 47710 | Non-Fenced Distr Sub Equip | 2,604,869 | 49,580 | 0 | 0 | 2,654,448 |
| Distribution | 47810 | Street Lights | 47810 | Street Lights | 6,344,651 | 782,820 | 0 | (5,341) | 7,122,129 |
| Distribution | 47820 | Sentinel Lights | 47820 | Sentinel Lights | 284,738 | 0 | 0 | 0 | 284,738 |
| Distribution | 47910 | Transformers | 47910INV | Inventory Reclass Transformers | 748,125 | 52,477 | 0 | 0 | 800,602 |
| Distribution | 47910 | Transformers | 47910 | Line Transformers | 13,728,705 | 1,427,301 | 0 | (18,276) | 15,137,730 |
| Corporate | 48000 | Land | 48000 | Land | 305,229 | 896 | 0 | 0 | 306,124 |
| Corporate | 48200 | Buildings and Structures | 48200 | Buildings and Structures | 3,051,533 | 85,079 | 0 | 0 | 3,136,612 |
| Corporate | 48200 | Buildings and Structures | 48100 | Land Rights | 19,148 | 101 | 0 | 0 | 19,250 |
| Corporate | 48300 | Office Furniture | 48300 | Office Furniture | 284,701 | 5,995 | 0 | (42,433) | 248,264 |
| Corporate | 48320 | Computer Equipment | 48320 | Computer Equipment | 37,207 | 2,796 | 0 | (557) | 39,446 |
| Corporate | 48401 | Vehicles Category 1 | 48450 | Trucks > 2 Tons < 3 Tons | 416,133 | 0 | 0 | 0 | 416,133 |
| Corporate | 48401 | Vehicles Category 1 | 48460 | Pole Cats | 156,818 | 0 | 0 | 0 | 156,818 |
| Corporate | 48401 | Vehicles Category 1 | 48470 | Trucks > 3 Tons | 0 | 5,083 | 0 | 0 | 5,083 |
| Corporate | 48401 | Vehicles Category 1 | 48480 | Tractors | 23,722 | 0 | 0 | 0 | 23,722 |
| Corporate | 48401 | Vehicles Category 1 | 48440 | 3/4 to 2 Ton Trucks | 940,125 | 89,845 | 0 | 0 | 1,029,970 |
| Corporate | 48401 | Vehicles Category 1 | 48430 | Pole Trailers > 10,000 lbs | 48,864 | 0 | 0 | 0 | 48,864 |
| Corporate | 48401 | Vehicles Category 1 | 48420 | Light Trucks and Pole Trailers | 207,057 | 0 | 0 | 0 | 207,057 |
| Corporate | 48401 | Vehicles Category 1 | 48410 | Cars | 28,209 | 0 | 0 | 0 | 28,209 |
| Corporate | 48500 | Loose Tools | 48500 | Loose Tools | 516,866 | 55,900 | 0 | (59,357) | 513,408 |
| Corporate | 48600 | Communication Equipment | 48600 | Communication Equipment | 393,308 | 41,357 | 0 | 0 | 434,664 |
| Corporate | 48810 | Houses Land | 48810 | Houses Land | 604 | 0 | 0 | 0 | 604 |
| Corporate | 48820 | Houses | 48820 | Houses | 287,621 | 48,728 | 0 | 0 | 336,349 |
| Corporate | 49100 | Franchise and Consent | 49100 | Franchise and Consent | 1,493 | 0 | 0 | 0 | 1,493 |
| Corporate | 49605 | Software - Oracle | 49605 | Software - Oracle | 235,498 | 0 | 0 | 0 | 235,498 |
| Grand Total: | | | | | **$102,601,752** | **$6,871,449** | **$0** | **($242,273)** | **$109,230,928** |

# THE YUKON ELECTRICAL COMPANY LIMITED

## 100 - 1100 1ST Avenue, Whitehorse, YT, Y1A 3T4

**DIRECTORS:**

William L.Britton

Basil K. French

Nancy C. Southern

Rondald D.Southern

Karen M. Watson

**OFFICERS:**

Ronald D. Southern ..... Chariman of the Board

Willaim L. Britton ..... Vice-Chairman of the Board

Nancy C. Southern ..... Chief Executive Officer

Siegfried W. Kiefer ..... Managing Director, Utilities

Sett F. Policicchio ..... President

Dennis A. DeChamplain ..... Vice President, Controller

Patrica Spruin .....Secrectary

# STATUTORY DECLARATION

IN THE MATTER OF A REPORT REQUIRED BY
SECTION 84 OF THE YUKON PUBLIC UTILITIES ACT
BY S.F. POLICICCHIO, PRESIDENT, AND P. SPRUIN,
CORPORATE SECRETARY,
OF
THE YUKON ELECTRICAL COMPANY LIMITED (the "Corporation")
(in thousands of dollars)

WE SOLEMNLY DECLARE THAT:

1. For 2006, the Net Rate Base for the Corporation was $40,930.

2. As of December 31, 2006, the total capitalization of the Corporation was $40,343 with a weighted average cost of 8.512%.

3. The revenues for the Corporation for the period from January 1, 2006 to December 31, 2006 were as follows:

| | |
|---|---|
| Retail Sales | $ 39,063 |
| Sales to other Utilities | 52 |
| Other Revenue | 1,104 |
| TOTAL | $ 40,219 |

4. The dividends paid by the Corporation for the period January 1, 2006 to December 31, 2006 were as follows:

| | |
|---|---|
| Common Shares | $ 1,400 |

5. The operating and maintenance costs of the Corporation for the period from January 1, 2006 to December 31, 2006 were $7,447

6. The Corporation estimates the following costs for new works, extensions and improvements during the current year:

| | |
|---|---|
| Distribution Projects | $ 5,400 |
| General Property & Equipment | 845 |
| Generating Plants | 873 |
| TOTAL | $ 7,118 |

WE MAKE THIS SOLEMN DECLARATION CONSCIENTIOUSLY BELIEVING IT TO BE TRUE AND KNOWING THAT IT IS OF THE SAME FORCE AND EFFECT AS IF MADE UNDER OATH.

Severally declared before me )
at the City of Edmonton )
in the Province of Alberta )
this 19 day of March, 2007. )

S. Policicchio
Sett F. Policicchio

GERALD P. ZADKO
NOTARY PUBLIC
MY APPOINTMENT EXPIRES DEC. 31, 2008

Severally declared before me )
at the City of Calgary )
in the Province of Alberta )
this 23 day of March, 2007. )

P Spruin
Patricia Spruin

NOTARY/ALBERTA

PERRY SPITZNAGEL

The Yukon Electrical Company Limited
An ATCO Company

March 31, 2008

Ms. Deana Lemke
Secretariat
Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 6L3

Dear Ms. Lemke:

RE: Annual Filings – The Yukon Electrical Company Limited

In accordance with Section 25 and 84 of the Public Utilities Act, attached please find the following information:

a) 2007 Audited Financial Statements
b) Utility Income and Rate of Return
c) Computation of Net Rate Base
d) Schedule of Allowance for Working Capital
e) Analysis of Depreciation Reserve
f) Reconciliation of Utility Income to Net Earnings
g) Cost of Debt Capital Employed
h) Property, Plant and Equipment
i) List of Officers and Directors
*j)* Draft of unsigned Affidavit *(Complete and signed Affidavit to follow by end of April)* .

Yours truly,

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Jerome Babyn,
General Manager

Encl.

# THE YUKON ELECTRICAL COMPANY LIMITED

## FINANCIAL STATEMENTS

## DECEMBER 31, 2007

PRICEWATERHOUSECOOPERS

**PricewaterhouseCoopers LLP**
**Chartered Accountants**
TD Tower
10088 102 Avenue NW, Suite 1501
Edmonton, Alberta
Canada T5J 3N5
Telephone +1 (780) 441 6700
Facsimile +1 (780) 441 6776

February 19, 2008

## Auditors' Report

**To the Shareholder of**
**The Yukon Electrical Company Limited**

We have audited the balance sheet of **The Yukon Electrical Company Limited** as at December 31, 2007 and the statements of earnings and retained earnings, cash flows and comprehensive income for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

**Chartered Accountants**

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF EARNINGS AND RETAINED EARNINGS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2007 | 2006 |
|---|---|---|---|
| **Revenues** | | $ 41,420 | $ 40,219 |
| **Costs and expenses** | | | |
| Purchased power | | 23,647 | 23,239 |
| Operation and maintenance | | 6,533 | 6,025 |
| Selling and administrative | | 3,637 | 3,579 |
| Depreciation and amortization | | 3,079 | 2,893 |
| Interest | 8 | 1,666 | 1,609 |
| | | 38,562 | 37,345 |
| | | 2,858 | 2,874 |
| **Interest and other income** | 4 | 137 | 53 |
| **Earnings before income taxes** | | 2,995 | 2,927 |
| **Income taxes** | 5 | 902 | 1,001 |
| **Earnings attributable to Class A and Class B shares** | | 2,093 | 1,926 |
| **Retained earnings at beginning of year as restated** | 3 | 9,524 | 8,998 |
| | | 11,617 | 10,924 |
| Dividends on Class A and Class B shares | | 1,400 | 1,400 |
| **Retained earnings at end of year** | | $ 10,217 | $ 9,524 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## BALANCE SHEET

*(Thousands of Canadian Dollars)*

| | Note | December 31 2007 | December 31 2006 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Accounts receivable | | $ 5,288 | $ 5,497 |
| Inventories | | 1,849 | 1,784 |
| Prepaid expenses | | 110 | 103 |
| Income and other taxes recoverable | | 285 | 11 |
| | | 7,532 | 7,395 |
| **Property, plant and equipment** | 6 | 41,222 | 39,127 |
| **Regulatory assets** | 2 | 115 | 54 |
| **Other assets** | | 724 | 156 |
| | | $ 49,593 | $ 46,732 |
| **LIABILITIES AND SHARE OWNER'S EQUITY** | | | |
| **Current liabilities** | | | |
| Bank indebtedness | 7 | $ 875 | $ 607 |
| Short term advances from parent and affiliated corporations | 8 | 2,200 | 1,000 |
| Accounts payable and accrued liabilities | | 3,961 | 3,392 |
| Owing to parent and affiliated corporations | | 814 | 729 |
| | | 7,850 | 5,728 |
| **Pension and other post employment benefits** | 12 | 707 | 661 |
| **Long term debt** | 8 | 23,800 | 23,800 |
| **Class A and Class B share owner's equity** | | | |
| Class A and Class B shares | 9 | 7,019 | 7,019 |
| Retained earnings | | 10,217 | 9,524 |
| | | 17,236 | 16,543 |
| | | $ 49,593 | $ 46,732 |

Director

Director

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF CASH FLOWS

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2007 | 2006 |
|---|---|---|---|
| **Operating activities** | | | |
| Earnings attributable to Class A and Class B shares | | $ 2,093 | $ 1,926 |
| Adjustments for: | | | |
| Depreciation and amortization | | 3,079 | 2,893 |
| Other | | 71 | 145 |
| Funds generated by operations | | 5,243 | 4,964 |
| Changes in non-cash working capital | 10 | 451 | (411) |
| **Cash flow from operations** | | 5,694 | 4,553 |
| **Investing activities** | | | |
| Purchase of property, plant and equipment | | (7,785) | (7,294) |
| Costs on disposal of property, plant and equipment | | 40 | (163) |
| Contributions by utility customers for extensions to plant | | 2,571 | 2,188 |
| Changes in non-cash working capital | 10 | 66 | (300) |
| Other | | (44) | 40 |
| | | (5,152) | (5,529) |
| **Financing activities** | | | |
| Issue of long term debt | | - | 3,000 |
| Repayment of long term debt | | - | (350) |
| Dividends paid to the Class A and Class B share owner | | (1,400) | (1,400) |
| Other | | (610) | (152) |
| | | (2,010) | 1,098 |
| **Cash Position**[1] | | | |
| Increase (decrease) | | (1,468) | 122 |
| Beginning of year | | (1,607) | (1,729) |
| **End of year** | | $ (3,075) | $ (1,607) |

[1] Cash position includes bank indebtedness and short term advances from parent and affiliated corporations.

# THE YUKON ELECTRICAL COMPANY LIMITED

## STATEMENT OF COMPREHENSIVE INCOME

*(Thousands of Canadian Dollars)*

| | Note | Year ended December 31 2007 | 2006 |
|---|---|---|---|
| **Earnings attributable to Class A and Class B shares** | | $ 2,093 | $ 1,926 |
| Other comprehensive income, net of income taxes | | - | - |
| **Comprehensive income** | | $ 2,093 | $ 1,926 |

# THE YUKON ELECTRICAL COMPANY LIMITED

## NOTES TO FINANCIAL STATEMENTS

**December 31, 2007**

(tabular amounts in thousands of Canadian dollars)

## 1. Summary of significant accounting policies

***Financial Statement Presentation***

The accompanying financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The Yukon Electrical Company Limited (the "Corporation") is engaged in the generation, transmission, distribution and sale of electric energy.

Effective January 1, 2007, the Corporation adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity, and other financial liabilities are measured at their amortized cost. This change in accounting had the following effect on the financial statements for the year ended December 31, 2007:

(a) Restatement of opening retained earnings at January 1, 2007 to recognize the prior years' earnings effect of accounting for certain financial assets and financial liabilities at amortized cost using the effective interest method (see Note 3).

Effective January 1, 2007, the Corporation adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the financial statements for the year ended December 31, 2007.

Effective January 1, 2007, the Corporation adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owner, and includes earnings of the Corporation and unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the financial statements.

Effective January 1, 2007, the Corporation adopted the CICA recommendations regarding the presentation of equity and changes in equity. These recommendations require separate presentation of the components of equity, including retained earnings, accumulated other comprehensive income, contributed surplus, share capital and reserves, and the changes therein. This change in accounting had no effect on the financial statements for the year ended December 31, 2007.

Effective January 1, 2007, the Corporation adopted the CICA recommendations that prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. Adoption of these recommendations had no effect on the financial statements for year ended December 31, 2007, except for the disclosure of the accounting changes that have been issued by the CICA but have not yet been adopted by the Corporation because they are not effective until a future date (see Future Accounting Changes below).

Certain comparative figures have been reclassified to conform to the current presentation.

**THE YUKON ELECTRICAL COMPANY LIMITED**

**NOTES TO FINANCIAL STATEMENTS**

**December 31, 2007**

(tabular amounts in thousands of Canadian dollars)

**1. Summary of significant accounting policies** (continued)

***Rate Regulation***

The Corporation is regulated primarily by the Yukon Utilities Board ("Board") which administers acts and regulations covering such matters as rates, financing, accounting, construction and operation and service area. Accounting for rate regulated operations is described in Note 2.

***Use of Estimates***

The preparation of the Corporation's financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

***Revenue Recognition***

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the Board.

Revenues from sales of electricity are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of services provided but not yet billed.

***Purchased Power***

Purchased power expense is based on the actual cost of electricity purchased.

***Income Taxes***

The Corporation utilizes the flow through method to account for income taxes. In accordance with the Board, future income taxes have not been recorded to the extent that the income tax component of rates approved by the Board was not designed to recover those taxes. Accordingly, the customer in future years will bear an additional charge as these unrecorded future income taxes are reversed.

***Cash and Short Term Investments***

Short term investments consist of certificates of deposit and bankers' acceptances with maturities generally of 90 days or less at purchase.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

**1. Summary of significant accounting policies** (continued)

***Inventories***

Inventories include materials and supplies and are valued at the lower of average cost or net realizable value.

***Property, Plant and Equipment***

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant. The Corporation includes in property, plant and equipment an allowance for funds used during construction at rates approved by the Board for debt and equity capital. Certain additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates are approved by the Board and include a provision for future removal and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net of disposal costs and site restoration costs.

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques.

***Asset Retirement Obligations***

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

The Corporation has determined that it has tangible long lived assets where there is a legal liability regarding asset retirement. For these tangible long lived assets, asset retirement obligations have not been recorded as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

**1. Summary of significant accounting policies** (continued)

***Long Term Debt Due Within One Year***

All of the long term debt is held by the parent corporation, ATCO Electric Ltd. When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on ATCO Electric Ltd.'s behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

***Employee Future Benefits***

The Corporation, together with its ultimate parent corporation, Canadian Utilities Limited and affiliate corporations, participates in a group defined benefit pension plan ("the Group Plan"). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid.

The Corporation accrues for its obligations under other post employment benefit and certain other defined benefit pension plans. These plans are administered on a combined basis with the Corporation's parent and affiliate corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for the plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of wage and salary increases, age at retirement and expected health care costs. Experience gains and losses and the effect of changes in assumptions in excess of 10% of the accrued benefit obligations, together with adjustments resulting from plan amendments, are amortized over the estimated average remaining service life of employees.

***Future Accounting Changes***

The CICA has issued new accounting recommendations for capital disclosures which require disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the Corporation's objectives, policies and processes for managing capital. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has issued new accounting recommendations for disclosure and presentation of financial instruments which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks arising from financial instruments to which the Corporation is exposed. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has issued new accounting recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any writedown to net realizable value, and on the cost formulas that are used to assign costs to inventories. The adoption of these recommendations will not have a material impact on the earnings or assets of the Corporation. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. The Corporation is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

**1. Summary of significant accounting policies** (continued)

The CICA has issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. These recommendations are effective for the Corporation beginning January 1, 2009, and will be applied prospectively. The amount of unrecorded future income tax liabilities of the regulated operations at December 31, 2007 is $1,554,000.

In 2006, the CICA announced that accounting standards in Canada are to converge with International Financial Reporting Standards ("IFRS"). The Corporation will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to GAAP, but there could be significant differences on recognition, measurement and disclosures that will need to be addressed. The Corporation is currently assessing the impact of these standards on its financial statements.

**2. Accounting for regulated operations**

***Nature and economic effects of rate regulation***

The Corporation is subject to a cost of service regulatory mechanism under which the Board establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base is the aggregate of the Board approved investment in property, plant and equipment less accumulated depreciation and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The Corporation earns a return on rate base intended to meet the cost of the debt and to provide the share owner with a fair return on the common equity component of rate base.

The Board approves rates of return for the debt and common equity component of rate base based on the actual or forecast weighted average cost of the Corporation's debt and common equity.

Under the cost of service methodology, the Corporation seeks approval for it's revenue requirement through submission of a general rate application to the Board. The Board may approve interim rates, subject to final determination.

***Financial statement effects of rate regulation***

Certain items in these financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations currently do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities on the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the Board renders a decision concerning these adjustments.

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

**2. Accounting for regulated operations** (continued)

The regulatory assets comprise the following:

| | 2007 | 2006 |
|---|---|---|
| Reserve for injuries and damages | $ 53 | $ 54 |
| Market differential loans | 62 | - |
| | $ 115 | $ 54 |

***Reserves for injuries and damages***

The Board has approved the use of a reserve for injuries and damages by the Corporation as a means of self-insurance. The reserve for injuries and damages is established based on annual amounts approved by the Board to be expensed by the Corporation and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general rate application or until a specific application is made to the Board requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses for 2007 would have been $1,000 lower (2006 – $24,000 lower) in the absence of rate regulation.

***Market differential loans***

The Corporation may provide interest free market differential loans to employees when relocating. Effective January 1, 2007, the CICA recommendations regarding the measurement of financial assets require that these loans be measured at fair value when recognized initially and then subsequently measured at amortized cost, resulting in a reduction in their carrying amount. Since revenue requirement includes a recovery from customers for imputed interest on these loans, the difference between the face value and the carrying amount of the loans has been accrued as a regulatory asset. GAAP requires that revenues be based on the customer rates approved by the Board and not adjusted for the imputed interest that will be recovered from customers in future years. Consequently, retained earnings at the beginning of 2007 as restated (see note 3) would have been $13,000 lower (2006 – nil) and revenues for 2007 would have been $49,000 lower (2006 – nil) in the absence of rate regulation. Assets of $62,000 are included in non-current regulatory assets (2006 – nil).

***Other items affected by rate regulation***

The Board permits an allowance for funds used ("AFU"), based on the Corporation's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes a common equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

## 2. Accounting for regulated operations (continued)

The Corporation follows the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 5).

## 3. Retained earnings at beginning of period as restated

| | Year ended December 31 | |
|---|---|---|
| | **2007** | 2006 |
| Retained earnings at beginning of year as previously reported | $ 9,524 | $ 8,998 |
| Adjustments to retained earnings to recognize the prior years' effect of: | | |
| a) the change in method of accounting for market differential loans at amortized cost using the effective interest rate method (net of income taxes) | (13) | - |
| b) regulatory asset for market differential loans (net of income taxes) | 13 | - |
| Retained earnings at the beginning of period as restated | $ 9,524 | $ 8,998 |

## 4. Interest and other income

| | **2007** | 2006 |
|---|---|---|
| Allowance for funds used during construction | $ 78 | $ 54 |
| Interest | 56 | 0 |
| Other | 3 | (1) |
| | $ 137 | $ 53 |

Interest received in 2007 amounted to $56,000 (2006 - $0).

## 5. Income taxes

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

| | **2007** | | 2006 | |
|---|---|---|---|---|
| Earnings before income taxes | $ 2,995 | % | $ 2,927 | % |
| Income taxes, at statutory rate | 1,111 | 37.1 | 1,087 | 37.1 |
| Unrecorded future income taxes | (203) | (6.8) | 123 | 4.2 |
| Other | (6) | (0.2) | (209) | (7.1) |
| Income taxes | $ 902 | 30.1 | $ 1,001 | 34.2 |

Unrecorded future income taxes receivable decreased by $388,000 to $1,554,000 at December 31, 2007.
Income taxes paid in 2007 amounted to $1,210,000 (2006 - $1,240,000).

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

## 6. Property, plant and equipment

| | Composite Depreciation Rates | 2007 Cost | 2007 Accumulated Depreciation | 2006 Cost | 2006 Accumulated Depreciated |
|---|---|---|---|---|---|
| Generation | 3.80% | $ 16,283 | $ 8,953 | $ 15,794 | $ 8,392 |
| Distribution | 3.83% | 92,422 | 41,214 | 86,186 | 37,967 |
| Other | 4.72% | 7,277 | 3,601 | 6,881 | 3,600 |
| Land | - | 469 | - | 371 | - |
| Construction work in progress | - | 1,035 | - | 871 | - |
| | 3.87% | $ 117,486 | $ 53,768 | $ 110,103 | $ 49,959 |
| Property, plant and equipment less accumulated depreciation | | | $ 63,718 | | $ 60,144 |
| Unamortized contributions by utility customers for extensions to plant | | | 22,496 | | 21,017 |
| | | | $ 41,222 | | $ 39,127 |

Accumulated depreciation includes an amount provided for future removal and site restoration costs, net of salvage value, of $4,688,000 (2006 - $4,050,000).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding non-depreciable assets and construction work in progress.

## 7. Bank indebtedness and credit lines

The Corporation has an operating credit line totaling $1,000,000 (2006 – $1,000,000) which is available on an uncommitted basis. The credit line enables the Corporation to obtain financing for general business purposes. At December 31, 2007, $1,000,000 (2006 – $1,000,000) of the credit line was still available.

## 8. Long term debt

| | 2007 | 2006 |
|---|---|---|
| Debentures | | |
| 2000 Series 7.05% due June 2008 | 600 | 600 |
| 1989 Series 10.33% due November 2009 | 2,000 | 2,000 |
| 2004 Series 5.16% due November 2014 | 500 | 500 |
| 2002 Series 6.21% due November 2017 | 3,900 | 3,900 |
| 2004 Series 5.47% due January 2019 | 1,000 | 1,000 |
| 1999 Series 6.85% due August 2019 | 4,500 | 4,500 |
| 1990 Series 11.91% due November 2020 | 1,500 | 1,500 |
| 1992 Series 9.51% due May 2023 | 2,500 | 2,500 |
| 2005 Series 5.23% due November 2030 | 4,300 | 4,300 |
| 2006 Series 5.07% due November 2036 | 3,000 | 3,000 |
| | $ 23,800 | $ 23,800 |

**THE YUKON ELECTRICAL COMPANY LIMITED**

**NOTES TO FINANCIAL STATEMENTS**

**December 31, 2007**

(tabular amounts in thousands of Canadian dollars)

**8. Long term debt** (continued)

The minimum annual repayments of long term debt for each of the next five years are as follows:

| 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|
| $ 600 | $ 2,000 | $ - | $ - | $ - |

***Interest expense***

Interest on debt is as follows:

| | 2007 | 2006 |
|---|---|---|
| Long term debt | $ 1,673 | $ 1,553 |
| Short term advances from parent and affiliated corporations | (7) | 56 |
| Other | - | - |
| | $ 1,666 | $ 1,609 |

Interest paid in 2007 amounted to $1,673,230 (2006 - $1,538,455).

***Fair values***

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are $27,073,000 (2006 - $28,083,000). Where market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

***Short term advances from parent and affiliated corporations***

Short term advances from parent are payable upon demand and bear interest based on short term Bankers' Acceptance rates.

**9. Class A and Class B shares**

***Authorized and issued***

| | Class A Non-Voting | | Class B Common | | Total | |
|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Shares | Amount |
| *Authorized:* | Unlimited | | Unlimited | | | |
| *Issued and Outstanding:* | | | | | | |
| December 31, 2006 | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |
| **December 31, 2007** | 1,591 | $ 4,371 | 964 | $ 2,648 | 2,555 | $ 7,019 |

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

## 10. Changes in non-cash working capital

| | 2007 | 2006 |
|---|---|---|
| *Operating activities, changes related to:* | | |
| Accounts receivable | $ 209 | $ (69) |
| Inventories | (13) | (62) |
| Prepaid expenses | (7) | 1 |
| Accounts payable and accrued liabilities | 451 | (338) |
| Income taxes and other taxes receivable | (274) | (186) |
| Owing to parent and affiliated corporations | 85 | 243 |
| | $ 451 | $ (411) |
| *Investing activities, changes related to:* | | |
| Inventories | (52) | (248) |
| Accounts payable and accrued liabilities | 118 | (52) |
| | $ 66 | $ (300) |

## 11. Related party transactions

| Entity | Relationship | Transaction | Recorded as | 2007 | 2006 |
|---|---|---|---|---|---|
| Northland Utilities Enterprises | Affiliate | Administration and financial management | Revenue | 80 | 74 |
| ATCO Frontec Corp. | Affiliate | Building Rent | Revenue | 45 | 43 |
| ATCO I-Tek Business Services Ltd. | Affiliate | Information system services | Selling and administrative | 331 | 311 |
| ATCO I-Tek Business Services Ltd. | Affiliate | Billing services | Selling and administrative | 916 | 434 |
| ATCO Gas | Affiliate | Meter services, Reprographics | Operation and maintenance | 51 | 34 |
| ATCO Electric Ltd | Parent | Administration, financial management, meter reading, computer services and equipment rent | Operation and maintenance | 341 | 299 |

These transactions are considered to be in the normal course of business and are measured at the exchange amount being the amount of consideration established and agreed to by the related parties. The amounts owing to the parent and affiliated corporations are subject to commercial terms and conditions.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

## 12. Employee future benefits

The Corporation, together with its parent and affiliate corporations, maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants.

Contributions to a group defined benefit pension plan, which is accounted for as a defined contribution plan, are expensed as paid. Other post employment benefit and certain other defined benefit pension plans, which the Corporation funds out of general revenues, are administered on a combined basis with the Corporation's ultimate parent and affiliated corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for the plan as a whole; for other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans.

Information about the benefit plans is as follows:

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | **Pension Benefit Plans** | **Other Post Employment Benefit Plans** | Pension Benefit Plans | Other Post Employment Benefit Plans |
| **Benefit plan expense** | | | | |
| Total benefit plans expense | $ 520 | $ 103 | $ 9 | $ 123 |
| Less: Capitalized | 112 | 23 | - | 25 |
| Benefit plan expense | $ 408 | $ 80 | $ 9 | $ 98 |
| **Benefit plan liabilities** | | | | |
| Accrued liability at beginning of year | $ (171) | $ (490) | $ (173) | $ (395) |
| Total benefit plans expense | (520) | (103) | (9) | (123) |
| Benefit payments | 521 | 56 | 11 | 28 |
| Accrued liability at end of year | $ (170) | $ (537) | $ (171) | $ (490) |

## 13. Risk management and financial instruments

***Interest rate risk***

The Corporation is not exposed to significant interest rate risk due to its long term debt having fixed interest rate.

***Fair value of non-derivative financial instruments***

Accounts receivable, bank indebtedness, short term advances from parent and affiliated corporations, accounts payable and accrued liabilities, and owing to parent and affiliated corporations are recorded at cost. Their respective fair value approximates their carrying value due to the relatively short term maturities of these instruments.

THE YUKON ELECTRICAL COMPANY LIMITED

NOTES TO FINANCIAL STATEMENTS

December 31, 2007

(tabular amounts in thousands of Canadian dollars)

## 14. Commitments & Contingencies

### *Commitments*

The Corporation has contractual obligations in the normal course of business.

### *Contingencies*

Measurement inaccuracies occur from time to time with respect to the Corporation's metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the Board.

As a result of decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

# THE YUKON ELECTRICAL COMPANY LIMITED
## UTILITY INCOME AND RATE OF RETURN
## For The Year Ended December 31, 2007
**($000s)**

| | | |
|---|---|---|
| UTILITY REVENUE | | 41,028 |
| UTILITY EXPENSE | | |
| Operation and Maintenance | | 33,582 |
| Less: | Non Allowables | 39 |
| | Non-Utility O&M | 299 |
| | Non Utility Income Taxes | 46 |
| | Non Utility Depreciation | |
| Add: | Depreciation | 4,171 |
| | Other Taxes | 236 |
| | Income Taxes | 902 |
| | Amortization of Contribution for Extensions | (1,092) |
| | Amortization of Deferred Study and Rate Case Cost | - |
| TOTAL | | 37,414 |
| UTILITY INCOME | | 3,614 |
| NET RATE BASE | | 42,778 |
| RATE OF RETURN | | 8.448% |

# THE YUKON ELECTRICAL COMPANY LIMITED
## COMPUTATION OF NET RATE BASE
## For The Year Ended December 31, 2007
### ($000s)

| | | |
|---|---|---|
| PROPERTY PLANT AND EQUIPMENT | | |
| BALANCE AT DECEMBER 31, 2006 | | 117,486 |
| Add: | Deferred Study Costs | - |
| Less: | Accumulated Depreciation | 53,768 |
| | Non-regulated Assets | |
| | Construction Work-in-Progress | 1,035 |
| | | 54,803 |
| NET BALANCE AT YEAR END | | 62,684 |
| Add: | Previous Year's Balance | 59,259 |
| TOTAL | | 121,943 |
| MID-YEAR BALANCE | | 60,971 |
| Add: | Allowance for Working Capital | 3,563 |
| | Mid-Year Rate Case Expense | - |
| Less: | Mid-Year Contribution for Extensions | 21,757 |
| NET RATE BASE | | 42,778 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## SCHEDULE OF ALLOWANCE FOR WORKING CAPITAL
## For The Year Ended December 31, 2007
**($000s)**

| | |
|---|---|
| Operation & Maintenance | 33,582 |
| Add: Other Taxes | 236 |
| Less: Non-Utility O&M / Allowables | 338 |
| Allowable Operating Expense | 33,480 |
| Utility Income Tax (Previous Year) | 1,034 |
| Current Year Income Taxes (Payable) Receivable | 285 |
| Allowance: Operating Expense<br>19/365 * Allowable Operating Expense | 1,742 |
| Allowance: Income Tax<br>30/365 * Income Tax (Previous Year) | 84 |
| Allowance: Final Tax Payment<br>196/365 * Income Taxes Payable | 153 |
| Three Year Average Inventory | 1,702 |
| GST Impact | (118) |
| TOTAL WORKING CAPITAL | 3,563 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## RECONCILIATION OF UTILITY INCOME TO NET EARNINGS
## For The Year Ended December 31, 2007
**($000s)**

| | |
|---|---|
| UTILITY INCOME | 3,614 |
| Add Non Utility Income: | |
| Allowance for Funds Used During Construction | 78 |
| Non Regulated Revenues | 392 |
| Short Term Interest From Parent | 25 |
| Non Utility Income | |
| Other Interest | 69 |
| | 564 |
| Sub-Total | 4,178 |
| Less Non Utility Expenses: | |
| Interest to Parent | 1,673 |
| Short Term Interest To Parent | 17 |
| Non Regulated Expenses | 299 |
| Non Regulated Depreciation | - |
| Preferred Dividends to Parent | - |
| Other Interest | 10 |
| Non Allowables | 39 |
| | 2,038 |
| Sub-Total | 2,139 |
| Add Income Tax Adjustment: | |
| Tax on Net Non Utility Income | (46) |
| NET EARNINGS | 2,093 |

# THE YUKON ELECTRICAL COMPANY LIMITED
## ANALYSIS OF DEPRECIATION RESERVE
## For The Year Ended December 31, 2007
### ($000s)

| | | |
|---|---|---|
| BALANCE - DECEMBER 31, 2006 | | 49,959 |
| Add: | Depreciation - Operating Expense | 4,171 |
| | Depreciation - Other | 24 |
| | | 54,154 |
| Less: | Retirements | 426 |
| | Sale and Salvage Proceeds | (95) |
| | Dismantling Expense | 55 |
| BALANCE - DECEMBER 31, 2007 | | 53,768 |

# YUKON ELECTRICAL COMPANY LIMITED
## COST OF CAPITAL CALCULATION
## For The Year Ended December 31, 2007
(%)

| | CAPITAL RATIO | COST | RETURN COMPONENT |
|---|---|---|---|
| LONG TERM DEBT | 57.60 | 7.030 | 4.049 |
| PREFERRED SHARES | - | - | - |
| COMMON SHARES AND RETAINED EARNINGS | 40.87 | 10.760 | 4.399 |
| NO COST CAPITAL | 1.53 | | |
| | 100.00 | | 8.448 |

(FA-420A) (New Version) Property Plant and Equipment Summary by Fiscal Year Book Type Code : 'YECL CORP' Period Name : 'DEC-2007' 1 of 1

| Function | Minor Account | Minor Description | Sub Category | Subcategory Description | Fiscal Year Beginning Bal Calc | Current Year Additions | Current Year Adjustments | Current Year Transfers | Current Year Retirements | Fiscal Year Ending Balance |
|---|---|---|---|---|---|---|---|---|---|---|
| Corporate | 48000 | Land | 48000 | Land | 306,124.30 | 10,500.00 | 0.00 | 0.00 | 0.00 | 316,624.30 |
| | 48200 | Buildings and Structures | 48100 | Land Rights | 19,249.57 | <16.89> | <84.41> | 0.00 | 0.00 | 19,148.27 |
| | 48200 | Buildings and Structures | 48200 | Buildings and Structures | 3,136,532.07 | 28,692.48 | 0.00 | 79.95 | 0.00 | 3,165,304.50 |
| | 48300 | Office Furniture | 48300 | Office Furniture | 248,263.82 | 10,018.97 | 0.00 | 0.00 | <38,555.11> | 219,727.68 |
| | 48320 | Computer Equipment | 48320 | Computer Equipment | 39,446.49 | 299.99 | 0.00 | 0.00 | <2,326.95> | 37,419.53 |
| | 48320 | Computer Equipment | 48320 | Computer Equipment | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | 48401 | Vehicles Category 1 | 48410 | Cars | 28,209.00 | 0.00 | 0.00 | 0.00 | 0.00 | 28,209.00 |
| | 48401 | Vehicles Category 1 | 48420 | Light Trucks and Pole Trailers | 207,057.35 | 15,157.44 | <196.52> | 0.00 | 0.00 | 222,018.27 |
| | 48401 | Vehicles Category 1 | 48430 | Pole Trailers > 10,000 lbs | 48,864.48 | 59,083.69 | 2,664.48 | 0.00 | 0.00 | 110,612.65 |
| | 48401 | Vehicles Category 1 | 48440 | 3/4 to 2 Ton Trucks | 1,029,970.29 | 86,427.18 | 6,325.70 | 0.00 | <974.99> | 1,121,748.18 |
| | 48401 | Vehicles Category 1 | 48450 | Trucks > 2 Tons < 3 Tons | 416,132.96 | 0.00 | 0.00 | 0.00 | <282,625.53> | 133,507.43 |
| | 48401 | Vehicles Category 1 | 48460 | Pole Cats | 156,818.41 | 0.00 | 0.00 | 0.00 | 0.00 | 156,818.41 |
| | 48401 | Vehicles Category 1 | 48470 | Trucks > 3 Tons | 5,083.35 | 659,146.09 | <248,730.20> | 0.00 | <4,935.28> | 410,563.96 |
| | 48401 | Vehicles Category 1 | 48480 | Tractors | 23,722.23 | 0.00 | 0.00 | 0.00 | 0.00 | 23,722.23 |
| | 48500 | Loose Tools | 48500 | Loose Tools | 513,408.16 | 49,053.93 | <769.80> | 0.00 | <60,901.02> | 500,791.27 |
| | 48600 | Communication Equipment | 48600 | Communication Equipment | 434,664.46 | 56,671.53 | 0.00 | 0.00 | 0.00 | 491,335.99 |
| | 48810 | Houses Land | 48810 | Houses Land | 603.60 | 0.00 | 0.00 | 0.00 | 0.00 | 603.60 |
| | 48820 | Houses | 48820 | Houses | 336,428.88 | 51,604.75 | 0.00 | <79.95> | 0.00 | 387,953.68 |
| | 49100 | Franchise and Consent | 49100 | Franchise and Consent | 1,493.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1,493.00 |
| | 49605 | Software - Oracle | 49605 | Software - Oracle | 235,497.57 | 0.00 | 0.00 | 0.00 | 0.00 | 235,497.57 |
| Distribution | 47000 | Land | 47000 | Land | 23,373.21 | 2,058.89 | <1,795.20> | 0.00 | 0.00 | 23,636.90 |
| | 47100 | Land Rights | 47100 | Land Rights | 858,824.86 | 69,734.58 | 70.17 | 0.00 | 0.00 | 928,629.61 |
| | 47300 | Poles and Fixtures | 47300 | Poles and Fixtures | 21,638,213.82 | 1,050,087.83 | 63,185.79 | 0.00 | <11,321.67> | 22,740,165.77 |
| | 47400 | Overhead Conductor | 47400 | Overhead Conductor | 13,585,566.10 | 1,402,526.58 | 104,538.60 | 0.00 | <132.20> | 15,092,499.08 |
| | 47410 | Overhead Services | 47410 | Overhead Services | 2,074,247.17 | 221,077.76 | 10,651.41 | 0.00 | 0.00 | 2,305,976.34 |
| | 47500 | Underground Conduit | 47500 | Underground Conduit | 16,573,565.19 | 779,624.63 | 72,702.39 | 0.00 | 0.00 | 17,425,892.21 |
| | 47510 | Underground Services | 47510 | Underground Services | 2,383,278.88 | 172,552.40 | <8,782.11> | 0.00 | 0.00 | 2,547,049.17 |
| | 47610 | Meters | 47610 | Meters | 364,466.61 | 48,704.22 | 0.00 | 0.00 | 0.00 | 413,170.83 |
| | 47610 | Meters | 47620 | Metering Equipment | 830,245.15 | 17,293.68 | 2,102.29 | 0.00 | 0.00 | 849,641.12 |
| | 47630 | AMR Meters | 47612 | AMR Meters | 0.00 | 22,396.53 | 163.71 | 0.00 | <14,524.55> | 8,035.69 |
| | 47710 | Distribution Substation | 47710 | Non-Fenced Distr Sub Equip | 2,654,448.26 | 0.00 | 0.00 | 0.00 | 0.00 | 2,654,448.26 |
| | 47710 | Distribution Substation | 47720 | Distr Substation Buildings | 477,067.35 | 0.00 | 0.00 | 0.00 | 0.00 | 477,067.35 |
| | 47810 | Street Lights | 47810 | Street Lights | 7,122,129.10 | 570,628.47 | 10,740.74 | 0.00 | <4,492.98> | 7,699,005.33 |
| | 47820 | Sentinel Lights | 47820 | Sentinel Lights | 284,738.28 | 0.00 | 0.00 | 0.00 | 0.00 | 284,738.28 |
| | 47910 | Transformers | 47910 | Line Transformers | 15,137,730.02 | 1,470,685.82 | 117,528.70 | 0.00 | <2,609.04> | 16,723,335.50 |
| | 47910 | Transformers | 47910INV | Inventory Reclass Transformers | 800,601.51 | 0.00 | 71,978.82 | 0.00 | 0.00 | 872,580.33 |
| Generation | 42000 | Hydro Land | 42000 | Hydro Land | 20,912.46 | 98,112.46 | 0.00 | 0.00 | 0.00 | 119,024.92 |
| | 42500 | Hydro Equipment | 42200 | Hydro Structures | 259,411.60 | 0.00 | 0.00 | 0.00 | 0.00 | 259,411.60 |
| | 42500 | Hydro Equipment | 42300 | Hydro Resv, Dams & Waterways | 757,083.44 | 0.00 | 0.00 | 0.00 | 0.00 | 757,083.44 |
| | 42500 | Hydro Equipment | 42500 | Hydro Generators | 272,629.36 | 0.00 | 0.00 | 0.00 | 0.00 | 272,629.36 |
| | 42500 | Hydro Equipment | 42600 | Hydro Accessory Electrical Equip | 105,192.21 | 0.00 | 0.00 | 0.00 | 0.00 | 105,192.21 |
| | 42500 | Hydro Equipment | 42700 | Hydro Misc Equip | 23,984.46 | 0.00 | 0.00 | 0.00 | 0.00 | 23,984.46 |
| | 44000 | Int Combust Land | 44000 | Int Combust Land | 7,130.15 | 0.00 | 0.00 | 0.00 | 0.00 | 7,130.15 |
| | 44200 | Int Combust Structures | 44200 | Int Combust Structures | 1,381,243.90 | 116,600.09 | 0.00 | 0.00 | 0.00 | 1,497,843.99 |
| | 44400 | Int Combust Fuel Holders | 44400 | Int Combust Fuel Holders | 2,057,374.99 | 25,562.13 | 57,002.55 | 0.00 | <3,199.74> | 2,136,739.93 |
| | 44500 | Int Combust Generators | 44500 | Int Combust Generators | 8,444,472.85 | 0.00 | <0.01> | 0.00 | 0.00 | 8,444,472.84 |
| | 44600 | Int Combust Access Elect Equip | 44600 | Int Combust Access Elect Equip | 2,071,664.94 | 62,745.11 | 7,411.14 | 0.00 | 0.00 | 2,141,821.19 |
| | 44700 | Int Combust Misc Equip | 44700 | Int Combust Misc Equip | 420,714.07 | 216,228.76 | 6,223.14 | 0.00 | 0.00 | 643,165.97 |
| Transmission | 45000 | Land | 45000 | Land | 11,550.51 | 0.00 | 0.00 | 0.00 | 0.00 | 11,550.51 |
| | 45700 | Transmission Substation | 45710 | Substation Misc Equip & Install | 1,401,497.52 | 0.00 | 0.00 | 0.00 | 0.00 | 1,401,497.52 |
| **Grand Total** | | | | | **109,230,927.96** | **7,373,259.10** | **272,931.38** | **0.00** | **<426,599.06>** | **116,450,519.38** |

# THE YUKON ELECTRICAL COMPANY LIMITED

## 100 - 1100 1ST Avenue, Whitehorse, YT, Y1A 3T4

**DIRECTORS:**

William L.Britton

Basil K. French

Nancy C. Southern

Ronald D.Southern

Karen M. Watson

**OFFICERS:**

Ronald D. Southern ..... Chariman of the Board

William L. Britton ..... Vice-Chairman of the Board

Nancy C. Southern ..... Chief Executive Officer

Siegfried W. Kiefer ..... Managing Director, Utilities

Sett F. Policicchio ..... President

Dennis A. DeChamplain ..... Vice President, Controller

Patrica Spruin .....Secrectary

# STATUTORY DECLARATION

IN THE MATTER OF A REPORT REQUIRED BY
SECTION 84 OF THE YUKON PUBLIC UTILITIES ACT
BY S.F. POLICICCHIO, PRESIDENT, AND P. SPRUIN,
CORPORATE SECRETARY,
OF
THE YUKON ELECTRICAL COMPANY LIMITED (the "Corporation")
(in thousands of dollars)

WE SOLEMNLY DECLARE THAT:

1. For 2007, the Net Rate Base for the Corporation was $42,778.

2. As of December 31, 2007, the total capitalization of the Corporation was $41,036 with a weighted average cost of 8.45%.

3. The revenues for the Corporation for the period from January 1, 2007 to December 31, 2007 were as follows:

| | |
|---|---|
| Retail Sales | $ 40,125 |
| Sales to other Utilities | 53 |
| Other Revenue | 1,242 |
| TOTAL | $ 41,420 |

4. The dividends paid by the Corporation for the period January 1, 2007 to December 31, 2007 were as follows:

| | |
|---|---|
| Common Shares | $ 1,400 |

5. The operating and maintenance costs of the Corporation for the period from January 1, 2007 to December 31, 2007 were $7,979.

6. The Corporation estimates the following costs for new works, extensions and improvements during the current year:

| | |
|---|---|
| Distribution Projects | $ 6,297 |
| General Property & Equipment | 1.069 |
| Generating Plants | 464 |
| TOTAL | $ 7,830 |

WE MAKE THIS SOLEMN DECLARATION CONSCIENTIOUSLY BELIEVING IT TO BE TRUE AND KNOWING THAT IT IS OF THE SAME FORCE AND EFFECT AS IF MADE UNDER OATH.

Severally declared before me )
at the City of Edmonton )
in the Province of Alberta )
this 19th day of June, 2008. )

Sett F. Policicchio

NOTARY PUBLIC IN AND FOR
THE PROVINCE of Alberta

Severally declared before me )
at the City of Calgary )
in the Province of Alberta )
this 24 day of June, 2008. )

~~Patricia Spruin~~ PS
Dennis A. DeChamplain

PATRICIA SPRUIN
A NOTARY PUBLIC
AND FOR THE PROVINCE OF ALBERTA
MY COMMISSION EXPIRES DECEMBER 31, 2009

**CW-YECL-5**

**Issue:** Accounting and Regulatory Practices

**Reference:** General

**Preamble:** CW desires to understand any changes in accounting and regulatory practices since the 1996 97 GRA.

**Request:**

Please provide any changes to accounting and regulatory practices that have occurred since the 1996 97 GRA.

**Response:**

In accordance with Board Order 2008-5, information dating prior to 2003 was not required to test the revenue requirement. However, given that changes occurring since 1997 impact the test period, to the extent the changes are still applicable, Yukon Electrical will provide the requested information as follows:

Changes in Accounting Practice:

2000 Effective January 1, 2000 the Corporation prospectively adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for employee future benefits. This accounting change had the effect of decreasing earnings by 35,000.

2001 Effective January 1, 2001, the Corporation retroactively adopted the Canadian Institute of Chartered Accountants recommendations to disclose its unrecorded future income taxes. Under these recommendations, income taxes are accounted for using the liability method where by future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted tax rates and substantively enacted tax rates.

Previously, the Corporation determined its unrecorded future income taxes using the normalized deferred method.

2004 Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. The impairment loss may be deferred by the Corporation if there is reasonable assurance that the loss will be included in future rate to customers. The adoption of this recommendation had no effect on earnings for the year ended December 31, 2004.

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for asset retirement obligations. The CICA recommendations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. An asset retirement obligation is recorded as a liability, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

The Corporation has determined that it has tangible long lived assets where there is a legal liability regarding asset retirement. For these tangible long lived assets, asset retirement obligations have not been recorded as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time.

2005 Effective January 1, 2005, the Corporation prospectively adopted the CICA guideline pertaining to the consolidation of variable interest entities. The guideline requires the Corporation to identify variable interest entities in which it has an interest, determine whether it is the primary beneficiary of such entities and, if so, to consolidate them. This change had no effect on the financial statements.

Effective January 1, 2005, the Corporation prospectively adopted the CICA guideline pertaining to lease arrangements. The guideline requires the Corporation to identify arrangements that do not take the legal form of a lease but convey a right to use a tangible asset in return for a payment or series of payments and, if so, to account for them as leases. This change had no effect on the financial statements.

2006 Effective January 1, 2006, the Corporation retroactively adopted the CICA Emergency Issues Abstract regarding conditional asset retirement obligations. This Abstract requires an entity to record a liability for an asset retirement obligation even if the obligation is conditional upon the occurrence of a future event that may or may not be within the control of the entity. This change had no effect on the financial statements.

2007 Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity and other financial liabilities are measured at their carrying value. This change in accounting had no effect on the financial statements for the year ended December 31, 2007.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses

from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the financial statements for the year ended December 31, 2007.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owners, and includes earnings of the Corporation, unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the financial statements.

Changes in Regulatory Practices:

The following components were added to the working capital schedule as compared to the same calculation in the 1996-1997 GRA.

- Return - Long Term Debt
- Return - 50 of Common Equity
- Net Depreciation

These changes are appropriate and are consistent with the calculation approved by the Alberta Utilities Commission for ATCO Electric.

As stated on Page 8-2 of the Application, other post employment benefits are now accounted for on the cash basis.

**CW-YECL-6**

**Issue:** Proposed Rate Increase for 2008 & 2009

**Reference:** Page 1-3

**Preamble:** YECL states, The revenue requirement during the test period is 46,660,000 in 2008 and 47,902,000 in 2009. This revenue requirement represents an increase over the amount that would be recovered under existing rates and riders of 2,220,000 in 2008 and 4,130,000 in 2009. This represents a 5.9 increase in 2008 and a 5.1 increase in 2009.

**Request:**

Please provide calculations for the respective 5.9 and 5.1 figures cited in the above passage.

**Response:**

Please refer to Schedule 2.1 of the Application for the calculation of the rate increases.

**CW-YECL-7**

**Issue:** Typical Criteria for Deferral Accounts

**Reference:** Page 1-5

**Preamble:** YECL states The above noted ongoing and new deferral accounts meet the typical criteria for the establishment of a deferral account and are required as the costs related to these deferral accounts are:

1) Not under the control of the company and are not reasonably forecastable;

   Or

2) An error in forecasting could produce a loss or gain of a substantial magnitude.

**Request:**

(a) Please provide the regulatory precedents relied upon for the second criterion.

(b) If the response to (a) is that the criterion has been used by the parent Company ATCO Electric, please provide the regulatory precedent or precedents from the Alberta Utilities Commission.

(c) If the response to (a) is that the precedent or precedents are found in GAAP, please provide the appropriate references.

**Response:**

(a&b) Both of the above criteria have been specifically tested, reviewed and approved in ATCO Electric's applications to the AUC since 2005.

(c) The precedents are not found in GAAP.

**CW-YECL-8**

**Issue:** Organizational Chart

**Reference:** Section 1, Attachment 1, Page 1 of 1

**Preamble:** CW wishes to understand which positions are in-scope, which are out-of-scope and further which operating positions are directly involved in generation versus distribution.

**Request:**

(a) Please indicate which positions are in-scope and which positions are out of scope.

(b) Please indicate which operating positions are directly involved in generation and which positions are involved with distribution functions.

(c) Please describe where staff is located, how and when they are deployed to the outlying communities, how their time and expenses are charged recorded by community and how time is charged recorded to capital versus operations.

(d) Please provide this organizational chart for the years from 2003 through 2007.

**Response:**

(a) The following positions are out of scope:

1. Administrative Assistant
2. Manager, Customer Services
3. Supervisor of Financial Services
4. Supervisor, Customer Accounting & Administration
5. Supervising Engineer

6. Superintendent, Operations & Maintenance

7. Planned Maintenance & HS&E Coordinator

8. Coordinator, Construction & Materials Management.

9. General Manager.

The remaining positions are in scope.

(b) Yukon Electrical does not charge labor directly to only generation and distribution. Labor is allocated to activity based on the type of work that individuals may be undertaking and somewhat based on the historical charge out pattern of any given employee. Field based personnel use a daily time sheet and charge out by activity and community or capital project as appropriate.

The Senior Serviceman, Lead linemen, Journeymen Linemen, and apprentices spend the majority of their O&M time on the distribution function.

The Tech Team Lead and Electrical Technologist are approximately 40 generation 60 distribution.

The Diesel Turbine Operators spend the majority of their time on generation.

(c) YECL has staff in the following communities:

- Watson Lake 2 Journeyman linemen (90 distribution)
  1 Maintenance man (100 generation)
  1 Diesel Turbine Operator (95 generation)
  1 Field Service Representative (75 distribution-25 generation)

The Journeyman Linemen and the Maintenance man make routine trips to Swift River for line and plant maintenance. Unless dispatched for unplanned outages due to line or generations failure.

- Haines Junction, 1 Journeyman lineman who is responsible for operations in the communities of Haines Junction, Burwash Landing, Destruction Bay and Beaver Creek. He also makes routine trips to these communities and responds to power outages. His time is approximately 80 distribution and 10 generation and 5 capital.

- Beaver Creek, 1 Diesel Turbine operator who is primarily responsible for the operation of the plants in Beaver Creek and Destruction Bay. Routine maintenance, trouble shooting and power restorations. His time is almost 90 charged to generation.

- Whitehorse, approx 20 FTE operating positions remain in YECL's complement, 2 are apprentices and in training and therefore unable to operate the system. Their time is allocated to approximately 50 capital distribution projects and the remaining time to operational activities and training.

  There are 2 meter readers and 1 Field Service Representative.

  There are 3 Electrical Technologists, who split there time between generation and distribution.

  1 is a Diesel Maintenance Man responsible for maintaining, trouble shooting and repairing generating plants, both operating and stand by.

  - Teslin ( Stand by)
  - Haines Junction ( Stand by)
  - Destruction Bay ( Operating unit)
  - Beaver Creek ( Operating unit)
  - Old Crow ( Operating unit)
  - Ross River ( Stand by)
  - Stewart Crossing ( Stand by)

- Pelly Crossing ( Operating unit)
- Carmacks ( Stand by )
- Fish Lake Hydro's

11 line and service positions remain of which 2 are currently vacant, 1 to be filled August 25, 2008.

4 of the 9 remaining positions are assigned to a construction crew which generally spend approximately 40 of their time on capital distribution projects and the remained on operational activities.

5 of the remaining linemen are primarily focused on operational activities and customer driven requests such as line locates, meter verifications, field checks etc. 80 of their time is charged to distribution operations.

The 9 linemen are also responsible for continuity of service in the outlying communities as well excluding Watson, Haines Junction, Burwash Landing, Destruction bay and Beaver Creek.

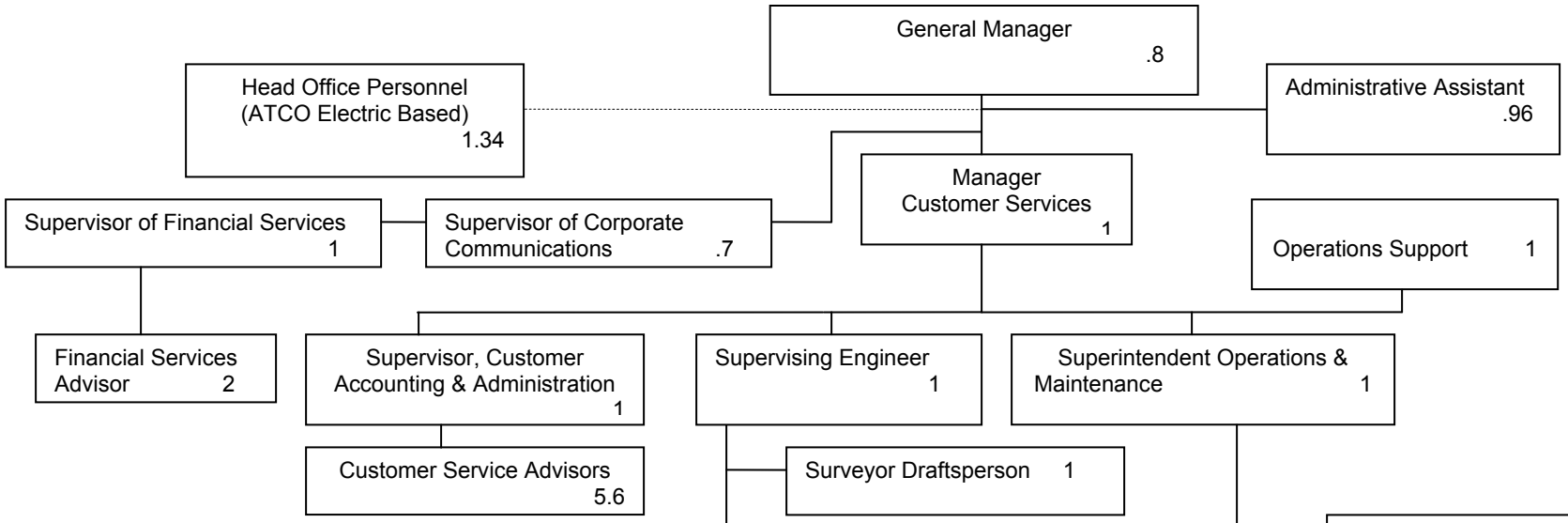
They provide standby and emergency service to the communities of Teslin, Tagish, Carcross, Carmacks, Pelly Crossing, Stewart Crossing, Ross River, Keno, Old Crow and Whitehorse.

This same group of employees is part of the 24 hour a day, 7 day a week trouble call stand by rotation. At any given time 2 men are on a published stand by list.

Yukon Electrical does not charge labor directly to only generation and distribution. Labour is allocated to activity based on the type of work that individuals may be undertaking and somewhat based on the historical charge out pattern of any given employee. However many of the field based personnel use a daily time sheet and charge out by activity and community or capital project as appropriate.

(d) Please refer to CW-YECL-8(d) Attachment 1

# Organizational Chart
# Yukon Electrical Company Limited
# 2003




Additions and Deletions to the Organizational Chart 2004-2009

| | |
|---|---|
| 2004 | No Changes |
| 2005 | Added Receptionist |
| 2006 | No Changes |
| 2007 | Added Planned Maintenance & HS&E Coordinator<br>Added Engineering Assistant<br>Added Apprentice Lineman |
| 2008 | Added Operations Support<br>Added Lineman Journeyman<br>Added Engineer in Training<br>Removed Supervisor Corporate Communications |
| 2009 | To Add Field Service Representative (Whitehorse)<br>To Add Draftsperson (Whitehorse)<br>To Delete Meter Reader (Whitehorse) |

**CW-YECL-9**

**Issue:** Growth of Commercial Sales

**Reference:** Section 2, page 2-1

**Preamble:** In 2007. commercial sales grew 3.1 . The increase in commercial growth was mainly due to the addition of a small number of larger retail stores, a new housing complex located near Yukon College as well as one time sales associated with the Canada Winter Games. The growth in secondary sales was mainly due to existing customers increasing their purchases.

**Request:**

(a) Please provide a breakdown of the 3.1 increase in commercial growth in 2007 by

i) the addition of a small number of larger retail stores

ii) a new housing complex located near Yukon College

iii) the one time sales associated with the Canada Winter Games

iv) other growth items

(b) What effect do the growth items referenced in a) above have on the forecast growth for 2008 and 2009?

(c) What portion, if any, of the one time sales associated with the Canada Winter Games is permanent?

**Response:**

(a) (i) the addition of a small number of larger retail stores 1.3

(ii) a new housing complex located near Yukon College 0.2

(iii) the one time sales associated with the Canada Winter Games 0.6

(iv) colder than average weather .2

(v) other growth items .8

(b) As the larger retail stores and housing complex were in place throughout 2007, they will not influence the growth rate between 2007 and 2008 or the growth rate between 2008 and 2009. The load associated with these customers was incorporated into the test years via the overall customer numbers and UPC. The one time sales associated with the 2007 Canada Winter Games will have a negative impact on growth between 2007 and 2008, but no impact on the growth between 2008 and 2009. The remaining other growth items that resulted in a .8 growth rate between 2006 and 2007 will have some impact on the growth rate between 2007 and 2008 as these customers would have been connected at various points during 2007 and are forecast to be in place throughout 2008. The load associated with these customers was incorporated into the test years via the customer numbers and UPC.

When looking at the absolute growth rates between 2007 and 2008, it is also important to note that 2007 was colder than the normal weather and Yukon Electrical used a weather normalized methodology for forecasting its commercial UPC in Whitehorse. Adjusting for the exclusion of one time Canada Winter Games impacts for the test periods and a colder 2007 year, results in an overall growth rate of 1.2 in total commercial energy in 2008 relative to 2007.

(c) As the one time sales associated with the Canada Winter Games related to (1) a temporary tent structure that hosted the opening and closing ceremonies as well as a festival as well as (2) a hotel that opened in February and March of 2007 when it is traditionally closed during the non-tourist season, none of these sales are permanent.

**CW-YECL-10**

**Issue:** Secondary Sales

**Reference:** Section 2, page 2-1

**Preamble:** Secondary sales are forecast to decrease by 28.5 in 2008 and 58.7 in 2009 as Yukon Energy is forecasting a decrease in surplus hydro and as a result has significantly reduced its forecast of secondary sales.

**Request:**

(a) Please explain how surplus hydro from Yukon Energy has benefited YECL to this point and which customers benefited from it and how.

(b) Please explain how Yukon Energy's forecast decrease in surplus hydro will affect YECL's operations and how it will affect the customers cited in a) above.

**Response:**

(a) From a Yukon Electrical financial perspective, surplus hydro secondary sales from Yukon Energy has provided little or no benefit as the majority of the incremental revenues associated with these sales are passed through to Yukon Energy (please refer to CW-YECL-13(c) Attachment 1 for a copy of the Secondary Sales Rates). From a Yukon Electrical operations perspective, secondary sales have made the operation of the distribution system more technically challenging as the large secondary sales loads located predominantly near or in downtown Whitehorse have contributed to the system running at or near capacity. From a customer relations perspective, secondary sales customers have been frustrated with Yukon Electrical staff when Yukon Electrical staff are instructed to turn them off due to Yukon Energy advising there is no longer surplus hydro available.

From the financial perspective of the 22 secondary sales customers, Yukon Electrical does not know whether their up front investments in electric space or

process heating have resulted in positive or negative paybacks through to this point in time.

(b) With respect to Yukon Electrical, the corollary to part (a) would be the case with respect to a decrease in surplus hydro secondary sales.

As for the financial impact of a decrease in surplus hydro secondary sales on the 22 secondary sales customers, Yukon Electrical does not know the impact.

**CW-YECL-11**

**Issue:** Energy Sales by Customer Class

**Reference:** Table 1 and Page 2-1

**Preamble:** CW requires additional information regarding energy sales.

**Request:**

(a) Please expand Table 1 to include forecast sales for 2006 and 2007.

(b) Please expand Table 1 to include actual and forecast sales for 2003, 2004, and 2005.

(c) Please provide explanations for the variances greater than 10 between forecast and actual energy sales for the years 2003 through 2007.

**Response:**

(a) As 2006 and 2007 were non-test years, no forecast is available.

(b) For actual 2003, 2004 and 2005 sales, please refer to the updated Schedule 2.1 filed on July 4, 2008. As 2003, 2004 and 2005 were non-test years, no forecast is available.

(c) Please refer to (a) and (b) above.

**CW-YECL-12**

**Issue:** Street Lighting Forecast

**Reference:** Application page 2-4, lines 15-18 and 9-3, lines 6-11

**Preamble:** YECL states: Lighting sales are forecast to increase by 1.7 in both 2008 and 2009. This is based on the average increase from 2005 to 2007 and includes an additional 60 new 250w HPS street lights at the end of 2008 for a new roadway in the Whitehorse area.

And: Expenditures are required to provide street and private lighting in Yukon Electrical's service area. Streetlights that require replacement due to age and obsolescence are included in this category. All streetlight work is completed in consultation with the communities. The forecast is determined based on known areas of development in the communities, the results of streetlight audits, as well as a review of historic replacement requirements.

**Request:**

(a) If YECL continuously consults with communities and municipalities to determine requirements for street lighting, why is it necessary to refer to growth for the previous three years to develop a forecast? Why isn't the customer's requirement for new and upgraded street lighting the best forecast of revenue for the street lighting service?

(b) What is the forecast increase in revenue based on customer demand for street lighting in the 2008 and 2009 test years? Is this higher or lower than the historical growth in demand?

**Response:**

(a) While consultations with communities and municipalities do identify major new developments, miscellaneous small lighting requests can also contribute to street light growth. Based on Yukon Electrical's past experience, a forecast containing only street light additions identified at the time the forecast was prepared might not capture all potential growth.

(b) Yukon Electrical is forecasting an increase in street lights revenue of 13,000 in 2008 and 13,000 in 2009. This compares to an average annual increase of 11,000 for the years 2005 2007.

**CW-YECL-13**

**Issue:** Forecast Process

**Reference:** Section 2, page 2-2

**Preamble:** The forecast process involves the review of historic sales data by customer class and takes into account the most recent information available at the time the forecast is prepared. The information is obtained through Yukon Electrical's work in the community as well as consultation with the City of Whitehorse, Yukon Government officials and local developers. The secondary sales forecast mainly comes from Yukon Energy as Yukon Energy is responsible for determining the forecast availability of surplus hydro.

**Request:**

(a) If possible please provide, if not, please describe, the information that was obtained through Yukon Electrical's work in the community and how it affects the sales forecasts for each rate class for 2008 and 2009.

(b) If possible please provide, if not please describe, the information that was obtained through consultation with the City of Whitehorse, Yukon Government officials and local developers and how it affects the sales forecasts for each rate class for 2008 and 2009.

(c) What portion of Yukon Energy's available surplus hydro did YECL use yearly over the period 2003 through 2007 and what portion is YECL forecasting to use in 2008 and 2009?

**Response:**

(a) As noted in the Application, Yukon Electrical's sales, and associated capital forecast, takes into account consultations with City of Whitehorse and Yukon Government officials as well as local developers that allow Yukon Electrical to identify customer additions. The Company's involvement with local Chambers of

Commerce also serves to identify projects that will result in new distribution extensions and or new customers. While this process has been in place for many years, it has taken on added importance of late as customers have recognized the importance of communicating their plans to Yukon Electrical given the long lead times required to obtain key pieces of electrical infrastructure. The information received as part of these consultants allows Yukon Electrical to identify what, if any, additional resources may be required to meet customers capital needs and reflect new customers and load in its sales forecast.

(b) The key information obtained from the City of Whitehorse and the Yukon Territorial Government (YTG) was their respective capital plans. The City of Whitehorse's plan provided information related to development in the Whitehorse area while the YTG plan provided government development plans for projects throughout the Yukon. As noted in the answer to part (a), the capital plan information allows Yukon Electrical to identify what, if any, additional resources may be required to meet customers capital needs and reflect new customers and load in its sales forecast.

(c) Yukon Electrical does not know what portion of Yukon Energy's available surplus was used to serve secondary sales customers for the period 2003 through 2007 nor does Yukon Electrical know what portion of the available surplus is forecast to be used in 2008 and 2009. As noted in the Application, the secondary sales forecast mainly comes from Yukon Energy as Yukon Energy is responsible for determining the forecast availability of surplus hydro. Please refer to CW-YECL-13(c) Attachment 1 for a copy of Rate Schedules 32 and 43 that address Secondary Energy and Wholesale Secondary respectively.

*Effective:* *2005 01 01*
Supercedes: 1997 01 01


# RATE SCHEDULE - 32

# SECONDARY ENERGY

**AVAILABLE:**

Secondary energy is available from time to time to General Service or Industrial customers in parts of the WAF and Mayo-Dawson systems as determined by Yukon Energy based on the availability of surplus hydro.

The rate is only available in areas where there is sufficient surplus distribution system capacity, unless the customer compensates the utility distributing the secondary energy for the cost of any necessary upgrades or, where upgrades are planned at a future date, the customer compensates the utility for the cost of advancing the upgrades.

Yukon Energy has discretion to end subscription to the program (and limit quantities delivered) on a system when the supply of surplus energy on that system becomes fully contracted. The specific subscription limit will be dependent on the types of loads that enroll in future, their seasonality and load diversity.

**APPLICABLE:**

Secondary energy is applicable only to customers satisfying all of the following conditions:

(1) The secondary energy is provided on a separate service fully interruptible at the request of the utility.

(2) The utility distributing the secondary energy (i.e., Yukon Energy or YECL) is satisfied that the secondary energy usage by the customer is in excess of normal consumption and represents incremental electric usage displacing an alternative fuel source by an appliance primarily installed in order to provide space or process heating.

(3) A viable alternative fuel source is available to the customer, capable of providing the same quantity of space or process heating in the event of electric power interruptions of unlimited duration.

(4) Customers taking Secondary Energy will not be allowed to have these loads shifted to be served by any firm (primary) service without providing the distributing utility (i.e., Yukon Energy or YECL) with 12 months notice (unless waived at Yukon Energy's discretion). Once any such Secondary Energy load is switched to firm service, it will not be able to switch back to Secondary Energy service in future.

**RATE:**

Charges for service in any one billing month during any Rate Period shall apply the Secondary Energy Charge for that Rate Period.

The Secondary Energy Charge for any three month Rate Period, starting January 1, 2005 and adjusted thereafter on the first day of every third subsequent month (i.e., on April 1, July 1 and October 1 in 2005 and similarly in each following year), is to be published and filed with the Board by Yukon Energy at least 30 days in advance of the Rate Period. The Secondary Energy Charge for any Rate Period is to be set in accordance with the following procedure:

**Step A: Determine a price per MJ for heat energy from oil:** The Oil Price Index (cents litre net of GST) for the Rate Period (as determined below) divided by 38.2 MJ litre to yield a price in cents per MJ.

**Step B: Determine a price per MJ of delivered heat from oil:** Divide the result from step A by an efficiency rate of 90 .

**Step C: Convert price of delivered heat energy from oil to an equivalent price for heat energy from electricity:** multiply the result from step B by 3.6 MJ kW.h to yield a price in cents per kW.h.

**Step D: Set at 66.67 ratio:** Multiply the result from Step C by 66.67 to yield the quarterly Secondary Energy Charge for the Rate Period in cents kW.h.

The Secondary Energy Charge derived in Step D for any Rate period shall be applied to all Secondary Energy kW.h consumed in each month during that Rate Period.

The Oil Price Index for each Rate Period shall equal the lowest of the three most recently reported Retail Heating Fuel Price values for Furnace Oil in Whitehorse (as collected bi-weekly and reported by the Yukon Bureau of Statistics) prior to the 20th day of the mid-month in the prior Rate Period (e.g., for the Rate Period starting January 1, 2005, the three latest prices published prior to November 20, 2004).

In accordance with the above procedure, the Secondary Energy Charge for the three month Rate Period starting January 1, 2005 is 5.5 cents per kW.h.

**INTERRUPTIONS:**

Customers have two options with regards to interruption:

(1) Customers can opt for installing a SCADA-controlled service that allows Yukon Energy to initiate interruptions on 15 minutes notice, as and when required only for actual real-time diesel generation being required on the respective system or for system emergencies or outages, or

(2) Customers can have a standard metered service. Under this option, the customers' supply will be interrupted after 24 hours notice at any time that Yukon Energy forecasts a need to run diesel units for more than 10 of the hours in the subsequent seven day period, or that Yukon Energy begins running diesels for unforecast reasons and expects the diesel operation to continue for more than 48 hours.

**INSTALLATION COST:**

The customer is responsible for any cost of installing the separate service, metering and any SCADA load control apparatus that is in excess of the relevant Utility Investment provision in the Electrical Service Regulations. The customer is also responsible for any costs of upgrading or advancing distribution system capacity improvements necessitated by their Secondary Energy load.

**ELECTRIC SERVICE REGULATIONS:**

The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.

*Effective:* *2005 01 01*
Supercedes: N A


# RATE SCHEDULE - 43

# WHOLESALE SECONDARY

**AVAILABLE:**

Wholesale secondary energy is available to YECL from time to time in parts of the WAF and Mayo systems as determined by Yukon Energy based on the availability of surplus hydro. Wholesale secondary energy is fully interruptible.

**APPLICABLE:**

To The Yukon Electrical Company Limited for facilitating secondary retail sales to YECL's customers under Rate Schedule 32. The monthly quantity of Rate Schedule 43 energy shall be equal to the kW.h quantity of Rate Schedule 32 Secondary Energy sales made by YECL to qualified customers each month.

**RATE:**

Energy Charge

The energy charge shall be equal to the energy charge per kW.h applicable under Rate Schedule 32, less 1.1 kW.h.

**ELECTRIC SERVICE REGULATIONS:**

The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.

**CW-YECL-14**

**Issue:** Forecast Process

**Reference:** Section 2, Schedule 2.1, line 4

**Preamble:** Forecast of Residential UPC

**Request:**

(a) Please confirm that the actual residential UPC for 2007 is 9.8244 MWh per customer. If not confirmed please specify.

(b) Please provide the calculation for the actual residential UPC for 2007.

(c) Please confirm that the forecast residential UPC for 2008 is 9.7661 MWh and for 2009 is 9.7645 MWh per customer. If not confirmed, please specify.

(d) Please provide the calculation for the forecast residential UPC values for 2008 and 2009.

(e) Please explain and quantify the factors that YECL took into consideration when forecasting a reduction in residential UPC of 0.6 over the two year period from 2007 to 2009.

**Response:**

(a) Confirmed.

(b) Please refer to (d) below for a summary of the 2007 UPCs by community. The overall UPC is as follows:

2007 Residential UPC Calculation

| | |
|---|---|
| Sales in MWh | 122,334 |
| divided by: Customers | 12,452 |
| MWh Sales per customer | 9.8244 |

(c) Confirmed on a Company wide basis. As noted on page 2-2 of the Application, residential UPC was determined by community.

(d) The forecast for residential UPC was determined on a community by community basis using a three year average UPC. The Whitehorse-Aishihik-Faro (WAF) and Watson Lake area communities' historical UPC was weather normalized prior to determining the three year average UPC. Please refer to the table below for the historical annual UPC and the forecast UPC, by community, for the test period.

**Residential UPC (kWh)**

| | 2005 | 2006 | 2007 | Avg (05-07) Forecast 2008 2009 |
|---|---|---|---|---|
| **Carmacks** | 10,492 | 10,371 | 10,648 | 10,504 |
| **Carcross** | 7,010 | 7,215 | 6,988 | 7,071 |
| **Haines Junction** | 7,888 | 7,742 | 8,089 | 7,906 |
| **Teslin** | 6,652 | 6,694 | 6,974 | 6,773 |
| **Whitehorse** | 10,585 | 10,515 | 10,472 | 10,524 |
| **Ross River** | 7,650 | 7,566 | 7,446 | 7,554 |
| **Tagish** | 4,163 | 4,508 | 4,759 | 4,477 |
| **Marsh Lake** | 7,406 | 7,675 | 7,816 | 7,632 |
| **Deep Creek** | 5,450 | 5,278 | 5,526 | 5,418 |
| **Takhini River** | 6,839 | 5,650 | 6,430 | 6,306 |
| **Keno** | 2,085 | 2,816 | 2,922 | 2,608 |
| **Stewart Crossing** | 9,271 | 10,229 | 9,270 | 9,590 |
| **Beaver Creek** | 8,333 | 8,750 | 8,987 | 8,690 |
| **Destruction Bay** | 5,565 | 6,288 | 6,557 | 6,136 |
| **Pelly Crossing** | 9,135 | 9,127 | 9,250 | 9,171 |
| **Swift River** | 12,900 | 14,923 | 14,714 | 14,179 |
| **Lower Post BC** | 7,551 | 8,632 | 9,132 | 8,438 |
| **Upper Liard** | 7,535 | 7,879 | 7,590 | 7,668 |
| **Watson Lake** | 8,801 | 8,933 | 8,869 | 8,868 |
| **Old Crow** | 7,241 | 7,152 | 6,992 | 7,128 |

Weather Normalized UPC. Details provided in Section 2 of Application, Attachments 1-26

The MWh sales per customer shown in the Schedule 2.1 is a division of total Sales in MWh by Customers (average during year).

2008 Residential UPC Calculation

| | |
|---|---|
| Sales in MWh | 123,961 |
| divided by: Customers | 12,693 |
| MWh Sales per customer | 9.7661 |

2009 Residential UPC Calculation

| | |
|---|---|
| Sales in MWh | 125,337 |
| divided by: Customers | 12,836 |
| MWh Sales per customer | 9.7645 |

(e) The 0.6 decrease in the average UPC between actual 2007 UPC and forecast 2009 UPC is the result of the forecast methodology used by Yukon Electrical. As detailed on page 2-2 of the Application, the average residential UPC for the test period was determined by taking a three year average of the monthly UPC, by community. UPC was also normalized for Whitehorse and Watson Lake area communities using a Normal temperature which is defined as a 20 year (1988-2007) average Heating Degree Days (HDD) for Whitehorse and a 12 year (1996-2007) average for Watson Lake. As detailed in Section 2 Attachment 27 of the Application (Watson Lake historical HDD) and Attachment 28 (Whitehorse HDD), 2007 was colder than the 12-year and 20-year Normals respectively. The use of normal temperature in the forecast methodology is the major factor resulting in the small decrease in UPC for the test period as compared to actual 2007 UPC.

**CW-YECL-15**

**Issue:** Forecast Process

**Reference:** Section 2, Schedule 2.1, line 10

**Preamble:** Forecast of Commercial UPC

**Request:**

(a) Please provide the calculation for the actual commercial UPC for 2007 of 55.0 MWh.

(b) Please confirm that the forecast commercial UPC for 2008 is 54.5860 MWh and for 2009 is 54.2275 MWh per customer. If not confirmed, please specify.

(c) Please provide the calculation for the forecast commercial UPC values for 2008 and 2009.

(d) Please explain and quantify the factors that YECL took into consideration when forecasting a reduction in commercial UPC of 1.4 over the two year period from 2007 to 2009.

**Response:**

(a) Please refer to Schedule 2.1, in Excel format, included with the application, for the calculation of the actual commercial UPC for 2007. It is a division of Sales in MWh by Customers (average during year)

2007 Commercial UPC Calculation

| | |
|---|---|
| Sales in MWh | 141,351 |
| divided by: Customers | 2,570 |
| MWh Sales per customer | 55.0 |

(b) Confirmed.

(c) The forecast for commercial UPC was determined on a community by community basis using a historical 3-year average UPC. Please refer to the table below for the historical annual UPC and the forecast UPC, by community, for the test period.

**Commercial UPC (kWh)**

| Community | 2005 | 2006 | 2007 | Avg (05-07) Forecast 2008 2009 |
|---|---|---|---|---|
| **Carmacks** | 26,303 | 27,826 | 32,984 | 29,038 |
| **Carcross** | 18,756 | 19,764 | 21,325 | 19,948 |
| **Haines Junction** | 25,456 | 25,692 | 25,901 | 25,683 |
| **Teslin** | 22,415 | 25,874 | 27,755 | 25,348 |
| **Ross River** | 25,305 | 25,239 | 24,791 | 25,111 |
| **Tagish** | 10,134 | 10,269 | 11,042 | 10,482 |
| **Whitehorse** | 65,434 | 67,414 | 68,246 | 67,572 |
| **Marsh Lake** | 8,746 | 9,887 | 11,026 | 9,886 |
| **Deep Creek** | 21,450 | 17,887 | 22,071 | 20,469 |
| **Takhini River** | 7,370 | 10,779 | 11,334 | 9,828 |
| **Keno** | 12,442 | 13,428 | 13,887 | 13,252 |
| **Stewart Crossing** | 19,961 | 23,423 | 21,089 | 21,491 |
| **Beaver Creek** | 25,715 | 25,604 | 25,557 | 25,625 |
| **Destruction Bay** | 16,720 | 18,161 | 18,394 | 17,758 |
| **Pelly Crossing** | 28,994 | 28,917 | 29,935 | 29,282 |
| **Swift River** | 15,224 | 15,296 | 16,019 | 15,513 |
| **Lower Post BC** | 17,897 | 20,897 | 16,494 | 18,429 |
| **Upper Liard** | 15,693 | 15,606 | 15,283 | 15,528 |
| **Watson Lake** | 37,800 | 36,957 | 37,092 | 37,283 |
| **Old Crow** | 21,924 | 21,774 | 21,187 | 21,629 |

As stated in Section 2 of the application, the Whitehorse commercial UPC forecast was based on the 2007 normalized UPC, reduced for load specifically attributable to the Canada Winter Games. Please refer to Section 2 Attachments 29 and 30 of the Application for the detailed calculations.

New commercial customers were forecast individually. Detailed information on the new customers cannot be provided due to customer confidentiality.

The MWh sales per customer shown in the Schedule 2.1 is a division of total Sales in MWh by Customers (average during year).

2008 Commercial UPC Calculation

| | |
|---|---|
| Sales in MWh | 141,869 |
| divided by: Customers | 2,599 |
| MWh Sales per customer | 54.5860 |

2009 Commercial UPC Calculation

| | |
|---|---|
| Sales in MWh | 142,564 |
| divided by: Customers | 2,629 |
| MWh Sales per customer | 54.2275 |

(d) There are three reasons for the reduction of 1.4 in commercial UPC between 2007 and 2009.

- New 2008 and 2009 commercial customer additions were forecast individually. There were several new commercial customers forecast to have a lower than the 2007 annual average UPC of 55.0 GWh. These new smaller customers will bring the overall average down. Please refer to YEC-YECL-2(j) for further information regarding new commercial customers.

- The Whitehorse forecast was based on the 2007 weather normalized UPC adjusted for the removal of one time load specifically attributable to the Canada Winter Games. These adjustments resulted in a reduction of the Whitehorse normalized commercial average UPC from 68,054 kWh customer in 2007 to 67,572 kWh customer in 2008 2009.

- The three-year average historical UPC, used as a forecast for 2008 and 2009 for existing customers (with the exception of Whitehorse), is lower than the 2007 actual UPC. Please refer to (c) above for the UPC by community.

**CW-YECL-16**

**Issue:** Forecast Process

**Reference:** Section 2, Schedule 2.1, line 45

**Preamble:** Forecast total revenues

**Request:**

(a) Please provide the calculation and rationale for the forecast total revenues of 45, 850,000 for 2008 and 47,075,000 for 2009.

**Response:**

(a) Please refer Schedule 1.1 for the Utility Revenue Requirement.

**CW-YECL-17**

**Issue:** Forecast Process

**Reference:** Section 2, page 1 of 3 of Attachments 1, 3, 5, 7, 9, 11, 13, 15, 17, 19, 21, 23, 25

**Preamble:** YECL provides the actual and normalized residential UPC for the years 1994 to 2007.

**Request:**

(a) Please provide the normalized sales per residential customer for 2008 and 2009 for the attachments referenced above.

**Response:**

(a) Please refer to CW-YECL-14(d).

**CW-YECL-18**

**Issue:** Forecast Process

**Reference:** Section 2, Page 2-2

**Preamble:** CW wishes to better understand the purpose of the regression analyses included in the application

**Request:**

(a) Please confirm that regression analyses were not used to determine average UPC for residential or commercial customers by community.

(b) If a) is not confirmed, please explain where regression analysis is used?

(c) If a) is confirmed, please explain why regression analysis is not used and also explain the purpose of the regression analyses summary outputs shown in Attachments 2, 4, 6, 8, 10, 12, 14, 16, 18, 20, 22, 24, 26 and 30 of Section 2.

**Response:**

(a&b) Not confirmed. Yukon Electrical detailed its forecast process on page 2-2 of the Application. Regressions were used to determine Whitehorse-Aishihik-Faro (WAF) and Watson Lake area communities' Residential weather normalized UPC forecast and Whitehorse's Commercial weather normalized UPC forecast.

(c) As indicated in (a), regression analysis was used. Please refer to YUB-YECL-4 Attachments 1-30 for the regression calculations in Excel format. Regressions were used to determine the quantifiable relationship between average UPC and HDD (Heating Degree Days). Once the HDD Coefficient was determined, the monthly historical UPC was weather normalized using this formula:

Normal UPC Actual UPC ( Normal HDD-ActualHDD) HDD Coeff

Normal HDD is defined as a 20 year (1988-2007) average HDD for Whitehorse and a 12 year (1996-2007) average HDD for Watson Lake). Please refer to Section 2 Attachments 27 and 28 of the Application for historical HDD.

This analysis was done for every community for which there is an attachment for. Yukon Electrical has provided the regression summary outputs to allow interested parties to understand how the results are derived.

**CW-YECL-19**

**Topic:** Revenues

**Reference:** Table 2, Page 2-5 and Schedule 2.1

**Preamble:** CW would like to review the revenues on existing rates.

**Request:**

Please provide the billing determinants in support of the revenues on existing and proposed rates as shown in Schedule 2.1.

**Response:**

Please refer to CW-YECL-19 Attachment 1 for billing determinants in support of revenues on existing rates. Billing determinants in support of revenues on proposed rates will be prepared with the Phase II filing.

# RESIDENTIAL AND COMMERCIAL RATES

(Applies to both 2008 and 2009 Revenue on Existing Rates)

| Existing Rates | Customer Charge | Energy Charge Block 1 | Energy Charge Block 2 | Demand Charge |
|---|---|---|---|---|
| 1160 - Res-Hydro Non-Govt | 11.90 | 0.0986 | 0.1045 | 0 |
| 1180 - Res-Hydro Govt | 15.00 | 0.1434 | 0.1045 | 0 |
| 1260 - Res-Small Diesel Non-Govt | 11.90 | 0.0986 | 0.1236 | 0 |
| 1280 - Res-Small Diesel Govt | 15.00 | 0.1434 | 0.1236 | 0 |
| 1360 - Res-Large Diesel Non-Govt | 11.90 | 0.0986 | 0.1045 | 0 |
| 1380 - Res-Large Diesel Govt | 15.00 | 0.1434 | 0.1045 | 0 |
| 1460 - Res-Old Crow Diesel Non-Govt | 11.90 | 0.0986 | 0.2577 | 0 |
| 1480 - Res-Old Crow Diesel Govt | 15.00 | 0.1434 | 0.2577 | 0 |
| 2160 - Com-Hydro Non-Govt | 0 | 0.0831 | 0.1045 | 6.00 |
| 2170 - Com-Hydro Govt-Muni | 0 | 0.0831 | 0.1045 | 6.00 |
| 2180 - Com-Hydro Govt-Fed | 0 | 0.1745 | 0.1045 | 10.00 |
| 2260 - Com-Small Diesel Non-govt | 0 | 0.0831 | 0.1236 | 6.00 |
| 2280 - Com-Small Diesel Govt-Fed | 0 | 0.1745 | 0.1236 | 10.00 |
| 2360 - Com-Large Diesel Non-Govt | 0 | 0.0831 | 0.1045 | 6.00 |
| 2370 - Com-Large Diesel Govt-Muni | 0 | 0.0831 | 0.1045 | 6.00 |
| 2380 - Com-Large Diesel Govt-Federal | 0 | 0.1745 | 0.1045 | 10.00 |
| 2460 - Com-Old Crow Diesel Non-Govt | 0 | 0.0831 | 0.2577 | 6.00 |
| 2480 - Com-Old Crow Diesel Govt-Fed | 0 | 0.1745 | 0.2577 | 10.00 |

# RESIDENTIAL AND COMMERCIAL 2008 BILLING DETERMINANTS
# REVENUE ON EXISTING RATES

| 2008 Billing Determinants | Cust Billed in the Year | kWh Energy Block 1 | kWh Energy Block 2 | kWh Energy Total Sales | kW Total Demand |
|---|---|---|---|---|---|
| 1160 - Res-Hydro Non-Govt | 136,580 | 90,265,953 | 22,994,200 | 113,260,153 | |
| 1180 - Res-Hydro Govt | 1,804 | 909,897 | 312,671 | 1,222,568 | |
| 1260 - Res-Small Diesel Non-Govt | 3,494 | 1,780,073 | 283,963 | 2,064,036 | |
| 1280 - Res-Small Diesel Govt | 312 | 216,526 | 51,155 | 267,681 | |
| 1360 - Res-Large Diesel Non-Govt | 8,179 | 5,188,282 | 799,535 | 5,987,817 | |
| 1380 - Res-Large Diesel Govt | 338 | 181,857 | 24,786 | 206,643 | |
| 1460 - Res-Old Crow Diesel Non-Govt | 1,474 | 731,702 | 105,431 | 837,133 | |
| 1480 - Res-Old Crow Diesel Govt | 138 | 77,946 | 37,386 | 115,332 | |
| 2160 - Com-Hydro Non-Govt | 20620 | 24,180,351 | 53,214,080 | 77,394,431 | 325,936 |
| 2170 - Com-Hydro Govt-Muni | 1967 | 1,953,533 | 12,060,872 | 14,014,405 | 51,363 |
| 2180 - Com-Hydro Govt-Fed | 4007 | 4,461,407 | 35,109,821 | 39,571,228 | 124,461 |
| 2260 - Com-Small Diesel Non-govt | 1070 | 1,040,122 | 1,004,190 | 2,044,311 | 9,162 |
| 2280 - Com-Small Diesel Govt-Fed | 612 | 520,069 | 440,926 | 960,995 | 5,082 |
| 2360 - Com-Large Diesel Non-Govt | 1845 | 1,788,282 | 2,244,429 | 4,032,712 | 17,967 |
| 2370 - Com-Large Diesel Govt-Muni | 209 | 246,461 | 797,324 | 1,043,786 | 4,569 |
| 2380 - Com-Large Diesel Govt-Federal | 430 | 515,668 | 1,512,085 | 2,027,753 | 8,150 |
| 2460 - Com-Old Crow Diesel Non-Govt | 192 | 174,519 | 183,808 | 358,327 | 1,524 |
| 2480 - Com-Old Crow Diesel Govt-Fed | 240 | 216,601 | 204,931 | 421,532 | 2,478 |
| **Total** | 183,511 | 134,449,249 | 131,381,595 | 265,830,843 | 550,691 |

| 2008 Revenue on Existing Rates | Customer Revenue | Energy Revenue Block 1 | Energy Revenue Block 2 | Total Energy Revenue | Demand Charge |
|---|---|---|---|---|---|
| 1160 - Res-Hydro Non-Govt | 1,625,302 | 8,900,223 | 2,402,894 | 11,303,117 | 0 |
| 1180 - Res-Hydro Govt | 27,060 | 130,479 | 32,674 | 163,153 | 0 |
| 1260 - Res-Small Diesel Non-Govt | 41,579 | 175,515 | 35,098 | 210,613 | 0 |
| 1280 - Res-Small Diesel Govt | 4,680 | 31,050 | 6,323 | 37,373 | 0 |
| 1360 - Res-Large Diesel Non-Govt | 97,330 | 511,565 | 83,551 | 595,116 | 0 |
| 1380 - Res-Large Diesel Govt | 5,070 | 26,078 | 2,590 | 28,668 | 0 |
| 1460 - Res-Old Crow Diesel Non-Govt | 17,541 | 72,146 | 27,170 | 99,315 | 0 |
| 1480 - Res-Old Crow Diesel Govt | 2,070 | 11,177 | 9,634 | 20,812 | 0 |
| 2160 - Com-Hydro Non-Govt | 0 | 2,009,387 | 5,560,871 | 7,570,259 | 1,955,618 |
| 2170 - Com-Hydro Govt-Muni | 0 | 162,339 | 1,260,361 | 1,422,700 | 308,178 |
| 2180 - Com-Hydro Govt-Fed | 0 | 778,515 | 3,668,976 | 4,447,492 | 1,244,605 |
| 2260 - Com-Small Diesel Non-govt | 0 | 86,434 | 124,118 | 210,552 | 54,972 |
| 2280 - Com-Small Diesel Govt-Fed | 0 | 90,752 | 54,498 | 145,250 | 50,816 |
| 2360 - Com-Large Diesel Non-Govt | 0 | 148,606 | 234,543 | 383,149 | 107,802 |
| 2370 - Com-Large Diesel Govt-Muni | 0 | 20,481 | 83,320 | 103,801 | 27,412 |
| 2380 - Com-Large Diesel Govt-Federal | 0 | 89,984 | 158,013 | 247,997 | 81,498 |
| 2460 - Com-Old Crow Diesel Non-Govt | 0 | 14,503 | 47,367 | 61,870 | 9,144 |
| 2480 - Com-Old Crow Diesel Govt-Fed | 0 | 37,797 | 52,811 | 90,608 | 24,777 |
| Total | 1,820,631 | 13,297,031 | 13,844,814 | 27,141,845 | 3,864,823 |

# RESIDENTIAL AND COMMERCIAL 2009 BILLING DETERMINANTS
# REVENUE ON EXISTING RATES

| 2009 Billing Determinants | Cust Billed in the Year | kWh Energy Block 1 | kWh Energy Block 2 | kWh Energy Total Sales | kW Total Demand |
|---|---|---|---|---|---|
| 1160 - Res-Hydro Non-Govt | 137,986 | 92,082,779 | 23,457,016 | 115,539,795 | |
| 1180 - Res-Hydro Govt | 1,849 | 970,108 | 333,361 | 1,303,469 | |
| 1260 - Res-Small Diesel Non-Govt | 3,691 | 943,997 | 150,590 | 1,094,587 | |
| 1280 - Res-Small Diesel Govt | 312 | 168,807 | 39,881 | 208,689 | |
| 1360 - Res-Large Diesel Non-Govt | 8,211 | 5,205,683 | 802,217 | 6,007,900 | |
| 1380 - Res-Large Diesel Govt | 337 | 182,711 | 24,902 | 207,613 | |
| 1460 - Res-Old Crow Diesel Non-Govt | 1,503 | 748,988 | 107,922 | 856,910 | |
| 1480 - Res-Old Crow Diesel Govt | 144 | 79,822 | 38,286 | 118,107 | |
| 2160 - Com-Hydro Non-Govt | 20847 | 24,303,514 | 53,485,128 | 77,788,642 | 329,451 |
| 2170 - Com-Hydro Govt-Muni | 1979 | 1,972,971 | 12,180,881 | 14,153,852 | 51,874 |
| 2180 - Com-Hydro Govt-Fed | 4048 | 4,538,467 | 35,716,258 | 40,254,725 | 126,688 |
| 2260 - Com-Small Diesel Non-govt | 1099 | 815,333 | 787,167 | 1,602,501 | 7,182 |
| 2280 - Com-Small Diesel Govt-Fed | 612 | 399,289 | 338,526 | 737,814 | 3,901 |
| 2360 - Com-Large Diesel Non-Govt | 1881 | 1,822,759 | 2,287,700 | 4,110,459 | 18,313 |
| 2370 - Com-Large Diesel Govt-Muni | 219 | 251,772 | 814,505 | 1,066,278 | 4,667 |
| 2380 - Com-Large Diesel Govt-Federal | 430 | 526,356 | 1,543,425 | 2,069,781 | 8,319 |
| 2460 - Com-Old Crow Diesel Non-Govt | 192 | 174,519 | 183,808 | 358,327 | 1,524 |
| 2480 - Com-Old Crow Diesel Govt-Fed | 240 | 216,601 | 204,931 | 421,532 | 2,478 |
| **Total** | 185,580 | 135,404,477 | 132,496,504 | 267,900,981 | 554,398 |

| 2009 Revenue on Existing Rates | Customer Revenue | Energy Revenue Block 1 | Energy Revenue Block 2 | Total Energy Revenue | Demand Charge |
|---|---|---|---|---|---|
| 1160 - Res-Hydro Non-Govt | 1,642,033 | 9,079,362 | 2,451,258 | 11,530,620 | 0 |
| 1180 - Res-Hydro Govt | 27,735 | 139,114 | 34,836 | 173,950 | 0 |
| 1260 - Res-Small Diesel Non-Govt | 43,923 | 93,078 | 18,613 | 111,691 | 0 |
| 1280 - Res-Small Diesel Govt | 4,680 | 24,207 | 4,929 | 29,136 | 0 |
| 1360 - Res-Large Diesel Non-Govt | 97,711 | 513,280 | 83,832 | 597,112 | 0 |
| 1380 - Res-Large Diesel Govt | 5,055 | 26,201 | 2,602 | 28,803 | 0 |
| 1460 - Res-Old Crow Diesel Non-Govt | 17,886 | 73,850 | 27,811 | 101,662 | 0 |
| 1480 - Res-Old Crow Diesel Govt | 2,160 | 11,446 | 9,866 | 21,313 | 0 |
| 2160 - Com-Hydro Non-Govt | 0 | 2,019,622 | 5,589,196 | 7,608,818 | 1,976,707 |
| 2170 - Com-Hydro Govt-Muni | 0 | 163,954 | 1,272,902 | 1,436,856 | 311,244 |
| 2180 - Com-Hydro Govt-Fed | 0 | 791,962 | 3,732,349 | 4,524,311 | 1,266,882 |
| 2260 - Com-Small Diesel Non-govt | 0 | 67,754 | 97,294 | 165,048 | 43,092 |
| 2280 - Com-Small Diesel Govt-Fed | 0 | 69,676 | 41,842 | 111,518 | 39,015 |
| 2360 - Com-Large Diesel Non-Govt | 0 | 151,471 | 239,065 | 390,536 | 109,880 |
| 2370 - Com-Large Diesel Govt-Muni | 0 | 20,922 | 85,116 | 106,038 | 28,002 |
| 2380 - Com-Large Diesel Govt-Federal | 0 | 91,849 | 161,288 | 253,137 | 83,187 |
| 2460 - Com-Old Crow Diesel Non-Govt | 0 | 14,503 | 47,367 | 61,870 | 9,144 |
| 2480 - Com-Old Crow Diesel Govt-Fed | 0 | 37,797 | 52,811 | 90,608 | 24,777 |
| Total | 1,841,183 | 13,390,049 | 13,952,977 | 27,343,026 | 3,891,930 |

# LIGHTING 2008 and 2009 BILLING DETERMINANTS
# REVENUE ON EXISTING RATES

| Street Lights Rates | Mthly Charge | Cust Billed in 2008 | Cust Billed in 2009 | Street Light Revenue 2008 | Street Light Revenue 2009 |
|---|---|---|---|---|---|
| 6110 | 13.41 | 0 | 0 | 0.00 | 0.00 |
| 6120 | 16.44 | 288 | 288 | 4,734.72 | 4,734.72 |
| 6130 | 22.48 | 528 | 528 | 11,869.44 | 11,869.44 |
| 6140 | 10.39 | 36,824 | 37,008 | 382,601.36 | 384,513.12 |
| 6180 | 16.44 | 12,504 | 13,164 | 205,565.76 | 216,416.16 |
| 6190 | 22.48 | 252 | 252 | 5,664.96 | 5,664.96 |
| 6360 | 12.41 | 3,674 | 3,696 | 45,594.34 | 45,867.36 |
| 6580 | 17.47 | 1,265 | 1,284 | 22,099.55 | 22,431.48 |
| 6590 | 23.51 | 636 | 636 | 14,952.36 | 14,952.36 |
| 6640 | 9.18 | 1,044 | 1,044 | 9,583.92 | 9,583.92 |
| 6720 | 15.47 | 384 | 384 | 5,940.48 | 5,940.48 |
| 6780 | 15.47 | 180 | 180 | 2,784.60 | 2,784.60 |
| 6790 | 23.66 | 180 | 180 | 4,258.80 | 4,258.80 |
| Total | | 57,759 | 58,644 | 715,650 | 729,017 |

| Sentinel Lights Rates | Mthly Charge | Cust Billed in 2008 | Cust Billed in 2009 | Sentinel Light Revenue 2008 | Sentinel Light Revenue 2009 |
|---|---|---|---|---|---|
| 7100 | 14.18 | 1,824 | 1,800 | 25,864.32 | 25,524.00 |
| 7120 | 9.87 | 0 | 0 | 0.00 | 0.00 |
| 7130 | 7.97 | 204 | 204 | 1,625.88 | 1,625.88 |
| 7300 | 23.03 | 24 | 24 | 552.72 | 552.72 |
| 7400 | 25.44 | 1,032 | 1,020 | 26,259.20 | 25,948.80 |
| 7420 | 17.75 | 36 | 36 | 639.00 | 639.00 |
| 7430 | 10.26 | 36 | 36 | 369.36 | 369.36 |
| 7500 | 11.64 | 4,623 | 4,572 | 53,807.06 | 53,218.08 |
| 7520 | 6.46 | 3,696 | 3,672 | 23,876.81 | 23,721.12 |
| 7530 | 7.34 | 84 | 84 | 616.56 | 616.56 |
| Total | | 11,559 | 11,448 | 133,611 | 132,216 |

**CW-YECL-20**

**Topic:** Summary of Customers, Energy Sales and Revenues

**Reference:** Schedule 2.1

**Preamble:** CW would like to assess the actual number of customers and sales per customer over the period 2005-2007.

**Request:**

(a) Please expand Schedule 2.1 to include forecasts and actuals for 2005-2007.

(b) Please provide an explanation for variances from forecast for 2005, 2006 and 2007.

(c) Please provide the population of Whitehorse at year-end 2005, 2006 and 2007.

**Response:**

(a&b) Please refer to Schedule 2.1 included with the July 4, 2008 filing for actual sales for 2003 2007. As 2003 2007 were non-test years, no forecast is available.

(c) 2005 23,511
2006 24,151
2007 24,473

Source: YTG : Bureau of Statistics : - Yukon Monthly Statistical Review

**CW-YECL-21**

**Issue:** Purchased Power Expenses and Deferral Account

**Reference:** Pages 3-1 and 3-2 and Schedule 3.1

**Preamble:** CW wishes to better understand the determination of the cost of purchase power.

**Request:**

(a) Please provide the actual and forecast monthly billing determinants for purchased power expense for the years 2004-2009.

(b) Please provide Schedule 3.1 expanded per (a) above but separately for the WAF system and the Mayo-Dawson system.

(c) Please explain why Primary Purchase Power is forecast to increase for 2008 and 2009.

(d) Please provide a continuity schedule of all costs and charges associated with the Purchased Power Deferral Account for the period commencing January 1, 2003 through the present.

**Response:**

(a) As 2004-2007 were not test years, forecasted purchased power expense is not available. Please refer to Schedule 3.1 included with the July 4, 2008 updated filing schedules for the actual annual billing determinants for purchased power expense for the years 2004-2007 as well as the forecast for the test period.

(b) Forecast information is not provided as per (a) above. Please refer to CW-YECL-21(b) Attachment 1 for a revised Schedule 3.1 on an annual basis separated into WAF and MD where appropriate. Also enclosed to be helpful is the monthly breakdown of purchased power separated into WAF versus MD. Please refer to CW-YECL-21(b) Attachment 2.

(c) Primary Purchase Power is forecast to increase for 2008 and 2009 due to increases in the volume of purchases due to increased sales and reduced production at Fish Lake hydro due to shutdowns associated with refurbishments. Please refer to Schedule 3.1 line 2 in the Application.

(d) There have been no charges into or out of a purchased power deferral account as the Rider J mechanism has resulted in all changes to the wholesale power rate being immediately flowed through to customers.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Purchase Power**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 |
|---|---|---|---|---|---|---|---|
| 1 | **Purchases (MWh)** | | | | | | |
| 2 | Primary Energy | | 229,971 | 235,982 | 237,419 | 251,861 | 254,914 |
| | WAF | | - | - | 237,029 | 251,016 | 254,059 |
| | MD | | - | - | 390 | 845 | 855 |
| | | | | | 237,419 | 251,861 | 254,914 |
| 3 | Secondary Sales | | 13,039 | 15,998 | 18,363 | 21,555 | 23,566 |
| 4 | | S.3.2 L.10 | 243,010 | 251,980 | 255,782 | 273,416 | 278,480 |
| 5 | **Purchase Power Rates** | | | | | | |
| 6 | Primary Energy Charge ( per KWh) | | 0.0684 | 0.0684 | 0.0684 | 0.0684 | 0.0684 |
| 7 | Secondary Sales ( per KWh) | | 0.0220 | 0.0220 | 0.0412 | 0.0524 | 0.0507 |
| 8 | Shortfall Rider J | | 14.93 | 14.93 | 14.93 | 14.93 | 14.93 |
| 9 | **Purchase Power Expense ( 000s)** | | | | | | |
| 10 | Primary Energy Expense | L.2 x L.6 | 15,730 | 16,141 | 16,239 | 17,227 | 17,436 |
| | WAF | | | | 16,213 | 17,169 | 17,378 |
| | MD | | | | 27 | 58 | 58 |
| | | | | | 16,239 | 17,227 | 17,436 |
| 11 | Secondary Energy Expense | L.3 x L.7 | 287 | 352 | 756 | 1,130 | 1,194 |
| 12 | Shortfall Rider J | S.2.1 L.44 | 4,545 | 4,618 | 4,686 | 4,882 | 5,017 |
| 13 | Total Purchase Power Expense | S.1.1 L.7 | 20,562 | 21,111 | 21,681 | 57,694 | 58,519 |

**Schedule 3.1 Line 2**
**Breakdown of Primary Energy Purchases by Month**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | TOTAL | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2004 MD | 36 | 31 | 29 | 22 | 19 | 12 | 13 | 15 | 18 | 19 | 21 | 29 | 264 | |
| WAF | 25,466 | 19,527 | 23,302 | 17,771 | 17,095 | 16,592 | 16,024 | 17,060 | 17,950 | 18,348 | 22,413 | 24,169 | 235,718 | |
| | 25,502 | 19,558 | 23,331 | 17,793 | 17,114 | 16,604 | 16,036 | 17,075 | 17,969 | 18,367 | 22,434 | 24,198 | 235,982 | S 3.1 Line 2 |
| 2005 MD | 33 | 30 | 26 | 23 | 14 | 10 | 11 | 15 | 17 | 38 | 80 | 93 | 390 | |
| WAF | 26,230 | 21,515 | 20,619 | 17,498 | 17,818 | 16,452 | 17,281 | 16,358 | 17,640 | 20,323 | 21,743 | 23,549 | 237,028 | |
| | 26,263 | 21,545 | 20,646 | 17,522 | 17,832 | 16,463 | 17,292 | 16,373 | 17,657 | 20,361 | 21,823 | 23,642 | 237,419 | S 3.1 Line 2 |
| 2006 MD | 100 | 83 | 92 | 63 | 56 | 40 | 46 | 46 | 50 | 69 | 109 | 100 | 854 | |
| WAF | 26,359 | 21,188 | 23,851 | 19,818 | 17,844 | 17,017 | 16,799 | 17,544 | 19,010 | 19,317 | 26,921 | 25,340 | 251,007 | |
| | 26,459 | 21,271 | 23,943 | 19,880 | 17,900 | 17,057 | 16,845 | 17,589 | 19,060 | 19,386 | 27,030 | 25,440 | 251,861 | S 3.1 Line 2 |
| 2007 MD | 98 | 97 | 99 | 76 | 61 | 46 | 52 | 54 | 52 | 60 | 71 | 87 | 855 | |
| WAF | 25,517 | 24,331 | 24,450 | 20,328 | 18,304 | 16,680 | 17,685 | 17,524 | 19,105 | 20,278 | 22,383 | 27,473 | 254,059 | |
| | 25,616 | 24,427 | 24,550 | 20,404 | 18,365 | 16,726 | 17,738 | 17,578 | 19,157 | 20,339 | 22,454 | 27,560 | 254,914 | S 3.1 Line 2 |
| 2008 MD | 118 | 83 | 105 | 78 | 58 | 51 | 47 | 51 | 61 | 57 | 76 | 85 | 869 | |
| WAF | 26,867 | 23,821 | 24,318 | 20,666 | 19,151 | 18,005 | 18,572 | 18,188 | 18,864 | 20,314 | 23,639 | 26,818 | 259,224 | |
| | 26,985 | 23,904 | 24,422 | 20,744 | 19,209 | 18,056 | 18,619 | 18,239 | 18,925 | 20,371 | 23,715 | 26,903 | 260,093 | S 3.1 Line 2 |
| 2009 MD | 118 | 85 | 105 | 78 | 58 | 51 | 47 | 51 | 61 | 57 | 76 | 85 | 872 | |
| WAF | 27,192 | 24,122 | 24,611 | 20,933 | 19,375 | 18,211 | 18,788 | 18,374 | 19,102 | 20,556 | 23,909 | 27,156 | 262,330 | |
| | 27,310 | 24,207 | 24,716 | 21,011 | 19,434 | 18,262 | 18,835 | 18,425 | 19,163 | 20,613 | 23,985 | 27,241 | 263,202 | S 3.1 Line 2 |

**CW-YECL-22**

**Issue:** Line Losses

**Reference:** Schedule 3.2

**Preamble:** CW wishes to better understand the calculation of the line losses

**Request:**

(a) Please explain how the level of line losses will affect customers' bills.

(b) Please provide the Schedule 3.2 information separately for the WAF system and the Mayo-Dawson system.

(c) For Schedule 3.2 and the schedules requested in a), please provide the breakdown between Losses and Company Used currently aggregated in line 3.

(d) Please define Company Used.

(e) Please explain why the company used portion is considered to be a loss rather than a charge to the company.

**Response:**

(a) For a given amount of sales, if line losses are lower than in the past, a lower amount of purchased power or generation will be required. This will result in a lower revenue requirement and a lower overall customer bill. The converse is true for a given amount of sales if line losses are higher than in the past.

(b) For a breakout of Schedule 3.2 please refer to YEC-YECL-04(a) Attachment 1. A breakout of Mayo-Dawson specifically has not been provided. The Mayo-Dawson system is a very small percentage of overall sales as the following table of billed sales for 2006 and 2007 shows. It was even smaller prior to 2006 as Stewart did not migrate off diesel until October 2005.

MD MAYO-DAWSON hydro grid.

| % of Billed KwHs | | | Year | |
|---|---|---|---|---|
| Rate Zone | Grid | Community | 2006 | 2007 |
| Hydro | MD | Keno City | 0.10% | 0.10% |
| | | Stewart Crossing | 0.15% | 0.16% |
| | MD Total | | 0.25% | 0.25% |
| | WAF | Carcross | 0.91% | 0.91% |
| | | Carmacks | 1.46% | 1.59% |
| | | Deep Creek | 0.08% | 0.08% |
| | | Haines Junction | 2.10% | 2.12% |
| | | Marsh Lake | 1.22% | 1.22% |
| | | Ross River | 0.88% | 0.84% |
| | | Tagish | 0.59% | 0.61% |
| | | Takhini River Acres | 0.08% | 0.08% |
| | | Teslin | 1.24% | 1.28% |
| | | Upper Liard | 0.02% | 0.00% |
| | | Whitehorse | 83.91% | 83.96% |
| | | Wholesale to YEC | 0.18% | 0.17% |
| | WAF Total | | 92.68% | 92.86% |
| Large | Diesel | Lower Post B.C. | 0.27% | 0.26% |
| | | Upper Liard | 0.28% | 0.27% |
| | | Watson Lake | 3.99% | 4.02% |
| | Diesel Total | | 4.54% | 4.55% |
| Small | Diesel | Beaver Creek | 0.64% | 0.42% |
| | | Destruction Bay | 0.49% | 0.53% |
| | | Pelly Crossing | 0.71% | 0.71% |
| | | Swift River | 0.09% | 0.09% |
| | Diesel Total | | 1.93% | 1.75% |
| Old Crow | Diesel | Old Crow | 0.61% | 0.59% |
| | Diesel Total | | 0.61% | 0.59% |
| Grand Total | | | 100.00% | 100.00% |

However to provide helpful information the following shows the line losses for 2006 and 2007 for the Mayo-Dawson grid:

**MAYO-DAWSON LOSSES (kWhs)**

| | Actual 2006 | Actual 2007 |
|---|---|---|
| Billed Sales | | |
| Keno City | 272,564 | 282,772 |
| Stewart Crossing | 436,783 | 456,055 |
| | 709,347 | 738,827 |
| Purchased power | | |
| Keno City | 289,950 | 261,300 |
| Stewart Crossing | 554,886 | 593,880 |
| | 844,836 | 855,180 |
| Losses (kWhs) | 135,489 | 116,353 |
| Loss Percentage | 16.0 | 13.6 |

(c) Yukon Electrical does not actively compile the company use electricity detailed in part (d). Yukon Electrical notes the quantum of electricity used for company use would be very small in relation to the overall line losses for the company.

(d) Company use electricity is electricity used for Yukon Electrical's downtown Whitehorse office and Service Complex, electricity used to operate distribution system devices and electricity used in the winter to keep the standby units heated when they are in standby mode.

(e) This approach is consistent with past Yukon regulatory practice and consistent with the concept of utility expenses forming part of the utility's revenue requirement.

**CW-YECL-23**

**Issue:** Rider F

**Reference:** Pages 4-1 to 4-3

**Preamble:** Prior to 2008, Yukon Electrical recovered the difference between the forecast 1997 fuel rates and the current fuel rate using Rider F

The variance between actual and forecast fuel prices, as outlined in Schedule 4.2 are refunded to or recovered from customers through a diesel fuel price rider (Rider F)

**Request:**

(a) Please confirm that prior to 2008 the Diesel Fuel Price Rider (Rider F) collected the difference between the forecast cost of diesel in a given year (calculated using 1997 fuel rates) and the actual cost of diesel in that given year; and that Rider F has now changed so that it will collect (or refund) the variance between the forecast cost of diesel (based on current forecasts for 2008 and 2009) and the actual cost of diesel for 2008 and 2009.

(b) If a) is not confirmed, please provide the appropriate explanation.

(c) Please confirm that Rider F has been incorporated into base rates as of 2008 (as per page 4-1, lines 5-6).

(d) If c) is not confirmed, please explain.

(e) Please provide the rationale for incorporating a deferral account into base rates. Are there unique aspects about Rider F that make it amenable to being incorporated into base rates? If so, please discuss.

(f) Please provide a continuity schedule for Rider F from January 1, 2003 to the present.

(g) Please provide the calculation of the forecast dollar values that would be collected in 2008 and 2009 by the deferral account proposed for Increased Fuel Costs Associated with Pelly Crossing (p.4-3). Are these amounts significant enough to warrant creating a deferral account? Please explain.

**Response:**

(a&b) Confirmed

(c&d) The forecast 2008 and 2009 revenue requirements are based on fuel rates as of January 2008. Through to December 31, 2007, Rider F was determined on the fuel rate variance (price variance) between 1997 fuel rates and actual fuel rates. From January 1, 2008 forward, Rider F will be determined based on the price variance between the final fuel rates approved by the Board as part of this Application and actual fuel rates. As noted above, the forecast base fuel rates used in determination of Rider F have been changed from 1997 to 2008 as of January 1, 2008. While this effectively means the fuel price variance between 1997 and 2008 has been incorporated into base rates as part of this Application, until such time as the Board approves new forecast fuel rates the net rate increase detailed on Schedule 2.1 line 48 backs out the impact of higher fuel costs recovered through Rider F. Once final fuel rates are approved by the Board effective January 1, 2008, Yukon Electrical will be in a position to complete a Rider F reconciliation that will account for the difference between the final approved forecast rates and actual rates.

(e) Please refer to (c) above. The Rider F deferral mechanism continues to be in place to address differences between the final approved forecast and actual 2008 2009 fuel rates.

(f) Please refer to the following schedule:

**Yukon Electrical**
**Continuity Schedule**
**Fuel Rider F 2003 to 2007**

| **( 000 s)** | **2003** | **2004** | **2005** | **2006** | **2007** |
|---|---|---|---|---|---|
| Rider F Opening Balance Receivable (Payable) | 187 | 230 | 106 | 629 | (32) |
| Rider F Fuel Variance | 906 | 1,254 | 2,389 | 2,860 | 3,172 |
| Rider F Collections from customers | (1,237) | (1,443) | (1,576) | (3,018) | (2,585) |
| Rider F Collections from Yukon Energy | - | (36) | (290) | (503) | (454) |
| Rider F Payments to Yukon Energy | 374 | 100 | - | - | - |
| Rider F Ending Balance Receivable (Payable) | 230 | 106 | 629 | (32) | 100 |

(g) Per Schedule 4.2 of the Application, Yukon Electrical generated 2,272,000 kWh of electricity and used 654,000 litres of fuel in Pelly Crossing in 2007. The average cost of this fuel was 85.48 cents per litre. Total actual 2007 fuel cost was 559,039 (654,000 .8548). If Pelly Crossing had been connected to the WAF grid in 2007, the purchased power cost would have been 155,405 (2,272,000 kWh 0.0684 cents per kWh). As can be seen with this simple illustration that just deals with fuel costs, there is a material difference in diesel production cost as compared to wholesale purchased power cost. As Yukon Electrical does not have control over when Yukon Energy will complete the interconnection of Pelly Crossing nor information on whether there will be any significant delays or advances from the assumed November 1, 2008 interconnection date, the requested use of a deferral account is reasonable.

**CW-YECL-24**

**Issue:** Required Employee Compensation and Benefits

**Reference:** Application page 5-2, lines 2-13

**Preamble:** YECL states: Over the past number of years, identifying, competing for, securing and retaining qualified personnel has become one of the most challenging and important ongoing activities of Yukon Electrical. Due to unprecedented demand for labour, due to western Canadian construction levels, as well as, pending work force retirements, skilled labour shortages have forced most employers, including utilities, to become very aggressive with respect to their compensation and quality of work life packages. In dealing with a tight south of 60 labour market, Yukon Electrical has had to respond to these competitive market forces and the reluctance of people to move to the north, when high paying jobs are available in the south, by developing and offering a compensation package that provides a fair compensation for the real and or perceived remoteness of the north, while at the same time building upon the inherent benefits of living in a smaller northern community.

**Request:**

(a) What steps has YECL taken to determine what compensation and quality of work life packages are necessary to stay competitive and attract a skilled labour force? If YECL has taken none or not consulted with personnel professionals, what evidence or studies does YECL possess that might indicate its compensation and benefits are not competitive? Please provide.

(b) Has YECL consulted with affiliates located south of 60 to determine what compensation packages are necessary for the affiliates to attract skilled labour and professionals? If yes, please provide the information provided by the affiliates. Have these affiliates provided compensation studies that have been placed on the public record before other Boards and Commissions? Please provide all studies that have been placed on the public record.

**Response:**

(a&b) Yukon Electric has done a number of things to determine what is required to attract and retain employees in the brisk labor market. In the past the Yukon was considered an attractive place for employees within the ATCO Group to move to and job postings were often met with several applications from qualified individuals. In the last two years or so Yukon Electric has faced several situations whereby there have been no applications for critical positions. When Yukon Electrical would talk to individuals in other jurisdictions about why they would not consider a position in the Yukon it was apparent that the compensation package being offered was no longer competitive. As a result Yukon Electrical was left with several vacancies in critical positions and it was putting a strain on the remaining resources. People were getting tired and burned out taking on additional responsibilities and some were talking of leaving the company. This was the compelling evidence that Yukon Electrical had that demanded an aggressive course of action.

One of the significant advantages that Yukon Electric has is its affiliation with the ATCO Group. Yukon Electric has access to a number of human resource professionals who provide expert advice to Yukon Electrical. Therefore Yukon Electric does not have to spend unnecessary dollars on studies as it is able to utilize the work that has been done in ATCO Electric. This is of great benefit to customers.

ATCO Electric identified that it also had difficulties in attracting and retaining trade positions especially in its northern communities. They implemented a Community Skills Premium in many of the northern communities. Because ATCO Electric is a major market for Yukon Electrical to hire trades people from Yukon Electric implemented a similar program. It was also a fact that based on recruiting efforts externally outside of ATCO that there was either a very limited or no response. It was only after the implementation of the Community Skills Premium and other benefits that vacancies began to be filled.

In addition to the above a salary study was done in preparation for the collective bargaining negotiations in the Northland companies in 2007. Yukon companies were surveyed and the results have shown that Yukon Electrical is behind in several wage range categories.

Yukon Electrical will be entering collective bargaining with it employees association this fall and will be updating its wage data. Due to the sensitive nature of negotiations Yukon Electric is hesitant to provide any data on the record at this time. However Yukon Electric will at a minimum be following the general settlement components provided by both ATCO Electric and Northland Utilities in order to remain competitive.

At the same time that the survey on salaries was being undertaken information was also being requested on what type of 'northern benefits' employers are providing to employees. Although some information was provided it was apparent through further discussions with participating companies that not all compensation was being disclosed because they saw the information as competitively sensitive. CW-YECL-24(a) Attachment 1 is an excerpt of the survey conducted by Sierra Systems on behalf of the company. Also attached is information provided in ATCO Electric's 2007-8 GTA: Towers Perrin Review (CW-YECL-24(a&b) Attachment 2), Compensation Planning Outlook (CW-YECL-24(a&b) Attachment 3). As well Yukon Electrical is filing an update to the Compensation Planning Outlook (CW-YECL-24(a&b) Attachment 4).

Below are some of the benefits that Yukon Electrical was told employers were offering but did not wish to include in the survey:

- Unlimited personal use of company vehicles including fuel
- Payment of travel flight to anywhere in the world once and in some cases twice per year.
- Bonuses for moving and contributions towards mortgages based on years of service.
- Profit sharing arrangements.
- Years of service bonuses

There were many creative ways that employers throughout the north compensate employees in an effort to attract and retain them. It is not easy to do an apples to apples comparison as employers see the information as competitively sensitive.

For Yukon Electric it makes sense that it follows the lead of ATCO Electric as it is the largest market where trades employees come from and transfer to.



The Yukon Electrical Company Limited
An ATCO Company

Northland Utilities (NWT) Limited
An ATCO Company

Northland Utilities (Yellowknife) Limited
An ATCO Company

# Yukon Electrical Company Limited Northland Utilities Limited

## 2007 Salary Survey

Participant Report

Sierra Systems

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## Appendices

**APPENDIX A. SURVEY JOB PROFILES**

**Confidentiality/Validity**

This document has been prepared by Sierra Systems for the sole purpose and exclusive use of Yukon Electrical Company Limited & Northland Utilities Limited. Due to the confidential nature of the material in this document, its contents should not be discussed with, or disclosed to, third parties without the prior written consent of Yukon Electrical Company Limited & Northland Utilities Limited.

# 1. SURVEY METHODOLOGY

In April 2007, Yukon Electric Company Limited (YECL) and Northland Utilities (NWT and Yellowknife) Limited initiated their 2007 Salary Survey. This year's Salary Survey requested base and variable pay data for 13 positions, as well as information relating to vacation, allowances, and other elements of what can be considered "employment conditions". Base pay data collected by the survey was effective April 1, 2007. A total of 10 organizations were contacted to request participation in the survey. All of these organizations provided survey responses representing a 100% response rate. In addition, data from YECL, Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited has been incorporated into the participant analysis. A final participant list appears on the following page.

Once survey data was submitted, all matches were entered into a spreadsheet for analysis purposes. To "clean" the data, each participant's submission was reviewed for inconsistencies, errors and/or omissions. As well, each survey benchmark was reviewed to ensure accurate and consistent matching. Where necessary, we contacted respondents by telephone or email to request additional information and/or to verify the accuracy of the data provided. The respondent's data submission was then updated, where appropriate.

Once all data was cleaned, a detailed statistical analysis was performed on each survey position.

On behalf of our clients, YECL and Northland Utilities (NWT and Yellowknife) Limited, we would like to thank you for your participation and cooperation in responding to our update and subsequent follow-up inquiries.

# 2. PARTICIPANT LIST

The following organizations were available to participate in the 2007 Salary Survey **(n=13):**

**There were 13 Northern companies who participated in the survey.**

# 3. SURVEY POSITIONS

The following benchmark positions were included in the 2007 Salary Survey. *Survey job profiles are included in Appendix A.*

| Survey Position |
|---|
| Clerk III |
| Customer Service Advisor - Qualified |
| Financial Assistant - Qualified |
| Engineering Assistant III |
| Serviceman Lineman Journeyman |
| Senior Serviceman Lead Lineman |
| Maintenance Technician |
| Lead Maintenance Technician |
| Labourer |
| Senior Warehouseman |
| Stockkeeper |
| Electrical Technologist - Qualified |
| Diesel Turbine Plant Operator |

# 4. FORM A EMPLOYMENT CONDITIONS

## General Overview

| | Total of Staff | Total Revenue (million) | Regulated | Union | Non-Union | Other |
|---|---|---|---|---|---|---|
| Average | 801 | 58 | 80 | 71 | 28 | 6 |
| Median | 167 | 41 | n a | 76 | 23.5 | 4 |
| n | 13 | 9 | 12 | 12 | 12 | 3 |

## Unionization

- **12 of 13 (92%)** of participating organizations are unionized employers, **1 of 13 (8%)** are non-unionized.

## Variable Pay

- **2 of 13 (15%)** of employers indicate they provide a variable pay programs for in-scope employees, **11 of 13 (85%)** have no variable pay programs. Of those providing variable pay, the respondents have indicated that variable pay programs are based on corporate goal achievement, while also factoring in business unit performance.

## Signing Bonus

- **0 of 13 (0%)** of employers provide a signing bonus or attraction bonus for in-scope positions.
- **3 of 13 (23%)** of employers provide a continuous service/ retention bonus ranging from $2,400 to $3,900.

## Vacation Entitlement

- **2 of 13 (15%)** of employers provide 2 weeks vacation for 1 year of service, **7 of 13 (54%)** provide 3 weeks for 1 year of service and **4 of 13 (31%)** provide 4 weeks for 1 year of service.
- On average, employers provide 3, 5, and 6 weeks vacation entitlements after 1, 8 and 15 years of service, respectively.
- Employers were split when providing vacation entitlements of 4 weeks. **8 of 13 (50%)** of employers provide 4 weeks after 1-2 years of service, while **4 of 13 (40%)** provide 4 weeks after 5-6 years.
- **7 of 13 (54%)** of employers provide more than 6 weeks vacation after (on average) 20 years of service.

## Vacation Allowance

- **8 of 13 (62%)** of employers provide a vacation allowance to employees travelling outside of local areas.
- Based on the quantitative responses provided, vacation allowances range from **$600** to **$4,700** with a median of **$1,600** and an average of **$1,362** paid per employee.

| Organization | Vacation Allowance Details |
|---|---|
| **B** | After 10 days of employment, employees receive a vacation allowance of 150 per month; after 2 years of service (then annually thereafter), employees are entitled to 1,100 per annum plus the monthly amount. |
| **F** | Employees are entitled to 600 to a maximum of 3,000 per annum. |
| **H** | Employees in Whitehorse are entitled to 2,100 per annum.<br>Employees in Yellowknife are entitled to 1,800 per annum.<br>Employees in Hay River are entitled to 1,600 per annum.<br>Employees in Inuvik are entitled to 4,700 per annum. |
| **I** | All permanent and temporary employees on their anniversary date are entitled to 1,300. All dependents receive 850 per annum. |
| **J** | Employees are entitled to the amount equivalent to the cost of return airfare from Edmonton to the organizations nearest town city. |
| **K** | Employees receive a maximum of 800 each, per employee, spouse, and dependent children over the age of two years, toward the purchase of a return airfare to any destination.<br>Employees 250 km outside of Whitehorse receive 2 working days of paid travel time annually. |
| **L** | After 1 year of employment, permanent employees receive an additional northern vacation of 1 week per calendar year. |
| **M** | After 1 year of employment, permanent employees receive an additional northern vacation of 1 week per calendar year. |

## Additional Leave Days

- **13 of 13 (100%)** of employers provide additional leave days.
- **11 of 13 (85%)** of employers provide bereavement leave.
- **7 of 13 (54%)** of employers provide birth/ adoption leave.
- **7 of 13 (54%)** of employers provide personal leave days.
- **4 of 13 (31%)** of employers provide marriage leave.

### Overtime

- **13 of 13 (100%)** of employers provide overtime pay for in-scope employees in excess of regularly scheduled hours.
- **8 of 13 (62%)** indicate an overtime rate of 1.5x. Of those providing, **5 of 8 (63%)** indicate 1.5x for the first 4 hours of overtime and 2x in excess. **5 of 13 (38%)** of employers offer an overtime rate of 2x.
- **8 of 13 (62%)** of employers provide time off in lieu of overtime for in-scope employees.

### Standby

- **11 of 13 (85%)** of employers offer standby pay, **2 of 13 (15%)** do not. Standby pay was significantly varied across participant organizations, however, **4 of 11 (36%)** indicated 1 hour base pay for every 8 hours of standby.

### Call-Out Pay

- **13 of 13 (100%)** of employers provide call-out pay. The majority of respondent organizations offer the greater of the overtime rate for hours worked or 4 hours of straight time compensation.

### Northern Living Location Allowance

- **11 of 13 (85%)** of employers provide a Northern Living Allowance or a location/ community allowance over and above their standard Northern Living Allowance, **2 of 13 (15%)** do not.

| Organization | Northern Living Location Allowance Details |
|---|---|
| **C** | Employees who live in the Northwest Territories or West Kitikmoet Region of Nunavut are paid 10,000 per annum. |
| **D** | All employees receive allowance based on community; Yellowknife employees receive 2,500 per annum; Hay River employees receive 4,793 per annum. |
| **E** | Allowances range from 600 to 8,200 per annum depending on location. |
| **F** | Employees receive 5,400 per annum. |
| **G** | Allowance varies according to community; Yellowknife employees receive 3,492 per annum; Hay River employees receive 2,673 per annum. |
| **H** | Allowance varies according to community; Whitehorse employees do not receive a Northern Living Allowance; Yellowknife employees receive 5,400 per annum, Hay River employees receive 2,700 per annum, Inuvik employees receive 7,800 per annum. |

| Organization | Northern Living Location Allowance Details |
|---|---|
| **I** | Employees receive 6,300 per annum plus 5 of base salary paid each pay period.<br>Permanent and temporary employees living in Dawson City, Mayo or Faro receive 2,100 per annum. |
| **J** | Full time employees receive an annual allowance of 5,400. |
| **K** | Employees receive 6,300 per annum plus 5 of basic salary paid each pay period. Full time employees receive a location allowance over and above their standard Northern Living Allowance for 3 locations per annum: Haines Junction ( 1,200), Watson Lake ( 2,100), and Beaver Creek ( 2,100). |
| **L** | Permanent employees receive 600 per month plus 5 of base salary (average 800 per month). |
| **M** | Permanent employees receive 550 per month plus 5 of base salary. |

### Housing Fuel Allowances

- **3 of 13 (23%)** of employers provide a housing allowance, **10 of 13 (77%)** do not. Of those providing, the average housing allowance is $350/ month ($4,200 per annum).
- **1 of 13 (8%)** of employers provide a fuel/ utilities allowance of $1,000 per annum; **12 of 13 (92%)** do not.

### Medical Dental Travel

- **7 of 13 (54%)** provide a travel allowance to assist with medical or dental travel, **6 of 13 (46%)** do not. Of those providing, **5 of 7 (71%)** of employers indicate they reimburse expenses paid, **2 of 7 (29%)** of employers indicate expenses are covered through their medical/ dental insurance programs.

### Tool Protective Footwear Clothing Allowances

- **8 of 13 (62%)** of employers provide a tool allowance, **5 of 13 (38%)** do not. Of those providing a quantitative response, the average tool allowance is $460 per annum; median $500.
- **12 of 13 (92%)** provide a protective footwear allowance, **1 of 13 (8%)** does not. The allowance ranges from $100 to $300 per annum.
- **9 of 13 (69%)** of employers provide a protective clothing allowance, **4 of 13 (31%)** do not. Of those providing a quantitative response, the average clothing allowance is $206 per annum; median $200.

TOWERS PERRIN

HR SERVICES

# ATCO Electric Ltd.

## 2006 Compensation Review

January 12, 2007

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# Contents

1. Background
2. Summary Findings

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# 1. Background

- ATCO Electric Ltd. asked Towers Perrin to assess the market competitiveness of compensation for union and non-union positions. We have benchmarked 48 positions from various functional areas and salary grades.
- This report addresses the following elements of total cash compensation:
  - Salary; and
  - Target total cash (TTC = salary + target bonus).

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# 1. Background

## *Comparator Groups*

- For purposes of this review, we used a comparator group of companies that reflects the marketplace for which ATCO Electric competes for talent. Specifically, we have used a sample of Alberta-based Gas & Energy Utilities, which is comprised of energy and pipeline companies with no restriction on size (as measured by annual revenue).
  - Data are presented as raw percentile distributions. Based on our consulting experience, there is typically not a relationship between organization size and compensation for non-executive positions.
- Where the number of matches for any one position in the comparator group is insufficient, we have expanded the sample to include either all Alberta-based companies or a national sample of gas and energy utilities. This reflects the broader labour markets for functional roles and/or industry specific positions.

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# 1. Background

### *Comparator Groups*

- Compensation data have been sourced from Towers Perrin's 2006 Canadian Middle Management, Professional, Technical and Administrative (MMPTA) survey. For industry-specific positions for which there was not a match reflective of the scope of responsibility of the ATCO Electric position in the MMPTA, we have used data from Towers Perrin's 2006 Power Services Survey (and in a few cases Towers Perrin's 2006 Energy Survey).
- All data represent 2006 levels of compensation.
- Based on Towers Perrin's Salary Management Survey, the average projected increase to compensation levels in a sample of Alberta-based gas & energy utilities for 2007 is 6% for the Management & Professional and Salaried (Non-union) levels.

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# 1. Background

## *Interpreting Market Data*

- The resulting market data are presented as percentiles, which are defined as follows:
  - 25th percentile – the point at which 25% of the sample values are lower and 75% are greater;
  - 50th percentile (median) – the point at which 50% of the sample values are lower and 50% are greater; and
  - 75th percentile – the point at which 75% of the sample values are lower and 25% are greater.
- To assist ATCO Electric in determining the competitiveness of its compensation, our commentary is based on the median (50th percentile) of the market.
- Towers Perrin considers compensation to be competitive at ±10% of the desired level. When results are aggregated, we would anticipate that the resulting positioning would be closer to the desired level, as more employee groups are combined.

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## 2. Summary Findings

- On average, ATCO Electric is positioned as follows:
  - Supervisory group: at median on salary, and 9% below median on target total cash (salary + target bonus); and
  - Occupational group: 1% above median on salary, and 6% below median on target total cash.
  - All positions combined: at median on salary, and 8% below median on target total cash.
- Positioning decreases on a target total cash basis as most of ATCO Electric's positions are not eligible for bonuses, while eligibility in the market is high.
  - Overall, bonus eligibility of the incumbents in each benchmark ranges from 70% - 100% for most of the benchmarks reviewed; however, some of the positions (n = 5) had bonus eligibility levels around 55% - 60%.
- The table on the following page shows positioning for the incumbents in each of the grades.

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# 2. Summary Findings

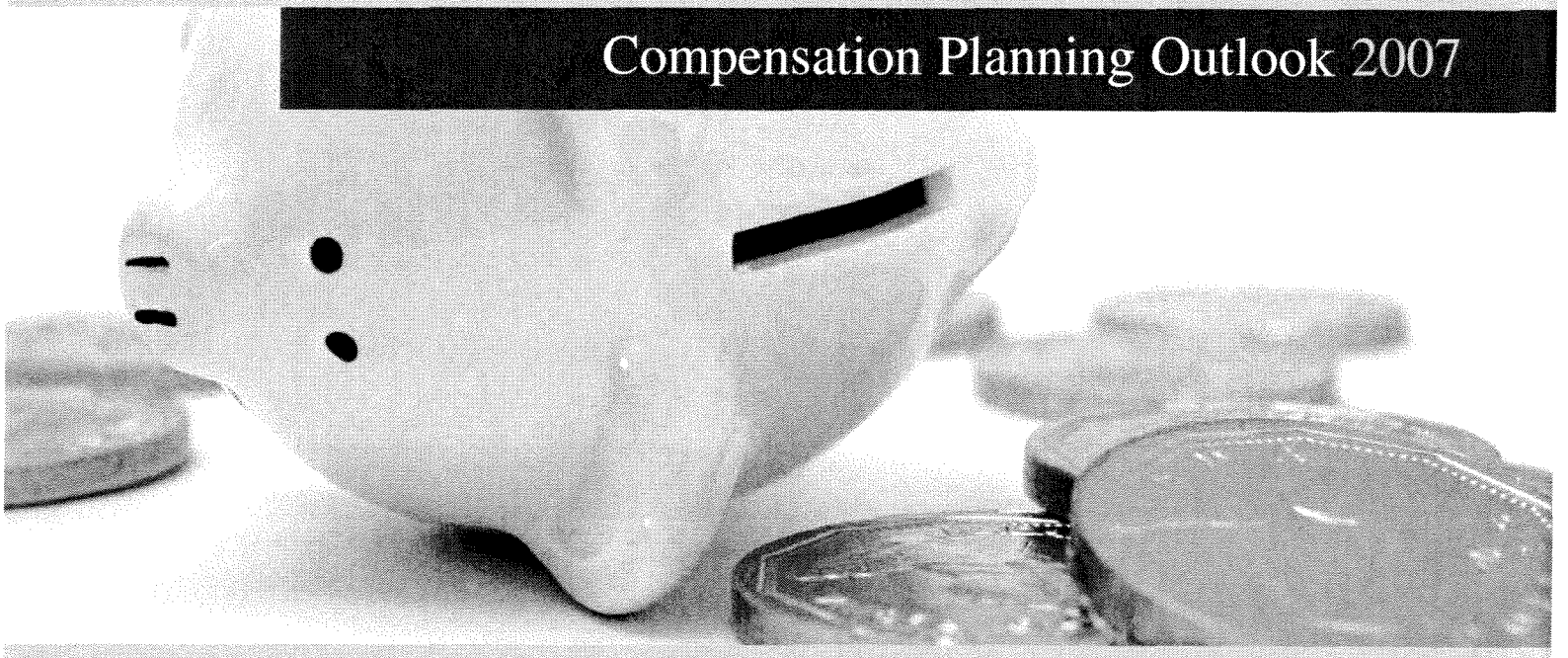
| Salary Grade | | ATCO Electric as a % above/below Salary | | | ATCO Electric as a % above/below TTC | | |
|---|---|---|---|---|---|---|---|
| | | 25th Percentile | 50th Percentile | 75th Percentile | 25th Percentile | 50th Percentile | 75th Percentile |
| **SUPERVISORY** | | | | | | | |
| 20, 18 | *n=6* | 8% | -1% | -14% | 8% | -5% | -23% |
| 17, 16 | *n=5* | 9% | 0% | -10% | -3% | -11% | -22% |
| 15, 14 | *n=9* | 8% | 0% | -6% | 0% | -11% | -17% |
| 13, 12 | *n=5* | 15% | 1% | -5% | 10% | -7% | -12% |
| 11, 10, 2 | *n=4* | 6% | -2% | -14% | 1% | -7% | -21% |
| **Average %** | | **9%** | **0%** | **-9%** | **3%** | **-9%** | **-19%** |
| **OCCUPATIONAL** | | | | | | | |
| 58 | *n=6* | 13% | 4% | -3% | 8% | -4% | -10% |
| 57, 55 | *n=5* | 14% | -7% | -13% | 19% | -8% | -17% |
| 53, 51 | *n=4* | 9% | -2% | -10% | -3% | -13% | -23% |
| 50, 46 | *n=4* | 21% | 8% | 4% | 8% | -1% | -9% |
| **Average %** | | **14%** | **1%** | **-6%** | **9%** | **-6%** | **-14%** |
| **Overall Average %** | | **11%** | **0%** | **-8%** | **5%** | **-8%** | **-17%** |

TTC (Target Total Cash) = Salary + Target Bonus

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The Conference Board of Canada
**Insights You Can Count On**

# Compensation Planning Outlook 2007



# Compensation Outlook

# Labour Shortages Put Pressure on Pay

HUMAN RESOURCE MANAGEMENT

The Conference Board of Canada
**Insights You Can Count On**

Compensation Planning Outlook 2007
by *Stephen Clarke*

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# Preface

*Compensation Planning Outlook 2007* is the 25th edition of this publication, which summarizes the results of The Conference Board of Canada's annual compensation survey. In June 2006, a questionnaire was sent to 1,732 predominantly large and medium-sized Canadian organizations in a variety of regions and sectors. A total of 279 respondents participated in the survey, representing a response rate of 16 per cent.

This publication was prepared under the auspices of the Conference Board's Compensation Research Centre and was made possible through the ongoing support of the funding members and survey participants. We owe a special thank you to all of the individuals who took the time to answer this year's comprehensive questionnaire and to the many organizations that participate year after year. Their efforts are very much appreciated, as it is through the commitment of respondents that The Conference Board of Canada is able to produce this report.

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EXECUTIVE SUMMARY

# Compensation Outlook

# Labour Shortages Put Pressure on Pay

### At a Glance

- The average non-union pay increase for 2007 is projected to be 3.9 per cent nationally. The highest increases—averaging 5.5 per cent—will occur in the oil and gas industry.
- Wage settlements for unionized workers are expected to average 3 per cent in 2007.
- Recruitment and retention issues are intensifying: 74 per cent of survey respondents report challenges in recruiting and/or retaining employees with specific skills.

Upward pressure on pay will continue in 2007. Canada's domestic economy is expected to perform well next year, and corporate profits are still rising. But with unemployment rates at record-low levels, labour markets are tight across the country. This is especially true in Western Canada, where Alberta's oil and gas sector will continue to see strong growth and British Columbia's mining and construction industries are robust and thriving. As a consequence, Canadian workers can once again expect a solid increase in real wages in 2007.

The average non-union pay increase for 2007, based on the responses of the 279 organizations participating in this year's Compensation Planning Outlook survey, is projected to be 3.9 per cent nationally. This increase is 2.5 percentage points ahead of the 1.4 per cent inflation rate forecast for 2007, and it continues the decade-long national trend of pay increases that outpace inflation.

- Wage increases will vary by industry and region: Projected increases are highest in the oil and gas industry, with an average of 5.5 per cent across all employee groups. This sector continues to drive Alberta's red-hot economy, contributing to intense competition for labour as the unemployment rate dips below 4 per cent.
- Above-average increases are also expected in the transportation and utilities sector and in education and health, where employers are seizing the opportunity to make up some ground in the competition for talent. Planned increases in these sectors average 4.2 per cent.
- Average increases are anticipated in the government and high-tech sectors, at 3.9 per cent each.
- The lowest average salary increase (3 per cent) is expected in the construction sector.
- Non-unionized employees in the broader public sector can look forward to average pay increases of 4 per cent, compared with 3.9 per cent for employees in the private sector. Wage settlements for unionized workers are predicted to average 3 per cent in 2007, 2.9 per cent in the public sector and 3 per cent in the private sector.
- Regionally, Alberta will lead, with an average increase of 5.1 per cent. Average increases in British Columbia are projected at 4 per cent, just ahead of the national average, while Saskatchewan, Manitoba and Quebec are expected to see increases that are just below the national average (3.8, 3.8 and 3.7 per cent, respectively).
- In Ontario, where the high dollar is negatively affecting the manufacturing sector, the average increase is anticipated to be 3.5 per cent. The lowest increase is expected in the Atlantic region (3.1 per cent).

Overall, forecast 2007 pay increases are just slightly higher than those reported for 2006. Looking back, the average salary increase in 2006 was 3.8 per cent,

four-tenths of a percentage point higher than last fall's projection for the year. As in previous years, salary increases were not applied "across the board," as the average salary increase for satisfactory performers was 4.1 per cent, compared with an average of 6.3 per cent for those whose performance was outstanding.

Increases to 2006 salary budgets also averaged 3.8 per cent, with less than 1 per cent of organizations freezing their budgets. Budget increases for 2007 will tick up slightly to 4 per cent. Including the 13 per cent of organizations that did not adjust their ranges, the average salary structure (range) increase was 2.4 per cent across all organizations in 2006. The average planned structure increase for 2007 is 2.6 per cent. Only 6 per cent of survey respondents are planning to hold their ranges steady next year.

The outlook for the Canadian economy remains healthy, mainly due to outstanding growth in domestic demand. However, a slowdown in the United States and a softening of commodity prices have taken some of the steam out of the outlook for the trade sector. Growth in gross domestic product is anticipated to rise from 2.7 per cent this year to 2.9 per cent in 2007 and up again to 3.3 per cent in 2008.

Inflation continues to present little concern—it is expected to slow from 1.9 per cent this year to 1.4 per cent in 2007. Growth in corporate profits is projected to ease off from 3.5 per cent this year to 3.1 per cent in 2007, down from 9.1 per cent in 2005. However, profit levels remain healthy, averaging just above 8 per cent of revenues. There is one exception: the manufacturing sector is facing declining profits and continues to shed jobs.

The Canadian economy is running at near full capacity. The current unemployment rate is 6.5 per cent and is projected at 6.6 per cent for 2007. This will contribute to a continuing tightening of the labour market, especially in Western Canada, where the unemployment rates for 2007 are projected to fall well below the national average. In fact, job creation will outstrip labour force growth in Alberta again this year, lowering the unemployment rate to 3.6 per cent.

With labour shortages looming, recruitment and retention issues are intensifying. Almost three-quarters (74 per cent) of this year's survey respondents report challenges with recruiting and/or retaining employees with specific skills. This proportion is up from the 67 per cent of organizations reporting difficulty just one year ago and notably higher than the 49 per cent reporting challenges in 2004. The situation is particularly acute in British Columbia and Alberta, where nearly 90 per cent of employers report recruitment and retention challenges.

Survey respondents also report increases in voluntary turnover rates. The average turnover rate across all industries is 7.9 per cent, consistent with last year but higher than the levels reported between 2001 and 2004. Turnover rates among top performers and individuals with critical or hot skills are on the rise at 5.1, 4.8 and 3.3 per cent, respectively—up from 2.5, 2 and 2 per cent two years ago. Turnover among satisfactory performers—the majority who keep the business running—is 6.8 per cent.

As we approach 2007, attracting and retaining talent is the number-one priority for compensation planners. Eighty per cent of respondents have formal or informal approaches to enhancing rewards packages for top performers or individuals with critical or hot skills. However, as the labour market tightens, compensation planners will need to develop total rewards packages that attract, engage, motivate and retain a broad range of talent.

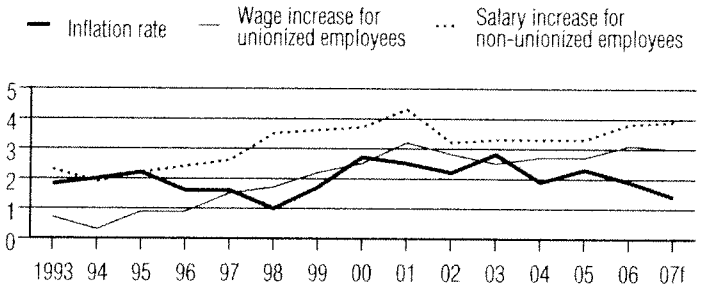
CHAPTER 1

# Compensation Planning and Practices

## Chapter Summary

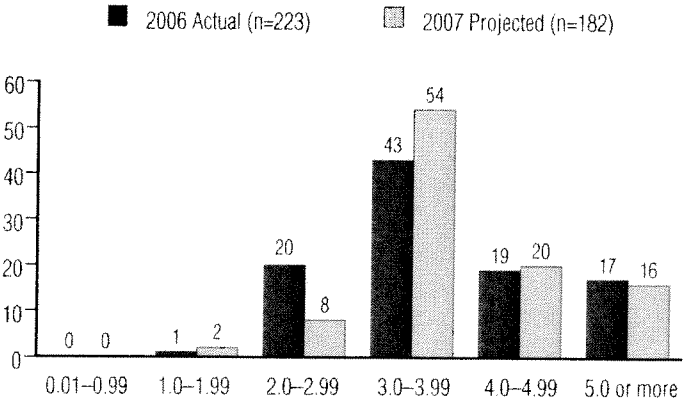
- Real wage gains are projected again for 2007, with average non-union pay increases expected to be 3.9 per cent. The actual average increase for 2006 was 3.8 per cent. Outstanding performers received an average increase of 6.3 per cent, while satisfactory performers received an average increase of 4.1 per cent.
- Compared with 2006, fewer organizations are expected to freeze salary budgets and ranges in the coming year, as competition for valuable talent heats up.
- Nearly 9 in 10 respondents have variable pay plans, primarily in the form of cash bonuses or incentives. Targets vary considerably across industry and employee groups, with the average cost representing 11.1 per cent of the total base pay spending.
- Long-term incentive plans are reported among 52 per cent of respondents in 2006. Their prevalence is increasing among employee groups below the management level.

**Chart 1**
Inflation versus Increases, 1993–2007
(percentage change)




f = forecast
Sources: The Conference Board of Canada; Human Resources and Skills Development Canada, Workplace Information Directorate.

**Chart 2**
Average Salary Increase Distribution
(per cent of organizations)




Source: The Conference Board of Canada.

## MANAGING BASE PAY

For the 12th year running, base pay increases are predicted to exceed inflation, resulting in real gains for Canadian employees. The average non-union pay increase for 2007 is projected to be 3.9 per cent, 2.5 percentage points ahead of the 1.4 per cent inflation rate forecast for next year.

We expect that salary budget increases will average 4 per cent in 2007, somewhat higher than the average budget increases witnessed in recent years (3.8 per cent in 2006, 3.3 per cent in 2005 and 3.4 per cent in 2004). Less than 1 per cent of respondents anticipate an overall freeze on salary budgets for the coming year, compared with 1 per cent in 2006 and 5 per cent in 2005.

Salary range (structure) movement over the past three years has also increased, with an average increase of 2.6 per cent expected for 2007, up from 2.4 per cent in 2006 and 2.1 per cent in 2005. In addition, a significantly lower proportion of organizations are planning to hold their ranges constant in the coming year. Only 6 per cent of organizations with salary ranges are planning to freeze their ranges in 2007, down from 13 per cent in 2006.

**Table 1**
2006 Actual Compensation Increases, by Employee Group
(non-unionized employees)

| Employee Group | Policy line (range increase; %) | | Total increase to budget (%) | | Employees receiving an increase (%) | Average increase for those receiving one (%) | Average increase among all employees (%) | | 2006 average base salary ($) |
|---|---|---|---|---|---|---|---|---|---|
| | zeros included | zeros excluded | zeros included | zeros excluded | | | zeros included | zeros excluded | |
| Senior executive | 2.5 | 3.2 | 3.8 | 4.1 | 91.7 | 4.5 | 4.3 | 4.5 | $249,477 |
| | *2.5* | *2.7* | *3.5* | *3.6* | *100.0* | *4.0* | *3.8* | *3.9* | *$220,500* |
| Executive | 2.5 | 3.0 | 3.8 | 3.9 | 93.0 | 4.7 | 4.2 | 4.3 | $162,139 |
| | *2.5* | *2.7* | *3.5* | *3.5* | *100.0* | *4.0* | *3.6* | *3.6* | *$153,030* |
| Management | 2.5 | 2.9 | 3.9 | 3.9 | 94.4 | 4.1 | 3.9 | 3.9 | $100,499 |
| | *2.5* | *2.5* | *3.5* | *3.5* | *99.0* | *3.6* | *3.5* | *3.5* | *$96,550* |
| Professional—technical | 2.4 | 2.8 | 3.8 | 3.9 | 94.3 | 3.9 | 3.7 | 3.7 | $72,493 |
| | *2.5* | *2.5* | *3.5* | *3.5* | *99.0* | *3.5* | *3.5* | *3.5* | *$69,669* |
| Professional—non-technical | 2.4 | 2.9 | 3.9 | 3.9 | 94.3 | 3.9 | 3.7 | 3.7 | $66,265 |
| | *2.5* | *2.5* | *3.5* | *3.5* | *99.0* | *3.5* | *3.4* | *3.4* | *$65,000* |
| Technical and skilled trades | 2.3 | 2.7 | 3.8 | 3.8 | 95.7 | 3.7 | 3.6 | 3.6 | $55,930 |
| | *2.5* | *2.5* | *3.5* | *3.5* | *100.0* | *3.4* | *3.4* | *3.5* | *$53,533* |
| Clerical and support | 2.3 | 2.7 | 3.7 | 3.7 | 94.3 | 3.7 | 3.6 | 3.6 | $42,162 |
| | *2.5* | *2.5* | *3.5* | *3.5* | *99.0* | *3.5* | *3.3* | *3.3* | *$42,000* |
| Service and production | 2.1 | 2.7 | 3.5 | 3.5 | 95.3 | 3.5 | 3.5 | 3.5 | $45,877 |
| | *2.5* | *2.5* | *3.4* | *3.5* | *100.0* | *3.2* | *3.3* | *3.3* | *$40,323* |
| **Overall** | **2.4** | **2.9** | **3.8** | **3.9** | **93.9** | **4.0** | **3.8** | **3.9** | **n.a.** |
| | ***2.5*** | ***2.5*** | ***3.5*** | ***3.5*** | ***98.5*** | ***3.7*** | ***3.5*** | ***3.5*** | ***n.a.*** |

***Definitions***
**Policy line:** increase to salary ranges, among organizations with ranges
**Total increase to budget:** increase to salary budget, including all budgeted components of compensation program (range, merit, economic, progression, promotion, etc.)
**Overall average increase:** average increase based on all employees in category
**Employees receiving an increase:** as a percentage of employees in category
**Average salary increase:** increase to those receiving an increase (i.e., total increase from all sources—range, merit, economic, progression—rolled into base pay)
**Base salary:** approximate average annual base salary after the increases have been applied

***Employee Group Definitions***
**Senior executive:** all executives reporting directly to the chief executive officer
**Executive:** all other executives
**Management:** senior and middle management: plan, develop, and implement policies and programs
**Professional—technical:** analysts, engineers, information technology specialists, developers, etc.
**Professional—non-technical:** all other professionals: accountants, lawyers, doctors, etc., excluding salespeople
**Technical and skilled trades:** technologists, technicians, millwrights, etc.
**Clerical and support:** secretaries, clerks, coordinators, assistants, word-processing staff
**Service and production:** service, production, maintenance, transportation, etc.

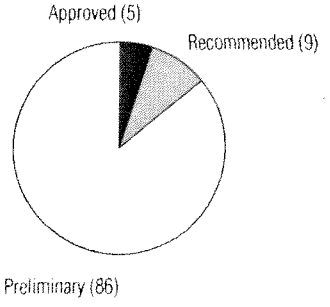
n.a. = not applicable
Note: For each result, the top number is the average (mean) and the bottom number (in italics) is the median.
Source: The Conference Board of Canada.

**Table 2**
2007 Planned Compensation Increases, by Employee Group
(non-unionized employees)

| | Policy line (range; %) | | Total increase to budget (%) | | Average increase among all employees (%) | |
|---|---|---|---|---|---|---|
| **Employee Group*** | **zeros included** | **zeros excluded** | **zeros included** | **zeros excluded** | **zeros included** | **zeros excluded** |
| Senior executive | 2.7 | 2.9 | 4.2 | 4.2 | 4.1 | 4.2 |
| | *2.8* | *3.0* | *4.0* | *4.0* | *3.8* | *3.8* |
| Executive | 2.5 | 2.8 | 4.2 | 4.2 | 4.1 | 4.1 |
| | *2.5* | *2.8* | *4.0* | *4.0* | *3.7* | *3.7* |
| Management | 2.7 | 2.8 | 4.1 | 4.2 | 4.0 | 4.0 |
| | *2.8* | *2.8* | *4.0* | *4.0* | *3.5* | *3.5* |
| Professional—technical | 2.6 | 2.8 | 4.1 | 4.1 | 3.9 | 3.9 |
| | *2.5* | *2.7* | *3.8* | *3.8* | *3.5* | *3.5* |
| Professional—non-technical | 2.6 | 2.8 | 4.1 | 4.1 | 3.9 | 3.9 |
| | *2.5* | *2.8* | *3.8* | *3.8* | *3.5* | *3.5* |
| Technical and skilled trades | 2.5 | 2.7 | 3.9 | 3.9 | 3.8 | 3.8 |
| | *2.5* | *2.5* | *3.5* | *3.5* | *3.5* | *3.5* |
| Clerical and support | 2.6 | 2.8 | 3.9 | 3.9 | 3.8 | 3.8 |
| | *2.5* | *2.5* | *3.5* | *3.5* | *3.5* | *3.5* |
| Service and production | 2.5 | 2.7 | 3.8 | 3.8 | 3.6 | 3.6 |
| | *2.5* | *2.5* | *3.5* | *3.5* | *3.5* | *3.5* |
| **Overall** | **2.6** | **2.8** | **4.0** | **4.1** | **3.9** | **3.9** |
| | ***2.5*** | ***2.7*** | ***3.8*** | ***3.8*** | ***3.5*** | ***3.5*** |

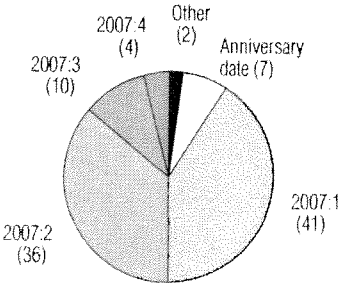
*See Table 1 for definitions.
Note: For each result, the top number is the average (mean) and the bottom number (in italics) is the median.
Source: The Conference Board of Canada.

**Chart 3**
Current Status of Salary Budget Recommendations for 2007
(n=270; per cent of organizations)




Source: The Conference Board of Canada.

**Chart 4**
Planned Implementation of Salary Increases for 2007
(n=274; per cent of organizations)




Source: The Conference Board of Canada.

**Table 3**
2006 Actual Compensation Increases by Industry, Sector and Region
(non-unionized employees)

| | Policy line (range; %) | | Total increase to budget (%) | | Employees receiving an increase (%) | Average increase for those receiving one (%) | Average increase among all employees (%) | |
|---|---|---|---|---|---|---|---|---|
| | zeros included | zeros excluded | zeros included | zeros excluded | | | zeros included | zeros excluded |
| **Overall** | **2.4** | **2.9** | **3.8** | **3.9** | **93.9** | **4.0** | **3.8** | **3.9** |
| **Industry** | | | | | | | | |
| Oil and gas (n=18) | 3.4 | 3.5 | 5.7 | 5.7 | 98.1 | 6.0 | 6.0 | 6.0 |
| Transportation and utilities (n=25) | 3.1 | 3.2 | 4.1 | 4.2 | 94.3 | 4.5 | 4.2 | 4.2 |
| Education and health (n=15) | 3.7 | 3.7 | 4.0 | 4.1 | 98.1 | 4.0 | 4.0 | 4.0 |
| Government (n=24) | 3.0 | 3.0 | 4.3 | 4.3 | 95.4 | 4.3 | 4.2 | 4.3 |
| High-technology (n=16) | 2.5 | 2.8 | 3.5 | 3.5 | 86.7 | 3.9 | 3.3 | 3.4 |
| Chemical, pharmaceutical and allied products (n=18) | 2.1 | 2.5 | 3.7 | 3.7 | 96.6 | 3.9 | 3.6 | 3.6 |
| Not-for-profit (n=6) | 1.4 | 2.8 | 3.7 | 3.7 | 98.2 | 3.7 | 3.5 | 3.5 |
| Manufacturing (n=26) | 2.0 | 2.6 | 3.4 | 3.4 | 95.3 | 3.7 | 3.7 | 3.7 |
| Natural resources, excluding oil and gas (n=11) | 3.1 | 3.1 | 3.9 | 3.9 | 98.3 | 3.9 | 3.8 | 3.8 |
| Retail trade (n=10) | 1.6 | 2.6 | 3.6 | 3.6 | 96.6 | 3.6 | 3.6 | 3.6 |
| Services—Professional, scientific and technical (n=19) | 1.8 | 2.6 | 3.8 | 3.9 | 92.5 | 4.2 | 3.8 | 3.8 |
| Wholesale trade (n=7) | 2.4 | 2.8 | 3.6 | 3.6 | 94.6 | 3.7 | 3.4 | 3.4 |
| Finance, insurance and real estate (n=51) | 2.3 | 2.7 | 3.6 | 3.7 | 92.6 | 3.8 | 3.6 | 3.6 |
| Services—Accommodation, food and personal (n=6) | 2.8 | 3.1 | 3.5 | 4.0 | 86.4 | 3.8 | 3.3 | 3.8 |
| Food, beverage and tobacco products (n=11) | 2.3 | 2.7 | 3.5 | 3.5 | 97.7 | 3.4 | 3.3 | 3.3 |
| Communications and telecommunications (n=11) | 1.2 | 2.8 | 2.4 | 2.7 | 80.2 | 2.9 | 2.7 | 2.9 |
| Construction (n=4) | 2.8 | 2.8 | 4.8 | 4.8 | 94.6 | 5.9 | 5.2 | 5.2 |
| **Sector** | | | | | | | | |
| Private sector (n=207) | 2.1 | 2.7 | 3.8 | 3.8 | 93.5 | 4.0 | 3.8 | 3.8 |
| Public sector (n=64) | 3.2 | 3.2 | 4.0 | 4.0 | 94.4 | 4.1 | 4.0 | 4.0 |
| **Region** | | | | | | | | |
| British Columbia (n=19) | 2.2 | 2.5 | 3.9 | 4.1 | 91.6 | 4.4 | 4.0 | 4.2 |
| Alberta (n=46) | 3.4 | 3.8 | 5.2 | 5.3 | 97.0 | 5.5 | 5.5 | 5.5 |
| Manitoba/Saskatchewan (n=23) | 2.7 | 2.8 | 3.6 | 3.6 | 95.1 | 3.9 | 3.8 | 3.8 |
| Ontario (n=131) | 2.1 | 2.8 | 3.5 | 3.5 | 92.6 | 3.6 | 3.4 | 3.4 |
| Quebec (n=48) | 2.3 | 2.6 | 3.6 | 3.6 | 94.1 | 3.7 | 3.5 | 3.5 |
| Atlantic (n=9) | 2.8 | 3.3 | 3.5 | 3.5 | 96.0 | 3.1 | 3.5 | 3.6 |

Note: Sample sizes above (n=) indicate the number of organizations providing a response for at least one 2006 increase.
Source: The Conference Board of Canada.

The average salary increase for 2006 was 3.8 per cent among all employees across all responding organizations. Nearly 94 per cent of employees received an increase to base salary in 2006, taking home raises of 4 per cent on average.

Outstanding performers received an average increase of 6.3 per cent, compared with an average increase of 4.1 per cent for satisfactory performers. The degree to which organizations differentiate base pay increases on the basis of performance varies widely: outstanding performers garnered increases that are anywhere from less than 1 percentage point up to 7.5 percentage points higher than those given to satisfactory performers. Among the 92 per cent of organizations that differentiate increases based on performance, 60 per cent reward outstanding performance with increases that are up to twice the average increase given to satisfactory performers. Roughly 18 per cent reward outstanding performance with increases that are two to three times

**Table 4**
2007 Planned Compensation Increases by Industry, Sector and Region
(non-unionized employees)

| | Policy line (range; %) | | Total increase to budget (%) | | Average increase among all employees (%) | |
|---|---|---|---|---|---|---|
| | zeros included | zeros excluded | zeros included | zeros excluded | zeros included | zeros excluded |
| **Overall** | **2.6** | **2.8** | **4.0** | **4.1** | **3.9** | **3.9** |
| **Industry** | | | | | | |
| Oil and gas (n=18) | 3.5 | 3.5 | 5.2 | 5.2 | 5.5 | 5.5 |
| Transportation and utilities (n=25) | 3.4 | 3.4 | 4.3 | 4.3 | 4.2 | 4.2 |
| Education and health (n=15) | 2.7 | 2.7 | 4.2 | 4.2 | 4.2 | 4.2 |
| Government (n=24) | 2.8 | 2.8 | 4.3 | 4.3 | 3.9 | 3.9 |
| High-technology (n=16) | 2.6 | 2.6 | 4.0 | 4.0 | 3.9 | 3.9 |
| Chemical, pharmaceutical and allied products (n=18) | 2.3 | 2.5 | 3.9 | 3.9 | 3.7 | 3.7 |
| Not-for-profit (n=6) | 2.8 | 2.8 | 3.4 | 3.4 | 3.7 | 3.7 |
| Manufacturing (n=26) | 2.3 | 2.5 | 3.6 | 3.6 | 3.7 | 3.7 |
| Natural resources, excluding oil and gas (n=11) | 3.1 | 3.1 | 3.7 | 3.7 | 3.7 | 3.7 |
| Retail trade (n=10) | 3.2 | 3.2 | 4.0 | 4.0 | 3.7 | 3.7 |
| Services—Professional, scientific and technical (n=19) | 2.3 | 2.7 | 4.1 | 4.1 | 3.7 | 3.7 |
| Wholesale trade (n=7) | 2.4 | 2.4 | 3.8 | 3.8 | 3.6 | 3.6 |
| Finance, insurance and real estate (n=51) | 2.2 | 2.5 | 4.0 | 4.1 | 3.5 | 3.5 |
| Services—Accommodation, food and personal (n=6) | 2.9 | 2.9 | 4.1 | 4.1 | 3.4 | 3.4 |
| Food, beverage and tobacco products (n=11) | 2.6 | 3.0 | 3.6 | 3.6 | 3.4 | 3.4 |
| Communications and telecommunications (n=11) | 1.7 | 2.5 | 3.0 | 3.2 | 3.2 | 3.3 |
| Construction (n=4) | 2.8 | 2.8 | 4.8 | 4.8 | 3.0 | 3.0 |
| **Sector** | | | | | | |
| Private sector (n=207) | 2.5 | 2.7 | 4.0 | 4.0 | 3.9 | 3.9 |
| Public sector (n=64) | 3.0 | 3.0 | 4.3 | 4.3 | 4.0 | 4.0 |
| **Region** | | | | | | |
| British Columbia (n=19) | 2.3 | 2.5 | 4.4 | 4.4 | 4.0 | 4.1 |
| Alberta (n=46) | 3.5 | 3.7 | 5.1 | 5.1 | 5.1 | 5.1 |
| Manitoba/Saskatchewan (n=23) | 2.7 | 2.7 | 3.8 | 3.8 | 3.8 | 3.8 |
| Ontario (n=131) | 2.4 | 2.7 | 3.7 | 3.8 | 3.5 | 3.5 |
| Quebec (n=48) | 2.5 | 2.6 | 3.8 | 3.8 | 3.7 | 3.7 |
| Atlantic (n=9) | 2.3 | 3.3 | 3.2 | 3.4 | 3.1 | 3.3 |

Note: The sample sizes above (n=) indicate the number of organizations that provided a response for at least one 2007 projected increase.
Source: The Conference Board of Canada.

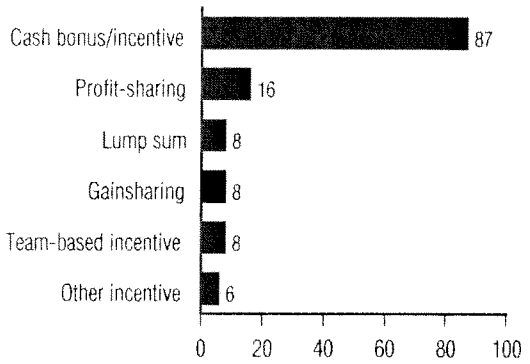
the average increase for satisfactory performance, while 15 per cent reported that average increases for outstanding performers are more than three times those for satisfactory performers.

## VARIABLE PAY

The majority of Canadian organizations (86 per cent) have one or more annual variable pay plan(s). These plans are especially popular in the private sector, where 94 per cent of organizations report having at least one plan. By comparison, 59 per cent of public sector organizations have one or more variable pay plans.

Cash bonus or incentive plans are the most common form of annual variable pay plan, used by 87 per cent of organizations that have at least one annual variable pay plan. Profit-sharing plans are a distant second at 16 per cent, followed by lump-sum cash incentives, gainsharing and team-based incentives at 8 per cent each.

**Chart 5**
Annual Variable Pay—Plan Types
(n=239; per cent among those with at least one annual variable pay plan in place)




Note: Figures do not add to 100 because some respondents have more than one plan.
Source: The Conference Board of Canada.

**Table 5**
Prevalence of Annual Variable Pay by Sector and Employee Group
(per cent)

| Employee group | Public sector (n=64) | Private sector (n=207) | All sectors combined (n=271) |
|---|---|---|---|
| **Overall** | **59** | **94** | **86** |
| Senior executive | 53 | 82 | 75 |
| Executive | 45 | 82 | 73 |
| Management | 50 | 92 | 82 |
| Professional—technical | 39 | 78 | 69 |
| Professional—non-technical | 36 | 78 | 68 |
| Technical and skilled trades | 20 | 48 | 41 |
| Clerical and support | 33 | 76 | 66 |
| Service and production | 14 | 41 | 35 |

Source: The Conference Board of Canada.

**Table 6**
Annual Variable Pay Plan Payouts, by Employee Group
(expressed as per cent of base salary; non-unionized employees)

**2006 Payouts***

| | Average payout | | | Per cent of organizations | | |
|---|---|---|---|---|---|---|
| Employee group | Target payout | Actual payout | Receiving payouts** | Exceeded target | Met target | Fell short of target |
| Senior executive (n=175) | 38.0 | 47.6 | 91.3 | 56 | 17 | 27 |
| Executive (n=171) | 28.1 | 33.6 | 90.4 | 56 | 14 | 30 |
| Management (n=200) | 15.9 | 19.5 | 91.5 | 52 | 15 | 34 |
| Professional—technical (n=161) | 9.5 | 11.8 | 89.5 | 55 | 13 | 32 |
| Professional—non-technical (n=156) | 9.1 | 10.7 | 89.0 | 55 | 14 | 31 |
| Technical and skilled trades (n=89) | 6.5 | 8.5 | 88.6 | 51 | 21 | 28 |
| Clerical and support (n=153) | 5.4 | 6.8 | 89.4 | 53 | 17 | 30 |
| Service and production (n=71) | 5.5 | 8.2 | 90.5 | 53 | 20 | 27 |

**2007 Projected Payouts***

| Employee group | Target payout | Plan maximum |
|---|---|---|
| Senior executive (n=155) | 39.1 | 68.6 |
| Executive (n=152) | 28.6 | 52.1 |
| Management (n=178) | 16.1 | 31.6 |
| Professional—technical (n=143) | 9.7 | 20.5 |
| Professional—non-technical (n=141) | 9.2 | 19.4 |
| Technical and skilled trades (n=83) | 6.6 | 18.3 |
| Clerical and support (n=139) | 5.6 | 13.2 |
| Service and production (n=63) | 5.5 | 13.8 |

*2006 payouts refer to payouts based on 2005 results and paid in 2006; 2007 payouts refer to payouts based on 2006 results, to be paid in 2007.
**Per cent of employees in category.
Source: The Conference Board of Canada.

**Table 7**
2007 Variable Pay Plan Targets for Selected Industries, by Employee Group
(expressed as per cent of base salary)

| Employee Group | Government | Financial services | Manufacturing | Oil and gas | Transportation and utilities | Natural resources | Chemical, pharmaceutical and allied products | Communications/ Telecom | High-tech |
|---|---|---|---|---|---|---|---|---|---|
| Senior executive | 14.3 | 38.3 | 41.2 | 48.5 | 36.8 | 43.1 | 37.2 | 45.8 | 50.0 |
| Executive | 10.3 | 26.7 | 29.7 | 34.7 | 25.8 | 33.1 | 27.7 | 33.2 | 40.0 |
| Management | 7.5 | 14.9 | 15.8 | 24.2 | 16.3 | 16.8 | 17.9 | 12.8 | 17.5 |
| Professional—technical | 5.5 | 9.0 | 8.2 | 13.9 | 9.1 | 13.5 | 10.7 | 7.1 | 7.0 |
| Professional—non-technical | 6.5 | 9.1 | 5.0 | 12.8 | 8.7 | 11.7 | 9.5 | 7.7 | 7.4 |
| Technical and skilled trades | 5.7 | 5.4 | 5.0 | 7.6 | 7.3 | 8.2 | 5.4 | 8.7 | 7.3 |
| Clerical and support | 5.7 | 5.0 | 4.8 | 7.1 | 5.8 | 5.8 | 4.5 | 6.9 | 12.2 |
| Service and production | – | 4.1 | 4.7 | 7.4 | 4.9 | 6.3 | 4.7 | 5.0 | 7.3 |

Source: The Conference Board of Canada.

**Table 8**
Variable Pay Plan Target Adjustments, by Employee Group
(n=225; per cent; based on organizations providing 2006 and 2007 targets)

| Employee Group | Adjusting target | Increasing targets | Average target increase | Decreasing targets | Average target decrease | Overall average target movement* |
|---|---|---|---|---|---|---|
| Senior executive (n=154) | 10.4 | 6.5 | 10.6 | 3.9 | –10.8 | 2.6 |
| Executive (n=151) | 12.6 | 6.6 | 7.9 | 6.0 | –6.8 | 0.9 |
| Management (n=176) | 10.8 | 5.7 | 2.6 | 5.1 | –4.2 | –0.6 |
| Professional—technical (n=140) | 12.9 | 6.4 | 2.9 | 6.4 | –3.0 | 0.0 |
| Professional—non-technical (n=138) | 15.2 | 6.5 | 1.9 | 8.7 | –3.1 | –1.0 |
| Technical and skilled trades (n=79) | 10.1 | 6.3 | 2.5 | 3.8 | –1.7 | 0.9 |
| Clerical and support (n=133) | 12.8 | 6.0 | 2.0 | 6.8 | –1.7 | 0.1 |
| Service and production (n=61) | 6.6 | 4.9 | 2.7 | 1.6 | –1.5 | 1.6 |

*Average target movements based upon data provided by those organizations adjusting targets.
Source: The Conference Board of Canada.

Variable pay targets vary considerably across employee groups and also across industries. The actual cost of annual variable pay plans averaged 11.9 per cent of base pay spending in 2006. These costs are highest for organizations in the oil and gas sector (average of 23 per cent of total base pay spending), and lowest in the education and health sector (average of 4.5 per cent of total base pay).

On average, 89 per cent of employees in organizations with variable pay received a payout in 2006. Overall spending on these plans is expected to increase in 2007, with plan targets predicted to average 11.1 per cent of base pay spending, up from the average target of 10.4 per cent in 2006.

Among organizations that have variable pay plans, 38 per cent include payouts in the calculation of pensionable earnings for all employees. An additional 3.9 per cent consider only a portion of variable pay as pensionable, while 8.7 per cent report that variable pay is included in pensionable earnings only for selected employees, typically executives.

Fifty-two organizations have made changes to their variable pay plans in the past year. In many cases, this involved fine-tuning as they adjusted targets, weighting and eligibility.

The prevalence of medium-term or "mid-term" plans that pay out after two or three years has increased in 2006. Nearly 13 per cent of organizations employ these types of incentives, up from 8 per cent in 2005. Seventeen per cent of private sector organizations use these types of plans, while they are non-existent among public sector respondents.

## LONG-TERM INCENTIVE PLANS

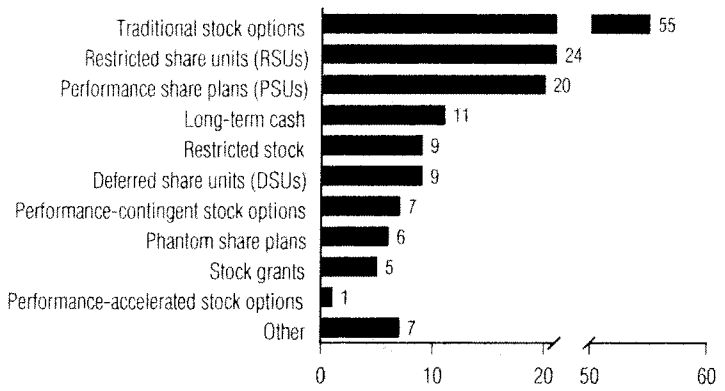
The prevalence of long-term incentive plans (LTIPs) has increased slightly in 2006, with 52 per cent of organizations reporting at least one type of LTIP this year, compared with 48 per cent in 2005. LTIPs remain far more common in the private sector, where 68 per cent of organizations use them. The vast majority of firms that are publicly traded (82 per cent) continue to offer LTIPs, and these plans are also used by the majority of firms that are controlled by a publicly traded company. LTIPs continue to be much less common in the public sector, where just 8 per cent of organizations use them.

**Table 9**
Prevalence of Long-term Incentive Plans,* by Sector and Employee Group
(per cent; based on organizations that reported for each employee category; non-unionized employees)

| Employee Group | Public sector (n=64) | Private sector (n=207) |
|---|---|---|
| **Overall** | **8** | **68** |
| Senior executive | 8 | 58 |
| Executive | 5 | 54 |
| Management | 3 | 38 |
| Professional—technical | 0 | 19 |
| Professional—non-technical | 0 | 19 |
| Other non-management | 0 | 12 |

*Refers only to ongoing plans. For the purposes of this question, any ad hoc rewards of stock options or grants are excluded.
Source: The Conference Board of Canada.

**Chart 6**
Long-term Incentive Plans*—Plan Types
(n=146; per cent; based on organizations with at least one LTIP in place)




*Refers only to ongoing plans. For the purposes of this question, any ad hoc rewards of stock options or grants are excluded.
Note: Figures add to more than 100 because some organizations have more than one LTIP in place.
Source: The Conference Board of Canada.

Stock option plans have traditionally been the most common form of LTIP, and their prevalence remains steady this year. More than half (55 per cent) of organizations have this type of plan in place, compared with 57 per cent in 2005. The prevalence of other types of LTIPs has also remained largely unchanged. Twenty-four per cent of organizations with LTIPs use restricted share units, and 11 per cent have long-term cash plans. Long-term cash is the sole type of plan currently in use by the few public sector organizations with LTIPs.

Last year the trend of offering LTIPs to employees below the management level appeared to reverse. In 2005, 14 per cent of organizations with LTIPs offered this type of plan to employees in professional non-technical roles, compared with 24 per cent in 2004. Currently, however, we are seeing a return to 2004 levels, as 28 per cent of

**Table 10**
Long-term Incentive Plans—Eligibility, by Employee Group*
(n=146; per cent; based on organizations with at least one LTIP in place)

| Employee Group | Organizations with LTIP for this category | Employees eligible for LTIP(s) (average) | Employees receiving LTI in 2006 (average) |
|---|---|---|---|
| Senior executive | 89 | 97 | 96 |
| Executive | 82 | 95 | 93 |
| Management | 57 | 82 | 76 |
| Professional—technical | 29 | 86 | 68 |
| Professional—non-technical | 28 | 86 | 66 |
| Other non-management | 18 | 78 | 70 |

*Definitions provided to respondents:
**% eligible:** as percentage of total employees in the category.
**% receiving:** as percentage of those employees eligible for the incentive.
Source: The Conference Board of Canada.

organizations with LTIPs report that they offer them to this employee group. Nearly 18 per cent of organizations offer these plans to other non-management employees, compared with 12 per cent in 2005. Twenty per cent of respondents with LTIPs have made plan changes in the past 12 months, while 11 per cent are anticipating changes to their plans in the coming year.

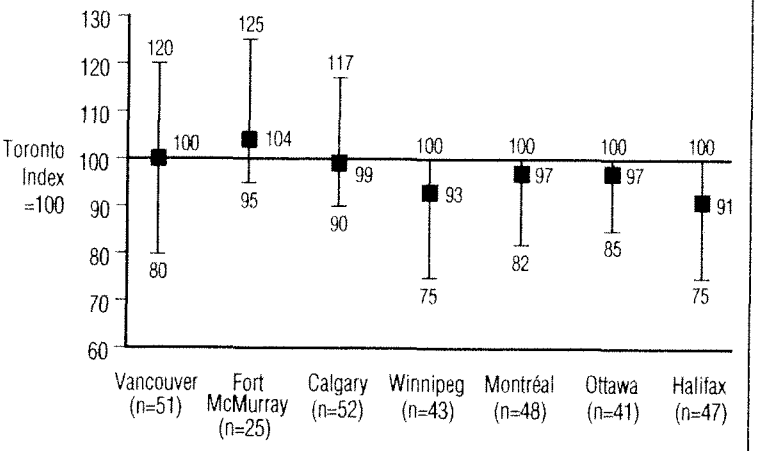
## REWARDS STRATEGY AND PRIORITIES

The prevalence of market-based pay strategies is virtually unchanged in 2006. The majority of responding organizations (63 per cent) employ this approach, compared with 64 per cent in 2005 and 58 per cent four years ago. Non-monetary recognition awards are equally popular, with 62 per cent of respondents citing their use. One-third of responding organizations use spot cash awards.

Nearly 3 in 10 organizations (28 per cent) use regional rates of pay, with the highest rates being applied in Fort McMurray.

Base pay continues to represent the most significant component of total cash compensation, particularly in the public sector. The proportion of compensation represented by annual variable pay remains steady in 2006. In the private sector, the use of long-term incentives for senior executives has seen a slight increase in 2006, compared with 2005.

**Chart 7**
Regional Compensation Levels




■ = average (mean) for location; high and low numbers represent range of responses.
Note: For ease of comparison, the Toronto area was used as the base (index=100).
Source: The Conference Board of Canada.

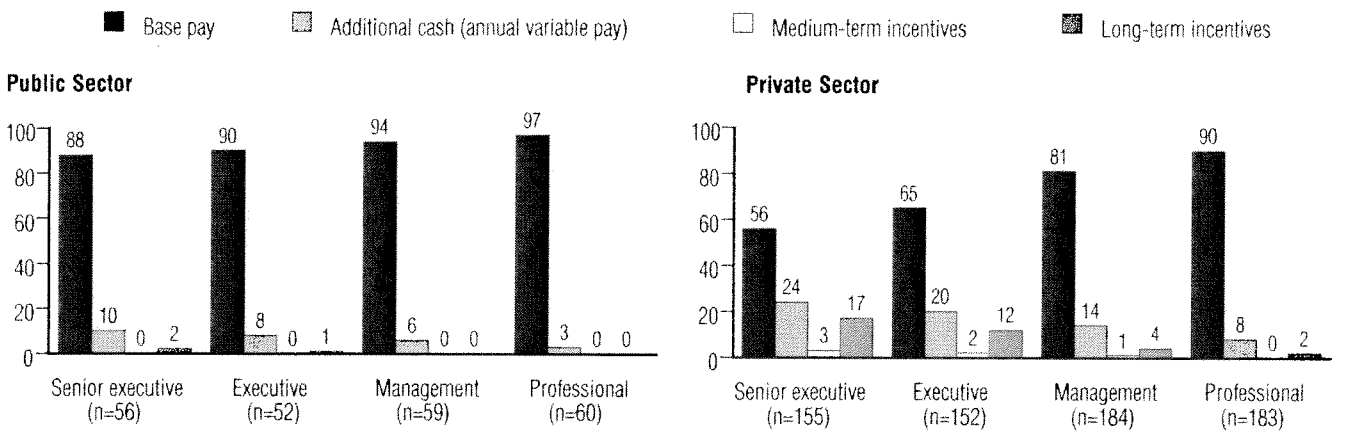
Attracting talent, retaining talent and maintaining competitive market position continue to be the top three rewards activities and priorities for organizations in 2006. The relative weight applied to each of these priorities has increased since 2005, especially with regard to retaining talent. This year, more than half of organizations (51.6 per cent) identified this as their top priority, compared with 42 per cent in 2005. This comes as no surprise given the human resources challenges currently facing organizations, especially in Western Canada.

**Table 11**
Prevalence of Selected Approaches to Compensation Strategy
(per cent of organizations)

| | In place | Implemented but disbanded | Being considered | Considered but decided against | Never considered |
|---|---|---|---|---|---|
| Broadbanding (n=262) | 32 | 3 | 10 | 19 | 35 |
| Competency-based pay (n=261) | 28 | 2 | 13 | 11 | 46 |
| Team-based pay (n=250) | 7 | 1 | 5 | 10 | 77 |
| Market pricing (n=257) | 63 | 0 | 9 | 7 | 22 |
| Non-monetary recognition awards (n=251) | 62 | 2 | 17 | 4 | 16 |
| Spot cash awards (n=253) | 36 | 3 | 8 | 5 | 49 |

Note: Totals may not equal 100 due to rounding.
Source: The Conference Board of Canada.

**Chart 8**
Distribution of Total Cash Compensation, by Sector*
(per cent of total cash)




*Refers to the desired distribution of total cash components based on the design of the total cash compensation strategy.
Note: Totals may not equal 100 due to rounding.
Source: The Conference Board of Canada.

**Table 12**
Top Rewards Activities and Priorities

| Next 12 to 18 months (n=275) | Per cent of organizations |
|---|---|
| 1. Retaining talent | 51.6 |
| 2. Maintaining competitive position | 46.9 |
| 3. Attracting talent | 45.5 |
| 4. Reviewing strategy and ensuring alignment with business objectives | 38.9 |
| 5. Connecting pay and performance | 37.8 |
| 6. Containing pension and benefit costs | 21.1 |
| 7. Communicating rewards to employees | 19.6 |
| 8. Ensuring internal equity | 10.9 |
| 9. Maximizing effectiveness of variable pay | 10.5 |
| 10. Managing rewards on a total rewards basis | 10.2 |
| 11. Managing executive compensation and long-term incentives | 6.2 |

Note: Respondents were asked to select their top three rewards activities/priorities in this time frame from a list.
Source: The Conference Board of Canada.

CHAPTER 2

# Human Resources Management

## Chapter Summary

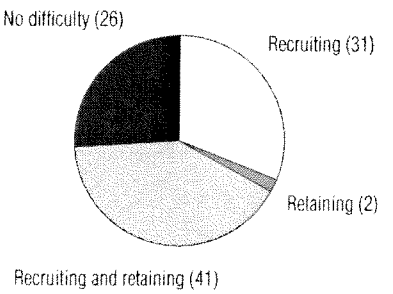
- Recruitment and retention pressure is at its highest level since 2001, especially in the education and health, natural resources, and oil and gas sectors. Skills in top demand this year are accounting and finance, engineering, and skilled trades.
- Turnover rates among top performers and individuals with "hot" or critical skills are on the rise, but the highest turnover rate is among the solid performers, pointing to a need for broad-based retention strategies.
- The labour market situation in Western Canada is putting upward pressure on employee compensation. Employers are responding in a variety of ways. In general, merit increases in Calgary and Fort McMurray are an average of 1 to 2 percentage points higher than the national average.

**Table 13**
Top Professions/Specializations/Position Types in Demand
(n=204; per cent; based on organizations reporting difficulty recruiting and/or retaining particular skills)

| | | |
|---|---|---|
| 1. | Accounting/finance | 41 |
| 2. | Engineering—electrical, mechanical, etc. | 33 |
| 3. | Skilled trades | 24 |
| 4. | Specialist IT | 22 |
| 5. | Sales and marketing | 20 |
| 6. | Management | 11 |
| 7. | Human resources | 8 |
| 8. | Physical sciences | 6 |
| 9. | Executives | 4 |
| 10. | General IT | 3 |
| 11. | Senior executives | 3 |
| | Other* | 29 |

*A wide variety of other responses were provided, representing a broad range of industries and occupations. The most common were health-care professionals (including nurses, pharmacists, technicians), researchers, auditors, project managers and operations managers.
Note: Respondents were asked to select the top three professions/specializations/position types they have difficulty with.
Source: The Conference Board of Canada.

**Chart 9**
Difficulty Recruiting and Retaining Particular Skills
(n=274; per cent of organizations)

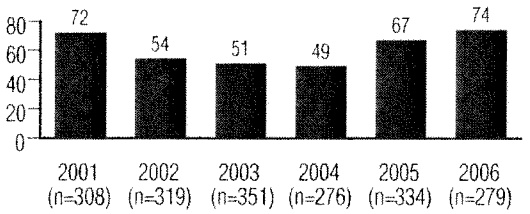



Source: The Conference Board of Canada.

## RECRUITMENT AND RETENTION

The pressures of a hot labour market currently manifest themselves in ever-increasing recruitment and retention challenges. Not since 2001 have organizations felt such pressure on their workforce. In 2005, two-thirds of organizations (67 per cent) reported challenges in recruiting and retaining employees with particular skills—a substantial increase from 2004. Currently, however, nearly three-quarters of organizations (74 per cent) are experiencing difficulty recruiting and/or retaining particular skills. The organizations that are more likely to experience difficulties in recruiting and/or retaining specific skills include those in the education and health (100 per cent), natural resources (excluding oil and gas; 91 per cent), and oil and gas (83 per cent) sectors. The skills in highest demand are consistent with those cited in 2005 and include accounting and finance, engineering, and skilled trades. Specialist IT, sales and marketing, and management round out the top six most sought-after skills.

**Chart 10**
Difficulty with Recruiting and Retaining—Trend over Time
(per cent of organizations reporting difficulties with recruitment and/or retention)




Source: The Conference Board of Canada.

In order to address the issue of recruitment and retention, 8 in 10 organizations have either formal compensation strategies or informal approaches to enhancing rewards packages for individuals in high demand. Generally speaking, there is no universal approach, but by a substantial margin, base pay adjustments continue to be the most common approach, followed by signing bonuses, referral bonuses and retention bonuses. Nearly all these approaches are more prevalent in 2006 than in 2005. More specifically, retention bonuses, hot skills bonuses and adjustments to base pay are being used with greater frequency this year.

**Table 14**
Specific Compensation Strategies/Approaches to Attract and/or Retain Key Individuals
(n=222; per cent; based on organizations that reported having at least one strategy)

| | Formal strategy | Ad hoc approach | Both | Total* |
|---|---|---|---|---|
| Adjustments to base pay (n=167) | 18 | 46 | 10 | 75 |
| Signing bonuses (n=113) | 8 | 43 | 0 | 51 |
| Referral bonuses (n=83) | 33 | 4 | 0 | 37 |
| Retention bonuses (n=79) | 11 | 23 | 1 | 36 |
| Milestone or project bonuses (n=52) | 6 | 17 | 1 | 23 |
| Stock options or grants (n=46) | 10 | 9 | 1 | 21 |
| Enhanced relocation support (n=44) | 5 | 14 | 1 | 20 |
| Hot skills bonuses (n=35) | 8 | 8 | 0 | 16 |
| Enhanced variable pay programs (n=28) | 5 | 6 | 1 | 13 |
| Stay bonuses (n=25) | 2 | 9 | 0 | 11 |
| Other (n=17) | 5 | 2 | 0 | 8 |

**Other compensation strategies include:**
Enhanced benefits to support work–life balance (leaves, vacation)
Market premiums
Relocation assistance (i.e., housing subsidies, interest buy-downs, sale protection)

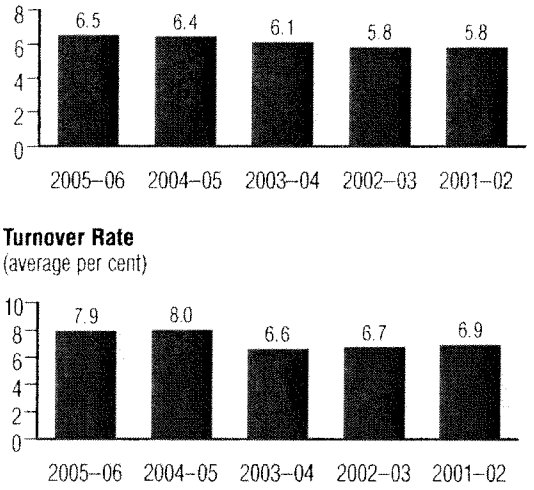
*Overall per cent of organizations with strategy in place.
Source: The Conference Board of Canada.

**Table 15**
Historical Usage of Specific Compensation Strategies/Approaches
(per cent of organizations)

| | Outlook 2002 | Outlook 2004 | Outlook 2006 | Outlook 2007 |
|---|---|---|---|---|
| Adjustments to base pay | 72 | 72 | 70 | 75 |
| Signing bonuses | 51 | 44 | 48 | 51 |
| Retention bonuses | 35 | 27 | 33 | 36 |
| Stock options | 33 | 33 | 21 | 21 |
| Milestone or project bonuses | 29 | 27 | 19 | 23 |
| Enhanced variable pay | 27 | 22 | 14 | 13 |
| Hot skills bonuses | 18 | 14 | 10 | 16 |

Source: The Conference Board of Canada.

**Chart 11**
Absenteeism and Turnover Rates
(based on responses of all organizations; rates are for August 1 to July 31 except for 2005–06, where rates are for July 1 to June 30.)




Notes:
1 Absenteeism is defined as an employee's absence from work (with or without pay) due to illness, disability, personal or family reasons for a period of at least half a day but less than 52 consecutive weeks. Maternity, adoptive, paternity, vacation and holiday, and bereavement leave and jury duty are excluded.
2 Voluntary turnover applies to regular employees only, not early retirements and severances.
Source: The Conference Board of Canada.

**Table 16**
Absenteeism and Turnover Rates, by Industry

| | Absenteeism rate* (days per employee) (n=167) | Turnover rate* (average percentage) (n=220) |
|---|---|---|
| **Overall** | **6.5** | **7.9** |
| **Industry** | | |
| Natural resources, excluding oil and gas | 5.4 | 4.9 |
| Oil and gas | 11.9 | 8.3 |
| Manufacturing | 5.2 | 5.8 |
| Food, beverage and tobacco products | –** | 10.3 |
| Chemical, pharmaceutical and allied products | 4.9 | 6.5 |
| Construction | –** | 11.2 |
| High-technology | 3.7 | 7.6 |
| Communications and telecommunications | 5.7 | 6.8 |
| Transportation and utilities | 7.5 | 5.6 |
| Finance, insurance and real estate | 7.3 | 7.8 |
| Wholesale trade | 6.4 | 7.8 |
| Retail trade | 4.9 | 26.9 |
| Education and health | 8.0 | 6.0 |
| Government | 8.0 | 4.9 |
| Not-for-profit | 5.1 | 7.2 |
| Services—Accommodation, food and personal | 4.5 | 15.8 |
| Services—Professional, scientific and technical | 4.8 | 13.1 |

*Please refer to Chart 11 for definitions.
**Not shown due to small sample sizes.
Source: The Conference Board of Canada.

The impact of labour market pressures is also reflected in average annual voluntary turnover rates. The average annual turnover rate is 7.9 per cent this year, consistent with 2005, but still higher than the levels witnessed between 2001 and 2004. In addition to these overall turnover rates, survey participants were also able to provide turnover data for specific employee groups:

- For "top performers," the average voluntary turnover rate is 5.1 per cent, based on data provided by 16 per cent of organizations surveyed. This compares with a rate of 4.1 per cent for top performers last year, and 2.5 per cent two years ago.
- The rate for "solid performers" is 6.8 per cent, based on data provided by 14 per cent of organizations surveyed.
- The rate for "poor performers" is 5.5 per cent, based on data provided by 13 per cent of organizations surveyed.
- For "employees with less than 2 years of service," the rate is 5.7 per cent, based on data provided by 25 per cent of organizations surveyed.
- For "employees with critical skills," the rate is 4.8 per cent, based on data provided by 15 per cent of organizations surveyed. This compares with a rate of 3.4 per cent for this employee group one year ago.
- For "employees with hot skills," the rate is 3.3 per cent, based on responses from 10 per cent of organizations surveyed, compared with last year's rate of 2.1 per cent.

Two observations are particularly significant. First, the turnover among special groups is increasing. Second, the turnover rate among the solid performers is high relative to these special groups. While a large majority of organizations (80 per cent) report having either formal compensation strategies or informal approaches to enhancing employee rewards packages, such programs are typically targeted at employees with critical or hot skills. These findings suggest a need to focus on the wider workforce when developing retention strategies, not just those top performers who provide a specific competitive or strategic advantage.

**Table 17**
Turnover Rates Among Specific Employee Groups
(average percentage)

| | |
|---|---|
| Top performers (n=44) | 5.1 |
| Solid performers (n=40) | 6.8 |
| Poor performers (n=37) | 5.5 |
| Employees with less than 2 years' service (n=69) | 5.7 |
| Employees with critical skills (n=42) | 4.8 |
| Employees with hot skills (n=29) | 3.3 |

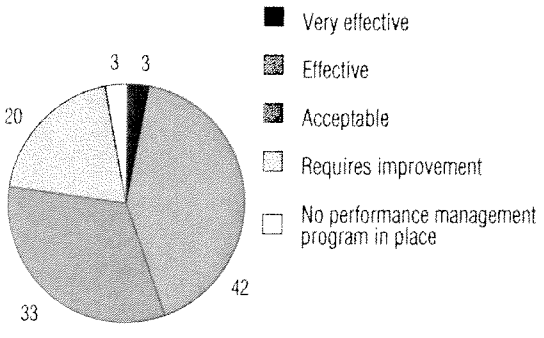
Source: The Conference Board of Canada.

## PERFORMANCE MANAGEMENT

Over the past few years, there has been a consistent increase in the perceived effectiveness of performance management systems among survey respondents, and this trend continues in 2006. Forty-five per cent of organizations report that their performance management system is either "very effective" (3 per cent) or "effective" (42 per cent), up slightly from 41 per cent in 2005. Still, one-third (33 per cent) of organizations rate their performance management system as "acceptable," and one in five (20 per cent) believe that improvement is needed.

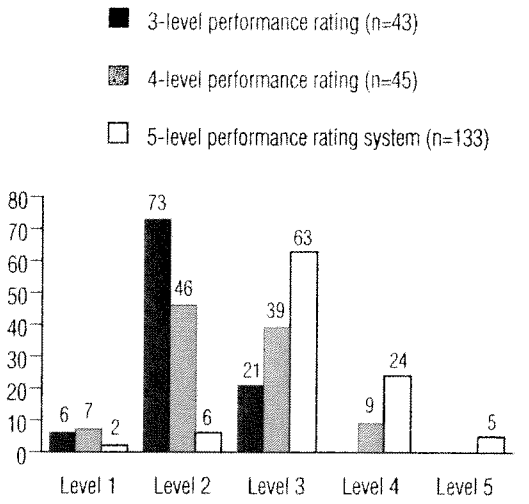
The proportion of organizations using a performance appraisal rating system remains unchanged from 2005. The majority of organizations (86 per cent) currently use such a system, with a five-level (59 per cent) or four-level (20 per cent) system being the most common. Eighteen per cent of these organizations force a performance distribution, while 39 per cent have distribution guidelines or recommendations in place for managers to use when carrying out performance assessments.

**Chart 12**
Effectiveness of Performance Management System
(n=276; per cent of organizations)



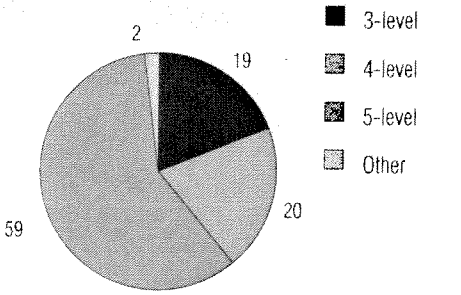

Note: Total does not equal 100 due to rounding.
Source: The Conference Board of Canada.

**Chart 13**
Performance Distribution
(average percentage of employees)




Notes:
1 Totals do not equal 100 due to rounding.
2 The high degree of variability in performance appraisal systems does not allow for labels to be assigned to each level presented in the chart.
3 For each of the three rating systems, "Level 1" represents unsatisfactory performers.
Source: The Conference Board of Canada.

**Chart 14**
Number of Performance Levels
(n=225; per cent of organizations)

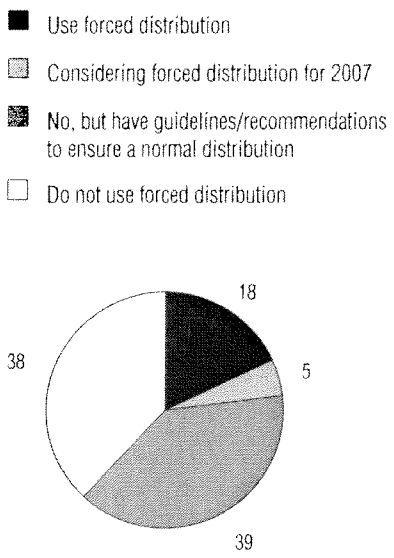



Source: The Conference Board of Canada.

## COMPENSATING IN A HOT LABOUR MARKET

The booming oil and gas sector in Western Canada is putting pressure on compensation in the region, particularly in specific markets such as Calgary and Fort McMurray. While this part of the country certainly represents a challenge, other regions may be falling victim to a spinoff effect. For instance, more than half of organizations this year (57 per cent) find themselves operating in a hot market, and while nearly three-quarters of these organizations identified Alberta (Calgary, Edmonton and

**Chart 15**
Forced Performance Distribution and Guidelines
(n=235; per cent of organizations with performance appraisal rating system)



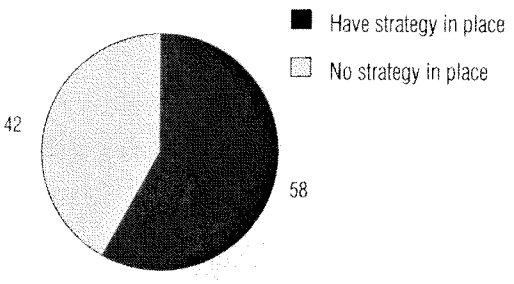

Source: The Conference Board of Canada.

**Table 18**
Cash Compensation Practices in a Hot Labour Market
(n=93; per cent; based on organizations that reported having a hot market and having at least one strategy)

| | Yes | No | Considering |
|---|---|---|---|
| Regional rates of pay/salary ranges | 56 | 27 | 8 |
| Regionally based salary premiums | 28 | 38 | 8 |
| Signing bonuses (only in hot markets) | 37 | 29 | 6 |
| Retention bonuses (only in hot markets) | 29 | 30 | 12 |
| Regional merit programs | 4 | 53 | 3 |
| Retention bonuses (more money for hot markets) | 14 | 39 | 6 |
| Stock options (higher awards in hot markets) | 6 | 51 | 2 |
| Short-term incentives (higher targets in hot markets) | 6 | 45 | 5 |
| Stock options (higher employee participation rates in hot markets) | 3 | 51 | 2 |
| Signing bonuses (more money for hot markets) | 11 | 37 | 5 |
| Other | 14 | 37 | 0 |

Source: The Conference Board of Canada.

**Chart 16**
Dealing with a Hot Labour Market
(n=160; per cent of organizations operating in a hot market)




Source: The Conference Board of Canada.

Fort McMurray) as their number-one hot market, more than 20 per cent identified locations in Central Canada. Among these organizations, slightly more than half (58 per cent) report having compensation practices in place to help alleviate some of the pressure.

By a wide margin, regional rates of pay or salary ranges are the most common approach employed by organizations to deal with their respective hot market. This practice is cited by 56 per cent of organizations that reported having a hot market and that have at least one strategy in place. Signing bonuses are the next most prevalent option in hot markets (used by 37 per cent of these organizations), with approximately 3 in 10 having retention bonuses and regionally based salary premiums.

Few organizations operating in a hot market provided concrete details on regional merit increases and salary premiums. However, the information shared by several respondents (fewer than 12) certainly paints an interesting portrait of the lengths to which these organizations must go to attract and retain employees. The average merit increase planned for 2007 is 4.9 per cent in Calgary and 5.8 per cent in Fort McMurray, compared with the national average of 3.9 per cent. Actual increases in 2006 for these areas were 4.6 and 4.2 per cent, respectively. Regional rates and premiums can be 5 to 25 per cent higher than national rates.

The use of flex days—which give employees time off in addition to their regular vacation entitlement and personal leave—is not a common approach to combatting workforce pressures among organizations responding this year. Nevertheless, 16 per cent have implemented the benefit—sometimes referred to as "Golden Fridays"—with the average allotment among these organizations being 10 days per employee. The prevalence of flex days among organizations operating in a hot market is 19 per cent.

Another creative approach cited by one organization coping with a hot market in the Greater Toronto Area involves paying the toll fees for employees who use Highway 407.

CHAPTER 3

# Collective Bargaining

## Chapter Summary

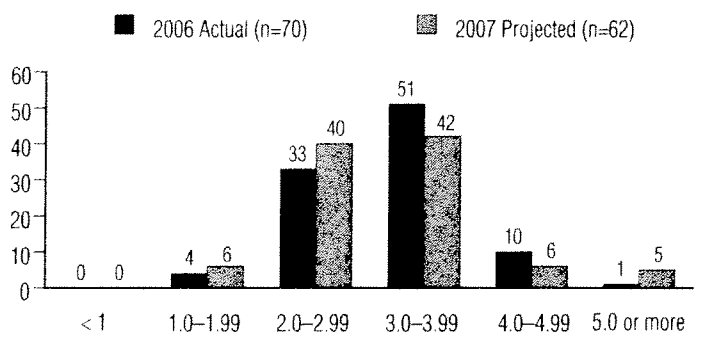
- The projected average wage increase among unionized employees is 3 per cent in 2007. The average for 2006 was 3.1 per cent.
- Four in 10 respondents have annual variable pay plans for their unionized employees, with cash bonus or incentive plans being most common. The majority of variable pay plans met or exceeded payout targets in 2006. Unionized workers in these organizations received payouts averaging 6.1 per cent of base pay.
- The key bargaining issue for management and unions in the coming year is expected to be wages.

## BASE PAY INCREASES

For unionized employees, the average wage increase projected for 2007 is 3 per cent: 3 per cent in the private sector and 2.9 per cent in the public sector.

The average actual negotiated increase in 2006 was 3.1 per cent. Employees in the public sector received increases that averaged 2.9 per cent, while those in the private sector averaged 3.2 per cent.

**Chart 17**
Distribution of Base Pay Increases*
(per cent)




*Base pay is the average increase applied to the base wage rate, for the year specified (includes any cost of living allowance increases).
Source: The Conference Board of Canada.

## VARIABLE PAY

The prevalence of annual variable pay plans for unionized employees has increased in recent years. This year, 42 per cent of unionized organizations have variable pay for unionized employees, up from 31 per cent in 2001. Cash bonus or incentive plans continue to be the most common forms of variable pay for unionized employees, followed by profit-sharing and gainsharing plans. The majority of variable pay plans achieved (36 per cent) or exceeded (47 per cent) payout targets in 2006, and the majority (91 per cent) of employees received a payout.

Three organizations reported having a long-term incentive plan in place for their unionized employees. These plans include traditional stock options and performance-contingent stock options.

## NEGOTIATION ISSUES

The vast majority (94 per cent) of unionized organizations do not expect work stoppages in 2007. Only seven organizations (5 per cent) believe that an interruption is possible in the coming year.

More than half of respondents (55 per cent) believe that the labour–management relationship within their organization is more cooperative than uncooperative, while one-third (37 per cent) perceive it to be balanced. As in recent years, most organizations (75 per cent) expect the relationship with their unions to remain stable over the next two years. One in six unionized respondents (16 per cent) believe their labour–management relationship will improve, while 9 per cent—12 organizations—believe it will deteriorate.

### Profile of Unionized Employers

- 57 per cent of responding organizations have unionized employees.
- 892 agreements are currently in place.
- 272 agreements expire in 2007, covering 214,647 employees.

Source: The Conference Board of Canada.

According to approximately 4 in 10 organizations, the key bargaining issues for management will include wages, flexible work practices, and health, pensions and other benefits. Productivity, business competitiveness and organizational change are expected to be the top management issues among 3 in 10 organizations.

By a wide margin, wages continue to be identified as the key union issue in the coming year. Health, pensions and other benefits and employment security round out the top three anticipated bargaining issues in 2007.

**Table 19**
Base Pay Increases*

| | | Average # of years in contract (n=75) | Year 1 2006 (n=68) | Year 2 2007 (n=68) | Year 3 2008 (n=60) |
|---|---|---|---|---|---|
| Contracts negotiated since Jan. 1, 2006 | (mean) | 3.1 | 3.1 | 3.0 | 2.9 |
| | (median) | *3.0* | *3.0* | *3.0* | *3.0* |

| | | Average # of years in contract (n=66) | Year 1 2007 (n=61) | Year 2 2008 (n=59) | Year 3 2009 (n=49) |
|---|---|---|---|---|---|
| Contracts to be negotiated before Dec. 31, 2007 | (mean) | 3.0 | 3.0 | 2.8 | 2.8 |
| | (median) | *3.0* | *3.0* | *2.8* | *2.8* |

*Base pay is the average increase applied to the base wage rate for the year specified, (includes any cost of living allowance increases).
Source: The Conference Board of Canada.

**Table 20**
Annual Variable Pay Plan Payouts
(per cent of base pay)

**2006 Payouts**
(Actual based on 2005 performance)

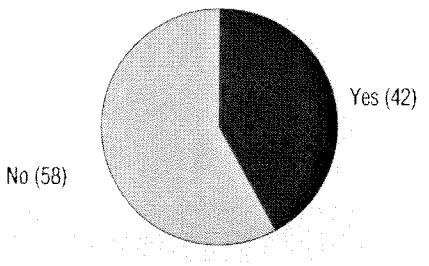
| | |
|---|---|
| Target payout (n=42) | 4.1 |
| Actual payout (n=37) | 6.1 |
| % of employees receiving (n=38) | 91 |
| % of organizations falling short of target | 17 |
| % of organizations meeting target | 36 |
| % of organizations surpassing target | 47 |

**2007 Payouts**
(Projections based on 2006 performance)

| | |
|---|---|
| Target payout (n=35) | 5.5 |
| Plan maximum (n=31) | 6.6 |

Source: The Conference Board of Canada.

**Chart 18**
Prevalence of Annual Variable Pay
(n=119; per cent of unionized organizations)




Source: The Conference Board of Canada.

**Table 21**
Current Negotiation Issues
(per cent of unionized organizations)

| Management issues (n=126) | Per cent of respondents | Union issues (n=126) | Per cent of respondents |
|---|---|---|---|
| 1. Wages | 45 | 1. Wages | 81 |
| 2. Flexible work practices | 45 | 2. Health, pensions and benefits | 59 |
| 3. Health, pensions and benefits | 41 | 3. Employment security | 47 |
| 4. Productivity | 38 | 4. Outsourcing/contracting out | 29 |
| 5. Business competitiveness | 32 | 5. Training and skills development | 20 |
| 6. Organizational change | 27 | 6. Employment/pay equity | 15 |
| 7. Training and skills development | 15 | 8. Organizational change | 12 |
| 8. Outsourcing/contracting out | 14 | 7. Flexible work practices | 10 |
| 9. Employment/pay equity | 10 | 9. Technological change | 8 |
| 10. Technological change | 7 | 10. Variable pay | 3 |
| 11. Variable pay | 6 | 11. Productivity | 2 |
| 12. Employment security | 3 | 12. Business competitiveness | 1 |

Note: Respondents were provided with a list of 12 possible choices (plus "other") and asked to indicate the top three negotiation issues for both management and union.
Source: The Conference Board of Canada.

APPENDIX A

# Respondent Profile

(Total number of responding organizations = 279)

| | Per cent of organizations |
|---|---|
| **Industrial Classification** | |
| Natural resources, excluding oil and gas | 4 |
| Oil and gas | 6 |
| Manufacturing | 9 |
| Food, beverage and tobacco products | 4 |
| Chemical, pharmaceutical and allied products | 6 |
| Construction | 1 |
| High-technology | 6 |
| Communications and telecommunications | 4 |
| Transportation and utilities | 9 |
| Finance, insurance and real estate | 18 |
| Wholesale trade | 3 |
| Retail trade | 4 |
| Education and health | 5 |
| Government | 9 |
| Not-for-profit | 2 |
| Services—Accommodation, food and personal | 2 |
| Services—Professional, scientific and technical | 7 |
| **Characteristics of Responding Organizations** | |
| *Sector* | |
| Private sector corporation | 76 |
| Federal/provincial Crown corporation or agency | 19 |
| Municipal government | 4 |
| *Operations* | |
| Canadian only | 55 |
| North American | 12 |
| Global | 34 |
| *Ownership* | |
| Publicly traded shares | 30 |
| Controlled by Canadian publicly traded company | 3 |
| Controlled by foreign publicly traded company | 19 |
| Privately held | 18 |
| Not applicable | 30 |
| *Assets (Canadian operations)* | |
| $0–$99 million | 20 |
| $100–$999 million | 27 |
| $1 billion and over | 53 |
| *Annual sales/service revenue (Canadian operations)* | |
| $0–$99 million | 17 |
| $100–$999 million | 43 |
| $1 billion and over | 40 |
| *Number of employees* | |
| Fewer than 500 | 24 |
| 500–1,499 | 26 |
| 1,500–5,000 | 29 |
| Over 5,000 | 21 |
| Total number of employees | 1,709,321 |
| Total non-unionized employees | 697,018 |

APPENDIX B

# Participating Organizations

A total of 279 organizations participated in the Compensation Planning Outlook 2007 Survey. The following participants have authorized the publication of their names.

3M Canada Company
Abitibi Consolidated Inc.
Acklands-Grainger Inc.
ADP Canada
Agricore United
Agrium Inc.
Air Canada
Alberta Energy
Alberta Energy and Utilities Board
Alcan Inc.
Alggin Metal Industries Ltd.
Allstate Insurance Company of Canada
AMEC Americas
Aon Reed Stenhouse Inc.
Apotex Inc.
Association of Universities and Colleges of Canada
Assumption Life
ATCO Electric
Atomic Energy of Canada Limited
AXA Canada Inc.
Ballard Power Systems Inc.
Bank of Canada
Bank of Montreal
Barry Callebaut Canada Inc.
Bata Limited
Baxter Corporation
Bayer Inc.
BC Public Service Agency
BCIT
Bell Aliant Regional Communications
Bell Canada/BCE
Biomira Inc.
Bloorview Kids Rehab
BNP Paribas (Canada)
Bombardier Aerospace
Bourse de Montréal Inc.
Boutique Jacob Inc.
Bow Valley College
BP Canada Energy Company
Brewers' Distributor Ltd.
British Columbia Lottery Corp.
Business Development Bank of Canada
CAA South Central Ontario
Cadillac Fairview Corp.
CAE Inc.
Calgary Board of Education
Camero Corporation
Canada Deposit Insurance Corporation
Canada Forgings Inc.
Canada Lands Company CLC Ltd. (Real Estate Division)
Canada Post Corporation
Canadelle
Canadian Blood Services
Canadian Nuclear Safety Commission
Canadian Pacific Railway
Canadian Telecommunications Employees Association
Canadian Tire Financial Services
Canadian Wheat Board
Cara Operations Limited
CBC/Radio-Canada
CDP Capital
Cedara Software
Celanese Canada
Celero Solutions
Centract Residential Property Services
Ceridian Canada Ltd.
Chubb Insurance Company of Canada
Cirque du Soleil
City of Calgary
City of Coquitlam
City of Ottawa
City of Toronto
City of Winnipeg
CMA Holdings Ltd.
CMC Electronics Inc.
CN
Coca-Cola Bottling Company
Cognos Inc.
College and Association of Registered Nurses of Alberta
College of Nurses of Ontario
College of Physicians and Surgeons of Ontario

Corel Corp.
Corus Entertainment Inc.
Credit Union Central Alberta Limited
Credit Union Central of BC
Credit Union Central of Manitoba
Desjardins Financial Security
Devon Canada
Dofasco Inc.
Domtar
Duke Energy Gas Transmission
Durham Regional Police
Dynea Canada Ltd.
EDS Canada Inc.
EHC (formerly Escalator Handrail Company)
E.I. du Pont Canada Company
EnCana Corporation
Enerplus Resources Fund
ENMAX Corporation
EPCOR Utilities Inc.
Ericsson Canada Inc.
Export Development Canada
Fairmont Hotels & Resorts
Federal Express Canada
Federated Cooperative Ltd.
Fédération des caisses Desjardins du Québec
Financial Transactions and Reports Analysis Centre of Canada
Finning (Canada)
Flint Energy Services Ltd.
Fluor Corporation
Ford Motor Company of Canada Limited
Forensic Technology WAI Inc.
Foresters
FortisAlberta Inc.
Franklin Templeton Investments
Frito Lay Canada
Gamma-Dynacare Medical Laboratories
Gaz Métro
General Electric Canada
Gibson Energy Ltd.
GlaxoSmithKline Inc.
Gore Mutual Insurance Company
Gouvernement du Québec (Secrétariat du Conseil du Trésor)
Government of Alberta
Government of Nova Scotia
Great Canadian Gaming Corporation
Guelph Hydro Electric Systems Inc.
Halifax Regional Municipality
Hershey Canada Inc.
Hewitt Équipement Ltée
Hewlett-Packard (Canada) Co.
HSBC Bank Canada
Hudson Bay Mining and Smelting Co. Limited
Hydro One
Hydro-Québec
IBM Canada Ltd.
IHS Energy (Canada) Ltd.
Industrial Alliance Insurance and Financial Services
ING Canada
Inmet Mining
Intergraph Canada Ltd.
Investissement Québec
IPSCO Inc.
Ivanhoe Cambridge
Kellogg Canada Inc.
Kinder Morgan Canada Inc.
KPMG MSLP
L-3 Wescam
Laurentian Bank of Canada
Ledcor Group of Companies
London Health Sciences Centre
Manitoba Hydro
Manpower Services Canada
Manulife Financial
Maxxam Analytics Inc.
MCAP Commercial LP
McCarthy Tétrault
McCormick Canada Inc.
McGill University
MDA Corporation
Meloche Monnex Inc.
Merck Frosst Canada & Co.
Meridian Technologies Inc.
Methanex Corporation
Metro Toronto Convention Centre
Minacs Worldwide
Minto Developments Inc.
Molson Canada
Moneris Solutions Corporation
MTS Allstream Inc.
National Bank of Canada
National Energy Board
NAV CANADA
NB Power Holding Corporation
Neenah Paper
Newfoundland and Labrador Liquor Corporation
Nexen Inc.
Nortel Networks
NPD Group Canada

Ogilvy Renault
Ontario Municipal Employees Retirement System
Ontario Power Generation
Ontario Real Estate Association
Oracle Corporation Canada Inc.
Panasonic Canada Inc.
Patheon Inc.
Pembina Pipeline Corporation
Pengrowth Corporation
People First HR Services Ltd.
Pepsi-QTG Canada
Petro-Canada
Petromont
Pfizer Consumer Healthcare
PharmaScience Inc.
Philips Electronics Ltd.
Polytainers Inc.
Potash Corporation of Saskatchewan Inc.
PPG Canada Inc.
Pratt & Whitney Canada
Purolator Courier Ltd.
QLT Inc.
RBC Financial Group
Red Deer College
Regional Municipality of Halton
Regional Municipality of Niagara
Regional Municipality of York
Reitmans
Research In Motion
Roche Diagnostics
Rogers Communications Inc.
Rothmans Benson & Hedges Inc.
Royal & Sun Alliance Insurance Company of Canada
Russel Metals Inc.
Sanofi pasteur
Sanofi-aventis
Saskatchewan Government Insurance
Saskatchewan Public Service Commission
Saskatchewan Transportation Company
Saskatchewan Wheat Pool
SaskEnergy
SaskPower
SaskTel
Schneider Electric
Scotiabank
Seneca College of Applied Arts and Technology
SGS Canada/SGS Lakefield Research Ltd.
Shaw Communications Inc.
Shell Canada Limited
Sherritt International Corporation
Sico Inc.
SNC-Lavalin
St. Lawrence Cement Inc.
Standard Aero Limited
Standard Life
Staples Business Depot
Startec Canada
Strathcona Paper
Suncor Energy Inc.
Syncrude Canada Limited
Sysco Food Services of Canada Inc.
Talisman Energy Inc.
Tarion Warranty Corporation
TBayTel
TD Bank Financial Group
Tech Data Canada Corporation
Teck Cominco Limited
The Beer Store
The Capital Care Group
The Co-operators General Insurance
The Dominion of Canada General Insurance Company
The North West Company
TimberWest Forest Corporation
Toronto Community Care Access Centre
Toronto Transit Commission
Torys LLP
Tourism British Columbia
Toyota Motor Manufacturing Canada Inc.
Toys "R" Us
TransCanada Corporation
Treasury Board Secretariat
TSX Group Inc.
UFA Co-operative Limited
Ultra Electronics Maritime Systems
Ultramar Ltd.
University of Calgary
University of New Brunswick
University of Toronto
University of Victoria
UPS Canada
Vancity
Vicwest Corporation
Wells Fargo Financial Corporation Canada
West Fraser Timber Co. Ltd.
Westminster Savings Credit Union
Workers Compensation Board—Alberta
Wrigley Canada
Xerox Canada Limited
Zurich

APPENDIX C

# Related Reports and Services

- **Too Few People, Too Little Time: The Employer Challenge of an Aging Workforce**

  Many Canadian employers will face critical talent shortages in the next decade, as the baby-boom generation retires. This briefing sheds light on employers' efforts to address this problem.

- **The Strategic Value of People: Human Resource Trends and Metrics**

  This inaugural report presents results from a 2005 survey of Canadian human resources management trends and metrics. It presents benchmark data and analysis, and a talent management framework to focus measurement.

- **Proceedings From the 2005 Compensation and Human Resources Outlook Conferences**

  These conferences offer a detailed look at the year ahead and provide the benchmarks you need to ensure your compensation strategies remain competitive.

- **Compensation of Boards of Directors, 16th Edition: Governance and Compensation in a Scandal-Scarred World**

  This 16th edition of the report summarizes the results of The Conference Board of Canada's biennial survey of the compensation received by directors for board and committee service during 2004.

- **Compensation Planning Outlook 2006: Pay Pressure Builds as Labour Markets Tighten**

  This report addresses questions concerning the vital topic of compensation and related issues, such as incentive plans, human resources challenges, benefits and collective bargaining.

- **Compensation Research Centre**

  Interact with senior compensation and human resources executives from major Canadian organizations. Gain access to independent, objective, leading-edge research into key compensation, industrial relations and human resources management issues.

- **Councils of Human Resource Executives (National, East and West)**

  Interact with senior human resources executives responsible for the Canadian operations of large organizations. Learn from experts, and discuss issues that support human resources management strategy and key operating decisions.

- **Strategic Human Resources Management Council (for the public sector)**

  Explore best practices in integrating human resources with business planning in the public sector. Examine the strategies for building human resources capacity in your organization and the strategic role of human resources in public sector environments.

- **Canadian Centre for Learning and Development**

  Examine best policies and practices in corporate training and education, learning, human resources and organizational development.

- **Human Resource Development Centre**

  Improve the strategic and competitive position of your organization by adopting the most effective management and leadership practices. Build insight into leading organizations' practices in human resources and organizational development.

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## Senior Leaders in HR

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### Who

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### What

The objective is to help members be more effective in meeting the central needs of their organizations by discussing human resources issues affecting strategy and key operating decisions.

### When

The councils meet three times per year to maximize information sharing, learning, and exposure to strategic human resources management and organizational effectiveness issues.

### Where

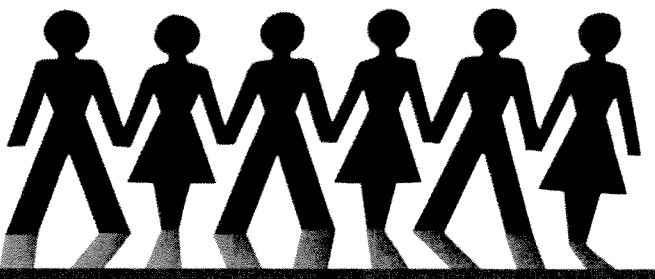
The councils meet in locations across Canada to address current critical human resources issues through both informal networking and structured presentations.

### Why

The Councils of Human Resource Executives facilitate access to Conference Board research and to senior staff and leading experts who present the latest findings on issues, trends and best practices of strategic importance to HR leaders.

### How

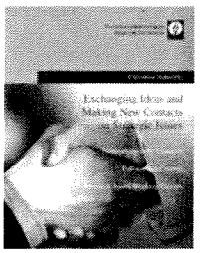
Please contact **Ruth Wright** at **wright@conferenceboard.ca** or **613-526-3280, ext. 369** to receive an invitation to an upcoming meeting.

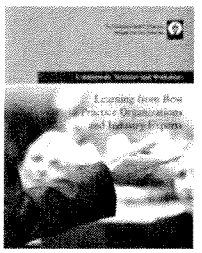


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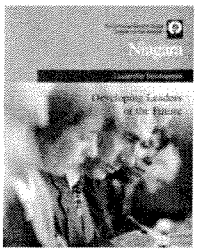




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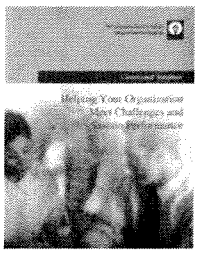
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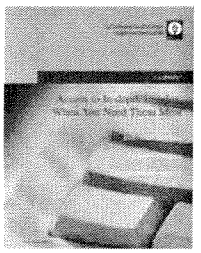




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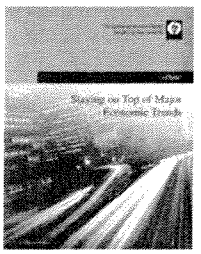
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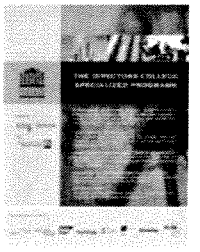




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Compensation Planning Outlook 2008



# Compensation Outlook
# The "Alberta Effect" Puts Upward Pressure on Pay

HUMAN RESOURCES MANAGEMENT

The Conference Board of Canada
**Insights You Can Count On**

Compensation Planning Outlook 2008
by *Stephen Clarke*

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## Preface

*Compensation Planning Outlook 2008* is the 26th edition of this publication, which summarizes the results of The Conference Board of Canada's annual compensation survey. In July 2007, a questionnaire was sent to 1,989 predominantly large and medium-sized Canadian organizations operating in a variety of regions and sectors. A total of 319 respondents participated in the survey, representing a response rate of 16 per cent.

This publication was prepared under the auspices of the Conference Board's Compensation Research Centre (CRC) and was made possible through the ongoing support of the funding members and of survey participants. We owe a special thank you to all of the individuals who took the time to answer this year's comprehensive questionnaire and to the many organizations that participate year after year. Their efforts are very much appreciated, as it is through the commitment of respondents that The Conference Board of Canada is able to produce this report.

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EXECUTIVE SUMMARY

# Compensation Outlook
# The "Alberta Effect" Puts Upward Pressure on Pay

**At a Glance**

- The average non-union pay increase for 2008 is projected to be 3.9 per cent nationally. The highest increases—averaging 5.7 per cent—will occur in the oil and gas industry.
- Wage settlements for unionized workers are expected to average 3.1 per cent in 2008.
- Recruitment and retention issues continue to place intense pressure on businesses; 73 per cent of survey respondents reported challenges with recruiting and/or retaining employees with specific skills.

A strong economy, coupled with a tight labour market, will put upward pressure on pay in 2008. Canada's domestic economy is expected to perform well next year despite the slowdown south of the border. However, with our unemployment rates at record low levels, labour shortages are being felt across the country. This is especially true in Western Canada, where Alberta's oil and gas sector will continue to see strong growth; Saskatchewan's mining and agriculture sectors are robust; and a construction boom, along with a positive outlook for manufacturing in Manitoba, will drive growth in that province. Overall, Canadian workers can once again expect an increase in real wages in 2008.

The average non-union pay increase for 2008, based on the responses of the 319 organizations participating in this year's Compensation Planning Outlook survey, is projected to be 3.9 per cent nationally. This increase is 1.7 percentage points ahead of the 2.2 per cent inflation rate forecast for 2008.

Wage increases will vary by industry and region:

- Projected increases are highest in the oil and gas industry, with an average of 5.7 per cent across all employee groups. Wage gains in this sector are strong nationally but are being driven by Alberta's surging economy, contributing to intense competition for labour as the unemployment rate remains well below 4 per cent—the lowest in the land. The labour market in Alberta will tighten even more next year, as the number of people relocating to the province (on a net basis) is subsiding due to soaring housing costs and improved economic prospects in neighbouring provinces.[1]
- Above-average increases are also expected in the construction, natural resources (excluding oil and gas), and transportation and utilities sectors. Projected increases in these sectors range from 4.4 per cent to 4.8 per cent. Organizations in the education and health, food, beverage and tobacco, services (professional, scientific, technical), and government sectors are also expected to see above-average increases in 2008 (between 4.1 and 4.2 per cent).

1 Economic information contained in this Executive Summary was taken from the Conference Board's Canadian and Provincial Outlook reports, fall and summer 2007 issues.

- Below-average increases are anticipated in the retail trade sector (3.7 per cent), as well as in the chemical, pharmaceutical and allied products, not-for-profit, and wholesale trade sectors (each at 3.6 per cent).
- The lowest average salary increases (3.1 per cent) are expected in the communications/telecommunications and services (accommodation, food, personal) sectors.
- Non-unionized employees in the broader public sector can anticipate average pay increases of 4.1 per cent, compared to 3.9 per cent for employees in the private sector. Anticipated wage settlements for unionized workers are expected to average 3.1 per cent in 2008—3.4 per cent in the public sector, and 3 per cent in the private sector.
- Provincially, Alberta will take the lead, with an average increase of 5.2 per cent. Average increases in British Columbia are projected at 4.2 per cent, while Saskatchewan and Manitoba are also expected to see increases above the national average, at 4.6 per cent.
- Quebec, Ontario, and the Atlantic region are expected to see increases that are below the national average (3.6, 3.4 and 3.2 per cent, respectively).

Overall, anticipated 2008 pay increases sit below those reported for 2007. The actual average salary increase in 2007 was 4.2 per cent, three-tenths of a percentage point higher than last fall's projection for the year. As in previous years, salary increases were not applied "across the board," as the average salary increase for satisfactory performers was 3.6 per cent, compared to an average of 5.5 per cent for those whose performance was outstanding.

Increases to 2007 salary budgets also averaged 4.3 per cent, with approximately 1 per cent of organizations freezing their budgets. Budget increases for 2008 are projected to fall slightly to 4.1 per cent as organizations try to keep their wage bills in check. The average salary structure (range) increase was 2.8 per cent in 2007, which includes the 11 per cent of organizations that did not adjust their ranges last year. The average planned structure increase for 2008 is 2.9 per cent; just over 5 per cent of organizations are planning to hold their ranges steady in the coming year.

The outlook for the Canadian economy remains healthy despite ongoing challenges in the trade sector. Canadian exporters and manufacturers (in the wood products and construction materials sectors, for example) have been hard hit and will continue to struggle in light of the slowdown in the U.S. housing market and the high-flying loonie. Higher resource prices, however, have served to soften the blow, generating solid income gains, especially in Western Canada. As a result, there remains plenty of momentum in the Canadian economy. Growth in gross domestic product is anticipated to accelerate from 2.6 per cent this year to 2.8 per cent in 2008.

Inflation continues to present little concern—it is expected to slow from 2.4 per cent this year to 2.2 per cent in 2008. While growth in corporate profits (before taxes) is anticipated to ease off from this year's 9.8 per cent to 7.3 per cent in 2008, corporate balance sheets remain in remarkable condition.

The Canadian economy is running near full capacity. The unemployment rate of 6 per cent is at a 33-year low and is projected at 5.9 per cent for 2008, contributing to a further tightening of the labour market, especially in Western Canada, where projections for unemployment rates in 2008 again call for record low levels. As the labour market tightens, voluntary turnover rates increase. According to survey respondents, the average turnover rate across all industries for 2007 is 8.5 per cent, over half a percentage point higher than in 2006.

With labour shortages continuing and turnover rates on the rise, recruitment and retention issues remain the hot issue for Canadian organizations. Almost three-quarters (73 per cent) of this year's survey respondents reported challenges in these areas, especially concerning employees with specific skills. The situation continues to be particularly acute in British Columbia and Alberta, where 9 in 10 employers reported recruitment and retention challenges. There appears to be no relief in sight for 2008, as almost 60 per cent of survey respondents from Alberta expect to increase the size of their workforce by an average of 7 per cent next year.

As we approach 2008, growth strategies in the oil and gas sector will create pressure across the land. As a consequence, attracting and retaining talent continues to be the number one priority for compensation planners, and the shortage of skilled workers and the "Alberta effect" will put upward pressure on pay across the country.

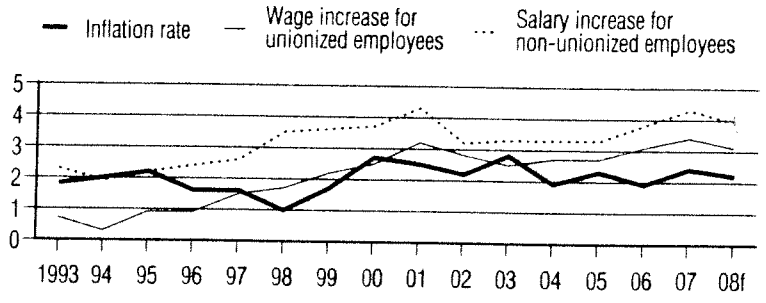
CHAPTER 1

# Compensation Planning and Practices

## Chapter Summary

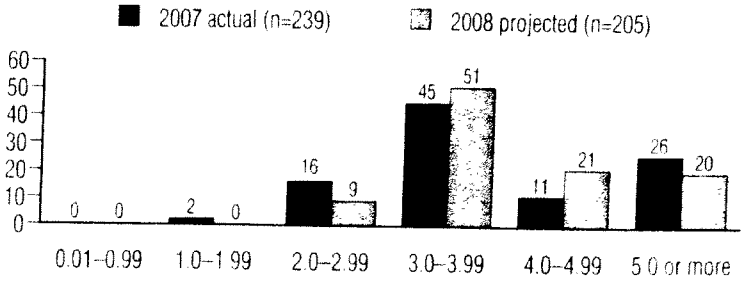
- Real wage gains are projected once again for 2008, with an average non-union pay increase of 3.9 per cent. The average increase for 2007 was 4.2 per cent. Outstanding performers received average increases of 5.5 per cent; those deemed "satisfactory" received 3.6 per cent.
- With competition for valuable talent even tighter than in 2007, very few organizations are expected to freeze salary budgets and ranges in the coming year.
- More than 8 in 10 respondents have variable pay plans, primarily in the form of cash bonuses or incentives. Targets vary considerably across industry and employee groups, with the average cost representing 12.2 per cent of total base pay spending.
- The use of traditional stock option plans continues to decline.

**Chart 1**
Inflation vs. Increases, 1993–2008
(percentage change)




f = forecast
Sources: The Conference Board of Canada; Human Resources and Social Development Canada, Workplace Information Directorate.

**Chart 2**
Average Salary Increase Distribution
(percentage of organizations)




Note: Totals may not equal 100 due to rounding.
Source: The Conference Board of Canada.

## MANAGING BASE PAY

For the 13th consecutive year, base pay increases are predicted to exceed inflation, resulting in real gains for Canadian employees. The average non-union pay increase for 2008 is projected to be 3.9 per cent, 1.7 percentage points ahead of the 2.2 per cent inflation rate forecast for the year.

**Table 1**
2007 Actual Compensation Increases, by Employee Group*
(non-unionized employees)

| Employee group | Policy line (range increase; %)** | | Total increase to budget (%) | | Employees receiving an increase (%) | Average increase for those receiving one (%) | Average increase among all employees (%) | | 2007 average base salary ($) |
|---|---|---|---|---|---|---|---|---|---|
| | zeros included | zeros excluded | zeros included | zeros excluded | | | zeros included | zeros excluded | |
| Senior executives | 2.7 | 3.5 | 4.4 | 4.5 | 91.2 | 4.8 | 4.7 | 4.8 | 249,010 |
| | *2.5* | *3.0* | *3.9* | *4.0* | *100.0* | *4.0* | *4.0* | *4.0* | *225,000* |
| Executives | 3.0 | 3.6 | 4.5 | 4.6 | 93.0 | 4.7 | 4.5 | 4.6 | 168,273 |
| | *2.5* | *3.0* | *4.0* | *4.0* | *100.0* | *4.0* | *3.9* | *3.9* | *161,092* |
| Management | 3.0 | 3.4 | 4.3 | 4.4 | 94.2 | 4.5 | 4.3 | 4.3 | 100,883 |
| | *2.7* | *3.0* | *3.9* | *3.9* | *99.0* | *4.0* | *3.8* | *3.8* | *96,681* |
| Professional—technical | 2.9 | 3.4 | 4.4 | 4.5 | 93.3 | 4.5 | 4.2 | 4.2 | 72,881 |
| | *2.5* | *2.8* | *3.9* | *3.9* | *99.0* | *4.0* | *3.6* | *3.6* | *70,900* |
| Professional—non-technical | 2.8 | 3.2 | 4.3 | 4.3 | 93.5 | 4.4 | 4.2 | 4.2 | 68,676 |
| | *2.5* | *2.8* | *3.8* | *3.8* | *99.0* | *3.8* | *3.6* | *3.6* | *67,763* |
| Technical and skilled trades | 2.7 | 3.2 | 4.2 | 4.3 | 93.9 | 4.1 | 3.9 | 4.0 | 60,053 |
| | *2.6* | *2.9* | *3.8* | *3.9* | *100.0* | *3.5* | *3.5* | *3.5* | *59,300* |
| Clerical and support | 2.7 | 3.2 | 4.2 | 4.2 | 91.5 | 4.1 | 3.9 | 3.9 | 43,923 |
| | *2.5* | *2.8* | *3.7* | *3.7* | *98.0* | *3.6* | *3.5* | *3.5* | *43,316* |
| Service and production | 2.4 | 2.9 | 4.0 | 4.1 | 93.4 | 3.9 | 3.8 | 3.9 | 45,129 |
| | *2.5* | *2.8* | *3.6* | *3.7* | *100.0* | *3.5* | *3.5* | *3.5* | *40,000* |
| **Overall** | **2.8** | **3.3** | **4.3** | **4.3** | **92.3** | **4.4** | **4.2** | **4.2** | **n.a.** |
| | ***2.6*** | ***2.9*** | ***3.8*** | ***3.8*** | ***98.5*** | ***3.9*** | ***3.7*** | ***3.7*** | ***n.a.*** |

***Employee Group Definitions***
**Senior executives:** all executives reporting directly to the chief executive officer
**Executives:** all other executives
**Management:** senior and middle management: plan, develop, and implement policies and programs
**Professional—technical:** analysts, engineers, information technology specialists, developers, etc.
**Professional—non-technical:** all other professionals: accountants, lawyers, doctors, etc., excluding salespeople
**Technical and skilled trades:** technologists, technicians, millwrights, etc.
**Clerical and support:** secretaries, clerks, coordinators, assistants, word-processing staff
**Service and production:** service, production, maintenance, transportation, etc.

***Definitions***
**Policy line:** increase to salary ranges, among organizations with ranges
**Total increase to budget:** increase to salary budget, including all budgeted components of compensation program (range, merit, economic, progression, promotion, etc.)
**Employees receiving an increase:** as a percentage of employees in category
**Average increase for those receiving one:** increase to those receiving an increase (i.e., total increase from all sources—range, merit, economic, progression—rolled into base pay)
**Average increase among all employees:** based on all employees in category
**Average base salary:** approximate average annual base salary after the increases have been applied

a. = not applicable
Note: For each result, the top number is the average (mean) and the bottom number (in italics) is the median.
Source: The Conference Board of Canada.

We expect that salary budget increases will average 4.1 per cent in 2008, slightly lower than the average seen in 2007 (4.3 per cent) but generally higher than the average witnessed in previous years (3.8 per cent in 2006, 3.3 per cent in 2005, and 3.4 per cent in 2004). For the second consecutive year, approximately 1 per cent of respondents anticipate an overall freeze on salary budgets for the coming year—down from 2006 (2 per cent) and 2005 (5 per cent).

As in the past three years, salary range (or "structure") movement is expected to edge upwards, with an average increase of 2.9 per cent planned for 2008, up from 2.8 per cent in 2007, 2.4 per cent in 2006, and 2.1 per cent in 2005. In addition, significantly fewer organizations are planning to hold their ranges constant in the coming year. Just over 5 per cent of organizations with salary ranges are planning to freeze them in 2008, down from 11 per cent in 2007 and 13 per cent in 2006.

**Table 2**
2008 Planned Compensation Increases, by Employee Group
(non-unionized employees)

| | Policy line (range increase; %) | | Total increase to budget (%) | | Average increase among all employees (%) | |
|---|---|---|---|---|---|---|
| **Employee group*** | **zeros included** | **zeros excluded** | **zeros included** | **zeros excluded** | **zeros included** | **zeros excluded** |
| Senior executives | 2.8 | 3.0 | 4.1 | 4.3 | 4.1 | 4.1 |
| | *3.0* | *3.0* | *3.8* | *4.0* | *3.5* | *3.5* |
| Executives | 2.9 | 3.1 | 4.2 | 4.3 | 4.1 | 4.2 |
| | *3.0* | *3.0* | *4.0* | *4.0* | *3.8* | *3.8* |
| Management | 3.0 | 3.1 | 4.2 | 4.3 | 4.0 | 4.0 |
| | *3.0* | *3.0* | *4.0* | *4.0* | *3.5* | *3.5* |
| Professional—technical | 3.0 | 3.1 | 4.2 | 4.3 | 4.0 | 4.0 |
| | *3.0* | *3.0* | *4.0* | *4.0* | *3.5* | *3.5* |
| Professional—non-technical | 3.0 | 3.1 | 4.2 | 4.2 | 4.0 | 4.0 |
| | *3.0* | *3.0* | *4.0* | *4.0* | *3.5* | *3.5* |
| Technical and skilled trades | 2.9 | 3.1 | 4.1 | 4.2 | 3.9 | 4.0 |
| | *3.0* | *3.0* | *4.0* | *4.0* | *3.8* | *3.9* |
| Clerical and support | 2.9 | 3.1 | 4.1 | 4.1 | 3.8 | 3.8 |
| | *2.8* | *3.0* | *3.8* | *3.8* | *3.5* | *3.5* |
| Service and production | 2.7 | 2.9 | 3.9 | 4.0 | 3.6 | 3.7 |
| | *2.5* | *2.7* | *3.5* | *3.6* | *3.5* | *3.5* |
| **Overall** | **2.9** | **3.1** | **4.1** | **4.2** | **3.9** | **3.9** |
| | ***2.8*** | ***3.0*** | ***3.8*** | ***3.9*** | ***3.5*** | ***3.5*** |

*See Table 1 for definitions.
Note: For each result, the top number is the average (mean) and the bottom number (in italics) is the median.
Source: The Conference Board of Canada.

**Table 3**
2007 Actual Compensation Increases, by Industry, Sector, and Region
(non-unionized employees)

| | Policy line (range increase; %) | | Total increase to budget (%) | | Employees receiving an increase (%) | Average increase for those receiving one (%) | Average increase among all employees (%) | |
|---|---|---|---|---|---|---|---|---|
| | zeros included | zeros excluded | zeros included | zeros excluded | | | zeros included | zeros excluded |
| **Overall** | **2.8** | **3.3** | **4.3** | **4.3** | **92.3** | **4.4** | **4.2** | **4.2** |
| **Industry** | | | | | | | | |
| Oil and gas (n=18) | 5.6 | 5.6 | 6.8 | 6.8 | 97.0 | 6.8 | **6.8** | 6.8 |
| Construction* (n=4) | 6.4 | 6.4 | 5.8 | 5.8 | 97.2 | 5.5 | **4.6** | 4.6 |
| Natural resources, excluding oil and gas (n=11) | 4.7 | 5.3 | 5.4 | 5.4 | 98.7 | 5.6 | **5.5** | 5.5 |
| Transportation and utilities (n=26) | 3.2 | 3.4 | 4.6 | 4.7 | 95.9 | 4.9 | **4.7** | 4.7 |
| Education and health (n=20) | 3.3 | 3.3 | 4.6 | 4.6 | 95.5 | 4.1 | **3.9** | 3.9 |
| Food, beverage, and tobacco (n=9) | 3.5 | 3.7 | 4.0 | 4.2 | 93.0 | 3.9 | **4.0** | 4.2 |
| Services—Professional, scientific, technical (n=25) | 2.5 | 2.8 | 4.3 | 4.3 | 93.6 | 4.7 | **4.4** | 4.4 |
| Government (n=32) | 3.2 | 3.5 | 4.5 | 4.7 | 99.2 | 4.7 | **4.9** | 4.9 |
| Retail trade (n=15) | 2.0 | 2.9 | 4.4 | 4.4 | 83.0 | 4.3 | **4.1** | 4.1 |
| Chemical, pharmaceutical, and allied products (n=15) | 2.7 | 3.2 | 3.4 | 3.7 | 90.4 | 3.9 | **3.6** | 3.7 |
| Not-for-profit (n=10) | 2.3 | 2.9 | 3.9 | 3.9 | 96.7 | 3.7 | **3.8** | 3.6 |
| Wholesale trade (n=9) | 2.6 | 2.6 | 3.8 | 3.8 | 87.3 | 3.8 | **3.5** | 3.5 |
| Manufacturing (n=37) | 2.3 | 2.9 | 3.7 | 3.7 | 96.0 | 3.7 | **3.7** | 3.7 |
| Finance, insurance, and real estate (n=53) | 2.2 | 2.7 | 3.9 | 4.0 | 84.9 | 4.1 | **3.8** | 4.0 |
| High-technology (n=15) | 2.4 | 3.1 | 3.4 | 3.4 | 90.0 | 3.6 | **3.3** | 3.3 |
| Communications and telecommunications (n=9) | 2.8 | 4.2 | 3.2 | 3.2 | 83.0 | 3.1 | **2.5** | 2.6 |
| Services—Accommodation, food, personal (n=9) | 2.9 | 3.8 | 3.7 | 3.7 | 96.1 | 3.3 | **3.2** | 3.2 |
| **Sector** | | | | | | | | |
| Private sector (n=233) | 2.6 | 3.2 | 4.2 | 4.2 | 92.0 | 4.3 | **4.1** | 4.1 |
| Public sector (n=86) | 3.3 | 3.5 | 4.7 | 4.8 | 93.4 | 4.7 | **4.5** | 4.5 |
| **Region** | | | | | | | | |
| British Columbia (n=24) | 3.1 | 3.7 | 4.7 | 4.8 | 87.3 | 4.9 | **4.5** | 4.6 |
| Alberta (n=53) | 4.1 | 4.7 | 6.2 | 6.2 | 95.8 | 6.2 | **6.0** | 6.0 |
| Manitoba/Saskatchewan (n=27) | 3.6 | 3.8 | 5.1 | 5.1 | 93.7 | 4.9 | **4.6** | 4.6 |
| Ontario (n=163) | 2.4 | 3.0 | 3.7 | 3.7 | 92.3 | 3.8 | **3.6** | 3.6 |
| Quebec (n=38) | 2.4 | 2.5 | 3.7 | 3.8 | 92.4 | 4.0 | **3.9** | 3.9 |
| Atlantic (n=12) | 2.3 | 2.6 | 3.3 | 3.9 | 90.0 | 2.7 | **2.5** | 2.5 |

Caution must be exercised in interpreting the data from this industry. Only two organizations provided information on range and overall salary increases for 2007–08.
Note: The sample sizes above (n=) indicate the number of organizations providing a response for at least one actual or projected increase.
Source: The Conference Board of Canada.

**Table 4**
2008 Planned Compensation Increases, by Industry, Sector, and Region
(non-unionized employees)

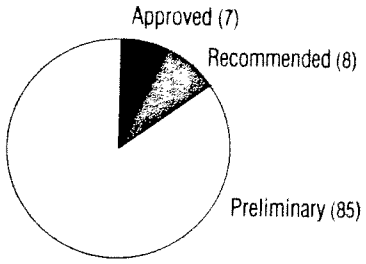
| | Policy line (range increase; %) | | Total increase to budget (%) | | Average increase among all employees (%) | |
|---|---|---|---|---|---|---|
| | zeros included | zeros excluded | zeros included | zeros excluded | zeros included | zeros excluded |
| **Overall** | **2.9** | **3.1** | **4.1** | **4.2** | **3.9** | **3.9** |
| **Industry** | | | | | | |
| Oil and gas (n=18) | 4.3 | 4.3 | 5.5 | 5.5 | **5.7** | 5.7 |
| Construction* (n=4) | 6.4 | 6.4 | 5.7 | 5.7 | **4.8** | 4.8 |
| Natural resources, excluding oil and gas (n=11) | 3.4 | 3.4 | 4.6 | 4.6 | **4.7** | 4.7 |
| Transportation and utilities (n=26) | 3.4 | 3.4 | 4.5 | 4.5 | **4.4** | 4.4 |
| Education and health (n=20) | 3.7 | 3.7 | 4.6 | 4.6 | **4.2** | 4.2 |
| Food, beverage, and tobacco (n=9) | 3.9 | 3.9 | 4.5 | 4.5 | **4.2** | 4.2 |
| Services—Professional, scientific, technical (n=25) | 2.4 | 2.9 | 4.5 | 4.5 | **4.2** | 4.2 |
| Government (n=32) | 2.9 | 3.1 | 4.4 | 4.4 | **4.1** | 4.1 |
| Retail trade (n=15) | 2.5 | 3.3 | 4.7 | 4.7 | **3.7** | 3.7 |
| Chemical, pharmaceutical, and allied products (n=15) | 2.9 | 2.9 | 3.5 | 3.8 | **3.6** | 3.6 |
| Not-for-profit (n=10) | 3.7 | 4.1 | 3.9 | 3.9 | **3.6** | 3.6 |
| Wholesale trade (n=9) | 3.1 | 3.1 | 3.5 | 3.5 | **3.6** | 3.6 |
| Manufacturing (n=37) | 2.4 | 2.6 | 3.6 | 3.7 | **3.4** | 3.5 |
| Finance, insurance, and real estate (n=53) | 2.3 | 2.5 | 3.6 | 3.8 | **3.4** | 3.6 |
| High-technology (n=15) | 2.3 | 2.3 | 3.6 | 3.6 | **3.3** | 3.3 |
| Communications and telecommunications (n=9) | 2.8 | 3.0 | 3.0 | 3.2 | **3.1** | 3.1 |
| Services—Accommodation, food, personal (n=9) | 2.8 | 3.0 | 3.7 | 3.7 | **3.1** | 3.1 |
| **Sector** | | | | | | |
| Private sector (n=233) | 2.8 | 3.0 | 4.0 | 4.1 | **3.9** | 3.9 |
| Public sector (n=86) | 3.3 | 3.3 | 4.6 | 4.6 | **4.1** | 4.1 |
| **Region** | | | | | | |
| British Columbia (n=24) | 3.4 | 3.4 | 5.0 | 5.0 | **4.2** | 4.2 |
| Alberta (n=53) | 4.0 | 4.0 | 5.4 | 5.4 | **5.2** | 5.2 |
| Manitoba/Saskatchewan (n=27) | 3.2 | 3.4 | 4.8 | 4.8 | **4.6** | 4.6 |
| Ontario (n=163) | 2.5 | 2.8 | 3.6 | 3.7 | **3.4** | 3.4 |
| Quebec (n=38) | 2.5 | 2.5 | 3.5 | 3.6 | **3.6** | 3.6 |
| Atlantic (n=12) | 2.7 | 2.7 | 3.4 | 3.4 | **3.2** | 3.2 |

*Caution must be exercised in interpreting the data from this industry. Only two organizations provided information on range and overall salary increases for 2007–08.
Note: The sample sizes above (n=) indicate the number of organizations that provided a response for at least one actual or projected increase.
Source: The Conference Board of Canada.

The average salary increase for 2007 was 4.2 per cent among all non-unionized employees across all responding organizations. Nearly 93 per cent of employees received an increase to base salary in 2007, taking home raises of 4.4 per cent on average.

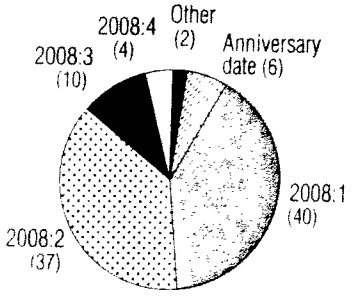
Outstanding performers received an average increase of 5.5 per cent, compared with 3.6 per cent for solid performers. The degree to which organizations differentiate base pay increases according to performance varies widely: outstanding performers garnered increases ranging from less than 1 percentage point up to 8 percentage points higher than those given to solid performers.

**Chart 3**
Current Status of Salary Budget Recommendations for 2008
(n=310; percentage of organizations)




Source: The Conference Board of Canada.

**Chart 4**
Planned Implementation of Salary Increases for 2008
(n=307; percentage of organizations)




Source: The Conference Board of Canada.

Sixty-one per cent of organizations provided data on increases for solid and outstanding performance. Among these, nearly 8 in 10 (79 per cent) reward outstanding performance with increases that are up to twice the average increase given to satisfactory performers. Nearly 1 in 5 (19 per cent) reward outstanding performance with increases that are two to three times the average increase for satisfactory performance, while only 2 per cent reported that average increases for outstanding performers are more than three times those for satisfactory performers.

## VARIABLE PAY

The majority of Canadian organizations (83 per cent) have at least one annual variable pay plan. These plans are especially popular in the private sector, where 93 per cent of organizations reported having at least one. By comparison, 56 per cent of public sector organizations have one or more variable pay plans.

**Table 5**
Prevalence of Annual Variable Pay, by Sector and Employee Group
(per cent; based on organizations that reported for each employee category; non-unionized employees)

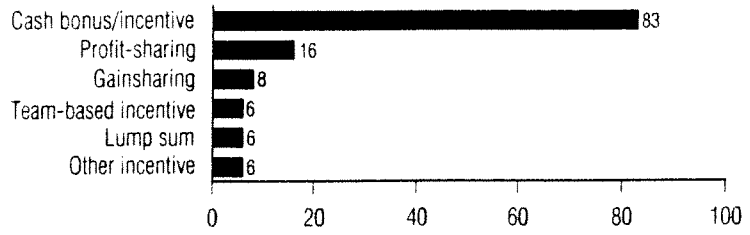
| Employee group | Public sector (n=86) | Private sector (n=233) | All sectors combined (n=319) |
|---|---|---|---|
| **Overall** | **56** | **93** | **83** |
| Senior executives | 52 | 80 | 73 |
| Executives | 47 | 77 | 69 |
| Management | 47 | 89 | 78 |
| Professional—technical | 35 | 76 | 65 |
| Professional—non-technical | 38 | 72 | 63 |
| Technical and skilled trades | 20 | 40 | 35 |
| Clerical and support | 34 | 68 | 59 |
| Service and production | 13 | 42 | 34 |

Source: The Conference Board of Canada.

Cash bonus or incentive plans are the most common form of annual variable pay plan, used by 83 per cent of organizations that have at least one of these plan types. Profit-sharing plans rank a distant second at 16 per cent, followed by gainsharing plans at 8 per cent, and team-based incentives and lump sum payments at 6 per cent each.

Variable pay targets differ considerably across employee groups and also across industries. The actual cost of annual variable pay plans averaged 12.2 per cent of total base pay spending in 2007. These costs are highest for organizations in the oil and gas sector (averaging 19 per cent of total base pay spending), compared with those in the government sector (a 6.4 per cent average).

**Chart 5**
Annual Variable Pay—Plan Types
(n=265; per cent; based on organizations with at least one annual variable pay plan in place)




Note: Figures do not add to 100 because some respondents have more than one plan.
Source: The Conference Board of Canada.

**Table 6**
Annual Variable Pay Plan Payouts, by Employee Group
(expressed as percentage of base salary; non-unionized employees)

**2007 Payouts***

| | Average payout | | | Percentage of organizations | | |
|---|---|---|---|---|---|---|
| **Employee group** | **Target payout** | **Actual payout** | **Receiving payouts**** | **Exceeded target** | **Met target** | **Fell short of target** |
| Senior executives (n=184) | 38.6 | 47.3 | 93.8 | 60 | 17 | 24 |
| Executives (n=180) | 28.7 | 35.3 | 94.0 | 60 | 17 | 22 |
| Management (n=216) | 15.8 | 19.1 | 91.8 | 56 | 15 | 29 |
| Professional—technical (n=179) | 10.1 | 12.1 | 89.1 | 50 | 21 | 28 |
| Professional—non-technical (n=172) | 9.8 | 12.3 | 90.6 | 50 | 21 | 29 |
| Technical and skilled trades (n=91) | 7.2 | 9.1 | 95.7 | 54 | 19 | 27 |
| Clerical and support (n=160) | 5.7 | 7.3 | 94.9 | 57 | 18 | 25 |
| Service and production (n=85) | 6.0 | 8.9 | 92.2 | 49 | 24 | 27 |

**2008 Projected Payouts***

| **Employee group** | **Target payout** | **Plan maximum** |
|---|---|---|
| Senior executives (n=171) | 38.9 | 65.5 |
| Executives (n=165) | 28.8 | 49.0 |
| Management (n=194) | 15.8 | 27.2 |
| Professional—technical (n=160) | 10.1 | 17.3 |
| Professional—non-technical (n=159) | 9.8 | 17.5 |
| Technical and skilled trades (n=84) | 7.0 | 13.8 |
| Clerical and support (n=147) | 5.5 | 11.4 |
| Service and production (n=81) | 5.9 | 11.6 |

*2007 payouts refer to payouts based on 2006 results and paid in 2007; 2008 payouts refer to payouts based on 2007 results, to be paid in 2008.
**Percentage of eligible employees in category.
Source: The Conference Board of Canada.

In 2007, on average, 93 per cent of eligible employees in organizations with variable pay received a payout. Overall spending on these plans is expected to increase slightly in 2008, with plan targets forecast to average 11.6 per cent of base pay spending, up from the average target of 11.1 per cent in 2007.

Among organizations that have variable pay plans, 35 per cent include payouts in the calculation of pensionable earnings for all employees. An additional 4.9 per cent consider only a portion of variable pay as pensionable, while 9.8 per cent report that variable pay is included in pensionable earnings only for selected employees, typically executives.

Almost one-quarter (62) of the organizations that have variable pay made changes to their plans in 2007. Most cases involved adjusting targets.

**Table 7**
2008 Variable Pay Plan Targets for Selected Industries, by Employee Group
(expressed as percentage of base salary)

| Employee group | Government | Financial services | Manufacturing | Oil and gas | Transportation and utilities | Natural resources | Chemical, pharmaceutical and allied products | Communications/ telecom | High-tech |
|---|---|---|---|---|---|---|---|---|---|
| Senior executive | 20.7 | 38.1 | 41.3 | 49.2 | 35.6 | 52.1 | 33.9 | 37.7 | 47.0 |
| Executives | 15.5 | 28.2 | 29.8 | 32.5 | 27.0 | 39.6 | 27.0 | 30.1 | 35.0 |
| Management | 10.9 | 15.4 | 16.0 | 22.5 | 13.3 | 23.3 | 17.6 | 14.9 | 16.6 |
| Professional—technical | 9.0 | 9.1 | 10.4 | 13.9 | 9.3 | 13.4 | 10.8 | 9.3 | 15.4 |
| Professional—non-technical | 8.6 | 9.4 | 9.3 | 12.9 | 9.5 | 12.1 | 10.2 | 9.4 | 16.4 |
| Technical and skilled trades | 7.9 | 5.9 | 7.7 | 7.5 | 7.4 | 9.2 | 7.1 | 8.8 | 8.5 |
| Clerical and support | 5.3 | 5.4 | 6.3 | 7.0 | 6.2 | 6.9 | 5.3 | 7.0 | 6.9 |
| Service and production | 4.0 | 5.8 | 6.5 | 7.3 | 6.5 | 7.5 | 5.6 | 5.0 | 7.0 |

Source: The Conference Board of Canada.

**Table 8**
Variable Pay Plan Target Adjustments, by Employee Group
(per cent; based on organizations providing 2007 and 2008 targets)

| Employee group | Adjusting target | Increasing | Average target increase | Decreasing | Average target decrease | Overall average target movement* |
|---|---|---|---|---|---|---|
| Senior executives (n=163) | 13.5 | 9.8 | 6.8 | 3.7 | -13.3 | 1.3 |
| Executives (n=155) | 13.5 | 7.7 | 4.1 | 5.8 | -4.0 | 0.6 |
| Management (n=187) | 11.2 | 6.4 | 4.3 | 4.8 | -3.7 | 0.9 |
| Professional—technical (n=154) | 10.4 | 7.8 | 1.4 | 2.6 | -2.4 | 0.5 |
| Professional—non-technical (n=154) | 10.4 | 7.8 | 1.3 | 2.6 | -2.4 | 0.4 |
| Technical and skilled trades (n=82) | 11.0 | 7.3 | 2.6 | 3.7 | -1.3 | 1.3 |
| Clerical and support (n=143) | 9.8 | 6.3 | 1.7 | 3.5 | -1.0 | 0.7 |
| Service and production (n=79) | 6.3 | 5.1 | 2.1 | 1.3 | -1.5 | 1.4 |

Average target movements based upon data provided by those organizations adjusting targets.
Source: The Conference Board of Canada.

The prevalence of medium-term or "mid-term" plans that pay out after two or three years has increased again. In 2007, nearly 18 per cent of organizations employed these types of incentives, up from 13 per cent in 2006 and 8 per cent in 2005. Twenty-three per cent of private sector organizations use these types of plans, while they are virtually non-existent among public sector respondents.

## LONG-TERM INCENTIVE PLANS

The prevalence of long-term incentive plans (LTIPs) remains stable, with 48 per cent of organizations reporting the use of at least one type of LTIP in 2007. LTIPs are far more common in the private sector, where 61 per cent of organizations use them. The vast majority of firms that are publicly traded (79 per cent) continue to offer LTIPs, as do most of the firms that are controlled by a publicly traded company. These incentive plans are not common in the public sector, with just over 12 per cent of organizations reporting their use.

Stock option plans remain the most prevalent form of LTIP but continue to decline slowly in popularity. More than half (52 per cent) of organizations with an LTIP currently have this type of plan in place, down from a high of 73 per cent 10 years ago when the Conference Board first collected this information. The prevalence of other types of LTIPs remains largely unchanged from the situation in 2006: 23 per cent of firms with LTIPs use restricted share units, and 18 per cent have long-term cash plans. Long-term cash is the type of plan most often used by the few public sector firms with LTIPs.

**Table 9**
Prevalence of Long-Term Incentive Plans,* by Sector and Employee Group
(per cent; based on organizations that reported for each employee category; non-unionized employees)

| | Public sector (n=86) | Private sector (n=233) |
|---|---|---|
| **Overall** | **12** | **61** |
| Senior executives | 9 | 53 |
| Executives | 6 | 50 |
| Management | 3 | 36 |
| Professional—technical | 0 | 18 |
| Professional—non-technical | 0 | 15 |
| Other non-management | 0 | 10 |

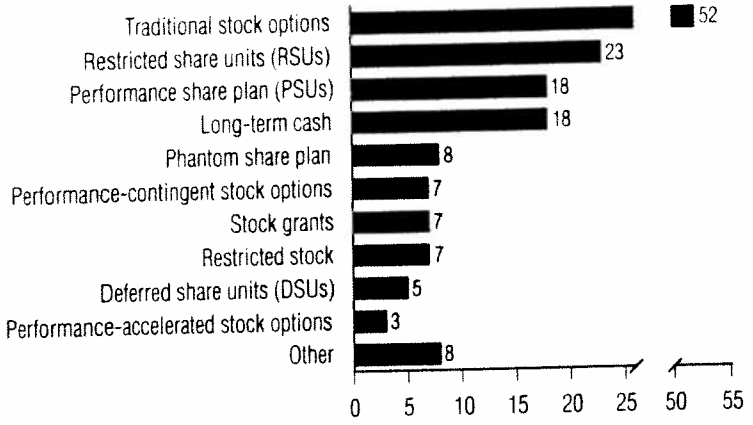
*Refers only to ongoing plans. For the purposes of this question, any ad hoc rewards of stock options or grants are excluded.
Source: The Conference Board of Canada.

**Table 10**
Long-Term Incentive Plans—Eligibility, by Employee Group*
(n=153; per cent; based on organizations with at least one LTIP in place)

| | Organizations with LTIP for this category | Employees eligible for LTIP(s) (average) | Employees receiving LTI in 2007 (average) |
|---|---|---|---|
| Senior executives | 86 | 96 | 93 |
| Executives | 80 | 96 | 93 |
| Management | 56 | 77 | 77 |
| Professional—technical | 27 | 76 | 60 |
| Professional—non-technical | 23 | 80 | 62 |
| Other non-management | 15 | 65 | 55 |

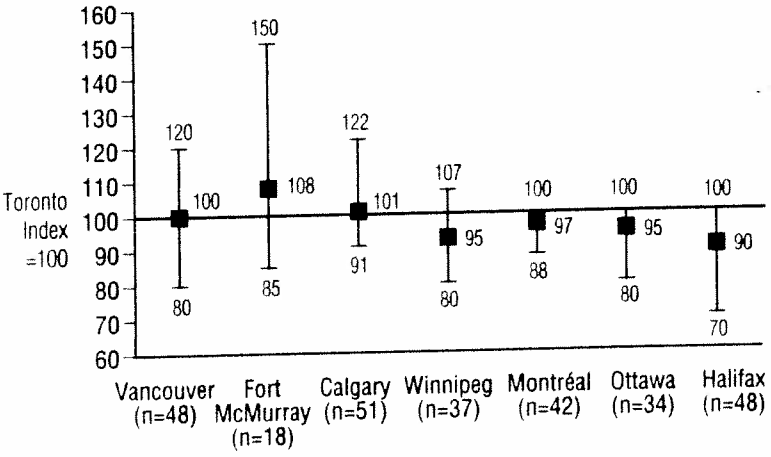
*Definitions provided to respondents:
**% eligible:** as percentage of total employees in the category.
**% receiving:** as percentage of those employees eligible for the incentive.
Source: The Conference Board of Canada.

**Chart 6**
Long-Term Incentive Plans*—Plan Types
(n=153; per cent; based on organizations with at least one LTIP in place)




*Refers only to ongoing plans. For the purposes of this question, any ad hoc rewards of stock options or grants are excluded.
Note: Figures do not add to 100 because some respondents have more than one plan.
Source: The Conference Board of Canada.

**Chart 7**
Regional Compensation Levels




■ = average (mean) for location; high and low numbers represent range of responses.
Note: For ease of comparison, the Toronto area was used as the base (index = 100).
Source: The Conference Board of Canada.

While typically used for executive-level compensation, LTIPs have also been applied to individuals below that level. Twenty-three per cent of organizations with LTIPs offer them to non-management-level employees (e.g., professional non-technical staff such as accountants, lawyers, and doctors), while 15 per cent of organizations offer these types of plans to other non-management employees (e.g., clerical and support, service and production). Seventeen per cent of respondents with LTIPs made changes to their plan in the past 12 months, while 10 per cent are anticipating changes in 2008.

## REWARDS STRATEGY AND PRIORITIES

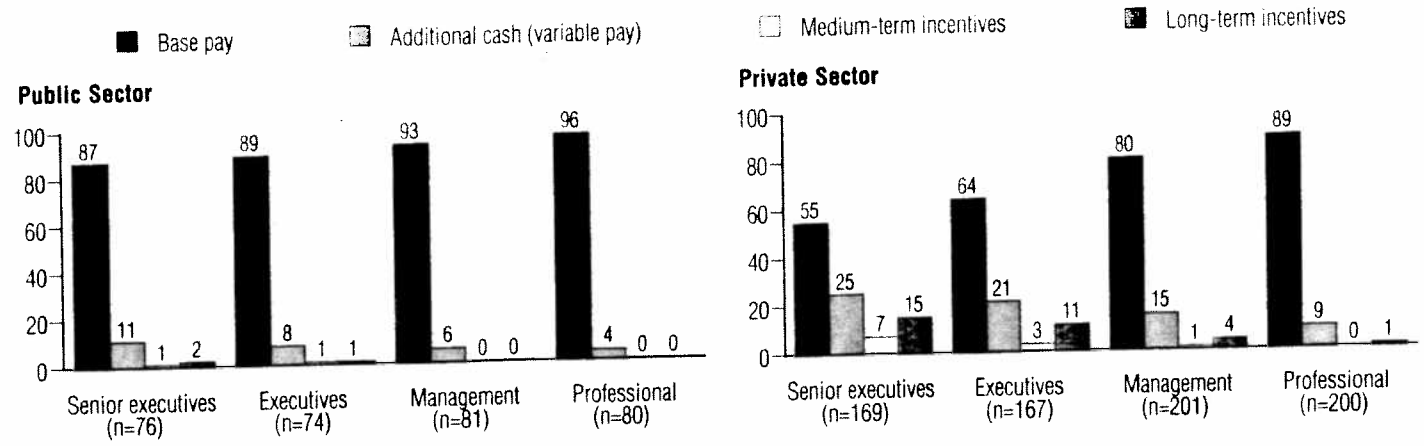
The prevalence of market-based pay strategies has changed minimally over the past few years. The majority of responding organizations (65 per cent) employed this approach in 2007, compared with 63 per cent in 2006 and 64 per cent in 2005. The use of non-monetary recognition awards increased slightly more, to 70 per cent, up from 62 per cent in 2006. Nearly 4 in 10 responding organizations use spot cash awards.

Twenty-three per cent of responding organizations use regional rates of pay, with the highest rates being applied in Fort McMurray.

Base pay continues to represent the most significant component of total cash compensation, particularly in the public sector. The proportion of compensation represented by annual variable pay remained steady in 2007. In the private sector, there was no change in the use of long-term incentives for senior executives.

Attracting and retaining talent and maintaining competitive market position continue to be the top three rewards activities and priorities for organizations. The relative weight applied to each of these priorities has changed since

**Chart 8**
Distribution of Total Cash Compensation, by Sector*
(percentage of total cash)




*Refers to the desired distribution of total cash components based on the design of the total cash compensation strategy.
Note: Totals may not equal 100 due to rounding.
Source: The Conference Board of Canada.

**Table 11**
Prevalence of Selected Approaches to Compensation Strategy
(percentage of organizations)

| | In place | Implemented but disbanded | Being considered | Considered but decided against | Never considered |
|---|---|---|---|---|---|
| Broadbanding (n=291) | 30 | 4 | 10 | 18 | 38 |
| Competency-based pay (n=295) | 32 | 1 | 13 | 9 | 45 |
| Team-based pay (n=276) | 8 | 1 | 4 | 8 | 80 |
| Market pricing (n=301) | 65 | 0 | 9 | 5 | 21 |
| Non-monetary recognition awards (n=303) | 70 | 0 | 15 | 2 | 13 |
| Spot cash awards (n=289) | 37 | 2 | 10 | 5 | 46 |

Note: Totals may not equal 100 due to rounding.
Source: The Conference Board of Canada.

2005, especially with regard to attracting talent. In 2007, more than half of organizations (55.5 per cent) identified this particular objective as their top priority, compared with 45.5 per cent in 2006 and 42 per cent in 2005. That comes as no surprise, given the human resources challenges currently facing organizations, especially in Western Canada.

**Table 12**
Top Rewards Activities and Priorities*
(n=317; per cent; based on organizations reporting)

| | |
|---|---|
| 1. Attracting talent | 55.5 |
| 2. Retaining talent | 52.7 |
| 3. Maintaining competitive position | 47.3 |
| 4. Reviewing strategy and ensuring alignment with business objectives | 37.5 |
| 5. Connecting pay and performance | 30.6 |
| 6. Containing pension and benefit costs | 19.9 |
| 7. Communicating rewards to employees | 17.7 |
| 8. Maximizing effectiveness of variable pay | 12.6 |
| 9. Managing rewards on a total rewards basis | 12.6 |
| 10. Ensuring internal equity | 8.8 |
| 11. Managing executive compensation and long-term incentives | 4.4 |

*Respondents were asked to select (from a list) their top three rewards and activities over the next 12 to 18 months.
Source: The Conference Board of Canada.

CHAPTER 2

# Human Resource Management

**Chapter Summary**

- Recruitment and retention pressures remained at the same high levels seen in 2006, especially in the natural resources sector (excluding oil and gas), education and health, and government sectors.
- In 2007, accounting and finance, skilled trades, and engineering workers were in top demand.

## RECRUITMENT AND RETENTION

The pressures of a hot labour market currently manifest themselves in ever-increasing recruitment and retention challenges. Nearly three-quarters of organizations (73 per cent) are experiencing difficulty attracting or retaining employees with particular skills. The organizations that are more likely to experience these difficulties include those in the natural resources sector (excluding oil and gas; 100 per cent), education and health (85 per cent), and government (81 per cent). The skills in highest demand are consistent with those cited in 2006 and include accounting and finance, skilled trades, and engineering. Specialist information technology (IT), sales and marketing, and management round out the top six most sought-after skills.

**Table 13**
Top Professions/Specializations/Position Types in Demand*
(n=231; per cent; based on organizations reporting difficulty recruiting and/or retaining particular skills)

| | |
|---|---|
| 1. Accounting/finance | 52 |
| 2. Skilled trades | 36 |
| 3. Engineering—electrical, mechanical, etc. | 26 |
| 4. Specialist IT | 23 |
| 5. Sales and marketing | 18 |
| 6. Management | 17 |
| 7. Professional staff | 13 |
| 8. Physical sciences | 8 |
| 9. General IT | 8 |
| 10. Human resources | 7 |
| 11. Executives | 6 |
| 12. Senior executives | 4 |
| 13. Technical staff | 3 |
| Other** | 27 |

*Respondents were asked to select the top three professions, specializations or position types that are most difficult in terms of recruitment and/or retention.
**A wide variety of other responses were provided, representing a broad range of industries and occupations. The most common were health-care professionals (including nurses, pharmacists, and technicians), researchers, auditors, project managers, and operations managers.
Source: The Conference Board of Canada.

To address the issues of recruitment and retention, nearly three-quarters of responding organizations have developed either formal compensation strategies or informal approaches to enhancing rewards packages for individuals in high demand. Generally speaking, there is no universal approach, but by a substantial margin, base pay adjustments continue to be the most common approach, followed by signing bonuses, referral bonuses, and retention bonuses.

**Table 14**
Specific Compensation Strategies/Approaches to Attract and/or Retain Key Individuals
(n=235, per cent; based on organizations that reported having at least one strategy)

| | Formal strategy | Ad hoc approach | Both | Total* |
|---|---|---|---|---|
| Adjustments to base pay (n=159) | 15 | 43 | 10 | 68 |
| Signing bonuses (n=131) | 7 | 46 | 3 | 56 |
| Referral bonuses (n=97) | 36 | 6 | 0 | 42 |
| Retention bonuses (n=96) | 12 | 26 | 3 | 41 |
| Milestone or project bonuses (n=61) | 4 | 19 | 3 | 26 |
| Enhanced relocation support (n=54) | 7 | 15 | 1 | 23 |
| Stock options or grants (n=48) | 11 | 8 | 2 | 21 |
| Hot skills bonuses (n=33) | 6 | 8 | 1 | 15 |
| Enhanced variable pay programs (n=33) | 7 | 5 | 2 | 14 |
| Stay bonuses (n=28) | 1 | 10 | 0 | 11 |
| Other (n=16) | 4 | 2 | 1 | 7 |

**Other compensation strategies include:**
Enhanced benefits to support work–life balance (leaves, vacation)
Market premiums
Relocation assistance (i.e., housing subsidies, interest buy-downs, sale protection)

*Overall percentage of organizations with strategy in place.
Source: The Conference Board of Canada.

**Table 15**
Historical Usage of Specific Compensation Strategies/Approaches
(percentage of all organizations)

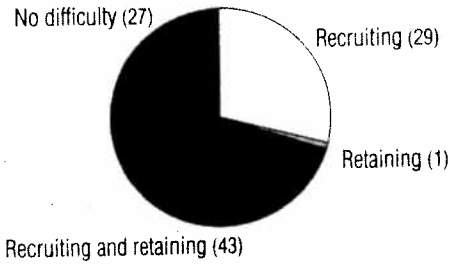
| | Outlook 2002 | Outlook 2004 | Outlook 2006 | Outlook 2007 | Outlook 2008 |
|---|---|---|---|---|---|
| Adjustments to base pay | 72 | 72 | 70 | 75 | 68 |
| Signing bonuses | 51 | 44 | 48 | 51 | 56 |
| Retention bonuses | 35 | 27 | 33 | 36 | 41 |
| Stock options | 33 | 33 | 21 | 21 | 20 |
| Milestone or project bonuses | 29 | 27 | 19 | 23 | 26 |
| Enhanced variable pay | 27 | 22 | 14 | 13 | 14 |
| Hot skills bonuses | 18 | 14 | 10 | 16 | 14 |

Source: The Conference Board of Canada.

Last year saw labour market pressures place great strain on voluntary turnover rates, especially among specific employee groups. The same pressures manifested themselves again in 2007, with the average annual turnover rate hitting 8.5 per cent, up from 7.9 per cent last year. In addition to this overall turnover rate, a small number of survey participants also provided turnover data for specific employee groups:

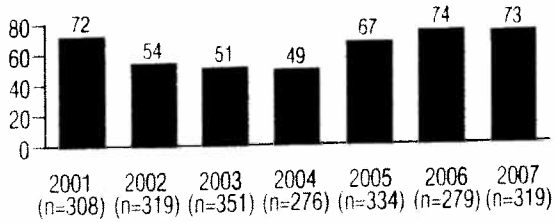
- For "top performers," the average voluntary turnover rate is 2.4 per cent, based on data provided by 13 per cent of organizations surveyed. That compares with a rate of 5.2 per cent for top performers last year, and 4.1 per cent two years ago.
- For "solid performers," the rate is 4.7 per cent, based on data provided by 11 per cent of organizations surveyed.
- For "poor performers," the rate is 5.5 per cent, based on data provided by 12 per cent of organizations surveyed.
- For "employees with less than two years of service," the rate is 7 per cent, based on data provided by 25 per cent of organizations surveyed.

**Chart 9**
Difficulty Recruiting and Retaining Particular Skills
(n=319; percentage of organizations)




Source: The Conference Board of Canada.

**Chart 10**
Difficulty with Recruiting and Retaining—Trend Over Time
(percentage of organizations reporting difficulties with recruitment and/or retention)




Source: The Conference Board of Canada.

**Table 16**
Absenteeism and Voluntary Turnover Rates, by Industry

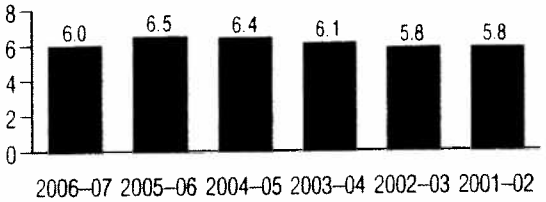
| | Absenteeism rate* (days per employee) (n=181) | Voluntary turnover rate (average percentage) (n=236) |
|---|---|---|
| **Overall** | **6.0** | **8.5** |
| **Industry** | | |
| Natural resources, excluding oil and gas | 7.4 | 5.8 |
| Oil and gas | 5.0 | 7.6 |
| Manufacturing | 5.3 | 6.0 |
| Food, beverage, and tobacco products | 1.0 | 7.6 |
| Chemical, pharmaceutical, and allied products | 6.1 | 4.6 |
| Construction | ** | ** |
| High-technology | 4.2 | 8.5 |
| Communications and telecommunications | 8.2 | 11.1 |
| Transportation and utilities | 7.3 | 6.9 |
| Finance, insurance, and real estate | 5.1 | 9.6 |
| Wholesale trade | 5.7 | 7.0 |
| Retail trade | 5.4 | 18.1 |
| Education and health | 7.5 | 5.9 |
| Government | 7.7 | 6.3 |
| Not-for-profit | 5.0 | 9.6 |
| Services—Accommodation, food, personal | 6.9 | 14.6 |
| Services—Professional, scientific, technical | 5.0 | 13.3 |

*Please refer to Chart 11 notes for definitions.
**Not shown due to small sample sizes.
Source: The Conference Board of Canada.

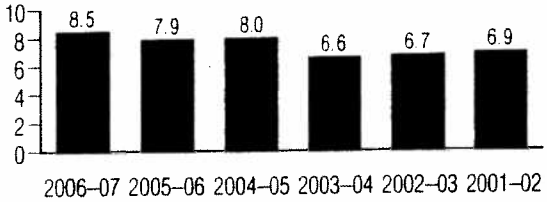
- For "employees with critical skills," the rate is 3.6 per cent, based on data provided by 12 per cent of organizations surveyed, compared with a rate of 4.8 per cent for this employee group in 2006.
- For "employees with hot skills," the rate is 3.8 per cent, based on responses from 9 per cent of organizations surveyed, compared with last year's rate of 3.3 per cent.

**Chart 11**
Absenteeism and Voluntary Turnover Rates
(based on responses of all organizations; rates reflect the period August 1 to July 31 except for 2005–07, where rates reflect July 1 to June 30)

**Absenteeism Rate**
(days per employee)




**Voluntary Turnover Rate**
(per cent; average)




Notes:
1 Absenteeism is defined as an employee's absence from work (with or without pay) due to illness, disability, personal or family reasons for a period of at least half a day but less than 52 consecutive weeks. Maternity, adoptive, paternity, vacation and holiday, and bereavement leave and jury duty are excluded.
2 Voluntary turnover applies to regular employees only, and does not include early retirements or severances.

Source: The Conference Board of Canada.

**Table 17**
Turnover Rates Among Specific Employee Groups
(average percentage)

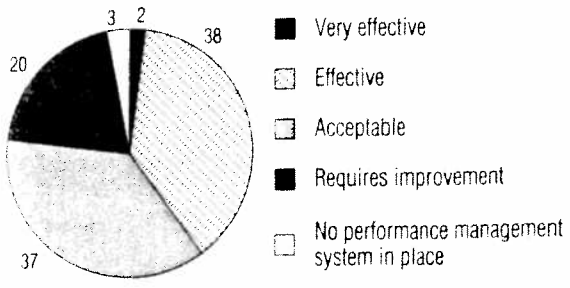
| | Turnover rate |
|---|---|
| Top performers (n=43) | 2.4 |
| Solid performers (n=35) | 4.7 |
| Poor performers (n=37) | 5.5 |
| Employees with less than two years' service (n=80) | 7.0 |
| Employees with critical skills (n=38) | 3.6 |
| Employees with hot skills (n=29) | 3.8 |

Source: The Conference Board of Canada.

## PERFORMANCE MANAGEMENT

Over the past few years, there has been a consistent increase in the perceived effectiveness of performance management systems among survey respondents. While participants continue to remain confident in the effectiveness of their performance management systems, fewer organizations indicated that their system is either "very effective" or "effective" in 2007 (40 per cent) than in 2006 (45 per cent). More than one-third (37 per cent) of organizations rated their performance management system as "acceptable," and one in five (20 per cent) believe that improvement is needed.

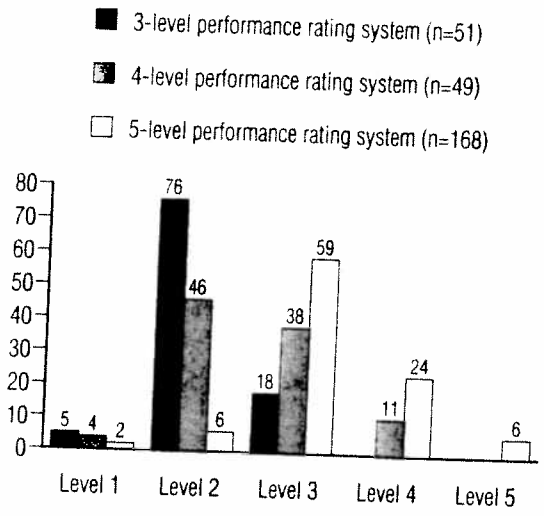
**Chart 12**
Effectiveness of Performance Management System
(n=315; percentage of all organizations)




Source: The Conference Board of Canada.

The proportion of organizations using a performance appraisal rating system has remained consistent in recent years. The majority of organizations (88 per cent) currently use such a system, with five-level (62 per cent) and three-level (19 per cent) systems being the most common. Thirteen per cent of the organizations with a rating system force a performance distribution, while 42 per cent have distribution guidelines or recommendations in place for managers to use when carrying out performance assessments.

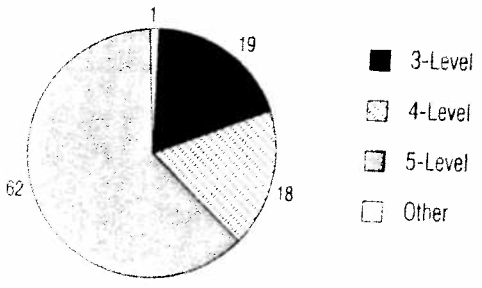
**Chart 13**
Performance Distribution
(average percentage of employees)




Notes:
1 For each of the three rating systems, "Level 1" represents unsatisfactory performers.
2 The high degree of variability in performance appraisal systems does not allow for labels to be assigned to each level presented in the chart.
3 Totals do not equal 100 due to rounding.

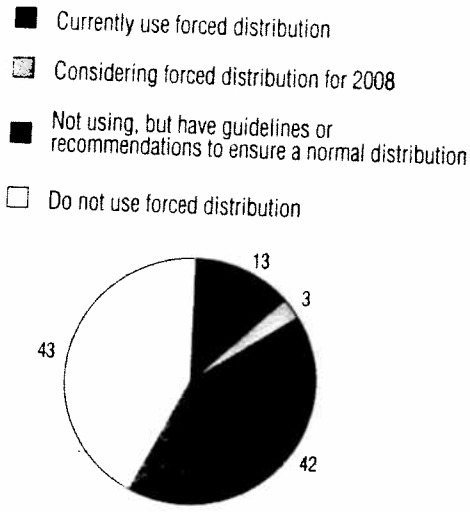
Source: The Conference Board of Canada.

**Chart 14**
Number of Performance Levels
(n=272; percentage of organizations)




Source: The Conference Board of Canada.

**Chart 15**
Forced Performance Distribution and Guidelines
(n=286; percentage of organizations with performance appraisal rating system)




Note: Total does not add to 100 due to rounding.
Source: The Conference Board of Canada.

## BENEFITS

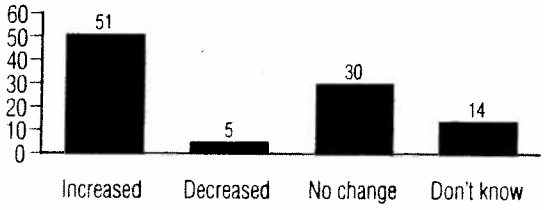
The rising cost of employee health benefits is a major concern for organizations. Just over half (51 per cent) of respondents indicated an increase in costs in 2007, by an average of 9.6 per cent. Only 5 per cent of organizations reported a decrease in the cost of their health benefits for active employees, by an average of 11 per cent. Among organizations with health benefits for retirees, just over one-third (34 per cent) reported an

increase in their costs, by an average of 9.7 per cent. Forty-three per cent of organizations incur their health-care benefits expense in the form of premiums, and a similar proportion (45 per cent) incurs actual claims expenses.

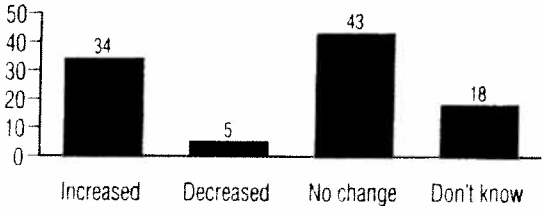
Twenty-seven per cent of organizations have a flexible benefits plan in place for all employees, while 14 per cent provide this benefit to only certain segments of their employee population. Fewer than 5 per cent are considering implementing a flexible benefits plan in 2008. An equivalent proportion of organizations (27 per cent) also offers a health spending account to all staff, and one-quarter (25 per cent) do so for specific employee groups. An additional 5 per cent are considering implementing health spending accounts in the coming year.

**Chart 16**
Changes in Health-Care Benefit Costs

**Health-Care Benefit Costs for Active Employees**
(n=273; percentage of organizations responding to question)



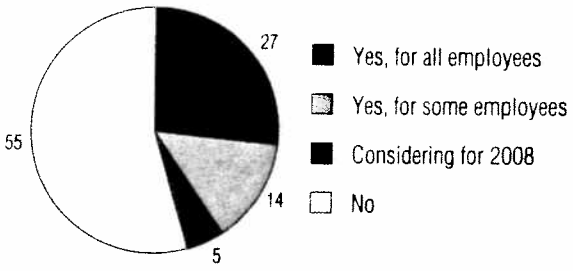

**Health-Care Benefit Costs for Retirees**
(n=148; percentage of organizations reporting health-care benefit costs for retirees)




Source: The Conference Board of Canada.

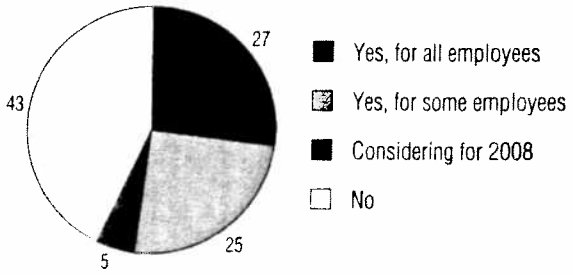
The use of flex days—employees can take time off in addition to their regular vacation entitlement and personal leave—remains a relatively uncommon approach to combatting workforce pressures. Only 19 per cent have implemented this benefit, sometimes referred to as "Golden Fridays," with the average allotment among these organizations being 11 days per employee.

**Chart 17**
Prevalence of Flexible Benefits Plans
(n=317; percentage of organizations)




Note: Total does not add to 100 due to rounding.
Source: The Conference Board of Canada.

**Chart 18**
Prevalence of Health Spending Accounts
(n=313; percentage of organizations)




Source: The Conference Board of Canada.

CHAPTER 3

# Collective Bargaining

**Chapter Summary**

- The projected average wage increase among unionized employees is 3.1 per cent in 2008. The average for 2007 was 3.4 per cent.
- Four in 10 respondents have annual variable pay plans for their unionized employees, with cash bonus or incentive plans being most common. The majority of variable pay plans met or exceeded payout targets in 2007. Unionized workers in these organizations received payouts averaging 8 per cent of base pay.
- The key bargaining issue anticipated for management in the coming year is productivity; for unions, it is expected to be wages.

## BASE PAY INCREASES

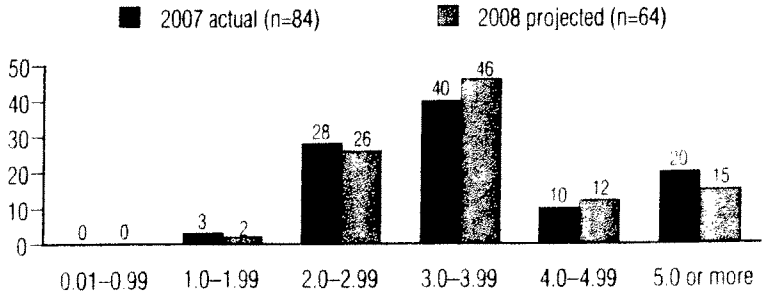
For unionized employees, the average wage increase projected for 2008 is 3.1 per cent: 3 per cent in the private sector and 3.4 per cent in the public sector.

The average actual negotiated increase in 2007 was 3.4 per cent. Employees in the public sector received increases that averaged 3.5 per cent, while those in the private sector averaged 3.3 per cent.

## VARIABLE PAY

The prevalence of annual variable pay plans for unionized employees has risen in recent years. In 2007, 45 per cent of unionized organizations had variable pay for unionized employees, up from 31 per cent in 2001. Cash bonus or incentive plans continue to be the most common forms of variable pay for unionized employees, followed by profit-sharing and gainsharing plans. Most variable pay plans achieved (23 per cent) or exceeded (55 per cent) payout targets in 2007, and the majority (95 per cent) of employees received a payout.

**Chart 19**
Distribution of Base Pay Increases*
(per cent)




*A base pay increase refers to the average increase applied to the base wage rate, for the year specified (includes any cost of living allowance increases).
Note: The totals do not add to 100 due to rounding.
Source: The Conference Board of Canada.

**Table 18**
Base Pay Increases*
(per cent, except for years in contract)

| | | Average # of years in contract (n=88) | Year 1 2007 (n=83) | Year 2 2008 (n=83 | Year 3 2009 (n=76) |
|---|---|---|---|---|---|
| Contracts negotiated since Jan. 1, 2007 | (mean) | 3.2 | 3.4 | 3.4 | 3.4 |
| | (median) | 3.0 | 3.0 | 3.0 | 3.0 |

| | | Average # of years in contract (n=71) | Year 1 2008 (n=64) | Year 2 2009 (n=62) | Year 3 2010 (n=54) |
|---|---|---|---|---|---|
| Contracts to be negotiated before Dec. 31, 2008 | (mean) | 3.3 | 3.1 | 3.2 | 3.2 |
| | (median) | 3.0 | 3.0 | 3.0 | 3.0 |

*A base pay increase refers to the average increase applied to the base wage rate, for the year specified (includes any cost of living allowance increases).
Source: The Conference Board of Canada.

**Table 19**
Annual Variable Pay Plan Payouts
(percentage of base pay)

**2007 Payouts**
(actual, based on 2006 performance)

| | |
|---|---|
| Target payout (n=46) | 4.6 |
| Actual payout (n=46) | 8.0 |
| % of employees receiving (n=45) | 94.5 |
| % of organizations falling short of target | 22.5 |
| % of organizations meeting target | 22.5 |
| % of organizations surpassing target | 55.0 |

**2008 Payouts**
(projections, based on 2007 performance)

| | |
|---|---|
| Target payout (n=41) | 4.8 |
| Plan maximum (n=35) | 7.1 |

Source: The Conference Board of Canada.

**Table 20**
Current Negotiation Issues*
(n=138; percentage of unionized organizations)

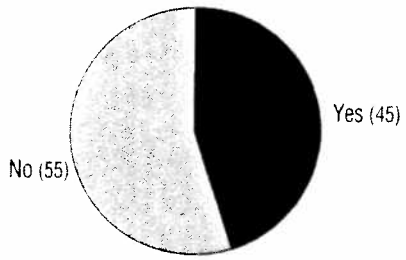
| Management issues | |
|---|---|
| 1. Productivity | 49 |
| 2. Flexible work practices | 45 |
| 3. Business competitiveness | 42 |
| 4. Wages | 38 |
| 5. Health, pensions, benefits | 37 |
| 6. Training and skills development | 22 |
| 7. Organizational change | 18 |
| 8. Outsourcing/contracting out | 12 |
| 9. Employment/pay equity | 9 |
| 10. Technological change | 9 |
| 11. Variable pay | 4 |
| 12. Employment security | 1 |

| Union issues | |
|---|---|
| 1. Wages | 83 |
| 2. Health, pensions, benefits | 73 |
| 3. Employment security | 41 |
| 4. Outsourcing/contracting out | 30 |
| 5. Training and skills development | 19 |
| 6. Employment/pay equity | 15 |
| 7. Flexible work practices | 15 |
| 8. Organizational change | 7 |
| 9. Variable pay | 5 |
| 10. Technological change | 3 |
| 11. Productivity | 1 |
| 12. Other | 7 |

*Respondents were provided with a list of 12 possible choices (plus "other") and asked to indicate the top three negotiation issues for both management and union.
Source: The Conference Board of Canada.

Ten organizations reported having a long-term incentive plan in place for their unionized employees. These plans include traditional stock options and performance-contingent stock options.

**Chart 20**
Prevalence of Annual Variable Play
(n=184; percentage of unionized organizations)




Source: The Conference Board of Canada.

## NEGOTIATION ISSUES

The majority (81 per cent) of unionized organizations do not expect work stoppages in 2008. Only 5 of 184 unionized organizations (3 per cent) that participated in the survey believe that an interruption is possible in the coming year.

Nearly half of the unionized respondents (47 per cent) believe that the labour–management relationship within their organization is more cooperative than uncooperative, while 4 in 10 (41 per cent) perceive it to be balanced. As in recent years, most organizations (68 per cent) expect the relationship with their unions to remain stable over the next two years. One in six unionized respondents (16 per cent) believes its labour–management relationship will improve, while 6 per cent—10 organizations—believe it will deteriorate.

### Facts About the Unionized Employers in the Survey

- 58 per cent of responding organizations have unionized employees.
- 1,132 agreements are currently in place.
- 282 agreements, covering 133,990 employees, expire in 2008.

Source: The Conference Board of Canada.

According to approximately 4 in 10 organizations, the key bargaining issues for management in 2008 will be productivity, flexible work practices, and business competitiveness. Wages, and health, pension and other benefits are expected to top the list of management issues among 3 in 10 organizations.

By a wide margin, wages continue to be identified as the key union issue in the coming year. Health benefits, pensions and employment security round out the top bargaining issues for labour in 2008.

APPENDIX A

# Respondent Profile

(Total number of responding organizations = 319)

| | Percentage of organizations |
|---|---|
| **Industrial Classification** | |
| Natural resources, excluding oil and gas | 3 |
| Oil and gas | 6 |
| Manufacturing | 12 |
| Food, beverage, and tobacco products | 3 |
| Chemical, pharmaceutical, and allied products | 5 |
| Construction | 1 |
| High-technology | 5 |
| Communications and telecommunications | 3 |
| Transportation and utilities | 8 |
| Finance, insurance, and real estate | 17 |
| Wholesale trade | 3 |
| Retail trade | 5 |
| Education and health | 6 |
| Government | 10 |
| Not-for-profit | 3 |
| Services—Accommodation, food, and personal | 3 |
| Services—Professional, scientific, and technical | 8 |
| **Characteristics of Responding Organizations** | |
| *Sector* | |
| Private sector corporation | 74 |
| Federal/provincial Crown corporation or agency | 22 |
| Municipal government | 5 |
| *Operations* | |
| Canadian only | 56 |
| North American | 13 |
| Global | 31 |
| *Ownership* | |
| Publicly traded shares | 26 |
| Controlled by Canadian publicly traded company | 4 |
| Controlled by foreign publicly traded company | 15 |
| Privately held | 21 |
| Not applicable | 34 |
| *Assets (Canadian operations)* | |
| $0–$99 million | 21 |
| $100–$999 million | 29 |
| $1 billion and over | 50 |
| *Annual sales/service revenue (Canadian operations)* | |
| $0–$99 million | 18 |
| $100–$999 million | 40 |
| $1 billion and over | 42 |
| *Number of employees* | |
| Fewer than 500 | 23 |
| 500–1,499 | 27 |
| 1,500–5,000 | 27 |
| Over 5,000 | 23 |
| Total number of employees | 1,528,127 |
| Total non-unionized employees | 827,188 |

APPENDIX 3

# Participating Organizations

A total of 319 organizations participated in the Compensation Planning Outlook 2008 survey. The following participants have authorized the publication of their names. At their request, 11 organizations have been excluded from this list.

3M Canada
Abitibi Consolidated Inc.
ADP Canada
Agricorp
Agrium Inc.
Agropur Cooperative
Alberta Cancer Board
Alberta Energy and Utilities Board
Alcan Inc.
Alcohol and Gaming Commission of Ontario
Alcool NB Liquor
Allstate Insurance Company of Canada
AltaLink Management Ltd.
AMEC
Apotex Inc.
Association of Universities and Colleges of Canada
Astra Zeneca Canada Inc.
ATB Financial
ATCO Electric
Atomic Energy of Canada Limited
AXA Canada
Ballard Power Systems Inc.
Bank of Canada
Bank of Montreal
Bausch & Lomb Canada
BC Public Service Agency
Bell Aliant
Bell Canada
Best Buy Canada Ltd.
Bethany Care Society
Blue Mountain Resorts Ltd.
BNP Paribas (Canada)
Bombardier Aerospace
Bombardier Inc.
BP Canada Energy Company
Brewers Distributor Ltd.
Brookfield Properties Corporation
Business Development Bank of Canada
CAE Inc.
Caisse de dépôt et placement du Québec
Calgary Co-operative Association Ltd.
Calgary Health Region
Cameco Corporation
Canada's Wonderland Company
Canada Bread Company Ltd.
Canada Deposit Insurance Corporation
Canada Forgings Inc.
Canada Lands Company Limited
Canada Post Corporation
Canadelle
Canadian Blood Services
Canadian Broadcasting Corporation
Canadian Institute for Health Information
Canadian Nuclear Safety Commission
Canadian Pacific Railway
Canadian Tire Corporation, Limited
Canadian Tire Financial Services
Canadian Wheat Board

Capital Health
Cara Operations Limited
Cedara Software
Ceridian Canada Ltd.
Children's Hospital of Eastern Ontario
Chubb Insurance Company of Canada
CI Investments
CIBC Mellon
Cirque du Soleil
City of Calgary
City of Regina
CN
Cognos Inc.
COM DEV International Ltd.
Commissionaires (Great Lakes)
Compass Group Canada
Concentra Financial
Corporation of the City of Kitchener
Corus Entertainment
Crane Plumbing Canada Corp.
Credit Union Central of BC
Crown Metal Packaging Canada LP
CVRD Inco Limited
Deloitte
Desjardins Financial Security
Devon Canada Corporation
Direct Energy
Dofasco Inc.
E.I. DuPont of Canada Company
EDS Canada
EHC-Global (formerly Escalator Handrail Company, Inc.)
Elk Valley Coal Corporation
Enbridge Inc.
Enerflex Systems Ltd.
Enerplus Resources Fund
ENMAX Corporation
EPCOR Utilities Inc.
Ericsson Canada Inc.
Expertech Network Installations
Export Development Canada
Fairmont Hotels & Resorts
Farm Credit Canada
Farmers Co-operative Dairy
Federated Cooperative Limited
FedEx Canada
Financial Transactions & Reports Analysis Centre of Canada
Finning (Canada)
First Calgary Savings
Fluor Corporation
Foresters
FortisAlberta Inc.
Fountain Tire Ltd.
Frito Lay Canada
Gamma-Dynacare Medical Laboratories
General Dynamics Land Systems — Canada
General Electric Canada
General Motors of Canada Limited
Gibson Energy Ltd.
GlaxoSmithKline Inc.
Goldcorp Canada Ltd — Perceiving Joint Venture
Goodmans LLP
Goodyear Canada Inc.
Gore Mutual Insurance Company
Government of Alberta
Great Canadian Gaming Corporation
Group Deschenes Inc.
Hadrian Manufacturing Inc.
Halifax Regional Municipality
HDS Retail North America
Hewitt Equipment Limited
Hewlett-Packard (Canada) Co.
Home Depot Canada
Hudson Bay Mining & Smelting Co., Limited
Husky Injection Molding Systems
Hydro-Québec
IBM Canada Ltd.
ICBC
IHS Energy (Canada) Ltd.
Imperial Oil Limited
Independent Electricity System Operator (IESO)
Industrial Alliance Insurance and Financial Services Inc.
ING Canada
Intergraph Canada Ltd.
International Development Research Centre (IDRC)
Investment Dealers Association of Canada
Investors Group Inc.
IPSCO Inc.
Island Savings Credit Union
Ivaco Rolling Mills LP
Ivanhoe Cambridge
Jervis B. Webb Company of Canada Ltd.
Kellogg Canada Inc.
Kinder Morgan Canada

KONE
L-3 Wescam
Lanxess Inc.
Laurentian Bank of Canada
Ledcor Group of Companies
Lehigh Inland Cement Limited
Lilydale Inc.
Liquor Control Board of Ontario (LCBO)
London Health Sciences Centre
Manitoba Hydro
Manulife Financial
Maple Leaf Consumer Foods
Maxxam Analytics Inc.
MCAP
McCormick Canada Inc.
McMaster University
MDA Corporation
MDS Nordion
Meloche Monnex
Meridian Technologies Inc.
Metro Richelieu
Metro Toronto Convention Centre
Michelin North America (Can) Inc.
Microsoft Canada Co.
Minacs Worldwide Inc.
Minto Developments Inc.
Miramac Mining Corporation
Molson Canada
Mountain Equipment Co-op
National Bank of Canada
National Energy Board (NEB)
NAV CANADA
NB Power Holding Corporation
Neenah Paper Company of Canada, Pictou Mill
Newalta Corporation
Nexans Canada Inc.
Nexen Inc.
North Shore Credit Union
Nova Scotia Power Inc.
Nova Scotia Public Service Commission
Office of Human Resources, Province of New Brunswick
Ontario Clean Water Agency
Ontario Municipal Employees Retirement System
Ontario Power Generation
Ontario Realty Corporation
Ontario Securities Commission
Oracle Corporation Canada Inc.
Oxford Properties Group
Panasonic Canada Inc.
Patheon Inc.
Pembina Pipeline Corporation
People First HR Services
Pepsi-QTG Canada
Petro-Canada
Petromont
Pfizer Canada Inc.
Pharmascience Inc.
Philips Electronics Ltd.
Post-Secondary Employers' Association
Potash Corporation of Saskatchewan Inc.
Prairie Agricultural Machinery Institute
Pratt and Whitney Canada
PricewaterhouseCoopers LLP
Purolator Courier Ltd.
QLT Inc.
Quebecor Media Inc.
Quixtar Canada Corporation
RBC Dexia Investor Services
RBC Financial Group
Regional Municipality of Durham
Regional Municipality of Halton
Regional Municipality of Niagara
Regional Municipality of Peel
Reitmans (Canada) Ltd.
Research In Motion
Roche Diagnostics Canada
Rogers Communications Inc.
Royal & Sun Alliance Insurance Company of Canada
Russel Metals Inc.
Ryerson University
Saint Elizabeth Health Care
SAIT Polytechnic
Sanofi-aventis Canada Inc.
Saskatchewan Government Insurance
Saskatchewan Public Service Commission
Saskatchewan Research Council
Saskatchewan Transportation Company
Saskatchewan Workers' Compensation Board
SaskEnergy Incorporated
Saskferco Products Inc.
SaskTel
Schneider Electric Canada
Scotiabank
Securit

Shell Canada Limited
Sherritt International Corp.
SIAST (Saskatchewan Institute of Applied Science and Technology)
Signature Vacations
SNC-Lavalin
Spectra Energy Gas Transmission
Standard Aero Ltd.
Stantec Inc.
St. Lawrence Cement
STM (Société de Transport de Montréal)
Strathcona County
Strathcona Paper
Suncor Energy Inc.
Sun Rich Fresh Foods Inc.
Sun-Rype
Symcor Inc.
Syncrude Canada Ltd.
Sysco Food Services of Canada Inc.
Taiga Building Products Ltd.
Talisman Energy Inc.
Tarion Warranty Corporation
TD Bank Financial Group
Teck Cominco Limited
Teknion Corporation
The Cumis Group
The Dominion of Canada General Insurance Co.
The Economical Insurance Group
The Equitable Life Insurance Company of Canada
The Law Society of Upper Canada
The Lowe-Martin Group
The TDL Group Corp. (Tim Hortons)
Thomson Carswell
Toronto Central Community Care Access Centre
Toronto Transit Commission
Torys LLP
Town of Banff
Town of Markham
TransCanada PipeLines Limited
Treasury Board Secretariat
Troy Sprinkler Ltd.
TSX Group Inc.
Ultramar Ltd.
University of Alberta
University of Calgary
University of New Brunswick
University of Regina
University of Saskatchewan
University of Toronto
UPS
VanCity Credit Union
Vancouver Coastal Health
Vancouver Public Library
Vansco Electronics LP
Velan Inc.
Wal-Mart Stores Inc.
WCB (Workers' Compensation Board)—Alberta
Wells Fargo Financial
West Fraser Timber Co. Ltd.
Winners Merchants International LP
Wrigley Canada
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Xstrata Nickel
Zurich Canada

APPENDIX C

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### What

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### When

The councils meet three times per year to maximize information sharing, learning, and exposure to strategic human resources management and organizational effectiveness issues.

### Where

The councils meet in locations across Canada to address current critical human resources issues through both informal networking and structured presentations.

### Why

The Councils of Human Resource Executives facilitate access to Conference Board research and to senior staff and leading experts who present the latest findings on issues, trends and best practices of strategic importance to HR leaders.

### How

Please contact **Ruth Wright** at **wright@conferenceboard.ca** or **613-526-3280, ext. 369** to receive an invitation to an upcoming meeting.



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**CW-YECL-25**

**Issue:** Forecast Operations and Maintenance Expenses

**Reference:** Pages 5-1 to 5-4, Schedule 5.1

**Preamble:** A separate forecast is developed for labour and non-labour costs.

**Request:**

(a) Please indicate when the O&M forecast was prepared and what actual results for 2007 were incorporated into the forecast.

(b) Please provide a copy of the 2007-2008 collective agreement with the Yukon Electrical's employee association.

(c) Please split Schedule 5.1 into labor and non-labor costs

(d) Please fully define in-scope and out-of scope and further split labor into in-scope, out-of-scope and variable or incentive pay.

**Response:**

(a) The O&M forecast was prepared during 2007 with amounts being finalized in February 2008. The forecast was based on results to the end of 2007.

(b) Please refer to CW-YECL-25(b) Attachment 1 for the current Yukon Electrical Employees Association collective agreement which expires December 31, 2008.

(c) This level of detail is not required in order to assess the reasonableness of YECL's forecast expenditures. YECL also observes that this level of detail is beyond the level agreed to in Alberta for the major Alberta Electric Utilities in their Minimum Filing Requirements. YECL has provided this information on a functional basis in CW-YECL-25(c) Attachment 1.

(d) In scope employees are those employees who are part of the Yukon Electrical Employees Association and are subject to the collective agreement. Out of

scope employees are typically management employees who do not fall under the collective agreement.

The information requested by function is not readily available, however, YECL can provide this information on a total basis as follows:

| | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| | | | | (000's) | | | |
| **In-Scope** | 2,616 | 2,825 | 2,991 | 3,253 | 3,590 | 4,304 | 4,721 |
| **Out-of-Scope** | 867 | 860 | 884 | 919 | 840 | 883 | 942 |
| **Variable** | - | - | - | 25 | 24 | 24 | 43 |
| **Total** | 3,483 | 3,685 | 3,875 | 4,197 | 4,454 | 5,211 | 5,706 |

# AGREEMENT

**THIS AGREEMENT** made as of the first (1st) day of January A.D. 2007.

**BETWEEN:**

**THE YUKON ELECTRICAL COMPANY LIMITED**, a body corporate with head office at the City of Whitehorse, in the Yukon Territory (hereinafter called "the Company").

**OF THE FIRST PART,**

**AND**

**THE YUKON ELECTRICAL EMPLOYEES' ASSOCIATION**, a trade union within the meaning of the Canada Labour Code, of the said City of Whitehorse, in Yukon Territory (hereinafter called "the Association").

**OF THE SECOND PART.**

Whereas the Company is a public utility engaged in the business of producing, purchasing, transmitting, distributing, delivering and selling electricity and of providing services in connection therewith and supplying electricity to communities and inhabitants in Yukon Territory and Northern British Columbia.

**AND**

Whereas by Certificate dated the 23rd day of December A.D., 1974 and issued by the Canada Labour Relations Board of the Yukon (hereinafter called "the Board"), and made pursuant to the provisions of the Canada Labour Code, the Association has been certified as bargaining agent for the unit of employees of the Company comprising: "All employees of the Yukon Electrical Company Limited employed in Yukon Territory, as listed within the Job Group Schedules contained within this Collective Agreement, excluding managerial designated "out of scope" supervisors, and all other persons acting on behalf of the Company in a professional or confidential capacity.

The above certificate is hereinafter referred to as "the Certificate".

## SPIRIT OF AGREEMENT

Whereas the Company is an organization wherein the money of investors is combined with the judgment, abilities, experience and energy of the management and employees to provide efficient public utility services.

**AND**

Whereas it is agreed that the service rendered by the Company, its management and employees directly or indirectly, to electric customers from time to time served by the Company, is essential to the welfare of these customers.

**AND**

Whereas it is essential to the livelihood and in the best interest of the Company, its management and employees, to direct their respective efforts towards the efficient and economical operation of the Company business.

**AND**

Therefore this Agreement recognizes and accepts the principles and spirit of good team work, based upon mutual responsibility, respect, confidence, loyalty, integrity and friendliness.

**AND**

This Agreement further recognizes that all successful employer-employee relations must be mutually advantageous, fair and just, not more favorable to one than to the other and of the same spirit of cooperation and friendliness in which this Agreement is reached.

**AND**

The Company and the Association agree to principles of employment equity and recognize that specific employment selection criteria and systems may be required to support those principles and obligations, and agree to work jointly and in harmony to develop and maintain an employment equity strategy.

**AND**

The Company, its management, employees, and the Association, are committed to the development of employees from within the bargaining unit.

Whereas subject to the terms and conditions herein contained, the parties hereto by these presents are entering into a Collective Agreement with respect to the terms and conditions of employment of such employees.

**AND**

The Company and the Association recognize the vital importance of employee and Association involvement along with Management in all aspects of health, safety and environment programs affecting them. In particular this includes the participation on Health, Safety and Environment Committees and in accident and unsafe incident investigations.

## ARTICLE 1.00 TERM OF AGREEMENT

1.01 This Agreement remains in force from January 01, 2007 to December 31, 2008 and from year to year thereafter, unless notice of amendment or termination is given as required in clause 1.02.

1.02 If either the Company or the Association wishes to amend or terminate this Agreement, it must give the other party notice by September 8, in the final year of the Agreement.

1.03 If either party wishes to negotiate and enter into another Collective Agreement to replace this Agreement, the parties shall meet and exchange proposals no later than September 15, in the final year of the Agreement. The parties will then undertake negotiations for a new Agreement.

1.04 If either party has not resolved all issues through negotiations by September 30, in the final year of the agreement, a new Collective Agreement will be concluded and will become effective October 01 of that year. That Agreement will contain the following items:

(a) the previous Collective Agreement with amendments to the extent agreed upon in negotiations;

(b) a list, prepared by each party, of all unresolved matters, indicating those items which either party wishes to have retroactive; and

(c) an article identical to Article 27.00 (Arbitration Procedures) of this Agreement.

That Agreement will then be settled by the arbitration board selected or appointed under Article 27.00 (Arbitration Procedures) for resolution of the unresolved issues and requests.

1.05 Until the arbitration board makes its award, the terms and conditions of the Agreement reached under clause 1.04 (a) and (c) will be in force.

## ARTICLE 2.00 APPLICATION

2.01 This Agreement shall apply with respect to all of the Company's employees comprised within the bargaining unit prescribed by the Canada Labour Relations Board or the said certificate as it may be amended from time to time.

## ARTICLE 3.00 DEFINITIONS AND INTERPRETATIONS

3.01 For purposes of this agreement:

(a) "Association" means the Yukon Electrical Employees' Association;

(b) "Association Officer" means any member of the Yukon Electrical Employees' Association Executive or person or party appointed by the Executive;

(c) "Agreement" means this current Collective Agreement;

(d) "Company" means The Yukon Electrical Company Limited;

(e) "Day" unless modified means a calendar day;

(f) "Dependent" means:

(i) an employee’s unmarried dependent child (natural, step, legally adopted or foster) up to age 18; or age 25 if a full-time student; or

(ii) an employee’s physically or mentally handicapped child of any age, if they are incapable of self-sustaining employment.

(g) "Holiday" means the twenty-four (24) hour period commencing at 12:01 a.m. on the day designated as a paid holiday in Article 18.00 (Holidays) of this agreement;

(h) Home Base means an employee's permanent work location;

(i) "Job" means a unique position within the Company;

(j) "Job Class" means all Jobs in the Company with the same basic title;

(k) "Job Posting" means a document which invites applications for a vacant Job or a new Job;

(l) Spouse means the person to whom the employee is legally married or living with, in a common law relationship, for the last twelve (12) months;

(m) "Working Day" means a day on which an employee is scheduled to work.

3.02 All employees covered by this Collective Agreement shall fall into the following categories: Permanent, Permanent Part-time, Probationary, Temporary, Seasonal.

3.03 "Permanent Employee" means an employee who has been appointed by written notice to a permanently established position on the completion of a maximum six (6) month probationary period (the "Probationary Period"). The appointment to Permanent status will be effective on the first (1st) of the month following successful completion of the Probationary Period. Such appointment shall be conveyed to the employee and the Association in writing within seven (7) Days of appointment.

3.04 "Permanent Part-time Employee" means an employee who has been appointed, by written notice, to a Permanent Part-time established position on the completion of a maximum of six (6) month probationary period (the "Probationary Period"). Such appointment shall be conveyed to the employee and the Association in writing within seven (7) Days of the appointment.

3.05 "Probationary Employee" means either:

(a) a new employee appointed to a permanently established position, for whom there shall be a maximum six (6) month probationary period, during which period his employment may be terminated at Company's discretion. A review of the performance of such employee will be discussed with him prior to the final thirty (30) Days of the probationary period.

(b) a Temporary or Seasonal Employee appointed to a permanently established position, for whom there shall be a maximum six (6) month probationary period, during which period his employment may be terminated at the Company's discretion. A review of the performance of such employee will be discussed with him prior to the final thirty (30) Days of the probationary period.

3.06 When a Temporary or Seasonal Employee is hired for a permanent position, and has been working in a related Job, the probationary period will be reduced as follows:

(a) If the person has been employed by the Company in a related Job for more than three months, the probationary period will be reduced by at least three months, and may be reduced up to six months, at the Company’s discretion.

(b) If the person has been employed by the Company in a related Job for less than three months, the probationary period will be reduced by the actual amount of time he has been employed in the related Job.

3.07 "Seasonal Employee" means an employee engaged in work of a seasonal nature and who will be laid off, subject to recall, on the completion of such work. This category of employee shall not be utilized so as to displace a Permanent Employee or position, or diminish the regular hours of work of a Permanent Employee. The above mentioned layoff and recall will be subject to the following:

(a) Layoffs A Seasonal Employee being laid off will be provided with two weeks' notice. Such layoff may occur at any point of the term contingent on work requirements and or job performance. Prior to layoff, a performance evaluation will be conducted and a letter shall be provided to the affected employee.

(b) Recall Recall of any Seasonal Employee will be based on their previous performance evaluation. Recall will be offered only to employees who have letters from a previous layoff stating they may be recalled. One month's notice will be provided to the individual prior to recall.

(c) Involvement of Association in layoff, recall and performance appraisals copies of letters of recall and layoff will be provided to the Association. Performance evaluations will remain confidential unless the employee requests help from the Association.

If a seasonal position is required for a continuous period of twelve (12) months or more, the Company and Association will review the position in view of it becoming a Permanent Position. The review will start within thirty (30) Days following the end of the twelve (12) month period and will be completed as soon as possible but within ninety (90) Days, whether or not the person is still employed with the Company.

3.08 "Temporary Employee" means an employee who is engaged full time or part-time for a special project or for work which is not of a permanent or continuing nature and further whose employment will be terminated on the completion of such work. A temporary position, other than utilization within a special project, shall not utilize a number of hours in excess of sixty percent (60 ) of the normal hours per year in that position. This category of employee shall not be utilized so as to displace any Permanent Employee or position or diminish the regular hours of work of any Permanent Employee. The Company shall undertake to notify the Association in writing of the name of the employees hired in this category and, in the

case of an employee hired for a special project, the expected duration of the special project.

3.09 "Casual Employee" means an employee who does not work more than thirty-two (32) Days within any three (3) calendar month period, and all employees performing janitorial work in district offices. It is agreed that Casual Employees shall not be included within the scope of this Collective Agreement.

3.10 The Company undertakes to notify the Association in writing of the name and wage rate and category of employee(s) when hired.

## ARTICLE 4.00 RECOGNITION

4.01 The Company recognizes the Association as the exclusive bargaining agency for all employees as defined in the Canada Labour Relations Board Certificate as referred to in Article 2.00 (Application) or said certificate as it may be amended from time to time. The Company recognizes the right of an employee to be represented by an Association Officer.

## ARTICLE 5.00 DISCRIMINATION

5.01 The Company shall not discriminate against any employee because of his connection with the Association, or his activities related thereto which are permitted by the Company, sanctioned by the terms of the Collective Agreement, or are in accordance with those rights and privileges defined in The Employment Standards Act of the Yukon Territory and the Canada Labour Code, nor shall the Association discriminate against any employee because of his non-membership in the Association or for activities in accordance with those rights and privileges defined in The Employment Standards Act of the Yukon Territory and the Canada Labour Code.

## ARTICLE 6.00 RIGHTS OF MANAGEMENT

6.01 The Company retains the sole and exclusive control of all matters concerning the operation, management and administration of its business and holds exclusive rights over matters on which this Agreement is silent, and in general, retains the residual rights of Management, and such control and rights shall not be abridged except by specific restrictions as set forth in this Agreement. Without restricting the generality of the foregoing the Company may hire, classify, promote and, for just cause, discipline, demote for disciplinary reasons, suspend or discharge any employee or employees, all in accordance with its commitments and responsibilities.

## ARTICLE 7.00 GRIEVANCE PROCEDURE

7.01 The grievance procedure described in this article will be used only to resolve disagreements regarding the interpretation, application, administration or any alleged violation of this Agreement.

Facilitation

7.02 (a) The parties believe that any grievance or prospective grievance should be resolved as early as possible and, wherever possible, should be resolved by the employee and the supervisor involved.

(b) To help try to resolve a disagreement, the parties may, by mutual agreement, use a problem solving process at any stage of the grievance process. The facilitator and the process to be used (e.g. the problem solving process) must be agreed to by both parties.

(c) The parties agree not to enforce the time limits under this article while the problem solving process is underway. When the attempts are completed, or mutual agreement to continue with the process is withdrawn, the applicable time limits will begin running again.

Discussions

7.03 Before submitting a grievance, the employee involved in the disagreement shall seek to settle the difference in discussion with:

(a) the selecting supervisor, if the disagreement relates to a Job Posting; or

(b) his most immediate supervisor, who is not a member of the bargaining unit, in any other case.

7.04 The discussion referred to in clause 7.03 should be held as soon as possible after the act which gave rise to the disagreement, since any grievance must be submitted within certain time limits.

(a) In the case of a Job Posting, a grievance must be submitted within five (5) Working Days of the employee receiving written reasons for not being selected. This time period will be extended to ten (10) Working Days upon the request of the employee.

(b) In the case of a dismissal, a grievance must be submitted within ten (10) Working Days of the dismissal.

(c) In any other case, a grievance must be submitted within fifteen (15) Working Days of the act giving rise to the grievance.

However, the parties agree that where the supervisor is not available or the discussion cannot be held, this requirement will not prevent any employee from submitting a grievance.

7.05 If the discussion does not resolve the matter, the disagreement may proceed to:

(a) Step 1 in case of a disagreement that does not involve the discharge of an employee; or

(b) Step 2 in the case of a disagreement that involves the discharge of an employee.

7.06 While this grievance procedure is in process, the employee involved will continue to faithfully perform the duties assigned to him.

Representation

7.07 An employee may be assisted and represented by an Association Officer at any stage of this procedure.

Calculation of Time

7.08 Whenever a time limit is imposed in this article, the following rules apply:

(a) Saturdays, Sundays and Holidays will not be included in calculating time;

(b) If either party fails to process the grievance within the time limits established, that party will be deemed to have conceded the grievance in favour of the other party.

Step 1

7.09 The employee will put the grievance in writing.

7.10 The grievance will include:

(a) the nature of the grievance;

(b) the date of the occurrence;

(c) the circumstances out of which the grievance arose;

(d) the requested remedy;

(e) the article, or articles, of the Agreement claimed to have been violated or infringed upon; and

(f) the signature of the employee(s) submitting the grievance.

7.11 (a) Where the grievance results from a Job Posting, the grievance will be sent to the selecting supervisor and his manager within five (5) Working Days of the employee being given written reason for not being selected for the position unless the time for filing of a grievance has been extended pursuant to clause 7.04 (a), where in the time for sending the grievance will be extended to ten (10) Working Days;

(b) In any other case, the grievance will be given to the employee's supervisor's manager within fifteen (15) Working Days of the act causing the grievance, with a copy, for information purposes, to the employee's supervisor.

7.12 The manager will meet with the employee and supervisor to discuss the grievance. If the grievance arises from Article 15.00 (Job Posting), the supervisor who made the decision shall attend.

7.13 Within six (6) Working Days of receiving the grievance, the manager will either uphold or deny the grievance. The manager's decision shall be in writing and given to the employee and the Association.

7.14 If the grievance is not resolved satisfactorily, either the Company or the Association may proceed to Step 2.

Step 2

7.15 Either the Company or the Association may request the formation of a grievance committee (the "Grievance Committee") by written notice.

7.16 In the case of a grievance resulting from the dismissal of an employee, receipt of the grievance shall constitute a request for a Grievance Committee. In such case, the grievance shall be in writing and include:

(a) the nature of the grievance;

(b) the date of the occurrence;

(c) the circumstances out of which the grievance arose;

(d) the requested remedy;

(e) the clause or clauses of this Agreement which, it is claimed, have been violated or infringed upon; and

(f) the signature of the employee(s) submitting the grievance.

7.17 The Company and the Association will each name three members to the Grievance Committee. The party requesting the Grievance Committee will include the names of its nominees in its notice under clause 7.15. The other party will respond with the names of its nominees in writing within five (5) Working Days of receiving the notice.

7.18 The employee initiating the grievance, his supervisor and his supervisor's manager are not eligible to sit on the Grievance Committee. In the case of a grievance resulting from a Job Posting, the selecting supervisor and his manager are also ineligible to sit as a member of the Grievance Committee.

7.19 The Grievance Committee shall appoint one of its members to be its chairperson and the person so appointed will retain the right to vote.

7.20 The written grievance will be presented to the Grievance Committee within five (5) Working Days of the Grievance Committee being appointed. In the case of a grievance resulting from an employee being dismissed, the grievance will be presented within ten (10) Working Days of the grievance being filed.

7.21 Within ten (10) Working Days of receiving the grievance, the Grievance Committee will issue a written report:

(a) upholding the grievance;

(b) denying it; or

(c) reporting that it is unable to reach a majority decision.

The Grievance Committee's report will be given to the Company and the Association.

7.22 A majority decision of the Grievance Committee is binding upon both parties.

7.23 If the Grievance Committee reports it is unable to reach a majority decision the grievance may proceed to Step 3.

Step 3

7.24 The Association or the Company shall submit the grievance to the Company's President.

7.25 The grievance shall be submitted, in writing, within six (6) Working Days of the Grievance Committee's report.

7.26 Within six (6) Working Days of receiving the grievance, the President or a designate will uphold or deny the grievance and notify the Association, in writing, of the decision.

7.27 If the grievance is not resolved satisfactorily, either party may submit the grievance to arbitration.

Grievance Arbitration

7.28 The Association or the Company shall notify the other party of its desire to proceed to arbitration within six (6) Working Days of a Step 3 decision. In the notice, the party requesting arbitration shall include the name of its nominees to the arbitration board.

7.29 Within seven (7) Working Days of receiving this notice, the party receiving the notice shall name its nominee to the arbitration board and notify the other party.

7.30 Within seven (7) Working Days of the appointment of the second nominee, the two nominees will select a chairperson for the arbitration board. If such agreement cannot be reached in that time, the nominees will request The Minister of Labour for the Government of Canada to appoint a chairperson.

7.31 The arbitration board will meet within twenty-one (21) Working Days of the chairperson's appointment and hear such evidence as the parties may wish to present to assure a full and fair hearing.

7.32 The arbitration board will make every reasonable effort to render its decision, in writing, within thirty (30) Days of its hearing.

7.33 The decision of a majority of the arbitration board is the decision of the arbitration board. It is final and binding on the parties.

7.34 The arbitration board's decision shall not alter, amend, add to or change the terms of this Agreement. It has no jurisdiction to determine any matter other than the grievance before it.

7.35 The arbitration board's jurisdiction is limited to the remedy requested by the grieving party.

7.36 In grievances concerning discharge or suspension, the arbitration board's jurisdiction is limited to determining whether there was just cause for the discipline. If it finds there was just cause, it shall not have the jurisdiction to review the penalty imposed. If it finds that there was not just cause for discipline, it may reinstate the employee involved and to declare that he is entitled to such reinstatement or redress as the arbitration board considers appropriate.

7.37 The parties will pay the expenses of their nominee. The expenses of the chairman shall be shared equally by the parties.

Policy Grievances

7.38 Either party to this Agreement may initiate a grievance regarding the interpretation, application, administration or any alleged violation of this Agreement.

7.39 A party initiating a policy grievance shall, within fifteen (15) Working Days of the act giving rise to the grievance, give notice to the other party, setting out:

(a) the nature of the grievance;

(b) the date of the occurrence;

(c) the circumstances out of which the grievance arose;

(d) the requested remedy;

(e) the article, or articles, of the Agreement claimed to have been violated or infringed upon; and

(f) the signature of the authorized official of the party initiating the grievance.

7.40 A grievance under this article, once served on the other party, shall constitute a notice of a request for the establishment of a Grievance Committee and the provisions of clause 7.08 and clauses 7.17 to 7.37 inclusive shall apply to the processing of such grievance.

## ARTICLE 8.00 CONTINUITY OF SERVICE

8.01 The Association agrees that it will not directly or indirectly sanction, authorize, or allow any stoppage of work or any action that restricts or limits service or production, and the employees agree that they will not be involved in such actions. The Company agrees that it will not cause any lockout of employees.

## ARTICLE 9.00 ASSOCIATION DUES

9.01 All employees now members of the Association, and all employees eligible to become members of the Association, shall, as a condition of employment pay semi-monthly to the Association, monies equal to the dues as established from time to time in accordance with the Constitution and Bylaws of the Association. Such dues shall be deducted semi-monthly by the Company from the employee's pay and remitted to the Association at the end of the month following the deduction. The payment of dues does not require the employee to become a member.

9.02 The Company shall provide the Association with a printout, monthly, containing the following specifics:

1. Employee Name
2. Employee Classification
3. Particulars of Association dues deducted

9.03 The Company will not authorize any other dues deduction except to the benefit of the Association, unless otherwise required by law.

## ARTICLE 10.00 WAGE SCHEDULES, NOTES AND APPENDICES

10.01 The provisions set forth in Wage Schedules 51, 52, 53, 54, 55, 56, 57, and 58 together with notes applying to these schedules and appendices, respectively annexed hereto, are hereby incorporated into and made part of this Agreement and shall apply for as long as this Agreement remains in force and effect. Further, any changes to the Agreement or addendum as officially agreed to and signed by both parties shall be attached to and form part of this Agreement.

## ARTICLE 11.00 NOTICES

11.01 Any notice required to be given by one party to the other hereunder shall be in writing and shall be sufficiently given, if presented by hand, or alternatively mailed to the party to whom such notice is to be given. Notice shall be directed to the parties as follows:

**Company:**
General Manager
The Yukon Electrical Company Limited
100 1100 1st Avenue
Whitehorse, Yukon Y1A 3T4

**Association:**
President
The Yukon Electrical Employees' Association
P.O. Box 31068
Whitehorse, Yukon Y1A 5P7

11.02 Each party may, from time to time, designate some other representative to be the person upon whom such notices are to be personally served, in lieu of the representatives theretofore so designated and or from time to time, may change its address for service hereunder, in all instances by serving the other party, in the manner herein before prescribed, with written notice to that effect.

11.03 Each notice mailed as aforesaid shall be deemed to have been received and the particular notice given, upon the expiration of five (5) clear Days excluding Saturdays, Sundays and Holidays next following the date of such mailing.

## ARTICLE 12.00 HEADINGS

12.01 The headings used throughout this Agreement are inserted for reference purposes only and are not to be considered or taken into account in construing the terms and conditions of this Agreement or of any portion herein, nor shall the same be

deemed to qualify, modify or explain the effects of any such term, condition or provision.

12.02 Wherever the singular or the masculine pronoun is used throughout this Agreement, the same shall be construed as meaning the plural or the feminine where the context or the parties so require.

## ARTICLE 13.00 JOB CLASSIFICATION

13.01 (a) For the purpose of this article evaluation plan means a formal system adopted for determining the relative value of a Job, and setting out specific criteria for making that determination. If no formal evaluation plan exists the Job will be evaluated using relative standards and assessment processes. Use of the terminology evaluations, re-evaluations and job assessment processes applies to all job classifications contained in the wage schedules.

(b) When new job classifications are established, the Company shall set the wage rate and shall notify the Association within fourteen (14) Days of the classification being established. The wage rate for the new classification may be set and implemented by the Company.

(c) When significant differences, or changes, in job content are made to existing job classifications to the extent that the Company or the Association or an employee requires that the Job be re-evaluated, the following procedure shall be followed:

(i) Should a written request for re-evaluation of a job classification be initiated by the Association or an employee (where such evaluation is initiated by an employee, a copy of the request must be filed with the Association), the Company shall proceed with the re-evaluation within thirty (30) Days of receiving the written request. The Company

shall complete the re-evaluation request as soon as possible, but no later than ninety (90) Days after receiving the written request for review. Within five (5) Working Days of the completion of any evaluation, the Company shall notify the Association of the results of the evaluation. If the re-evaluation results in a reclassification or new classification to a higher wage group, the reclassification or new classification shall be retroactive to the date the Company received the written request for review.

(ii) Should a written request for re-evaluation of a job classification be initiated by the Company, the Association shall be notified in writing within five (5) Working Days of the initiation of the review. The Company shall complete the re-evaluation request as soon as possible, but not later than ninety (90) Days from the date the Association was notified. Within five (5) Working Days of the completion of any evaluation the Company shall notify the Association of the results of the evaluation. If the re-evaluation results in a reclassification or new classification to a higher wage group, the reclassification or new classification shall be retroactive to the date the Company notified the Association of the initiation of the review.

(d) Should any dispute arise between the Company and the Association regarding the evaluation and setting the wage rate of a new job classification or the evaluation of an existing job classification, such dispute shall be settled by adopting the following procedure:

A committee of four (4) persons will be established to attempt to resolve the dispute. Two (2) representatives will be appointed by the Company and two (2) representatives will be appointed by the Association, each of the four (4) having one equal

vote. Every effort should be made to resolve the dispute within ten (10) Working Days of the committee's appointment. In the event that the dispute remains unresolved, the following method of settlement shall be adopted:

The Company and the Association shall submit the dispute jointly to two (2) appointees qualified in wage determination and administration, one (1) appointed by the Company and the other by the Association. Such appointees shall meet and hear all pertinent matters and render a decision within fourteen (14) Days of their first meeting.

In the event that the appointees cannot reach unanimity in their decision, they may appoint a third party of similar qualifications to act as Chairman. The unanimous decision of the first two (2) appointees, or a majority decision of the three (3) appointees, shall be final and binding upon both parties. It is agreed that the Company and the Association, each respectively, bear the costs and expenses of their appointees, and that costs and expenses of the third party, if appointed, be borne equally by the Company and the Association.

13.02 The Company undertakes to inform the Association in writing of changes in an employee's job classification. This will not be necessary in the case of progression movement within a classification.

13.03 (a) Job descriptions will be established for each employee in consultation with the incumbent and then issued to the incumbent and the Association.

(b) When a job description is changed, the Company will, within fourteen (14) Days of the change, give a copy of the revised job description to the Association and the incumbent.

(c) During the annual performance review meeting, the job description will be reviewed by the supervisor and the employee. If there have been significant changes to the Job, the supervisor will notify the Human Resources Department within ninety (90) Days. The Human Resources Department will confirm those changes to the job description by notice to the employee, in writing, within forty-five (45) Days of receiving notice from the supervisor.

## ARTICLE 14.00 TEMPORARY ASSIGNMENT TO HIGHER CLASSIFICATION PREMIUM

14.01 (a) Supervisors may, at their discretion, temporarily assign a Permanent or Probationary Employee to a Job, which has a higher maximum rate of pay than the employee's current Job.

(b) Any such assignment shall be in writing.

14.02 (a) When an employee is temporarily assigned to a Job, which is covered by this Agreement, the employee's rate of pay while so assigned shall be calculated, from the first Day, as follows:

(i) The rate shall usually be equal to the employee's normal pay plus one increment, as identified for the employee's normal Job.

(ii) If the rate set out in sub-paragraph (i) is less than the minimum of the salary range for the Job to which the employee is assigned, the employee shall be paid the minimum rate for that Job.

(iii) If the rate set out in sub-paragraph (i) is higher than the maximum of the salary range for the Job to which the employee is assigned, the employee shall be paid the maximum rate for that Job.

(iv) If the employee's normal Job is paid at a flat rate and therefore does not have an increment; the rate paid shall be equal to the employee's normal pay plus one increment as identified for the temporarily assigned Job, or the maximum rate of the temporarily assigned Job, whichever is lesser. For clarity, if there is no increment for the temporarily assigned Job, the employee shall be paid the flat rate as identified for the temporarily assigned Job.

(b) While acting in a Job which this clause applies, the employee's salary in the acting Job will be used as the basis for overtime and any other payment, which relates to the employee's hourly rate of pay.

14.03 (a) An employee who is temporarily assigned to a Job which is outside the scope of this Agreement, will be paid, from the first Day, at a rate of five percent (5 ) higher than the employee's normal pay.

(b) Prior to the temporary assignment taking effect, the employee and supervisor will sign a written agreement setting out any additional increment (not to exceed five percent (5 )) that may be payable during the temporary assignment and the time and conditions under which such payment shall be made.

(c) While acting in a Job to which this clause applies the salary of the employee's normal Job will be used as the basis for overtime and any other payment, which relates to the employee's hourly rate of pay.

14.04 An employee on temporary assignment will be paid at the Job rate of the higher classification for any annual vacation and the first fourteen (14) Days of sick leave if:

(a) the employee has been in the temporary assignment for at least thirty (30) Days before the vacation or sick leave, and

(b) the employee continues the temporary assignment following the employee's return from annual vacation or sick leave.

14.05 An employee who remains in a temporary assignment for more than one year will receive the increments which would be awarded to an employee in the Job to which the temporary assignment has been made, so long as the employee remains in that Job. This is not to be deemed as a change in the employee's permanent Job Class.

14.06 Employees who are serving in temporary assignments are entitled to receive the increments they would have received in their regular Jobs.

## ARTICLE 15.00 JOB POSTING, JOB NOTICE AND JOB PROGRESSION

15.01 (a) When a permanent position, within the scope of the Agreement, becomes vacant or a new position is created, a Job Posting or Job Notice outlining details of the vacancy will be posted on Company bulletin boards for ten (10) Working Days except as stated in clauses 15.01 (h), 15.06, 15.07, and 15.10.

(b) All Job Postings and notices shall contain hiring criteria including educational and or experience and related skill areas.

(c) A copy of each Job Posting and notice will be directed to the Association.

(d) Job notices shall be for those positions contained in Appendix A and will be posted within the Company for information purposes only. The Company is not obligated to hire from within the bargaining unit and may select external applicants. For the purposes of sequence [15.01 (h)], these positions will only be considered as part of a sequence should an internal applicant be awarded the position, creating a vacant Job Posting.

(e) Job Postings shall be for those positions not specifically listed in Appendix A, or otherwise specifically excluded within this article.

(f) All employees have the privilege of applying to posted positions. While first consideration will be given to applicants who are members of the bargaining unit, the Company reserves the right to fill vacancies from outside the bargaining unit and as defined in Appendix C (Letter of Understanding: Job Postings).

(g) Applicants will receive a personal written reply to their application.

(h) No more than two (2) Job Postings shall be required in any one sequence. After the second vacancy in a sequence has been filled the third vacancy created by the second posting shall not require posting. This third vacancy may be filled at the company's discretion, utilizing for example the options to fill as an internal career development or external placement. Should the Company choose to post the third vacancy, the Job Posting procedures and obligations will apply and will be considered the first in the new sequence.

15.02 In considering such applicants, the factors which shall be considered are related ability, education, behaviour, performance, related skill areas, and length of service. The Company is not necessarily obliged to consider the application of any employee with less than two (2) years in his present position and location.

15.03 When making promotions and or transfers, the above outlined procedures and criteria of selection shall apply and when the overall assessment based on the above stated factors is equal for two (2) or more of the applicants, the applicant with the most seniority with the Company shall be selected for the posting. An unsuccessful internal applicant shall be given a written reason for not being selected. All applicants will receive a personal written reply to their applications.

15.04 Unless the date of transfer is specified on the Job Posting, the successful applicant shall be transferred to his new position within four (4) weeks of being notified by the Company of his selection. Should there be good and sufficient reason why the transfer to the new position cannot be made within the four (4) week period, the employee shall be notified in writing as to the reasons therefore and be given a specific date prior to or at which the transfer shall be made.

15.05 No posting is required if a Job has been re-assessed or re-evaluated to a higher class, if the person who held the Job before the re-assessment or re-evaluation remains in the Job.

15.06 When an employee assumes a Job in a remote and difficult to fill position and has been assured a time certain rotation, the employee will be brought back to an equivalent level Job in another location without posting.

15.07 An employee on an approved educational leave may be brought back to an equivalent level Job within the bargaining unit without posting. The employee must remain a member in good standing with the Association while on leave.

15.08 In the case of clauses 15.06 and 15.07, the Company will inform the Association in advance of the application of these clauses.

15.09 When an employee wishes to appeal a decision under this article, such appeals will be governed by the terms and procedures contained within Article 7.00 (Grievance Procedure).

15.10 An employee, with prior mutual consent, may for compassionate reasons be assigned, without a posting, a different position within the bargaining unit. Such consent will not be unreasonably withheld.

15.11 Progression as set out in Appendix B of this Agreement does not constitute a new or vacant Job or position.

## ARTICLE 16.00 HOURS OF WORK AND OVERTIME

The hours of work stated in this article shall not be construed as a guarantee of any minimum nor as a restriction on any maximum hours to be worked, but serve only as a basis for the calculation of overtime.

16.01 Normal Hours of Work

(a) A normal day's work shall be eight (8) hours between 0700 and 1700 hours. A maximum lunch period of one (1) hour shall be observed. The normal work week shall consist of forty (40) hours worked in any five (5) consecutive days Monday through Saturday inclusive.

(b) By mutual consent of the affected employees and management, the normal hours of work may be extended during the period of Monday to Saturday. Such a change in the normal hours will subsequently be reviewed by the Employee Relations Council. This review will take place within a time frame agreed to prior to the start of the change.

(c) By mutual agreement between the employee and the supervisor, the hours of work per day for a specific Job assignment may be extended to a maximum ten (10) hours per Working Day so as to average forty (40) hours per week over a pre-determined period of time and, consequently, overtime payment for the hours worked over eight (8) per Working Day would not apply.

(d) In order to provide continuity of service to the Company's customers, certain work of a construction, maintenance and replacement nature on the Company's transmission, distribution and production facilities, is required on a pre-planned basis to be performed during other than normal hours of work. In such cases the Company, on forty-eight (48) hours' notice, may reschedule the normal hours of work of employees so affected as set out in clause 16.01 (a).

(e) Authorized overtime shall be paid as follows: Employees in this category shall receive overtime pay at the hourly equivalent rate of two (2) times the employee's regular rate of pay for all authorized overtime worked in excess of eight (8) hours per Working Day [ten (10) hours in the application of clause 16.01 (c) above] and for all authorized overtime worked in excess of forty (40) hours per week and for all overtime worked on Holidays as specified in Article 18.00 (Holidays) of this Agreement.

(f) Time required for travel outside regular working hours between headquarters and the temporary Job headquarters shall be paid for at applicable overtime rates.

(g) Employees working sixteen (16) or more consecutive hours in any twenty-four (24) hour period shall be allowed eight (8) consecutive hours of rest at no loss of wages before reporting for duty again.

(h) An employee who, as a result of a call-out, works at any time between midnight and the time three (3) hours before the start of his or her next regularly scheduled shift is entitled to have eight (8) consecutive hours of rest beginning at the end of the work for which the employee was called out.

(i) If an employee's eight (8) hours of rest under paragraph (g) or (h) extends into the last two (2) hours of his or her next regularly scheduled shift, the employee shall not be required to work those hours.

(j) Notwithstanding paragraphs (g), (h) and (i), in emergency situations the employee may be called back to work at equivalent to overtime rate of pay.

(k) Employees will not normally be called upon to be away from home base on weekends except for work of an emergency nature or by mutual agreement or in economically viable situations (e.g. weather, transportation restrictions, etc.).

(l) Except in the case of an emergency, the Company will endeavor to give a minimum of twenty (20) hours advance notice to employees prior to their being required to work away from home base for any period exceeding one (1) normal Working Day.

(m) When an employee is at rest because of this clause, the employee will not suffer any loss of wages.

16.02 Other Hours

(a) An employee who is instructed or directed to participate in an activity outside his normal hours of work will be paid at the overtime rate for any time which exceeds his normal hours of work.

(b) An employee who volunteers to participate in an activity outside of his normal hours of work shall not receive any compensation for any time which exceeds his normal hours of work.

(c) An employee who is invited to participate in an event or training that is of mutual benefit to both parties will receive his normal rate of pay for any time which exceeds his normal hours of work. An employee may accept or decline such an invitation.

(d) Whenever possible an employee will be scheduled to travel during his normal working hours when required to travel for training, interviews or for functions referred to in clauses (a) and (c) above. When this is not possible, an employee will be paid for travel time that exceeds his normal working hours as follows:

(i) at his normal rate of pay for Nisku training (field or Nisku delivered), interviews and mutual benefit and optional developmental activities under (c). With supervisor approval, due to business reasons, travel from outlying areas to Whitehorse will be paid at the overtime rate

(ii) the overtime rate for all other situations where attendance is mandatory

16.03 Overtime Banking

In recognition that from time to time an employee may require time off for personal reasons or unforeseen circumstances, the following conditions may apply:

(a) When an employee works overtime, he may direct that the amount payable for that overtime be banked rather than paid to him.

(b) Nothing in this clause guarantees an employee that a supervisor will approve any request to take time off.

(c) In any year, an employee may bank overtime pay to a maximum of five (5) Working Days.

(d) An employee may take time off and be paid out of his banked overtime by mutual agreement with his supervisor. An employee shall make a request at least six (6) Working Days prior to the first Working Day he wishes to take off. The request should be made only when no overtime will result and scheduled vacations will not be affected for themselves or other employees. The supervisor shall approve or reject the request as soon as possible, but at least three (3) Working Days prior to the first day the employee wishes to take off.

(e) At the end of each calendar year, each employee will be paid any amount which remains banked.

16.04 Time Off Without Pay

Arrangements may be made to take time off without pay subject to the prior approval of the employee's immediate supervisor.

16.05 Rest Breaks

The Company and Association acknowledge the benefits of rest breaks approximately midway through each half Working Day and will, whenever reasonable, provide such a break.

**ARTICLE 17.00 CALL-OUT**

17.01 Employees will be paid at the overtime rate when called out to perform work outside their normal working hours.

17.02 (a) If an employee is called out within two hours of the start of his regularly scheduled shift, he will be paid for the period from the time of the call-out to the start of his shift.

(b) If an employee is called out any other time, he will be paid for the time actually worked, or for two (2) hours, whichever is greater. The time required to travel between the job site and the specified community for his location shall be considered time actually worked.

17.03 Employees called out are deemed to be on duty for the minimum period set out in clause 17.02, or until the work for which they have been called out is completed. Further calls received during this period will be considered a continuation of the initial call and not subject to call-out pay.

17.04 (a) When an employee is required to work more than two (2) hours beyond the scheduled quitting time, the Company will provide the employee with a reasonable meal in the third ($3^{rd}$) hour and every four (4) hours thereafter, as long as work continues after the meal break.

(b) When an employee is called out under Article 17.00, the Company shall provide the employee with a reasonable meal in the fourth ($4^{th}$) hour and every four (4) hours thereafter, as long as work continues after the meal break.

(c) When an employee is called out under Article 17.00 to work more than two (2) hours prior to the beginning of the normally scheduled Working Day or shift, the company shall provide the employee with a meal.

(d) If the employee takes a meal break on site, and the break does not exceed thirty (30) minutes, and the employee continues working after the meal break, the employee will be paid at the overtime rate for the meal break.

(e) In lieu of providing the meals set out in this article, the Company may, at its option, pay an employee the amount of 11.00, noted for lunch in 20.02 (b) (ii), for each meal to which the employee is entitled.

(f) The employee and supervisor may agree to a practical application of the arrangement in this article.

## ARTICLE 18.00 HOLIDAYS

18.01 All employees covered by this Agreement, except as provided by clause 18.03, shall receive a regular Working Day's pay for the recognized Holidays listed below:

| | |
|---|---|
| New Year's Day | Christmas Day |
| Good Friday | Boxing Day |
| Easter Sunday | Discovery Day |
| Victoria Day | The Friday Designated for the |
| Canada Day | celebration of the Yukon |
| Labour Day | Sourdough Rendezvous |
| Thanksgiving Day | Remembrance Day |

18.02 If the Canadian or Yukon governments declare or proclaim an additional statutory holiday, it shall replace the Day designated for the celebration of the Yukon Sourdough Rendezvous. Should a new, non-statutory holiday be established, the parties will meet to decide on a course of action to amend clause 18.01.

18.03 To be eligible for and paid for any of the Holidays listed above, an employee must have completed thirty (30) Days or two hundred and forty (240) hours of employment in the twelve (12) months immediately preceding the Holiday and he must have worked his scheduled work shift immediately before and immediately after the Holiday. The only exclusion to this requirement will be where an employee is absent due to sickness or accident or by authority of the Company.

18.04 In the event of work being scheduled on a Holiday, employees will be paid two (2) times the regular rate in addition to the regular pay for the Holiday.

18.05 If one of the recognized Holidays for employees falls on a Saturday, either the previous Friday or the following Monday shall be observed as the Holiday as determined by the Company. If one of the recognized Holidays for employees falls on Sunday, the following Monday shall be observed as the Holiday. Employees shall receive Holiday pay only once for a given Holiday.

## ARTICLE 19.00 ANNUAL VACATIONS

19.01 (a) All Permanent Employees who have completed twelve (12) months of continuous employment shall be entitled to four (4) weeks of annual vacation with regular pay.

(i) In the particular case of a new Permanent, Permanent Part-time or Probationary Employee who has completed six (6) months of continuous employment he may, with the permission of his supervisor, take up to, two (2) weeks vacation with pay in his second six (6) months of employment, providing however that the receipt of the vacation days with pay is recognized as an advance draw on his vacation entitlement described in clause 19.01(a).

(b) All Permanent Employees who have completed eight (8) years of continuous employment shall be entitled to five (5) weeks of annual vacation with regular pay.

(c) All Permanent Employees who have completed sixteen (16) years of continuous employment shall be entitled to six (6) weeks of annual vacation with regular pay.

(d) All Permanent Employees who have completed twenty-five (25) years of continuous employment shall be entitled to seven (7) weeks of annual vacation with regular pay.

(e) Subject to vacation scheduling under clause 19.02, employees may be permitted to take their earned vacation one (1) Working Day at a time up to a maximum of five (5) Working Days in a calendar year, subject to receiving the prior approval of their immediate supervisor and providing such scheduling does not unduly interfere with efficiency or incur overtime.

19.02 (a) Vacations may be taken at any time during the calendar year by mutual agreement between the employee and his supervisor provided, however, that vacation scheduling is arranged to suit the work schedules of the Company.

(b) In the year in which an employee qualifies for increased vacation entitlement under clause 19.01 the increased entitlement may be taken only after the employee's anniversary date of vacation entitlement.

19.03 In the event that a recognized Holiday falls within the annual vacation period of an employee, such period shall be increased by one (1) Working Day for each of the Holidays so affected.

19.04 Sick leave shall not be deemed to have broken the continuity of employment for purposes of establishing annual vacation entitlement.

19.05 For purposes of this Agreement, one (1) week of vacation shall be deemed to be five (5) Working Days.

19.06 An employee may apply in writing for the carryover of vacation entitlement to the next year. Such carryover will only be granted if mutually agreed between the employee and his supervisor and, if granted, must be arranged to suit the work schedules of the Company.

19.07 Permanent and Permanent Part-time Employees that are stationed in the districts more than two hundred and fifty (250) kilometers outside of Whitehorse and who proceed on annual vacation shall be allowed two (2) Working Days of paid travel time annually for allowable trips reimbursable pursuant to Article 31.00 (Vacation Travel Expenses).

19.08 (a) Employees are entitled to full vacation entitlement only if they have worked 90 percent of their regularly scheduled Working Days in the year which ended on their most recent anniversary date.

(b) For the purpose of this clause, statutory holidays and annual vacation count as Days worked.

(c) Employees who have worked less than 90 per cent of their regularly scheduled Working Days in the year which ended on their most recent anniversary date shall be entitled to a vacation on a prorated basis bearing the same relationship to their regular vacation entitlement as the number of Days worked bears to 90 per cent of their regularly scheduled Working Days. An example of the calculation of prorated vacation is as follows:

**PRO-RATED VACATION ENTITLEMENT CALCULATION**

**Total number of Working Days in a year is 261 Days**

- 365 days in a year
- 104 Saturdays and Sundays
- Total Working Days 365 minus 104

**Assumptions**

1. Employee's normal vacation entitlement is 4 weeks or 20 Days.
2. The employee missed 70 regularly scheduled Working Days because the employee was on short term disability.

**Pro-Rated Vacation Calculation**

**Working Days in a Year minus of Regularly Scheduled Working Days Missed in the Year**
**90 of the Working Days in a Year**

261 Working Days - 70 Days
235 Working Days
0.813

**Vacation Entitlement**

Multiply 0.813 by the Normal Vacation Entitlement of 20 Days. 0.813 x 20 days 16.25 days. (Always round up). Therefore the employee is entitled to 17 Days of vacation.

**ARTICLE 20.00 BOARD AND LODGING**

20.01 The Company will, on production of receipts, pay for room or alternatively provide accommodation for employees when working away from home.

20.02 (a) When an employee is working away from his Home Base, and such work requires an overnight absence, the Company will reimburse the employee for the cost of reasonable meals, unless the meals were provided to them at no charge or as part of a registration fee.

(b) The employee may, at the employee's option, claim either:

(i) the actual cost of the meals, evidenced by receipts, or

(ii) the following allowances for each meal:

| | |
|---|---|
| Breakfast | 9.00 |
| Lunch | 11.00 |
| Dinner | 20.00 |

(c) A choice in 20.02(b) above will apply for the duration of the work assignment or on a week- to-week basis. Exceptions may be considered by the supervisor.

20.03 (a) When an employee is working away from his Home Base over the lunch break, and returns to the Home Base the same Day, the employee will be reimbursed 7.00 for lunch only.

(b) If an employee is unexpectedly required to work away from his Home Base over the lunch break, but returns to the Home Base the same Day, the employee will be reimbursed for lunch, on the production of a receipt, or, 7.00 for lunch only.

20.04 This will not apply to locally hired help employed for a specific Job in the community in which they reside and who will be laid off prior to the crew moving to another location.

20.05 An employee who is required to work away from home shall be paid incidental expenses of six dollars and fifty cents ( 6.50) per night for all nights away from home.

## ARTICLE 21.00 STANDBY

21.01 An employee who is requested to standby shall be paid as follows:

(a) One (1) hour of regular pay where the standby period begins on a regularly scheduled Working Day.

(b) Two (2) hours of regular pay where the standby period begins on a scheduled Day of rest.

(c) Three (3) hours of normal pay where the standby period begins on a Holiday recognized in Article 18.00.

In addition the employee shall be paid the applicable rate for work performed as outlined in Article 17.00 (Call-Out).

21.02 The Company shall determine the number of employees required to standby in each circumstance and shall so designate these employees by schedule. Standby allowance will be paid only to employees officially designated for such duty. In designating employees for standby, the Company will endeavor to arrange for the equitable distribution of standby duties.

21.03 Standby on a regular Working Day means availability on-call outside of normal hours of work. On each scheduled Day of rest and recognized Holiday, standby means availability on-call for the full twenty-four (24) hour period. An employee on standby may leave his home for personal reasons, provided he makes arrangements to be reached and to be available for duty.

21.04 An employee who is scheduled by the Company to standby for more than 100 Days in a calendar year shall be paid 1.5 times the applicable rate set out in clause 21.01 for every Day he is scheduled to standby after the $100^{th}$ Day.

## ARTICLE 22.00 BEREAVEMENT

22.01 In the case of a death in the immediate family, a Permanent, Probationary or Permanent Part-time Employee shall be given time off with pay up to a maximum of five (5) Working Days. The term "immediate family" shall be interpreted to mean a mother, father, sister or brother, spouse, son or daughter, mother-in-law, or father-in-law, sister-in-law or brother-in-law, son-in-law or daughter-in-law, grandfather or grandmother (including spouse's) or grandchild, and step-relatives at the same levels or any dependent relative living in the employee's household.

## ARTICLE 23.00 TERMINATION OF SERVICE

23.01 In the event of a Permanent Employee giving notice of termination to the Company, such termination shall require notice of ten (10) Working Days.

23.02 In the event of the Company giving notice of termination to a Permanent Employee, such termination shall require notice of thirty (30) Days.

23.03 An employee may be discharged for just cause without notice or pay in lieu therefore, subject to Article 7.00 (Grievance Procedure).

23.04 In the event of the Company terminating the employment of a Permanent or Permanent Part-time Employee, other than for just cause, severance pay shall be paid to the employee in an amount equal to one-half (1 2) a week's normal pay per year of employment based on their last month's wage rate.

## ARTICLE 24.00 MATERNITY AND PARENTAL LEAVE

24.01 An employee who has completed twelve (12) months of continuous employment with the Company is entitled to maternity and parental leave in accordance with the provisions of the Yukon Employment Standards Act.

## ARTICLE 25.00 CALCULATION OF PREMIUM RATES

25.01 If two (2) or more premiums are applicable to the same hours worked, an employee shall receive only the highest premium rate applicable to such hours. For the same hours worked, an employee shall not receive a premium rate under more than one (1) provision of this Agreement unless otherwise specifically provided.

## ARTICLE 26.00 REDUCTION OF STAFF

26.01 This clause does not restrict the Company's right to terminate an employee for discipline or performance reasons.

(a) Before there is a reduction in staff by way of layoff or termination(s) of Permanent or Permanent Part-time Employee(s), the Company will notify the Association and arrange a meeting to discuss the reduction in staff and the procedure to be used. The Company representatives at the meeting will include the General Manager and the management of the department in which the layoff or termination is to occur.

(b) In the event a reduction in staff is required as a result of re-organization, automation, equipment changes or changes in methods of operation, the Company will attempt to provide alternate employment opportunities in the Company, within the Yukon. The Company and the Association will work together to attempt to achieve the alternate job placement.

(c) The Company will consider retraining or development as an alternative to reduction of staff, when a vacancy exists and the employee demonstrates the ability and aptitude to meet the new Job requirements.

(d) In the event of a reduction in staff the factors which shall be considered are: related ability, education, performance, related skill areas and length of service. These factors are not listed in order of priority.

26.02 (a) In the event of an increase in staff of a department within one (1) year following reduction of staff, a Permanent, Probationary or Permanent Part-time Employee will be eligible for re-hire on a last-out first-in basis. When it is not possible to determine which employee was last out, consideration for re-hire will be based on related ability, education, performance, related skill areas and length of service. These factors are not listed in order of priority.

To be eligible for re-hire, the employee affected by the staff reduction shall subsequently advise the Company of any change in address. The Company will contact an eligible former employee by double registered mail and the former employee must acknowledge receipt of the Company correspondence within seven (7) Days of the date of receipt of the Company correspondence and be prepared to report to work with the Company within twenty-one (21) Days of the date of receipt of the Company correspondence.

(b) When re-hired the employee will be credited with their length of service and benefits under the Agreement that had accrued to the employee up to the date of their termination. The Company shall reinstate the employee in their former position occupied at the time of their termination or provide them with alternate work of a comparable nature at an appropriate wage commensurate with their experience and qualifications.

## ARTICLE 27.00 ARBITRATION PROCEDURES

27.01 The Company and Association agree that an arbitration board will be convened immediately to settle and determine those matters referred to it as matters not resolved by the parties in direct negotiation. The said arbitration board shall settle and determine the said matters referred to it during the operation of this Agreement.

27.02 The arbitration board shall consist of a nominee of the Company and a nominee of the Association; such nominees shall elect within seven (7) Days of the appointment of the second of them, a third person who shall be Chairman. In the event the two nominees fail to agree upon a Chairman, the appointment of a Chairman shall be made forthwith by the Minister of Labour for the Government of Canada upon request of either nominee. The nominees of the Company and the Association must be conveyed in writing to the other party within seven (7) Days of execution of this Agreement.

27.03 The arbitration board by its decision may alter, amend, change or delete the matters referred to it for settlement and determination.

27.04 The arbitration board shall issue an award in writing and the decision is final and binding upon the Company and the Association and upon an employee affected by it. The decision of a majority is the award of the arbitration board.

27.05 It is agreed that the following matters are to be the only matters referred to the arbitration board and that those items listed below under clause 27.07 shall be effective until altered, amended, changed or deleted by the decision of the arbitration board and those items listed under clause 27.08 shall not be effective unless the arbitration board by its decision incorporates them into the Agreement whether in their present form or in an altered, amended, or changed form.

27.06 Each party shall bear the expenses of its respective nominee to the arbitration board and the parties shall bear equally the expenses of the Chairman.

27.07 The parties are directed to list those requests etc. which have not been resolved and which have been proposed to not have a retroactive application.

27.08 The parties are directed to list those requests etc. which have not been resolved and which have been proposed to have a retroactive application.

## ARTICLE 28.00 CONVERTING MONTHLY SALARY TO HOURLY RATE

28.01 The hourly rate for employees is calculated by dividing the monthly salary by 174 and rounding off to the nearest cent. The figure 174 represents the average hours of work per month and is calculated using an 8 hour Working Day and a 40 hour week as follows:

365 Days - 52 Sundays - 52 Saturdays 261 Working Days per year

$$\frac{\text{261 Working Days x 8 hours}}{\text{12 months}} \quad \text{174 hours per month}$$

## ARTICLE 29.00 NORTHERN ALLOWANCE

29.01 The Company's assistance to Permanent Employees to alleviate the higher cost of living in the Yukon will be:

Five hundred and twenty five dollars ( 525.00) per month plus five percent (5 ) of basic monthly salary.

29.02 The Company's assistance to Permanent Part-time Employees to alleviate the higher cost of living in the Yukon will be:

Five hundred and twenty five dollars per month ( 525.00) x
$$\frac{\text{Regular hours to be worked per month}}{\text{Total Regular Hours per month for the Job classification}}$$

plus five percent (5 ) of basic monthly salary.

29.03 Temporary Employees who have been continuously employed on a special project for more than five (5) months, or scheduled to a term project of more than five (5) months shall be entitled to fifty percent (50 ) of the 525.00 per month northern allowance for the total time worked.

29.04 Seasonal Employees, upon commencing employment, shall receive fifty (50) per cent of the 525.00 per month northern

allowance plus two and one half percent (2.5 ) of basic monthly salary for the total time worked.

## ARTICLE 30.00 LOCATION ALLOWANCE

30.01 Location allowance specified in this article shall be paid to employees on a pay period basis, and payroll administered in like manner to the Article 29.00 (Northern Allowance).

(a) Permanent Employees who are stationed in the following areas shall receive a location allowance as specified herein per year over and above their standard northern allowance.
(i) Haines Junction - 1,200.00
(ii) Watson Lake - 2,100.00
(iii) Beaver Creek - 2,100.00

30.02 Permanent Part-time Employees who are stationed in the locations noted in clause 30.01 (a) shall receive a prorated location allowance on the basis of total hours to be worked in the year divided by the total regular hours for the Job classification.

30.03 Temporary Employees who are stationed in the locations noted in clause 30.01 (a) and who have been continuously employed on a special project for more than five (5) months, or scheduled to a term project of more than five (5) months shall be entitled to fifty percent (50 ) of the designated location allowance for the total time worked.

30.04 Seasonal Employees who are stationed in the locations noted in clause 30.01 (a), upon commencing employment, shall receive fifty percent (50 ) of the designated location allowance for the total time worked.

## ARTICLE 31.00 VACATION TRAVEL EXPENSES

31.01 The Company supports the need for Permanent and Permanent Part-time Employees, their spouses and Dependents to take annual vacations and in recognition of the northern travel costs has established the following provisions.

31.02 (a) Only when claimed, the Permanent or Permanent Part-time Employee is entitled to reimbursement for travel expenses once per calendar year after completion of twelve (12) months employment with the Company.

(b) A Permanent or Permanent Part-time Employee who transfers to the Company from another ATCO company with at least twelve (12) months of continuous service with another ATCO company, will have vacation travel expenses applied on a prorated basis in the first calendar year. The vacation travel expenses will be prorated based on the number of months to be worked for the Company, including the month they started in the first calendar year.

31.03 The Company shall reimburse a Permanent Employee, and if applicable, the employee's spouse, and dependent children over the age of two years, a maximum of eight hundred dollars ( 800) each toward the purchase of a return airfare to any destination. The eight hundred dollars ( 800) represents an approximation of the current seven (7) Day advance return economy airfare to Edmonton from Whitehorse.

31.04 If a Permanent Employee does not elect to fly, the Company shall pay the employee:

SINGLE STATUS Eight hundred dollars ( 800)

FAMILY STATUS One thousand, six hundred dollars ( 1,600)

31.05 A Permanent or Permanent Part-time Employee's eligibility for an entitlement to travel expenses shall not be cumulative.

31.06 Where for any reason a Permanent or Permanent Part-time Employee's employment with the Company terminates prior to their anniversary date, a prorated amount of travel expenses advanced to such employee during such uncompleted year of employment shall be repayable to the Company by way of a deduction from the final pay cheque of such employee.

31.07 The Permanent or Permanent Part-time Employee will be responsible for retaining receipts for income tax purposes.

31.08 Clauses 31.03 and 31.04 shall apply to Permanent Part-time Employees, their spouses, and Dependents on a prorated basis of the total regular hours to be worked in the year divided by the total regular hours for the Job classification.

## ARTICLE 32.00 EMPLOYEE RELATIONS COUNCIL

32.01 The parties agree to establish a standing Employee Relations Council (the "Council").

32.02 The Council will consider matters relating to technological change, employee relations and contract issues and make recommendations to the parties as appropriate.

32.03 The Council will consist of an equal number of representatives from the Company and the Association.

32.04 Each of the parties will name its own representatives to the Council and may change its representatives at any time. The parties will use their best efforts to ensure that their representatives are also members of their respective bargaining committees.

32.05 The Company and the Association will each nominate one of their representatives to be a co-chairperson of the Council.

32.06 The Council will meet at the call of the co-chairperson and may establish its own procedures and practices.

32.07 The Company will recognize employee's involvement in the Council by acknowledging the employee's efforts in their performance evaluation.

## ARTICLE 33.00 JOB-SHARING

33.01 Two Permanent Employees may apply to the Company for permission to jointly fill one permanent Job.

33.02 The Company is not obliged to agree to such a request.

33.03 If the Company agrees to such a request, the two employees, their manager and the Company shall sign a Job-sharing agreement.

33.04 The Job-sharing agreement shall set out the terms of the arrangement, including the right of either employee to withdraw from the arrangement after giving certain amount of notice.

33.05 The Job-sharing agreement will also include the Company's right to terminate the arrangement if it proves unsatisfactory and will explain what will happen to the employees if the company withdraws it consent.

33.06 Nothing in a Job-sharing agreement may contradict this Agreement.

33.07 If either of the employees involved in a Job-sharing agreement withdraws from the arrangement, the other employee must fill the Job on a full-time basis.

33.08 The status of a full time Permanent Employee once entering into a Job-sharing agreement, will change to that of a Permanent Part-time Employee.

33.09 The company shall send the Association a copy of every Job-sharing agreement as soon as it has been signed.

33.10 Employees involved in a Job-sharing agreement will be paid at the overtime rate when the combined hours worked exceed eight (8) hours per Day or forty (40) hours per week.

## ARTICLE 34.00 JOB-SPLITTING

34.01 This article applies only when:

(a) A vacancy occurs in a Customer Service Advisor position fulfilling receptionist duties; and

(b) The Company believes the Job must be staffed for more than eight hours a Working Day.

34.02 The Company may choose to fill a Customer Service Advisor position fulfilling receptionist duties with two Permanent Part-time Employees.

34.03 Once the Company has decided to use this article to fill a Job, it may end the arrangement only if it provides the employees filling the Job with other Jobs which:

(a) provide at least the same number of hours of work per week;

(b) provide at least the same hourly rate of pay; and

(c) are in the same location.

34.04 If the Company terminates a Job-Splitting arrangement:

(a) the Job involved will revert to the same hours of work that were in effect prior to the Job being split; and

(b) the Job will be offered to one of the persons occupying the Job.

If both employees wish to assume the Job on a full-time basis, the Company will, in deciding upon the successful candidate, consider the following factors (not in order of priority): related ability, education, performance, related skill areas and length of service.

34.05 This article will not be used to reduce the number of hours of existing Permanent Employees without their consent.

## ARTICLE 35.00 CONTRACT LABOUR

35.01 The Company agrees to advise the Association at the beginning of each year of the proposed capital and operational and maintenance plans and to review the status of these plans with the Association at the end of each year.

## ARTICLE 36.00 WAIVER OF SPECIFIC CLAUSES

36.01 The Company, or the Association, may, from time to time, ask each other to waive one or more provisions of the Collective Agreement in a particular set of circumstances for the purpose of managing the Company's business or the employees' interests. Either party may, upon due consideration, waive such provision or provisions for the benefit of the employees or the Company.

36.02 Upon receiving such a request, the Association or Company shall review it, along with any documentation provided by the Company or Association, and shall provide the Company or Association with a response as soon as practical under the circumstances.

36.03 Any waiver by the Association or Company pursuant to this article applies only to the specific request made by the Company or Association. Should a further waiver of the same clause be desired on a subsequent occasion, the procedure outlined in clauses 36.01 and 36.02 shall apply.

## ARTICLE 37.00 EXTENSIVE OVERNIGHT AND WEEKEND ABSENCES

37.01 (a) On an annual basis, an employee who is required to spend extensive overnight absences from Home Base will qualify for additional vacation as identified below:

| | |
|---|---|
| (i) 40 overnight absences | one (1) Day |
| (ii) 50 overnight absences | two (2) Days total |
| (iii) 60 overnight absences | three (3) Days total |

(iv) 70 or more overnight absences four (4) Days total

Overnight absences that are related to training or meetings do not count toward the totals in the above.

The additional vacation days earned will be added to the following year's vacation entitlement and administered as part of Article 19.00.

(b) On an annual basis, an employee who is required to spend extensive weekend absences on a Friday, Saturday or Sunday working away from his Home Base in order to cover off for a vacant position, vacation, or an illness in Watson Lake, Haines Junction, or Beaver Creek, will qualify for additional pay as identified below:

| | | |
|---|---|---|
| (i) | three (3) overnight absences | 12 hours of his normal pay |
| (ii) | six (6) overnight absences | 24 hours of his normal pay |
| (iii) | nine (9) overnight absences | 48 hours of his normal pay |

It is understood that weekend assignment working away from Home Base will be rotated equally among qualified staff.

Overnight weekend absences count toward the totals in (a) above.

## ARTICLE 38.00 COMPASSIONATE CARE LEAVE

38.01 An employee is entitled to compassionate care leave in accordance with the provisions of the Canada Labour Code Part III 206.3 (1).

## ARTICLE 39.00 PERSONAL DAYS

39.01 Permanent and Permanent Part-time Employees in Schedules 51, 52, 53, and 57 are eligible for three (3) working Days of personal leave (Personal Days) with pay in each calendar year. This leave will be granted at the employee's request in all but exceptional or emergency work situations.

Whenever possible the employee will provide at least 48 hours notice prior to taking the leave. It is understood that there will be situations where 48 hours notice cannot be given due to personal emergencies or short notice situations. Notice given of less than 48 hours will not be sufficient grounds to deny the leave.

Any unused time in Personal Days that remains at the end of a calendar year expires and does not carry over into the next year.

IN WITNESS WHEREOF the Company has hereunto affixed its corporate seal, duly authenticated by the signature of its proper officers thereunto authorized, and the Association has caused these presents to be executed, all as of the day and year first above written.

| **THE YUKON ELECTRICAL COMPANY LIMITED** | **THE YUKON ELECTRICAL EMPLOYEES ASSOCIATION** |
|---|---|
| President | President |
| General Manager | Vice-President |

**THE YUKON ELECTRICAL COMPANY LIMITED**
**SCHEDULE 51**
**General Office and Administration Jobs**
**Minimum Monthly (Hourly) Wage Ranges**

| Job Class Number | Job Title | Wage Range Effective Jan. 1, 2007 (3.5 ) | Increment | Wage Range Effective Jan. 1, 2008 (3.5 ) | Increment |
|---|---|---|---|---|---|
| 510100 | Receptionist | 3,142-3,766<br>(18.06-21.64) | 208<br>(1.20) | 3,253-3,898<br>(18.70-22.40) | 215<br>(1.24) |
| 510200 | Customer Service Advisor Entry Level | 3,351-3,975<br>(19.26-22.84) | 208<br>(1.20) | 3,469-4,114<br>(19.94-23.64) | 215<br>(1.24) |
| 511200 | Financial Assistant Entry Level | 3,351-3,975<br>(19.26-22.84) | 208<br>(1.20) | 3,469-4,114<br>(19.94-23.64) | 215<br>(1.24) |
| 510300 | Customer Service Advisor Qualified | 3,583-4,415<br>(20.59-25.37) | 208<br>(1.20) | 3,709-4,569<br>(21.32-26.26) | 215<br>(1.24) |
| 511300 | Financial Assistant Qualified | 3,583-4,415<br>(20.59-25.37) | 208<br>(1.20) | 3,709-4,569<br>(21.32-26.26) | 215<br>(1.24) |
| 510400 | Customer Service Advisor Senior Qualified | 3,996-4,828<br>(22.97-27.75 | 208<br>(1.20) | 4,137-4,997<br>(23.78-28.72) | 215<br>(1.24) |
| 511400 | Financial Assistant Senior Qualified | 3,996-4,828<br>(22.97-27.75) | 208<br>(1.20) | 4,137-4,997<br>(23.78-28.72) | 215<br>(1.24) |

**THE YUKON ELECTRICAL COMPANY LIMITED**
**SCHEDULE 52**
**Draftsperson and Engineering Assistant Jobs**
**Minimum Monthly (Hourly) Wage Ranges**

| Job Class Number | Job Title | Wage Range Effective Jan. 1, 2007 (3.5 ) | Increment | Wage Range Effective Jan. 1, 2008 (3.5 ) | Increment |
|---|---|---|---|---|---|
| 520000 | Draftsperson Entry Level | 3,292-3,751<br>(18.92-21.56) | 153<br>( .88) | 3,408-3,882<br>(19.59-22.31) | 158<br>( .91) |
| 521000 | Engineering Assistant - Entry Level | 3,292-3,751<br>(18.92-21.56) | 153<br>( .88) | 3,408-3,882<br>(19.59-22.31) | 158<br>( .91) |
| 520100 | Draftsperson I | 3,493-4,488<br>(20.07-25.79) | 199<br>( 1.14) | 3,615-4,645<br>( 20.78-26.70) | 206<br>( 1.18) |
| 521100 | Engineering Assistant I | 3,493-4,488<br>(20.07-25.79) | 199<br>( 1.14) | 3,615-4,645<br>(20.78-26.70) | 206<br>( 1.18) |
| 520500 | Draftsperson II | 4,684-5,528<br>(26.92-31.77) | 211<br>( 1.21) | 4,849-5,721<br>(27.87-32.88) | 218<br>( 1.25) |
| 521300 | Engineering Assistant II | 4,684-5,528<br>(26.92-31.77) | 211<br>( 1.21) | 4,849-5,721<br>27.87-32.88 | 218<br>( 1.25) |
| 520900 | Draftsperson III | 5,300-6,316<br>(30.46-36.30) | 254<br>(1.46) | 5,486-6,538<br>(31.53-37.57) | 263<br>(1.51) |
| 521500 | Engineering Assistant III | 5,300-6,316<br>(30.46-36.30) | 254<br>(1.46) | 5,486-6,538<br>(31.53-37.57) | 263<br>( 1.51) |

1) Annual increments except those marked with an asterisk ( ) which are semi-annual.

**THE YUKON ELECTRICAL COMPANY LIMITED**
**SCHEDULE 53**
**Operations and Maintenance Support Jobs**
**Minimum Monthly (Hourly) Wage Ranges**

| Job Class Number | Job Title | Wage Range Effective Jan. 1, 2007 (3.5 ) | Increment | Wage Range Effective Jan. 1, 2008 (3.5 ) | Increment |
|---|---|---|---|---|---|
| 530400 | Capital and Construction Assistant | 3,583-4,415 (20.59-25.37) | 208 (1.20) | 3,709-4,569 (21.32-26.26) | 215 (1.24) |
| 530500 | Operations Support | 3,583-4,415 (20.59-25.37) | 208 (1.20) | 3,709-4,569 (21.32-26.26) | 215 (1.24) |

1) Annual increments except those marked with an asterisk ( ) which are semi-annual.

**THE YUKON ELECTRICAL COMPANY LIMITED**
**SCHEDULE 54**
**Apprenticeship Jobs**
**Minimum Monthly (Hourly) Wage Ranges**

| Job Group Code(s) | Apprentice Journeyman Ticket Title | Training Term Wage Range Effective January 1, 2007 (4.75 ) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 543001 | 543002 | 543003 | 543004 | 543005 | 543006 | 543007 | 543008 |
| | | 1-1 | 1-2 | 2-1 | 2-2 | 3-1 | 3-2 | 4-1 | 4-2 |
| | | 3,438 | 3,725 | 4,011 | 4,297 | 4,583 | 4,869 | 5,157 | 5,443 |
| 543001 - 543008 | Power Lineman | (19.76) | (21.41) | (23.05) | (24.70) | (26.34) | (27.98) | (29.64) | (31.28) |

| | | Training Term Wage Range Effective January 1, 2008 (4.5 ) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 543001 | 543002 | 543003 | 543004 | 543005 | 543006 | 543007 | 543008 |
| | | 1-1 | 1-2 | 2-1 | 2-2 | 3-1 | 3-2 | 4-1 | 4-2 |
| | | 3,593 | 3,893 | 4,191 | 4,490 | 4,789 | 5,088 | 5,389 | 5,688 |
| 543001 - 543008 | Power Lineman | (20.65) | (22.37) | (24.09) | (25.80) | (27.52) | (29.24) | (30.97) | (32.69) |

1) The Company Apprenticeship Guidelines set out all articles, conditions and administration necessary toward these apprenticeship arrangements.
2) Employees enrolled in recognized apprenticeship programs must successfully meet all apprenticeship requirements before being advanced.
3) When the Company enrolls an employee in a recognized apprenticeship program, the employee shall be reclassified to the applicable Journeyman Job classification upon successful completion of the full program and receipt of the Journeyman ticket.

**THE YUKON ELECTRICAL COMPANY LIMITED**
**SCHEDULE 55**
**Line and Service Jobs**
**Minimum Monthly (Hourly) Wage Ranges**

| Job Class Number | Job Title | Wage Range Effective Jan. 1, 2007 (4.75 ) | Increment | Wage Range Effective Jan. 1, 2008 (4.5 ) | Increment |
|---|---|---|---|---|---|
| 556100 | Serviceman Lineman<br>Journeyman | 5,731-6,023<br>(32.94-34.61) | 292<br>( 1.68) | 5,989-6,294<br>(34.42-36.17) | 305<br>( 1.75) |
| 556300 | Serviceman Lineman<br>Journeyman<br>(Maximum Range) | 6,023-6,380<br>(34.61-36.67) | 357<br>( 2.05) | 6,294-6,667<br>(36.17-38.32) | 373<br>( 2.14) |
| 558100 | Senior Serviceman<br>Lead Lineman | 6,083-6,959<br>(34.96-39.99) | 292<br>(1.68) | 6,357-7,272<br>(36.53-41.79) | 305<br>(1.75) |

1) Annual increments except those marked with an asterisk ( ) which are semi-annual.

**THE YUKON ELECTRICAL COMPANY LIMITED**
**SCHEDULE 56**
**Plant Maintenance Jobs**
**Minimum Monthly (Hourly) Wage Ranges**

| Job Class Number | Job Title | Wage Range Effective Jan. 1, 2007 (4.75 ) | Increment | Wage Range Effective Jan. 1, 2008 (4.5 ) | Increment |
|---|---|---|---|---|---|
| 566100 | Maintenance Man I | 2,542-4,152<br>(14.61-23.86) | 322<br>( 1.85) | 2,658-4,338<br>(15.28-24.93) | 336<br>( 1.93) |
| 566300 | Maintenance Man II | 4,168-5,134<br>(23.95-29.51) | 322<br>( 1.85) | 4,357-5,365<br>(25.04-30.83) | 336<br>( 1.93) |
| 566500 | Maintenance Man III | 5,146-5,790<br>(29.57-33.28) | 322<br>( 1.85) | 5,379-6,051<br>(30.91-34.78) | 336<br>( 1.93) |
| 566501 | Maintenance Man III<br>(Flat Rate) | 6,107<br>(35.10) | | 6,382<br>(36.68) | |
| 566700 | Lead Maintenance Man | 6,334<br>(36.40) | | 6,619<br>(38.04) | |

1) Annual increments except those marked with an asterisk ( ) which are semi-annual.
2) Employees in the following Jobs must have completed 12 months at the top of the increment range before being changed to maximum or flat rate:
   (a) Maintenance Man III (Job Class Number 566500)

**THE YUKON ELECTRICAL COMPANY LIMITED**
**SCHEDULE 57**
**General Operations Jobs**
**Minimum Monthly (Hourly) Wage Ranges**

| Job Class Number | Job Title | Wage Range Effective Jan. 1, 2007 (3.5 ) | Increment | Wage Range Effective Jan. 1, 2008 (3.5 ) | Increment |
|---|---|---|---|---|---|
| 570000 | Labourer Groundman | Shall be paid the going hourly rate | | Shall be paid the going hourly rate | |
| 570100 | Warehouseman | 2,866-3,937<br>(16.47-22.63) | 153<br>( .88) | 2,968-4,074<br>(17.06-23.41) | 158<br>( .91) |
| 570300 | Senior Warehouseman | 3,784-4,396<br>(21.75-25.26) | 153<br>( .88) | 3,917-4,549<br>(22.51-26.14) | 158<br>( .91) |
| 570500 | Stockkeeper | 3,918-4,868<br>(22.52-27.98) | 190<br>(1.09) | 4,054-5,039<br>(23.30-28.96) | 197<br>(1.13) |
| 572100 | Meter Reader | 2,780-4,096<br>(15.98-23.54) | 188<br>( 1.08) | 2,876-4,241<br>(16.53-24.37) | 195<br>( 1.12) |
| 573000 | Equipment Operator Entry Level | 2,970-4,110<br>(17.07-23.62) | 190<br>( 1.09) | 3,073-4,255<br>(17.66-24.45) | 197<br>( 1.13) |
| 573100 | Equipment Operator | 4,121-4,978<br>(23.68-28.61) | 190<br>( 1.09) | 4,265-5,153<br>(24.51-29.61) | 197<br>( 1.13) |

1) Annual increments except those marked with an asterisk ( ) which are semi-annual.

**THE YUKON ELECTRICAL COMPANY LIMITED**
**SCHEDULE 58 - Technical Jobs**
**Minimum Monthly (Hourly) Wage Ranges**

| Job Class Number | Job Title | Wage Range Effective Jan. 1, 2007 (4.75 ) | Increment | Wage Range Effective Jan. 1, 2008 (4.5 ) | Increment |
|---|---|---|---|---|---|
| 585100 | Technologist Assistant | 3,362-4,947<br>(19.32-28.43) | 317<br>( 1.82) | 3,514-5,169<br>(20.20-29.71) | 331<br>( 1.90) |
| 585300 | Technologist I | 4,628-6,530<br>(26.60-37.53) | 317<br>( 1.82) | 4,837-6,823<br>( 27.80-39.21) | 331<br>( 1.90) |
| 585500 | Technologist II | 6,121-6,943<br>(35.18-39.90) | 274<br>(1.57) | 6,397-7,255<br>(36.76-41.70) | 286<br>(1.64) |
| 585800 | Technologist Team Leader | 6,243-7,083<br>(35.88-40.71) | 280<br>(1.61) | 6,524-7,403<br>(37.49-42.55) | 293<br>(1.68) |
| 586100 | Diesel Turbine Operator Entry Level | 2,729-4,307<br>(15.68-24.75) | 263<br>( 1.51) | 2,852-4,502<br>(16.39-25.87) | 275<br>( 1.58) |
| 586300 | Diesel Turbine Operator I | 4,056-5,108<br>(23.31-29.36) | 263<br>( 1.51) | 4,239-5,339<br>(24.36-30.68) | 275<br>( 1.58) |
| 586301 | Diesel Turbine Operator I (Maximum Range) | 5,108-5,371<br>(29.36-30.87) | 263<br>(1.51) | 5,338-5,613<br>(30.68-32.26) | 275<br>(1.58) |
| 586700 | Diesel Turbine Operator II | 4,324-5,113<br>(24.85-29.39) | 263<br>( 1.51) | 4,519-5,344<br>(25.97-30.71) | 275<br>(1.58) |
| 586701 | Diesel Turbine Operator II (Maximum Range) | 5,114-5,903<br>(29.39-33.93) | 263<br>(1.51) | 5,344-6,169<br>(30.71-35.45) | 275<br>(1.58) |

1) Annual increments except those marked with an asterisk ( ) which are semi annual.
2) Job title Technologists in Job Class Numbers 585100, 585300 and 585500 shall incl. all recognized technologies (e.g. Civil, Electrical, Engineering, Chemical, Communic.)
3) Employees in the following Jobs must have completed 12 months at the top of the increment range before being changed to maximum or flat rate:
   (a) Diesel Turbine Operator I (Job Class Number 586300)
   (b) Diesel Turbine Operator II (Job Class Number 586700)

**THE YUKON ELECTRICAL COMPANY LIMITED**

Notes Applying to: Wage Schedules 51, 52, 53, 54, 55, 56, 57, 58 and Minimum Hourly Wage Ranges

1. Administration of Increments

   a) Progression through the range will be annually (January) or semi-annually (January and July) to range ceiling as provided by the particular Schedule and subject to satisfactory performance.

   b) Progression - Schedules 51, 52, 54, 55, 56, 57 and 58.

      Progression subject to acceptable performance standards being met and contingent on time, theory (as applicable), necessary tickets or certificates or technology graduation and or Company examinations. Company examinations shall refer to existing written examinations.

   c) New Employees - new employees entering the service of the Company will be appropriately placed at the discretion of the Company on the basis of market hiring rates. This provision is waived for apprenticeship employees.

      A new employee on the first (1st) of the month following successful completion of the probationary period will be advanced one increment in the wage range as applicable. At the date of the first increment review (January 1st or alternatively July 1st) following the employee's appointment to permanent staff the increment adjustment as applicable shall be retroactive to the date of appointment to permanent staff by applying 1 12 or 1 6 of the increment per month subject to annual or semi-annual review respectively as indicated by the schedule. Increments for a new employee shall be subject to the requirements of a) and b) above.

2. When promotion occurs, the employee concerned shall be placed in that position within the new range which reflects an increase in wage which shall be no less than one increment in the range from which he was promoted. If the Job from which the employee was promoted is paid at a flat rate, the employee shall receive an increase which reflects no less than one increment from the new range, or the maximum rate for the new range, whichever is lesser. For clarity, if there is no

increment for the new range, the employee shall be paid the flat rate as identified for the new range. This will not apply in the case of progression Jobs.

3. If an employee is accepted under a posting for a lower level Job or is transferred at his own request, he will be paid at an appropriate level within the wage range for such Job.

4. Salary ranges for progression Jobs, designated in APPENDIX B, shall be calculated by applying the percentage to the bottom of the salary range for the lowest Job in the family and applying the percentage to the top of the salary range for the highest Job in the family. These bottom and top calculated salary range figures will be adjusted in accordance with the accepted formula to ensure the increments equally fit the total range of all Jobs.

**THE YUKON ELECTRICAL COMPANY LIMITED**
**APPENDIX A**
**ENTRY LEVEL JOBS**

| | |
|---|---|
| 510100 | Receptionist |
| 510200 | Customer Service Advisor Entry |
| 511200 | Financial Assistant - Entry |
| 521000 | Engineering Assistant Entry Level |
| 521100 | Engineering Assistant I |
| 543001 - 543008 | Power Lineman Apprentice |
| 566100 | Maintenance Man I |
| 570000 | Labourer Groundman |
| 570100 | Warehouseman |
| 572100 | Meter Reader |
| 573000 | Equipment Operator Entry Level |
| 585100 | Technologist Assistant |
| 585300 | Technologist I |
| 586100 | Diesel Turbine Operator Entry Level |
| 586300 | Diesel Turbine Operator I |

## APPENDIX B
## JOB PROGRESSION

For information purposes only, the following consolidates the current progression provisions as contained in the Corporate Job Descriptions.

NOTE: All apprentice Jobs are progression. Upon completion of the apprentice program, the move to Journeyman is a progression appointment.

| PROGRESSION FROM: | PROGRESSION TO: |
|---|---|
| 510200 Customer Service Advisor Entry | 510300 Customer Service Advisor Qualified |
| 511200 Financial Assistant Entry | 511300 Financial Assistant - Qualified |
| 520000 Draftsperson Entry Level | 520100 Draftsperson I |
| 520100 Draftsperson I | 520500 Draftsperson II |
| 521000 Engineering Assistant Entry Level | 521100 Engineering Assistant I |
| 521100 Engineering Assistant I | 521300 Engineering Assistant II |
| 556100 Serviceman Lineman Journeyman | 556300 Serviceman Lineman Journeyman (Maximum Range) |
| 566100 Maintenance Man I | 566300 Maintenance Man II |
| 570100 Warehouseman | 570300 Senior Warehouseman |
| 573000 Equipment Operator Entry Level | 573100 Equipment Operator |
| 585100 Technologist Assistant | 583500 Technologist I |
| 586100 Diesel Turbine Operator Entry Level | 586300 Diesel Turbine Operator I |

1) Progression shall not be considered automatic or natural. Progression shall be dependent on meeting the position criteria, satisfactory performance and complement control requirements.

## APPENDIX C

## LETTER OF UNDERSTANDING RE: JOB POSTINGS

The parties have discussed the interpretation that is to have application in respect to Clause 15.01 (f) of the Collective Agreement and have now agreed on the interpretation of the clause.

It is agreed by the parties that this Letter of Understanding shall be attached as an addendum to the Collective Agreement between the parties.

Clause 15.01 (f) makes provision that "first consideration" will be given on applications for a Job Posting to members of the bargaining unit. It is agreed that for the purposes of this agreement that the bargaining unit referred to in Clause 15.01 (f) will be composed of the six (6) bargaining units (composite bargaining unit) who represent the employees of ATCO Electric, ATCO Power, ATCO I-Tek Business Services Ltd., Northland Utilities (Yellowknife) Limited, Northland Utilities (NWT) Limited, and Yukon Electrical Company Limited. Those six (6) bargaining units will be treated as one (1) unit in respect to this Article. For all Job Postings, the Company will therefore hire through the posting procedures in respect to the composite bargaining unit, provided a suitable candidate meets the minimum Job requirements. If a suitable candidate cannot be hired, then the Company will have the right to hire externally.

It is agreed that the terms hereof are subject to the following conditions:

(a) ATCO Electric, its Employees' Association, ATCO Power, its Employees' Association, ATCO I-Tek Business Services Ltd., its Employees' Association, Northland Utilities (Yellowknife) Limited, its Employees' Association, Northland Utilities (NWT) Limited, and its Employees' Association must enter into agreements that are in substance identical to the above;

(b) No employee of ATCO Electric Limited, ATCO Power, ATCO I-Tek Business Services Ltd., Northland Utilities (Yellowknife) Limited, and Northland Utilities (NWT) Limited will have a right to grievance under the Yukon Electrical Company Limited Yukon Electrical Employees' Association Collective Agreement;

(c) The Company will not appoint a member of the Association to a bargaining unit Job (not governed by the Collective Agreement). This means that the Company cannot appoint a member of the Association into a bargaining unit Job in respect to ATCO Electric Limited, ATCO Power, ATCO I-Tek Business Services Ltd., Northland Utilities (Yellowknife) Limited, or Northland Utilities (NWT) Limited. This limitation, however, does not apply so as to restrict the

Company from promoting a member of the Association into a management Job.

(d) In the event that the size of the bargaining units at ATCO Electric, ATCO Power, ATCO I-Tek Business Services Ltd., Northland Utilities (Yellowknife) Limited, Northland Utilities (NWT) Limited, or Yukon Electrical Company Limited should increase by more than fifty (50 ) percent, it is understood that this Letter of Understanding may be revised or terminated on thirty (30) Days notice in writing given by either party to the other.

(e) This letter of understanding will be terminated 60 Days after written notice is given by one of the following to all of the others:

(1) Canadian Energy Workers Association Chapter 101
(2) ATCO Electric Limited
(3) Canadian Energy Workers Association Chapter 102
(4) ATCO Power
(5) Canadian Energy Workers Association Chapter 103
(6) ATCO I-Tek Business Services Ltd.
(7) Canadian Energy Workers Association Chapter 104
(8) Northland Utilities (Yellowknife) Limited
(9) Northland Utilities Employees' Association
(10) Northland Utilities (NWT) Limited
(11) Yukon Electrical Employees' Association
(12) Yukon Electrical Company Limited

The terms of this Letter of Understanding will not continue in force and effect beyond the termination date of the Collective Agreement.

# Yukon Electrical
## 2008-2009 General Rate Application
## Operations and Maintenance Expense Details
## ( 000's)

| | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test 2008 | Test 2009 |
|---|---|---|---|---|---|---|---|
| **Production** | | | | | | | |
| Labour | 420 | 483 | 502 | 516 | 557 | 683 | 747 |
| Fringe | 36 | 54 | 59 | 57 | 131 | 132 | 141 |
| Contractor Services | 333 | 303 | 272 | 250 | 212 | 350 | 239 |
| Other | 414 | 383 | 347 | 372 | 410 | 429 | 473 |
| | 1,203 | 1,223 | 1,181 | 1,196 | 1,311 | 1,594 | 1,600 |
| **Distribution** | | | | | | | |
| Labour | 747 | 875 | 860 | 871 | 915 | 1,362 | 1,487 |
| Fringe | 85 | 99 | 101 | 97 | 205 | 269 | 287 |
| Contractor Services | 290 | 292 | 296 | 344 | 316 | 415 | 434 |
| Other | 290 | 388 | 306 | 469 | 455 | 407 | 398 |
| | 1,412 | 1,655 | 1,563 | 1,781 | 1,890 | 2,453 | 2,606 |
| **General** | | | | | | | |
| Labour | 7 | 6 | 7 | 10 | 7 | 13 | 14 |
| Fringe | 1 | 1 | 1 | 1 | 2 | 3 | 3 |
| Contractor Services | 50 | 55 | 74 | 67 | 80 | 81 | 85 |
| Other | 55 | 61 | 52 | 58 | 59 | 68 | 71 |
| | 113 | 123 | 134 | 136 | 147 | 164 | 173 |
| **Public Information** | | | | | | | |
| Labour | 49 | 46 | 51 | 52 | 22 | 24 | 27 |
| Fringe | 5 | 6 | 7 | 5 | 6 | 5 | 6 |
| Contractor Services | 2 | 11 | 34 | 40 | 17 | 48 | 50 |
| Other | 74 | 94 | 37 | 58 | 49 | 51 | 53 |
| | 130 | 158 | 129 | 155 | 93 | 128 | 135 |
| **Customer accounting** | | | | | | | |
| Labour | 814 | 830 | 865 | 810 | 863 | 910 | 1,025 |
| Fringe | 98 | 107 | 117 | 101 | 217 | 194 | 214 |
| Contractor Services | 57 | 61 | 60 | 67 | 60 | 61 | 64 |
| Other | 472 | 493 | 499 | 527 | 543 | 626 | 764 |
| | 1,441 | 1,490 | 1,540 | 1,506 | 1,683 | 1,791 | 2,067 |
| **Administration** | | | | | | | |
| Labour | 647 | 683 | 709 | 780 | 819 | 984 | 1,050 |
| Fringe | 72 | 91 | 89 | 98 | 189 | 194 | 203 |
| Contractor Services | 2 | 9 | 301 | 304 | 141 | 281 | 172 |
| Other | 988 | 1,039 | 1,109 | 1,014 | 1,016 | 1,168 | 1,311 |
| | 1,709 | 1,821 | 2,208 | 2,196 | 2,165 | 2,628 | 2,736 |
| **Total O M expense** | 6,008 | 6,469 | 6,755 | 6,969 | 7,290 | 8,758 | 9,317 |

**CW-YECL-26**

**Issue:** Forecast Operations and Maintenance Expenses

**Reference:** Pages 5-2

**Preamble:** HR requires further information to fully understand and assess the forecast operating and maintenance expenses for the test years

**Request:**

(a) Please fully describe and provide the incremental cost for the proposed increase in 2008 and 2009 for certain job classifications that are technical in nature and are mandatory to delivering safe and reliable service to customers.

(b) Please fully describe and provide the incremental cost for the proposed additional travel benefits to which employees will be entitled commencing in 2009.

(c) Please indicate the specific lines where each of the above incremental costs is reflected in Schedules 5.1 and 5.2

**Response:**

(a) CW-YECL-26(a) Attachment 1 is the policy related to the Community Skills Premium paid to certain technical job classes. These specific job classes can be found in the collective agreement provided in CW-YECL-25(b) Attachment 1.

(b) Please refer to the collective agreement provided in response to CW-YECL-25(b) Attachment 1 and specifically Article 31.00 for a description of this benefit. An additional trip will be provided in 2009 in order to be competitive with ATCO Electric and other northern businesses that provide a similar benefit. The incremental cost for the additional travel benefit is approximately 80k.

(c) In schedule 5.1 and 5.2 the incremental costs for the community skills premium are reflected in most functions and activities as these costs follow the labor allocations for the trades people that qualify for the program. In addition some of the premium would be reflected in capital projects as the costs follow actual labor distribution.

In regard to the travel benefit those costs are coded to line 42 on Schedule 5.1-Employees Expenses and in revised July 4th Schedules, Schedule 5.2 line 236.

| The Yukon Electrical Company Limited | Corporate Administration Policies and Procedures | Page 1 of 1 |
|---|---|---|
| ***Community Skills Premium*** | | |

**PURPOSE**

Due to the current labour market conditions the company is experiencing a greater than normal degree of difficulty in attracting and retaining certain qualified skills in designated communities. As an extra incentive, permanent and probationary employees in specific job classes will be provided an additional incentive in the form of a lump sum payment. It is calculated as a percentage of base salary and will change with changes to base pay.

**POLICY**

The Community Skills Premium will be paid in semi-annual lump sum payments on July 1, and January 1. To be eligible to receive the full lump sum payment, the employee must reside on the job and in the community for the full term of the semi-annual period. Certain exceptions will apply:

a) If the employee in the designated job class remains in the community for the full term of the semi-annual period, they will receive the full lump sum payment;

b) If the employee transfers out due to a promotional opportunity or at the request of the company, they will receive a pro-rated payment based on their length of time in the community;

c) If an employee voluntarily moves out of the community on a lateral move, or resigns from the company, no payment will be made.

d) If an employee moves into a designated community part way through the term, they will receive a prorated lump sum.

| **Community Skills Premium (Paid out as 50% lump sums July & January)** | **%** |
|---|---|
| Schedule 56<br>Job Classes 586100 - 586701 | 10% |
| Schedules 54 & 55<br>Job Classes 585100 - 585800 | 16.25% |

| **Approved By:** | **Approval Date:** |
|---|---|
| **Effective Date:** **January 1, 2008** | **Expiry Date:** **December 31, 2008** |

**CW-YECL-27**

**Issue:** Forecast Operations and Maintenance Expenses

**Reference:** Page 5-3

**Preamble:** The total labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. These labour costs are then distributed to operations and maintenance accounts or capital accounts depending on the nature of work being performed by the staff in that job class.

**Request:**

(a) Please provide the actual forecast headcount at year-end 2003-2009, the number of actual and forecast FTE's for each of those years (other than actuals for 2008 and 2009) and the vacancies for each of those years.

(b) Please provide the total labor expense forecast to be charged to each of O&M, capital and other for each of 2003-2009 and the actual amounts charged to each for the years 2003-2007.

(c) Please show the calculation of how the vacancy rate of 4.0 (2.25 FTE's) for 2008 and 1.7 (1.0 FTE) for 2009 was applied to all labour expenses to arrive at the forecast total labour cost.

(d) Why does YECL expect the vacancy rate to decline in 2009 given its acknowledged difficulties in recruiting personnel?

**Response:**

(a) There are no approved forecasts for the years 2003 2007, as these were non-test years. As such no forecasts are available. The number of actual headcount and FTEs for the years 2003 2007, as well as, the forecast for 2008 and 2009 are summarized in the table below. Vacancies are calculated based on an approved complement of FTEs. As such, vacancies are not applicable, given that there were no Board approved FTEs for this period.

| | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Forecast 2008 | Forecast 2009 |
|---|---|---|---|---|---|---|---|
| **Year-End Headcount** | 45 | 47 | 49 | 48 | 52 | 55 | 57 |
| **FTEs** | 43.8 | 45.9 | 47.3 | 46.7 | 50.0 | 54.2 | 56.4 |

(b) There are no approved forecasts for the years 2003 2007, as these were non-test years. As such no forecasts are available. The actual total dollars charged to each are as follows:

| | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test 2008 | Test 2009 |
|---|---|---|---|---|---|---|---|
| | | | | **( 000's)** | | | |
| **O M** | 2,694 | 2,756 | 3,047 | 3,168 | 3,344 | 3,864 | 4,250 |
| **Capital** | 673 | 736 | 727 | 894 | 978 | 1,150 | 1,244 |
| **Other** | 116 | 193 | 101 | 135 | 132 | 197 | 211 |
| | 3,483 | 3,685 | 3,875 | 4,197 | 4,454 | 5,211 | 5,706 |

(c) The calculation requested was not performed. The vacancy rate was applied by specific position, and the related salary and labour distribution of the specific position, to O&M, Capital, and Other accordingly. The positions which make up the vacancies in the 2008 and 2009 test years are as follows:

| **Vacancies (FTEs)** | | **2008** | **2009** |
|---|---|---|---|
| **Journeyman Lineman** | | 0.50 | 0.50 |
| **Journeyman Lineman** | | 0.50 | 0.50 |
| **Journeyman Lineman** | | 0.25 | |
| **Journeyman Lineman** | | 0.50 | |
| **Operations Support** | | 0.25 | |
| **Field Service Representative** | | 0.25 | |
| | a | 2.25 | 1.00 |
| **Total FTE's (b)** | b | 56.43 | 57.43 |
| **Vacancy Rate** | a b | 4.0 | 1.7 |

(d) Please refer to YUB-YECL-8(e) shown below.

Although it is a tight labor market, based on the programs that Yukon Electrical has put into place in recent months the vacancies have been reduced substantially. Yukon Electric has also begun an apprentice lineman and Field Service Representative program. As a result, Yukon Electrical is confident that these measures will stabilize its workforce. At the present time Yukon Electrical has only two journeyman lineman vacancy (one being filled by the end of August) indicating that its approach is helping to minimize vacancies.

The program enhancements that Yukon Electric has added are a Community Skills Premium similar to the program implemented by its parent company ATCO Electric and the Northland Companies. This program provides a payment to difficult to attract and retain trades people to northern communities.

In addition Yukon Electric proposes to enhance its northern benefit package to include one additional flight out for employees and their families. This is also in an effort to match similar benefits in the Northwest Territories and northern Alberta communities as well as some Yukon competitors.

There have been no improvements to the northern benefit package in Yukon Electrical for over 10 years.

Carrying an involuntary lower complement than considered ideal over the past few years particularly in trade positions has put a burden and strain on the employees who are asked to get the work completed. Extended on call responsibilities and a negative impact on quality of life has forced Yukon Electrical to improve its recruiting methods and compensation packages. Part of this means providing overlap where possible for positions prior to an employee leaving to another job or retiring. This change in managing recruitment also places downward pressure on vacancy rates.

These programs are some of the components that are required to attract and retain employees. Yukon Electrical has seen positive results and therefore believes that a 1 FTE vacancy rate is reasonable for the test period.

**CW-YECL-28**

**Issue: Forecast Operations and Maintenance Expenses Affiliate Costs**

**Reference: Page 5-3**

**Preamble:** Yukon Electrical outsources certain major administrative functions to affiliate companies, such as ATCO Electric, to take advantage of the economies associated with the scope and scale of services available from a larger utility. The cost of these services is detailed in Schedule 5.3 and is based on a fully allocated cost methodology that does not contain any element of profit or return.

**Request:**

Please provide a current copy of the Master Service Agreements between Yukon Electrical and ATCO Electric and a copy of the code of conduct which governs those agreements.

**Response:**

CW-YECL-28 Attachment 1 - Master Services Contract with ATCO Electric
CW-YECL-28 Attachment 2 - Amending Agreement
CW-YECL-28 Attachment 3 - Various Services
CW-YECL-28 Attachment 4 - Affiliate Code of Conduct

# MASTER SERVICES CONTRACT

**THIS MASTER SERVICES CONTRACT DATED** effective the 31 day of October, 2003.

**BETWEEN**:

*The Yukon Electrical Company Limited*, a body corporate,
incorporated under the laws of the Yukon,
with offices in Whitehorse, Yukon

and

*Northland Utilities (NWT) Limited*, a body corporate,
incorporated under the laws of the Northwest Territories,
with offices in Hay River, Northwest Territories

and

*Northland Utilities (Yellowknife) Limited*, a body corporate,
incorporated under the laws of Canada,
with offices in Yellowknife, Northwest Territories

(hereinafter referred to as "*North of 60 Companies*")

- and -

*ATCO Electric Ltd.*, a body corporate,
incorporated under the laws of Alberta,
with offices in Edmonton, Alberta

(hereinafter referred to as "*ATCO Electric*")

**WHEREAS** *North of 60 Companies* desires to engage *ATCO Electric* to provide services as described in this Services Contract (the "Contract"), in accordance with the terms and conditions described in this Contract; and

**WHEREAS** *ATCO Electric* has the expertise and is capable of providing the services to and for *North of 60 Companies* as described in this Contract, in accordance with the terms and conditions described in this Contract;

**THIS CONTRACT WITNESSES** that in consideration of the respective covenants and agreements of *North of 60 Companies* and *ATCO Electric* (individually each a "Party" and collectively, the "Parties") contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

## 1. SCHEDULES

**1.1** The following Schedules are attached hereto and made a part of this Contract:

(a) Schedule A - Scope of Services - detailing the services to be provided by *ATCO Electric* to *North of 60 Companies* pursuant to this Contract (the "Services");

(b) Schedule B - Scope of Terms – detailing, if applicable:

(i) the date, if any, set for commencement of the Services by *ATCO Electric* (the "Commencement Date");

(ii) the schedule, if any, set for performance of the Services by *ATCO Electric*;

(iii) the date, if any, set for completion of the Services by *ATCO Electric* (the "Completion Date");

(iv) the term, if any, of the duration for which the Services will be provided by *ATCO Electric* (the "Term");

(v) the compensation to be paid by *North of 60 Companies* to *ATCO Electric*;

(vi) any categories of out-of-pocket expenses for which reimbursement will be payable from *North of 60 Companies* to *ATCO Electric* in accordance with Section 5.1 herein;

(vii) any invoice requirements or provisions desired by the Parties in supplement to Article 6 herein; and

(viii) any other supplemental provisions or agreements desired by the Parties to form part of this Contract.

(c) Schedule C - *North of 60 Companies*'s Representative

(d) Schedule D - *ATCO Electric*'s Representative

**1.2** In case of a conflict between this main body of this Contract and the Schedules, this main body of this Contract shall govern.

## 2. THE SERVICES

**2.1** *North of 60 Companies* hereby engages *ATCO Electric*, and *ATCO Electric* hereby agrees to provide the Services on the terms and conditions set forth herein.

**2.2** *ATCO Electric* shall furnish all personnel, materials, and supervision necessary for successful performance of the Services, at *ATCO Electric*'s own expense, subject to

Section 5.1 herein providing for reimbursement for certain identified categories of expenses.

**2.3** Any material amendments to the Services shall be made in accordance with Section 22.3 of this Contract.

**2.4** *ATCO Electric* shall periodically, but no more frequently than monthly, furnish to *North of 60 Companies* written progress reports, when and as requested by *North of 60 Companies*.

## 3. TIME OF PERFORMANCE

**3.1** *ATCO Electric* shall commence the Services on the Commencement Date if any such date is set forth in Schedule B. *ATCO Electric* shall perform the Services with due diligence and dispatch or as otherwise expressly provided in Schedule B.

**3.2** *ATCO Electric* shall complete the Services by the Completion Date, or by the end of the Term, if any such date or time period is set forth in Schedule B. If *ATCO Electric* determines that it will be unable to complete the Services within any such time schedule, it will promptly so notify *North of 60 Companies* in writing.

**3.3** Should *ATCO Electric*, with the prior written authorization of *North of 60 Companies*, continue to provide services beyond the end of the stated Completion Date or Term of this Contract in order to complete a project, then the Completion Date or Term shall be automatically extended by an additional one month, extendable month to month thereafter.

## 4. COMPENSATION

**4.1** As full consideration for performance of the Services, *North of 60 Companies* will pay *ATCO Electric* in accordance with the terms detailed in Schedule B.

**4.2** In accordance with Articles 8 and 9 herein, compensation from *North of 60 Companies* shall be payable without deduction, including, without limitation, no deductions for federal income taxes, employment insurance, Canada pension plan, or provincial income taxes, all of which shall be the responsibility of *ATCO Electric*.

## 5. EXPENSES

**5.1** In accordance with Schedule B, *ATCO Electric* may also be entitled to be reimbursed by *North of 60 Companies* for reasonable out-of-pocket expenses incurred by *ATCO Electric* in the performance of the Services and recognized in Schedule B as belonging to certain identified categories of reimbursable expenses. In accordance with Section 6.2 herein, *ATCO Electric* is required to submit itemized requests for reimbursement of such expenditures supported by sufficient documentation of the expenditures and explanation of their purpose.

**5.2** Any Goods and Services Tax ("G.S.T.") which is applicable to *ATCO Electric*'s reimbursable expenses shall be identified separately as a part of all invoices submitted by *ATCO Electric*.

## 6. INVOICING AND PAYMENT

**6.1** *ATCO Electric* shall present on or before the **5th** day of each calendar month, or at such other times and for such other periods as may be determined in Schedule B, an original invoice(s) for any monies owed by *North of 60 Companies* for the immediately prior month for Services provided pursuant to this Contract.

**6.2** For reimbursement for reasonable pre-approved out-of-pocket expenses as described in Section 5.1 herein, invoices must be submitted with a complete statement of costs actually incurred during the preceding calendar month, and with back-up documents necessary to support the expenditures listed in *ATCO Electric*'s statement.

**6.3** All invoices shall provide a G.S.T. registration number, and identify the total amount of G.S.T. included in the invoice. In the event that *ATCO Electric* does not invoice *North of 60 Companies* for G.S.T., *ATCO Electric* shall indicate on the invoice the basis upon which *ATCO Electric* claims exemption from the statutory obligation to collect G.S.T.

**6.4** All invoices shall be provided in accordance with Section 21.2 herein.

**6.5** All payments are due and payable by *North of 60 Companies* **twenty-five (25)** days after receipt in *North of 60 Companies*'s offices of the invoice and any substantiating documentation required by this Contract. If *North of 60 Companies* has any objection to the invoice or substantiating documentation, it shall notify *ATCO Electric* within 15 days of receipt of the invoice. Interest on overdue amounts shall be due and payable by *North of 60 Companies* to *ATCO Electric* at a rate of Prime plus 2 % percent per annum from the date on which payment was due until the date of payment, inclusive. "Prime" means the Bank of Montreal prime lending rate for demand loans made in Canadian funds to Canadian customers. *North of 60 Companies* shall be entitled to set off any mutually agreed upon amount owed by *ATCO Electric* to *North of 60 Companies* against any amount owing to *ATCO Electric*. Notwithstanding any such set-off, separate invoices of each transaction shall be provided to the other Party.

## 7. AUDIT

**7.1** This Article 7 shall only apply in the event compensation paid by *North of 60 Companies* under this Contract is based on *ATCO Electric*'s costs.

**7.2** *ATCO Electric* shall keep and maintain complete and accurate records of costs incurred for the subject Services, and maintain books and accounts in accordance with

generally accepted accounting principles and practices respecting all matters pertinent to this Contract or to the Services for the longer of (a) 2 years following the date of termination of this Contract; or (b) such time period required by statute.

**7.3** *North of 60 Companies*, upon providing written notice to *ATCO Electric*, shall have access to and the right to audit, during business hours and for a maximum of a two (2) year period following total completion of the Services, all files, data, correspondence, books, and accounting records relating in any way to the Services. *ATCO Electric* shall preserve all of its relevant documents during the aforementioned period, and shall make them readily available to *North of 60 Companies* and its authorized representatives, and shall also make available those employees or sub-contractors of *ATCO Electric* reasonably required to supply desired information during the audit.

**7.4** *North of 60 Companies* will notify *ATCO Electric* in writing of any erroneous statements made by, or payments made to, *ATCO Electric*. Subject to *ATCO Electric*'s right to have the matter determined in accordance with Article 27 herein, *ATCO Electric* will promptly make appropriate adjustments and *ATCO Electric* shall reimburse *North of 60 Companies* for any amounts of overpayments still outstanding as reflected by said adjustments, notwithstanding that a temporary withholding may have been effected pursuant to this Contract.

**7.5** *ATCO Electric* shall use reasonable efforts to cause any of its sub-contractors to allow *North of 60 Companies* to carry out audits of the books, records, and accounts of such sub-contractors relating to the Services in accordance with the forgoing provisions of this Article 7 herein.

## 8. INDEPENDENT CONTRACTOR

**8.1** In the performance of the Services, *ATCO Electric* is an independent contractor and not an employee, in particular, but without limitation, for the purposes of the Income Tax Act, the Workers' Compensation Act and other applicable labour legislation. Nothing contained in this Contract shall be regarded or construed as creating any further relationship (such as employer and employee, joint venture, association, or partnership) between the Parties.

**8.2** All persons employed by *ATCO Electric* in connection with the Services shall be *ATCO Electric*'s employees and not employees of *North of 60 Companies* in any respect.

**8.3** Neither Party shall enter into any contract or commitment in the name of or on behalf of the other Party and nothing in this Contract shall constitute or deem one Party as the agent of the other Party.

## 9. WORKERS' COMPENSATION AND OTHER CONTRIBUTIONS

**9.1** *ATCO Electric* shall promptly pay or cause to be paid, and *North of 60 Companies* shall not be responsible for, any assessment or contribution required to be paid in connection

with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed.

**9.2** Before commencement of the Services, *ATCO Electric* will, if requested by *North of 60 Companies* deliver to *North of 60 Companies* certificates from the relevant Workers' Compensation Boards or Commissions, as the case may be, that all required assessments and contributions have been paid by *ATCO Electric* and its sub-contractors. Before the final payment owed under this Contract is made by *North of 60 Companies*, *North of 60 Companies* may request that *ATCO Electric* deliver to *North of 60 Companies* similar certificates with *ATCO Electric*'s application for final payment from *North of 60 Companies*.

**9.3** *North of 60 Companies* may, in addition to any other rights reserved to it under this Contract, withhold from compensation to be paid to *ATCO Electric* the amount, if any, of *ATCO Electric*'s required assessment or contribution in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed, where *North of 60 Companies*, in its sole discretion, determines that such amounts may be assessed against *North of 60 Companies*. Any such withholding or deduction shall not be construed as an admission by *North of 60 Companies* that *ATCO Electric* in performing the Services is an employee of *North of 60 Companies*. *North of 60 Companies* will assist *ATCO Electric* in defending any claims against *ATCO Electric* in the event that *ATCO Electric* disputes such claims.

**9.4** In the event that *North of 60 Companies* does not deduct and maintain an amount sufficient to provide for *ATCO Electric*'s required assessments or contributions as specified in Section 9.3 herein, *ATCO Electric* shall indemnify and save harmless *North of 60 Companies* for any amounts assessed against and paid by *North of 60 Companies* as a result of failure by *ATCO Electric* to comply with the provisions of this part of the Contract or any such Workers' Compensation legislation.

**9.5** *ATCO Electric* shall pay or cause to be paid, and *North of 60 Companies* shall not be responsible for, any required or assessed contributions or payments to or for the Canada Pension Plan, employment insurance, federal or provincial withholding taxes, or any other contributions or benefits that might be expected in an employer-employee relationship, for *ATCO Electric*'s employees and *ATCO Electric*.

## 10. LIABILITY AND INDEMNIFICATION

**10.1** *ATCO Electric* shall:

(a) be liable to *North of 60 Companies* for all losses, costs, damages, and expenses whatsoever which *North of 60 Companies* and *North of 60 Companies*'s directors, officers, agents, and employees, (collectively, the "Indemnified Parties") may suffer, sustain, pay, or incur; and

(b) indemnify and save harmless the Indemnified Parties against and from all actions, proceedings, claims, demands, losses, costs, damages, and expenses whatsoever which may be brought or made against or suffered by the Indemnified Parties, or which the Indemnified Parties may sustain, pay, or incur;

as a result of *ATCO Electric*'s negligence or wilful acts or omissions but excluding such actions, proceedings, claims, demands, losses, costs, damages and expenses to the extent that they are sustained, paid, or incurred by reason of or are otherwise attributable to

(c) the negligence or wilful acts or omissions of the Indemnified Parties while not acting under the direction or control of *ATCO Electric* or its employees or sub-contractors; or

(d) *ATCO Electric* while under the direction of the Indemnified Parties.

**10.2** *ATCO Electric* shall not be liable for any of the Indemnified Parties' indirect or consequential damages, except to the extent that such damages are recoverable under any applicable insurance coverage.

## 11. INSURANCE

**11.1** Without in any way limiting the liability of *ATCO Electric* under this Contract, it shall be the responsibility of *ATCO Electric* while this Contract is in effect to maintain and keep in force and good standing the following insurance coverage:

(a) **Automobile Liability Insurance** - covering all vehicles used for operations in any way connected with the Services, including owned, non-owned, and hired vehicles. The limits of such coverage shall not be less than, for bodily injury (including passenger hazard) and property damage, **$2,000,000** inclusive, any one accident, or equivalent limits.

(b) **Comprehensive General Liability Insurance** - covering all operations in any way connected with the Services, including employers' liability, owners' and contractors' protective liability, contractual liability assumed by *ATCO Electric* under this Contract, and products/completed operations liability. The limits of such coverage shall not be less than, for bodily injury and property damage, **$5,000,000** inclusive, any one occurrence, or equivalent limits.

(c) Such other insurance as may from time to time be required by law or reasonably required by *North of 60 Companies*.

**11.2** *ATCO Electric*, or contractors engaged in the provision of the Services, shall provide *North of 60 Companies* 30 days prior written notice of material changes, cancellation, or proposed lapse of their respective insurance policies.

**11.3** *ATCO Electric* shall require all of its sub-contractors to obtain, maintain, and keep in force and good standing, during the time in which they are engaging in performing the Services, all required insurance coverage

**11.4** Upon request by *North of 60 Companies*, *ATCO Electric* shall, before commencement of the Services, deposit with *North of 60 Companies* information satisfactory to *North of 60 Companies* as evidence of the insurance required in Sections 11.1 and 11.2 herein.

## 12. COMPLIANCE WITH LAW AND POLICY

**12.1** The Parties hereto and their employees and sub-contractors shall observe and comply with all applicable laws, ordinances, codes, and regulations of governmental agencies, including federal, provincial, municipal, and local governing bodies having or asserting jurisdiction in respect of this Contract, the Services, or any part thereof. All Services performed by *ATCO Electric* must be in accordance with such laws, ordinances, codes, and regulations.

**12.2** *ATCO Electric* and its employees and sub-contractors shall observe and comply with all rules, regulations, policies, advice, and directives of *North of 60 Companies* from time to time in force which are brought to *ATCO Electric*'s notice and which are not contrary to law or the provisions of this Contract.

**12.3** *ATCO Electric* shall promptly notify *North of 60 Companies* in writing upon discovery of any failure to comply with such laws, ordinances, codes, regulations, policies, advice, or directives.

**12.4** Unless otherwise specified in this Contract and subject to Section 5.1 herein, *ATCO Electric* shall obtain and pay for all permits, licenses, and approvals required for the provision of the Services.

## 13. PUBLICITY RELEASE

**13.1** *ATCO Electric* shall not, without the prior written consent of *North of 60 Companies*, use *North of 60 Companies*'s, name in advertising, publicity releases, or any other form of promotional material relating to this Contract, the Services to be performed, or the results thereof, except to the extent that such information is in the public domain.

## 14. CONFIDENTIAL INFORMATION

**14.1** The term "Confidential Information" shall mean all confidential information of or relating to *North of 60 Companies* or its business or its customers and shall include without limitation all information which *ATCO Electric* or its employees or sub-contractors, directly or indirectly, receives or acquires from *North of 60 Companies* either in writing, orally, or through observation, or which *ATCO Electric* or its employees or sub-contractors develops in connection with this Contract or the Services, and shall include, but shall not be limited to, all business plans and information, customer information, software, source code, inventions (whether patentable or

not), technical information, process and apparatus designs, design calculation, drawings, engineering appraisals and studies, data reports, flow sheets, plans, sketches, surveys, field notes, and design concepts, but shall not include information falling into any one of the following categories:

(a) information which was in the possession of *ATCO Electric* or its employees or sub-contractors, reasonable proof of which lies on *ATCO Electric*, prior to receipt or acquisition thereof from *North of 60 Companies* and which was not acquired by *ATCO Electric* or its employees or sub-contractors under any obligation of confidentiality;

(b) information which, at the time of the receipt or acquisition thereof by *ATCO Electric* or its employees or sub-contractors from ATCO, was or thereafter became a part of the public domain through no act or failure on the part of *ATCO Electric* or its employees or sub-contractors nor on the part of any third party under an obligation of confidentiality with respect to such information; and

(c) information which is disclosed to *ATCO Electric* or its employees or sub-contractors by a third party without a covenant of confidentiality, provided such third party is under no obligation of confidentiality to *North of 60 Companies* with respect to such information.

**14.2** *ATCO Electric* and its employees and sub-contractors shall, unless expressly otherwise permitted or requested by *North of 60 Companies* in writing, hold all Confidential Information in the strictest of confidence at all times and shall take all necessary precautions necessary to maintain such confidence, and shall not use (except in *ATCO Electric*'s performance of the Services) or disclose to any third party (except as required to be disclosed by operation of law) such Confidential Information, provided that *ATCO Electric* may disclose such Confidential Information to those of *ATCO Electric*'s employees or sub-contractors to whom disclosure is required for *ATCO Electric*'s performance of the Services, but only after such employee or sub-contractor has agreed to assume obligations identical in principle with those which *ATCO Electric* has assumed in this Article 14, and *ATCO Electric* shall ensure that all employees and sub-contractors at all times comply with such obligations.

**14.3** *North of 60 Companies* shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 14 without the requirement of posting a bond or proof of actual damage.

**14.4** The terms of this Article 14 shall apply, mutatis mutandis, to *North of 60 Companies*'s treatment of Confidential Information of or relating to *ATCO Electric*.

## 15. INTELLECTUAL PROPERTY

**15.1** For the purposes of this Contract, "Intellectual Property" means

(a) all inventions, whether or not patentable,

(b) all applications for patent, registration, inventor certificate or like protection now existing, or filed in the future for inventions,

(c) all patents, registrations, inventor certificates or like protection presently issued, issued in the future, re-issued or extended in any way, for inventions, including, but not limited to, divisions or divisionals, continuations, continuations-in-part, supplemental disclosures, re-issues and re-examinations, and

(d) all other intellectual property rights anywhere in the world, including without limitation, all copyrights, trademarks, service marks, trade secrets, industrial designs, integrated circuit topographies and all rights in any matured cause of action related thereto in Canada and throughout the World.

**15.2** All Intellectual Property made or conceived by *ATCO Electric*, its employees or sub-contractors:

(a) in the course of providing the Services;

(b) during the Term and which relates in any manner to the business of *North of 60 Companies*;

(c) made with or which arises with the use of the materials, equipment or resources of *North of 60 Companies*; and

(d) which are improvements or enhancements on or relating in any way to the Confidential Information or the intellectual property defined in this Article 15;

shall be the exclusive property of *ATCO Electric*.

**15.3** *ATCO Electric* shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 15 without the requirement of posting a bond or proof of actual damage.

## 16. ASSIGNMENT

**16.1** With the exception of the subcontracting of Services in the normal course of business, neither Party shall sell, assign or transfer this Contract or subcontract any part this Contract (except for the delivery of materials) without the prior written consent of the other Party, such consent not to be unreasonably withheld. Such consent shall not release or relieve either Party from any of its obligations or liabilities under this Contract. Any such assignment or delegation by a Party without such consent from the other Party will be void.

## 17. FORCE MAJEURE

**17.1** For the purposes of this Contract "Force Majeure" means any acts of God, including therein, but without restricting the generality thereof, lightning, earthquakes and storms, and, in addition, shall mean any strikes, lockouts or other industrial disturbances, acts of the Queen's enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, floods, fires, washouts, arrests and restraints, civil disturbances, explosions, breakages of or accidents to machinery, the orders of any court or governmental authority, or any other causes, excepting financial, whether of the character or kind herein enumerated or otherwise, and not within the control of the Party claiming suspension and whether or not arising out of or resulting from an event, cause or occurrence under this Contract or otherwise, which, by the exercise of due diligence, such Party could not have prevented or is unable to overcome.

**17.2** Delay in or failure of performance by either of the Parties under this Contract shall not constitute default under this Contract, or give rise to any claim for damages, if and to the extent that such delays or failure are caused by an event of Force Majeure.

**17.3** In the event that performance of the Service or this Contract is in the reasonable opinion of either of the Parties made impossible by Force Majeure, then such Party shall if at all possible so notify the other in writing, and *North of 60 Companies* shall either:

(a) terminate this Contract, or

(b) authorize *ATCO Electric* to complete the performance of the Services with such adjustments as are required by the existence of the force majeure and are agreed upon by the Parties.

## 18. TERMINATION

**18.1** In the event that either Party violates, or is in breach of, their obligations under this Contract or the terms herein or otherwise fails to perform the Services in accordance with the terms herein, the other Party shall provide written notice of said violation, breach or non-performance. If, within five (5) days of receipt of written notice, such Party fails to correct the deficiency, the other Party shall have the right to immediately terminate this Contract.

**18.2** In the event of termination pursuant to this Article 18, *ATCO Electric* shall only be entitled to receive such remuneration as is owing up to the date of termination, including any obligations to third parties made in order to permit *ATCO Electric* to carry out its duties under this Contract. *North of 60 Companies* shall not be liable for damages or loss of anticipated profits on account of such termination.

## 19. REMEDIAL WORK

**19.1** *ATCO Electric* shall after receipt of notice from *North of 60 Companies*, at *North of 60 Companies*'s option and at no cost to *North of 60 Companies*, without prejudice to any other right that *North of 60 Companies* might have, provide such services as may be necessary to remedy any defect caused by the performance, purported performance, or non-performance by *ATCO Electric* in carrying out the Services pursuant to this Contract (the "Remedial Work") in accordance with the service standards and specifications agreed upon by the Parties. *North of 60 Companies* reserves the right to complete such remedial work or have such remedial work completed by other parties but at *ATCO Electric*'s expense, in the event *ATCO Electric* fails to complete the Remedial Work as soon as reasonably possible after receiving written notice from *North of 60 Companies*.

## 20. WAIVER

**20.1** Failure of either of the Parties to insist upon strict compliance with any of the terms, covenants, and conditions in this Contract shall not be deemed a waiver or relinquishment of any similar right or power hereunder at any subsequent time or of any other provision herein.

## 21. REPRESENTATIVES AND NOTICES

**21.1** *North of 60 Companies*'s representative, who has full authority to represent *North of 60 Companies* in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "C", attached hereto.

*ATCO Electric*'s representative, who has full authority to represent *ATCO Electric* in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "D", attached hereto.

**21.2** Unless otherwise specified in this Contract, any notice required or permitted to be given under this Contract shall be sufficient and effective if in writing and if sent by facsimile, mail, or personally delivered to the Party to whom notice should be given at that Party's respective address as follows:

***North of 60 Companies***: See Schedule "C" ***ATCO Electric***: See Schedule "D"

**21.3** Unless otherwise specified in this Contract, notice shall be deemed effective upon receipt if made by personal delivery; three (3) days following deposit with Canada Post if sent by mail, and, upon receipt of a facsimile confirmation if sent by facsimile.

## 22. ENTIRETY OF AGREEMENT

**22.1** This Contract contains the entire understanding and agreement between the Parties. All previous proposals and communications relative to the services to be

provided under this Contract, oral or written, are hereby superceded, except to the extent that they have been expressly incorporated into this Contract.

**22.2** There is no representation, warranty, collateral term, or condition affecting this Contract for which either Party can be held responsible in any way, whether they be contained in any material or alleged against and director, officer, agent, or employee of either Party, other than as expressed in this Contract in writing. The representations, warranties, terms, and conditions expressed in writing in this Contract shall be paramount, and no action in tort, under any statute or in equity, relating to any other representation, warranty, collateral term, or condition affecting this Contract, or made prior to the execution of this Contract, but not expressed in writing in this Contract, shall be brought by either Party against the other Party. The Parties confirm that their rights, obligations, remedies, rights of indemnity, and measure of damages in the event of a breach, are limited to those conferred by or arising out of this Contract.

**22.3** No amendment to this Contract shall be binding unless made in writing and signed by both Parties.

## 23. SEVERABILITY

**23.1** Any invalid or unenforceable provision of this Contract, whether prohibited by any applicable law, by-law, or regulation of any appropriate or relevant governmental authority, or held to be unenforceable, invalid, or illegal by any court of competent jurisdiction, or invalid or unenforceable for any other reason, shall be ineffective to the extent of such invalidity or unenforceability without affecting any other provisions of this Contract, and this Contract shall be construed as though such invalid or unenforceable provision were omitted.

## 24. SURVIVAL OF TERMS

**24.1** The provisions of this Contract respecting audit (Article 7 herein), indemnity for Workers' Compensation and other contributions (Article 9 herein), liability and indemnification (Article 10 herein), publicity release (Article 13 herein), confidential information (Article 14 herein), Intellectual Property (Article 15 herein), remedial work (Article 19 herein), and all obligations which have accrued hereunder prior to the termination of this Contract, shall survive the Completion Date, the date of actual completion of the Services if different from the Completion Date, the end of the Term of this Contract, and any termination of this Contract.

## 25. GOVERNING LAW

**25.1** The validity and interpretation of this Contract, the legal relations of the Parties, and the conflict of laws rules to determine the system of law governing this Contract shall be governed by and construed in accordance with the laws in force

from time to time in the Province of Alberta and the federal laws of Canada applicable therein.

**25.2** The Courts of the Province of Alberta and any Court of Appeal therefrom shall have exclusive jurisdiction to determine all matters in dispute hereunder, and the Parties hereby attorn to the jurisdiction of such Courts.

## 26. INTERPRETATION

**26.1** Title headings contained in this Contract are for convenience and reference only, and are not to be construed as limiting or extending the meaning of any of the provisions herein.

**26.2** In this Contract, words importing the singular number shall include the plural and vice versa, words importing masculine gender shall include the feminine and neuter and vice versa, and words importing a person or Party shall include individuals, partnerships, firms, associations, corporations, joint ventures, trusts, or other entities, as the context or reference to the Parties requires.

**26.3** Where reference is made in this Contract to "*North of 60 Companies*'s affiliates", such reference shall be meant to include:

(a) an Affiliate, within the meaning of the *Business Corporations Act*, of *North of 60 Companies*; and

(b) a partnership, joint venture, or person is which *North of 60 Companies* has a controlling interest or that is otherwise subject to the control of *North of 60 Companies*.

## 27. DISPUTE RESOLUTION

**27.1** The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the respective Presidents of *North of 60 Companies* and *ATCO Electric*.

**27.2** If such dispute is not resolved pursuant to Section 27.1 above, then upon mutual agreement, the Parties may submit the dispute to arbitration pursuant to the *Arbitration Act* of Alberta.

**27.3** In the event that:

(a) such dispute is not resolved pursuant to Section 27.2 above; or

(b) the Parties do not agree to submit the dispute to arbitration;

then either Party may pursue any other remedy available at law to resolve such dispute.

## 28. GENERAL PROVISIONS

**28.1** The Parties agree to perform any further acts and to execute and deliver any further documents which may be necessary or appropriate to carry out the purposes of this Contract.

**28.2** All amounts quoted in this Contract shall be payable in Canadian funds, unless expressly stated otherwise.

**28.3** This Contract shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

**28.4** Time is of the essence in the performance of every obligation of this Contract.

**28.5** This Contract may be executed in any number of counterparts, each of which when so executed shall be deemed an original, and all of which together shall constitute one and the same contract.

**IN WITNESS WHEREOF** the Parties have duly executed this Contract with effect from the date and year first above written.

| ***North of 60 Companies*:** | | ***ATCO Electric*:** | |
|---|---|---|---|
| Per: | Paul Goguen - General Manager | Per: | |
| Name: | | Name: | |
| Per: | | Per: | |
| Name: | | Name: | |

# North of 60 Companies Amending Agreement

**WHEREAS** *North of 60 Companies* and *ATCO Electric ("the Parties")* have entered into a **MASTER SERVICES CONTRACT ("MSC")** effective the 31 day of October, 2003; and

**WHEREAS** *North of 60 Companies* and *ATCO Electric* wish to amend that MSC,

**THEREFORE** the Parties covenant and agree as follows:

Clause 27.1 in the MSC is to be deleted and replaced with the following provision:

The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the Managing Director of *North of 60 Companies* and the President of *ATCO Electric*.

The Parties have duly executed this amending agreement in effect from the 21st day of October, 2005.

***North of 60 Companies*:**

Per: _____

Name: Doug Tenney

Date: October 21, 2005

***ATCO Electric*:**

Per: _____

Name: SCOTT POLICICCHIO

Date: October 27/2005

**Schedule "A" to the Master Service Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## SCOPE OF SERVICES

ATCO Electric will make available to YECL the following services:

A. Financial Reporting Services

ATCO Electric will provide the following Financial Reporting support:

- Preparation of month end and year end accounting to Canadian Utilities
- Fixed asset administration
- Support for preparation of annual business plan
- Maintain a dotted line reporting relationship with supervisor of financial services in Yukon

B. Payroll Services

ATCO Electric will provide the following payroll services:

- Production of employee payroll advice
- Set up and maintenance of automatic payroll deposits to employee bank account
- Maintenance of employee information on Payroll System
- Recording employee time sheet information on Payroll System as applicable
- Payment of employee and employer source deductions to Federal Government
- Preparation of yearly source deductions summary for submission to Federal Government
- Maintenance of annual TD1 forms for employee exemptions
- Preparation of annual T4s for employees
- Set up and monitoring of miscellaneous employee payroll deductions (i.e. staff loans for housing, staff purchases, market differential loans etc. where applicable)
- Preparation of assessable earnings schedules for submission to WCB
- Payment and reconciliation of payments to Workers Compensation Boards
- ATCO Flex group benefit payment and account reconciliation

**Schedule "A" to the Master Service Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## SCOPE OF SERVICES

C. Use of Systems

ATCO Electric will provide the following computer processing services:

- Monthly processing of accounting and payroll information
- Maintaining chart of accounts
- Access to and maintenance of historical information on the Oracle Financial Information System
- Use of the query software which is part of Oracle Financials
- Use of human resources systems, including the Employee Biographics System (EBS), the Benefits Administration System (BAS) and the Job Costing System (JCS)

D. Metering and Load Information Services

ATCO Electric will provide the following metering services:

- Supplying new and used meters
- Testing, verifying and re-sealing the meters
- Performing load and loss research studies

**Schedule "A" to the Master Service Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## SCOPE OF SERVICES

E. Health, Safety and Environment

Health, Safety and Environment (HS&E) Management System support related to the ongoing development and maintenance of YECL's HS&E Management System. Typical activities, as requested by the General Manager, would include support in:

- Identify and prioritize YECL's HS&E risks and developing management strategies
- Conduct reviews of YECL's HS&E Management System and the Safe Standards Manual to the appropriate (Yukon, Northwest Territory and British Columbia) OH&S, WCB and environmental regulatory requirements and to corporate and other requirements such as the Canadian Electricity Association, as required
- Develop, implement and provide ongoing maintenance of HS&E Best Practices and Programs in YECL's HS&E Management System and Safe Standards Manual
- Conduct evaluations and audits of YECL's HS&E Management System to identify potential improvement opportunities
  - Conduct environmental compliance audits to identify regulatory and policy non-compliances and management practice non-conformances
- Research HS&E issues and conduct major incident investigations
- Provide expert assistance in the capabilities of the Safety First Software (SWMS) application
- Provide medical management through Occupational Health Services

F. Corporate Communications

ATCO Electric will provide the following Corporate Communications shared services:

- ATCO Electric will include North of 60 web pages on its company intranet

**Schedule "A" to the Master Service Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## SCOPE OF SERVICES

G. Human Resources

ATCO Electric will make available to YECL, through services provided by the Human Resources staff the following:

- Advice and counsel on the interpretation and application of employment legislation
- Advice on and support for the implementation of corporate human resource policies and programs, including compensation and benefits, staffing and performance management, and employee relations
- Support for the negotiation and application of collective agreements
- Assistance in the recruitment, selection and orientation of employees, including preparation of internal and external advertising, coordination and conducting of interviews, assessment of candidates, and preparation of employment offers
- Coordination and administration of programs and services dealing with corporate pension and benefits plans, including Life, Health and Disability Insurance, and Pension
- Support for the implementation and administration of employee service programs including the Employee Assistance Program, Violence and Harassment-Free Workplace Program, and Disability Management Program
- Inclusion of YECL employees (less than 10 per year on average) in the long service recognition program

H. Regulatory Support

The use of Regulation & Business Plan staff to support Phase I regulatory matters on an as available basis. This will involve performing such tasks as:

- Preparation of filing
- Information requests
- Witness preparation
- Negotiations with customers

The use of Electric Pricing staff to support Phase II regulatory matters on an as available basis. This will involve performing such tasks as:

- Preparation of filing
- Information requests
- Load and losses forecast
- Rate / rider design
- Cost of service

**Schedule "A" to the Master Service Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## SCOPE OF SERVICES

I. Materials Management

ATCO Electric will provide the following materials management services:

- Fill inventory requisitions submitted by YECL, from existing inventory or through the purchasing group, and arrange delivery to YECL
- Provide buying services to process requisitions into purchase orders for services or material not available through inventory
- Provide materials management consulting, for purchasing, inventory, investment recovery, warehousing and systems, education and training, on an as required basis

J. Information Technology

ATCO Electric will provide the following information technology support services:

- Contract support
- Resolution of service and billing issues

K. Governance

ATCO Electric senior management will provide support relating to governance, policy and strategic direction.

L. Training and Development

On an as requested and as available basis, ATCO Electric will provide training to YECL staff that is consistent in nature and scope to that provided to ATCO Electric employees.

**Schedule "A" to the Master Service Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## SCOPE OF SERVICES

M. Outage Call Management

ATCO Electric will provide to YECL the following After Hours Assistance (AHA) services associated with answering emergency and outage telephone calls outside of YECL's normal business hours:

- Answer outage and emergency calls received on YECL's toll free number from 6 p.m. until 9 a.m. MST Monday through Friday and 24 hours a day on weekends and on Yukon Territory statutory holidays. This service is effective December 1, 2006. Hours will be extended until 9 a.m. MST on weekdays effective April 1, 2007.
- Dispatch YECL service personnel and track their status for "working alone" until return.
- Provide a single dedicated telephone line for both outage and emergency calls with a maximum capacity of four concurrent calls in queue after which a busy signal is received.
- Provide a dedicated phone line for YECL servicemen to contact the AHA agent. Unanswered calls will receive a message to call back. Maintain radio communication with YECL service personnel.
- Forward to service personnel customer requests for urgent connections or disconnections outside of YECL's regular hours of operation. Receive outage-related complaints and forward to YECL.
- Provide email hand-off of ongoing situations at commencement of normal YECL business hours.
- Priority in answering will be given to ATCO Electric calls.
- Monthly reporting will be provided as follows:
  - Total number of calls answered by agents
  - Total number of calls processed by agents
  - Average Speed of Answer (daily measure)
- Answered calls will be recorded and retained for 90 days.
- Planned outages are excluded from this service. Dispatched work will not be logged. Outage messaging (TVD system) will not be provided to callers in queue.
- No dedicated emergency line for use by police, ambulance and fire departments.
- Scripting, contact lists, procedures for emergency call out of OIC, call forwarding of YECL phone lines, and hand-offs of ongoing situations at ending of YECL business hours are all the responsibility of YECL.

**Schedule "B" to the Master Service Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## TERMS AND CONDITIONS

(i) The effective service date as amended is January 1, 2008

(ii) The term is in perpetuity subject to either party giving a six-month notice to terminate. In the event that new amendments are required, a new agreement will be negotiated three months prior to the effective date of the new contract.

ATCO Electric shall provide YECL reasonable notice of changes to ATCO Electric's systems or operation of its systems that would result in material changes in the cost of the service.

(iii) The method of cost allocation and compensation to be paid by YECL to ATCO Electric is based on the following and will be administered in compliance with accounting policy G5 of ATCO Electric.

The time analysis of services rendered will be reviewed a minimum of annually but may be reviewed at any time by either party with a one month notice.

(iv) The estimated cost of the services for 2008 is detailed in Appendix I.

**Schedule "C" to the Master Services Contract**

**VARIOUS SERVICES**

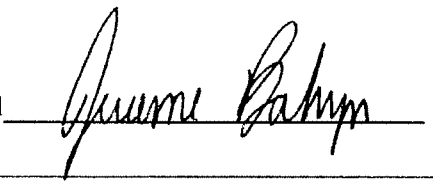
**dated October 31, 2003 between**

**Yukon Electrical Company Limited (YECL) and ATCO Electric**

**as amended January 1, 2008**

## YECL'S REPRESENTATIVE

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Fax: (867) 668-3965
jerome.babyn@atco.com

**Signed** 

**Schedule "D" to the Master Services Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**The Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## ATCO ELECTRIC'S REPRESENTATIVES

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**Schedule "D" to the Master Services Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**The Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

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**Schedule "D" to the Master Services Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**The Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## ATCO ELECTRIC'S REPRESENTATIVES

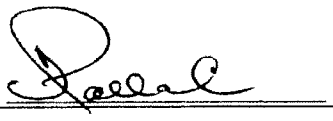
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**Schedule "D" to the Master Services Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**The Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

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Signed _____

**Schedule "D" to the Master Services Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**The Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## ATCO ELECTRIC'S REPRESENTATIVES

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**Schedule "D" to the Master Services Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**The Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

## ATCO ELECTRIC'S REPRESENTATIVES

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**Schedule "D" to the Master Services Contract**

**VARIOUS SERVICES**

**dated October 31, 2003 between**

**The Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

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**Appendix I to the Master Services Contract**

**VARIOUS SERVICES**

**Dated October 31, 2003 between**

**The Yukon Electrical Company Limited ("YECL") and ATCO Electric**

**as amended January 1, 2008**

The estimated cost of the services for 2008 is as follows

| | | |
|---|---|---|
| Financial Reporting, Accounts Payable, Use of Systems, And Regulatory Support | $ | 104,000 |
| Payroll Services | $ | 9,000 |
| Metering and Load Information Services | $ | 40,000 |
| Human Resources | $ | 87,000 |
| Information Technology | $ | 2,000 |
| Governance | $ | 24,000 |
| After Hours Service | $ | 26,000 |
| Total | $ | 292,000 |
| Materials Management | $ | 43,000 |

# ATCO Group Inter-Affiliate

## Code of Conduct

May 22, 2003

Alberta Energy and Utilities Board

**ALBERTA ENERGY AND UTILITIES BOARD**
Appendix 5
Decision 2003-040: ATCO Group Inter-Affiliate Code of Conduct
Application No. 1237673

Published by
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# APPENDIX 5

# ATCO GROUP
# INTER-AFFILIATE
# CODE OF CONDUCT

This ATCO Group Inter-Affiliate Code of Conduct forms Appendix 5 to Decision 2003-040 dated May 22, 2003, being the ATCO Affiliate Transactions and Code of Conduct Proceeding Part B: Code of Conduct.

## 1 PURPOSE AND OBJECTIVES OF THE CODE

### 1.1 Purpose and Objectives of the Code

At page 38 of Decision 2003-040, the EUB sets out the purpose and objectives of the Code established by the EUB for the ATCO Group of businesses and the need to respect the spirit and intent behind the Code in the following words:

> **Purpose of the Code**
>
> The purpose of this Code is to establish standards and conditions for interaction between each ATCO Utility and its Utility and Non-Utility Affiliates. This Code attempts to anticipate and adjust for the potential misalignment of interest between shareholders and Utility customers occasioned by Affiliate interactions through the establishment of parameters for transactions, information sharing and the sharing of services and resources, while permitting economies of scale and operating efficiencies.
>
> These parameters are intended to:
>
> (a) prevent Utilities from cross-subsidizing Affiliate activities;
>
> (b) protect confidential customer information collected in the course of providing Utility services;
>
> (c) ensure Affiliates and their customers do not have preferential access to Utility services; and
>
> (d) avoid uncompetitive practices between Utilities and their Affiliates, which may be detrimental to the interests of Utility customers.
>
> **Objectives of Code**
>
> While the overall purpose of the Code is to establish standards and parameters which prohibit inappropriate Affiliate conduct, preferences or advantages, which may adversely impact the customers of regulated businesses, this purpose reflects several important underlying objectives, including:

(a) creating a clearly defined set of rules designed to enhance inter-affiliate transparency, fairness and senior management accountability with respect to inter-affiliate interactions impacting regulated businesses;

(b) providing an environment in which inter-affiliate economies and efficiencies can legitimately occur for the mutual advantage of both a Utility's customers and its shareholders;

(c) developing support and respect for the Code by the employees, officers and directors of the ATCO group of companies, which will in turn promote ratepayer confidence in the application of the Code; and

(d) the creation of regulatory processes and cost efficiencies through the consistent application of a clear set of standards and reporting requirements to Utility inter-affiliate transactions, enhanced by a practical, resolution driven, dispute process.

**Respect for the Code**

Standards and rules alone, however, will always be insufficient to achieve the objectives of this Code. These objectives can only be fully realized through a demonstrated respect for the spirit and intent behind the words by those individuals to whom the Code applies.

## 1.2 Application

This Code is not meant to replace or modify in any manner, any statutory or regulatory requirements relating to Utilities.

# 2 General Provisions

## 2.1 Definitions

In this Code the following words and phrases shall have the following meanings:

a) **"ABCA"** means the *Business Corporations Act*, R.S.A.2000 c. B-9.

b) **"Affiliate"** means with respect to any Utility:

i) an "affiliate" as defined in the ABCA;

ii) a unit or division within the Utility or any Body Corporate referred to in clause (b)(i) above;

iii) a partnership, joint venture, or Person in which the Utility or any Body Corporate referred to in clause (b)(i) above has a controlling interest or that is otherwise subject to the control of the Utility or such Body Corporate;

iv) any partnership, joint venture, or Person deemed by the EUB to be an affiliate of the Utility for the purposes of this Code; and

v) an agent or other Person acting on behalf of any Body Corporate, operating division, partnership, joint venture or Person referred to in clauses (b)(i) to (iv) above.

c) **"Affiliated Party Transactions Summary"** unless otherwise directed by the EUB, means in respect of any period of time, a summary overview of each type of business transaction or

service, other than Major Transactions or Utility Services, performed by an Affiliate for a Utility or by a Utility for an Affiliate, which summary shall contain a general description of the transactions and services, the parties involved and the approximate aggregate value of each type of transaction or service during the said period.

d) **"ATCO"** means ATCO Ltd.

e) **"ATCO Affiliates"** means any entity to which this Code applies pursuant to section 2.3 hereof.

f) **"Body Corporate"** means a "body corporate" as defined in the ABCA.

g) **"Code"** means this ATCO Group Inter-Affiliate Code of Conduct.

h) **"Compliance Officer"** shall have the meaning ascribed thereto in section 7.3 hereof.

i) **"Compliance Plan"** shall mean the document to be prepared and updated by a Utility pursuant to section 7.5 hereof.

j) **"Compliance Report"** shall have the meaning ascribed thereto in section 7.6 hereof.

k) **"Confidential Information"** means any information relating to a specific customer or potential customer of a Utility, which information the Utility has obtained or compiled in the process of providing current or prospective Utility Services and which is not otherwise available to the public.

l) **"Cost Recovery Basis"** with respect to:

i) the use by one Affiliate of another Affiliate's personnel, means the fully burdened costs of such personnel for the time period they are used by the Affiliate, including salary, benefits, vacation, materials, disbursements and all applicable overheads;

ii) the use by one Affiliate of another Affiliate's equipment, means an allocated share of capital and operating costs appropriate for the time period utilized by the Affiliate;

iii) the use by a Utility of an Affiliate's services, means the complete costs of providing the service, determined in a manner acceptable to the Utility, acting prudently;

iv) the use by an Affiliate of a Utility's services, means the complete costs of providing the service, determined in a manner acceptable to the Utility, acting prudently; and

v) the transfer of equipment, plant inventory, spare parts or similar assets between Utilities, means the net book value of the transferred assets.

m) **"EUB"** means the Alberta Energy and Utilities Board.

n) **"Fair Market Value"** means the price reached in an open and unrestricted market between informed and prudent parties, acting at arms length and under no compulsion to act.

o) **"For Profit Affiliate Service"** means any service, provided on a for-profit basis:

i) by a Utility to a Non-Utility Affiliate, other than a Utility Service; or

ii) by a Non-Utility Affiliate to a Utility.

p) **"Information Services"** means any computer systems, computer services, databases, electronic storage services or electronic communication media utilized by a Utility relating to Utility customers or Utility operations.

q) **"Major Transaction"** means a transaction or series of related transactions within a calendar year between a Utility and an Affiliate relating to the sale or purchase of an asset(s) or to the provision of a service or a similar group of services, other than Utility Services, which has an aggregate value within that calendar year of $500,000 or more.

r) **"Non-Utility Affiliate"** means an Affiliate that is not a Utility.

s) "**Occasional Services**" shall have the meaning ascribed thereto in section 3.3.6 hereof.

t) **"Person"** means a "person" as defined in the ABCA.

u) **"Services Agreement"** means an agreement entered into between a Utility and one or more Affiliates for the provision of Shared Services or For Profit Affiliate Services and shall provide for the following matters as appropriate in the circumstances:

i) the type, quantity and quality of service;

ii) pricing, allocation or cost recovery provisions;

iii) confidentiality arrangements;

iv) the apportionment of risk;

v) dispute resolution provisions; and

vi) a representation by the Utility and each Affiliate party to the agreement that the agreement complies with the Code.

v) **"Shared Service"** means any service, other than a Utility Service or a For Profit Affiliate Service, provided on a Cost Recovery Basis by a Utility to an Affiliate or by an Affiliate to a Utility.

w) **"Subsidiary"** shall have the meaning ascribed thereto in section 2(4) of the ABCA.

x) **"Utility"** means any Body Corporate or any unit or division thereof, that provides a Utility Service and falls within the definition of:

i) "electric utility" under the *Electric Utilities Act,* S.A. 2003, c. E-5.1;

ii) "gas utility" under the *Gas Utilities Act*, R.S.A. 2000, c. G-5; or

iii) "public utility" under the *Public Utilities Board Act*, R.S.A. 2000, c. P-45.

y) **"Utility Service"** means a service, the terms and conditions of which are regulated by the EUB, and includes services for which an individual rate, joint rate, toll, fare, charge or schedule of them, have been approved by the EUB.

## 2.2 Interpretation

Headings are for convenience only and shall not affect the interpretation of this Code. Words importing the singular include the plural and vice versa. A reference to a statute, document or a provision of a document includes an amendment or supplement to, or a replacement of, that statute, document or that provision of that document.

## 2.3 To Whom this Code Applies

All Utilities directly or indirectly owned, controlled or operated by ATCO are obligated to comply with this Code and all Affiliates of these Utilities are obligated to comply with the Code to the extent they interact with the Utilities.

## 2.4 Coming into Force

This Code comes into force on September 1, 2003, provided however that, to the extent existing agreements or arrangements are in place between parties to whom this Code applies that do not conform with this Code, such agreements or arrangements must be brought into compliance with this Code on or before October 31, 2003.

## 2.5 Amendments to this Code

This Code may be reviewed and amended from time to time by the EUB on its own initiative, or pursuant to a request by any party to whom this Code applies or by any interested party.

## 2.6 Exemptions

A party to whom this Code applies may apply to the EUB for an exemption with respect to compliance with any provision of this Code. Any such application will specify if the requested exemption is in respect of a particular transaction, series of transactions, for a specified period of time, or is for a general exemption from a particular provision.

## 2.7 Authority of the EUB

Although this Code has been approved by the EUB, such approval does not detract from, reduce or modify in any way, the powers of the EUB to deny, vary, approve with conditions, or overturn, the terms of any transaction or arrangement between a Utility and one or more Affiliates that may be done in compliance with this Code. Compliance with the Code does not eliminate the requirement for specific EUB approvals or filings where required by statute or by EUB decisions, orders or directions.

# 3 GOVERNANCE AND SEPARATION OF UTILITY BUSINESSES

## 3.1 Governance

### 3.1.1 Separate Operations

The business and affairs of a Utility should be managed and conducted separately from the business and affairs of its Non-Utility Affiliates, except as required to fulfill corporate governance, policy, and strategic direction responsibilities of a corporate group of businesses as a whole.

### 3.1.2 Common Directors

A Utility may have common directors with its Affiliates.

### 3.1.3 Separate Management

Subject to section 3.1.4 hereof, a Utility must have a separate management team and separate officers from its Non-Utility Affiliates, but may share management team members or officers with other Affiliated Utilities.

### 3.1.4 Separate Management Exception

Officers of a Utility may also be officers of any Affiliate of which the Utility is a Subsidiary or of any Affiliate that is a Subsidiary of the Utility, as may be required to perform corporate governance, policy and strategic direction responsibilities of an affiliated group of businesses.

### 3.1.5 Guiding Principle

Notwithstanding sections 3.1.2, 3.1.3 and 3.1.4 hereof, an individual shall not act both as a director, officer or member of a management team of a Utility and as a director, officer or member of a management team of any other Affiliate (thereby acting in a dual capacity) unless the individual is able to carry out his/her responsibilities in a manner that preserves the form, and the spirit and intent, of this Code. In particular, an individual:

(a) shall not agree to act in a dual capacity if it could reasonably be considered to be detrimental to the interests of customers of the Utility, and

(b) if acting in a dual capacity, shall abstain from engaging in any activity that could reasonably be considered to be detrimental to the interests of customers of the Utility.

## 3.2 Degree of Separation

### 3.2.1 Accounting Separation

A Utility shall ensure accounting separation from all Affiliates and shall maintain separate financial records and books of accounts.

### 3.2.2 Physical Separation

A Utility shall be located in a separate building or shall otherwise be physically separated from all Non-Utility Affiliates through the use of appropriate security-controlled access.

### 3.2.3 Separation of Information Services

Where a Utility shares Information Services with an Affiliate, all Confidential Information must be protected from unauthorized access by the Affiliate. Access to a Utility's Information Services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols shall be periodically confirmed by the Utility, through a review that complies with the provisions of the Canadian Institute of Chartered Accountants Handbook and updates thereto.

### 3.2.4 Financial Transactions with Affiliates

A Utility shall ensure that any loan, investment, or other financial support provided to a Non-Utility Affiliate is provided on terms no more favorable than what that Non-Utility Affiliate would be able to obtain as a stand-alone entity from the capital markets.

## 3.3 Resource Sharing

### 3.3.1 Sharing of Employees

A Utility may share employees on a Cost Recovery Basis with an Affiliate provided that the employees to be shared:

(a) do not have access to Confidential Information;

(b) do not routinely participate in making decisions with respect to the provision of Utility Services or how Utility Services are delivered;

(c) do not routinely deal with or have direct contact with customers of the Utility; and

(d) are not, subject to the provisions of section 3.1.4 hereof, routinely involved in operating, planning or managing the business of the Utility.

### 3.3.2 Transferring of Employees

A Utility may transfer employees to or from an Affiliate, provided any employee transferred by the Utility who had access to Confidential Information shall execute a confidentiality agreement with respect to such Confidential Information prior to the transfer.

### 3.3.3 Sharing of Assets

The plant, assets and equipment of a Utility shall be separated in ownership and separated physically from the plant, assets and equipment of other Non-Utility Affiliates. Utility Affiliates may share ownership and may physically share office space, equipment, rights-of-way and other assets on a Cost Recovery Basis.

### 3.3.4 Shared Services Permitted

Where a Utility determines it is prudent in operating its Utility business to do so, it may obtain Shared Services from, or provide Shared Services to, an Affiliate. Utilities shall periodically review the prudence of continuing Shared Services arrangements with a view to making any necessary adjustments to ensure that each of the Utilities and its Affiliates bears its proportionate share of costs.

### 3.3.5 Services Agreement

A Utility shall enter into a Services Agreement with respect to any Shared Services it provides to, or acquires from, an Affiliate.

### 3.3.6 Occasional Services Permitted

Where a Utility has otherwise acted prudently, a Utility may receive, or provide, one-off, infrequent or occasional services ("**Occasional Services**") to, or from, an Affiliate on a Cost Recovery Basis, documented by way of work order, purchase order or similar instrument. In the event that occasional services become material as to value, frequency or use of resources, the Utility shall enter into a Services Agreement with the Affiliate for Shared Services.

### 3.3.7 Emergency Services Permitted

In the event of an emergency, a Utility may share services and resources with an Affiliate without a Services Agreement on a Cost Recovery Basis.

## 4 TRANSFER PRICING

### 4.1 For Profit Affiliate Services

Where a Utility determines it is prudent in operating its Utility business to do so, it may obtain For Profit Affiliate Services from an Affiliate or provide For Profit Affiliate Services to an Affiliate.

If a Utility intends to outsource to an Affiliate a service it presently provides for itself, the Utility shall, in addition to any other analysis it may require to demonstrate the prudence of a For Profit Affiliate Services arrangement, undertake a net present value analysis appropriate to the life cycle or operating cycle of the services involved.

Each Utility shall periodically review the prudence of continuing For Profit Affiliate Services arrangements.

### 4.2 Pricing For Profit Affiliate Services

### 4.2.1 Utility Acquires For Profit Affiliate Service

When a Utility acquires For Profit Affiliate Services it shall pay no more than the Fair Market Value of such services. The onus is on the Utility to demonstrate that the For Profit Affiliate Services have been acquired at a price that is no more than the Fair Market Value of such services.

### 4.2.2 Utility Provides For Profit Affiliate Service

When a Utility provides For Profit Affiliate Services, it shall not charge less than the Fair Market Value of such services. The onus is on the Utility to demonstrate that the For Profit Affiliate Services have been charged at a price that is not less than the Fair Market Value of such services.

### 4.3 Services Agreement

A Utility shall enter into a Services Agreement with respect to any For Profit Affiliate Services it acquires or provides.

### 4.4 Asset Transfers

Subject to section 4.6 hereof, assets transferred, mortgaged, leased or otherwise disposed of by a Utility to an Affiliate or by an Affiliate to a Utility shall be at Fair Market Value.

### 4.5 Determination of Fair Market Value

In demonstrating that Fair Market Value was paid or received pursuant to a For Profit Affiliate Service arrangement or a transaction contemplated by sections 4.1, 4.2 and 4.4 hereof, the Utility, subject to any prior or contrary direction by the EUB, may utilize any method to determine Fair Market Value that it believes appropriate in the circumstances. These methods may include, without limitation: competitive tendering, competitive quotes, bench-marking studies, catalogue pricing, replacement cost comparisons or recent market transactions. The Utility shall bear the onus of demonstrating that the methodology or methodologies utilized in determining the Fair Market Value of the subject goods or services was appropriate in the circumstances.

### 4.6 Asset Transfers Between Utilities for Operational Efficiencies

Where operational efficiencies between Utilities that are Affiliates can be obtained through the use of common facilities (such as shared warehousing or field offices), combined purchasing power or through the use of other cost saving procedures, individual assets or groups of assets used in Utility operations (such as equipment, plant inventory, spare parts or similar assets) may be transferred in the ordinary course of business between Utilities on a Cost Recovery Basis. All such transactions shall be properly accounted for on the books of the Utilities involved.

## 5 EQUAL TREATMENT WITH RESPECT TO UTILITY SERVICES

### 5.1 Impartial Application of Tariff

A Utility shall apply and enforce all tariff provisions relating to Utility Services impartially, in the same timeframe, and without preference in relation to its Affiliates and all other customers or prospective customers.

### 5.2 Equal Access

A Utility shall not favor any Affiliate with respect to access to information concerning Utility Services or with respect to the obtaining of, or the scheduling of, Utility Services. Requests by an Affiliate or an Affiliate's customers for access to Utility Services shall be processed and provided in the same manner as would be processed or provided for other customers or prospective customers of the Utility.

### 5.3 No Undue Influence

A Utility shall not condition or otherwise tie the receipt of Utility Services to a requirement that a customer must also deal with an Affiliate. Each Utility shall ensure that its employees do not,

explicitly or by implication, suggest that an advantage will accrue to a customer in dealing with the Utility if the customer also deals with an Affiliate of the Utility.

### 5.4 Affiliate Activities

A Utility shall take reasonable steps to ensure that an Affiliate does not imply in its marketing material or otherwise, favored treatment or preferential access to Utility Services. If the Utility becomes aware of any such inappropriate activity by an Affiliate, it shall:

(a) immediately take reasonable steps to notify affected customers of the violation;

(b) take necessary steps to ensure the Affiliate is aware of the concern; and

(c) inform the EUB in writing of such activity and the remedial measures that were undertaken by the Utility.

### 5.5 Name and Logo

A Utility shall take reasonable steps to ensure that an Affiliate does not use the Utility's name, logo or other distinguishing characteristics in a manner which would mislead consumers as to the distinction or a lack of distinction between the Utility and the Affiliate.

### 5.6 Access to Shared and Occasional Services

A Utility is not required to provide non-Affiliated parties with equal access to Shared Services or Occasional Services.

## 6 CONFIDENTIALITY OF INFORMATION

### 6.1 Utility Information

Subject to section 6.2 hereof, a Utility shall not provide Non-Utility Affiliates with information relating to the planning, operations, finances or strategy of the Utility or of an Affiliated Utility before such information is publicly available.

### 6.2 Management Exception

Officers of a Utility who are also officers of an Affiliate as permitted pursuant to section 3.1.4 hereof may disclose, subject to the provisions of section 3.1.5 hereof, Utility planning, operational, financial and strategic information to the Affiliate to fulfill their responsibilities with respect to corporate governance, policy and strategic direction of an affiliated group of businesses, but only to the extent necessary and not for any other purpose.

### 6.3 No Release of Confidential Information

A Utility shall not release to an Affiliate Confidential Information relating to a customer or prospective customer, without receiving the prior written consent of the customer or prospective customer, unless such Confidential Information may be disclosed to an Affiliate in connection with a disclosure required:

(a) for the purpose of a court proceeding or a proceeding before a quasi-judicial body to which the customer is a party;

(b) for the purpose of complying with a subpoena, warrant, or order issued or made by a court, person or body having jurisdiction to compel the production of information or with a rule of court that relates to the production of information;

(c) to a municipal or provincial police service for the purpose of investigating an offence involving the customer, if the disclosure is not contrary to the express request of the customer;

(d) by law or by an order of a government or agency having jurisdiction over the Utility; or

(e) for the purpose of providing Shared Services or For Profit Affiliate Services to the Affiliate or for the purpose of receiving Shared Services or For Profit Affiliate Services from the Affiliate; provided appropriate measures are first put in place by the Affiliate to protect the Confidential Information and the Confidential Information is used by the Affiliate only for the purpose intended by the Utility.

### 6.4 Aggregated Confidential Information

A Utility may disclose Confidential Information when aggregated with the Confidential Information of other customers in such a manner that an individual customer's Confidential Information can not be identified, provided that the Utility shall not disclose such aggregated customer information to an Affiliate prior to making such information publicly available.

## 7 COMPLIANCE MEASURES

### 7.1 Responsibility for Compliance

Each Utility shall be responsible for ensuring compliance with this Code.

### 7.2 Communication of Code

Each Utility shall:

(a) communicate the contents of the Code, and any modifications to it from time to time, to each of its directors, officers, employees, consultants, contractors, agents and Affiliates; and

(b) make the Code available on the Utility's web site.

### 7.3 Compliance Officer

Each Utility shall appoint a compliance officer (the **"Compliance Officer"**). The same individual may be the Compliance Officer for more than one Utility. The Utility shall ensure that the Compliance Officer is an officer of the Utility and has adequate resources to fulfill his or her responsibilities.

### 7.4 Responsibilities of the Compliance Officer

The responsibilities of the Compliance Officer shall include:

(a) providing advice and information to the Utility for the purpose of ensuring compliance with this Code;

(b) monitoring and documenting compliance with the Code by the Utility, its directors, officers, employees, consultants, contractors and agents;

(c) monitoring and documenting compliance with the Code by Affiliates of the Utility with respect to the interactions of the Affiliates with the Utility;

(d) providing for the preparation and updating, of a Compliance Plan for the Utility pursuant to Section 7.5 hereof;

(e) filing the Compliance Plan and any modifications or replacements with the EUB, posting the Compliance Plan on the Utility's website, and advising interested parties promptly when the Compliance Plan, or any modifications or replacements, have been posted on the website;

(f) performing an annual review of compliance with the Compliance Plan and preparing an annual compliance report (**"Compliance Report"**) containing the information required in section 7.6 hereof. The Compliance Officer shall file the Compliance Report with the EUB within 120 days of the fiscal year end of the Utility with respect to the immediately preceding fiscal year, post the Compliance Report on the Utility's website, and advise interested parties promptly when the Compliance Report has been posted on the website;

(g) receiving and investigating internal and external disputes, complaints and inquiries with respect to the application of, and alleged non-compliance, with the Code in accordance with Section 8 hereof;

(g) recommending to the Utility measures required to address events of non-compliance with the Code; and

(i) maintaining adequate records with respect to all aspects of the Compliance Officer's responsibility.

### 7.5 The Compliance Plan

Each Utility shall prepare a Compliance Plan. The Compliance Plan shall detail the measures, policies, procedures and monitoring mechanisms that the Utility will employ to ensure its full compliance with the provisions of the Code by the Utility its directors, officers, employees, consultants, contractors and agents, and by Affiliates of the Utility with respect to the interactions of the Affiliates with the Utility. The Utility shall review and update the Compliance Plan at least annually.

### 7.6 The Compliance Report

The Compliance Report shall include the following information prepared in respect to the period of time covered by the Compliance Report:

(a) a copy of the Compliance Plan and any amendments thereto;

(b) a corporate organization chart for the Utility and its Affiliates indicating relationships and ownership percentages;

(c) a list of all Affiliates with whom the Utility transacted business, including business addresses, a list of the Affiliates' officers and directors, and a description of the Affiliates' business activities;

(d) a list of all Services Agreements in effect at any time during such period;

(e) an overall assessment of compliance with the Code by the Utility, including compliance by the directors, officers, employees, consultants, contractors and agents of the Utility and by Affiliates of the Utility with respect to the interactions of the Affiliates with the Utility;

(f) an assessment of the effectiveness of the Compliance Plan and any recommendations for modifications thereto;

(g) in the event of any material non-compliance with the Code, a comprehensive description thereof and an explanation of all steps taken to correct such non-compliance;

(h) subject to the confidentiality provisions of section 8.1 hereof, a summary of disputes, complaints and inquiry activity during the year;

(i) a list and detailed description of all Major Transactions between the Utility and its Affiliates;

(j) an Affiliated Party Transactions Summary;

(k) a summary description together with an estimated aggregate value for each Occasional Service provided by the Utility to an Affiliate and by Affiliates to the Utility;

(l) a summary list of any exemptions granted to this Code or exceptions utilized, including the exception for emergency services;

(m) a list of all employee transfers, temporary assignments and secondments between a Utility and its Affiliates, detailing specifics as to purpose, dates and duration of such employee movements; and

(n) two certificates, each in the form attached as Schedule "A" attached to this Code, attesting to completeness of the Compliance Report and compliance with the Code, one certificate signed by the Compliance Officer and a second certificate signed by the highest ranking operating officer of the Utility.

### 7.7 Documents to be Provided to the EUB upon Request

If required by the EUB, a Utility shall provide the EUB with a copy of any document referred to in a Compliance Report or other supporting records and material.

### 7.8 Compliance Records and Audit

The records required to be maintained by the Compliance Officer pursuant to section 7.4(i) hereof shall be retained for a period of at least six years. Compliance records shall be maintained in a manner sufficient to support a third party audit of the state of compliance with the Code by the Utility, its directors, officers, employees, consultants, contractors and agents, and by Affiliates of the Utility with respect to the interactions of the Affiliates with the Utility. Subject to the confidentiality provisions of section 8.1 hereof, all such records shall be made available for inspection or audit as may be required by the EUB from time to time.

# 8 DISPUTES, COMPLAINTS AND INQUIRIES

## 8.1 Filing with the Compliance Officer

Disputes, complaints or inquiries from within the Utility or from external parties respecting the application of, or alleged non-compliance with, the Code shall be submitted in writing to the Compliance Officer and may be made confidentially. The identity of the party making the submission to the Compliance Officer shall be kept confidential by the Compliance Officer unless the party otherwise agrees.

## 8.2 Processing by Utility

### 8.2.1 Compliance Officer Acknowledgment

The Compliance Officer shall acknowledge all disputes, complaints or inquiries in writing within five working days of receipt.

### 8.2.2 Disposition

The Compliance Officer shall respond to the dispute, complaint or inquiry within 21 working days of its receipt. The response shall include a description of the dispute, complaint or inquiry and the initial response of the Utility to the issues identified in the submission. The Utility's final disposition of the dispute, complaint or inquiry shall be completed as expeditiously as possible in the circumstances, and in any event within 60 days of receipt of the dispute, complaint or inquiry, except where the party making the submission otherwise agrees.

## 8.3 Referral to the EUB

In the event:

(a) a Utility fails to abide by the process identified in section 8.2 hereof,

(b) the Utility or a party is unsatisfied with the resolution of a dispute, complaint or inquiry following the conclusion of the section 8.2 process, or

(c) of an urgent and significant matter, where there is a reasonable expectation that a party's position may be prejudiced by allowing the process contemplated by section 8.2 to operate,

the Utility (subject to the confidentiality provisions of section 8.1 hereof) or a party with a dispute, complaint or inquiry may refer the matter to the EUB for consideration. A referral to the EUB must be in writing and shall describe the dispute, complaint, or inquiry and must include the response, if any, of the Utility to the submission.

# 9 NON-COMPLIANCE WITH THE CODE

## 9.1 Non-Compliance

Any non-compliance with the Code by any director, officer, employee, consultant, contractor or agent of a Utility or by an Affiliate (or any director, officer, employee, consultant, contractor or agent of an Affiliate) with respect to the interactions of the Affiliate with the Utility will be considered to be non-compliance by the Utility.

## 9.2 Consequences for Non-Compliance with Code

Non-compliance with this Code could be considered as *prima facie* evidence in a regulatory proceeding of inappropriate conduct by a Utility or of an inappropriate transaction, expense or activity by the Utility. Non-compliance with the Code by a Utility shall subject the Utility to the full range of powers and authorities of the EUB. Non-compliance with the Code by a director, officer, employee, consultant, contractor or agent of a Utility may subject such individual to disciplinary action by the Utility.

## SCHEDULE A – OFFICERS CERTIFICATE

## OFFICER'S CERTIFICATE

To: The Alberta Energy and Utilities Board

I, _____ of the City of _____, in the Province of Alberta, acting in my position as an officer of _____ (the Utility) and not in my personal capacity, to the best of my knowledge do hereby certify as follows:

1. My position with the Utility is _____, and as such I have personal knowledge of, or have conducted due inquiry of individuals who have personal knowledge of, the facts and matters herein stated.

2. Capitalized terms used herein (which are not otherwise defined herein) shall have the meanings ascribed thereto in the ATCO Group Inter-Affiliate Code of Conduct (the Code).

3. I have read the Code, the Compliance Plan of the Utility dated _____ and the Compliance Report of the Utility dated _____.

4. The form and contents of the Compliance Report comply with the requirements of the Code and the matters reported therein are fully and accurately described.

5. I am not aware of any material non-compliance with the provisions of the Code by any director, officer, employee, consultant, contractor or agent of the Utility, or by any Affiliate of the Utility (including any director, officer, employee, consultant, contractor or agent of the Affiliate) with respect to the any interaction between an Affiliate and the Utility that is not fully and accurately described in the Compliance Report.

Name: _____

Title: _____

Date: _____

**CW-YECL-29**

**Issue:** Forecast Operations and Maintenance Expenses Affiliate Costs

**Reference:** Page 5-4

**Preamble:** In addition to the labour support provided from ATCO Electric, Yukon Electrical purchases information technology and billing system services from ATCO I-Tek and ATCO I-Tek Business Services respectively. Yukon Electrical is aware the costs associated with these services are being reviewed as part of a benchmarking process and that a final report is to be filed by ATCO with the Alberta Utilities Commission (AUC). Yukon Electrical will update the placeholders included in this application once the appropriate approvals have been finalized and approved by the AUC.

**Request:**

(a) ATCO Gas updated its Information Technology and Customer Care & Billing placeholders by filing on February 28, 2008. Please update the Yukon Electric placeholders

(b) Please provide a copy of the Master Service Agreements with ATCO I-Tek and ATCO I-Tek Business Services and any updating Statements of Work that govern the provision of Information Technology and Customer Care & Billing services to Yukon Electric.

**Response:**

(a) Please refer to YEC-YECL-11(b) below:

This collaborative process was put in place to determine the Fair Market Value of the services being charged by ATCO I-Tek. The collaborative process involved the ATCO Utilities as well as interested parties. An independent consultant was selected to prepare a benchmark report for the years 2003-2007 and an Evergreen Strategy to cover the process for the years subsequent to 2007. This

benchmark report provided the market value for the prices to be charged by ATCO I-Tek.

This report was filed with the Alberta Utilities Commission on February 21, 2008.

This application has not yet been approved, however, the report has been signed off by the Customer Group agreeing that:

*"The report satisfies and meets the Terms of Reference established pursuant to the Commission's decision and directions…"* [ATCO Utilities, February 21, 2008 Application, page 2 of 3]

As such, Yukon Electrical now submits that the results of this report be incorporated into Yukon Electrical's application and has attached detailed schedules (please refer to YEC-YECL-11(b) Attachments 2 and 3) incorporating the updated prices from this report. The results of this are as follows:

| **I-Tek** | **2008** | **2009** |
|---|---|---|
| Costs per Application | 353 | 370 |
| Updated for Benchmarking | 329 | 324 |
| Reduction in I-Tek Costs | 24 | 46 |

| **ITBS** | **2008** | **2009** |
|---|---|---|
| Costs per Application | 434 | 484 |
| Updated for Benchmarking | 416 | 448 |
| Reduction in ITBS Costs | 18 | 36 |

These reductions will be incorporated into a compliance filing relating to this proceeding.

The market price for ITBS costs was based on the 2003 market price adjusted for inflation for those components that are inflation sensitive which is typically labour. This approach is consistent with the Evergreen Strategy approach.

(b) Please refer to the following for the requested documents:

CW-YECL-29(b) Attachment 1 for the Master Services Agreement

CW-YECL-29(b) Attachment 2 for an Amending Agreement

CW-YECL-29(b) Attachment 3 for the updating Statements of Work

# INFORMATION TECHNOLOGY

# MASTER SERVICES AGREEMENT RENEWAL

# FOR

# THE ATCO GROUP

**ATCO I-Tek**
**10035 105 Street**
**Edmonton, Alberta**
**T5J 2V6**

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# INFORMATION TECHNOLOGY MASTER SERVICES AGREEMENT

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# INFORMATION TECHNOLOGY MASTER SERVICES AGREEMENT

BETWEEN:

ATCO I-Tek Inc.
("ATCO I-Tek")

- and -

ATCO Electric Ltd.
("Client")

WHEREAS:

A. ATCO I-Tek has agreed to provide information technology services to each member of the ATCO Group (as hereinafter defined) who signs a counterpart of this Agreement, on the terms and conditions set forth below; and

B. Client is a member of the ATCO Group;

NOW, THEREFORE, IN CONSIDERATION OF the mutual covenants and agreements set forth herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto do hereby agree as follows.

## ARTICLE 1
## INTERPRETATION AND DEFINITIONS

1.1 **Interpretation**

(a) The parties intend to develop a long-term relationship that supports the evolution of Client's information technology ("IT") systems and investment, and operates with a spirit that yields mutual benefit based on the following values and objectives.

(i) Values

| | | |
|---|---|---|
| (A) | Integrity: | Openness, honesty and fairness in all communications and dealings. |
| (B) | Trust: | A spirit of true cooperation on the understanding that the parties "win or lose" together. |
| (C) | Focus: | A relationship that permits both parties to focus on their respective core competencies. |

(D) Business Driven: A relationship that extends beyond the provision of IT services and operates within the framework of Client's business.

(E) Added Value: A relationship that, in addition to benefiting each party, adds value to Client's business as a whole.

(ii) Objectives — Work with Client to meet Client's IT needs on an immediate and long term basis.

(iii) Principles and Goals

(A) Provide the ATCO Group's existing IT services efficiently and at service levels comparable or superior to the service levels being provided prior to the Effective Date, using methods designed to effect continuous improvement in service levels throughout the term of this Agreement.

(B) Reflect a balance between the interests of the ATCO Group and the interests of ATCO I-Tek.

(C) Provide leadership in identifying, reaching agreement on, and adopting, an appropriate set of standards which will support the optimum level of integration of IT solutions within and across the ATCO Group.

(D) Seek to implement the most cost effective IT solutions which will be responsive to the needs and priorities of each member of the ATCO Group.

(E) Effectively provide information management and IT leadership across the ATCO Group, and operate in a diverse and multi-vendor environment.

(F) Objectively assess alternative service delivery methods and technology solutions on a business case basis, and consider the full range of options – from packaged to custom-developed technology solutions.

(G) Work towards minimizing costs to the ATCO Group, and implement a fair and reasonable pricing approach that provides maximum benefit to the ATCO Group.

During the term of this Agreement, each member of the ATCO Group has the right to obtain, at a minimum, the same IT services on the same terms and conditions as ATCO Ltd., at no more than the unit costs in effect at that time.

(b) Wherever in this Agreement the context so requires, the singular number shall include the plural number and vice versa, any gender shall include the feminine, masculine or neuter genders, and person shall include an individual, partnership, corporation (including a business trust), trust, unincorporated association, joint venture, government or other entity, or any agency, department or instrumentality thereof.

(c) The term "including" shall be read as "including, but not limited to." Other expressions derived from the word "include" are for illustrative purposes only and are not meant to be limiting.

(d) The insertion of headings herein and the division of this Agreement into articles and sections are for convenience of reference only and shall not affect the interpretation hereof. The words "hereof", "hereunder" and similar expressions refer to this Agreement in its entirety and not any particular article or section hereof. The words "article", "section", and "subsection" mean and refer to the specified article, section or subsection of this Agreement.

(e) This Agreement shall not be interpreted more favourably towards one party than the other party as a result of any rules of interpretation, including *contra proferentum*.

1.2 **Definitions**

Whenever used in this Agreement, unless there is something in the subject matter or context inconsistent therewith, the following capitalized words and phrases shall have the respective meanings ascribed to them as follows:

"**Acknowledgement**" has the meaning given in section 10.3.

"**Affiliate**" has the meaning given in the *Business Corporations Act* (Alberta).

"**Agreement**" means this Information Technology Master Services Agreement, including the Schedules hereto and any Statements of Work attached hereto or as may be executed by the parties at a future date, as well as all amendments, additions or modifications made pursuant to section 18.8.

"**Annual Review**" has the meaning given in section 7.2.

"**Associate**" has the meaning given in the *Business Corporations Act* (Alberta).

"**ATCO Group**" means ATCO Ltd., Canadian Utilities Limited and their respective Affiliates and Associates.

"**ATCO I-Tek Designated Manager**" has the meaning given in section 5.2.

"**ATCO I-Tek Know-How**" has the meaning given in section 13.6.

"**ATCO I-Tek Project Manager**" has the meaning given in section 5.4.

"**ATCO I-Tek Systems**" means any Systems owned by ATCO I-Tek or licensed to ATCO I-Tek by third parties, and utilized to provide the Services.

"**Benchmark**" means determining the value of one or more of the services being received from a service provider by comparison to a reference group of companies contained in a database of IT studies. Analysis includes resources consumed, volumes of output, service level and cost.

"**Business Day**" means each of Monday, Tuesday, Wednesday, Thursday and Friday, except when the day occurs on a statutory holiday observed in the Province of Alberta.

"**Business Hours**" means the hours of 8:00 a.m. to 5:00 p.m., Mountain Time, during any Business Day.

"**Change**" means any change, modification or enhancement to the provision of the Services which requires an amendment to this Agreement.

"**Change Window**" means a predefined, regularly scheduled block of time set aside to implement hardware and software changes.

"**Claim**" means any and all claims, actions, damages, liabilities, losses, penalties, causes of action, suits, proceedings, judgments, demands of whatsoever nature, costs and expenses, including reasonable legal fees and disbursements.

"**Client Data**" means the data provided to ATCO I-Tek by Client or obtained by ATCO I-Tek acting on behalf of Client, and all data derived from such data.

"**Client Designated Manager**" has the meaning given in section 5.3.

"**Client Know-How**" has the meaning given in section 13.7.

"**Client Project Manager**" has the meaning given in section 5.5.

"**Client Systems**" means any Systems owned by Client or licensed to Client by third parties.

"**Commencement Date**" means the date, set by agreement of the parties in writing, on which the Services shall commence.

"**Computer Viruses**" has the meaning given in section 9.2(c).

"**Confidential Information**" has the meaning given in section 14.1.

"**Deliverable**" means a deliverable which arises from the Services and which ATCO I-Tek has agreed in writing to deliver to Client.

"**Disclosing Party**" has the meaning given in section 14.1.

"**Discretion**" means sole, absolute and unfettered discretion and, in each case where such term is used in conjunction with the provision of consent, also means that the person whose consent is required may unreasonably and arbitrarily withhold such consent.

"**Dispute**" means any dispute, controversy or claim arising out of or in connection with this Agreement or the breach, termination, validity or enforceability of any provision of this Agreement.

"**Documentation**" means any documentation, manuals or other guides provided by ATCO I-Tek to Client to support Client's use of the Services.

"**Effective Date**" means January 1, 2005.

"**Emergency Services**" means an unplanned change scheduled outside of the normal Change Window to correct or avoid a high severity outage, being a problem to which a "critical" priority code is attached in Schedule C.

"**Indemnified Persons**" means, with respect to a party, its Representatives, shareholders, directors, officers, consultants, suppliers, Affiliates and Associates.

"**Initial Term**" has the meaning given in section 15.1.

"**Interest**" means interest calculated at a rate equal to two percent (2%) per annum above the prime rate established from time to time by the main branch in Edmonton of the Bank of Montreal, calculated and payable monthly.

"**IP Rights**" means all intellectual property, industrial property and other proprietary rights, whether conferred by statute, common law, contract, equity or otherwise, including copyright, patent, integrated circuit topography, trade secret, trade-mark rights and comparable rights, and rights of ownership of applicable applications and registrations.

"**IT Plan**" has the meaning given in section 7.2.

"**Pre-paid Technology Expense**" means a one time cost that will be charged to Client for technology that belongs to ATCO I-Tek but is used by Client, including hand-held devices.

"**Recipient**" has the meaning given in section 14.1.

"**Representatives**" means employees, agents or contractors of a party, and shall include the Designated Manager, Statement of Work Manager and Project Manager of each party, and the Change Management Coordinator.

"**Schedule**" means each completed schedule that is attached to and forms part of this Agreement.

"**Service Level**" means, subject always to section 2.3, the minimum level of performance to be achieved for certain Services as set out in Schedule C.

"**Services**" means the services to be provided by ATCO I-Tek to Client as set out in this Agreement.

"**Specified Expense**" means service fees that are based on costs from third party service providers, that are incurred by ATCO I-Tek in delivering the Services, that are variable, and for which a constant monthly fee could not be established, including long distance usage expenses. The nature of each Specified Expense shall be set forth on a Schedule hereto.

"**System**" means hardware, firmware, middleware, computer software programs and supporting documentation, including interfaces, utilities, data, input and output formats, program listings, narrative descriptions and operating instructions, and all updates, enhancements or changes to the foregoing.

"**Tier 1 Services**" means operational services ("mouse pad to mainframe") described in Schedule B and any Statement of Work.

"**Tier 2 Services**" means new IT-related projects exceeding forty (40) man-days, including systems development and major enhancements, described in Schedule B and any Statement of Work.

"**Tier 3 Services**" means services related to corporate technology strategy, including investment services, business process improvement and technology advice, as described in Schedule B and any Statement of Work.

"**Time and Materials Rate**" means ATCO I-Tek's time and materials rate, as may be amended by ATCO I-Tek pursuant to this Agreement, including as part of the Annual Review of Schedules B and D.

"**Work Location**" means the location at which the Services are rendered.

"**Year 2000 Ready**" and "**Year 2000 Readiness**" means that all software, hardware and equipment, whether individually or as a system, containing date-recording or date sensitive electronic components and used, directly or indirectly, by a party hereto:

(a) is designed to be used and will, correctly and without human intervention, store, record, process, use, calculate, sequence and exchange data that references dates prior to, during and after the calendar year 2000 without error relating to date data, and will operate transparently to the user during such time periods without a difference in functionality or performance;

(b) is capable of operating without error relating to logical or mathematical operations, or both, carried out on date data that represents or references different centuries or more than one century;

(c) correctly recognizes the year 2000 as a leap year;

(d) does not use date fields as indicators, or for purposes other than to store valid dates;

(e) will not experience interruption, malfunction or failure as a result of any value of current date; and

(f) is designed such that the century in all data fields, date-related user interfaces and other interfaces is specified either explicitly or by unambiguous algorithms or inferencing rules (and that, in the latter case, the products or systems respond to two-digit year dates in a way that resolves the ambiguity as to the century in a disclosed, defined and pre-determined manner).

1.3 **Schedules**

This Agreement includes the following Schedules, which are included in and form part of this Agreement:

Schedule A – Service Level Agreement

Schedule B – Definition of Services

Schedule C – Service Measures

Schedule D – Pricing

Schedule E – Special Terms

Schedule F – Asset Transfer

Schedule G – Termination Transition Plan

Except where otherwise provided to the contrary herein, in the event of a conflict between the text of this Agreement and a Schedule, the text of this Agreement shall prevail.

## ARTICLE 2
## SERVICES

2.1 **Provision of Services**

ATCO I-Tek will provide to Client the services described in Schedule B, following:

- identification of the services required by Client;
- identification of the expenses related to such services;
- identification of the service levels and critical measures; and

- Client's receipt of a proposal from ATCO I-Tek setting forth what is achievable for Client, such proposal to include a breakdown of the transition costs as a separate line item.

Commencing on the Commencement Date, ATCO I-Tek agrees to provide to Client, and Client agrees to obtain from ATCO I-Tek, the Services, on the terms and conditions set forth herein. ATCO I-Tek and Client shall cooperate to achieve reasonable economy, efficiency and effectiveness in the provision of the Services. The Services, as further described in Schedule B, shall be set forth in Statements of Work pursuant to Article 4. Client agrees to source all Tier 1 Services exclusively from ATCO I-Tek.

Unless otherwise specified herein, Services (other than Emergency Services and Services provided during a Change Window) will be performed during Business Hours. All inclusions and exclusions for Tier 1 Services are outlined in Schedule B.

Any Tier 1 Services requested by Client to be performed outside Business Hours (other than Emergency Services and Services provided during a Change Window) shall be performed at a premium cost as outlined in section 8.4. For Tier 2 Services, where the approved Statement of Work does not specifically include in its scope the performance of services outside Business Hours, Services performed after Business Hours will be performed at the Discretion of ATCO I-Tek and at no extra cost.

## 2.2 **Project Management**

ATCO I-Tek is committed to industry standards in project management, including participating in appropriate industry certification programs (as determined by ATCO, in its Discretion), and to consulting with Client on an ongoing basis. ATCO I-Tek will, on Client's request, advise Client of the project management training and programs in which ATCO I-Tek's Representatives are participating, and will provide reasonable assistance to facilitate the participation of one or more of Client's Representatives in the same training and programs. Costs associated with Client's Representatives participating in training or programs will not be borne by ATCO I-Tek but will instead be borne by Client.

## 2.3 **Remote Provision of Services**

The Client's System must be connected to the grouping of computers that are inter-connected via a supported and protected network managed by ATCO I-Tek (the "ATCO Domain") in order for ATCO I-Tek to perform the Services in accordance with Schedule C. Services in respect of a Client's System connected to the ATCO Domain through the Internet, dial-up, VPN or other remote connectivity service will be performed at ATCO I-Tek depots or authorized agent locations, or otherwise on a reasonable commercial efforts basis negotiated between ATCO I-Tek and Client.

## 2.4 **Use of Other Suppliers**

ATCO I-Tek retains a "right of first proposal" on all new Tier 2 Services required by Client. All new Tier 2 Services required by Client shall commence with a Request, as

provided for in section 4.1. However, if within a reasonable time (as defined by ATCO I-Tek in its Discretion) following the making of a Request, Client and ATCO I-Tek have not agreed on a Statement of Work (i.e., Client has not received a proposal from ATCO I-Tek that is acceptable to Client), Client shall notify the Chief Information Officer of the ATCO Group of the Client's intent to obtain a quote for the Tier 2 Services which are the subject of the Request from another systems management service provider. In the event that Client selects a vendor other than ATCO I-Tek to perform such Tier 2 Services, Client shall pay ATCO I-Tek at the Time and Materials Rate for any services required from ATCO I-Tek to integrate such Tier 2 Services, or any Deliverables arising from such services, into the Tier 1 Services and any Tier 2 Services provided by ATCO I-Tek.

## 2.5 **System Changes**

ATCO I-Tek may make modifications to any System that is used to provide the Services as such modifications are required in order to conform the provision of the Services to industry or regulatory changes and to implement general enhancements to the Services. ATCO I-Tek shall initiate the modifications in accordance with the pre-defined change process as outlined in the Management Procedures Manual referred to in Schedule A.

## 2.6 **Client Support**

ATCO I-Tek's Customer Support Center will provide Client with 24 hour support as provided for in Schedule C.

## 2.7 **Other Services**

Any services other than the Services that are requested by Client and that ATCO I-Tek is willing to provide will, unless otherwise agreed in writing by Client and ATCO I-Tek, be provided at the Time and Materials Rate. Such other services shall, from the time that both parties agree in writing to the provision of such other services, thereafter be deemed to form part of the Services for the purposes of this Agreement.

## 2.8 **Regulatory Compliance**

In providing the Services, ATCO I-Tek agrees to comply with all applicable laws and regulations, to obtain and comply with any necessary regulatory approvals, and to obtain any necessary permits. The parties shall consult and cooperate with one another to ensure that the Services are provided in compliance with all applicable laws and regulations. In performing its obligations under this Agreement, ATCO I-Tek shall not be required to undertake any activity that would conflict with the requirements of any laws, regulations, judgments or orders.

Client agrees to, at its sole expense, comply with all applicable laws, obtain and comply with any necessary regulatory approvals, independently examine government regulations, and obtain any necessary permits applicable to ATCO I-Tek's provision, or Client's use, of the Services. The parties shall consult and cooperate with one another to ensure that the Services are provided in compliance with all applicable laws and regulations.

2.9 **Service Level Incentives**

The parties acknowledge that, where the parties have established Service Level incentives with respect to certain portions of the Services, and where holdbacks by Client are expressly provided for in Schedule C, Client may institute such holdbacks on the terms and conditions in connection therewith set forth in Schedule C. Such holdbacks, if any, shall constitute Client's exclusive remedy for any failure of ATCO I-Tek to achieve the relevant Service Level. Any Dispute in respect of such holdbacks shall be determined in accordance with the Dispute resolution process set out in Article 16.

2.10 **Changes in Services**

In the event that Client or ATCO I-Tek desires to make a Change to the Services or to the provisions of a Statement of Work, the following procedure will be followed:

(a) **Change Request** Subject to subsection (b) hereof, ATCO I-Tek, with the assistance of Client, shall, as soon as reasonably practical after receipt of a request for a Change (or development of a proposal for a Change, in the case of a Change proposed by ATCO I-Tek), develop and deliver to Client a response ("Change Response"):

(i) specifying how the proposed Change will be implemented;

(ii) describing the effect, if any, that such Change will have on the schedule for performance of the Services;

(iii) specifying the applicable acceptance testing and acceptance procedures to implement the Change, if any;

(iv) describing the changes to charges, if any, that would result from the implementation of such Change; and

(v) providing sufficient supporting documentation to justify any change in the schedule for performance or in the cost of executing such Change.

(b) **Additional Charges** Prior to preparing the Change Response, ATCO I-Tek will notify Client of any costs which must be incurred to prepare the Change Response (the "Estimated Cost"). In such event, Client may:

(i) withdraw the request for the Change; or

(ii) authorize ATCO I-Tek in writing to proceed to prepare the Change Response, in which event Client will be liable to ATCO I-Tek for reasonable costs which it must incur to prepare the Change Response, up to an amount not to exceed the Estimated Cost.

Upon receiving such authorization, ATCO I-Tek will make reasonable commercial efforts, in line with the size and scope of the request, to prepare the Change Response.

If the number of Change Responses that ATCO I-Tek is required to prepare in any month exceeds ATCO I-Tek's capacity to properly handle such work, ATCO I-Tek will give notice thereof to Client. In such event, the parties will meet promptly:

(i) to identify the requests for Change that may be deferred or withdrawn, and to prioritize the remaining requests for Change;

(ii) to discuss what additional costs ATCO I-Tek is required to incur to permit it to prepare the Change Responses, and to determine whether Client should compensate ATCO I-Tek for any of such additional costs; and

(iii) to assess whether any other mutually agreeable solution is available.

(c) **Change Response** Promptly after ATCO I-Tek delivers a Change Response to Client, both parties will meet to determine whether to proceed with the Change in accordance with the Change Response. All approved Change Responses shall be deemed part of the Statement of Work, where applicable, and shall be implemented by the applicable parties. If any approved Change Response requires an amendment of this Agreement, such amendment must be made prior to the Change in question being effected and in accordance with section 18.8.

(d) **Reasonable Requests** Each party shall consider in good faith any Change proposed by the other, and shall, subject to the procedure set forth elsewhere in this section 2.10, agree to reasonable requests therefor.

(e) **Cancellation or Rescheduling of Change Window by Client** If Client requests that ATCO I-Tek cancel or reschedule a Change Window, the following rules shall apply:

(i) if one or more of ATCO I-Tek's clients other than Client requests that the Change Window proceed as scheduled, a representative of ATCO I-Tek selected by it to mediate the conflict (the "Change Management Coordinator") shall mediate the conflict between the Client and the other ATCO I-Tek client or clients, failing which the Chief Information Officer of the ATCO Group will mediate the conflict;

(ii) ATCO I-Tek will assist Client in identifying the technical (but not the business or legal) risks associated with cancelling or rescheduling the Change Window;

(iii) if the Change Window is cancelled or rescheduled and ATCO I-Tek has already incurred out-of-pocket expenses with respect to the cancelled or

rescheduled Change Window, the Client will reimburse ATCO I-Tek the amount of such expenses forthwith upon receiving an invoice in respect of same; and

(iv) notwithstanding anything else to the contrary in this Agreement, ATCO I-Tek shall not in any event be responsible for any Claims related to the cancellation or rescheduling of the Change Window, nor shall Client seek recourse against any other member of the ATCO Group in respect thereof.

(f) **Conflict in Scheduling of Change Window** If one or more of ATCO I-Tek's clients other than Client requests that ATCO I-Tek cancel or reschedule a Change Window, the following rules shall apply:

(i) if Client requests that the Change Window proceed as scheduled, the Change Management Coordinator shall mediate the conflict between the Client and the other ATCO I-Tek client or clients, failing which the Chief Information Officer of the ATCO Group will mediate the conflict;

(ii) ATCO I-Tek will assist Client in identifying the technical (but not the business or legal) risks associated with cancelling or rescheduling the Change Window;

(iii) if the Change Window is cancelled or rescheduled and ATCO I-Tek has already incurred out-of-pocket expenses with respect to the cancelled or rescheduled Change Window, ATCO I-Tek will not look to Client for recovery of such expenses, but may, in its Discretion, look to the ATCO I-Tek client or clients who requested the cancellation or rescheduling of the Change Window; and

(iv) notwithstanding anything else to the contrary in this Agreement, ATCO I-Tek shall not in any event be responsible for any Claims related to the cancellation or rescheduling of the Change Window, nor shall Client seek recourse against any other client of ATCO I-Tek in respect thereof.

## ARTICLE 3
## INSURANCE

### 3.1 Insurance Obligations of ATCO I-Tek

ATCO I-Tek shall obtain and maintain throughout the duration of this Agreement and until all Services have been fully performed and completed, such insurance as a prudent supplier of systems management services in similar circumstances would maintain, based on factors including the availability of such insurance on commercially reasonable terms.

Such insurance shall include:

(a) commercial general liability insurance, written on an "occurrence" basis, including products and completed operations liability, contractual liability and personal injury, with a combined single limit of not less than Two Million Dollars ($2,000,000.00) for each occurrence involving bodily injury, death or property damage;

(b) crime and fidelity insurance in an amount not less than Two Million Dollars ($2,000,000.00) per occurrence and covering all of ATCO I-Tek's Representatives for theft and fraud, including computer fraud, which results in loss to Client;

(c) to the extent reasonably available, data processing errors and omissions coverage with a combined single limit of not less than Two Million Dollars ($2,000,000.00) per loss or claim;

(d) errors and omission insurance with a combined single limit of not less than Two Million Dollars ($2,000,000.00) per loss or claim, protecting ATCO I-Tek and its Representatives against their legal liability for loss or damages arising out of the rendering or failing to render the Services;

(e) property insurance for the full replacement value of any ATCO I-Tek property located at Client's premises and Client property in ATCO I-Tek's possession or control;

(f) employer's liability insurance covering each worker of ATCO I-Tek to the extent of not less than Two Million Dollars ($2,000,000.00) where such worker is not covered by Workers' Compensation or where Workers' Compensation coverage is not the worker's exclusive remedy; and

(g) automobile public liability insurance covering all vehicles used to provide the Services, whether owned, operated and/or leased by ATCO I-Tek or its Representatives, with a combined single limit of Two Million Dollars ($2,000,000.00) for each occurrence of bodily injury, death or property damage.

The foregoing represents ATCO I-Tek's global insurance obligations to all of its clients, including Client, and shall in no event be interpreted to mean that ATCO I-Tek must satisfy each of these obligations for each of its clients, including Client, severally.

3.2 **Insurance Obligations of Client**

Client shall, at its own expense, obtain such insurance as is required to protect ATCO I-Tek and all assets of ATCO I-Tek that are at any time and from time to time on the premises of the Client or the Work Location. Such insurance, which shall name ATCO I-Tek as an additional named insured, shall include:

(a) commercial general liability insurance, written on an "occurrence" basis, including products and completed operations liability, contractual liability

and personal injury, with a combined single limit of not less than Two Million Dollars ($2,000,000.00) for each occurrence involving bodily injury, death or property damage;

(b) crime and fidelity insurance in an amount not less than Two Million Dollars ($2,000,000.00) per occurrence covering all of Client's Representatives for theft and fraud, including computer fraud, which results in loss to ATCO I-Tek;

(c) property insurance for the full replacement value of any Client property located at ATCO I-Tek's premises and ATCO I-Tek property in Client's possession or control; and

(d) employer's liability insurance covering each worker of Client to the extent of not less than Two Million Dollars ($2,000,000.00) where such worker is not covered by Workers' Compensation or where Workers' Compensation coverage is not the worker's exclusive remedy.

The insurance required under this section 3.2 shall:

(a) name ATCO I-Tek as an additional insured;

(b) provide a waiver of subrogation in favour of ATCO I-Tek;

(c) require the insurer to provide ATCO I-Tek with no fewer than thirty (30) calendar days written notice prior to canceling or effecting a material change to the policies; and

(d) be maintained in effect during the term of this Agreement, provided that any policies written on a "claims made" basis shall be maintained for at least one (1) year following the expiry or termination of this Agreement, howsoever caused.

## ARTICLE 4
## STATEMENTS OF WORK AND APPROVAL OF DELIVERABLES

### 4.1 **Development of Statements of Work**

Client shall initiate a request for Services by submitting a request therefor (the "Request") to ATCO I-Tek. The Request will describe the specific services that are required, including whether the services are intended to be Tier 1 Services, Tier 2 Services or Tier 3 Services, and any other relevant information needed to develop a Statement of Work in respect thereof. Upon receipt of the Request, ATCO I-Tek, in consultation with, and with the reasonable assistance of, Client, shall promptly prepare a draft Statement of Work, which shall, as applicable:

(a) describe the Services to be performed by ATCO I-Tek and any services to be performed and items to be provided by Client;

(b) name the representative of each party who shall be its contact person for the development of the Statement of Work (in each case, the "Statement of Work Manager");

(c) specify the Work Location(s) where the Services will be performed;

(d) set forth the credentials and skills of ATCO I-Tek's Representatives who will perform the Requested Services;

(e) set forth the Commencement Date for the Services described in the Statement of Work and the period of time during which the Services will be provided thereunder;

(f) describe the Systems, equipment and Deliverables to be provided during and at the completion of the Services;

(g) include a schedule showing the estimated time frame for all stages of the Services;

(h) specify the costs of the Services and the schedule of payments to be made during and at the completion of the Services;

(i) describe the acceptance tests or means proposed for testing the Systems, equipment and Deliverables to be delivered during and at the completion of the Services; and

(j) specify such additional provisions as the parties agree.

4.2 **Requirement for Formal Execution**

No agreement shall be formed in respect of a Statement of Work until execution by both parties of such Statement of Work in accordance with the provisions of this Agreement. Either party may, at any time and without liability, withdraw from any negotiations related to any Request or draft Statement of Work.

4.3 **Approval of Deliverables**

To the extent that any Deliverable delivered to Client by ATCO I-Tek requires Client's approval under the terms of the relevant Statement of Work, Client will have five (5) Business Days (or such other period as the parties' respective Statement of Work Managers may agree in writing or as may be specified in the Statement of Work) (the "Review Period") after delivery thereof within which to approve or reject such Deliverable. If Client has a reasonable objection to any Deliverable, Client may reject the Deliverable. In such event, Client will deliver to ATCO I-Tek in writing within the Review Period the specific reasons for rejection and, where applicable, a single annotated

copy of the Deliverable identifying required changes. ATCO I-Tek shall make the appropriate changes and deliver the revised Deliverable. Client shall again be entitled to the Review Period to approve or reject the revised Deliverable. If Client does not expressly reject or approve a Deliverable or revised Deliverable, as the case may be, within the Review Period, the Deliverable in question shall be deemed approved.

Corrections to a Deliverable that is deficient because of ATCO I-Tek's omissions or errors or due to non-conformity with any applicable specifications provided to ATCO I-Tek as part of the applicable Statement of Work shall be made at the sole cost of ATCO I-Tek (unless the Deliverable is to be costed on a Time and Materials Rate basis). The cost of corrections to a Deliverable occasioned by changes made to the Statement of Work by Client or costs incurred as a result of delays caused by Client (and provided such delays are not caused by or contributed to by ATCO I-Tek) shall be the responsibility of Client. If Client requires additional time to review any Deliverable provided to it under this section for approval, ATCO I-Tek will cooperate with Client to extend the Review Period.

4.4 **Conflict**

In the event of any inconsistency between a Statement of Work and the text of this Agreement, the Statement of Work shall govern in respect of the specific work to be performed pursuant to such Statement of Work.

## ARTICLE 5
## PERSONNEL

5.1 **General**

(a) Client shall make available its personnel with such skills and expertise as may be necessary to coordinate and assist ATCO I-Tek in the provision of the Services.

(b) Subject to the balance of this section 5.1, ATCO I-Tek shall be entitled to utilize any ATCO I-Tek Representatives in the provision of the Services but, unless otherwise specified herein, shall remain responsible for the performance by such Representatives of, and shall bind any such Representatives to, the obligations of ATCO I-Tek hereunder.

(c) ATCO I-Tek shall provide such Representatives who or which possess sufficient skill, knowledge, and training to perform the Services. The working hours and schedules of such Representatives shall be consistent with the local practice of the Work Location (as disclosed by Client to ATCO I-Tek prior to the commencement of the Services) and with applicable ATCO I-Tek employment policies and regulations, including those regarding sickness, disability, leaves of absence, holidays, vacations, seminars and off-site meetings ("Policies"). ATCO I-Tek shall disclose all applicable ATCO I-Tek Policies to Client prior to the commencement of the

Services. Following commencement of the Services, if ATCO I-Tek advises Client of other applicable Policies, or of any changes to Policies previously disclosed to Client, and such Policies or changes thereto would impact the schedule for the performance of the Services, then ATCO I-Tek shall provide additional resources as necessary to compensate. If such other or revised Policies will result in an increase in ATCO I-Tek's cost of performing its obligations under this Agreement, or would result in increased costs or expenses to Client, ATCO I-Tek shall be responsible for absorbing such additional costs.

(d) For further certainty, unless otherwise specifically agreed to in writing by ATCO I-Tek, ATCO I-Tek's Representatives shall work during Business Hours, and any Services required to be performed outside Business Hours shall be performed at an incremental cost as provided for in section 8.4.

5.2 **ATCO I-Tek Designated Manager**

ATCO I-Tek will designate a representative of ATCO I-Tek (the "ATCO I-Tek Designated Manager") who will act as Client's primary point of contact and coordinate ATCO I-Tek's provision of the Services. ATCO I-Tek's Designated Manager shall serve as the ATCO I-Tek contact person for Client. ATCO I-Tek shall ensure that its Designated Manager is available for consultation with Client during Business Hours.

5.3 **Client Designated Manager**

Client will designate a representative of Client (the "Client Designated Manager") who will act as ATCO I-Tek's primary point of contact and coordinate ATCO I-Tek's provision of the Services. The Client Designated Manager shall be responsible for directing, insofar as ATCO I-Tek is concerned, all activities of Client affecting the provision by ATCO I-Tek of the Services.

5.4 **ATCO I-Tek Project Manager**

ATCO I-Tek will designate, with respect to each Statement of Work, a representative of ATCO I-Tek (the "ATCO I-Tek Project Manager") who will act as Client's primary point of contact in dealing with ATCO I-Tek with respect to that particular Statement of Work. The ATCO I-Tek Project Manager for any Statement of Work may be the same person as the ATCO I-Tek Designated Manager, its Designated Representative and/or its Statement of Work Manager.

5.5 **Client Project Manager**

Client will designate, with respect to each Statement of Work, a representative of Client (the "Client Project Manager") who will act as ATCO I-Tek's primary point of contact in dealing with Client with respect to that particular Statement of Work. The Client Project Manager shall be responsible for directing, insofar as ATCO I-Tek is concerned, all activities of Client affecting the provision by ATCO I-Tek of the Services pursuant to such Statement of Work. The Client Project Manager for any Statement of Work may be

the same person as the Client Designated Manager, its Designated Representative and/or its Statement of Work Manager.

5.6 **Selection of Representatives**

Each party shall have the right to designate its representatives who will act on its (the "Designating Party's") behalf under the terms and conditions set forth herein (the "Designated Representatives"), and to remove such Designated Representatives from time to time. Each party (the "Other Party") reserves the right to not accept one or more of the Designating Party's Designated Representatives during the selection process, and shall have the right to require the Designating Party to remove a Designated Representative from the Other Party's premises, including the Work Location, if such Designated Representative is not performing his responsibilities in a competent manner and such performance adversely affects the Designating Party's performance of its obligations hereunder. Before removing one of its Designated Representatives, the Designating Party shall provide the Other Party with as much prior notice as practical, the Other Party acknowledging that prior notice may not be possible when a Designated Representative chooses to leave the employ of the Designating Party or where a Designated Representative is terminated by the Designating Party. If a Designated Representative is removed, the Designating Party shall take all reasonable steps to ensure a smooth transition, with the least disruption to the Services and cost to the Other Party reasonably possible in the circumstances.

5.7 **Replacement Representatives**

In circumstances where the provision by ATCO I-Tek of the services of an ATCO I-Tek Representative is charged to Client on an hourly basis or at the Time and Materials Rate, and ATCO I-Tek wishes to remove such ATCO I-Tek Representative from the performance of Services, ATCO I-Tek shall provide a replacement ATCO I-Tek Representative of suitable skill, knowledge, and training. Client will not be charged for any time or costs required to effect a transition to a temporary or permanent replacement, including time spent by the replacement ATCO I-Tek Representative to acquire knowledge of any Systems being maintained or services previously being provided by the replaced ATCO I-Tek Representative. If an ATCO I-Tek Representative is removed, ATCO I-Tek shall use reasonable commercial efforts to ensure that there is the least disruption reasonably possible in the circumstances to the services previously being provided by the replaced ATCO I-Tek Representative.

5.8 **Cooperation in Replacement of ATCO I-Tek Representatives**

Client shall cooperate with ATCO I-Tek in making replacements and substitutions of ATCO I-Tek's Representatives, as provided in section 5.7, in an orderly fashion.

5.9 **Compliance With Policies**

Each party (the "Accessing Party") shall require all of its Representatives, when performing Services or otherwise attending at the premises of the other party (the "Granting Party"), to comply with such other party's applicable and lawful policies and

regulations of which the Accessing Party is made aware, including those relating to security. The Granting Party shall disclose all its relevant policies and regulations prior to access being granted to the Accessing Party and its Representatives and, if applicable, prior to the parties reaching agreement on the costing of particular Services. If a Representative of the Accessing Party violates a material policy or regulation of the Granting Party (as determined by the Granting Party, acting reasonably) or if a Representative of the Accessing Party repeatedly violates one of the Granting Party's non-material policies or regulations of which the Accessing Party or such Representative is made aware, the Granting Party may reject the Accessing Party's Representative for cause stated in writing to the Accessing Party, in which event the Accessing Party shall endeavour to replace the Representative in accordance with section 5.9 below. If, following commencement of the relevant Services or access to the Granting Party's premises, as the case may be, the Granting Party advises the Accessing Party of other policies or regulations, or of any changes to policies and regulations previously disclosed to the Accessing Party, and such policies or regulations or changes thereto would impact the schedule for the performance of the Accessing Party's obligations under this Agreement or would result in an increase in the Accessing Party's cost of performing its obligations under this Agreement, the provisions of section 2.10 shall apply. Any conflict between the policies of the Accessing Party and those of the Granting Party shall be resolved using the dispute resolution procedure set forth in Article 16. Client shall ensure that its Designated Manager is available for consultation during Business Hours and that he has authority to make decisions and commitments on the part of Client.

5.10 **Reliance**

Each party shall have the right to rely upon the instructions and decisions received from the other party's Designated Manager or Project Manager, as the case may be, with respect to all matters relating to this Agreement or any Statement of Work, as applicable.

## ARTICLE 6
## CLIENT RESPONSIBILITIES

6.1 **General**

Client shall provide such cooperation, information and assistance as described in this Agreement or as may be reasonably requested by ATCO I-Tek to enable ATCO I-Tek to provide the Services. Client shall also be responsible for, on an ongoing basis during the term of this Agreement:

(a) providing ATCO I-Tek with written feedback and/or commentary on the provision of the Services, including areas of concern to Client,

(b) providing management direction and decisions,

(c) making available for reference and use by ATCO I-Tek all required data, documentation, materials, systems and information,

(d) describing the specific Deliverables, and

(e) achieving the specific results or objectives,

all as specified or contemplated to be provided, made available, described or achieved by Client under this Agreement or as otherwise agreed on by the parties, to enable ATCO I-Tek to provide the Services.

6.2 **Workspace in Client Work Location**

In connection with any Services to be performed by ATCO I-Tek at a Work Location owned or controlled by Client (including Tier 2 Services, Tier 3 Services and any support or maintenance services), Client shall provide reasonable working space to ATCO I-Tek's Representatives, which working space shall include working space for any ATCO I-Tek equipment required to be installed at a Work Location in order to provide the Services, telecommunications access, computer equipment, office equipment, and an adequate environment for same. The working environment provided by Client shall be safe and comply with all applicable laws and regulations.

6.3 **Client Data**

Client agrees to provide all necessary Client Data in a format as described in this Agreement (or as agreed to by the parties in writing) and to take reasonable steps to ensure the accuracy, legibility and completeness of all Client Data. Client shall be responsible to ATCO I-Tek for charges associated with any additional services that ATCO I-Tek must provide to Client as a result of Client's failure to provide accurate Client Data in the format or at the times agreed to by the parties, or for any other errors or deficiencies in the Client Data.

6.4 **Third Party Software, Equipment and Telecommunications Facilities**

Client acknowledges that it may be required to license or obtain, at its own expense, certain third party software, equipment and/or telecommunication services, as expressly described in or implied by this Agreement or as Client may be notified by ATCO I-Tek from time to time, in order to receive certain of the Services, including wide area network facilities, routers and system monitoring software.

6.5 **ATCO I-Tek Systems**

Client shall be responsible for maintaining the confidentiality and use of user identifiers and passwords provided by ATCO I-Tek for the purpose of accessing ATCO I-Tek Systems. Client shall take commercially reasonable steps to prevent Client's Representatives from interfering with, damaging or engaging in unauthorized use of ATCO I-Tek Systems.

6.6 **Consents**

Client shall be responsible for obtaining, at its sole expense, all necessary consents (whether required at the Commencement Date or at a future date) required to transfer any System, or part thereof, to ATCO I-Tek, or permit ATCO I-Tek and its Representatives to use or access any Systems, or part thereof, owned by or licensed to Client, which use or access is required in order to provide the Services, provided that ATCO I-Tek shall be entitled, upon request, to participate in applying for and reviewing such consents.

6.7 **Year 2000**

Client will remain responsible and liable for the Year 2000 Readiness of all Client Systems and all Systems transferred to ATCO I-Tek pursuant to Schedule F or any asset transfer agreement which relates to this Agreement.

6.8 **Workload Planning**

Client acknowledges that it will be required to provide workload planning information as input to the development of each Annual Review (as hereinafter defined). Client will prioritize workload requirements such that hours allocated are used to meet appropriate business requirements. ATCO I-Tek will provide the personnel to deliver a block of Development/Maintenance/Enhancement ("D/M/E") hours per year, balanced across the year. These D/M/E hours will have an average billable rate as set out in Schedule D. Usage in excess of this block of hours will be billed at the Time and Materials Rate.

## ARTICLE 7
## REVIEWS

7.1 **Periodic Reviews of Statements of Work**

Upon the request of, and with a frequency reasonably directed by Client, ATCO I-Tek's Designated Manager shall make a presentation to Client's Designated Manager on the status of all Statements of Work then under way by ATCO I-Tek.

7.2 **Annual Planning Reviews**

Annually, ATCO I-Tek shall provide Client with recommendations for changes to service measures, pricing and/or Services ("Annual Review"). ATCO I-Tek will work with Client to complete each Annual Review during the planning cycle (third quarter) of Client's fiscal year. As part of each Annual Review:

(a) ATCO I-Tek shall provide Client with:

(i) a report of the Services performed during the twelve (12) month period immediately preceding the last completed month of the Services;

(ii) a list of standards and processes for the evaluation and selection of Systems required to be used in providing Services, and of the provision of Services; and

(iii) a description of the project management methodology used during the twelve (12) month period immediately preceding the last completed month of the Services; and

(b) Client shall provide ATCO I-Tek with:

(i) a summary of any potential Statements of Work expected during the twelve (12) month period commencing from the next anniversary of the Effective Date; and

(ii) feedback and commentary on the project methodology used by ATCO I-Tek, as described by it.

After the exchange of such information, ATCO I-Tek and Client shall meet to assess the Services provided during the twelve (12) month period immediately preceding the last completed month of the Services, to revise Schedule B as necessary and to jointly develop a mutually agreeable information technology plan for the twelve (12) month period commencing on the next anniversary of the Effective Date, which plan (the "IT Plan") will include an operational component and a longer-term strategy component.

7.3 **Price Reviews**

(a) A review of the charges for the Services may be conducted by a third party on behalf of the ATCO Group no more than once each year. The process will consist of:

(i) a review of the volumes of each service element being consumed,

(ii) a review of the service levels being delivered,

(iii) a review of Schedule D,

(iv) a review of the terms and conditions of the arrangement, and

(v) a determination of the market competitiveness proposed in Schedule D; and

(vi) the development of Benchmarks.

Client is responsible for the costs of the third party or parties retained during such review process, and will ensure that the results of the review are provided to ATCO I-Tek promptly following completion of the review.

(b) If ATCO I-Tek's total charges are within 2% of the Benchmark price, no pricing action need be undertaken by ATCO I-Tek.

(c) If ATCO I-Tek's total charges are greater than the Benchmark by 2% or more, ATCO I-Tek must investigate and report to the ATCO Group on the reasons for the difference, and provide action plans to address the difference. If the ATCO Group agrees with ATCO I-Tek's investigation and action plan, no further action is required other than the implementation of the action plan by ATCO I-Tek. However, if the ATCO Group does not agree with ATCO I-Tek, ATCO Group may undertake its own investigation and propose suggested changes. If ATCO I-Tek agrees with the ATCO Group's proposal and agrees to implement it, then the price review process is complete. However, if ATCO I-Tek disagrees with ATCO Group's proposal, the issue will be resolved pursuant to Article 16.

## ARTICLE 8
## CHARGES AND PAYMENTS

8.1 **Financial Responsibility**

Client shall have financial responsibility for all costs and expenses related to each item which is to be provided by Client under this Agreement or for which financial responsibility is not expressly allocated to ATCO I-Tek under this Agreement. If requested by ATCO I-Tek, Client shall provide ATCO I-Tek with a deposit or other form of advance payment in respect of such costs and expenses. ATCO I-Tek shall have financial responsibility for all costs and expenses related to each item which is to be provided by ATCO I-Tek under this Agreement and for which financial responsibility is not expressly allocated to Client under this Agreement.

8.2 **Charges**

In consideration of the provision by ATCO I-Tek to Client of the Services, Client shall pay to ATCO I-Tek the charges set forth in Schedule D and/or in any applicable Statement of Work. Client shall also pay all of ATCO I-Tek's charges with respect to any services other than the Services, including those referred to in section 2.7.

8.3 **Price Increases**

(a) ATCO I-Tek may increase the charges for Tier 1 Services and/or Tier 2 Services, and/or the Time and Materials Rate on each anniversary of the Commencement Date. Increases to charges other than labour charges will be based on the Consumer Price Index for Alberta based on the previous twelve (12) month average, calculated on a monthly basis, and increases to labour charges will in no event exceed the Wynford Group Survey for Alberta, provided that, if either the Consumer Price Index for Alberta or the Wynford Group Survey for Alberta should no longer be published or should be substantially changed in content or format after the date of this

Agreement, ATCO I-Tek and Client will substitute another comparable measure published by a mutually agreeable source.

(b) ATCO I-Tek may delay implementing any increase up to four (4) months pending completion of the Annual Review, provided that any increase implemented after completion of the Annual Review shall be retroactive to the last anniversary of the Effective Date. Any increase otherwise permitted under this provision which is not implemented by ATCO I-Tek in any year may be carried forward (and added to any increase otherwise permitted during) any subsequent year.

(c) The unit prices set out in Schedule D are based on a forecast provided by the Client (the "Initial Forecast") of estimated usage of the Services by Client for the Initial Term (as hereinafter defined). The Initial Forecast is attached to Schedule D. During the last Annual Review of the Initial Term and each Renewal Term (as hereinafter defined), Client shall advise ATCO I-Tek of Client's expected usage of the Services in the forthcoming five (5) year period (the "Updated Forecast"). If the Updated Forecast is not within ten percent (10%) of the Initial Forecast or previous Updated Forecast, as the case may be, ATCO I-Tek may adjust the unit price to Client to compensate for changes in projected usage. During any annual period, increases or decreases resulting from Client's actual usage will be reflected in ATCO I-Tek's monthly billing, subject to the bandwidth described in Schedule D for each category. No increases made under the provisions of this subsection (c) shall be subject to the restrictions on increases set forth in subsection (a).

8.4 **Premium**

Notwithstanding anything else herein to the contrary, ATCO I-Tek shall be entitled to charge a premium of twenty-five (25%) percent above its then-current labour rates for work performed outside Business Hours at the request of Client.

8.5 **Expenses**

Client will reimburse ATCO I-Tek for reasonable out-of-pocket expenses incurred by ATCO I-Tek in connection with its performance under this Agreement (including travel and travel-related expenses) at the request and with the prior approval of Client.

8.6 **Specified Expenses**

Client shall be responsible for payment of all charges described as a "Specified Expense" on any Schedule. Any Specified Expenses paid in advance by ATCO I-Tek for the benefit of and reimbursement by Client may be subject to an administration fee where support or administrative services have been expended.

8.7 **Additional Expenses**

If Client fails, or its Representatives fail, to comply with any of its or their obligations hereunder, and such failure is not due to a failure of ATCO I-Tek or ATCO I-Tek's Representatives, then:

(a) if such failure of Client or its Representatives can be reasonably expected to result in ATCO I-Tek being unable to perform its obligations in accordance with this Agreement, ATCO I-Tek shall be released from responsibility for such inability to perform for the period and to the extent that is justified by Client's or Client's Representatives' failure; and

(b) if such failure can be reasonably expected to result in ATCO I-Tek incurring additional expenses, Client shall compensate ATCO I-Tek to the extent of such expenses, provided such expenses are reasonable in the circumstances. Such expenses shall be added to any invoices issued by ATCO I-Tek to Client hereunder.

If, through ATCO I-Tek's negligence, it fails to comply with any of its obligations, and such failure is not due to a failure of Client or Client's Representatives, and if such failure can be reasonably expected to result in a delay or interruption of the Services and in Client incurring additional expenses, ATCO I-Tek shall compensate Client to the extent of such expenses, provided such expenses are reasonable in the circumstances. Client shall invoice ATCO I-Tek the amount of such expenses, which invoice shall be due and payable upon receipt, provided that if ATCO I-Tek, acting reasonably, disputes any portion of such invoice, it shall pay Client only the undisputed portion thereof and may withhold the balance following resolution of the Dispute in accordance with Article 16.

8.8 **Taxes**

Client shall pay all taxes (including sales, use, consumption, value added, goods and services and similar taxes), duties, rates and levies of any nature whatsoever arising out of or in respect of this Agreement or the Services, excluding taxes on ATCO I-Tek's net income, any gains on capital of ATCO I-Tek, and payroll taxes/deductions in respect of ATCO I-Tek's Representatives. Where ATCO I-Tek pays such taxes, duties, rates or levies, or is obligated to collect the same, the same shall be added to any invoices issued by ATCO I-Tek hereunder.

8.9 **Credit for Use of Client Assets**

In the event ATCO I-Tek provides Client with Tier 1 Services using assets owned by Client but not transferred to ATCO I-Tek pursuant to Schedule F, ATCO I-Tek shall issue Client a credit in respect of the expenses incurred by Client as a result of ATCO I-Tek's use of such assets. Such credit will be based on the cost that ATCO I-Tek would have incurred to effect the transfer of ownership of such assets on the Commencement Date at fair market value, including ATCO I-Tek's cost of capital and depreciation, but excluding depreciation, financing and/or tax methods used by Client, and will be applied against the fees for the services in a manner agreed to by the parties.

8.10 **Payment for Services**

All charges for Services performed by ATCO I-Tek which are to be paid on a periodic or recurring basis, as identified in any Schedule, shall be payable by Client monthly in arrears. Charges will be calculated on a calendar month basis and will be prorated for any partial month. Unless otherwise agreed to by the parties in writing, all charges for any other Services (including Tier 2 Services where a payment schedule is not set out in the applicable Statement of Work) and for expenses incurred pursuant to sections 8.5 or 8.6 shall be invoiced by ATCO I-Tek following the end of the month in which such Services are performed or expenses incurred.

8.11 **Invoices**

(a) Except where provided otherwise herein, ATCO I-Tek shall invoice Client monthly. Invoices shall be prepared and sent by ATCO I-Tek to Client by the seventh (7th) Business Day following the month in which the Services are provided or charges were otherwise incurred. All invoices shall be accompanied by supporting information and documentation and are due and payable upon receipt.

(b) If Client fails to pay any charges within thirty (30) days of the date of the relevant invoice, then ATCO I-Tek shall have the option to:

(i) charge Interest on such unpaid charges from the date that is thirty (30) days following the date of the invoice until the date that payment is received by ATCO I-Tek; and

(ii) charge Client for ATCO I-Tek's costs of collecting all past due amounts, including reasonable legal fees and disbursements on a solicitor and own client basis.

(c) Invoices shall be forwarded to the address and person identified in the relevant Schedule or Statement of Work.

(d) In the event that Client, acting reasonably, disputes any portion of an invoice, it shall pay ATCO I-Tek all amounts not in dispute and may withhold the amount in dispute pending resolution of the Dispute in accordance with Article 16. If Client is ultimately found liable for payment of the disputed amount, Client shall pay the disputed amount together with Interest on the disputed amount from the date the amount would have otherwise been subject to payment of Interest to the date on which payment is received by ATCO I-Tek.

(e) ATCO I-Tek will work with Client to design the form of invoice and specify the required supporting information relating to the Services and applicable charges so that Client will have sufficient detail about the charges to enable it to charge its clients for their share of the charges, if any.

## ARTICLE 9
## REPRESENTATIONS, WARRANTIES AND COVENANTS

### 9.1 **Mutual Representations, Warranties and Covenants**

Each party represents, warrants and covenants to the other that:

(a) it is a corporation duly incorporated or organized, validly existing and in good standing under the laws of its place of incorporation or registration, is properly qualified where qualification is necessary for the conduct of its business, and has adequate corporate or other power to enter into and perform this Agreement;

(b) this Agreement has been duly executed and delivered by such party and (assuming the due authorization, execution and delivery hereof by the other party) is a valid and binding obligation of such party, enforceable against it in accordance with its terms;

(c) the execution and delivery of this Agreement and the performance by such party of its obligations set forth in this Agreement are not limited or restricted by, nor do they conflict with, or violate, any law, regulation, decree, judgment, contract or other instrument to which such party is a party or by which it is bound, nor do they or will they infringe or violate the rights of any third party;

(d) it is free, as of the date hereof, of any material contractual or statutory rights or obligations in favour of any third party that would prevent or impair it from entering into and fulfilling its obligations under this Agreement and, further, is unaware of any facts that would prevent it from performing its obligations under this Agreement; and

(e) it is not a non-resident of Canada for purposes of the *Income Tax Act* (Canada), and will provide prior written notice to the other party of any change in its status in such regard;

(f) the obligations of it (the "IP Indemnitor") under this Agreement and

(i) in the case of ATCO I-Tek, the provision of the Services and any Deliverables (excluding any third party components), and

(ii) in the case of Client, any Systems, data, software, material or other content provided to ATCO I-Tek for use in providing the Services or any Deliverables,

shall be free of any claim of any third party for infringement of any IP Rights.

9.2 **Representations, Warranties and Covenants of ATCO I-Tek**

ATCO I-Tek represents, warrants and covenants that:

(a) the Services will be performed in a conscientious, diligent and efficient manner by competent personnel, and will be carried out in accordance with standards of care practiced by leading national and international suppliers of services that are the same or comparable to the Services;

(b) all electrical equipment installed by ATCO I-Tek at Client's premises shall be approved by the Canadian Standards Association or by the applicable provincial electrical authority;

(c) it shall take all reasonable steps and utilize reasonable commercial means and practices, in keeping with current available technology and, as set out in Schedule B, to detect and, if practical, eliminate any routines, programs or devices, including those commonly referred to as computer viruses, worms and Trojan horses ("Computer Viruses"), in ATCO I-Tek Systems or in any electronic data introduced into Client Systems, or which could otherwise interfere with the performance of the Services; and

(d) it shall use reasonable commercial efforts to ensure that ATCO I-Tek Systems, excluding any Systems transferred from Client to ATCO I-Tek under this Agreement or any asset transfer agreement which relates to this Agreement, when used in accordance with its associated documentation, are date compliant provided that all Systems used with ATCO I-Tek's Systems are date compliant and properly exchange accurate date data with it.

9.3 **Representations, Warranties and Covenants of Client**

Client represents, warrants and covenants that:

(a) it shall take all reasonable steps and utilize reasonable commercial means and practices, in keeping with current available technology, to detect and, if practical, eliminate any Computer Viruses in Client Systems, in any electronic data introduced into ATCO I-Tek Systems, or which could otherwise interfere in the performance of the Services;

(b) it shall communicate to ATCO I-Tek as soon as practical after the execution of this Agreement the date compliance of, any date compliant problems with, and any other defects, deficiencies or faults known to Client in, all Client Systems and any Systems transferred from Client to ATCO I-Tek under this Agreement or any asset transfer agreement which relates to this Agreement; and

(c) it has the right to deliver the Client Data to ATCO I-Tek and to permit ATCO I-Tek to use the Client Data and the Client Systems as contemplated herein.

9.4 **Limited Warranties**

THE WARRANTIES PROVIDED IN THIS AGREEMENT ARE EXCLUSIVE AND ARE IN LIEU OF ANY OTHER UNDERSTANDINGS, REPRESENTATIONS, WARRANTIES, COVENANTS, CONDITIONS, PROMISES, GUARANTEES OR AGREEMENTS, WHETHER EXPRESS, IMPLIED, STATUTORY OR OTHERWISE, AND WHETHER ARISING FROM A COURSE OF DEALING OR USAGE OF TRADE, RELATING TO THE SERVICES OR ANY DELIVERABLES, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR FITNESS OR ADEQUACY FOR ANY PARTICULAR PURPOSE OR USE, OR OF QUALITY, PRODUCTIVENESS, CAPACITY OR ACCURACY.

## ARTICLE 10
## INDEMNITIES

10.1 **Cross Indemnity**

Each of ATCO I-Tek and Client (the "Indemnitor") agrees to indemnify, defend and hold harmless the other, including its Indemnified Persons (the "Indemnitee"), from any and all Claims arising out of the negligence or willful act or omission of the Indemnitor resulting in injuries, including the death or bodily injury of any Representative, client, business invitee or business visitor of the Indemnitee, or loss or destruction of any real or tangible personal property of the Indemnitee, or arising out of such party's failure or the failure of its Representatives to comply with the law, including any additional costs for Services that must be re-performed as a result, provided, however, that this indemnity will not apply unless the Indemnitee notifies the Indemnitor promptly of any matters in respect of which the foregoing indemnity may apply and of which the Indemnitee has knowledge, and gives the Indemnitor full opportunity to control the response thereto and the defense thereof, including any agreement relating to the settlement thereof.

10.2 **Client's Indemnity**

Without restricting the generality of section 10.1, Client specifically agrees to indemnify, defend and hold harmless ATCO I-Tek and its Indemnified Persons from any and all Claims arising in connection with the loss or theft of, or damage to, any of ATCO I-Tek's equipment, including all charges incurred by ATCO I-Tek in respect of financing and carrying costs, as well as from any and all Claims of whatsoever nature caused by or arising out of Client's failure to obtain the consents contemplated by section 6.6 and the permits contemplated by section 2.8.

10.3 **Intellectual Property Indemnity**

The IP Indemnitor shall, if notified promptly in writing, and given authority, information and assistance, by the other party, defend, indemnify and hold harmless the other party (including any Indemnified Persons) (the "IP Indemnitee") from any Claim against the IP Indemnitee based on a claimed infringement that constitutes a breach of the warranty in Section 9.1(f). The IP Indemnitee shall promptly notify the IP Indemnitor of any such

Claim, and the IP Indemnitor shall be given the opportunity to lead the defense or settlement of such Claim upon it acknowledging in writing ("Acknowledgment") to the IP Indemnitee that the IP Indemnitor is obligated to indemnify the IP Indemnitee. If the IP Indemnitor does not provide an Acknowledgement to the IP Indemnitee within fifteen (15) days of receiving notice of the Claim from the IP Indemnitee, the IP Indemnitee may carry on the defence of such claim, and the IP Indemnitor shall thereafter be entitled only to participate in the defense or settlement of such Claim.

10.4 **Settlement of Claims**

Neither party shall settle any Claims that are subject to the indemnification provisions hereunder without the prior written consent of the other party, which consent may not be unreasonably withheld, conditioned or delayed.

## ARTICLE 11
## REMEDIES AND LIMITATIONS

11.1 **Accuracy and Reliability**

ATCO I-Tek shall make reasonable efforts to ensure the consistency, timeliness, accuracy and reliability of the Services and the Deliverables. However, Client acknowledges that ATCO I-Tek will not be held liable for any Claims of whatsoever nature arising out of any fault, interruption, or delay in providing, or inaccuracy or unreliability in, the Services or the Deliverables, except as

(a) provided in section 2.9,

(b) result from any inaccuracies, errors or omissions in the information provided by ATCO I-Tek to Client in connection with the Services,

(c) provided for in section 11.2, or

(d) are due to ATCO I-Tek's willful misconduct.

11.2 **Exclusive Remedy**

The express warranties provided in section 9.2 are given in lieu of all obligations or liabilities on the part of ATCO I-Tek for losses or damages arising out of or in connection with this Agreement or the provision of the Services. Client's exclusive remedy, and ATCO I-Tek's entire liability, for a breach of any such representation, warranty or covenant shall be that, to the extent practicable, ATCO I-Tek shall re-perform the Services which were not provided in conformance with the standards set forth in section 9.2, failing which ATCO I-Tek shall apply, against one or more of the invoices subsequently issued by ATCO I-Tek to Client, a service credit in respect of the portion of such Services which failed to conform to such representation, warranty or covenant.

11.3 **Limits on Liability; No Consequential Damages**

Notwithstanding any other provision of this Agreement to the contrary:

(a) ATCO I-Tek's liability to Client for all Claims, whether based in contract (including fundamental breach), warranty or tort (including negligence), or otherwise arising out of or relating to this Agreement shall not in the aggregate exceed the total charges paid by Client to ATCO I-Tek under this Agreement (excluding Specified Expenses, pursuant to section 8.6, and taxes, pursuant to section 8.8) for the Services performed during the three (3) month period preceding the event giving rise to the first Claim, regardless of the number of Claims; and

(b) neither party shall in any event be liable to the other party for any indirect, incidental, consequential or punitive damages arising out of or in connection with the delivery, use, performance or failure of the Services or any Deliverables or Systems, or any breach of this Agreement (including fundamental breach), or the negligence of that party or its Indemnified Persons, even if advised of the possibility of such damages.

11.4 **Exclusions from Limits on Liability**

The limitations contained in this Article 11 shall not apply to any:

(a) unauthorized disclosure of Confidential Information by either party;

(b) breach of warranty relating to intellectual property;

(c) breach by ATCO I-Tek or Client of an indemnity or other requirement to indemnify Client or ATCO I-Tek, respectively, for intellectual property infringement;

(d) claims for personal injury or death or damage to real or tangible personal property to the extent caused by the negligence of the non-claiming party; and

(e) claims that are recoverable under insurance by the non-claiming party.

11.5 **No Claim Against Certain Third Parties**

Client agrees that it will not Claim against any other client of ATCO I-Tek that has signed a counterpart of this Agreement for losses suffered by Client in connection with this Agreement.

11.6 **Allocation of Risk**

The provisions of this Article 11 allocate the risk under this Agreement between Client and ATCO I-Tek. ATCO I-Tek's pricing reflects this allocation of risk and the limitation of liability specified herein.

## ARTICLE 12
## RECORDS, AUDITS AND SECURITY

12.1 **Maintenance and Inspection of Records**

ATCO I-Tek will maintain, in accordance with generally accepted accounting principles, all records and documents relating to the Services as are reasonably necessary to enable Client to verify that Services are being performed in accordance with this Agreement and all applicable laws and regulations. ATCO I-Tek shall also maintain proper time sheets, accounts, records and invoices relating to all Services provided on a time and materials basis, and all expenses incurred by ATCO I-Tek for which Client is required to reimburse ATCO I-Tek. The foregoing records and documents shall be available, upon reasonable notice, for review and inspection by authorized representatives of Client during the term of this Agreement and for a minimum of (2) years following termination, or such time period as may be required pursuant to any applicable laws or regulatory requirements or under the terms of any contract to which Client is subject, as ATCO I-Tek is notified from time to time by Client.

12.2 **Access to ATCO I-Tek Facilities**

(a) ATCO I-Tek will cooperate with and assist Client, including providing Client and its auditors with escorted access to ATCO I-Tek's facilities (including any Work Location within the control of ATCO I-Tek where Client Data is processed or stored) and the records and documents described in section 12.1, in accordance with its security procedures, to enable Client and its auditors to conduct appropriate inspections and audits of ATCO I-Tek's operations and processes, including as required by law, to the extent necessary to verify:

(i) the accuracy of the charges and any reimbursable expenses;

(ii) that the security procedures and standards of care being practiced by ATCO I-Tek are consistent with its obligations under this Agreement;

(iii) that the Services are being provided in accordance with this Agreement; and

(iv) that the reporting of Service Levels complies with Schedule C.

Such escorted access will be available upon fifteen (15) Business Days' notice to ATCO I-Tek and at reasonable hours (as determined by ATCO I-Tek, in its Discretion),

provided any such access does not unduly interfere with ATCO I-Tek's ability to perform the Services or provide services to other clients. ATCO I-Tek shall also provide Client and its auditors with escorted access to ATCO I-Tek's computing facilities, Work Locations, and any other location where Client Data is processed or stored, as may be required by any regulatory authority, provided that Client shall use best efforts to ensure that ATCO I-Tek is given reasonable notice of any requirement for access, and further provided that any person seeking such access complies with ATCO I-Tek's security procedures. ATCO I-Tek shall provide such additional assistance as may be reasonably required in connection with the foregoing inspections and audits.

(b) ATCO I-Tek will not, however, allow Client access to:

(i) other data (including the data of other ATCO I-Tek clients); or

(ii) any proprietary data or Confidential Information of ATCO I-Tek or its suppliers; or

(iii) areas which do not form part of the computing facilities or Systems used by ATCO I-Tek to provide the Services.

12.3 **Internal Procedures of ATCO I-Tek**

Upon request by Client, and at least once in any calendar year, ATCO I-Tek will provide to Client and its auditors, certified copies of relevant excerpts from reports prepared by ATCO I-Tek's auditors to establish that the internal audit procedures maintained by ATCO I-Tek with respect to the Services meet or exceed the relevant requirements set forth in section 5900 of the Handbook of the Canadian Institute of Chartered Accountants, as amended from time to time.

12.4 **Security Practices of ATCO I-Tek**

ATCO I-Tek's security practices will be not less than those implemented by Client immediately prior to the Commencement Date, of which Client advises ATCO I-Tek in writing. ATCO I-Tek shall revise such practices to reflect the requirements of any operational security procedure developed jointly by Client and ATCO I-Tek and, on an ongoing basis, as required to adhere to standards of care practiced by leading national and international suppliers of systems management services. If deficiencies are identified by Client as a result of inspections, audits or otherwise, ATCO I-Tek shall implement such additional security practices as are consistent with the standards of care practiced by leading national and international suppliers of system management services. At Client's request, ATCO I-Tek will provide Client with all reasonable assistance in identifying, tracking and closing security loopholes. ATCO I-Tek shall apply the same or equivalent level of physical protection to Client Data as existed for such Client Data prior to the Commencement Date. Physical protection for such Client Data is expected to improve over time in accordance with process audits and industry standards.

12.5 **Charges Related to Records, Audits and Security**

Client shall pay ATCO I-Tek, at the Time and Materials Rate, for services performed in respect of sections 12.1 and 12.2 except

(a) in respect of an inspection or audit once in every twelve (12) month period (from the Effective Date) during the term of this Agreement, or

(b) if such inspection or audit reveals that ATCO I-Tek is in material breach of its obligations under this Agreement,

in which case there shall be no charge to Client.

## ARTICLE 13
## OWNERSHIP

13.1 **Client Data**

ATCO I-Tek agrees that Client Data is, and shall remain, the exclusive property of Client at all times, and shall be held by ATCO I-Tek in trust for the sole benefit of Client. Client, its Representatives and third parties designated by it shall be permitted electronic access to all Client Data at all times, which access shall not be denied by ATCO I-Tek for any reason whatsoever (except when access is unavailable during reasonable periods of repair or maintenance), provided that such access must be exercised subject to the ATCO Group's security standards and such commercially reasonable terms and conditions imposed by ATCO I-Tek (including those relating to read-only access and the cost of access), as revised from time to time.

13.2 **ATCO I-Tek Systems**

ATCO I-Tek may process Client Data through Client Systems, ATCO I-Tek Systems and/or Systems of third party suppliers as may be provided for in this Agreement. ATCO I-Tek Systems, including any associated IP Rights therein, are and shall remain the exclusive property of ATCO I-Tek and/or the third party licensors or suppliers of such Systems.

13.3 **Client Systems**

(a) Client Systems, including any associated IP Rights therein, are and shall remain the property of Client or the third party licensors or suppliers of such Systems. For any Client Systems owned by Client that will be used by ATCO I-Tek to provide the Services, Client grants to ATCO I-Tek the right to use such Client Systems solely in connection with the Services. For Client Systems licensed from third parties, Client will use all reasonable efforts to obtain permission from the licensors of such Systems to permit ATCO I-Tek to

operate such Systems, subject to the terms and conditions of the existing licenses and subject to the restriction that such Systems be used solely to permit ATCO I-Tek to provide the Services. ATCO I-Tek shall not:

**(i)** allow Client Systems to be disclosed, sold, assigned, leased, copied or otherwise disposed of or commercially exploited by ATCO I-Tek, its Representatives or third parties; and

**(ii)** use any Client Systems on its own behalf or on behalf of any unrelated third person without the prior written consent of Client, ATCO I-Tek shall not remove or destroy any markings or legends placed upon any Client System or documentation therefore, and shall reproduce such markings or legends if copies are made of Client Systems or such documentation. ATCO I-Tek further agrees to comply fully with any restrictions or obligations of which ATCO I-Tek is made aware, including any licensing or nondisclosure obligations, imposed by any third parties on the use of Client Systems, and to execute such non-disclosure agreements as may be reasonably required by the third party licensors of Client Systems.

(b) If Client has been unable to obtain any one or more of the permissions contemplated by this section 13.2 or section 6.6 then, where reasonable in the circumstances and where deemed appropriate by Client, Client will either obtain substantially equivalent Systems or accept a reduction in Services to the extent necessary to reflect ATCO I-Tek's inability to use such Systems until permission is obtained. The applicable charges will be adjusted to reflect any reduction in Services.

(c) Unless Client otherwise agrees in a Statement of Work (complete and incomplete), the Client shall own all new developments, Deliverables and/or Know-How and all IP Rights therein (including without limitation, all new custom designed programs and all improvements, enhancements and modifications to existing or new custom designed programs and all new ATCO I-Tek software and all new improvements, enhancements and modifications thereto), which arise out of or are otherwise created during the course of or as a consequence of providing the Services; provided that, in respect of any particular new development, Deliverable, Know-How and / or IP Right, it was funded substantially by Client or by a combination of Client and one or more other utilities affiliated with the Client. In all other cases, IP Rights shall vest with ATCO I-Tek. Each party agrees to execute (and to obtain the agreement of its Representatives to execute) all additional agreements, instruments or documentation reasonably required to give effect to this provision.

13.4 **Documentation**

ATCO I-Tek will supply Client with such Documentation applicable to the Services as may be set out in a Schedule or Statement of Work. Any Documentation relating to ATCO I-Tek Systems and/or the Services, including any associated IP Rights therein, is and shall remain the exclusive property of ATCO I-Tek. ATCO I-Tek grants Client a limited, non-exclusive, non-transferable license to permit use by Client and its Representatives of such Documentation during the term of this Agreement and in support of the provision of the Services. For further certainty, the foregoing does not apply to any Documentation produced as a Deliverable from Tier 2 Services, with the exception of any proprietary information of ATCO I-Tek contained in such Documentation.

13.5 **Prohibited Uses**

Client agrees it shall not, nor shall it permit any third party to, use Client's access to ATCO I-Tek Systems or any Documentation relating to Services or ATCO I-Tek Systems for the purpose of developing a competing System that is intended to provide functionality similar to ATCO I-Tek Systems and / or Services.

13.6 **ATCO I-Tek Know-How**

Client acknowledges that ATCO I-Tek, in the course of its business, has developed know how, ideas, techniques, concepts, devices, trade secrets, works of authorship, inventions, whether patentable or not, innovations or improvements in any device, process or thing, methodologies, processes, technologies and algorithms used in the provision of the Services hereunder or relating to the conduct or operation of its business ("ATCO I-Tek Know-How"). Client acknowledges and agrees that such ATCO I-Tek Know-How constitutes confidential, valuable proprietary information and trade secrets of ATCO I-Tek or its suppliers and that ATCO I-Tek shall retain exclusive ownership of such ATCO I-Tek Know-How, including any applicable IP Rights therein.

13.7 **Client Know-How**

ATCO I-Tek acknowledges that Client, in the course of its business, has developed know how, ideas, techniques, concepts, devices, trade secrets, works of authorship, inventions, whether patentable or not, innovations or improvements in any device, process or thing, methodologies, processes, technologies and algorithms relating to the conduct or operation of its business ("Client Know-How"). ATCO I-Tek acknowledges and agrees that such Client Know-How constitutes confidential, valuable proprietary information and trade secrets of Client or its suppliers and that Client shall retain exclusive ownership of such Client Know-How, including any applicable IP Rights therein.

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13.8 **IT Assets**

Notwithstanding anything else in this Agreement, all IT assets that are not expressly designated elsewhere in this Agreement or in a Statement of Work as belonging to the Client shall belong to and remain the property of ATCO I-Tek.

## ARTICLE 14
## CONFIDENTIALITY, PUBLICITY

14.1 **Confidential Information**

Each of ATCO I-Tek and Client acknowledges that, in the course of providing or obtaining the Services, it ("Recipient") and its Representatives may be supplied with, come into possession of, or have access to, information, material or data from the other party ("Disclosing Party") which is designated as confidential or which ought to be considered as confidential from its nature or from the circumstances surrounding its disclosure (the "Confidential Information"). Confidential Information of a Disclosing Party includes information owned by the Disclosing Party (or to which the Disclosing Party has rights of exclusion with respect to the commercial use of such Confidential Information):

(a) relating to the Disclosing Party's software or hardware products and services or to its research and development projects or plans, including, in the case of ATCO I-Tek, ATCO I-Tek Know-How, Documentation and ATCO I-Tek Systems, and including, in the case of Client, Client Systems and associated documentation, Client Data and Client Know-How;

(b) relating to the Disclosing Party's trade secrets, business policies, strategies, operations, finances, plans or opportunities, including the identity of, or particulars about, same;

(c) relating to the Disclosing Party's clients or suppliers;

(d) that is marked or otherwise identified as confidential, restricted, secret or proprietary, including information made available to the Recipient for inspection or by oral disclosure, provided such information is identified as confidential at the time of disclosure or inspection and the Disclosing Party promptly provides the Recipient with written confirmation summarizing the confidential information disclosed; and

(e) disclosing the terms and conditions set forth herein.

Each Recipient agrees not to remove, cover, deface or alter any copyright, trade secret or trade mark notices contained on the Confidential Information.

14.2 **Confidentiality of Agreement**

Except where either party is required to disclose any provision of this Agreement in order to exercise any right or to perform any obligation hereunder, and subject to any requirement for disclosure under any applicable law or by any regulatory authority, neither party shall disclose the terms and conditions of this Agreement to any other person.

14.3 **Disclosure to Representatives**

Each Recipient agrees to disclose the Confidential Information only to those of its Representatives who have a need to know the Confidential Information, and who are under a written and enforceable obligation to keep confidential the Confidential Information received from the Disclosing Party and to use the Confidential Information only for the purposes described in this Agreement. Client Data shall not be used by ATCO I-Tek for any purpose other than to provide the Services to Client. Each Recipient will, prior to disclosing the information to its Representatives, advise them of its obligations under this Article 14. Upon request, each Recipient agrees to provide the Disclosing Party with a list of the Recipient's Representatives who have been provided with access to the Confidential Information of the Disclosing Party.

14.4 **Preventing Other Disclosure or Use**

Each Recipient agrees to make reasonable efforts to ensure that the Disclosing Party's Confidential Information is not directly or indirectly disclosed to or used by any person except as provided for in this Agreement or as is expressly authorized in writing by the Disclosing Party. Each Recipient's efforts will not be less than those which the Recipient takes or would be reasonably expected to take to prevent disclosure of its own Confidential Information of like significance.

Each Recipient shall notify each Disclosing Party promptly if the Recipient becomes aware or has reasonable grounds to suspect that unauthorized disclosure of Confidential Information of the Disclosing Party has occurred or is likely to occur. Each Recipient shall, at the request of each Disclosing Party and at each Recipient's own expense, use all reasonable efforts to assist the Disclosing Party in identifying any use, copying, or disclosure of any Confidential Information by any present or former Representative of the Recipient in any manner contrary to the provisions of this Agreement, provided that the Disclosing Party shall have provided the Recipient with information reasonably justifying the conclusion of the Disclosing Party that such contrary usage may have occurred.

14.5 **Permitted Disclosure**

Notwithstanding the foregoing, neither party shall be obligated to comply with the above-mentioned obligations of this Article 14 relating to Confidential Information if such Confidential Information:

(a) was known to the Recipient at the time of disclosure, as evidenced by any written documents in the possession of the Recipient;

(b) is available to the general public at the time of disclosure to the Recipient, or is subsequently made available to the general public without fault of the Recipient;

(c) pertains to general industry knowledge, processes or techniques;

(d) is disclosed or becomes available to the Recipient by reason of any act of any third person or organization having the right to disclose or publicize it;

(e) is intentionally distributed, without restriction as to confidentiality, by the Disclosing Party;

(f) is required to be disclosed in connection with the conduct of any arbitration or court proceeding carried out pursuant to this Agreement, provided that such disclosure is made pursuant to, and in accordance with, the approval, and at the direction, of the arbitrators conducting such arbitration or applicable judicial officers, and further provided that both parties hereto use their best efforts to have such arbitrators execute confidentiality agreements, the terms of which are similar to those set out herein; or

(g) is required to be disclosed pursuant to a final order to disclose issued by a court of competent jurisdiction, a government agency or regulatory body, provided that the Recipient subject to such order provides to the Disclosing Party immediate written notification of any such requirement for disclosure, and further provided the Recipient takes such steps as are reasonably necessary and available to maintain confidentiality by the court, government agency or regulatory body.

14.6 **No Breach for Use of General Knowledge**

Both parties acknowledge and agree that their Representatives, during the course of performing or obtaining the Services, may develop their general knowledge, skills and experience as they relate to data processing. The subsequent use by either party or its Representatives of such general knowledge, skills and experience relating to data processing in the ordinary course of business will not constitute a breach of the confidentiality provisions contained in this Agreement.

14.7 **Injunctive Relief**

Each Recipient acknowledges and agrees that any use or disclosure of Confidential Information of the Disclosing Party in a manner inconsistent with the provisions of this Agreement may cause the Disclosing Party harm which will not be compensable by monetary damages alone and, accordingly, each Disclosing Party will, in addition to other available legal or equitable remedies, be entitled to seek an immediate injunction restraining the Recipient and its Representatives from using or disclosing, or continuing to use or disclose, such Confidential Information. In such event, the Disclosing Party applying for injunctive relief need not show or prove any actual damage sustained by it and may avail itself of injunctive relief in addition, and without prejudice, to any other remedies available to it.

14.8 **Return of Information**

Promptly upon the termination of this Agreement, or such earlier date upon which Confidential Information of the Disclosing Party is no longer required by a Recipient for the purposes of this Agreement, the Recipient shall return the Confidential Information to the Disclosing Party and shall erase all copies of such Confidential Information in the possession or control of the Recipient or its Representatives.

14.9 **Publicity**

Each party will submit to the other all advertising, sales promotion, press releases and other publicity materials relating to this Agreement in which the other party's name or mark is mentioned or in which language is used, from which the connection of said name or mark may be inferred or implied. Neither party will publish or use such advertising, sales promotion, press releases or publicity materials without the prior written approval of the other party. However, either party may include the other party's name and a general factual description of the work performed under this Agreement in employee bulletin boards, lists of references, the experience section of proposals to third parties, internal business planning documents and communications, and annual reports to shareholders, and whenever required by reason of legal, accounting or regulatory requirements.

## ARTICLE 15
## RENEWAL AND TERMINATION

15.1 **Initial Term**

This Agreement shall be in effect for an initial term ending five (5) years from the Effective Date (the "Initial Term"), subject to earlier termination or renewal as hereinafter provided.

15.2 **Renewal**

It is contemplated that, as part of each annual planning process, ATCO I-Tek will provide the Client with a five (5) year view of pricing. Starting on the third anniversary of the commencement of the Initial Term, the parties will enter into negotiations regarding whether the Agreement will be renewed for a further three (3) years following the expiry of the Initial Term.

15.3 **Automatic Renewal**

ATCO I-Tek will, eighteen (18) months prior to the end of the Initial Term (or as soon thereafter as may be reasonably practicable for ATCO I-Tek), send Client a notice (the "Renewal Notice") requesting that Client advise ATCO I-Tek if Client does not wish to renew this Agreement following the expiry of the Initial Term. If Client does not respond in writing to the Renewal Notice within fifteen (15) days following the date of the Renewal Notice, this Agreement will be automatically renewed for three (3) years at the pricing set forth as part of the most recent annual planning process.

15.4 **Subsequent Renewals**

If this Agreement is renewed following the expiry of the Initial Term, pursuant to sections 15.2 or 15.3, the process set forth therein for renewal shall continue and shall apply to each renewal term, except that the negotiations referenced in section 15.2 will commence on the first anniversary of the renewal term then in effect, and the Renewal Notice will be sent by ATCO I-Tek six (6) months thereafter (or as soon thereafter as may be reasonably practicable for ATCO I-Tek).

15.5 **Triggering Events**

Each of the following events shall constitute a "Triggering Event" with respect to a party for the purposes of section 15.6(c):

(a) a receiver (unless the receivership order is vacated within thirty (30) days), trustee of bankruptcy or any other similar officer (unless such officer's appointment is vacated within thirty (30) days) is appointed to take charge of all or any substantial part of the other party's business or property;

(b) the other party becomes an insolvent person or commits an act of bankruptcy within the meaning of those terms in the *Bankruptcy and Insolvency Act* (Canada);

(c) a petition is filed or any other action is taken with respect to the other party for reorganization or for arrangement under any provision of the *Bankruptcy and Insolvency Act* (Canada) or any similar law of Canada or any province thereof then in force and providing a plan for a debtor to settle, satisfy or to extend the time for payment of debts;

(d) any application, petition, certificate or order is made or granted for the winding up or dissolution of the other party, voluntarily or otherwise.

15.6 **Termination**

This Agreement may be terminated:

(a) at the expiry of the Initial Term or a Renewal Term, as the case may be, if Client notifies ATCO I-Tek of Client's intention to terminate this Agreement, pursuant to sections 15.2 or 15.3;

(b) immediately upon giving notice by a party not in breach if the other party commits a material breach of this Agreement, as defined below;

(c) immediately upon giving notice if a Triggering Event occurs in respect of the other party;

(d) by Client, for convenience, on ninety (90) days prior written notice any time after the first anniversary of the Effective Date upon payment to ATCO I-Tek of a termination charge equal in amount to the average monthly charge paid in the previous twelve (12) month period multiplied by three-quarters the number of months remaining in the Initial Term or Renewal Term, as the case may be, (to compensate ATCO I-Tek for lost profits and the cost of reallocating resources);

(e) pursuant to section 18.13.

For the purposes of this Agreement, either party shall be deemed to be in material breach of this Agreement if it fails to perform any obligation hereunder which has a material adverse effect on the other party, and such failure is not cured either within thirty (30) days following notice by the non-defaulting party hereunder, or, if such failure is not capable of being reasonably cured within such thirty (30) day cure period, according to an action plan agreed upon by the parties within thirty (30) days following notice, provided that, in the latter case, the party attempting to effect the cure commences the cure within such thirty (30) day period and continues thereafter to diligently exert all reasonable commercial efforts to cure the failure.

15.7 **Effect of Termination**

(a) Subject to the Termination Transition Plan, upon termination of this Agreement for any reason all applicable Statements of Work shall also terminate.

(b) The parties agree that, upon termination of this Agreement for any reason, Client shall remain liable to ATCO I-Tek for all charges that are to be paid by Client in accordance with the provisions of this Agreement.

(c) Upon any early termination of this Agreement by ATCO I-Tek pursuant to section 15.6(b) or section 15.6(c), Client shall pay commercially reasonable compensation to ATCO I-Tek for any severance expenses, early termination expenses and other costs suffered by ATCO I-Tek for reallocating resources, effecting early termination of sub-contracts and supply arrangements and, if necessary, winding up all or part of its operations.

(d) Upon any early termination of this Agreement by Client pursuant to section 15.6(b) or section 15.6(c), ATCO I-Tek shall pay Client all commercially reasonable direct costs incurred by Client to transfer the provision of Services back to Client or their third party service provider, and, notwithstanding anything contained in section 15.7(e) or Schedule G to the contrary, ATCO I-Tek shall be responsible for all costs incurred by either ATCO I-Tek or Client in connection with items 1, 2, 5 and 7 of the Termination Transition Plan set out in Schedule G.

(e) Upon expiry or termination of this Agreement for any reason whatsoever, ATCO I-Tek shall, subject to the terms and conditions of this section 15, and the limitations of ATCO I-Tek's liability set forth in Article 11, provide transition services ("Termination Transition Services") to the Client in accordance with Schedule G ("Termination Transition Plan") for a period of up to a maximum of twelve (12) months after the date of such termination, or in the case of expiry of the Agreement, during the twelve month period prior to the expiry thereof ("Transition Assistance Period"). During the Transition Assistance Period, the Client shall continue to pay all applicable Fees to ATCO I-Tek for the Services, and any additional tasks performed by ATCO I-Tek, including the Termination Transition Services, shall be charged to Client on a Time and Materials basis, or otherwise as agreed in a Statement of Work, including the Termination Transition Plan. ATCO I-Tek shall perform the Termination Transition Services in a timely, workmanlike, competent, conscientious and professional manner, in accordance with generally accepted standards of care in the energy industry.

## ARTICLE 16
## DISPUTE RESOLUTION

16.1 **Informal Review**

In the event of a Dispute, not subject to an exception pursuant to section 16.4, the following dispute resolution procedure will be followed:

(a) **Level 1 Review** Upon the written request of either party, each of the parties will appoint a designated officer whose task it will be to meet for the purpose of endeavouring to resolve the Dispute or to negotiate for an adjustment to the provisions of this Agreement, including any affected Statements of Work. The designated officers will meet as soon as possible following either party receiving notice of the Dispute, giving due regard to the nature and the impact of the Dispute, and as often thereafter as each party reasonably deems necessary in order to gather and furnish to the other party all information which the parties believe to be appropriate and germane to resolution of the Dispute. Such designated officers will discuss the Dispute and negotiate in good faith in an effort to resolve the Dispute and to renegotiate the applicable section or provision of this Agreement, as required, without the necessity of any formal proceeding relating thereto. The specific format for such discussions will be left to the discretion of the designated officers but may include the preparation of agreed upon statements of fact or written statements of position, which shall be made on a "without prejudice" basis, furnished to the other party. If the Dispute is not resolved within thirty (30) days of this Level 1 Review, or if both representatives conclude that resolution of the Dispute through continued negotiations during this thirty (30) day period is not likely to occur, then either party may escalate the Dispute to a Level 2 Review.

(b) **Level 2 Review** Each party will appoint an executive officer to represent that party in a negotiation to resolve the Dispute. If the Dispute is not resolved within thirty (30) days of the later of such appointments, or if both representatives conclude that resolution of the Dispute through continued negotiations during this thirty (30) day period is not likely to occur, then either party may escalate the Dispute to a Level 3 Review.

(c) **Level 3 Review** An executive officer of each party will meet with a representative of the ATCO Group's Office of the Chairman to resolve the Dispute. If the Dispute is not resolved within thirty (30) days of this Level 3 Review, or if both representatives conclude that resolution of the Dispute through continued negotiations during this thirty (30) day period is not likely to occur, then either party may commence formal proceedings for arbitration of the Dispute, as provided for in section 16.2.

16.2 **Arbitration**

Subject to section 16.4 or the parties having unsuccessfully followed the dispute resolution process set out in section 16.1, any Dispute will be settled by arbitration conducted in accordance with the *Arbitration Act*, S.A. 1991, c. A-43.1, as amended from time to time (the "Arbitration Act"), by a board of arbitration (the "Board"). The Board, which shall conduct the arbitration in either Edmonton, Alberta or Calgary, Alberta, shall be appointed as follows:

(a) Subject to paragraph (2) hereof, the Board will be composed of one person appointed by the party requesting resolution of the Dispute by the Board (the "Applicant"), one person appointed by the other party (the "Respondent") and a third person to act as chairperson, chosen by the first two chosen members of the Board, provided that if both parties agree, the Board will consist of a sole arbitrator appointed by both parties.

(b) The Applicant shall deliver to the Respondent written notice of the Applicant's intent to refer the Dispute to the Board within one hundred (100) days after the failure of the Level 3 Review to resolve the Dispute, and shall, at the same time, name its appointee to the Board. The Respondent shall, within fifteen (15) Business Days of receipt of such notice, advise the Applicant, in writing, of the name of its appointee to the Board. If the Respondent fails to notify the Applicant of its appointee, the Respondent shall be deemed to have concurred in the appointment of the Applicant's appointee, and such appointee shall alone constitute the Board.

(c) If the Respondent appoints an arbitrator pursuant to paragraph (2) above, then, within five (5) Business Days of the appointment of such arbitrator, the two (2) appointed arbitrators shall agree on the appointment of a third arbitrator to act as chairperson (the "Chairperson"). If the appointed arbitrators cannot agree on the appointment of the third arbitrator, either the Applicant or the Respondent may apply to the Court of Queen's Bench of Alberta to appoint the third arbitrator, or promptly take such other action to appoint a Chairperson as the parties may agree.

No decision of the Board shall be subject to appeal except as otherwise required by the Arbitration Act.

16.3 **Conditions Precedent to Commencing an Action or Proceeding**

Other than any action necessary to enforce the award of the Board, and subject to section 16.4, the parties agree that exhausting the provisions of sections 16.1 and 16.2 is a condition precedent to a party's right to commence an action or proceeding in respect of a Dispute, and accordingly, subject to section 16.4, this Article 16 is a complete defense to any suit, action or other proceeding instituted in any court or before any administrative tribunal with respect to any Dispute arising under or in connection with this Agreement.

Notwithstanding the foregoing, nothing in this Article 16 prevents the parties from exercising their rights to terminate this Agreement in accordance with its provisions.

16.4 **Disputes Not Subject to Informal Review or Arbitration**

The parties acknowledge and agree that, with respect to any Dispute arising under Article 14, to protect an IP Right, or in respect of a claim for injunctive relief, a party may refer such matter to arbitration in accordance with this Article 16 or apply to the appropriate court for relief without having to first follow the other dispute resolution mechanisms set forth in this Article 16.

## ARTICLE 17
## NOTICE

17.1 **Notices**

(a) Unless otherwise specified herein or otherwise agreed by the parties in writing, any notice required to be given hereunder must be given in writing and delivered by postage-paid mail, personally, by prepaid courier, by fax or by other electronic means, addressed to the appropriate party at its address for notice set forth on the signature page of this Agreement.

(b) Any notice provided herein shall be deemed to have been given as follows:

(i) if delivered by mail, seventy-two (72) hours after the mailing thereof, Saturdays, Sundays and statutory holidays excepted, provided that if there shall be, prior to the time of mailing or the actual receipt of a notice, a threatened or actual postal strike or other interruption that might affect the delivery of the notice by mail, then such notice shall be delivered personally, by courier, by fax or by other electronic means;

(ii) if delivered personally or by courier before 2:00 p.m. (time of the recipient) on a Business Day, on that Business Day;

(iii) if delivered personally or by courier at or after 2:00 p.m. (time of the recipient) on a Business Day or on a day that is not a Business Day, on the next Business Day;

(iv) if sent by fax or other electronic means on a Business Day and the sending party obtains confirmation that all of the pages of the notice have been successfully transmitted before 2:00 p.m. (time of the recipient), on that Business Day;

(v) if sent by fax or other electronic means on a Business Day and the sending party obtains confirmation that all of the pages of the notice have been successfully transmitted, but that some or all of the pages of the notice

were transmitted after 2:00 p.m. (time of the recipient), on the next Business Day;

(vi) if sent by fax or other electronic means on a day that is not a Business Day and the sending party obtains confirmation that all of the pages of the notice have been successfully transmitted, on the next Business Day.

(c) Either party hereto may, from time to time, give notice of a change in its address, contact person, fax number or other electronic address by notice as provided herein and, in that event, such information shall be deemed to be changed accordingly.

(d) Neither party shall prevent, hinder or delay, or attempt to prevent, hinder or delay the service on that party of a notice relating to this Agreement.

## ARTICLE 18
## GENERAL

### 18.1 Assignment

Neither party shall assign this Agreement or any rights, benefits, warranties or obligations granted hereunder without the express written consent of the other party, which consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, ATCO I-Tek may assign this Agreement to a corporate entity in the event of a transfer to that entity of all or substantially all of the assets of ATCO I-Tek used to provide the Services.

### 18.2 Non-Solicitation of Employees

Except as otherwise agreed by the parties in writing, for the term of this Agreement and for a period of one (1) year thereafter, neither party will, directly or indirectly (including through a successor service provider used by Client), recruit, hire as an independent contractor or offer employment to any Representative of the other party who is or was substantially involved in the delivery or receipt of Services without the prior written consent of the other party or until a period of at least twelve (12) months has elapsed after such Representative's employment with the other party has ended. Each party agrees to act in good faith and provide its consent during the term of this Agreement and while both parties are Affiliates or Associates, provided no termination is contemplated or reasonably foreseeable during the one (1) year period from the Effective Date. Notwithstanding the foregoing, Client and ATCO I-Tek recognize the value and mutual benefit of instituting a staff rotation program among the members of the ATCO Group, and both parties will cooperate to maintain this rotation program.

### 18.3 Severability

If any term or provision of this Agreement or the application thereof to any person or circumstances shall, to any extent, be deemed by a court of competent jurisdiction to be

invalid or unenforceable, such term or provision shall be deemed severed from this Agreement, and the remainder of this Agreement or the application of such term or provision to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and shall be valid and enforceable to the extent permitted by law.

18.4 **Independent Contractors**

The parties acknowledge that they are independent contractors and that this Agreement shall not create a relationship of employment, partnership, or joint venture between the parties or between one party and the other party's Representatives. Each party specifically acknowledges that its Representatives are not employees, agents or partners of the other party. Unless otherwise provided in this Agreement, each party has the right and obligation to supervise, manage, contract, direct, procure, perform or cause to be performed all work to be performed by that party under this Agreement. ATCO I-Tek may, from time to time, perform services similar to the Services for ATCO I-Tek's other clients.

18.5 **Governing Law**

This Agreement and any disputes, including Disputes, arising or resulting from the transactions contemplated under this Agreement shall be construed in accordance with and governed in all respects by the laws of Alberta and the federal laws of Canada applicable therein. Subject to Article 16, the parties submit to the exclusive jurisdiction of the courts of Alberta.

18.6 **Survival**

Notwithstanding the termination of this Agreement for any reason, any obligations which by their nature are intended to survive such termination shall continue in full force and effect until discharge of the obligation or until the parties mutually agree to a release of the obligation, which obligations shall include those pursuant to Sections 1.1, 1.2, 3.2 and 15.7, and Articles 8, 9, 10, 11, 13, 14, 16, 17 and this Article 18.

18.7 **Entire Agreement**

This Agreement constitutes the entire agreement between the parties hereto pertaining to the subject matter of this Agreement, and supersedes all prior or contemporaneous agreements, understandings, representations, negotiations and discussions, whether oral or written, including letters of intent or other agreements of the parties hereto, and there are no warranties, representations or other agreements between the parties hereto, implied or express, statutory or otherwise, in connection with the subject matter hereof except as specifically set forth herein. For further clarification, Client acknowledges and agrees that it is not relying upon any representation in any advertising, marketing material, catalogue or similar material provided to Client by ATCO I-Tek. In no case shall any printed terms and conditions on any standard transactional documentation of Client (including Client's form of purchase order) modify this Agreement or otherwise apply to ATCO I-Tek or the provision of the Services hereunder.

18.8 **Amendments**

This Agreement may not be amended, modified or superseded unless expressly agreed to in writing by both parties.

18.9 **No Waiver**

The observance of any term of this Agreement may be waived (either generally or in a particular instance, and either retroactively or prospectively) by the party entitled to enforce such term, but such waiver shall be effective only if it is in writing and signed by the party against which such waiver is to be asserted. Unless otherwise expressly provided in this Agreement, no delay or omission on the part of either party in exercising any right or privilege under this Agreement shall operate as a waiver thereof, nor shall any waiver on the part of either party of any right or privilege under this Agreement operate as a waiver of any other right or privilege under this Agreement, nor shall any single or partial exercise of any right or privilege preclude any other or further exercise thereof or the exercise of any other right or privilege under this Agreement.

18.10 **Enurement**

This Agreement shall enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns.

18.11 **Further Assurances**

The parties agree to do or cause to be done all such further acts or things required to implement and carry into effect this Agreement to its full extent.

18.12 **Currency**

Unless indicated otherwise in a particular Schedule or Statement of Work, all amounts referred to herein are stated and shall be payable in Canadian funds.

18.13 **Force Majeure**

Except with respect to any payments required pursuant to this Agreement, neither party hereto shall be liable to the other party or considered to be in default under this Agreement for any delay or failure to perform its obligations hereunder due to an event of force majeure, which shall include strikes, labour disputes, riots, explosions, earthquakes, acts of God, severe weather conditions materially preventing or impairing work, failure or fluctuations in electrical power, heat, light, air conditioning, water sprinklers, telecommunications equipment or lines, acts of any governmental authority, war, failure or delay of any third party supplier, unavailability or shortages of materials, equipment failures or, without limitation, any other cause or causes beyond the reasonable control of such party and which could not have been reasonably foreseen and protected against. The parties hereto shall use commercially reasonable efforts during the term of this Agreement to avoid or, if unavoidable, minimize the effects of any event of force majeure upon the performance of their respective obligations under this Agreement.

Notwithstanding the foregoing, if the period during which one party's performance of its obligations hereunder is impaired due to an event of force majeure extends or can be reasonably expected to extend for greater than ninety (90) days, then the other party may terminate this Agreement. Without limiting the generality of the foregoing, ATCO I-Tek shall be relieved of any failure or delay in performing the Services, and any failure in meeting any Service Level, to the extent that such failure or delay is caused by the direct and substantive failure or delay of Client in performing its responsibilities hereunder.

18.14 **Time of Day and Time**

Unless otherwise specified, references to time of day or date mean the local time or date in the City of Edmonton, Alberta. Time is of the essence in the performance by the parties of their respective obligations hereunder.

18.15 **Remedies**

Unless stated otherwise herein, all remedies provided for in this Agreement shall be cumulative and in addition to and not in lieu of any other remedies available to either party at law, in equity or otherwise. No single or partial exercise by a party of any right or remedy precludes or otherwise affects the exercise of any other right or remedy to which that party may be entitled.

18.16 **Understanding**

Each of the parties acknowledges that it has read and understood this Agreement and agrees to be bound by its provisions.

18.17 **Facsimile; Counterparts**

This Agreement, and any document contemplated under this Agreement, may be executed in any number of counterparts which may be exchanged by facsimile, each of which shall be deemed an original and all of which together shall constitute one and the same Agreement.

18.18 Each of the parties hereto represents and warrants to the other that the Master Services Agreement, as amended hereby, complies with the ATCO Group Inter-Affiliate Code of Conduct (EUB Decision 2003-040).

IN WITNESS WHEREOF ATCO I-Tek and Client have executed this Agreement by their authorized officers in that regard, as of the 14 day of March 2005.

**ATCO I-TEK**
10035 – 105 Street
Edmonton, AB T5J 2V6
Attention: President
Facsimile: (780) 420-3157

Per: _____
Name: Bobbi Lambright
Title: President

Per: _____
Name: Pam Moellmann
Title: Vice President, Technologies

**CLIENT: ATCO Electric**
10035 – 105 Street
Edmonton, AB T5J 2V6
Attention: President
Facsimile: (780) 420-3590

Per: _____
Name: Sett Policicchio
Title: President

Per: _____
Name: Owen Edmondson
Title: Senior Vice President, Controller ATCO Utilities Group
ATCO Gas/ATCO Electric

# INFORMATION TECHNOLOGY

# MASTER SERVICES AGREEMENT

# Schedule A – Service Level Agreement



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# SCHEDULE A – SERVICE LEVEL AGREEMENT

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## 1.0 Introduction

This Service Level Agreement ("SLA") is Schedule A to the IT Master Services Agreement (Agreement) and provides a list of the Services and supported infrastructure available to the Client from ATCO I-Tek. All capitalized Terms used herein shall, unless otherwise indicated to the contrary, have the meanings given thereto in the Agreement.

## 1.1 Statement of Intent

This SLA represents the agreement between Client and ATCO I-Tek regarding the information system Services and Service Levels necessary to support the Client's business requirements. The Clients will know what they can reasonably expect, assuming that they live up to their responsibilities as outlined in the Governance document.

## 1.2 Objective

ATCO I-Tek will continue to provide a stable environment for production Services and act as a catalyst for the implementation of new technology direction and business efficiencies.

## 1.3 Scope

This SLA outlines the specific service descriptions, Service Level measurements, specific applications and servers as of the Effective Date with respect to the delivery of the Services by ATCO I-Tek to Client.

### *1.3.1 Designated Managers*

The Client Designated Manager and the ATCO I-Tek Designated Manager will be responsible for the management and administration of this SLA and have full authority in connection with the management of this SLA.

## 1.4 Service Management

ATCO I-Tek's focus is on client satisfaction while providing efficient support and Services. ATCO I-Tek intends to meet or exceed the expectations established within this SLA. The main aspects of service management are *availability*, *responsiveness*, and *serviceability*.

### *1.4.1 Availability*

Wide Area Network, Enterprise Server, Mid-range and Local Area Network Servers, Applications, Customer Support Center, and ATCO I-Tek support staff are generally available on a continuous 24 hours per day 7 days per week basis, with the exclusion of Change Windows.

This availability accommodates different scheduled uses of the environments for on-line processing, batch processing, backups, etc. Each application and/or server has an established schedule that meets its requirements for each type of use as set out in Appendix A.

### *1.4.2 Responsiveness*


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Wide Area Network, Enterprise Server, Mid-range and Local Area Network Servers, Applications, Customer Support Center, and ATCO I-Tek support staff are engaged to ensure that service expectations as set out in and are identified in the Service Measures Schedule (Schedule C) are met and/or exceeded. Specific response times have not been documented for each application.

### *1.4.3 Serviceability*

Serviceability is a measure of the support personnel's capability to resolve problems effectively. Due to the diversity of issues and resolutions, serviceability will be measured based upon the time to resolve the problem completely or provide an interim solution with a negotiated action plan that, upon completion, will have resolved the problem completely.

### *1.4.4 Management Procedures Manual*

ATCO I-Tek will periodically update the Management Procedures Manual within a reasonable time frame of changes being agreed to by Client to reflect alterations in the operations or procedures described therein. This manual will be written so that it is suitable for Client and ATCO I-Tek personnel to gain an understanding of the operational aspects of Tier I in-scope Services.

## 1.5 Technology Planning

On an annual basis, ATCO I-Tek will develop a technology plan that identifies and translates Client's business goals, security policies and existing infrastructure into a set of infrastructure requirements and a high-level, phased implementation strategy. This technology plan will address Client's changing business needs and leverage emerging technologies. The purpose of the plan will be to:

- Establish a foundation for a secure, distributed client/server, Web, and mainframe environment that can be managed with a maximum of reliability and uniformity at a minimal cost.
- Provide input to an annual capital and operating budget.
- Promote information sharing, corporate efficiency, and user effectiveness.
- Expand the use of information technology, where applicable, while attempting to maintain operating costs and meet business needs.
- Identify trends, anticipate problems and develop innovative and cost-effective solutions.
- Seek a variety of views in the decision-making process.
- Recognize the value of proactive technology planning as an important I.T. community development resource.

ATCO I-Tek will work with Governance and the Chief Information Officer for the ATCO Group to jointly establish a technology policy that should include the characteristics of inter-operability, portability, flexibility, scalability, and usability.

The technology policy will promote the use of standard products and should address the following topics as applicable:


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- ATCO business direction and operations.
- Enterprise-wide planning assumptions for the application of technology.
- Quantities of users, applications, Systems, and capital/operating costs as part of the annual planning process.
- Quantities to support automation plan for supported sites.
- Cost benefit analysis and risk analysis for major supported product changes.
- Preferred and minimum levels, as well as types, of user training.
- Security.
- Desktop and server standards and configurations.
- LAN/WAN design.
- Approved products list.
- Technology refresh schedule.

## 1.6 Client Satisfaction Survey

ATCO I-Tek and the Clients have developed a "Client Survey" process to help identify the needs, opinions, and expectations of the Client. The Client Survey process will help evaluate and improve the Services provided by ATCO I-Tek to the Client by generating information that:

- Measures Client satisfaction in respect of Services provided
- Identifies key issues
- Evaluates the effectiveness of action plans

## 1.7 Service Level Review and Change Procedure

ATCO I-Tek and Client agree to annually review this SLA as part of the Annual Review. This will be done with the objective of reviewing annual service levels, productivity expectations, business transaction volume projections, and responding to the impact of changes in information technology and management techniques, as well as changes in Client's expense reduction, service and application needs. It will contemplate the impact of the following items on the Services and/or Service Levels then being provided by ATCO I-Tek:

- Client's annual business planning process.
- Client's annual budget process.
- Mutually agreed additions, deletions or changes to the Services.
- ATCO I-Tek's performance over the previous year.
- Client Survey results from the previous year.

Services and/or Service Levels can be changed and implemented when there is agreement by Client and ATCO I-Tek. The process to change a Service or Service Level is as follows:


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1) The ATCO I-Tek Vice President, Technologies and/or ATCO I-Tek Vice President, Applications and Client VP with IT Responsibility agree on and approve the change.

2) As the contract owners, the applicable ATCO I-Tek Designated Manager and the Client Designated Manager should be made aware of the change.

These changes will be documented in an amended version of this SLA with an Effective Date of January 1st of the following year. The Client President (or his or her designate) and ATCO I-Tek President will sign the amended SLA. Any adjustments to the price for the Services resulting from such amendments will be reflected in a revised Pricing Schedule (Schedule D).

In the event that a new SLA is not in place as of January 1st of the following year, this SLA will remain in effect.

ATCO I-Tek will provide "Monthly Service Level Management Reports" to Client to summarize ATCO I-Tek's Service Level performance as outlined in the Service Measures Schedule (Schedule C). Monthly meetings will be held to discuss missed Service Levels. Depending on the severity of the problem, escalation may occur and additional meetings may be required. SLA change requests can be submitted by Client or by ATCO I-Tek at any time and should be directed to the other party's Designated Manager.

In addition to the Annual Review, three interim reviews of Services and Service Levels will be conducted on a quarterly basis. The interim reviews will (a) review ATCO I-Tek's performance to date (as reflected in the Service Level Management Reports), and (b) review any SLA change requests submitted for consideration. As a by-product of these interim reviews, any changes, additions or deletions to the Services and/or Service Levels provided by ATCO I-Tek (and any associated pricing adjustments) agreed to by the parties in writing shall be documented for inclusion in the following year's revised SLA and Pricing Schedule. Such changes, additions or deletions can be made effective at any time agreed to by the Client Designated Manager and the ATCO I-Tek Designated Manager, with an adjustment to invoicing as of such Effective Date.


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## 2.0 Information Technology Services

The following is the list of all the Information Technology Services that are provided to the Client under the terms of the Agreement. The complete descriptions of the Information Technology Services offered are detailed in the Definition of Services Schedule (Schedule B).

1. Planning
2. Account Management
3. Standards
4. New Technology & Infrastructure
5. Customer Support Center
6. Security Management
7. Asset Management
8. Disaster Recovery
9. Computer and Facilities Management
10. Contract Management
11. Consulting
12. Training
13. Mainframe Management & Support
    - Production Management
    - Print Management
    - Hardware & Software
14. Workstation Management & Support
15. Server Management & Support
16. Network Equipment Management & Support
    - Manage LAN
    - Manage WAN
    - Manage Voice
    - Manage Video Conference
17. Application Management & Support
    - Development
    - Maintenance & Enhancement
18. Database Management & Support
    - Development
    - Maintenance & Enhancement
19. Data Management


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## 3.0 Appendices

The documents listed below are referred to within this document and are deemed to be part of this SLA. Client and ATCO I-Tek recognize that the content of these documents is subject to change in response to operational changes. Changes to the documents will be adopted and agreed to by ATCO I-Tek pursuant to the Service Level Review and Change Procedure.

**Appendix A - Application Availability**: includes the Application Availability list.

**Appendix B - Security Framework Standards**: is a summary of the ”Security Framework” which is a comprehensive set of standards to address all aspects of the security of information for the ATCO Group .

**Appendix C - Disaster Recovery Methodology**: describes the common critical path of activities included in the enterprise server disaster recovery plan.

**Appendix D - Consolidated Technology Specifications**: is the adopted consolidated set of Information Technology Standards for the ATCO Group.

**Appendix E – Client Survey Process**: is a process to determine Client satisfaction with the Services.

**Appendix F – Priority Level Definitions & Notification Escalation**: details the priority level criteria and the escalation procedure on problem tickets, and the interim process for service request tickets.


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# Appendix A: Application and Server Availability

## Production Applications

Client relies on their applications being operational during certain hours to:

- Access information;
- Update information; and
- Produce results and reports.

An application's availability and accessibility are dependent on one or more inter-connected components and the general support requirements for those components. In general, the network, the enterprise server and the LAN servers are available 24 hours a day, 7 days a week (7x24). However, certain times are set aside for System and data backups, System maintenance and application changes. General support includes Change Windows used to perform scheduled and emergency maintenance, and batch processing windows used to perform backups, database management (reorganizations and optimizations) and off-line (batch) processing. During these times on-line access to an application is impacted.

Also, applications are dependent on the Services and computers they use. The ATCO Network, enterprise server, LAN servers, IMS, ADABAS, DB2 and the availability of applications all have an impact on the applications and the Clients using them. The Client may be unaware of these interdependencies.
The unavailability of an application, during the scheduled on-line hours is designated as an "outage". A planned "outage" can be scheduled with the agreement of the Client, based on predetermined requirements and an implementation plan. Each application must be available for on-line processing during agreed to service hours. An unscheduled "outage" is assigned a critical status and receives immediate attention to rectify the situation promptly, based on the problem management priority status. Many applications also have critical batch processing operations, which must be completed before the data can be accessed on-line. Ensuring the integrity of the application data takes precedent over maintaining on-line availability, unless the Client authorizes otherwise.

## Enterprise Server

The enterprise server is currently used for several of the Client's production applications. The production applications use one of the three main database management systems:

- IMS
- ADABAS
- DB2

along with teleprocessing software (e.g. IMS, TSO, CICS) and application development languages (e.g. COBOL, NATURAL).

The availability of a production application depends largely on the availability of the production environment (the database and the teleprocessing software) it uses. Test and development environments are maintained and follow their own availability schedules. If Client wishes to use



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these environments or know these schedules, Client should call the ATCO I-Tek Change Coordinator or call the Customer Support Center.

The on-line availability of a production application also depends on the batch processing requirements for the application.

- Daily batch processing is normally scheduled to begin at 18:00 each day, Monday to Friday. At this time, most applications become unavailable for on-line use, due to files being unavailable or locked.
- Certain applications have special requirements.
- Payroll batch jobs are initiated at 16:00 on Payroll days.
- Scheduled System tests, for application changes, may affect availability.
- Year-end processing for the financial applications and for the Benefits Administration System is planned each year as part of the year-end processing project. Application availability will vary per year.

Database optimizations, space increases and reorganizations are required from time to time, which restrict access to the applications data. Generally, these activities are scheduled; however, emergency processes may be required to rectify certain problems.

The enterprise server has some scheduled maintenance activities that affect general availability.

- Backup processing (full and incremental).
- Incremental backups are scheduled between 23:00 and 07:00 each day, Monday to Friday. Files being used during those times will be bypassed.
- ADABAS backups are scheduled for Sunday - Friday at 04:30. The databases can still be active during these backups, but files being used will not be backed up.
- ADABAS backups are scheduled for Saturday - Sunday 21:00-07:00. ADABAS is shut down (inactive) for this period. All files will be inactive and therefore backed up.
- Full "backups and defrag" jobs are scheduled for Saturdays at 21:00 and are completed by 06:30 Sunday.
- Change Windows are outlined in the Change Management category in the Definition of Services Schedule (Schedule B).

ATCO I-Tek will try to avoid outages to GMS/TIS processing and file transfers during the 3rd Sunday Change Window between 8:00 and 11:30 am. However, there will be circumstances when this outage is unavoidable. These GMS processes are given priority, so they will run as soon as the system becomes available after the Change Window is over.



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When application availability is not specifically stated, the default is Business Hours, Monday to Friday, 8 AM to 5 PM.



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# Application Availability

| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| | | | | | | |
| AC Master | PACE | 01<br>15 | Mon - Fri | 07:30 - 18:00 | | |
| Accounts Payable System | APS | 01<br>02<br>03<br>45<br>65<br>99 | Mon - Fri | 07:30 - 18:00<br>07:30 - 16:30 | Mon - Fri | 18:00 - 07:00 |
| AccPac | AccPac | 70 | Mon - Fri | 07:30 - 18:00 | | |
| Accreditation, DataCap, Verification, Install, CAD, Etc. | ADVICE | 01 | | | | |
| Accumap | Accumap | 01<br>03<br>15 | Mon - Fri | 07:30 - 18:00 | | |
| Activity Tracking System | ATS | 02 | | | | |
| Aircraft Reservations System | RESERVATION | 70 | | | | |
| Alberta Online Registry | Alberta Online Registry | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Alberta Petroleum Marketing Commission | APMC | 03 | | | | |
| Alldata Electronic Tool Box | ALLDATA | 01 | | | | |
| AllMark | ALLMARK | 01 15 | | | | |



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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Altrade | ALTRADE | 15 | Mon - Fri | 07:30 - 18:00 | | |
| ATCO Electric Geospatial I.S. | AEGIS | 02 | | | | |
| ATCO Electric Outage Notification System | AEONS | 02 | | | | |
| Audiology/Audiograf | AUDIO | 01 | | | | |
| Auto Parts Management | WinSell - Auto Parts | 01 | | | | |
| Autodesk Map Guide (StrataWeb) | STRATAWEB | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Aware Learning Manager | AWARE | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Bank Reconciliation System | BARS | 01<br>02<br>03<br>99 | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |
| Barcode | BARCODE | 01<br>02 | | | | |
| Barton Scan Base | BARTON | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Beaumont Bill Print | BBS | 65 | | | | |
| Benefits Administration System | BAS | 01<br>02<br>03<br>31<br>45<br>65<br>70 | Mon - Fri<br>Payroll Day | 07:30 - 18:00<br>07:30 - 16:30 | Mon - Fri | 18:00 - 07:00 |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| | | 99 | | | | |
| Bill Print (Document Automation Platform) | DAP | 65 | | | | |
| Bill2000 - Telus 800 Billing | BILL2000 | 01<br>70 | | | | |
| Bills 30 | BILL30 | 02 | | | | |
| BRE Tsweet / Prosim | BRETSWEET | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Business Objects | BO | 02 | Mon - Fri LWD, 1st & 2nd wrk days of month | 07:30 - 20:30<br>07:30 - 18:00 | Mon - Fri Last, 1st, 2nd wrkday of month | 20:30 - 07:30<br>18:00 - 07:30 |
| Call Ahead PC | Call Ahead PC | 01 | | | | |
| Call Center Calculator | C3 | 65 | | | | |
| Call Centre | CALLCENTRE | 69 | | | | |
| Call Management | DAVOX | 65 | | | | |
| Capital Budget System | | 01<br>03 | | | | |
| CCH Tax Programs | TAX | 70 | | | | |
| Ceridian Payroll | CERIDIAN | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Chemical Information<br>CCINFODISC | CCINFO | 01 | | | | |



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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Claris Draw | Claris Corp. | 01 | | | | |
| Commercial Inspections | COMM_INSP | 01 | | | | |
| Competency Management Information System | CMIS | 45 | Mon - Fri | 7:30am-4:30pm | | |
| Complement Management System | CMS ELECTRIC | 02 | Mon - Fri | 08:30 - 18:00 | | |
| Computer Aided Dispatch | CAD | 01 | Mon - Fri<br>Sat<br>Sun & Holidays | 07:30 - 07:30<br>00:00 - 21:00<br>07:30 - 02:00 | Mon - Fri | 18:00 - 07:00 |
| Computer Aided Drafting | Intergraph | 01<br>03 | | | | |
| Computer Output to Laser Disk (COLD) | COLD | 65 | | | | |
| Consolidated Billing System | MAGTAPE | 65 | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |
| Construction Automated Tracking System | CATS | 01 | | | | |
| Contact Index System | COIN | 05 | Mon - Fri<br>Sat<br>Sun & Holidays | 00:00 - 23:59<br>00:00 - 21:00<br>07:00 - 21:00 | Mon - Fri | 18:00 - 07:00 |
| Contact Registry System | CRS | 01<br>70 | | | | |
| Contract Meter Reading | CMR | 01 | | | | |
| Corrective Action Request | CAR | 01 | | | | |
| Corrosion Tracking System | Corr32 | 01 | | | | |



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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| CPXMM32 Maintenance manager | CPXMM32 | 01 | | | | |
| Credit & Collection Management System | APLCMS | 05 | Mon - Fri | 07:30 - 17:30 | Mon - Fri | 18:00 - 07:00 |
| CSA C22.1 Database (Canadian Electrical Code Part1) | CSA (??) | 03 | | | | |
| CSA Z662 Database (Oil & Gas Pipeline Systems) | CSA | 03 | | | | |
| CU Reprographics Requisitions | CUREPRO | 01 | | | | |
| CU Water Billing System - Diamond | WIS | 18 | | | | |
| Customer Account Copy Utility | CA Copy | 65 | | | | |
| Customer Information System | OLDCIS | 65 | Mon - Fri<br>Sat<br>Sun & Holidays<br>Cash | 07:00 - 21:00<br>07:00 - 21:00<br>07:00 - 21:00<br>07:00 - 20:00 | Mon - Fri | 21:00 - 07:00 |
| Customer Information System | ATCO-CIS | 65 | Mon - Fri ,<br><br><br><br>Sat | 07:00 - 19:00 Update mode, 19:00 - 21:00 Inquiry mode<br><br>08:00 - 16:00 Update mode | Mon - Fri | 19:00 - 07:00 |
| Customer Information System - Natural | CISNAT | 65 | Mon - Fri<br>Sat<br>Sun | 07:00 - 21:00 | | |
| Customer Management Module | CMM | 01 | | | | |



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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Daily Oil Bulletin (Nickles) | Nickles | 01<br>03<br>15 | Mon - Fri | 07:30 - 18:00 | | |
| Deferred Gas Analysis | DGA | 01 | Mon - Fri | 07:30 - 18:00 | | |
| Directline Banking | Bank of Montreal | 01 | | | | |
| Drawing Management System | DMS | 45 | Mon - Fri | 07:30 - 18:00 | | |
| Drayton Valley Billing System | BDS | 01 | | | | |
| ECHO Charitable Donation Database | ECHO | 01<br>02 | | | | |
| Emergency Mapping | EGIS EMERG | 01 | | | | |
| Employee Biographics System | EBS | 01<br>02<br>03<br>31<br>45<br>65<br>70<br>99 | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |
| Employee Community Service Fund | ECSF | 03 | | | | |
| Energy Navigator | | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Engineering Work Requests | EWR | 45 | Mon - Fri | 07:30 - 18:00 | | |
| ESSBASE | ESSBASE | 02 | | | | |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Event Tracking System | EVENTS | 03 | | | | |
| Executive Graphics Info System | EGIS | 01 | | | | |
| Executive Information System | EIS | 01 | | | | |
| Expedite | Expedite | 01<br>02<br>03 | | | | |
| Facility Maintenance Management System | FMMS - Maximo | 02 | Mon - Fri<br>Sat<br>Sun & Holidays | 00:00 - 23:30<br>00:00 - 23:30<br>00:00 - 23:30 | Mon - Fri<br>Sat<br>Sun & Holidays | 23:30 - 23:59<br>23:30 - 23:59<br>23:30 - 23:59 |
| FIS Data Warehouse | FISDSS | 02<br>45 | | | | |
| Fleet Asset Reporting Module | FARM | 01 | | | | |
| Fleet Repair Database | FRD | 01 | | | | |
| FMMS - Substation Inspection System | SINS | 02 | | | | |
| FMMS - Tapchart | Tapchart | 02 | | | | |
| FMMS - Testform | Testform | 02 | | | | |
| FMMS - Testline | Testline | 02 | | | | |
| Frontec Security Payroll | Frontec Security Payroll | 69 | | | | |
| Fuel Cardlock System | PHOENIX | 01 | | | | |
| Gannett Flemming | GANFLEM | 01 | | | | |
| Gas Accounting (Gas Management System) | GMS | 01<br>03 | Mon - Fri<br>Sat<br>Sun & Holidays | 00:00 - 24:00 | Mon - Fri<br>Sat<br>Sun & Holidays | 18:00 - 07:00 |



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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Gas Chromatograph | EZChrome | 01 | | | | |
| Gas Odorant Systems | Odor_Monitor | 01 | | | | |
| Gas Purchase Contracts Database System | CDBS | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Gas Specifications Management System Development | GSMS | 01 | | | | |
| Gas Valve Inspection (formerly Valve Inspection Tracking) | GAS VALVE (formerly Valves) | 01 | | | | |
| General Accounting (Financial Information System) | General Acctng (FGS) | 01<br>03 | Mon - Fri | 07:30 - 18:00 | | |
| Generation Effective Management System | GEMM | 45 | Batch Only | Batch Only | | |
| GLDI (Desktop Integrator) | GLDI | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Global Tables System | GTS | 99 | Mon - Fri<br>Sat<br>Sun & Holidays | 07:30 - 02:00<br>07:30 - 02:00<br>07:30 - 02:00 | Mon - Fri | 18:00 - 07:00 |
| Graphics Information (Ensight) | EGIS ENSIGHT | 01 | | | | |
| GRI - GLY Calculator | GRI | 15 | Mon - Fri | 07:30 - 18:00 | | |
| High River Bill print | BHS | 01 | | | | |
| Hydrate | Hydrate | 03 | | | | |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Hyperion | Hyperion | 70 | Mon - Fri | 07:30 - 18:00 | | |
| Industrial Revenue, Reporting and Forecasting System | IRRFS | 02 | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |
| Infomaker | Infomaker | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Instrument Recording System | IRS GAS | 01 | | | | |
| Internet/Intranet Web Sites | Internet | 01<br>02<br>03<br>65<br>70<br>99 | | | | |
| IRIMS | IRIMS | 15<br>69 | Mon - Fri | 07:30 - 18:00 | | |
| Isolated Generation Reporting | IGR | 02 | | | | |
| Isolated Plants System | ISOSYS | 02 | | | | |
| Job Costing System | JCS | 01<br>02<br>03<br>45<br>65<br>70<br>99 | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| JV Uploads | JVUPLOAD | 01<br>03 | | | | |
| Kedit | KEDIT | 01 | | | | |
| KeyPlus | KEYPLUS | 65 | Mon - Fri | 07:30 - 18:00 | | |
| Land and Properties Management System | LPMS | 02 | | | | |
| Land Information System | LIS | 01 | | | | |
| LCSD | LCSD | 02 | | | | |
| Leak Analysis Mangement System | LAMS XP | 01 | | | | |
| Line, equipment, valves | LEV | 45 | Mon - Fri | 07:30 - 18:00 | | |
| Load Duration Curve Models | Load Duration Curve Models | 01 | | | | |
| Load Research | LOADR | 01<br>03 | | | | |
| Load Research Data Maintenance & Analysis | DMA | 02 | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |
| LodeSTAR | LodeSTAR | 02 | Mon-Fri | | | |
| Loss Control Information System, now renamed to Colater | LCIS | 02 | | | | |
| LPSS | LPSS | 02 | Mon-Fri | | | |
| Managerial Reporting | MR | 01<br>70 | | | | |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Mastertech/Techview (Techview for Windows) | TECHVIEW | 01 | | | | |
| Materials Management System | MMS | 01<br>02<br>03 | Mon - Fri | 07:00 - 18:00<br>07:30 - 16:30 | | |
| Materials Safety Data Sheets | MSDS | 02<br>45 | | | | |
| Mercury | MERC | 03 | | | | |
| Meter Prover | DRESSER | 01 | | | | |
| Meter Proving System | MPS | 01 | | | | |
| MeterMaster | METERMASTER | 01 | | | | |
| Metretek DC2000 | METRETEK | 03 | | | | |
| Metscan | Metscan | 01 | | | | |
| Metscan Device Setup | CID | 01 | | | | |
| Micrographics (VersaImage) | VersaImage | 01 | | | | |
| MicroPoint POS (Cashier System) | MicroPoint | 01<br>02<br>65 | Mon - Fri | 08:00 - 18:00 | | |
| Microstation | USTATION | 01<br>02 | | | | |
| Mileage Tracking System | Mileage Tracking System | 01 | | | | |
| Monarch | Monarch | 01 | | | | |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| MP2000 | IVR | 01 | | | | |
| MSDS View-Print 32 bit | MSDS - 32 | 15 | | | | |
| Natural Gas Exchange | NGX | 03 | | | | |
| Natural Gas Vehicle Billing | NGV | 01 | | | | |
| NGX Streamline | NGX MIDSTR | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Non-Gas Sales Information System | NGSIS | 01 | Mon - Fri<br>Sat<br>Sun & Holidays | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |
| NrG Information Highway | NrG | 03 15 | | | | |
| O&M Summary Reporting System | OMSRS | 01 | | | | |
| Operating and Maintenance Manuals | OMManual | 45 | Mon - Fri | 07:30 - 18:00 | | |
| Oracle Financial Analyser | OFA | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Oracle Financials 10.1.0 SC14 | ORAFIN | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Oracle Financials 11i | OFIN | 65<br>99 | | | Mon - Fri | 17:00 - 8:00 |
| Oracle Financials 11i | OFIN | 01<br>02<br>03<br>15<br>31<br>45<br>69 | Mon - Sun & Holidays | 04:30 - 21:00 | Mon - Sun & Holidays | |



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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| | | 70<br>99 | | | | |
| Orders Processing System | OPS | 01<br>02<br>03 | Mon - Fri | 07:30 - 18:00<br>07:30 - 16:30 | | |
| Org Plus | ORGPLUS | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Palisade @ Risk Decision Tools | @RISK | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Payroll Distribution System | PDS | 01<br>02<br>03<br>31<br>45<br>99 | Batch Only | Batch Only | Mon - Fri | 18:00 - 07:00 |
| Payroll Human Resources System | PHRS | 01<br>02<br>03<br>31<br>45<br>65<br>70<br>99 | Mon - Fri<br>Payroll Day | 07:30 - 18:00<br>07:30 - 16:30 | Mon - Fri | 18:00 - 07:00 |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Payroll T4 System | HPS | 01<br>02<br>03<br>31<br>45<br>65<br>70<br>99 | | | | |
| PC Automate | PCAUTO | 01 | | | | |
| Peaksimple Chromatography | CHROM | 01 | | | | |
| Pegasys Server Application | Pegasys | 02 | Mon-Fri | | | |
| Pension Quotation Software | PQS | 70 | | | | |
| Petroleum Safety Training | MAKESAFE | 01 | | | | |
| Pipeline Evaluation Program | PEP | 03 | | | | |
| Pipeline Reg Station Inspection | PIPELINE REGS | 01 | | | | |
| Pipeline Tax Calculation | LINE PIPE | 01 | | | | |
| Pipeline Valve Inspection | PIPELINE VALVE | 03 | | | | |
| PO Requisition Tracking System | POREQN | 02<br>45 | | | | |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Point Cast (Entry Point) | POINTCAST | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Power Builder | PBUILDER | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Power Generation Billing System | PGBS | 45 | Mon - Fri, Sat & Sun | 00:30 - 23:30 | Mon - Fri, Sat&Sun | 00:30 - 23:30 |
| Premier Plus 4 | PP4 or P+4 | 01 | Mon - Sun | 7X24 | | |
| Pressure Factor Measurement System | PFMS | 01 | | | | |
| Procurement Access Link | PAL | 02 | | | | |
| Property Tax System | PTX - 01,03<br>PTS - 02 | 01<br>02<br>03<br>45 | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |
| Qwiz | Qwiz | 01 | | | | |
| Rate Expert | | 02 | | | | |
| Remittance Processing | REMITTANCE | 65 | | | | |
| RightFax NT | RIGHTFAX | 01<br>02<br>03 | | | | |
| Rivest Tracker | RIVEST | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Royal Bank -EFT Express | RB-EFT | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Safety Reporting System | Safety Reporting System | 01 | | | | |
| Sedar | Sedar | 70 | Mon - Fri | 07:30 - 18:00 | | |
| SeriesFive | SeriesFive | 65 | | | | |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Service Interruption Reporting | SIR | 02 | | | | |
| Smart Label Printer Pro | LABELPRINT | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Staff Purchases Tracking System | Staff Purchases Tracking System | 02 | | | | |
| Standards and Quality Assurance Database | SQAM | 01<br>03 | | | | |
| Surface Lease Management System | SLMS | 01<br>03 | | | | |
| SynerGEE | SYNERGEE | 01 03 15 | | | | |
| SynerGEE CMM | SynerGEE CMM | 01 | | | | |
| SynerGEE USM | SynerGEE USM | 03 | | | | |
| Tables on Diskette | TOD | 03 | | | | |
| Tax Prep Applications | TAXPREP | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Textbridge Pro 98 | TEXTBRIDGE | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Time Entry System | TES | 01<br>02<br>03<br>45<br>65<br>70 | Mon - Fri<br>Payroll Day | 07:30 - 18:00<br>07:30 - 16:30 | Mon - Fri | 18:00 - 07:00 |
| ToolHound | ToolHound | 01 | | | | |
| Totalflow Meters | TOTALFLO | 01 | | | | |


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| Application | ID | Co No | On-line Available Days | On-line Available Times | Batch Processing Days | Batch Processing Times |
|---|---|---|---|---|---|---|
| Tracker Training Information System | Tracker | 65 | | | | |
| Trading Partner PC | EDI | 01<br>03 | | | | |
| Transenergy | TEM | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Transportation Information System | TIS | 03 | Mon - Sun & Holidays | 7X24, except 3rd Sunday, which is best effort | Mon - Fri | 18:00 - 07:00 |
| TRIM Records Management | TRIM | 01 | | | | |
| UCAD | UCAD | 01 | | | | |
| Units Converter | UCONVERT | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Variance Explanation System | VES | 01 | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 |
| Vista | PEGASYS | 02 | | | | |
| Way to View | FRAMME | 01 | | | | |
| Web Client | WEBCLIENT | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Weld Calculation | WELDIT | 03 | Mon - Fri | 07:30 - 18:00 | | |
| WHMIS ParkLane | ParkLane | 01 | | | | |
| Winbeep 32 | WINBEEP32 | 01 | | | | |
| WinCats | WINCATS | 15 | Mon - Fri | 07:30 - 18:00 | | |
| Winfuel | WINFUEL | 01 | | | | |
| Wingis | WINGIS | 15 | Mon - Fri | 07:30 - 18:00 | | |
| WolfPAC | WolfPAC | 01 | | | | |
| Work Management System | Work Management System | 05 | | | | |
| X windows | XWIN | 03 | | | | |


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# ENTERPRISE SERVER

| Component | ID | Level 2 Support | Level 3 Support | Post Avail | On-line Processing Days | On-line Processing Time | Batch Processing Days | Batch Processing Time | Notes |
|---|---|---|---|---|---|---|---|---|---|
| ADABAS | ADA200 | Database Management (DBM) | Technical Support (TS) | Yes | Mon-Fri Sat Sun & Hol | 00:00 - 23:59<br>00:00 - 21:00<br>07:00 - 21:00 | | | |
| AFP | | TS | TS | No | | | | | |
| CICS/ESA | CICS | TS | TS | Yes | Mon-Fri Sat Sun & Hol | 00:00 - 23:59<br>00:00 - 21:00<br>07:30 - 21:00 | | | |
| DB2 | | DBM | TS | Yes | Mon-Fri Sat Sun & Hol | 00:00 - 23:59<br>00:00 - 21:00<br>07:30 - 21:00 | | | |
| Express Delivery | | Production Systems Support (PSS) | PSS | Yes | Mon - Sun | 00:00 - 23:59 | | | |
| IMS Data Dictionary | DSIM UCC10 | DBM | DBM | No | Mon - Fri | 07:30 - 18:00 | Mon - Fri | 18:00 - 07:00 | Mainframe: IMS |
| IMS/ESA | IMS | DBM | TS | Yes | Mon-Fri Sat Sun & Hol | 07:30 - 23:59<br>07:30 - 21:00<br>07:30 - 21:00 | | | |
| JOBTRAC | JOBTRAC | PSS | PSS | Yes | Mon-Fri Sat Sun & Hol | 00:00 - 23:59<br>00:00 - 21:00<br>07:30 - 23:59 | | | Batch Job Scheduling on the Mainframe |
| Keyplus | | PSS | PSS | Yes | Mon - Fri | 07:30 - 23:00 | | | |
| Z/OS | | TS | TS | Yes | Mon-Sun | 00:00 - 23:59 | | | |
| Natural | | Systems Development (SD) | TS | Yes | Mon-Sun | 00:00 - 23:59 | | | |
| OPS/MVS | | TS | TS | No | | | | | |
| SAR<br>SARRPT<br>SARPSM | | PSS | PSS | Yes | Mon-Sun | 00:00 - 23:59 | | | |
| ServiceCenter | SCPROD | TS | TS | Yes | Mon-Sun. | 5:00 - 4:00 | | | Unavailable from 4:00-5:00. Must come down to do the backup. |



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| Component | ID | Level 2 Support | Level 3 Support | Post Avail | On-line Processing Days | On-line Processing Time | Batch Processing Days | Batch Processing Time | Notes |
|---|---|---|---|---|---|---|---|---|---|
| SNSTCP | | TS | TS | Yes | | | | | |
| TLMS | | PSS | TS | Yes | Mon-Fri | 00:00 - 23:59 | | | |
| TSO/E ESA | TSO | TS | TS | Yes | Mon-Fri<br>Sat<br>Sun & Hol | 00:00 - 23:59<br>00:00 - 21:00<br>00:00 - 23:59 | | | |
| VPS | | TS | TS | | | | | | |


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# Appendix B: Security Framework Standards

## Security Management – Access and Data Protection

Data security is the control established to protect against accidental or intentional modification, destruction or disclosure of Client and ATCO I-Tek proprietary data. Security is provided for all computers (enterprise server, mid-range, and LAN servers). However, Client is responsible to authorize and track who can retrieve and update data. It is the responsibility of the Client to address situations where unauthorized access attempts have been reported.

ATCO I-Tek will provide Services to maintain and manage data and computer access security in accordance with jointly developed security standards.

Access to computer processors is restricted to people with a valid user-ID and password. Access to databases and files is further restricted through security software features that allow full or read-only access and/or refuse access totally.

Remote access security is in place on the ATCO I-Tek supported network for the dial-up access service as well as for the VPN (Virtual Private Network) access service. The dial-up security device monitors incoming calls and determines whether or not the caller is authorized to access the network. VPN connectivity is protected by the creation of a secure, encrypted tunnel across the internet to the ATCO corporate network for each session.

ATCO I-Tek provides Services to maintain and manage information and computer security in accordance with the security framework standards.

## Security Planning

Security planning is the formulation of a security policy for the computing infrastructure. The security planning policy addresses the assessment of security audits, utilization of security software, virus detection, disinfection and communication, as well as physical and logical security aspects, including networks, data, remote Systems, user access, Internet firewalls, and facilities.

Security ensures that no unauthorized access to the network and data from outside the ATCO Network occurs. ATCO I-Tek provides computer and data access administration that ensure the integrity, currency and accuracy of security and data guardian records. Client profile information and access request processing is provided within 1 Business Day of receiving appropriate authorizations.

## Security Administration

ATCO I-Tek will continue to support the security policies and processes developed by ATCO's Database Management & Data Security group including the use of the SRMS (Security Resource Management System) tool and the Data Owner philosophy. User logon security is generally provided through the server operating systems and, in some cases, by individual applications.



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ATCO I-Tek responsibilities for security administration are:

- Immediately notify Client of known security violations.
- Resolve security violations as they pertain to ATCO I-Tek facilities, Systems, networks, personnel or other assets.
- Provide training in security administration to application coordinators, as appropriate.
- Provide System security utilizing password aging features, protected log-ins, directory and file protection at the user level/group level, protection with read/write/execute privileges, and security encryption features.
- Generate and provide monthly user-ID administration reports.
- Investigate, report, and resolve security issues, with Client's assistance as required.
- Process emergency / non-routine requests for ID adds, changes and deletes within mutually agreed upon (Client and ATCO I-Tek) timelines.

**Security Monitoring**

Security monitoring is the security process that protects ATCO I-Tek and Client assets from threats through the following actions:

- Scanning the network resources for viruses.
- Establishing secure information access and usage.
- Authorizing and authenticating access to resources.
- Conducting security monitoring.
- Backing up and restoring data and application files.

ATCO I-Tek responsibilities for security monitoring are:

- No access without appropriate authorization from Client.
- Managed supervisory access to administer servers.
- Ensure only authorized users are provided with password resets.
- Ensure compliance with the established security standards.
- Security patch compliance monitoring.



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Information is one of the most valuable assets the Client possesses. Unless the information is timely, accurate and protected from unauthorized disclosure or alteration, the Client's business cannot succeed. The widespread use of computers is providing new opportunities for creating, communicating and analyzing key information upon which the Client's business depends. This same power to process and transfer large amounts of data very rapidly also has the potential to create a number of new risks. In recognizing these risks, ATCO I-Tek has created a security framework that addresses all aspects of the security of information. These standards provide a set of rules and practices that regulate how the Client manages, protects, and distributes sensitive information.

**Access**

*Authentication* - All System users, either individuals or connected processors, must be uniquely identified and authenticated. Authentication is typically provided when a password is used with a user identification (user ID) and provides a method for uniquely identifying and verifying who is attempting to use a System resource.

*Authorization* - Access to System resources is limited to authorized individuals. The resources of the Client are protected from access except to individuals or connected processors that have been specifically granted access on a need to know basis.

*Passwords* - User identification must be authenticated by the use of passwords. Passwords must be kept secret and should be complex enough to prevent guessing, but not so complex to not be remembered.

**Management**

*Compliance Monitoring* - Mechanisms and procedures to monitor compliance with security measures and policy will be maintained. The monitoring of compliance to the policies will establish accountability for the actions of users.



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*Data Guardianship (Ownership)* - The ”ownership” of all corporate data must be assigned to an individual known as a “Data Guardian”. The Data Guardian is typically the Manager of the department that generates the data or information. The Data Guardian is responsible for making and communicating decisions, on behalf of the organization, to ensure that the data is controlled and accessed only by those with the authority to do so.

*Data Custodianship (Management)* - The management of all corporate data must be assigned to an individual known as a “Data Custodian”. The Data Custodian is responsible for defining the procedures required for data access and invoking the authorization process based on approval from the Data Guardian.

*Deviations to Policies and Standards* - All deviations from and non-compliance with policies and standards will be recorded and processed in accordance with their nature and circumstances. Non-compliance or deviations to the policies and standards can cause security exposures and potential impact to the business.

*Management Responsibilities* - Management is directly responsible for monitoring and enforcing adherence to the security policies and standards by the individuals and System components within their direct control.

*Operational Support* - An operational support function should be in place and be responsible for providing a stable operating environment of computer Systems. Lack of attention or avoidance of operational support activities may provide an unstable environment that may be open to compromise.

*Risk Assessment* - Identification and evaluation of the type of risks, their probability of occurrence, and their potential adverse impact on an information System will be used as a base for determining security requirements.

*Security Administration* - A security administration function has the responsibility to carry out the administration of security components, processes, and procedures.

*Segregation of Duties* - To reduce the opportunities for any person to breach security, no individual, regardless of seniority, should have the ability to carry out every step of a sensitive business transaction. Consider controls that separate a process into component parts and require different authorized users to perform different parts in order to complete the process.

*Systems Development* - Security considerations must be considered whenever a new computer System is being designed and developed. Security features should include but not be limited to standard access policies, controls through data classification, data and System integrity, and user accountability through audit information, and should provide for continuity of service.



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*Standards* - The use of standards is an important principle that will apply to all Systems and business processes where adoption of standards has been approved and documented. Deviations from the documented standards will require business justification.

**Software**

*Software Copyright* - All users of software will strictly adhere to the terms and conditions regarding copyright, as outlined in licensing agreements accompanying each software product.

*Virus Protection* - A virus protection and detection process is required to be maintained in the operation of the computer Systems. All external data and software introduced into the System must be first checked for the presence of any viruses.

**Data**

*Classification of Data* - All data must be classified by its nature and purpose in order to apply the appropriate measures regarding integrity, availability and confidentiality of the information.

*Integrity of Data* - Data that is used to carry out the Client's business must be accurate and available for use when required. The data must be protected and measures invoked to ensure accuracy and availability of the data. The measures used will be in accordance with the classification of data.

**Information**

*Audit Information* - Where identified as a requirement for a specific application, a record of System activities will be maintained that is sufficient to enable the reconstruction, review and examination of a completed transaction, from its inception to output of final result. These records must be maintained in accordance with legal, government, industry, or corporate regulations.

*Privacy of Information* - Personal and Client Data will be protected from accidental or deliberate disclosure in compliance with the Protection of Privacy Act of the Province of Alberta.

*Classification of Information* - The information that is maintained within the Client organization should be reviewed and classified according to its importance, availability and sensitivity requirements.



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*Integrity of Information* - Mechanisms, processes, and procedures must be maintained to provide integrity of Systems information. This is a required standard for business computing Systems and will promote the secure operation of Systems.



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**Systems**

*Classification of Systems* - All data, information, and Systems generated or maintained are subject to a classification depending on their nature and use. Classification enables ATCO I-Tek to make decisions on the level of protection required, as well as providing input into the backup and recovery plans.

*Business Continuity* - All business Systems will be subject to an appropriate level of business continuity planning to meet availability requirements and to limit the impact of service interruption. The unavailability of data, components or Systems could have a serious impact on business operation.

**Users**

*Personal Use* - Employees shall not utilize the System resources to support any activities other than those that support their duties of employment. All product(s) developed on System resources are owned by Client and permission must be granted for personal use. An employee does not have the right to sell, distribute or copy any material developed in support of their job functions without an appropriate level of authorization.

*Use of Information Systems* - Users must not use information Systems in an illegal, immoral, unethical, or harmful manner. The expanding use of technology for electronic mail and information exchange both internally and externally provides an expedient method for creating and distributing information. The users of these information Systems must utilize the Systems in a legal, responsible manner.

*User Awareness* - Communication programs will be implemented and maintained to ensure users are aware of the requirement for security and the facilities, processes and procedures that support the security requirements.

*User Responsibilities* - Users of the Systems must be knowledgeable of and adhere to the security framework as specified. Users are responsible and accountable for all System(s) access made using their identification code.

**Network**

*Electronic Mail* - The use of electronic mail Systems must be limited to company and company related interests. Privacy and confidentiality of communications must be respected and the Systems used in a secure manner.



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*Facsimile and Telephone Integrity* - The privacy of telephone and facsimile communication must be respected and these forms of communication must be used in a secure manner. Both facsimile and telephone facilities are to be used for business use only. Non-business use is discouraged. The privacy of telephone conversations and facsimile transmissions should be respected, and the use of these facilities for exchanging highly Confidential Information should be restricted.

*Toll Fraud* - Telecommunications Systems must be protected to deter unauthorized and fraudulent use of facilities. Access to functions / features must be controlled by safeguards implemented into the System including, but not limited to the adequate control of calling privileges, protected physical access and authorized remote access methods.

*Remote Network Access (Employee)* - The appropriate justification and security measures must be utilized to provide employees remote access to Systems from a remote location. Implementing access to local Systems or the ATCO Network without adhering to the approved security measures is considered a serious exposure and is strictly prohibited.

*Remote Network Access (Non-employee)* – Remote access to the ATCO Network may be granted to non-employees with the appropriate business justification. Stringent network access measures will be enforced to control access requirements for individuals who are not in the employ of ATCO I-Tek. Abuse of any non-employee access will result in immediate termination of the privilege.

*Internet* - The Internet is to be used for business related activities only and by authorized personnel with a valid Internet account. Corporate user identification code(s) and password(s) are not to be disclosed over the Internet, and all sensitive or Confidential Information that is transmitted must be encrypted. The downloading of games, viruses, inappropriate graphics or picture files, and illegal software from the Internet is prohibited.

**Other**

*Physical Security* - Measures are required for protecting computers, related equipment (including utilities), and the processing facility itself. Physical security mechanisms such as the use of locks, security guards, access cards, badges and alarms are to be utilized to prevent unauthorized personnel from gaining access to the facility or equipment.

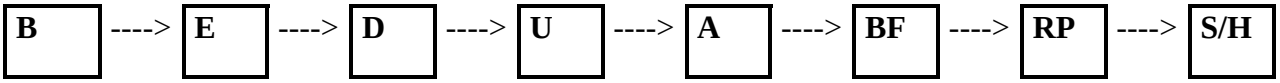
*External Processing* - External service organizations supplying processing Services to the Client, or off-premises processing done by employees requires a secure environment and controls. The use of external processing service bureaus or external processing of information is subject to a review of security controls and adherence to appropriate management mechanisms.



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## Appendix C: Disaster Recovery Methodology

During a recovery effort, ATCO I-Tek follows a common critical path of activities as graphically illustrated below. There are major nodes along the critical path which are followed regardless of computing resource and business organization.




Where: **B** Is the last backup taken prior to contingency.

**E** Is the event, or contingency. Any disruption must be evaluated to determine the severity and estimated time to recover.

**D** Decision whether or not to declare disaster - Emergency Management Team will make final determination to activate plan. Included are the 'Initial Response/Reaction' steps required for protection of life, property, damage assessment and staff mobilization. This is considered Stage 1 of the recovery plan.

**U** Stage 2 - Is the point at which the data processing utility is restored. This will include the operating system and associated program products as well as the backup telecommunication network.

**A** Stage 3 - Is the restoration and verification of the enterprise server applications. This operation is highly dependent of the backup and restoration procedures in place.

**BF** Stage 4 - Is the point where ATCO I-Tek brings forward the applications in order to synchronize data. ATCO I-Tek needs to validate application data status, determine/re-enter lost data and process data stockpile/backlog prior to normal resumption processing.

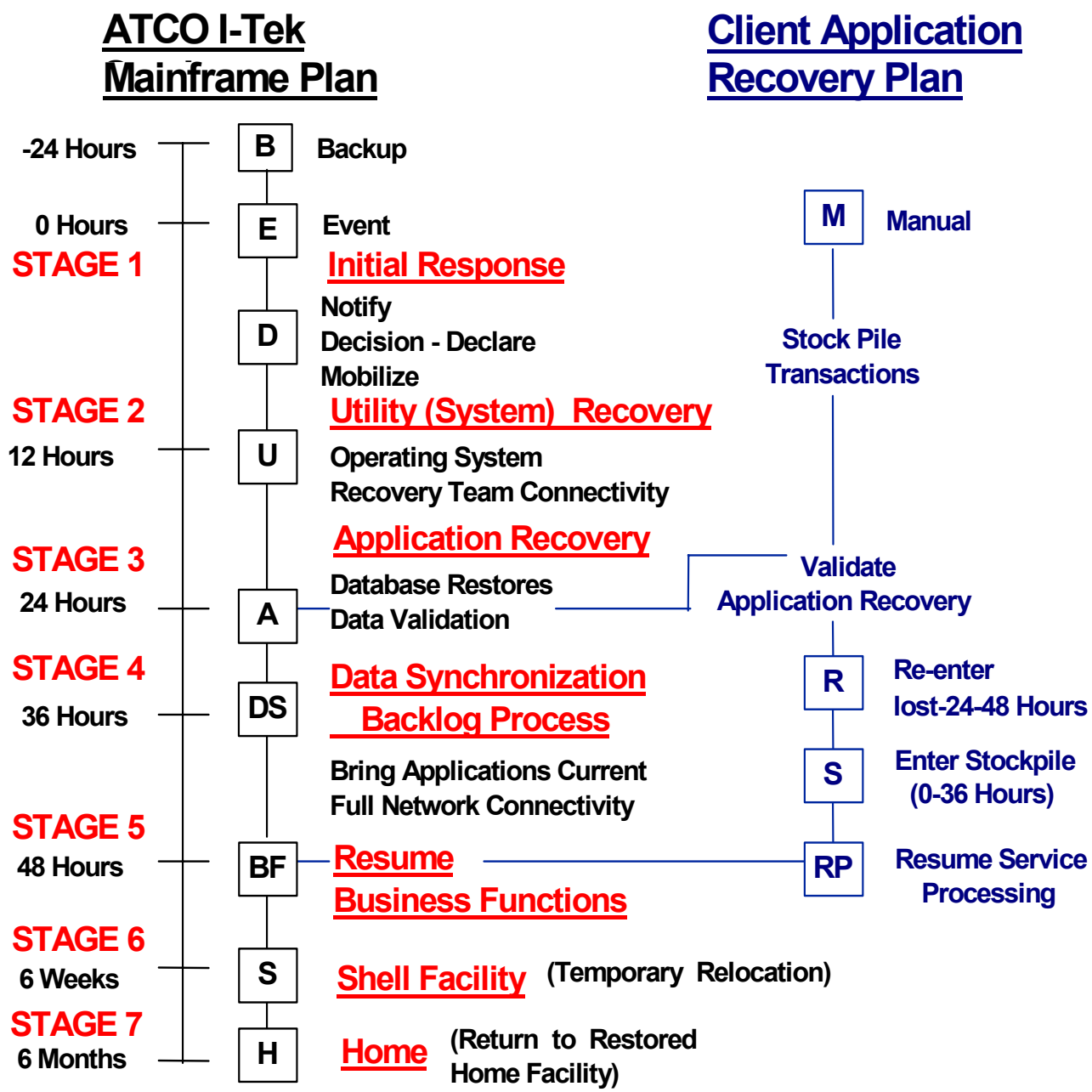
**RP** Stage 5 - Is the point at which the normal resumption processing can occur and business functions are considered fully recovered.

**S/H** Stage 6 - Is the optional transition migration to a Shell Facility should the outage exceed the alternate site capacity or availability and Stage 7 - is the pre-planned return to the recovered host facility (home).

The following diagram illustrates the timelines associated with the seven stages of recovery, as they apply to the ATCO I-Tek enterprise server disaster recovery plan.


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**DISASTER RECOVERY PLAN OVERVIEW**




The ATCO Group is currently undertaking an initiative to review the business requirements and recovery time objective for both the mainframe and distributed environments. This is as a result of changes in the portfolio of applications. The results of this assessment will be provided to ATCO I-Tek who will then prepare proposal(s) to meet the requested recovery time objective for ATCO's consideration. Upon completion of this process contractual recovery time objectives can then be agreed to by both parties pursuant to Article 4 of the Agreement.


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# Appendix D: Consolidated Technology Specifications

***Client / Desktop***

| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| Operating System | Windows XP | Win 32 API's | WIN XP | |

***Network Infrastructure Server***

| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| Corporate Network Operating System (CNOS) | Windows 2000 Server, Windows 2003 Server | Win 32 API | Windows 2000 Server, Windows 2003 Server | |
| | UNIX-NFS | | | |

***Application / Database Server***

| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| Application Server OS | Windows 2000 Server, Windows 2003 Server, Solaris | Win 32 API, UNIX | Windows 2000 Server, Windows 2003 Server, Solaris | |
| Database Server OS | Sun Solaris | UNIX System 5 Cmpliant | Solaris | |


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***Data Access***

| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| Mainframe DBMS | DB2, Adabas, IMS | Ansi SQL Compliant | DB2 | |
| Shared DBMS , non MVS | Oracle, MS Access | Ansi SQL Compliant | Oracle | |
| Desktop DBMS | MS Access | Win 32 API | MS Access | |
| Data API | ODBC, direct data access to all DBMS's | ODBC or direct to DB2, Oracle, MS Access | | |

***Communications***

| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| | | | | |
| Protocol | TCP/IP, 802.3, | TCP/IP, 802.3 | TCP/IP, 802.3 | |
| Horizontal Wiring | Cat 5E UTP, T568A | Category 5E UTP, T568A | Commodity | |
| Vertical Wiring | Cat 5E T568A, Fibre, | Cat 5E T568A, fibre, | Commodity | |
| Horizontal Topology | 802.3, | 802.3 | Commodity | |
| Vertical Topology | 802.3, | 802.3 | Commodity | |
| WAN Connectivity | Frame Relay, Megastream, Dedicated, VPN | High speed converged, VPN for small office sites where applicatable | Carrier commodity | |


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**Messaging / E-mail**

| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| Email Engine/Client | Microsoft Exchange 2000/ Microsoft Outlook | Client/server mail architecture | Microsoft Exchange 2000/Microsoft Outlook, Microsoft Exchange 2003 | |
| | | MAPI mail enablement | | External E-mail. |

**Hardware Platform**

| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| Workstation | Pentium Class 700 Mhz or greater | Processor: Intel Pentium PCI bus<br>Disk SubSystem: EIDE, Video:SVGA, 16MB<br>Monitor: 17 Inch, True color,<br>1024x768 Resolution<br>Bios: Flash BiosMemory: 512 MB on board | Dell Business Class workstations at current specification | |
| Departmental Printers | HP3, HP4, HP4Si, HP4SiMx, HP5Si, HP4100, HP4200 | Postscript Level 2, HPGL 5E, Duplex Handler, | Multifunction printers<br>HP Laserjet 4200 series | Migration through standardization of photo copier/print/fax functions |
| Personal Printers | HP II, HP3, HP4P, HP2200, HP2300 | Postscript Level 2, HPGL 5E, Duplex Available | HP Laserjet 2300 series | Migration through attrition or positive business case. |
| Colour Printers | QMS, Lexmark, HP | Postscript Level 2, HPGL | HP OJ Inkjet | Migration through attrition or positive |


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| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| | | 5E, Inket and Laser | HP 5500 series Laser Printer | business case. |

**Personal Productivity**

| Element | Current | 3 Year Target Specification | 3 Year Target Product/Buy List | Comments |
|---|---|---|---|---|
| Word Processing | MS Word XP, WordPerfect, PageMaker | Win 32 API<br>MS Office Suite | Word | |
| Presentation | PowerPoint, IGRAFX Flow Charter, Corel Draw, Adobe product set | Win 32 API<br>MS Office Suite, Adobe Presentation Suite | PowerPoint, Adobe Product set | |
| Spreadsheet | Excel | Win 32 API<br>MS Office Suite | Excel | |


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## Appendix E: Client Survey Process

ATCO I-Tek and Clients have agreed that, for all closed Problem Tickets and Requests, ATCO I-Tek will survey the end users to confirm that their problems or requests have been dealt with satisfactorily. ATCO I-Tek and Clients have agreed that the ATCO I-Tek account manager will be obligated to meet at least monthly with Clients to discuss Client satisfaction with regard to Services.



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**Appendix F: Priority Level Definitions & Notification Escalation:**

## Problem Tickets

| Priority Levels | Escalation Time (During Normal Business Hours) | Management Contact | Priority Definition |
|---|---|---|---|
| Critical | Immediate<br><br>Immediate<br><br>Immediate<br><br>Exceed TTS | Client Governance Representative<br><br>CSC Supervisor<br><br>Direct Support<br><br>ATCO I-Tek Manager<br>Client Designated Manager<br>ATCO I-Tek Designated Manager<br>ATCO I-Tek Service Area Manager<br>CIO Office | A problem causing an unscheduled interruption to availability of an application, a production server or interrupted customer Services. Business impact is or will be severe. |
| High | Immediate<br><br>Exceed TTS | Direct Support<br><br>CSC Supervisor<br>ATCO I-Tek Manager<br>Client Designated Manager | Problem has disrupted customer service. Customer can continue to process, but at great inconvenience. Business impact is high. |
| Medium | Exceed TTS/TTR | CSC Supervisor<br><br>ATCO I-Tek Manager | Customer service is degraded. Business impact is moderate to low. Solution required in the short term. |
| Low | Exceed TTS/TTR | CSC Supervisor<br><br>ATCO I-Tek Manager | Current customer service has low or negligible impact. Business impact is low. Solution required in the long term. |



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## Appendix F: Priority Level Definitions & Notification Escalation: (cont'd)

## Service Request Process

**Service Request Escalation Process** - ATCO I-Tek's service request process is based on industry standards as defined in the IT Infrastructure Library (ITIL). To manage the service request process, ATCO I-Tek utilizes an automated service desk solution that provides problem, request and change management across the enterprise. The process includes service request logging, efficient routing to the appropriate work areas, and escalation. This promotes quality control by increasing resource efficiency, managing the cost of service delivery and improving Client satisfaction.

A full lifecycle process is implemented to monitor and confirm that all service requests are correctly completed and escalated when necessary. The central point of contact for service requests is the Customer Support Centre (CSC). Upon receipt of a request, the CSC will determine whether the request can be solved at the time of the request or will coordinate the escalation of the request to Tier II level support. All requests are tracked and monitored. In the event that a request is not closed within the original estimated time to completion (dependent on the complexity of work), an automated escalation is sent to the appropriate Tier II support for follow up. Regular exception reporting is completed and provided to the ATCO I-Tek Team Leads and Management for resolution.

The Client will provide updates to forecasts and other workload planning information to ATCO I-Tek at each monthly meeting with the ATCO I-Tek Account Manager, at the time of the Annual Review and from time to time as reasonably requested by ATCO I-Tek and at other times as reasonably provided by the Client, to enable ATCO I-Tek to plan the Services, Service Requests and Statements of Work.

ATCO I-Tek is relying on the forecasts and the workload planning information as they are essential to ATCO I-Tek to identify workload planning and capacity issues that will impact Service Levels.

If the number of service requests or Statements of Work initiated or agreed to by the Client that ATCO I-Tek is required to prepare in any month exceeds ATCO I-Tek's capacity to properly handle the work, ATCO I-Tek will give notice to the Client and the parties will meet promptly:

(i) to identify the service request(s) or Statement(s) of Work that may be deferred or withdrawn and to assign priorities to the remaining Service Request(s) or Statement(s) of Work;

(ii) to discuss what additional costs ATCO I-Tek is required to incur to permit it to prepare the service request(s) or Statement(s) of Work and to determine whether the Client should compensate ATCO I-Tek for any additional costs; and

(iii) to assess whether any other mutually agreeable solution is available.

In the event that a client is dissatisfied with the work performed, they have the option to respond with their concerns through the automatic online client feedback process. This feedback process is in place for all closed requests. ATCO I-Tek reviews all client feedback to determine if



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further action is necessary. Outstanding client requests are managed through internal escalation processes.

Should the escalation to the CSC not resolve the issue, the clients have the option to escalate a complaint directly to the IT Account Manager. It is this Manager's responsibility to then own the issue until the proper area has addressed the issue with the clientClient. The IT Account Manager will perform the necessary escalation within ATCO I-Tek, working with the appropriate manager/management groups to obtain resolution. In the further event that the issue is not resolved, the client has the option to escalate the issue to ATCO's CIO.

Should the parties not be able to resolve the issues, the Dispute Resolution process can be invoked as per Article 16 of the Information Technology Master Services Agreement for the ATCO Group.



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# INFORMATION TECHNOLOGY

# MASTER SERVICES AGREEMENT

# Schedule B – Definition of Services


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# SCHEDULE B – DEFINITION OF SERVICES

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## 1.0 Overview

This Definition of Services is Schedule B to the IT Master Services Agreement (Agreement). The purpose of this document is to describe the Services that will be provided to the Client and the level to which these Services are being delivered. This document is intended to describe the major scope items within each service category, but is not intended to be all-inclusive.

**1.1** **Tier 1 Services** are the Client operational Services ("Mouse pad to Mainframe"). These Services are exclusive to ATCO I-Tek. These Services include Information Technology Services, which are provided to each Client that is participating in the SLA. These Services will be delivered and will meet or exceed the Service Levels outlined in the service measurement document. These include all major Services defined in this section and are generally described as:

- Applications maintenance and enhancements (<40 person days)
- Operations (mainframe and distributed systems)
- Operational technology support
- Customer support center
- Telecommunication Services (data & voice)

The Services will exclude SCADA, AMR and Microwave, which will be retained by the Client.

**1.2** **Tier 2 Services** involve the introduction of Change or new technologies to the Client and apply to development projects requiring more than 40 person-days of work. These projects will require more formal project management. Tier 2 project cost estimates will include all costs associated with the development, implementation and operation and maintenance of the project. ATCO I-Tek will have first right of proposal for all Tier 2 Services.

All new Tier 2 Services required by Client shall commence with a Request, as provided for in Article 4.1 of the IT Master Services Agreement Terms and Conditions. However, if within a reasonable time (as defined by ATCO I-Tek in its Discretion) following the making of a Request, Client and ATCO I-Tek have not agreed on a Statement of Work (i.e., Client has not received a proposal from ATCO I-Tek that is acceptable to Client), Client shall notify the Chief Information Officer of the ATCO Group of the Client's intent to obtain a quote for the Tier 2 Services which are the subject of the Request from another systems management service provider. In the event that Client selects a vendor other than ATCO I-Tek to perform such Tier 2 Services, Client shall pay ATCO I-Tek at the Time and Materials Rate for any Services required from ATCO I-Tek to integrate such Tier 2 Services, or any Deliverables arising from such Services, into the Tier 1 Services and any Tier 2 Services provided by ATCO I-Tek.

**1.3** **Tier 3 Services** - Investment Services is Strategic Planning, Business Planning and Business Improvement Processes. ATCO I-Tek is responsible for assisting the ATCO Group in the development of the ATCO Group corporate technology strategy that coincides with the Business Planning Process. ATCO I-Tek will accomplish this role by


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assessing the ATCO Group's current information technology strategy, and by providing the CIO's and I.T. Governance office with proposals, which contain recommendations of what IT strategies could be implemented to bring the highest value to the ATCO Group. For future business opportunities, ATCO I-Tek will bring forward a business proposal documenting the risks of proceeding and the tangible benefits.

ATCO I-Tek's Technologies department follows the Information Technology Infrastructure Library (ITIL) processes to ensure quality control for hardware and software management. These processes cover a number of areas focusing on IT service delivery and service support.

As it pertains to IT service delivery, ITIL defines management practices to ensure IT Services are provided as agreed between ATCO I-Tek and Clients. These areas include:

- **Service Level Management**
- **Capacity Management**
- **Continuity Management**
- **Availability Management**
- **IT Financial Management**

As it pertains to IT service support, ITIL defines management practices that enable ATCO I-Tek to effectively provide Services. These practices include:

- **Configuration Management**
- **Incident Management**
- **Problem Management**
- **Change Management**
- **Help Desk**
- **Release Management**

ATCO I-Tek's Applications department follows industry standard development practices during the development, enhancement and maintenance of applications. There will be 3 facets to quality management:

- **Quality planning** – identifies which quality standards are relevant to the project and how to satisfy them. These standards will be identified during the project initiation workshop and will be built into the project plan.
- **Quality assurance** – involves the periodic evaluation of overall project performance to ensure the project will satisfy the relevant quality standards.
- **Quality control** – involves monitoring specific project results to ensure they comply with relevant quality standards while identifying ways to improve overall quality.


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These processes will be used in conjunction with Clients input to produce the quality management plan, quality improvement, acceptance decisions and process adjustments throughout the project lifecycle. Some key quality control mechanisms are:

- Project management
- Quality Planning
- Client involvement – part of the development team and regular discussions during the development releases
- Short release/delivery timelines
- Audit reviews
- Pair programming
- Acceptance testing
- Functional walkthroughs
- Development Standards
- Client Quality Reports (scorecard to measure Client's satisfaction)
- Completeness and Correctness checklist


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# 2.0 Definition of Services

## 2.1 Planning

| Tier | Category | Major Scope Items not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | ATCO Group Information Resource Planning for Information Technology | • Define requirements (ATCO & ATCO I-Tek)<br>• Prepare workload plan (ATCO & ATCO I-Tek)<br>• Budget (ATCO)<br>• Obtain resources (ATCO I-Tek) | | | Prepare as required | Approve plans & schedule | Included in all Rates |
| 3 | IT Strategic Planning | • Create 3 year technology plan including architecture & business improvement opportunities<br>• Directed toward senior management and meeting their long term business goals | | | Ensure all other planning efforts are guided by this plan | Free to go to the open market | Included in all Rates |
| 1 | IT Budget Planning | • Prepare estimates for projects & operational costs for Tier 1, 2 and 3 activities requested. | Yearly | | Ensure budget prepared in concert with Strategic plan & reflects current fiscal position of ATCO Group of companies | Lead, prioritize & approve budget plan | Included in all Rates |
| 1 | IT Operational Planning | • Prepare and Manage a Yearly Operational Plan that will provide monthly operational status reports to the CIO's Office.<br>• Development of action plans for the acquisition & deployment of resources to carry out the strategies identified in the Strategic Plan<br>• Includes plans dealing with the day to day operations that are necessary for accomplishing the action plans<br>• Analyze, report, and forecast resource usage to predict future computing capacity requirements.<br>• Provide ATCO with future Technology direction for connectivity, interoperability, and manageability.<br>• Provide coordination of preventive maintenance Services only for those assets that are managed and operationally controlled by ATCO I-Tek that support ATCO. | | | | | Included in all Rates |


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## 2.1 Planning continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | IT Feasibility Studies | • Prepare an Opportunity assessment to warrant further investigation or initiation of a proposal or feasibility study.<br>• Match project proposals to the needs of the business to identify the high savings initiatives or improvements in the current process<br>• Ensure all the standard components of a Feasibility Study are completed (Business Area Analysis, Opportunity Assessment, Cost Benefit, Alternatives, Project Definition) | | | Prepare the plan | Approve plan & schedule | Included in all Rates |

## 2.2 Financial Account Management

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Financial Billing | • Prepare and manage all aspects of the financial billing process as it relates to Information Technology Services provided by ATCO I-Tek. | | | Ensure correct billing for Services provided. | | Included in all Rates |

## 2.3 Standards

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | IT Standards | • Create standards with ATCO business in mind, for the effective development, maintenance & operation of the ATCO Group information & Systems Services<br>• Assist the CIO's Office in the formulation of policies , standards & procedures for the development of strategic & operational plans that enhance the use of information technology. | | | Prepare the standards<br><br>Inform ATCO of non-adherence to Standards | Prepare policies & approve standards<br><br>Approve all non-standard requests | Included in all Rates |


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## 2.4 New Technology & Infrastructure

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | New Technology | • Evaluate new products or Services<br>• Establish new product standard if necessary<br>• Ensure new products are cost effective & fit into overall technology infrastructure environment.<br>• Prepare a conversion strategy and costs<br>• Develop & implement evaluation & testing processes<br>• Obtain Business case approval prior to implementation<br>• Work with the CIO's Office. | All hardware & software including infrastructure<br><br>New Technology evaluations will be determined by the Workload Plan. | | Inform ATCO of non-adherence to Standards<br><br>Ensure proper testing & change management is part of general practices & built into methodology | Review & audit standards when required<br>Approve all non-standard requests<br><br>Validate requests for implementation of non-standard products | Included in all Rates |
| 1 | Release Management | • Release Management is the management and structured release of desktop, server, and network software standards that are mutually determined by ATCO and ATCO I-Tek, within the server environment.<br>• Ensure all standard desktops deployed through the Release Management function will be loaded with the standard set of software applications as mutually determined by ATCO and ATCO I-Tek.<br>• Create, maintain and periodically update a master release schedule with regard to the third party Software that exists in ATCO's environment.<br>• Keep a release calendar current and communicate information to ATCO.<br>• Set tentative release dates for new rollouts that will be determined jointly with ATCO.<br>• Mutually define release standards with ATCO.<br>• Put an integrated process in place across the Release Management and Technology Planning functions. | | | | | Included in all Rates |


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## 2.5 Customer Support Center

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Customer Support Center | • A "single point of contact" for the ATCO Client. If the CSC support analyst cannot resolve the problem/request, a service ticket is created and assigned to the appropriate support group.<br>• The Customer Support Center can be contacted by telephone and by email for non-critical situations<br>  • 420-7466 Edmonton & area<br>  • 245-7466 Calgary & area<br>  • 1-877-420-7466 Toll Free North America | ATCO I-Tek's normal business hours are from 08:00 to 17:00. Monday through Friday<br><br>CSC staff are available "On-site" Monday to Friday 07:00 until 17:00 ("On-site" means that there is a support analyst in the ATCO I-Tek CSC office). After hours, on weekends and statutory/Client holidays, CSC support is provided through our message and paging System.<br><br>24 hours a day, 7 days a week (7x24) coverage to respond to the Client's questions, requests, problems or difficulties in using information Systems Services. | | | | Included in all Rates |
| 1 | Reporting | • Provide statistical reports on Service Tickets as required by Service Level Agreement | Monthly. | | | | Included in all Rates |
| 1 | Problem Management | ***Problem Management***<br>• Manages availability, responsiveness, and serviceability.<br>• Every trouble ticket will have a priority code assigned and agreed to with the caller based on the nature of the situation and the impact of the problem. The impact to availability, on-line response time, usability of an application, integrity of an application, impact on the business, impact on the Clients, the number of people affected, are all considered when assigning the priority code.<br>***Problem Communication and Escalation***<br>• Follow a documented problem communication and escalation procedure. See Schedule A Appendix F – Priority Level Definitions & Notification Escalation. | Application and distributed desktops have their own process for problem management and will be reflected in the Procedures Manual. | | To take ownership of problems & ensure they are resolved to the client's satisfaction | | Included in all Rates |


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## 2.5 Customer Support Center- continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Problem Management – continued | • Immediately inform designated Client contacts (Client governance representative and/or application coordinators) of problems assigned critical priority that affect their Client.<br>• Concerns about quality of service should be first communicated to the support analyst providing the service. If the concern is not resolved, or there is an issue around interpretation of the Service Level Agreement, contact the Supervisor, Customer Support Center. ATCO I-Tek will address such quality concerns with the appropriate Client governance group and/or the CIO Office. If concerns are not resolved, escalation will continue to the ATCO I-Tek Designated Manager<br>***Problem Post-Analysis***<br>• All problems are recorded with information on the nature of the problem, the impact and the resolution.<br>• The problem database is analyzed to determine the nature of problems or the service ticket trends and what proactive efforts would eliminate the root cause of the problems. Root cause analysis is performed as part of the post mortem when a major problem (Critical or High) has occurred. This effort is focused on determining the actual cause of the problem and developing appropriate corrective action. | | | | | |


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## 2.5 Customer Support Center- continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Change Management | • Change Management will be provided to maintain availability, responsiveness and serviceability for the ATCO Group of companies enterprise computing environment<br>• When the Client or ATCO I-Tek deems that a change to an application, computing tool or service is required, to meet a new business need, a technical need or resolve a problem, a process is commenced to define the requirements; an analysis of impact; an analysis of options; and a costing of service and financial justification<br>• A record of changes is created, to notify all potentially affected parties, to co-ordinate changes, to reduce conflicts, and to provide a standard methodology.<br>• Provide change management reports.<br>• Pre-determined and planned outages will be communicated to Clients.<br>• Key contact people listed in Appendix A will receive a weekly schedule of all scheduled outages by electronic mail.<br>• Clients can call the Customer Support Center to receive information about any scheduled outages.<br>• All new application releases are tested and the ATCO I-Tek staff is briefed for support of their use before the changes are implemented. This will ensure appropriate communications between ATCO I-Tek and the Client. ATCO I-Tek must arrange Service Requests to be addressed in the acceptable timeframe required by the | **Change Windows**<br>Changes are implemented according to the following scheduled "Change Windows":<br>REGULAR SUNDAY: Each Sunday from 15:00 to 02:00 Monday.<br><br>THIRD SUNDAY: The 3rd weekend of each month from 08:00 Sunday to 07:00 Monday. | Individual workstation specific changes do not necessarily follow the Change Windows schedule. | Pre-arrange scheduled downtimes ("Change Windows") between ATCO I-Tek and the Clients.<br><br>Notify the Clients of the planned outages and exceptions or delays to the changes.<br><br>Endeavor to minimize changes outside the Change Windows. | In order to ensure change is managed by ATCO I-Tek, Clients must not move, install or remove hardware or software from the workstation or make workstation configuration changes.<br><br>Agreement for changes will not be unreasonably withheld.<br><br>ATCO Clients are responsible for reviewing change notification and raising any issues or concerns with ATCO I-Tek. | Included in all Rates |


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## 2.5 Customer Support Center- continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Change Management - continued | ***Change Lead-time Exceptions***<br>• Sufficient lead-time for changes are required as outlined in the Services Level Measurements document. The nature of some changes may extend the lead time requirements if the changes require work or equipment from third party suppliers.<br>• Change schedules can be negotiated considering the needs of the Clients, their business cycles, the impact on the business, short and long-term preventative maintenance and the consequences of not performing the change<br>***Year-end Freeze***<br>• To facilitate completion of year-end processing, a no-change period (yearend freeze) is instituted from late December to late January. The period generally begins after the third Sunday Change Window in December and ends before the third Sunday Change Window in January.<br>• Changes during the year end freeze can be negotiated considering the needs of the Clients, their business cycles, the impact on their business, impact on other Companies on the ATCO Network, and the consequences of not performing the change. During the year-end freeze, ATCO I-Tek and ATCO senior management must approve all changes.<br>• ATCO I-Tek will work with the telecommunication service providers to minimize telecommunications company network changes that occur within this window. | | | | | |


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## 2.5 Customer Support Center- continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Change Management - continued | ***Application Changes***<br>• Application changes are made according to the schedule dictated by the owners of the respective applications. For the mainframe environment this may involve a release management approach or be single change implementations.<br>• Ensure that any changes that may impact the client environment is logged | | | | | |
| 1 | Corrective Action Team (CAT) | • A process that brings a cross functional team together to manage a major outage, on-going issue, or problem to resolution | | | | | Included in all Rates |
| 1 | Client Satisfaction | • Confirm with client that problem was resolved to Client satisfaction | | | | | Included in all Rates |

## 2.6 Security Management

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Security Management | • Provide Services to maintain and manage data and computer access security. Security Management and Framework Standards are contained in Schedule A Appendix B.<br>• Manage user ids<br>• Monitor, report & control access violations<br>• Follow all procedures for the administration of data security<br>• Manage security policies & procedures as approved by the ATCO Group<br>• Investigate security breaches<br>• Implement corrective actions for security breaches<br>• Provide Security and Documentation for the Logical Network. | | Data and ID access changes as a result of major dept. / Corporate restructuring | ATCO I-Tek to recommend Policy and security standards<br><br>See Security Framework Standards in Appendix B | ATCO to approve Policy and security standards<br><br>See Security Framework Standards in Appendix B | Included in all Rates |


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## 2.7 Asset Management

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Purchasing | • Manage the order process (i.e., from the inception of a new purchase through the installation and user acceptance of the product).<br>• A quarterly installation plan, based upon the Business Plan, will be established and agreed to with each Client for new, replacement, and re-deployed equipment. Exceptions and changes to the plan will be factored in as required.<br>***Standards Management/End-User Consultation***<br>• Provide and maintain an ATCO based standard and to assist end users in the proper selection of the desktop and network configurations and Services. The intent will be to ensure that this equipment is consistent with the standards of the Client to minimize the costs and maximize the compatibility with other corporate Systems and equipment prior to implementation<br>• Document and communicate problems with processes, product availability concerns or any other related issues to ATCO management.<br>• Ensure physical identification of assets.<br>• Maintain configuration and usage profiles of the equipment.<br>• Maintain inventory of spare parts for critical components.<br>• Analyze the implications of using older equipment and migrating to new equipment. Plan the migration strategy.<br>• Complete a recommendation that meets the Client's business needs. | Workstation installs and technology refreshes are included in the PC support fees. All other Moves/Adds/Changes to workstations and voice are charged a per fee instance.<br><br>ATCO I-Tek provides a comprehensive asset management program for all leased devices. Asset management includes recommendation and selection of standards, vendor management, procurement, tagging, Client assignment, tracking, refresh, removal, decommissioning and disposal. | For adds / moves after regular ATCO I-Tek business hours, as agreed to by Client, incremental charges will apply. | Identify when deviations from standard products are requested.<br><br>Verify request to ATCO's standards.<br><br>In consultation with Clients, ensure the refresh strategy addresses Client needs & review process as required.<br><br>ATCO I-Tek develops annual refresh schedules and provides these reports to the Clients. | Will be responsible for having a policy around the purchase of non-standard software by a user<br><br>Review & audit processes. | Included in Lease Rates |


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## 2.7 Asset Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Purchasing - continued | ***Asset Management***<br>• Manage and maintain asset information for software, hardware and network components (e.g. location, model type, serial number, user, and Client).<br>• Record purchasing information for each asset (e.g. manufacturer, vendor, cost, and warranty information).<br>• Record maintenance agreement information.<br>• Maintain and manage software-licensing information.<br>• Report/query on replacement cost for all assets.<br>• Plan moves and track the components and workstations that require connection to the network.<br>• Provide asset-reporting information for budget and capacity planning purposes.<br>***Workstations***<br>• Plan, test, acquire, implement, support, maintain, re-deploy, and ultimately replace and retire the equipment, while following the consolidated technology specifications (see Technology Roadmap).<br>• Work with individual Client to plan for technology as required to meet new and growing business requirements.<br>• Ensure that the equipment is properly tested to identify any issues and make necessary adjustments prior to implementation.<br>• Maintain the equipment in proper working condition and to provide any support as required to fix problems as they occur. | | | | | |


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## 2.7 Asset Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Purchasing - continued | • Work with Representatives of the individual Client to determine the best place to deploy the new technology. In general, this means that the new equipment will be deployed to a client with higher relative demand and the existing equipment will be "cascaded" to the lower end user, whose machine will, in most cases, be targeted for disposal. Only one cascade will be allowed per refresh deployment. | | | | | |
| 1 | Inventory | • Maintain & track an inventory of hardware & software<br>• Log all adds, moves, repairs & retirements of assets<br>• ATCO I-Tek will take appropriate measures to ensure that the physical existance of assets is accurate and complete. The assurance can be derived through physical review of the employment of appropriate software tools. | Licenses acquired by an ATCO business unit are not managed by ATCO I-Tek. | | Ensure that inventory Systems are in place & associated processes are followed correctly to ensure accurate inventory. ATCO I-Tek tracks software to ensure software license compliance. All software that is purchased through and installed by ATCO I-Tek will be managed and tracked to ensure license compliance. Licenses that are acquired or installed by the client are the responsibility of the Client. | Enforce compliance with inventory management processes (e.g. movement of all computing assets just be handled by ATCO I-Tek staff to ensure inventory information is maintained). | Included in all Rates. In the event that the client moves hardware from one location to another location without enlisting ATCO I-Tek staff, that client will be charged a handling and update fee to identify the movement and correct all asset information on that asset. |
| 1 | Reporting | • Financial reporting.<br>• Reports on Service Levels and delivery measurements.<br>• Ad hoc Service Level reporting.<br>• Auditing/QA reporting.<br>• Tier 1 enhancement and maintenance priority and status reporting.<br>• Tier 2/3 project management and status reports.<br>• Provide hardware & software inventory reports<br>• Maintain cost information on all computing assets<br>• Track software licenses. | | | Track disposal of assets | Identify reporting requirements | Included in all Rates |


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## 2.8 Disaster Recovery

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Disaster recovery plan | In a disaster situation, the primary goal of ATCO I-Tek is the restoration of centrally managed Data Processing Services, using the established Disaster Recovery plan.<br>• Provides Services to recover production processing and data in the event of a major disaster impacting the production environment (as outlined in Schedule A Appendix C Disaster Recovery Methodology). Disaster Recovery is distinct from Operational Recovery in that the host site is assumed to be incapacitated.<br>• Disaster recovery/continuity planning deals with technical Systems issues, such as System fault tolerance and System and network redundancy, backup, and recovery, and addresses the ability to recover servers, workstations, applications, and the support personnel to provide such Services.<br>• ATCO I-Tek will provide the level of disaster recovery as identified with, and agreed to with Clients .<br>• Create and maintain a plan (as outlined in Schedule A Appendix C for recovery from a disaster or major outage for critical applications.<br>***Enterprise Server and ATCO Network***<br>• Disaster Recovery for the server and network is the restoration of mainframe Services and products to their original operational state after they have been disrupted by a natural or man-made disaster.<br>• Disaster Recovery Planning is the overall process for developing practices and procedures to allow continuous System service. Specifically, the Disaster Recovery service provides the execution of predefined Disaster Recovery Plans | Time spent on disaster recovery plan is approximately 2500 hours per year.<br><br>Restore host System Services within 48 hours following a declared disaster.<br><br>Recover network connectivity to the host within 48hours following a declared disaster.<br><br>Restore all application data to the last backup immediately prior to the disaster. The assumed loss of System updates/data is up to 24 hours; since identified backups are done on a daily basis and stored off-site. This is shortened in some specific cases through additional backup strategies.<br><br>Although System Services will be restored within 48 hours, System operations may be performed remotely (from a recovery center in Calgary, Toronto or Chicago for example). It is assumed that the distance will present numerous telecommunications, response time and logistics problems. Primary printing support will be done at ATCO I-Tek's Calgary Data Centre and transported by courier to Edmonton. Clients must assume a lag time of 24 hours in receiving all printed output. Depending on refurbishment requirements and equipment availability, normal operations will be restored within 6 months. | Client initiated Disaster Recovery and work area recovery testing projects are excluded. | Responsible for disaster recovery planning for those computing resources managed and supported by ATCO I-Tek data center site | Approve plan<br><br>Each Client must review backup, retention, and off-site storage specifications for their application Systems on a regular basis, particularly in cases where tape is used as a routine storage media.<br><br>Deficiencies identified in this review must be rectified to ensure accurate recovery of Systems to within the 24 hours of a disastrous event, as is assumed in ATCO I-Tek recovery plan.<br><br>The Client's responsibility during the ATCO I-Tek recovery plan is to bring forward, reenter and synchronize application data | Included in all Rates |


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## 2.8 Disaster Recovery - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Disaster recovery plan - continued | • ATCO I-Tek has developed, tested, and documented a disaster recovery plan for the enterprise server and ATCO network environment. the disaster recovery plan is tested and audited annually. | ATCO has a disaster recovery plan that encompasses its existing enterprise server (mainframe). The disaster recovery plan for distributed (Client / server) Systems is incomplete. There is one major application (tis) from the service center in Edmonton ATCO pipelines disaster recovery plan. This will continue to be supported.<br><br>This plan includes a recovery of mainframe application source code, data, and hardware, network recovery; identification of hardware & software replacement sources; identification of disaster teams with specific duties assigned; and an execution of the plan as part of a test | | | | |
| 1 | Disaster Recovery - Oracle Financials | • This service will recover the key components of the Oracle Financials application.<br><br>• The recovery time objective (RTO) is 72 hours and the recovery point objective (RPO) is 24 hours.<br><br>• The recovered System will not have the same performance capabilities as the full scale production System. The disaster recovery solution will accommodate update users with similar levels of responsiveness to the production application.<br><br>• The Internet infrastructure is backed up by a second, active infrastructure. The Internet connection will include the protection mechanisms necessary to ensure that secure communications | | Any work performed other than that by ATCO I-Tek.<br><br>Business recovery facilities, including office equipment, workstations, printers, fax machines and special forms.<br>Email and Oracle Application Work Flow email notifications.<br>Custom email notifications and alerts.<br>• Distributed applications and interfaces to distributed applications not required to meet the recovery time objective.<br>• Access for iExpense, | ATCO I-Tek will provide the following recovery:<br>• The Oracle Financials application, database and Unix environment<br>• Workstation software – specifically Oracle Discoverer, Application Desktop Integrator (ADI) and J-Initiator.<br>• Printing support required for Oracle Financials reports.<br>• File transfers enabling cheque printing and | The Client is responsible for communicating to ATCO I-Tek their Disaster Recovery Site and the Asset ID's of the workstations that would have Oracle Financials software distributed to them. | Statement of Work |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | will be supported across the Internet. This includes boundary router filtering, firewall protection, and intrusion detection monitoring. | | iProcurement and inquiry users. | interfaces with other applications.<br>• Backup of critical reporting files as defined by each Client. | | |
| 1 | Offsite data storage | • Maintain offsite data storage as outlined in the backup and restore category of the data management section. | | | | | Included in Tape Rates |
| 1 | Disaster Recovery Test | • Plan & implement a test.<br>• Define the team<br>• Schedule the test<br>• Determine scope and functional areas to be tested<br>• Review Client's application test plans<br>• Coordinate with ATCO I-TEK, ATCO Group Management & Application Clients<br>• Post analysis of the disaster recovery test. | Annual test. | | | Ensure client participation in test is adequate | Included in all Rates |

## 2.9 Computer and Facilities Management

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Computer and Facilities Management | • Provide facility management Services for the computer facilities covered by the Service Level Agreement.<br>• Usage monitoring and capacity planning.<br>• Connect hardware and software to data and voice networks.<br>• Provide advice on enhancements to software, hardware and communications to keep in step with standards.<br>• Ensure security and computer room | 3 main campus buildings (in Edmonton & Calgary) | | Where such facilities are in locations outside the ATCO I-Tek Supported Locations, ATCO I-Tek will work with ATCO to define specific facilities responsibilities. | Where such facilities are in locations outside the ATCO I-Tek Supported Locations, ATCO I-Tek will work with ATCO to define specific facilities responsibilities | Included in all Mainframe Rates<br>Included in all workstation Rates<br>Included in Business / Distributed Application Pricing |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | environmental requirements are met & maintained<br>• Work with hardware vendors & Property Management during hardware installs to ensure all physical requirements are met.<br>• Maintain Computer room layout & cabling diagrams<br>• Maintain electrical & mechanical profiles that outline power and cooling availability & usage.<br>• Ensure fire protection policies, procedures & equipment is in place & operational<br>• On-site ATCO staff will continue to provide ATCO I-Tek staff with AdHoc assistance where required at remote sites | | | | | |
| 1 | Power outages | • Coordinate with building owners when known power outages are scheduled<br>• Create plan with ATCO I-Tek support staff to minimize effect of outage on it equipment<br>• Communicate instructions to clients to minimize effect of outage | 3 main campus buildings (in Edmonton & Calgary) | | | | Included in all Mainframe Rates<br>Included in all workstation Rates<br>Included in Business/Distributed Application Pricing |


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## 2.9 Computer and Facilities Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Test Lab | • Test Lab is the physical technical environment to be used solely for proof of concept activities. Such an environment is in place today.<br>• ATCO I-Tek will configure and maintain test lab.<br>• Evaluate new office automation products that could become part of ATCO's standard environment<br>• Perform a technical and basic functional test of proposed new approved products list items to test compatibility with the existing infrastructure and to attempt to minimize problems before installation into the production environment<br>• Analyze infrastructure impact of upgrades and changes in the applications based on input from standard suppliers and developers. | | | | | Included in all Rates |

## 2.10 Contract Management

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1, 2 | Contract Administration | • Manage Master Services and Service Level Agreements<br>• Manage 3rd party contracts for software/hardware and Services included in this SLA<br>• Monitor compliance with contractual obligations.<br>• Monitor the performance of contractors to ensure that all obligations are being fulfilled.<br>• Maintain contract records.<br>• Maintain vendor relationships. | Contracts covered under the Service Level Agreement. | Contracts negotiated and executed by ATCO business units. | Maintain standards and policies for the procurement of IT related licenses, equipment and Services. | Enforce compliance with contract standards and policies including scope of use and other contractual limitations. | Included in all Rates |

## 2.11 Consulting

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 3 | Business re-engineering for a complete business unit | • Provide re-engineering Services | Not included in Base | | | Free to go to the open market | Labour Rates |


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## 2.11 Consulting continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 2 | Re-engineering for business functions affected by a development project | • Provide re-engineering Services as part of any new development project, if a requirement by the business unit. | Not included in Base | | Ensure business re-engineering included in all major development projects | Ensure business re-engineering included in all major development projects<br><br>Free to go to the open market | Labour Rates |
| 1 | Client Liaison | • Provide consulting Services to the Client<br>• Manage Client expectation and satisfaction<br>• Ensure any changes undertaken have the clients' interests in mind<br>• Provide interface to ATCO clients in relation to the shared & dedicated facilities & Services within ATCO Group<br>• Provide a single point of contact for client requests | Consulting Services are limited to initiative of 7 hours or less. | | Ensure Clients are aware of processes & procedures for interfacing with ATCO I-Tek personnel. | Shared responsibility to ensure processes & procedures are followed | Labour Rates for Consulting Services of more than 7 hours |
| 1 & 2 | Project Leadership | • Undertake project leadership and management of projects on behalf of ATCO<br>• Provide a methodology for projects | Projects under 40 man days | Projects over 40 man days | Ensure project leaders are adequately trained in project management | Ensure project is approved and funded. | Labour Rates |
| 1 | Hardware / Software Product Consulting | • Provide consulting to the ATCO Group concerning new Hardware / Software technology<br>• Adhere to standards | | | | | Labour Rates |

## 2.11 Training

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Software | • Provide consulting & advice on available training for software products | | Client Training Course Fees.<br><br>Any setup costs for customized training will be billed to the project. | ATCO I-Tek will recommend training for ATCO clients. | Ensure Clients have received training on all software products required to perform their duties. | Training Directs |


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## 2.13 Mainframe Management & Support

### Production Management

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Batch & Online | • Manage and run Batch & On-line jobs.<br>• Maintain libraries of source & object code for production applications<br>• Maintain JCL libraries<br>• Support batch stream submissions, job checking & clearing<br>• Ensure all on-line teleprocessing packages are available when required<br>• Ensure required tapes are available for on-line & batch processing<br>• Startup/shutdown databases as required to maintain online & batch applications<br>• Manage automatic transmission of System information as per ATCO Group schedule<br>• Maintain current level of lights-out mainframe operations<br>• Maintain operations Documentation<br>• Maintain operators log<br>• Open & close service tickets | Critical financial and data transmissions | | | Define requirements (or changes to requirements) | CPU Rates |
| 1 | Job Recovery | • Provide standby/call-back support<br>• Provide on-call support for emergencies<br>• Notify clients where required<br>• Monitor/restart jobs in failure situations<br>• Maintain job recovery manuals | | | Maintain & monitor backup/recovery products<br>Ensure compliance with Service Levels | | CPU Rates |


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## 2.13 Mainframe Management Support continued

### Production Management – continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Operational Recovery | • ATCO I-Tek provides Services to recover production processing and data in the event of an outage causing any impact to the production environment or a production application. Operational Recovery is distinct from Disaster Recovery in that the computing facilities are assumed to be largely intact and operational. Data can be recovered up to six weeks prior to current date.<br>• The recovery of operational Systems, software tools, application software and application data is dependent on the latest backups. During the on-line processing of the applications, the database updates and transactions are logged. In the event of an outage, they can be used to reestablish part of or a full day's on-line processing. | ***Enterprise Server***<br>ATCO I-Tek responds to a crisis situation requiring a recovery of System processing capabilities recovered in 24 hours. 100% of data is recovered in 24 hours. Fully synchronized production is recovered in 48 hours. (*Depends on the database management concerns: recovery requirement, priority of data, backup location, backup type, backup currency, synchronization, the amount of data, server location, and capacity)* This requires Client involvement to verify data and bring the data to a known, synchronized and accurate state. Data recovery is limited to 6 weeks. | | Ensure compliance with established Service Levels | Verify System and application backup and archive requirements to meet business needs. Verify the System integrity for all operational recovery events. | CPU Rates |
| 1 | Storage Management | • Configure & maintain Systems Managed storage environment<br>• Support all storage management software products<br>• Monitor device activity, response time & capacity<br>• Perform data management on System volumes (i.e.: Backup, Archiving) to meet Service Levels requirements.<br>• Send tapes offsite for storage (used for Disaster Recovery & archiving) | | | | | Data Storage Rates |


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## 2.13 Mainframe Management Support continued

### Production Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Performance Tuning/Capacity Planning | • Customize software performance tools to provide appropriate reporting<br>• Provide usage & performance exception reports & charts<br>• Maintain multiple years historical processing usage data & statistics<br>• Monitor System performance & perform corresponding tuning | | | | | Included in all Mainframe Rates |
| 1 | Reporting | • Supply reports of inactive HSM managed mainframe data sets to clients on an AdHoc basis | | | | ATCO responsible for deleting unwanted datasets. | Storage Rates |

### Print Management

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | Output & distribution | • Manage output distribution<br>• Ensure all output is printed on schedule meeting quality control standards & user expectations<br>• Manage report distribution & electronic storage of output<br>• Manage distribution of output, shrink wrapping, binding, decollating, bursting, etc<br>• Maintain Systems & hardware required to manage mainframe output & distribution of that output<br>• Define print requirements<br>• Acquire & maintain print stock, warehouse stock<br>• Monitor spools<br>• Purge outdated & unwanted output | Number of print units = 1,000,000 monthly. Up to 23 cycles | | | Form costs are Specified Expenses. | Print Rates |


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## 2.13 Mainframe Management Support continued

### Print Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Mainframe Printers | ***Enterprise Server Printing***<br>Generally, enterprise server print Services are measured from the end of the processing job creating the report, the amount of printing required and the type of printing required.<br>• Manage printer environment<br>• Configure standard printer<br>• Configure & install specialized printer software<br>• Test<br>• Take out of service | The production batch window is generally 18:00 - 07:00, Monday to Friday. Refer to Schedule A Appendix A for application specific batch windows. Due to the high volumes at monthend and yearend, specific print timeframes may need to be arranged and certain output scheduled to meet the Client and business needs. | | | The Client is responsible for collection and distribution. | Print Rates |
| 1 | Mainframe Printers - continued | • Manage hardware upgrades<br>• Monitor extended device interventions. | | | | | |
| 1 | Printing | • High Speed Electronic Printing | | | | | Print Rates |


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## 2.13 Mainframe Management Support continued

### Hardware & Software

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Hardware | • Manage hardware<br>• Evaluate, purchase, receive & test mainframe-related hardware (including terminals)<br>• Install or upgrade hardware<br>• Take hardware out of service<br>• Activate tape library Systems<br>• Ensure accurate data retention in tape libraries<br>• Maintain scratch tape pools & add new tape capacity when required | | Impact from Tier 2 development projects will be assessed & pricing adjusted accordingly | | | Included in all Mainframe Rates |
| 1 | Software | **Software License Management**<br>Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement.<br>• ATCO I-Tek will determine requirements for meeting license agreements based on accepted industry standards to manage software.<br>• Configure & install specialized mainframe software (including backup software) | As required to maintain current Service Levels | | Will make a best effort (over time) to reduce the number of software products in use | Will make a best effort (over time) to reduce the number of software products in use | Included in all Mainframe Rates. |
| 1 | | • Ensure all installed software is properly licensed<br>• Take out of service<br>**Software Upgrades**<br>• Research upgrades or replacement products<br>• Evaluate and test the upgrades<br>• Plan implementation ensure licensing is valid<br>• Evaluate technical capabilities<br>• Ensure Installation meets requirements. | | | | | |


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## 2.14 Workstation Management & Support

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Workstations | • Manage workstations and configurations.<br>• Support ATCO's current technology standard.<br>• The service guidelines listed by ATCO I-Tek and reproduced in this document are not complete, nor are they intended to be.<br>• Follow ATCO I-Tek philosophy of supporting all the hardware and software in place. | PC workstations operating under standard workstation operating system will be configured in one of three profiles: type A, B, or C. Type A provides the user with workstation administrative privileges and the support for these stations is limited to reloading a Type A configuration and standard products. Types B and C are the most prevalent configurations and are fully supported. | Standalone workstation support is not included in base support. If required will be completed per the established standalone fees. | ATCO I-Tek will recommend a policy concerning the configuration of Type A, B, or C clients. ATCO I-Tek to configure Type A clients to Type B clients as per SLA for client loaded software problems.. | ATCO will approve the policy on Client Type.<br><br>ATCO will approve client classification into Type A, B, or C. | Workstation rates. |
| 1 | Hardware & software installs | • Hardware and software installation Services support the installation and maintenance of distributed computing and network platforms and software<br>***Site Preparation***<br>• Site preparation is the preparation of the physical equipment site prior to installation of a new piece of equipment. | Configure standard build including CORE applications (operating system, email, word processing, spreadsheet, internet connectivity software, virus protection) | | | Compliance with Change Management Process. | Workstation rates. |


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## 2.14 Workstation Management Support - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Hardware & software installs - continued | • Work with the ATCO Representatives to understand the current environment and determine additional requirements for hardware, software, power, communications wiring, and network connectivity.<br><br>• Document all hardware, software, power, communication wiring, and network connectivity orders for the site preparation.<br><br>• Place all of the orders for the site preparations, with the proper ATCO approval.<br><br>• In order to conduct the physical surveys of all hardware, software, power, communications wiring, network connectivity or other items, ATCO I-Tek will coordinate and gain access to all of the facilities during appropriate time frames (this could imply Business Day access to critical areas or after hours access).<br><br>***Onsite Staging and Integration***<br>On-site staging and integration is the inspection and setup of desktop and servers in accordance with existing processes.<br>• Recommend process changes to ATCO where appropriate.<br>• Provide onsite and on-call technicians to perform staging and integration Services.<br>• Integrate and stage equipment and provide ATCO with a document certifying that the integration was completed according to existing ATCO I-Tek processes.<br>***Installation***<br>• Installation is adding hardware and/or software to the environment (desktop or shared resources), connecting to the applicable network, verifying general working condition of the hardware and/or software, and backing up and | Configure, test & install specialized business software<br><br>Configure standard build including CORE applications (operating system, email, word processing, spreadsheet, mainframe connectivity software, internet connectivity software, virus protection)<br><br>Configure, test & install specialized business software. | | | Compliance with Change Management Process. | Workstation rates. |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | restoring data, if necessary as jointly determined by ATCO I-Tek and ATCO. | | | | | |


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## 2.14 Workstation Management Support - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Hardware & software installs - continued | • Provide on-site and on-call technicians to perform server and desktop installation Services for servers and desktop devices.<br>• Provide a brief orientation (less than 10 minutes) for the end user on the basic functionality of the newly installed workstations.<br>***Move and Add Services***<br>Move and add Services are those activities to make updates to the ATCO network and desktop-computing environment.<br>• Conduct a site survey to determine operational requirements and communicate any additional items required to support move, and add activity.<br>• Disconnect a System at one location, reconnect at another location and provide functional testing after move, and add service activity verifying correctness of changes.<br>• Jointly with ATCO end users, determine and perform necessary back-ups of data files on workstations prior to any move or add service being performed. | | | | | Time and materials workstation rates |
| 1 | Repair & Support | ***Workstation Support***<br>Workstation support consists of the technical assistance or troubleshooting at a specific physical device when problems related to such device cannot be resolved through the use of remote diagnostic tools or through phone support.<br>• ATCO I-Tek workstation support Service Levels will be based on the problem and priority criteria as outlined in the Service Level Measurements document.<br>Remote Site Support ATCO I-Tek will continue to provide Services to the various ATCO locations outside Edmonton and Calgary main building complexes. The Services are provided using one or all of the following three scenarios: | | | | | Workstation rates. |


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## 2.14 Workstation Management Support - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Repair & Support - continued | • Onsite staff Services the specific site and surrounding area.<br>• ATCO I-Tek contracts a local supplier to service the specific site and surrounding area.<br>• ATCO I-Tek staff makes periodic and emergency site visits based on the need.<br>ATCO I-Tek will continue to provide remote support in the same manner it is done as of the Effective Date of the Agreement. As technology changes, remote support requirements may change. ATCO I-Tek will recommend changes to ATCO to modify the Service Level agreement to reflect such changes.<br>***Hardware Maintenance***<br>Hardware maintenance, also known as "Break Fix," is the technical diagnosis and repair Services for physical problems related to hardware (desktop, server, and network) components. ATCO I-Tek will continue to provide hardware maintenance to meet or exceed the Service Level Measurements**.**<br>• Provide on-site and on-call technicians to perform server and desktop hardware maintenance Services at the Service Levels defined by ATCO.<br>• Troubleshoot and repair server and desktop hardware covered by the Service Level Agreement.<br>• Maintain and/or coordinate adequate spare parts inventories to perform server and desktop hardware maintenance.<br>• Abide by original equipment manufacturer (OEM) guidelines during the warranty coverage period.<br>On-site ATCO staff will continue to provide ATCO I-Tek staff with AdHoc assistance where required at remote sites | | | | | |


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## 2.14 Workstation Management Support - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Software | **Software License Management**<br>Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement.<br>• ATCO I-Tek will determine requirements for meeting license agreements based on accepted industry standards to manage software.<br>• Ensure all installed software is properly licensed<br>• Take out of service<br>***Software audit compliance.***<br>• ATCO I-Tek will own, manage and be responsible for third party software vendors and their respective software.<br>• Record<br>• Track<br>• Dispose<br>***Software Upgrades***<br>• Research upgrades or replacement products<br>• Evaluate<br>• Test to confirm functionality.<br>• Plan implementation ensure licensing is valid<br>• Build package or evaluate technical capabilities<br>• Install or upgrade | As required to maintain current Service Levels<br><br>A substantial number of shrink-wrapped software products are identified in the ATCO environment. Currently a significant number of these applications are not directly supported by ATCO I-Tek. Most specialized applications are managed by the clients, with only basic functionality (open product, print, save from product) being supported by ATCO I-Tek | | Will make a best effort (over time) to reduce the number of software products in use | Will make a best effort (over time) to reduce the number of software products in use<br><br>Compliance with Change Management process.<br><br>Enforce compliance with contact standards and policies including scope of use and other contractual limitations. | Workstation rates (Includes CORE Apps.)<br><br>Business application service fees for all special software. |

## 2.15 Server Management & Support

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Hardware and Software | • Manage Servers and Configurations<br>• Configure standard build<br>• Configure & install specialized server software (including backup software)<br>• House server hardware in a secure location and maintain existing UPS Systems.<br>• Ensure all installed software is properly licensed | | These Services exclude SCADA, AMR and Microwave<br><br>New and improved business applications as a result of Tier 1 or 2 projects will be estimated and priced separately | | | Workstation rates. (includes file and print Services) |


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## 2.15 Server Management Support - continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Hardware and Software | • Ensure required wiring & protocols required for a server are in place<br>• Test to confirm functionality.<br>• Take out of service<br>***Printer and Peripheral Device Definition Queue Management***<br>Printer and peripheral device definition involves the logical addition and deletion of printers and other peripherals to the network and the management of the print queue.<br>• ATCO I-Tek is responsible for the remote configuration of network printers and print queues.<br>***Configure, Install, Move, Remove Network printers***<br>Larger print jobs should be routed through the enterprise server, however technology is currently unavailable. Output from the enterprise server can be printed on the LAN or mid-range environments' remote printers, however the.turnaround will depend on print volume and workload on the network, the enterprise server, LAN server and printer. ATCO I-Tek provides assistance to define the best approach to meet the Client needs<br>• Configure standard build<br>• Configure & install specialized printer software<br>• Enable printer drivers for appropriate users<br>• Test to confirm functionality<br>• Take out of service<br>• Purchase, receive & install parts<br>***File Services***<br>• ATCO I-Tek will configure the System disks to be used for operating system areas, swap or paging areas, an area for the system to use for temporary files, an application area, and user area. | | | | | Business application service fees for all special hardware and software Services. |


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## 2.15 Server Management Support continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Hardware and Software - continued | ***Naming Standard Services***<br>Naming standard Services is the establishment and maintenance of standards for names and addresses to ensure consistency within the ATCO environment.<br>• ATCO I-Tek will coordinate names and addresses to provide consistency within the environment and to provide Systems administration. Existing naming standards will be adhered to.<br>***Application Environment Services***<br>Application environment Services involve configuring the System software so that application software is able to execute.<br>• ATCO I-Tek will test and maintain server integration and compatibility for any application additions and upgrades as included within the Service Level agreement.<br>***Server Virus Detection/Repair***<br>Desktop and Server virus detection and repair addresses ATCO's need to safeguard data from damage by computer codes hidden in software that can corrupt and destroy valuable programs and data.<br>• Provide detection and correction of viruses in servers based on current commercially available software.<br>• Detect and remove viruses from end-user desktop Systems and attempt to remove viruses from all known locations (determine where virus came from and remove) using current ATCO I-Tek tools and processes.<br>• Manage the removal of existing viruses from all files, boot sectors, (used to load the operating system) and partitions, minimizing damage to data.<br>• Provide advice to end users on a regular and periodic basis relating to the identification, prevention and removal of potential virus problems. | | | | | |


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## 2.15 Server Management Support - continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Hardware and Software - continued | • Maintain current signature file with up-to-date virus signature information.<br>• Maintain current virus detection software code levels.<br>• Provide the continuous monitoring and correction for viruses on shared servers.<br>***Remote Desktop/Server Management Services***<br>Remote management service is accomplished through a software agent on the desktop that allows ATCO I-Tek to control the ATCO end-user's workstation and servers, allowing a trained technician to perform hands-on investigation of a reported problem.<br>• Provide remote control<br>• Use the remote control capabilities as agreed to by ATCO.<br>• Policy and process definitions will be completed and maintained. Communication to the participating Clients will be coordinated through the appropriate groups.<br>***Software Distribution***<br>Software distribution is the distribution of operating system and user application software throughout a specified Client's organization.<br>• ATCO I-Tek will provide software distribution as mutually agreed by the parties.<br>• Regular upgrade schedules and an annual upgrade plan will be completed by ATCO I-Tek.<br>Provide version management and inventory management of application updates. | | | | | |


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## 2.15 Server Management Support - continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Hardware and Software - continued | • Maintain two previous releases of both major and minor software releases where necessary and with the establishment of a migration plan.<br>• Maintain records of usage and locations of distribution.<br>• Ensure all distribution is completed in a timely, non Client-impacting manner | | | | | |
| 1 | Repair & Support | ***Midrange Computing Services***<br>Maintain the midrange System hardware and software at the Service Levels defined in the Service Level measurements.<br>Maintain hardware and software ownership responsibilities for those assets owned by ATCO I-Tek.<br>Provide move and add activity for routine updates to the midrange environment. Where such activity results in changes to existing Services or activities are larger projects, additional charges may apply.<br>***Engineering***<br>ATCO I-Tek will continue to offer sustaining engineering on midrange Systems. This consists of periodically gathering performance and capacity data from these Systems and analyzing this data using a variety of tools.<br>• Monitor the performance and capacity of the midrange Systems and submit to ATCO capacity planning projections for midrange System processors, disk storage and back-up resources.<br>• Notify ATCO and recommend alternatives when midrange System hardware, hardware components or operating system software are no longer supported because they are considered obsolete by the manufacturer and/or third party maintenance vendor and cannot be procured or obtained in sufficient time to meet the required performance level. | | New and upgraded business applications as a result of a Tier 1 or 2 project will be estimated and priced separately. | | | Business application service fees for all special hardware and software Services. |


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## 2.15 Server Management Support - continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Repair & Support - continued | ***Operation and Administration***<br>The section below describes the responsibilities of ATCO and ATCO I-Tek with respect to the operation and administration of ATCO's midrange computing Systems.<br>• Monitor availability and reliability of the midrange platforms and production database/subsystems based on user feedback and problem resolution. Fluctuations and variances in available capacity are analyzed, diagnosed and corrected as necessary through appropriate priority level and in keeping with a cost-effective solution. The midrange platform will be available on a continuous basis except during Change Windows and back up of disk storage as scheduled.<br>• Provide problem management to include identification, Documentation, communication, escalation, corrective action, confirmation, and measurement. All Service Level standards relative to problem management are based upon the definitions of priority<br>• Provide problem management reports. The frequency of utilization reports will be determined by ATCO.<br>• Execute specific midrange System jobs to maintain the midrange System files.<br>• Receive and evaluate requests for special processing and advise ATCO on the recommended scheduling of those requests.<br>• Notify ATCO of scheduled maintenance prior to such scheduled maintenance. | | | | | |


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## 2.15 Server Management Support - continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Repair & Support - continued | • Provide data security, to the extent allowed by the operating software for the midrange System, including adding changing and deleting User access information, in accordance with ATCO's data security policy.<br>• Order, install, diagnosis, repair, upgrade and remove hardware/software.<br>***Production Control***<br>Production control is the management and facilitation of production on the midrange server environment. Production control also includes midrange environment backups.<br>• Define standards for test to production turnover and provide these standards to ATCO for approval.<br>• Perform test to production tasks by use of agreed upon production processes and tools.<br>• Report on production results in a format and at a frequency mutually defined by ATCO and ATCO I-Tek.<br>• Be responsible for restart/recovery for production jobs.<br>• Maintain Documentation for job scheduling and re-run requirements, and make this information available to ATCO.<br>• Maintain production job scheduling tables in accordance with the schedules provided by ATCO.<br>• Provide production batch initiators/queue, validate job requests and re-run instructions, and notify ATCO of job completion through a mutually defined process.<br>• Provide back up and restore functions.<br>• On-site ATCO staff will continue to provide ATCO I-Tek staff with AdHoc assistance where required at remote sites | | | | | |


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## 2.15 Server Management Support - continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Software | ***Software License Management***<br>Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement.<br>• Provide Software technology planning.<br>• Implement ATCO I-Tek corporate standard software distributions and individual products as appropriate.<br>• Investigate, evaluate, install and implement any required non-standard products when required by a Client.<br>• Maintain all software in production using ATCO I-Tek corporate standard processes.<br>• Disaster recovery planning for all supported software platforms.<br>***Software audit compliance.***<br>• ATCO I-Tek will manage and be responsible for third party software vendors and their respective software<br>• Record<br>• Track<br>• Dispose<br>***Software Upgrades***<br>• Research upgrades or replacement products<br>• Evaluate<br>• Test to confirm functionality.<br>• Plan implementation ensure licensing is valid<br>• Build package or evaluate technical capabilities<br>• Install or upgrade | | Licenses acquired by an ATCO business unit are not managed by ATCO I-Tek. | | Compliance with change management process. | Business application service fees for all specialized hardware and software Services. |


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## 2.15 Server Management Support - continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Performance Tuning | ***Performance Tuning***<br>Performance tuning is making modifications such as changes to operating system software, to the existing network and to system configurations to achieve maximum System responsiveness and throughput.<br>This will be done through periodic gathering of performance and capacity data using a variety of tools. The gathering and analysis of this data is performed in various fashions.<br>• ATCO I-Tek will keep the System(s), comprised of the hardware and software covered by the Service Level Agreement operating within mutually determined thresholds.<br>***System Monitoring***<br>System monitoring consists of monitoring the availability and utilization of System resources within ATCO's client/server computing environment.<br>• Respond to automatic paging associated with predetermined server events and build on existing processes to allow for proactive problem determination.<br>• Collect capacity and performance data for the following items on an ad hoc or problem basis:<br>  • Disk monitoring<br>  • CPU utilization<br>  • Uptime analysis<br>  • Memory utilization<br>• Provide Systems monitoring event notification<br>• Resolve System problems as per the problem management and service request process.<br>• Have authority over servers thereby establishing account IDs on managed servers | | | | | Business application service fees for all specialized hardware and software Services. |


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## 2.15 Server Management Support - continued

(File, print & database servers; includes mid-range servers)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Operational Recovery | • ATCO I-Tek provides Services to recover production processing and data in the event of an outage causing any impact to the production environment or a production application. Operational Recovery is distinct from Disaster Recovery in that the computing facilities are assumed to be largely intact and operational. Data can be recovered up to six weeks previously. | ***Mid Range and Local Area Network Servers*** Recovery of a distributed server's data is at a rate of 1 GB per hour. Recovery of individual files (less than 1 GB in size) is within 2 hours. Data recovery is limited to 6 weeks | | ATCO I-Tek ensure clients understand their role in backup procedures at remote sites. | ATCO to ensure clients follow documented backup procedures at remote sites. | Workstation rates (include file and print services)<br><br>Business application service fees for all specialized hardware and software Services |
| 1 | Citrix Terminal Server | • Citrix helps deal with bandwidth issues from Clients wanting access to the domain from remote locations. Clients can login from remote sites that have slow network connections and run their applications. | | ATCO I-Tek does not support non-MSA hardware.<br><br>ATCO I-Tek does not support the internet connection provided by Client's Internet Service Provider. | ATCO I-Tek is responsible for supporting connectivity to the Citrix server and availability of the hosted applications.<br><br>All software, hardware, and security maintenance is included.<br><br>Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | The Client requires access to the ATCO network which requires:<br>i. Virtual Private Network (VPN) or RAS connection. The Client must be able to connect to the ATCO domain via a VPN or a RAS connection.<br><br>ii. ICA WEB Client. This software allows clients to run applications on the Citrix servers.<br><br>iii. UniPrint WEB Client. Allows Clients to print to their local or default printer. This printer can be network or locally connected.<br><br>iv. Adobe Acrobat Reader. This is used in conjunction with | Included in network access rates. |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | | | | | the UniPrint client. Basically, Acrobat Reader brings the documents in as a PDF format so that the Client can print to any printer. Version 4.05 or greater is required. | |
| 1 | Blackberry Service | • The Blackberry solution allows for an encrypted wireless real-time calendar and email synchronization with ATCO's business email environment.<br>• ATCO I-Tek provides full support for product capability including:<br>  • Wireless e-mail<br>  • Voice support<br>  • Wireless calendaring<br>  • Wireless Internet<br>  • Attachment capability | | Monthly voice and data costs from 3rd party service provider.<br><br>Support of 3rd party wireless network. | ATCO I-Tek provides the infrastructure to link Microsoft Exchange and Microsoft Outlook servers to the Blackberry servers.<br><br>ATCO I-Tek does not lease, support or spare Blackberry devices. ATCO I-Tek will liaison with vendor, at Time and Materials Rates, for Blackberry device support.<br><br>ATCO I-Tek provides procurement and asset management of Blackberry devices. Cost of device is Specified Expense.<br><br>Support of synchronization between ATCO's Microsoft Exchange environment and Blackberry servers is standard.<br><br>In the event that a Blackberry device fails, ATCO I-Tek will work with third party device vendors on behalf of the Client on a Time and Materials | | Included in network access rates. |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | | | | basis. | | |

## 2.16 Network Equipment Management & Support

### Manage LAN

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Network and Systems Management | Network and Systems management is the management of the network infrastructure and shared Systems to meet or exceed defined Service Levels.<br>***Network Service***<br>The Network Service consists of circuits and equipment to facilitate client to client connectivity, local or wide area.<br>• Perform network planning, consisting of network design, capacity planning and technology refresh planning.<br>• Provide proactive, centralized monitoring and configuration management.<br>• Provide problem resolution by following the existing Problem Management process.<br>• Provide network fault isolation, trouble ticket generation and management of the recovery of network-related problems, including interface with carrier and other vendors. | Maintain availability for all monitored devices on a 7 x 24 basis except during Change Windows and back up of disk storage as scheduled.<br><br>Automated processes will be implemented as available and required. | | | | Network Connection rates. |


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## 2.16 Network Equipment Management Support - continued

**Manage LAN - continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Network and Systems Management – continued | • Manage the relationship with, third party vendors of ATCO I-Tek for the acquisition and maintenance of all data telecommunications Services and equipment.<br>• Collect and analyze network performance data to evaluate efficiency, measure availability, and utilize as input for network tuning.<br>• Recommend to ATCO, technology upgrades with regard to increases in WAN requirements for improved efficiencies.<br>• Maintain inventory information and Documentation on ATCO owned WAN related equipment in the format and reflecting the information as the parties may mutually agree.<br>• Perform network change requests in accordance and frequency with the existing change request process.<br>• Gather, analyze, and validate entire network traffic and transactions against the current network design.<br>• Confirm and document the network design and capacity requirements and submit to ATCO capacity-planning projections in a format mutually determined by ATCO and ATCO I-Tek.<br>• Provide Telecommunication Engineering Services only for those assets managed and operationally controlled by ATCO I-Tek.<br>• In the event that current network hardware and software does not meet the minimum standards required for ATCO I-Tek to perform the network management Services described in this document, ATCO will work with ATCO I-Tek to determine the best alternative solution and participate as required in the implementation of this solution. | | | | | |


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## 2.16 Network Equipment Management Support continued

**Manage LAN – continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Network Device Management | Network device management and monitoring is to remotely maintain the configuration of network devices and monitor the operating environment for error conditions.<br>• Provide for the setting of operational parameters, port configurations and management software activities including:<br>• Device chassis configuration<br>• Device segmentation configuration<br>• Device port configuration including port activation/de-activation<br>• Device hardware failure detection and notification<br>• Associate a Network Interface Card (NIC) to a specific port<br>• Identify where errors on the segment are being generated<br>• ATCO I-Tek will execute the capacity management plan on an annual basis over a defined period to be agreed to with ATCO.<br>• ATCO I-Tek will provide prices proposals and justification to ATCO for additional capacity requirements | Automated processes will be implemented as available and required. | | | | Network Connection rates |
| 1 | LAN Segment Utilization and Network Utilization | LAN Segment Utilization and Network Utilization is determining the baseline performance and collecting the performance data of the network during a definitive time frame.<br>• Perform comparisons of utilization to baseline.<br>• Monitoring platforms will be upgraded, as required, to enhance service capabilities. This may occur because of advances in software provided by vendor or modifications to existing software developed by vendors or ATCO I-Tek | Automated processes will be implemented as available and required. | | | | Network Connection rates |


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## 2.16 Network Equipment Management Support continued

**Manage LAN – continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Configure, Install, Move, Remove | • Design and coordinate the installation of physical configuration<br>• Configure / install / de-install specialized network software<br>• Ensure all installed software is properly licensed<br>• Coordinate wiring<br>• Test to confirm functionality | Network equipment includes hubs, bridges, modems, gateways & dial-up facilities on ATCO Network, as outlined in this Agreement. | Impact of additional sites implemented will be assessed & priced | | | Network Connection Time and Materials Rates |
| 1 | Support/Repair | • Purchase, receive & install parts or software<br>• Repair hardware | | | | | Network Connection rates |
| 1 | Performance Tuning | ***Network Monitoring***<br>Network Monitoring keeps track of the availability of networks, LAN segments utilization, and the performance of resources.<br>• Network utilization problems that are identified, will be provided before ATCO is affected.<br>• Respond to end-user detected changes in usage and/or erratic response activity. Users are encouraged to contact the CSC and report any such incidents.<br>• Monitor fluctuations and variances in available capacity. These will be analyzed, diagnosed and corrected (including root cause analysis) as necessary through appropriate priority levels.<br>***System Management***<br>System management is the monitoring of network resources to maintain the optimum server environment and provide centralized control of resource configurations.<br>• Measure and record data and provide report information regarding the performance and capacity of the managed Systems, comprised of the hardware and software, as required.<br>• Perform long-term trending of the utilization of key System resources and recommendations for replacement/upgrade of resources | Monitor the network resources and maintain availability for all monitored devices on a 7 x 24 basis except during Change Windows and back up of disk storage as scheduled.<br><br>Automated processes will be implemented as available and required. | | | | Network Connection rates |


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## 2.16 Network Equipment Management Support continued

**Manage LAN – continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Performance Tuning - continued | • Regular meetings between ATCO I-Tek and ATCO will be scheduled to review resource utilization and trends.<br>• Assess ATCO's platform environment, including hardware, desktop operating system and network operating system.<br>• Provide an impact study document of a performance simulation containing recommendations for improving the environment's performance, including usage thresholds, performance tuning and configuration changes | | | | | |
| 1 | Software | ***Software License Management***<br>Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement.<br>• Provide Software technology planning.<br>• Implement ATCO I-Tek corporate standard software distributions and individual products as appropriate.<br>• Investigate, evaluate, install and implement any required non-standard products when required by a Client.<br>• Maintain all software in production using ATCO I-Tek corporate standard processes.<br>• Disaster recovery planning for all supported software platforms. | Automated processes will be implemented as available and required. | | | | Network Connection rates |

## 2.16 Network Equipment Management Support continued

**Manage LAN – continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Software - continued | ***Software audit compliance.***<br>• ATCO I-Tek will manage and be responsible for third party software vendors and their respective software as outlined in Appendix B<br>• Record<br>• Track<br>• Dispose | | | | | |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | ***Software Upgrades***<br>• Research upgrades or replacement products<br>• Evaluate<br>• Test to confirm functionality.<br>• Plan implementation ensure licensing is valid<br>• Build package or evaluate technical capabilities<br>• Install or upgrade | | | | | |
| 1 | Provide Capacity Planning | • Monitor network capacity<br>• Analyze trends & predict capacity requirements<br>• Report on areas requiring upgrade | Automated processes will be implemented as available and required. | | | | Network Connection rates |

**Manage WAN**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Configure, Install, Move, Remove | • Design and coordinate the installation of physical configuration<br>• Configure / install / de-install specialized network software<br>• Ensure all installed software is properly licensed<br>• Coordinate wiring<br>• Test to confirm functionality | Network equipment includes routers & circuits on ATCO WAN | Impact of additional sites implemented will be assessed & priced | | | Wide Area Network Service Time and Materials Rates. |
| 1 | Telecommunication Engineering Services | • Submit a completed assessment and design recommendations for new requests and recommend cost estimates for the technical design, hardware, software, circuits, labour and organizational impact to ATCO for review and approval.<br>• Analyze current technology trends and changes; analyze new technology to assess its ability to meet present and future design requirements, and work with ATCO to evaluate new business requirements against traffic trends. | | | | | Wide Area Network Service rates. |


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## 2.16 Network Equipment Management Support continued

**Manage WAN– continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Telecommunication Engineering Services – continued | • ATCO I-Tek's recommendations will conform to appropriate policies and procedures of ATCO's telecommunications standards and take into account ATCO future needs for additional desktop users, centralization of network equipment or peripherals and new applications, and will leverage available facilities (bandwidth, hardware, floor space, etc.) whenever possible. | | | | | |
| 1 | Support/Repair | • Purchase, receive & install parts or software<br>• Repair hardware | | | | | Wide Area Network Service rates. |
| 1 | Network Optimizing | • Monitor, analyze and adjust to achieve optimal performance of the supported network. | Automated processes will be implemented as available and required. | | | Review when required | Wide Area Network Service rates. |
| 1 | Recovery | • WAN recovery | | | | | Wide Area Network Service rates. |


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## 2.16 Network Equipment Management Support continued

**Manage WAN– continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Software | ***Software License Management***<br>Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement.<br>• Provide Software technology planning.<br>• Implement ATCO I-Tek corporate standard software distributions and individual products as appropriate.<br>• Investigate, evaluate, install and implement any required non-standard products when required by a Client.<br>• Maintain all software in production using ATCO I-Tek corporate standard processes.<br>• Disaster recovery planning for all supported software platforms.<br>***Software audit compliance.***<br>• ATCO I-Tek will manage and be responsible for third party software vendors and their respective software as outlined in Appendix B<br>• Record<br>• Track<br>• Dispose<br>***Software Upgrades***<br>• Research upgrades or replacement products<br>• Evaluate<br>• Test to confirm functionality.<br>• Plan implementation ensure licensing is valid<br>• Build package or evaluate technical capabilities<br>• Install or upgrade | Automated process will be implemented as available and required. | | | | Wide Area Network Service rates. |


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## 2.16 Network Equipment Management Support continued

**Manage WAN– continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Provide Capacity Planning | • Manage network capacity.<br>• Monitor network capacity<br>• Analyze trends & predict capacity requirements<br>• Report on areas requiring upgrade | Automated process will be implemented as available and required. | | | | Included in Wide Area Network Rates |
| 2 | Development | • Design, plan, test & implement WAN networks for new sites or significant upgrades to existing sites | | | | | Labour Rates. |
| 1 | VPN Remote Branch | • This service refers to a virtual private network connection across the Internet from a remote office to the ATCO Corporate network. A permanent, encrypted tunnel is created through the Internet to connect the local area network in the remote office to the ATCO Corporate network. | | The Internet Service Provider (ISP) investigation, installation, setup, and monthly fee are not included.<br><br>Local area network connections are not included.<br><br>Availability of the connection across the Internet cannot be guaranteed and is not included.<br><br>Internal wiring and electrical facilities necessary for the installation in the remote office are not included.<br><br>Travel time and associated costs incurred by ATCO I-Tek to install the service are not included. | Central Network Connection Equipment:<br>• The network and security devices used to interface the Internet based connection into the ATCO corporate network are included.<br>• All software, hardware, and security maintenance is included.<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.<br>Remote Branch VPN Gateway<br>• Creates the secure, encrypted tunnel across the Internet to the ATCO corporate network.<br>• Protects the connected devices in the remote office from malicious access on the Internet.<br>• Capacity planning, design and engineering, technology certification, refresh, | | Included in network access rates |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | | | | vendor management, monitoring, and support are standard. | | |
| 1 | VPN Firewall | • This service refers to a virtual private network connection from a small office shared with four or less devices that use the VPN – Remote Client service to connect to the ATCO Corporate network. A firewall/router devices with four ports is supplied to connect four or less devices. | | The Internet Service Provider (ISP) investigation, setup, and monthly fee are not included.<br><br>Local area network connections are not included.<br><br>The installation and maintenance of the service is not included and is offered on a Time and Materials Rates basis.<br><br>Internal wiring and electrical facilities necessary for the installation in the remote office are not included.<br>Travel time and associated costs incurred by ATCO I-Tek to install the service are not included.<br>Printing from mainframe applications is excluded but is available as an additional service.<br>Network based printing is also not included.<br>Availability of the connection across the Internet is not guaranteed. | Central Network Connection Equipment<br>• The network and security devices used to interface the Internet based connection into the ATCO corporate network are included.<br>• All software, hardware, and security maintenance is included. Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard<br>Remote Office Firewall/Router<br>• Creates the secure, encrypted tunnel across the Internet to the ATCO corporate network. Protects the connected devices from malicious access on the Internet.<br>• Software, hardware, and security maintenance are included | | Included in network access rates |

## Manage Voice

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Voice Equipment | • Manage voice equipment<br>• Design<br>• Monitor<br>• Ensure environment is maintained (wiring, telephone jacks) | | Voice Services not managed by ATCO I-Tek are excluded. | | | Voice Rates |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | • Implement<br>• Identify & implement upgrades | | | | | |
| 1 | Telecommunications Services | ATCO I-Tek's approach is to provide and maintain Services and Service Levels identified in the Service Level Measurement document.<br>• Be the single point of contact for telecommunications network installations, moves and adds, fault notification and resolution.<br>• Provide telecommunications service coordination and management of third-party service providers including exchange carriers.<br>• Administer and coordinate the physical and logical configuration of the telecommunications network.<br>• Provide planning, engineering, installation and maintenance support for the telecommunications network.<br>• Provide integration support for new telecommunications network Systems.<br>• Provide reporting for telecom-munications network performance. | | | | | Voice Rates |


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## 2.16 Network Equipment Management Support continued

**Manage Voice - continued**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Telecommunications Services - continued | • Provide input and advise in the development of design and implementation plans to meet service requirements.<br>• Provide input and advise in the development of a telecommunications architecture technology policy.<br>• Contract with a third party for the provision of the physical layer of the voice and data network.<br>• On-site ATCO staff will continue to provide ATCO I-Tek staff with AdHoc assistance where required at remote sites. | | | | | |
| 1 | Voice Tele-communications Service | The Voice Telecommunications service is Voice Premises Services, consisting of standard analog and/or digital telephone line Services, desktop voice instruments, and Public/Private Voice Services. Public/Private Voice Services includes: Telecommunication Company provided dial tone through local, 800, tie lines and long distance facilities. ATCO I-Tek will manage and provide these Services for the participating Clients.<br>• Serve as the single point-of-contact for ATCO in coordination of third party telecommunications network suppliers and telecommunication equipment providers.<br>• Manage ATCO installed voice network equipment consisting of circuits, access equipment, wiring and standard telecommunications lines and equipment covered by the Service Level Agreement.<br>• Perform voice service planning consisting of network design, capacity planning and technology refresh planning.<br>Provide voice usage reports in the frequency, format and reflecting the information as mutually determined by ATCO and ATCO I-Tek, as currently provided. | | | | | Voice Rates |


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## 2.16 Network Equipment Management Support continued

### Manage Voice - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Voice Tele-communications Service - continued | • Manage ATCO contracts for long distance, local exchange, 800# services, tie lines, pager, cellular phones and calling card services<br>• Coordinate and manage the resolution of voice network issues, including equipment issues and interfaces with carriers and other vendors. Provide problem resolution up to the point of determination that the problem is related to particular equipment, forwarding the problem to the appropriate repair/maintenance entity, and serving as a single point of contact during the problem resolution process.<br>• Manage and coordinate through designated maintenance providers the support of Private Branch Exchange ("PBX"), tie lines, key System and voice mail service.<br>• Coordinate through designated maintenance providers to perform moves, adds and changes on telecommunications equipment as follows which may include: changing telephones and features, installing new telephone sets and lines, moving telephones, removing and disconnecting telephone sets and lines, adding voice mail boxes, and changing voice mail features.<br>• Manage and coordinate the publication of electronic telephone directories. | | | | | |


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## 2.16 Network Equipment Management Support continued

### Manage Voice - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Moves and Adds | • Provide move and add Services to the ATCO network or will coordinate work through a designated maintenance provider.<br>• Coordinate moves and adds service through the designated maintenance provider.<br>• Manage and coordinate the instal-lation, configuration and testing of equipment, related devices and Services. | | | | | Voice Services Time and Materials Rates. |
| 1 | Moves and Adds – continued | • Coordinate removal Service for telecommunication equipment, being the physical and logical de-installation and proper disposal or cancellation of telecommunication equipment and Services | | | | | Voice Services Time and Materials Rates. |
| 1 | Call Center Symposium Application | • This service provides the centralized call flow control, monitoring, reporting, agent assignment and supervision applications used within call centers. It will integrate closely with the other call center services. | | The design, programming, and configuration of the application is not included.<br><br>Changes to existing applications are not included.<br><br>The hardware used to deliver the applications to the caller and the call center organization are separate services. | Call Center Symposium Application<br>• This is the software that provides the centralized call flow control, monitoring, reporting, agent assignment and supervision functionality required for the call center.<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | | Included in voice rates |
| 1 | Call Center Symposium Server | • This service provides the hardware utilized by the Call Center Symposium Core application. It is the delivery mechanism for the centralized call flow control, monitoring, reporting, agent assignment and supervision applications used within call centers. It will integrate | | The Symposium Core application software is not included. | Call Center Symposium Servers<br>• This is the hardware for the Call Center Symposium Core application.<br>• Capacity planning, | | Included in voice rates |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | closely with the other Call Center services. | | | design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | | |
| 1 | Call Center Call Pilot Applications | • This service provides messaging and announcements for call answering applications used within call centers. It will integrate closely with call processing operating systems like Nortel Symposium. The message must be made available to callers through ports and is therefore, closely associated with the Call Center Call Pilot Ports service. | | The programming, recording, and configuration of the announcements and messages are not included.<br><br>Changes to existing announcements and messages are not included.<br><br>The voice ports used to deliver the announcements and messages to the caller are a separate service. | Call Pilot Server<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | | Included in voice rates |
| 1 | Call Center Call Pilot Ports | • This service provides the delivery mechanisms for the Call Center Call Pilot Applications messaging and announcements. The number of concurrent callers accessing the application determines the number of Ports required. It will integrate closely with call processing operating systems like Nortel Symposium. | | The programming, recording, and configuration of the announcements and messages are not included.<br><br>Changes to existing announcements and messages using the ports are not included.<br><br>The Application containing the announcements and messages to the caller are a separate service. | Call Pilot Server<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | | Included in voice rates |
| 1 | Call Center Readerboard | • This service provides a customizable, 32 X 128 visual display of real time call centre statistics like average speed of answer and number of calls waiting. It is integrated closely with the Nortel | | The programming and configuration of the displays and messages are not included. | Call Center Readerboard Server<br>• Capacity planning, design and engineering, | | Included in voice rates |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | Symposium call processing operating systems. | | Changes to existing displays and messages are not included.<br><br>Installation and cabling required for the Readerboard are not included. | technology certification, refresh, vendor management, monitoring, and support are standard. | | |
| 1 | Centrex Telephone | • This service provides a basic business telephone set for use on the telecommunication carriers Centrex based telephony service. | | The installation, cabling, Centrex line and feature costs are not included.<br><br>Telephone add-on modules, headsets are not included. | The telephone set, routine maintenance and technology refresh are included. | | Included in voice rates |
| 1 | Voice Feature - Voicemail Remote Notify | • This service provides a notification that you have received a voice mail into the corporate voice mail System. The notification can be a voice call, pager notification, or ATCO I-Tek corporate email message | | Basic Voice Mail is a prerequisite for this service and is not included.<br><br>Voice Mail Desktop is a prerequisite for email notification and is not included.<br><br>Installation of the software on the Client's workstation is not included.<br><br>The service is restricted to the local calling area.<br><br>A separate Voice Line may also be required in special situations and is not included. | Voice Mail Remote Notify Server<br>• This is the System that hosts the operating system and application that delivers the notification service<br>Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | | Included in voice rates |
| 1 | Voice Feature –Voice Mail Fax | • This service provides an incoming fax capability through the Microsoft Outlook email application on a standard ATCO I-Tek provided personal computer. Fax messages are displayed in a standard Inbox format. | | Basic Voice Mail and Voice Mail Desktop are prerequisites for this service and are not included.<br><br>Installation of the software on the Client's workstation is not included.<br><br>A separate Voice Line is also required and is not included. | Voice Mail Fax Server<br>• This is the System that hosts the operating system and application that delivers the Fax.<br>Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | | Included in voice rates |
| 1 | Voice Feature –Voice Mail Desktop | • This service provides access to the | | Basic Voice Mail is a prerequisite for this service | Voice Mail Server | | Included in voice rates |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | ATCO I-Tek provided corporate voice mail through the Microsoft Outlook email application on a standard ATCO I-Tek provided personal computer. Capability includes displaying a list of voice mail messages in an Inbox, Outbox, Deleted Items, and Sent Items format.<br>• | | and is not included.<br><br>Installation of the software on the Client's workstation is not included. | • This is the System that hosts the operating system and application that delivers the voice mail service.<br>Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | | |

**Manage Video Conference**

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Configure, Install, Move, Remove hardware & Software | • Design & Coordinate Installation of physical configuration<br>• Configure & install/de-install software<br>• Ensure all installed software is properly licensed<br>• Coordinate wiring<br>• Test<br>• Document | Standard video conferencing Equipment (CODEC's, monitors, DUS's, network interface components, microphones, document camera on Video equipment) | Future technology changes to equipment used | | | Included in video conference rates |
| 1 | Manage service agreements with 3rd party | • Contact potential suppliers<br>• Develop contracts/agreements<br>• Ensure agreements are met | All video conferencing equipment and related networks | | | Review and audit | Included in video conference rates |
| 1 | Problem Management | • Prioritize problems<br>• Assign<br>• Analyze problems<br>• Find root cause<br>• Resolve problems<br>• Post analysis<br>• Document | All video conferencing equipment and networks | Out of scope hardware and software | | | Included in video conference rates |


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## 2.16 Network Equipment Management Support continued

### Manage Video Conference - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Support/Repair | • Purchase, receive & install parts or software | All video conferencing hardware and network equipment | Out of scope hardware and software | | | Included in video conference rates |
| 1 | Optimization | • Monitor, analyze, and adjustment configuration. | All video conferencing hardware and network equipment | Out of scope hardware and software | | | Included in video conference rates |
| 1 | Security: Physical | • Provide standards and guidelines for the physical security of all video conferencing equipment. | All video conferencing hardware and network equipment | Out of scope hardware and software. Monitoring, reporting, and control of physical security of equipment is the responsibility of FRONTEC and the clients | | | Included in video conference rates |
| 1 | Security: Logical | • Provide standards and guidelines for the logical security of all video conferencing hardware<br>• Recommend, maintain, and publish policies and procedures on logical security<br>• Provide security and ID administration for the logical network | All video conferencing hardware and network equipment<br>Monitoring, reporting, and control of logical security of video conferencing equipment | Out of scope hardware and software | | | Included in video conference rates |
| 1 | Upgrades | • Research upgrades or replacement for video conferencing equipment<br>• Evaluate, Test, and Implement<br>• Ensure licensing is valid<br>• Build package | All video conferencing hardware and network equipment | Out of scope hardware and software | | | Included in video conference rates |
| 1 | License Management | • Record<br>• Track | All video conferencing hardware and network equipment | Out of scope hardware and software | | | Included in video conference rates |
| 1 | Provide Capacity Planing | • Monitor usage.<br>• Analyze trends & predict capacity requirements at sites and MCU. | All video conferencing hardware and network equipment | Out of scope hardware and software | | | Included in video conference rates |
| 1 | Videoconferencing Rental | • This service provides a fully equipped video conference facility including a Polycom video conference unit, a local and remote monitor, and ISDN connections in three 128Kbps increments up to 384 Kbps.<br>• Booking and coordination of the use of the facility, setup, support and maintenance are all included in the fee. | | Other audio visual equipment that may be required is not included. | Polycom video conference unit<br><br>Local and remote monitor<br><br>ISDN connections in three 128Kbps increments up to 384 Kbps.<br><br>Meeting room | | Included in rental rates |


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## Other Network Services

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| 1 | Terminal Server Service | • This service refers to a device connected on the local area network that interfaces dialup ports to the ATCO Corporate network. Protocol translation software, within the device, translates dial protocols into TCP/IP for transmission across the ATCO Corporate network.<br>• This service is available in 1, 4, 8, 20 port configurations at differing prices. | | Support for the Terminal Server is excluded but available and charged as Time and Materials Rates.<br><br>Modems and telecommunication lines used for the dial mechanism are excluded.<br><br>Installation and any associated travel costs incurred by ATCO I-Tek are excluded.<br><br>Internal wiring and electrical facilities necessary for the installation in the remote office are not included. | Central network connection equipment<br>• The network and security devices used to interface the terminal server connection into the ATCO corporate network are included.<br>• All software, hardware, and security maintenance is included.<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.<br>Terminal Server<br>• This device provides the protocol translation mechanism that translates dial protocols into TCP/IP for transmission across the ATCO Corporate network.<br>• Software, hardware, and security maintenance are included. | | Included in network access rates |
| 1 | Asymmetric Digital Subscriber Line (ADSL) Light | • This service refers to a wide area network data connection from a remote office local area network to the ATCO Corporate network. The service utilizes a telecommunications carrier service based on differing | | The installation charge from the telecommunications carrier is not included.<br><br>Internal wiring and | Central network connection equipment<br>• The network and security devices used to interface the ADSL connection | | Included in network access rates |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | speeds to the remote office and from the remote office to the corporate network. The speed from the office will vary from 256Kbps to 800 Kbps. The speed to the office from the corporate network will vary from 1Mbps to 3 Mbps. The variability of the speed of the service is dependant on the distance to the remote office from the telecommunications carrier facility and the quality of the telecommunications cable.<br>• The amount of data transferred on the service during each month is a factor in the cost of the service. ADSL Light includes 5GB of data transfer each month. Exceeding this amount for two consecutive months will require the client to move to the ADSL Unlimited service. | | electrical facilities necessary for the installation in the remote office are not included.<br><br>Travel time and associated costs incurred by ATCO I-Tek to install the service are not included. | into the ATCO corporate network are included.<br>• All software, hardware, and security maintenance is included.<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.<br>Remote Office Router<br>• This device provides the connection point from the remote office local area network to the telecommunications ADSL facility to the ATCO corporate network.<br>• The underlying telecommunication facility is included.<br>• All software, hardware, and security maintenance is included.<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard. | | |
| 1 | ADSL Unlimited | • This service refers to a wide area network data connection from a remote office local area network to the ATCO | | The installation charge from the telecommunications carrier | Central network connection equipment<br>• The underlying | | Included in network access |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | Corporate network. The service utilizes a telecommunications carrier service based on differing speeds to the remote office and from the remote office to the corporate network. The speed from the office will vary from 256Kbps to 800 Kbps. The speed to the office from the corporate network will vary from 1Mbps to 3 Mbps. The variability of the speed of the service is dependant on the distance to the remote office from the telecommunications carrier facility and the quality of the telecommunications cable.<br>• The amount of data transferred on the service during each month is a factor in the cost of the service. ADSL Unlimited includes an unlimited amount of data transfer. | | is not included.<br><br>Internal wiring and electrical facilities necessary for the installation in the remote office are not included.<br><br>Travel time and associated costs incurred by ATCO I-Tek to install the service are not included. | telecommunication facility is included.<br>• The network and security devices used to interface the ADSL connection into the ATCO corporate network are included.<br>• All software, hardware, and security maintenance is included.<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.<br>Remote office router<br>• This device provides the connection point from the remote office local area network to the telecommunications ADSL facility to the ATCO corporate network.<br>• The underlying telecommunication facility is included.<br>• All software, hardware, and security maintenance is included.<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, | | rates |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | | | | monitoring, and support are standard. | | |
| 1 | Network Connectivity | • This service provides local area network connectivity to the ATCO Corporate network for devices that are approved by ATCO I-Tek but not owned and operated by ATCO I-Tek. This includes process control or Category 6 devices.<br><br>*All devices connected to the ATCO Corporate network must be approved by ATCO I-Tek. This mitigates the amount of risk introduced to ATCO's corporate network. The process for approval is to open a Request with the CSC identifying the device. The Request will be forwarded to the appropriate group depending on the device type.* | | Any security devices like firewall or intrusion detection equipment required to mitigate the risk to the ATCO Corporate network are excluded.<br><br>Any new or additional wide area network equipment required to support the addition of the network connected device to the corporate network is excluded.<br><br>Cabling from the device to the network connection point is excluded. | Local area network switch port<br>• This device provides the interface point into the ATCO Corporate network<br>• All software, hardware, and security maintenance is included.<br>• Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are included. | | Included in network access rates |


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## 2.17 Application Management & Support

### Development

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | New Application Development Services | Provides the Client with development activities for applications that support the business requirements. ATCO has a very diverse and complex environment. ATCO I-Tek recognizes that specialty services and expertise may be required that ATCO I-Tek does not have. In these instances, ATCO I-Tek may be requested to provide Project Management Services for the development and/or integration of these projects where agreed to by ATCO and ATCO I-Tek.<br>Use the Service Request process in place as of the Effective Date of the Agreement for all ATCO directed application development activities. Application Service Requests will be managed and prioritized jointly by ATCO and ATCO I-Tek, taking into consideration the impact upon the business, the | Under 40 man-days for Tier 1. | Over 40 man-days for Tier 2 | ATCO I-Tek uses industry standard methodologies to ensure consistent development and enhancements of applications. | Work with ATCO I-Tek to prepare Business Cases<br><br>Review priorities, assign new priorities, determine if requests have outstanding obstacles & work to remove those obstacles<br><br>Ensure adequate client representation on the project team | Labour Rates. |


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## 2.17 Application Management Support - continued

**Development - continued**

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | New Application Development Services - continued | Clients, the number of people affected, resource availability, on-line response time, usability of an application and integrity of an application.<br>• Log request<br>• Perform feasibility study<br>• Provide Project Management personnel and Services, as deemed appropriate by each project, for developing and managing integration projects encompassing ATCO I-Tek responsibilities. These personnel will align with ATCO project personnel and may include a Champion, Sponsor, Committee Members, and Project Manager. Upon request, ATCO I-Tek can also provide Client Project Management.<br>• Define & document requirements<br>• Analyze & design System/program<br>• Provide estimate<br>• Assign priority (with ATCO Representative)<br>• Perform application development Services to the extent such Services are documented and specified by way of agreed to processes for additional Services between ATCO and ATCO I-Tek. Use ATCO I-Tek standard tools, methods and processes when developing new applications<br>• Provide capacity planning for the definition and coordination of additional hardware/software, Services or purchases requiring ATCO approval for the appropriate project<br>• Test to confirm functionality<br>• Ensure client testing completed | | | | | |


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## 2.17 Application Management Support - continued

**Development - continued**

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | New Application Development Services - continued | • Provide application Documentation to a level consistent with existing application Documentation as of the Effective Date of the Agreement. This will apply to all new application software developed and implemented by ATCO I-Tek<br>• Post implementation review.<br>• Monitor application performance for compliance with mutually agreeable, documented requirements | | | | | |
| 1,2 | Requirements Determination Services | • Requirements Determination Services identify specific business needs and develop alternative approaches with regard to these business needs. An approach will be recommended but must be jointly agreed between ATCO and ATCO I-Tek prior to implementation.<br>• A project plan supporting the agreed approach and reflecting the scope will be jointly developed to define the work, schedule, resources, budget, environment, risks and communications to be performed or provided by the respective parties.<br>• ATCO and ATCO I-Tek will jointly provide a high-level description of ATCO's business problem or opportunity with respect to the impact and requirements.<br>• Agree to the project plan and respective tasks | Under 40 man-days for Tier 1 | Over 40 man-days for Tier 2 | | | Labour Rates. |


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## 2.17 Application Management Support - continued

**Development - continued**

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Requirements Analysis Services | • Refine the high-level business requirements into detailed business requirements that define the functions and Services to be delivered and the attributes of those functions and Services.<br>• Develop logical application specifications to provide a detailed analysis and description of the processes and data that support required application functions. | | | | | Statement of Work |
| 1,2 | Application Design Services | The Application Design Services build upon the detailed requirements and logical specifications determined in the Requirements Analysis Services. A solution is designed and specifications provided for producing the finished product.<br>• Provide a technical design to support the recommended approach to meet the detailed requirements and logical specifications dictated by the change;<br>• Provide application design specifications to define the manner in which the change will impact the business flow/processes; provide specifications for the technical architecture, application design and physical data requirements;<br>• Develop a transition strategy for converting existing application software or data components;<br>• Provide an implementation plan detailing the steps, the individuals responsible, the resources needed and the time frames for implementing all the application components; and<br>• Define new training requirements | Under 40 man-days for Tier 1 | Over 40 man-days for Tier 2 | | | Labour Rates. |


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## 2.17 Application Management Support - continued

**Development**

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Application Construction Services | Application Construction Services translate designs and specifications into the final products. Components are tested as individual units.<br>• Produce/update the application software in conformance with the specifications and standards;<br>• Produce/update application Documentation;<br>• Develop training material if this was jointly agreed to;<br>• Develop an implementation contingency plan; and | Under 40 man-days for Tier 1 | Over 40 man-days for Tier 2 | | | Labour Rates. |
| 1,2 | Application Construction Services - continued | • Perform preliminary unit testing of the applications and training material (if previously jointly agreed to) before any integration is attempted. Unit testing consists of the development of a unit test plan, test cases and test data | | | | | |


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## 2.17 Application Management Support - continued

**Development**

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Application Testing Services | Application Testing Services demonstrate that the application and delivered products meet the requirements defined in the Application and Design Services.<br>Following "Unit" testing, components are "System" tested with the rest of the application to validate functionality and interoperability. Additional "Integration" testing may be required to verify operating system compatibility, performance and load capacity. Produced components are "User Acceptance Tested" in the Model Office environment by the Client, intended users and other stakeholders before authorized for implementation.<br>If required, additional testing may be necessary to verify security and disaster recovery requirements outside the normal disaster recovery testing schedule.<br>• Construct and manage the application test plan;<br>• Create test cases and perform integration testing; and<br>• Conduct performance testing and tuning, including comparisons to existing Service Levels covering the application as applicable | Under 40 man-days for Tier 1 | Over 40 man-days for Tier 2 | | | Labour Rates. |


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## 2.17 Application Management Support - continued

**Development**

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Application Implementation Services | Application Implementation Services complete application delivery in accordance with project plans and requirements. All components of the application are installed in the production environment.<br>• Implement the change to the application into production.<br>• Verify application functionality;<br>• Perform data conversion of existing data structures;<br>• Perform post installation monitoring;<br>• Establish appropriate application security and access;<br>• Upgrade the change management Documentation for the configuration items<br>• Transition the updated application to a maintenance and production control status. | | | | | Labour Rates. |
| 1 | Project Methodology (ATCO I-Tek) | • Educate and communicate methodology to ATCO clients.<br>• Ensure quality assurance processes are in place during project development | | | | | Labour Rates. |


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## 2.17 Application Management Support - continued

**Maintenance & Enhancement**

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Application Maintenance and Enhancement Services | ATCO I-Tek will provide application software maintenance and enhancement Services to maintain ATCO's applications.<br>Application maintenance and enhancement Services are provided by ATCO I-Tek to maintain and/or implement enhancements to existing applications.<br>Application maintenance is deemed to include Application Support (emergency fixes) and Data Base Administration (DBA) Services.<br>Application maintenance Services are performed to:<br>• Enable existing computer program to remain usable in a changed or changing environment. Improve the performance, maintainability, or other attributes of a computer program.<br>• Prevent problems before they occur.<br>• Achieve compliance to ATCO I-Tek operating standards.<br>• Correct application problems/errors caused by hardware or software.<br>• Provide support for application functionality.<br>DBA Services include:<br>• Administration Services to support and maintain the use of a database product, program or process (e.g. product support, security access, software upgrades, batch cycle maintenance, reviews, disaster recovery, data base performance, data base reorganizations).<br>• Correction of application problems/errors related to databases and associated software.<br>• Provide application support that cannot be addressed by the application developers. | Under 40 man-days for Tier 1. | Over 40 man-days for Tier 2<br><br>Impact of Tier 2 projects will be assessed & support requirements reviewed | ATCO I-Tek uses industry standard methodologies for consistent maintenance and enhancements of applications. | Review priorities, assign new priorities, determine if requests have outstanding obstacles & work to remove those obstacles | Labour Rates. |


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## 2.17 Application Management Support - continued

**Maintenance & Enhancement - continued**
(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Application Maintenance and Enhancement Services - continued | • Application enhancement Services of an existing application include the creation, modification and installation of additional functionality in response to changing business requirements, whether tactical or strategic in nature. Application enhancements are deemed to include application development, including DBA Services (data base definition, testing and implementation), < 40 man-days of effort.<br>• Manage third party application support Services for applications where ATCO I-Tek has agreed to this role with ATCO. Such management would consist of being a liaison with the third party and the coordination and management of the third party agreements | | | | | |
| 1,2 | Scope of Application Maintenance and Enhancement Services | **ATCO I-Tek responsibilities related to both maintenance and enhancement Services are**:<br>• Provide estimates for necessary service requests.<br>Implement the application modifications related to maintenance, enhancements, and application support to achieve and maintain the standards specified in the Service Level Measurements.<br>• Provide performance reports that are currently being provided.<br>• Update application Documentation to reflect the changes in application functionality.<br>• Provide third party vendor management of maintenance activity | | | | Any risks or costs associated with using unsupported third party vendor application products will be the responsibility of ATCO.<br><br>Conduct acceptance testing of application modification prior to implementation into production. | Labour Rates. |


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## 2.17 Application Management Support - continued

**Maintenance & Enhancement - continued**
(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Scope of Application Maintenance and Enhancement Services - continued | **ATCO I-Tek responsibilities related to maintenance Services are**:<br>• Resolve abend and production problems for supported applications within the time frame specified in the Service Level Measurements. Abends are conditions in the application logic that are inconsistent with the agreed upon logic for the application or errors that are caused by failures in hardware or system software<br>• Provide production problem analysis and resolution. ATCO I-Tek will log its activities with a description of the resolution and impact to ATCO. Root cause analysis may result in a new maintenance or enhancement activity.<br>• Maintain problem notification and resolution procedures for each application. The designated ATCO contact(s) will be notified of problems.<br>• Take corrective action to repair or recover data bases, data and files to support the application and fix production problems.<br>• Provide necessary restarts and reruns of production jobs in keeping with the established production schedule.<br>• Provide application backups. An application backup consists of:<br>(a) The periodic copying of source libraries (code, control language).<br>(b) The periodic copying of application data files before or after using or updating those files. Application backup includes only data managed by processes internal to the application. | | | | | |


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## 2.17 Application Management Support - continued

### Maintenance & Enhancement - continued

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Scope of Application Maintenance and Enhancement Services - continued | • Provide data base performance analysis, tuning and space management; and Create and maintain any contact lists necessary.<br>**ATCO I-Tek responsibilities related to enhancement Services are:**<br>• Provide installation and maintenance of application upgrades. This consists of analysis and testing to determine impacts on ATCO applications resulting from environmental (supporting software/hardware) changes.<br>• Provide DBA Services (data base definition, testing and implementation) related to the installation and maintenance of application upgrades.<br>• Each upgrade to third party vendor application products will be evaluated to assess the impact to the ATCO applications.<br>• Initiate, where appropriate, third party / vendor application changes to meet operating standards, minimize risk (e.g.: unsupported releases) or improve performance.<br>• Implement into production maintenance and enhancement changes to applications, following the change management process.<br>**Assumptions:**<br>A service request process exists. ATCO currently has a method of requesting and prioritizing Services via the ATCO System Advisory Committee (SAC).<br>All third party software will be maintained at a vendor supported release level. | | | | | |

### Application Service Provider (ASP)

(Under 40 Man-days Tier 1, Over 40 Man-days Tier 2)

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | Applications | The Application Service Provider (ASP) offering provided by ATCO I-Tek includes | | | | | Statement of Work |


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| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| | | three components:<br><br>• Application license and annual maintenance Fee - The application license and annual maintenance fees include database and application licensing, annual maintenance fees and license management.<br><br>• Application hosting - Application hosting includes hardware support and maintenance, annual capacity planning, operating system and application code storage, security administration, performance monitoring and operational recovery.<br><br>• Application support and administration - Application support and administration includes database administration and maintenance, applications maintenance and tuning, System administration and application support. Minor application upgrades (point releases for example. 11.z to 11.y) are included in the ASP offering, however, full application upgrades (11.x to 12.x) are excluded. Data storage, archiving, disaster recovery and the infrastructure required to connect to the application are excluded from the ASP offering. | | | | | License fees may or may not be included in ASP price. |


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## 2.18 Database Management & Support

### Development

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | New databases | • Feasibility study<br>• Gather requirements<br>• Analysis<br>• Functional Design<br>• Create physical data model<br>• Create data dictionary<br>• Develop security requirements/procedures<br>• Ensure backup/recovery procedures & products are in place<br>• Implement in test environment<br>• Test to confirm functionality<br>• Assist with data conversion<br>• Implement in production<br>• Prepare a post implementation review | Under 40 man-days for Tier 1 | Over 40 man- days for Tier 2 | | Provide requirements | Labour Rates. |
| 1 | Database products | • Evaluate<br>• Test to confirm functionality<br>• Make configuration changes required<br>• Implement | | | | | Labour Rates. |

### Maintenance & Enhancement

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1,2 | Support | • Design database change<br>• Test to confirm functionality<br>• Update existing data models & data dictionaries for database changes<br>• Implement changes to meet business requirements<br>• Ensure adequate backup & recovery is available for all databases<br>• Follow disaster recovery plan procedures<br>• Follow security procedures<br>• Evaluate product upgrades<br>• Plan database upgrades<br>• Implement upgrades | Under 40 man-days for Tier 1 | Over 40 man- days for Tier 2 | | | Labour Rates. |


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## 2.18 Database Management Support

### Maintenance & Enhancement

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Capacity Planning | • Manage capacity<br>• Liase with System owners to improve data quality.<br>• Proactively manage use of DASD, predict growth and request additional DASD as required | | | | | Labour Rates. |
| 1 | Performance tuning on mainframe databases | • Monitor performance<br>• Tune where necessary to maintain agreed to Service Levels.<br>• Implement data reorganization to maximize performance. | | | | | Labour Rates. |

## 2.19 Data Management

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Data Security | • Manage user access rights and data access rights for both distributed & mainframe environment<br>• Manage security policies and procedures as approved by the ATCO Group | | Data management relating to major ATCO reorganizations and Tier I or II projects | | Define requirements for data security | Included in all Rates. |
| 1 | Data Management | ***Data Management for the Enterprise Server***<br>• ATCO I-Tek provides Services to electronically maintain and manage the storage and retrieval of data.<br>• Data management includes HSM data-set deletion standards. The standards are required to help with DASD capacity management and to avoid unneeded costs for increasing data storage capacity.<br>  • Data on the enterprise server is managed by applications or Clients and is stored in various files, data sets and databases on the enterprise server. Clients are responsible for the maintenance of their data. | Data base management software tools review, investigated and implement if necessary the 2-5 year timeframe. | Data management relating to major ATCO Reorganizations and Tier I or II projects. | ATCO I-Tek is responsible for informing clients of redundant data sets and procedures for the maintenance of the data. | ATCO clients are responsible to follow the recommended procedures. This will assist in DASD capacity management and to avoid unneeded costs for increasing data storage capacity | Storage Rates. |


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## 2.19 Data Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Data Management - continued | • A monthly batch process can be run that identifies all data sets and files (All other data sets and files including user data sets (prefix U***) are included) that have not been accessed for 12 months or more that summarizes the findings in a report. Data-set owners are responsible for deletion of redundant data sets<br>• Follow all procedures for the administration of data, including user notification, data archives, file deletions and a process to handle data owned by terminated employees<br>• Move data as required due to client position changes | | | | | |
| 1 | Backup and Restore | ***Backup and Restore***<br>Backup and Restore are functions required to ensure the availability of data. These include the backup of shared data on servers, the storage of that data and the process to restore data once it is lost.<br>The backups can be retrieved and used to recover the computer facility to a point in time, in order to continue business operations and processes.<br>The backups are used in the event of any type of outage for:<br>file recovery; application database recovery; full production recovery; and disaster recovery.<br>• Back up operating system software, application software and application data to tape. Tape backups will be held in offsite storage. | | Backup and restore of workstation data. | ATCO I-Tek to define backup methodologies / strategies<br><br>ATCO I-Tek to recommend levels of authentication needed for restores of any file<br><br>ATCO I-Tek to define process for backup and restores and communicate to clients.<br><br>Policies and procedures for backup and restores communicated to all users | ATCO to approve backup methodologies / strategies.<br><br>ATCO to approve levels of authentication needed for restores of any file<br><br>ATCO personnel to assist in the backup process at remote locations. | Storage Rates. |


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## 2.19 Data Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Backup and Restore - Enterprise Server | There are four types of backups that can be required by an application. Backups are performed for the application, the database, the full volume DASD and the software product used. The Application Coordinator is responsible for providing data retention requirements for their respective applications. ATCO I-Tek will ensure that the respective application is recoverable from regular backups. | Weekly backup tapes will be retained for six weeks. In the event of recovery from backup, work with ATCO to ensure databases are synchronized before normal on-line processing resumes<br><br>Full enterprise server System backups are taken weekly with incremental backups taken daily. "Full backups" means that the whole storage space (DASD volume) is copied to tape and incremental means that only those files that have changed, since the last backup, are copied to tape.<br>The backup strategy addresses backups for databases, DASD volumes, application files and product software. The goal of the strategies is to minimize the potential for data loss to a timeframe not exceeding 24 hours.<br>Production database backups are scheduled daily by the automated production scheduling product. Job names must follow the naming standards. Dual copies are required, one copy for onsite and one copy offsite. The data-set names must conform to Production JCL standards. All development, test, production and application data sets are controlled through the SMS (Storage Management System). All tape data sets must be added to the TLMS RMF file. | | ATCO I-Tek to define backup methodologies and strategies. | ATCO to approve backup methodologies and strategies.<br><br>ATCO to verify backup methods, frequency and retention meet business needs. | Storage Rates. |


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## 2.19 Data Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Backup and Restore - Enterprise Server - continued | | | | | | |
| 1 | Backup and Restore - Enterprise Server - continued | | Offsite DB2 backups are kept based on date control for 35 days<br>Onsite DBP1 archive log data sets are kept for 35 days<br>Offsite DB2 catalog backups - 8 generations are kept<br>The full DASD volume backups are run every weekend, scheduled from 21:00 Saturday to 7:30 Sunday. The entire DASD volume is backed up. Incremental backups are completed daily.<br>weekly full DASD volume backups - 6 generations kept (approximately six weeks)<br>daily incremental backups - 6 generations kept (approximately 1 week) | | | | |


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## 2.19 Data Management - continued

| Tier | Category | Major Scope Items (not all inclusive) | Included in Base | Excluded | ATCO I-Tek Responsibility | Client Responsibility | Service Rates |
|---|---|---|---|---|---|---|---|
| 1 | Back up and restore – Mid Range and Local Area Network Servers | Mid Range and Local Area Network servers have weekly full and daily incremental backups taken each Monday to Saturday during the 18:00 - 07:00 window.<br>Applications using a database (e.g. Oracle, Access) are unavailable during the backup of that database. The unavailable period depends on when the backup of that database starts and the length of time to perform the backup, (i.e. the size of the database).<br>The timing of backups may create a synchronization issue:<br>In the event of a recovery from backups, the database will require an evaluation and synchronization before normal on-line processing can be resumed.<br>In the event of a backup failure ATCO I-Tek rectifies the situation:<br>Failed backups for the enterprise server are corrected at the time of failure. The standby analyst is paged.<br>Failed backups of the distributed Systems are re-done the next Business Day after 16:30. | Local Area Network Servers will have weekly full and daily incremental backups taken each Monday to Saturday during the 18:00 – 07:00 window. Backup failures will be rerun the next Business Day after 16:30.<br><br>Continue to support recovery of a distributed server at a rate of approx. 10 GB per hour. Recovery of individual files (approx. 5 GB per hour) is within two hours if backup is on site; one day if back up is off site. | Disaster Recovery for server is currently being evaluated. | ATCO I-Tek to define backup methodologies and strategies | ATCO to approve backup methodologies and strategies.<br><br>ATCO to verify backup methods, frequency and retention meet business needs | Workstation rates (include file and print services)<br><br>Business application service fees for all specialized hardware and software Services |
| 1 | Back up and restore – Mid Range and Local Area Network Servers | Distributed Systems backups are taken on a weekly and daily basis for those servers managed by ATCO I-Tek. Weekly backup tapes are sent offsite and retained for six weeks | | | | | storage rates. |
| 1 | Backup and Restore - Desktop Systems | To ensure that all data is included in the scheduled backup, it must be stored on the network. The backup of data files residing on the desktop is the responsibility of the user. | Excludes backup and restore of desktop Systems. | Desktop Systems are not backed up (as applicable to this Agreement). | | Backup of data files residing on the desktop. | N/A |
| 1 | Policies & procedures | Develop & maintain policies & standards for the definition, creation & accessibility of server data | | | Ensure quality assurance & change control is part of general practice | Review proposed policies & standards Ensure proper checks & balances are in place | Included in all Rates. |


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# INFORMATION TECHNOLOGY

# MASTER SERVICES AGREEMENT

# Schedule C – Service Measures


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# SCHEDULE C - SERVICE MEASURES

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# 1.0 Introduction

## *1.1 Overview*

This Service Measures document is Schedule C to the IT Master Services Agreement (Agreement). The purpose of Schedule C is to detail the Service Levels for the Information Technology Services.

The Services outlined in the Service Level Agreement are the Services being delivered to the Clients today. ATCO I-Tek will deliver these Services at the current level of service and strive to exceed this level of service during the term of the Agreement.

The Client has identified the monthly "Target" Service Levels. The Target Service Level is the current level of service being delivered to the Client today.

Where new Target Service Levels are requested, ATCO I-Tek will determine the difference from the current Service Level and establish a time line to move to this Target Service Level. Costs associated with delivering this new level of service will be brought forward to the Client for approval.

Service Level Reporting will continue on a monthly basis and will include exception-based reporting. ATCO I-Tek will continue to suggest a method of reporting Service Levels for those Service Levels that are not currently being measured because they are new measures or where measurement tools are not currently available.

The Client and ATCO I-Tek have agreed on the performance targets set out in the SLA. Critical Service Levels and the Target Service Levels may be subject to the application of incentives described in this document.

These "Target" Service Levels are used for holdbacks and will be measured by the average per month.

# 2.0 General

## *2.1 Hours of Availability*

The hours of availability are defined in Section 8.0.

## *2.2 Help Desk Hours of Operation*

ATCO I-Tek shall provide seven (7) days a week, twenty-four (24) hours a day support for all Services through ATCO I-Tek single point of contact or through specially designated processes as shall be developed together with the Client.


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### *2.3 Service Level Measurements*

a) Upon Effective Date, ATCO I-Tek agrees to the Service Measures specified in Section 8.0.

b) ATCO I-Tek and the Client shall review the Service Measures detailed in Section 8.0 and agree upon the Service Levels and associated incentives on an on-going basis. The Service Levels detailed in Section 7.0 (Critical Measures) and 8.0 (Service Measures) will apply commencing within the first 60 days of the signing of this Master Agreement, unless additional data supports a Change to this section and is agreed to by the Client.

c) ATCO I-Tek and the Client may propose new, revised or improved Service Level measurements or Service Level targets at any time during the term of this Agreement and will utilize the following process:

1) The ATCO I-Tek Vice President, Technologies and/or ATCO I-Tek Vice President, Applications and Client VP with IT Responsibility agree on and approve the Change.

2) As the contract owners, the applicable ATCO I-Tek Designated Manager and the Client Designated Manager should be made aware of the Change.

d) ATCO I-Tek will apply any incentives described in Section 5.0, as of the signing of the Master Services Agreement and as agreed to during the Annual Review period.

e) Regular management review meetings shall be scheduled with the Information Technology Steering Committee to review actual performance against projected performance, and to recommend actions to be taken to resolve any performance deficiencies.

f) The parties anticipate that ATCO I-Tek's provision of Services will improve over the term of this Agreement based on ATCO I-Tek's knowledge of, and access to, state-of-the-art resources and technology, implementation of improved methods and procedures for providing the Services, and efficiencies arising from the use of ATCO I-Tek resources and their accompanying skills.

g) ATCO I-Tek, shall during the Term, investigate methods to improve the systems to the benefit of the Client.

h) ATCO I-Tek, shall not be responsible for failures to meet Service Levels while operating under the Disaster Recovery Plan.

i) Certain critical and/or target Service Levels will be subject to the application of incentives, as described in Section 5.0 of this Schedule.

j) During the first year of this Agreement, ATCO I-Tek, will work toward achieving or bettering all the Client Service Levels stated in Section 7.0 and 8.0.

k) Changes to business and Service Level requirements during the term may result in a revision to service categories and levels to improve Services being delivered. A formal review and re-establishment of the Service Levels will be undertaken annually, during the price re-determination process.


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l) Should ATCO I-Tek fail to meet Service Levels, an action plan will be developed to address the situation. This action plan will be presented to the Information Technology Steering Committee for review and discussion within 10 days of failure.

m) Target Service Levels are the Service Levels required by the Client. Service levels are defined by the business.

n) Requests that do not follow standard processes are not subject to Service Levels.

## 3.0 Time To Respond Service Level Priority Codes

The following table outlines the response Service Level for each priority code.

| Priority Code | Description | Time To Respond * (TTR) Office Hours | Time To Respond * (TTR) After Hours |
|---|---|---|---|
| Critical | A problem causing an unscheduled interruption to an applications availability or interrupted Client service. Business impact is or will be severe. | Less than 20 minutes (NOTE 1) | Less than 1 hour (NOTE 1) |
| High | Problem has disrupted Client service. Client can continue to process, but at great inconvenience. Business impact is high. | Less than 1 office hour | NOTE 2 |
| Medium | Client service is degraded. Business impact is moderate to low. Solution required in the short term. | Less than 4 office hours | NOTE 2 |
| Low | Current Client service has low or negligible impact. Business impact is low. Solution required in the long term. | Less than 24 office hours | NOTE 2 |

** Time To Respond (TTR) is the elapsed time between when the problem is detected (by a caller or automated alert) and when work begins on the trouble ticket issued.*

*NOTE 1: For all critical problems work on the problem will be continuous regardless of time of day, or day of week, until a complete or interim resolution is completed.*

*NOTE 2: Problems reported outside office hours will be processed as if the call was received at 8:00 of the next Business Day.*


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## 4.0 Time To Solution Service Level For Priority Codes

The following table outlines the solution Service Level for each priority code.

| Priority Code | Description | Time To Solution * (TTS) Office Hours | Time To Solution * (TTS) After Hours |
|---|---|---|---|
| Critical | Complete or interim resolution/action plan provided. | Less than 2 hours | Less than 4 hours |
| High | Complete or interim resolution/action plan provided. | Less than 4 office hours | NOTE 1 |
| Medium | Complete or interim resolution/action plan provided. | As Scheduled Within 1 month | NOTE 1 |
| Low | Complete or interim resolution/action plan provided. | As Scheduled Within 3 months | NOTE 1 |

** Time To Solution (TTS) is the elapsed time between when the problem is detected (by a caller or automated alert) and when an interim solution, a resolution or action plan is provided.*

*NOTE 1: Problems reported outside office hours will be processed as if the call was received at 8:00 of the next Business Day.*

### *Measurement Assumptions*

For measurement purposes the following assumptions have been used:

1. 7 X 24 hours service is based on an average of 30.4 days per month or an estimated 720 hours per month. Availability will be calculated on this basis.

2. Availability target Service Levels exclude the impact of force majeure and events beyond the control or influence of ATCO I-Tek which affect availability.

3. For remote locations, the above times exclude travel and shipping time where applicable.


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## 5.0 Incentives

### *5.1 Critical Measures*

ATCO I-Tek and the Client have agreed that there will be a minimum number of Critical Measures. These measures will reflect those Services that impact the ATCO Group's revenue stream, Client service and business operations.

During the term of this Agreement ATCO I-Tek will track, measure and report against these metrics and identify corrective action where deviations have been reported.

### *5.2 Service Measures*

For the 1st Event of not achieving the Service Levels for the same measure over a one-month period, ATCO I-Tek to identify cause, response and a corrective action plan within 10 Business Days.

For the 2nd Consecutive Event (within six-month rolling average) of not achieving the Service Levels over a one-month period,. ATCO I-Tek to identify cause, response and a corrective action plan within 10 Business Days. Client to with hold 5% of the monthly service fee for the affected service until ATCO I-Tek has achieved three consecutive months of meeting the Service Level.

## 6.0 Service Level Reporting

### *6.1 Tier 1 Service Level Reporting*

Clients will continue to receive current reports, and new reporting requirements will be dealt with during the annual renewal of the service Agreement. ATCO I-Tek proposes that new reporting procedures will be developed to coincide with finalized Service Level measurements.

### *6.2 Tier 2 and 3 Service Level Reporting*

Service level reporting for Tier 2 Services will be developed jointly for inclusion in the SLA. Tier 2 and 3 Service Levels and reporting requirements will be created in the respective Tiered proposals which are approved by Client and these Service Levels will be implemented into the Service Level agreement on an annual basis.


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## 7.0 Critical Measures

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED / Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Oracle Financials Clients:**<br><br>Oracle Financials | Availability of the application | 99.4% average per month. | Help Desk<br><br>Critical | PR | Client Survey |
| **ATCO Electric:**<br><br>LPSS (Load Settlement) | Availability of the application. Required for compliance with AESO for settlement data availability and compliance reporting. | 99% average per month | Help Desk<br><br>Critical | PR | Client Survey |


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## 7.0 Critical Measures - Continued

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED / Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **ATCO GAS:**<br><br>Non-Gas Sales/Service Billing | Availability of the application billing function. | 100% of invoices available by the 4th day before the end of the month. | Help Desk<br><br>Critical | PR | Client Survey |
| Work Management | Availability of mainframe component of the application. | 99.5% average per month. (3.6 hours/ month average for all workstations.) | Help Desk<br><br>Critical | PR | Client Survey |
| **ATCO Pipelines:**<br><br>SCADA System network connectivity | Between ATCO Center Edmonton and PPC Edmonton only. Corporate network connectivity and availability only. | 99% average per month. (7.2 hours/ month unavailability | Help Desk<br><br>Critical | PR | Client Survey<br>Industry Trend |
| TIS Nominations | Availability of the application function. Excludes internet service provider availability. | 99% per month. | Help Desk<br><br>Critical | PR | Client Survey |
| Gas Management System | Availability of the application. | 99.5% average per month. (3.6 hours/ month average unavailability) | Help Desk<br><br>Critical | PR | Client Survey |


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## 7.0 Critical Measures - Continued

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Alberta Power Pool connectivity** | Corporate network connectivity and availability only.<br><br>Excludes internet service provider availability | 99.5% average per month. (3.6 hours/ month average unavailability) | Help Desk<br><br>Critical | P | Client Survey |

## 8.0 Service Measures

### *8.1 Mainframe Availability And Response*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Operating System Availability** | | 99.9%<br>0.72 hrs/per month average | Monitoring Tool<br><br>Critical | PR | Industry Trend |


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## 8.0 Service Measures - Continued

### *8.1 Mainframe Availability And Response - Continued*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **General Database Availability** | | 99.9%<br>0.72 hrs/per month average | Monitoring Tool<br><br>Critical | PR | ATCO |
| **IMS Applications Response**<br><br>**ADABAS Applications Response**<br><br>**CICS Applications Response (Includes DB2 elapsed time)** | Average response as determined by current measurement capabilities and current transaction profile | 0.25 Sec<br><br>0.25 Sec<br><br>0.75 Sec | Monitoring Tool<br><br>Critical | PR | ATCO |


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## 8.0 Service Measures - Continued

### *8.1 Mainframe Availability And Response - Continued*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Production Control**<br><br>Production jobs completed successfully<br><br>Code elevation<br><br>Output distribution | Applies to all applications | 96%<br>within 24 hours of planned schedule<br>within 2 hours of receipt of output | Help Desk<br><br>Critical | PR | ATCO |

### *8.2 Server And Midrange Availability And Response*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Operating System Availability**<br>As described for database and application availability below. | Includes Database, Midrange, Mail Exchange and File/Print Servers<br><br>Excludes LAN/WAN Availability<br><br>Average by Location | 99%<br>7.2 hrs/per month average | Help Desk<br><br>Critical | R | ATCO |


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## 8.0 Service Measures - Continued

### *8.2. Server And Midrange Availability And Response - Continued*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **General Database Availability**<br>24 hours a day, 7 days a week (7x24)<br>Prime: 7:00 to 19:00<br>Mon to Fri<br>Non Prime: 19:00 to 7:00<br>Mon to Fri<br>Block Time: Sunday 7:00 to24:00<br>Other Maintenance Upon Request, with 5 Business Days notification | Includes Database, Midrange, Mail Exchange and File/Print Servers<br><br>Excludes LAN/WAN Availability<br><br>Includes Remote Sites<br><br>Average by Location | 99%<br>7.2 hrs/per month average | Help Desk<br><br>Critical | R | ATCO |
| **General Application Availability:**<br>24 hours a day, 7 days a week (7x24)<br>Prime: 7:00 to 19:00<br>Mon to Fri<br>Non Prime: 19:00 to 7:00<br>Mon to Fri<br>Block Time: Sunday 7:00 to24:00<br>Other Maintenance Upon Request, with 5 Business Days notification | Includes Database, Midrange, Mail Exchange and File/Print Servers<br><br>Excludes LAN/WAN Availability<br><br>Averages by Location.<br><br>Includes Remote Sites | 99%<br>7.2 hrs/per month average | Help Desk<br><br>Critical | R | ATCO |


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## 8.0 Service Measures - Continued

### *8.2. Server And Midrange Availability And Response - Continued*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Server/Midrange Response** | Average Response as determined by current measurement capabilities and current transaction profile.<br>Monitoring tools are required for File/Print and Database computers.<br><br>Average by computer. (Period Audit) | 2.8 sec/simple transaction | Monitoring Tool Required<br><br>Critical | R | ATCO |


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## 8.0 Service Measures - Continued

### *8.3 Wan/Lan Availability And Response*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **WAN Availability**<br>LAN servers are available 24 hours a day, 7 days a week (7x24)<br>Prime: 7:00 to 19:00<br>Mon to Fri<br>Non Prime: 19:00 to 7:00<br>Mon to Fri<br>Block Time: Sunday 7:00 to24:00<br>Other Maintenance Upon Request, with 5 Business Days notification.<br>Emergency maintenance may be performed outside the above Block Times, based on prior written notification | Includes routers, modems, DSU/CSU, and circuits at networked location. Measurement is aggregate average across all network locations.<br><br>Measurement is aggregate average across all network components. | 99%<br>7.2 hrs/per month average prime and non-prime | Network Services/Help Desk<br><br>Critical | R | ATCO |


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## 8.0 Service Measures - Continued

### *8.3 Wan/Lan Availability And Response - Continued*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **LAN Availability**<br>available on a continuous 24 hours per day 7 days per week basis<br>Prime: 7:00 to 19:00<br>Mon to Fri<br>Non Prime: 19:00 to 7:00<br>Mon to Fri<br>Block Times: Sunday 7:00 to 24:00<br>Other Maintenance Upon Request, with 5 Business Days notification.<br><br>Note:<br>ATCO Pipelines TIS prime hours are 24x7<br><br>Emergency maintenance may be performed outside the above Block Times, based on prior written notification | Includes hubs and switches. Each remote site and floor within the ATCO Campuses are separate LANs.<br><br>Measurement is aggregate average across all LANs. | 99%<br>7.2 hrs/per month average prime and non-prime | Monitoring Tool/Network Services & Help Desk<br><br>Critical | R | ATCO |


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| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **WAN RESPONSE** | Includes front end processors and routers. Response time definition: Based on network latency which is the average delay time from remote routers to local campus interface route. Measurement is aggregate average across all remote sites. | 2.8 Secs/Average | Network Services/Help Desk<br><br>Critical | R | ATCO |
| **LAN RESPONSE** | Average delay time for LAN based campus ethernet devices.<br><br>Measurement by Audit. | | | | |


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## 8.0 Service Measures - Continued

### *8.4 Enterprise Print Availability*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Printing Availability**<br>Edmonton:<br>Sunday – Friday 22:00 - 24:00<br>Monday – Friday 00:00 - 16:30 | As per print schedules. | 99%<br>of all print volume/month for all applications as per defined Schedule. | Print Services/Help Desk<br><br>Critical | R | Master Service Agreement |

### *8.5 Enterprise Voice Availability*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Voice**<br>Telephone Service Response | Average for in and out bound calls | 98% | Network Services/ Help Desk | R | ATCO |
| Availability | Defined as the Uptime for the PBX | 99%; 7.2 hours/mos prime and non-prime | Monitoring tools | | |
| Adds, Moves & Changes | Defined as planned changes to the System | 7 Business Days | High | | |


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## 8.0 Service Measures - Continued

### *8.6 Support Service Availability & Response - Help Desk*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **HELP DESK Availability/ Client Support**<br>On-Site support (Monday to Friday 07:00 until 17:00):<br>Prime: 7:00 - 17:00 Mon to Fri<br>Non-prime 17:00 - 7:00 | ATCO I-Tek support is twenty-four hours a day, seven days a week to answer Client calls and respond to problems. | 98%<br>4.8 hrs/per month | Help Desk<br><br>Critical | PR | Master Service Agreement & ATCO & Industry Trend |
| **Telephone Response**<br>Prime Only<br><br>Standby-On Call (Non-Prime) | Response target is based on a base of 200 calls per day at a typical rate | 80% of calls will be answered within 30 seconds and;<br>the Average Speed of Answer (ASA) under 30 seconds | Help Desk | R | Current Service Level Reports |
| **First Time Call Resolution** | % of calls resolved at first contact<br>Assumes current pattern of problem categories per month | 60% | Help Desk | R | Master Service Agreement |
| **Help Desk Call Backs** | Random survey of Clients who have reported and logged trouble tickets to ensure satisfaction level was met | 20% of all calls will be verified | Help Desk | S/R | ATCO |


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## 8.0 Service Measures - Continued

### *8.7 Support Service Availability & Response - Desktop*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Problem Resolution** | Second Level call back from time page is received.<br><br>Remotes exclude travel and shipping time | See Section 3.0 and 4.0 in this Schedule | Help Desk<br><br>High | R | ATCO |


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## 8.0 Service Measures - Continued

### *8.8 Desktop Hardware And Software - installs/moves/changes*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| Desktop hardware and software installs/moves/changes | Includes installation and removal managed on a project basis.<br>Quantities of more than 5 are considered a project and will be negotiated for an agreed upon date.<br><br>Equipment is leased to clients for various term durations, dependant on equipment type. As part of the lease agreement, ATCO I-Tek will refresh the standard leased device, with a new standard device, within the calendar year that the lease expires. Any costs associated with client added peripherals or upgrades are not included in the lease prices. | By Plan Schedule<br><br>Includes Campus and Non-Campus By Mutually Agreed Date<br><br>Please see Sections 3.0 and 4.0 in this Schedule.<br>Quarterly plan | Service Requests/Help Desk<br><br>High | R<br><br>R<br><br>R | ATCO |


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## Service Measures – Continued

### *8.8 Desktop Hardware And Software - installs/moves/changes*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED/ Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| | Within the first 60 days of each calendar year, ATCO I-Tek will provide the client with a summary of the equipment that will be eligible for a refresh. ATCO I-Tek will develop a schedule to complete the refresh during the calendar year. ATCO I-Tek will work with the clients and attempt to schedule refreshes to meet any client business requirements. The Client will be notified of any refreshes that are not completed in the scheduled year. | | | | |


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## 8.0 Service Measures - Continued

### *8.9 Desktop Hardware And Software Changes – install/upgrade Software*

| SERVICE | NOTES/RULES | TARGET | HOW MEASURED / Formula | TYPE P/PR/R/S | SOURCE |
|---|---|---|---|---|---|
| **Install/Upgrade Software Packages**<br>Edmonton/Calgary Campus Standard (standard desktop package or business packages required by the business)<br><br>Edmonton/Calgary Campus Non-standard<br><br>Non-Campus (remote) | Packages on ATCO 'supported list' are standard.<br><br>Non-standard will be a critical service request if business-critical applications are affected<br><br>Service levels do not apply to workstations with unauthorized software loaded onto them. | As per agreed time frame<br><br>As per agreed time frame<br><br>As per agreed time frame<br>Excludes power outages and microwave outages | Systems Development/ Help Desk<br><br>High | R | Master Service Agreement & ATCO |


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# INFORMATION TECHNOLOGY

# MASTER SERVICES AGREEMENT

# Schedule D – Price Schedule


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# SCHEDULE D - PRICE SCHEDULE

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# 1 GENERAL PROVISIONS

This Price Schedule is Schedule D to the IT Master Services Agreement (Agreement).

## 1.1 Inflation

All prices are quoted in 2005 dollars and are subject to annual price adjustments as set out in section 8.3 of the MSA.

## 1.2 Early return of equipment

Leased equipment may be returned with three months written notice subject to:

- Return of specialty or non-standard equipment ordered at the Client request will be subject to a charge equal to the present value of all remaining lease payments for the subject device.
- Specific conditions for a particular service offering will take precedence over this clause.
- Section 1.4 “Bandwidth Pricing”
- The requirement for three months written notice may be waived on a case by case basis by ATCO I-Tek at its’ Discretion where the client allows ATCO I-Tek to manage any returns to fit into ATCO I-Tek’s workload and refresh program.

## 1.3 Definitions

- DSN - Database System Name
- Core Software – see section 2.14 of “Schedule B – Definition of Services”
- CSC – Customer Support Centre (Help Desk)
- WAN – Wide Area Network
- LAN – Local Area Network
- PBX – Private Branch Exchange

## 1.4 Bandwidth Pricing

Prices quoted relate to the volumes specified in Section 11. Consumption outside a 10% bandwidth on either side of the forecast category volume totals will be cause for price re-negotiation or volume discounts.



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# 2 EXPRESS SERVICE REQUESTS

## 2.1 General Provisions

Allows the client to make a service request and schedule that request outside the normal queue.

### *2.1.1 Products or Services Provided within the Fee*

Included in the fee, ATCO I-Tek will provide to the Client:

- Placing priority of express requests over normal service requests.

### *2.1.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are exceptions and not included in the fee:

- This is an additional fee and does not include the fee for the applicable service being provided.

## 2.2 Price Schedule

| Description | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| Express Request Service Fee | 123.18 | 123.18 | 123.18 | 123.18 | 123.18 |

# 3 DISTRIBUTED APPLICATION HOSTING

## 3.1 General Provisions

Application Hosting is a service to provide the technical infrastructure for clients to run their business specific applications. Any applications that are hosted by ATCO I-Tek and are not included in the schedule, will be charged a fee that is consistent with the other application hosting fees.

### *3.1.1 Products or Services Provided within the Fee*

Included in the fee, ATCO I-Tek will provide to the Client:

- Application server hardware for a production environment.
- Application server hardware for development and testing environments.
- Hardware maintenance.
- Other special equipment.
- Operating System and operational support tools.



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- Operational support efforts for the hardware required to meet established Service Levels.
- Operational backup and recovery.
- Review of application fee annually.

### *3.1.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are exceptions and not included in the fee:

- Project Services for development, maintenance, enhancements and upgrades to the application are excluded from the operating fee.
- Increases in license fees for any reason will result in an increase in the operating fee.
- Application license fees and maintenance fees will be Specified Expenses.
- Increased equipment capacity requirements will result in an increase in the operating fee.
- Any license transfer fees owing due to the restructuring of the Clients or transfer of business functions from one company to another will be a Specified Expense.
- Maintenance and Services specific to the application.
- Non standard database and /or support tools.
- Decommissioning of the Distributed Application is excluded from the fee. In the event that a Distributed Application is no longer required, the Client will be billed incrementally with Time and Materials Rates to decommission the application.
- Disaster Recovery and Business Continuity Services are excluded from the price.
- Application Security Services specific to an application are excluded from the fee and will be charged as incurred with Time and Materials Rates.


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## 3.2 Price Schedule

(Price per distributed application per month)

| APPLICATION NAME | 2005 TOTAL MONTHLY PRICE | 2006 TOTAL MONTHLY PRICE |
|---|---|---|
| ADP PaySpecialist | $ 733.20 | $ 733.20 |
| AEONS | $ 1,814.67 | $ 1,814.67 |
| Aspen One | $ 48.00 | $ 48.00 |
| ATS | $ 4,600.27 | $ 4,600.27 |
| AutoCAD Lic. Mgr. | $ 48.00 | $ 48.00 |
| Autodesk Lic. Mgr. | $ 48.00 | $ 48.00 |
| Barcode | $ 48.00 | $ 48.00 |
| Barcode | $ 48.00 | $ 48.00 |
| Brighton Beach Backup Disk | $ 135.00 | $ 135.00 |
| Business Objects | $ 2,879.20 | $ 2,879.20 |
| CADD Drawings | $ 7,185.70 | $ 7,185.70 |
| Canadian Standards Database | $ 48.00 | $ 48.00 |
| CMM Customer Management Module | $ 48.00 | $ 48.00 |
| Commercial Inspections | $ 48.00 | $ 48.00 |
| Competency Management Information Sys. (CMIS) | $ 48.00 | $ 48.00 |
| Contact Registry System | $ 48.00 | $ 48.00 |
| CU Water/ Diamond | $ 1,498.80 | $ 1,498.80 |
| Details On Line | $ 48.00 | $ 48.00 |
| Details on Line | $ 48.00 | $ 48.00 |
| DGIS | $ 4,138.95 | $ 4,138.95 |
| Doble | $ 48.00 | $ 48.00 |
| Dropchute | $ 1,422.73 | $ 1,422.73 |
| Dropchute | $ 1,422.73 | $ 1,422.73 |
| Dropchute - Additional sites | $ 54.78 | $ 54.78 |
| ECHO Charitable Donation Database | $ 48.00 | $ 48.00 |
| Employee Community Service Fund | $ 48.00 | $ 48.00 |
| ESSBase | $ 1,354.04 | $ 1,354.04 |
| Event Tracking System | $ 48.00 | $ 48.00 |
| Expedite | $ 48.00 | $ 48.00 |
| Expedite | $ 48.00 | $ 48.00 |
| FIS Datamart | $ 3,730.85 | $ 3,730.85 |
| FIS Query | $ 4,751.98 | $ 4,751.98 |


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| APPLICATION NAME | 2005 TOTAL MONTHLY PRICE | 2006 TOTAL MONTHLY PRICE |
|---|---|---|
| Gas Chromotography (EZChrom) Edm&Cal | $ 1,266.30 | $ 1,266.30 |
| Gas Mgmt System (GM-TIS) - Oct/04-Sept/05 | $ 3,299.75 | $ 3,299.75 |
| GBO - CS | $ 457.50 | $ 457.50 |
| GIV | $ 490.00 | $ 490.00 |
| IDM (Industry Dialog Mgr.) | $ 15,674.60 | $ 15,674.60 |
| Instrument Recording System | $ 48.00 | $ 48.00 |
| Intergraph\CADD | $ 7,356.16 | $ 7,356.16 |
| Ion Enterprises | $ 1,379.13 | $ 1,379.13 |
| ISOSYS | $ 1,615.94 | $ 1,615.94 |
| Khalix | $ 6,601.12 | $ 6,601.12 |
| Land Information System (Access 97) | $ 48.00 | $ 48.00 |
| Landman | $ 1,641.71 | $ 1,641.71 |
| Leak Analysis Management | $ 48.00 | $ 48.00 |
| Line Management Information System | $ 48.00 | $ 48.00 |
| Lodestar | $ 5,416.11 | $ 5,416.11 |
| LPMS | $ 2,377.18 | $ 2,377.18 |
| LPSS (Customer Choice) | $ 16,310.23 | $ 16,310.23 |
| Materials Mgmt. System | $ 999.98 | $ 999.98 |
| Maximo | $ 13,154.87 | $ 13,154.87 |
| Meter Proving System | $ 3,461.37 | $ 3,461.37 |
| Metretek | $ 2,454.75 | $ 2,454.75 |
| Metscan | $ 3,590.04 | $ 3,590.04 |
| Microstation | $ 16.00 | $ 16.00 |
| Mileage Tracking System | $ 48.00 | $ 48.00 |
| MV90 | $ 2,019.32 | $ 2,019.32 |
| Natural Gas Exchange | $ 48.00 | $ 48.00 |
| NGV Billing | $ 48.00 | $ 48.00 |
| O&M Summary Reporting System | $ 48.00 | $ 48.00 |
| Oracle Financials | Variable – ASP Price | Variable – ASP Price |
| PAL - Procurement Access Link | $ 3,973.12 | $ 3,973.12 |
| PC Automate | $ 3,142.51 | $ 3,142.51 |
| PGBS | $ 5,985.97 | $ 5,985.97 |
| Pipeline Reg Station Inspection | $ 48.00 | $ 48.00 |
| Pipeline Valve Inspection | $ 48.00 | $ 48.00 |
| PO Requisition Tracking System | $ 48.00 | $ 48.00 |
| PremierPlus4 | $ 8,947.03 | $ 8,947.03 |
| Pressure Factor Measurement System | $ 48.00 | $ 48.00 |



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| APPLICATION NAME | 2005 TOTAL MONTHLY PRICE | 2006 TOTAL MONTHLY PRICE |
|---|---|---|
| ProjectWise | $ 4,769.68 | $ 4,769.68 |
| Prover link | $ 490.51 | $ 490.51 |
| Rate Expert - Test | $ 420.00 | $ 420.00 |
| Reg Station Inspections | $ 48.00 | $ 48.00 |
| Service Interuption System (SIRS) | $ 2,044.67 | $ 2,044.67 |
| S-O Comply | $ 2,317.93 | $ 2,317.93 |
| Surface Lease Management System | $ 48.00 | $ 48.00 |
| SWMS | $ 2,464.67 | $ 2,464.67 |
| SWMS | $ 4,307.76 | $ 4,307.76 |
| Syclo - Maximo Mobile Mgr. | $ 490.00 | $ 490.00 |
| Tables on Diskette | $ 48.00 | $ 48.00 |
| TISOnline | $ 8,855.55 | $ 8,855.55 |
| ToolHound | $ 48.00 | $ 48.00 |
| TransEnergy | $ 1,823.34 | $ 1,823.34 |
| Transportation Information System (TIS) | $ 24,063.52 | $ 24,063.52 |
| TRIM Context | $ 2,489.39 | $ 2,489.39 |
| TWACS | $ 5,881.80 | $ 5,881.80 |
| Valve Inspection Tracking | $ 48.00 | $ 48.00 |
| V-Pro | $ 48.00 | $ 48.00 |
| Weld Calculation | $ 48.00 | $ 48.00 |
| West Pembina Server | $ 1,268.12 | $ 1,268.12 |
| Whitehorse Local Server | $ 1,797.73 | $ 1,797.73 |
| Winfuel | $ 48.00 | $ 48.00 |
| Winsell | $ 490.51 | $ 490.51 |
| WolfPAC - Gas | $ 1,130.38 | $ 1,130.38 |
| Wolfpac/Oracle - Midstream | $ 1,318.00 | $ 1,318.00 |


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## 3.3 Web Hosting Services

The Web hosting service is a specific subset of the application-hosting fee. In addition to the terms identified for the application-hosting fee, the following terms will apply.

### *3.3.1 Products or Services Provided within the Fee*

The following are included in the price:

- Hosted on Windows platform.
- 200 MB of Web Space.
- FrontPage 2000 Site Access and Support.
- Microsoft Active Server Pages Support (ASP).
- High-Speed T1.
- Own CGI Directory.
- Active Server Pages.
- Vbasic, Java, Perl 5.
- Access 2000 with a limit of three DSNs.
- WEB Statistics by Webtrends.
- Daily Tape Backup.
- Counter.
- Technical Support.
- Web Site Submission and Unique IP Address.
- Search Index Catalog.

### *3.3.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- E-mail accounts.
- E-Commerce capability
- Secure File Transfer Protocol (FTP) Hosting.
- Development & Maintenance of the Web site.
- Relational Database Hosting.


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- Publishing.
- Personalization and Membership Services.
- Registration fee and InterNIC fee.
- Security access setup.
- Special firewall requirements.

### *3.3.3 Exceptions Handling*

The following are exceptions to the price:

- Additional DSNs will be charged with Time and Materials Rates.

### *3.3.4 Price Schedule*

(Price per Website per month)

| Description | 2005 | 2006 |
|---|---|---|
| FTP Site Hosting | 82.82 | 82.82 |
| Internet Intranet Hosting | 118.53 | 118.53 |
| Secure Site Hosting | 185.66 | 185.66 |


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# 4 PROJECT LABOUR

## 4.1 General Provisions

Project labour rates will be invoiced on an hourly basis for the following types of Services:

- Software development, maintenance and enhancement project Services.
- Evaluation, Systems implementation and integration Services.
- Consulting Services (under agreed upon proposals) including:
  - IT planning and strategic planning.
  - Business re-engineering, project leadership and hardware product consulting.
  - Other special Projects.

### *4.1.1 Products or Services Provided within the Fee*

The following are included in Labour Prices:

- Standard development tools needed to build and maintain System.
- Standard development methodology.
- Standard development support tools.
- One standard workstation per analyst.
- Office facilities and office supplies.
- Professional development for standard methodology and standard development.

### *4.1.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from Labour Prices:

- Special equipment or enhanced equipment.
- Special facilities (test, development etc) or project specific facility enhancements and if required will be a Specified Expense to the project.
- Non-standard or special tools, software or methodologies specific to a project rates.
- Training, training aids or other professional development for non-standard or special tools, software or methodologies specific to a project.
- Travel and living expenses and other disbursements related to the project.


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### *4.1.3 Exceptions Handling*

The following is an exception to the price:

- Labour rates exclude extraordinary items and if required will be a Specified Expense on a project by project basis.

Labour rates other than the standard listed rates may be used in cases where an individual has been recruited due to a specialized skill set. The rate for the specialized skill set will be determined on a case by case basis and will be communicated to the Client along with the requirements for this skill set in relation to the project and the Deliverables.

The ATCO Group's commitment is to a minimum of 55,000 D/M/E hours per year. Any under-utilization of hours across the ATCO Group of Companies will be apportioned to the participating Clients proportionate to their individual annual commitment from their Business Plan.

## 4.2 Price Schedule

(Price per hour)

| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Analyst 1 (DME) | $ 86.52 | $ 86.52 | $ 86.52 | $ 86.52 | $ 86.52 | $ 86.52 |
| Analyst 2 (DME) | $ 99.37 | $ 99.37 | $ 99.37 | $ 99.37 | $ 99.37 | $ 99.37 |
| Analyst 3 (DME) | $ 114.56 | $ 114.56 | $ 114.56 | $ 114.56 | $ 114.56 | $ 114.56 |
| Analyst 4 (DME) | $ 128.61 | $ 128.61 | $ 128.61 | $ 128.61 | $ 128.61 | $ 128.61 |
| Administrator (DME) | $ 57.29 | $ 57.29 | $ 57.29 | $ 57.29 | $ 57.29 | $ 57.29 |
| Consultant (DME) | $ 142.63 | $ 142.63 | $ 142.63 | $ 142.63 | $ 142.63 | $ 142.63 |
| Project Manager (DME) | $ 170.68 | $ 170.68 | $ 170.68 | $ 170.68 | $ 170.68 | $ 170.68 |
| Analyst 1 (Large) | $ 86.52 | $ 86.52 | $ 86.52 | $ 86.52 | $ 86.52 | $ 86.52 |
| Analyst 2 (Large) | $ 99.37 | $ 99.37 | $ 99.37 | $ 99.37 | $ 99.37 | $ 99.37 |
| Analyst 3 (Large) | $ 114.56 | $ 114.56 | $ 114.56 | $ 114.56 | $ 114.56 | $ 114.56 |
| Analyst 4 (Large) | $ 128.61 | $ 128.61 | $ 128.61 | $ 128.61 | $ 128.61 | $ 128.61 |
| Administrator (Large) | $ 57.29 | $ 57.29 | $ 57.29 | $ 57.29 | $ 57.29 | $ 57.29 |
| Consultant (Large) | $ 142.63 | $ 142.63 | $ 142.63 | $ 142.63 | $ 142.63 | $ 142.63 |
| Project Manager (Large) | $ 170.68 | $ 170.68 | $ 170.68 | $ 170.68 | $ 170.68 | $ 170.68 |
| Analyst 1 (Non-SLA) | $ 99.50 | $ 99.50 | $ 99.50 | $ 99.50 | $ 99.50 | $ 99.50 |
| Analyst 2 (Non-SLA) | $ 114.27 | $ 114.27 | $ 114.27 | $ 114.27 | $ 114.27 | $ 114.27 |
| Analyst 3 (Non-SLA) | $ 131.75 | $ 131.75 | $ 131.75 | $ 131.75 | $ 131.75 | $ 131.75 |
| Analyst 4 (Non-SLA) | $ 147.90 | $ 147.90 | $ 147.90 | $ 147.90 | $ 147.90 | $ 147.90 |



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| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Administrator (Non-SLA) | $ 65.89 | $ 65.89 | $ 65.89 | $ 65.89 | $ 65.89 | $ 65.89 |
| Consultant (Non-SLA) | $ 164.02 | $ 164.02 | $ 164.02 | $ 164.02 | $ 164.02 | $ 164.02 |
| Project Manager (Non-SLA) | $ 196.29 | $ 196.29 | $ 196.29 | $ 196.29 | $ 196.29 | $ 196.29 |
| Hardware Install/Move/Add/Change Labour | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 |
| Premium Labour | $ 142.86 | $ 142.86 | $ 142.86 | $ 142.86 | $ 142.86 | $ 142.86 |
| Software Integration/Pkging Labour | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 |
| Software Support Labour | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 | $ 114.29 |

# 5 MAINFRAME SERVICES

## 5.1 General Provisions

Pricing for mainframe Services falls into three broad categories - processing, storage and printing. Mainframe processing rates for CPU, storage and print usage are charged for development, maintenance and enhancement projects in addition to the traditional production processing. Charges will apply to TIER I, TIER II and TIER III Project Services for all development and test environments.

### *5.1.1 Products or Services Provided within the Fee*

The following are included in the price:

- Facility operations, tuning and management.
- Production management of batch and online applications.
- Job and System operational recovery.
- Disaster recovery planning and annual test.
- System performance monitoring, tuning and capacity planning.
- Information Security Management of the development, test and production environments.

### *5.1.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price and will be charged incrementally as required:

- Labour associated with application modifications, enhancements, performance and tuning is excluded from mainframe prices.


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## 5.2 Central Processing Unit

### *5.2.1 Products or Services Provided within the Fee*

The following is included in the price:

- CPU hardware acquisition, installation and maintenance.
- Mainframe network support.
- Security monitoring and control.

### *5.2.2 Mainframe Normalization*

When a new mainframe processor is installed new rates will be established by ATCO I-Tek. When a mainframe processor is upgraded, and it is agreed to continue with the rates that were established for that mainframe processor, equivalency factors will be used to determine mainframe rates. Equivalency factors will only be applied for a maximum of two generations of mainframe processor upgrades. Should there be additional generations beyond the two upgrades, then prior to each upgrade, new rates will be established to eliminate the use of equivalency factors.

ATCO I-Tek will collect sample CPU usage data on a weekly basis for purposes of observing average CPU usage by workload and for maintaining a historical CPU performance database. When equivalency factors need to be developed for the first and second generation upgrades, they will be based on these historical CPU performance statistics. The developed equivalency factors will be Benchmarked against industry recognized equivalency factors supplied by the manufacturer of the mainframe and an industry accepted authority. Significant deviations will be investigated and explained by ATCO I-Tek. ATCO I-Tek will also review CPU performance statistics and equivalency factors with the Clients at the Annual Review.

### *5.2.3 Mainframe Overhead*

Computer tools are used to capture the CPU minutes of technology platforms (TSO, CICS, DB2, IMS, ADABAS, etc.) used by applications. These CPU minutes are billed to Clients by mainframe application. The tools used to capture the CPU usage of online applications do not capture the overhead CPU minutes of the technology platforms used by any subsystem(s) entered through the online applications. The total mainframe CPU minutes less the total of all the applications CPU minutes is the overhead CPU minutes that need to be allocated to Clients. This is done on the basis of establishing technology platform to total mainframe ratios and using these to apportion the overhead.



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CPU time capture ratios will be confirmed monthly. ATCO I-Tek will take monthly samplings of the major applications which are representative of normal business cycle workloads and develop a separate CPU time capture ratio for each technology platform. The sampling details, methodology used to establish the ratios, and the final CPU time capture ratios will be reviewed by ATCO I-Tek and the Clients at the Annual Review.

Bandwidth Pricing (Schedule D – Section 1.4) will apply. When the actual CPU usage is +/- 10% of what is used to bill the mainframe overhead, no adjustment is needed. When the actual CPU usage varies by more than 10% for three or more consecutive months, the CPU usage factor used in the billing of CPU minutes will be adjusted to mutually agreed (between ATCO I-Tek and the Client(s)), CPU time capture ratio(s). This pricing adjustment will occur at the annual pricing review between ATCO I-Tek and the Client(s).

## 5.3 MVS (ADABAS) CPU Minutes

### *5.3.1 Products or Services Provided within the Fee*

The following are included in the price:

- Online and batch application access to ADABAS data base system.
- ADABAS infrastructure support including database and programming language NATURAL, PREDICT) software acquisition, installation and maintenance.
- ADABAS system performance and tuning.
- Interface to DB2 and IMS databases.
- The current ATCO I-Tek ADABAS software is included below, and is subject to change or modification without prior notification:

  ADABAS

  ADABAS CICS

  ADABAS IMS/DC

  ADABAS SQL

  ADABAS TSO

  NATURAL

  NATURAL ADABAS

  NATURAL DLI

  NATURAL IMS/DC

  NATURAL Security



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NATURAL TSO

PREDICT

Securitre

TRIM

## 5.4 MVS (Batch) CPU Minutes

### *5.4.1 Products or Services Provided within the Fee*

DB2 run in batch mode is billed as MVS (Batch) CPU Minutes

The following are included in the price:

- Batch program execution.
- MVS OS 390 operating system installation, maintenance and tuning.
- IBM Program Product acquisition, installation and maintenance.
- ATCO I-Tek standard system software acquisition, installation, maintenance and support.
- The current ATCO I-Tek system software is included below, and is subject to change or modification without prior notification:

  SMFUTIL

  CMF

  Stop X37-II

  Stop X37-II/Recat Option

  Omegamon MVS

  Supersession

  MVS/Quick-Ref

  ASTEX Cache Manager

  ASTEX DASD Manager

  ASTEX Storage Manager

  CA-11

  CA-DYNAM/TLMS

  Deliver MVS

  Jobtrac/JCLtrac

  OPS - Automation Point for NT


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OPS - Automation Point 3270

PDSMAN

Prevail/XP Automation - Multi System Facility

Prevail/XP Automation - MVS

PROWL

TSOMON

View

View ERO

Jobscan

Canadian Code 1 Plus

5647-A01 (1643/1644) SDSF

5647-A01 (2024/2025) GDDM PGF

5647-A01 (2422/2423) DFDSS DSS/HSM

5647-A01 (3034/3035) Security Server

5647-A01 (3982) High Level Assembler (HLA) Toolkit

5647-A01 (411/412) OS/390 V2

5647-A01 (4401) Hardware Configuration Mgr (HCD)

5648-063 ACF/NCP V7

5655-007 NETVIEW/ESA V3

5655-041 ACF/SSP V4

5668-985 HCF V2

5695-040 (9582) Netspool Function

IBM Information Network (IIN) (AT&T)

IBM - SoftwareXcel

Talklink Fee

FATS/FATAR

FDR/CPK/ABR

MXG

MVS Thruput Manager

TM/Job Binding Services

IR Expert

MVS Axces



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SC 3270

Windows Client

Service Centre

SAS ITSV

SAS/Base

SAS/Connect

SAS/ETS

SAS/FSP

SAS/GRAPH

SAS/STAT

HSC

### *5.4.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- ADABAS, IMS, DB2 and CICS CPU time have separate rates.
- BASIC (product # 5665-948) - license fee is billed directly to client, usage is billed at batch rate.
- APL (product # 5748 AP1) - license fee is billed directly to client, usage is billed at batch rate.
- Keyplus - license fee is billed directly to client, usage is billed at batch rate.

## 5.5 MVS (CICS) CPU Minutes

### *5.5.1 Products or Services Provided within the Fee*

The following is included in the price:

- Support for interfaces with terminals, printers, and workstations.
- Installation, enhancement, monitoring, tuning of CICS MVS software to facilitate use of online applications.

  Omegamon CICS

  Prevail/XP Automation – CICS

  5655-147 CICS Transaction Server for MVS



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## 5.6 MVS (DB2) CPU Minutes

### *5.6.1 Products or Services Provided within the Fee*

DB2 run in batch mode is billed as MVS (Batch) CPU Minutes

The following is included in the price:

- Online and batch application access to DB2 data base system.
- DB2 infrastructure support including database and programming language software acquisition, installation and maintenance.
- DB2 system performance and tuning.
- The current ATCO I-Tek DB2 system software is included below, and is subject to change or modification without prior notification:

  DB2 Catalog Manager

  DB2 Change Manager

  DB2 Copy Plus

  DB2 DASD Manager

  DB2 Load Plus

  DB2 Recover Plus

  DB2 Reorg Plus

  Insight/DB2

  Insight/DB2 24 x 7

  Move for DB2

  5645-DB2 DB2 UDB for OS/390

  5697-F44 DB2 High Perform Unload

  Logmax

  R+/Resource Maximizer

## 5.7 MVS (IMS) CPU Minutes

### *5.7.1 Products or Services Provided within the Fee*

The following is included in the price:

- Online and batch application access to IMS database system.
- IMS infrastructure support including database and programming language software acquisition, installation and maintenance.



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- IMS system performance and tuning.
- The current ATCO I-Tek IMS software is included below, and is subject to change or modification without prior notification:

  ETA

  Prevail/XP Automation – IMS

  DS IMS Dictionary

  5655-A14 BTS V2

  5655-158 IMS/ESA V6 DB

  5655-158 IMS/ESA V6 TM

  5655-158 IMS/ESA V6 Extended Terminal Option

  BTS V2

## 5.8 MVS (TSO) CPU Minutes

### *5.8.1 Products or Services Provided within the Fee*

The following are included in the price:

- Online or batch access to Time-Sharing Option (TSO).
- Acquisition, installation, performance monitoring and tuning of TSO system and related products.
- PIE/TSO

## 5.9 Mainframe Print

Mainframe printing has two basic pricing components. Equipment, labor and the CPU cycles used to create the print are charged at one price while paper is priced based on the type of paper. Standard forms are blank sheets of paper while "Special Forms" paper is paper of non-standard size or that comes from the manufacturer with information preprinted on the form.

## 5.10 MVS Print Forms (Blank, continuous form)

### *5.10.1 Products or Services Provided within the Fee*

The following are included in the price:

- Blank, continuous, 11 x 8.5 standard paper.


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- Price may vary month to month as specified via contract with the supplier.

## 5.11 MVS Print Forms (blank, cut sheet)

### *5.11.1 Products or Services Provided within the Fee*

All print forms are billed as a Specified Expense according to the cost of the paper stock.

## 5.12 MVS Print Forms (special forms)

### *5.12.1 Products or Services Provided within the Fee*

Special forms, which are billed as a Specified Expense to the consuming Client.

## 5.13 MVS Print Pages

### *5.13.1 Products or Services Provided within the Fee*

The following are included in the price:

- Printing on centralized printers.
- VPS.
- PSF software.
- Acquisition, installation and maintenance of centralized printers and associated facilities.
- Acquisition, installation and maintenance of operating system print related.

### *5.13.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Non-mainframe associated print.
- Paper cost of special forms which will be charged directly to the consuming Client.

## 5.14 Storage

Storage is a device onto which data can be placed, held and later retrieved. "Main storage" refers to the computer's memory, the space used for executing


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instructions; "auxiliary storage" refers to disks, diskettes, magnetic tape, and other media for holding data.

#### *5.14.1 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Main Storage which is billed within the CPU rates.
- Centralized DASD associated with distributed Systems.
- Diskettes.
- Optical storage.

### 5.15 MVS DASD Gigabyte Months

#### *5.15.1 Products or Services Provided within the Fee*

The following is included in the price:

- DASD directly connected to the mainframe.
- Centralized DASD managed by the mainframe (MVS data set).
- Direct Access Storage Device (DASD) acquisition, installation, maintenance.
- Data storage.
- Data transfer to/from DASD.
- Acquisition, installation, maintenance and tuning of DASD management software including HSM.
- Backup and recovery including offsite tape storage and retrieval.

#### *5.15.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded in the price:

- Non-MVS data sets.

### 5.16 MVS Tape Gigabyte Months

#### *5.16.1 Products or Services Provided within the Fee*

The following are included in the price:


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- Virtual tape Services.
- Mainframe managed tape including HSM tapes.
- Mainframe tape and silo acquisition, installation and maintenance.
- Data storage and data retrieval to/from standard and extended mainframe tape.
- Tape support software acquisition, installation and maintenance.

### *5.16.2 Products or Services not Provided within the Fee (Additional charges will apply)*

- All backup and recovery Services are built into the DASD charge and will not be charged using this rate.


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## 5.17 Price Schedule

(Price per unit)

| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| MVS (ADABAS) CPU Minutes | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 |
| MVS (IMS ADABAS Batch) CPU Minutes | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 |
| MVS (NON-IMS ADABAS Batch) CPU Minutes | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 |
| MVS (CICS) CPU Minutes | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 |
| MVS (DB2) CPU Minutes | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 |
| MVS (IMS) CPU Minutes | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 | $ 13.47 |
| MVS (TSO) CPU Minutes | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 | $ 10.50 |
| MVS DASD Gigabyte Months | $ 73.00 | $ 73.00 | $ 73.00 | $ 73.00 | $ 73.00 | $ 73.00 |
| MVS Tape Gigabyte Months | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 |
| MVS HSM Gigabyte Months | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 |
| Mainframe Print Forms | Variable | Variable | Variable | Variable | Variable | Variable |



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# 6 SPECIFIED EXPENSES

## 6.1 General Provisions

The Client shall be responsible for payment of certain charges described as a "Specified Expense" on any Schedule ("Specified Expense"). Any expenses paid by ATCO I-Tek for the Client's benefit shall be subject to an administrative fee where support or administrative Services have been expended. Administrative fees can be charged on a percentage basis, ranging from 5% to 20% of the Specified Expense or on negotiated flat fee basis depending on the level of effort expended. Administrative Services will include (but not be limited to) contract negotiation, contract management, payment processing, or client invoicing.

## 6.2 Microfiche

### *6.2.1 Products or Services Provided within the Fee*

The following will be charged:

- Microfiche service requirements are unique by Client and may include contract administration with third party microfiche service providers, archive and storage, off- site storage and general support Services.
- Microfiche Services will be a Specified Expense.

## 6.3 Training Directs

- Client training service requirements are unique by Client and may include contract administration with training centres, scheduling of special courses, course design, in-house training, availability of dedicated training facilities, provision of general course calendar information, invoice administration and general support Services.
- All Client training coordinated by ATCO I-Tek on behalf of the Clients will be a Specified Expense.


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# 7 RENTAL

## 7.1 General Provisions

Client is responsible for any loss of or damage to rented equipment. All rentals are subject to availability.

### *7.1.1 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Delivery and set-up of equipment will be additional.

## 7.2 Videoconferencing Rental

This service provides a fully equipped video conference facility including a Polycom video conference unit, a local and remote monitor, and ISDN connections in three 128Kbps increments up to 384 Kbps.

### *7.2.1 Products or Services Provided within the Fee*

The following are included in the price:

- Polycom video conference unit
- Local and remote monitor
- ISDN connections in three 128Kbps increments up to 384 Kbps.
- Meeting Room

### *7.2.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Other audio visual equipment that may be required.

## 7.3 Desktop Rental

### *7.3.1 Products or Services Provided within the Fee*

The following is included in the price:

- Desktop rentals include a standard single partition build with core applications.
- Short term rental is less than 3 months


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#### *7.3.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Any additional application requirements or configuration changes will be charged with Time and Materials Rates.

### 7.4 Laptop Rental

#### *7.4.1 Products or Services Provided within the Fee*

The following is included in the price:

- Laptop rentals include a standard single partition build with core applications.
- Short term rental is less than 3 months

#### *7.4.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Any additional application requirements or configuration changes will be charged with Time and Materials Rates

### 7.5 HP Printer Rental

#### *7.5.1 Products or Services Provided within the Fee*

The following is included in the price:

- HP printer rentals include a cable for hookup to workstation.
- Short term rental is less than 3 months

#### *7.5.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Any configuration changes to workstation for printer will be charged with Time and Materials Rates

### 7.6 Training Room Rental

ATCO I-Tek offers a training room for rent at the Edmonton Campus. The capacity of the training room is 12 workstations plus one additional workstation for the instructor. All workstations are connected to the ATCO Network. All voice requirements are excluded.



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## 7.7 Training Room setup fee – specialty software per workstation

### *7.7.1 Products or Services Provided within the Fee*

Setup of workstation for training includes:

- Data security Setup and Cleanup.
- Software Distribution and Cleanup.
- Minimum charge of 4 workstation setups.

### *7.7.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Room Rental.
- Software Configuration and Integration.
- Licensing for Software over Core.
- Changes to Room configuration will be done with Time and Materials Rates.

## 7.8 Training Room setup fee - standard workstation price/workstation

### *7.8.1 Products or Services Provided within the Fee*

Setup of workstation for training includes:

- Data security Setup and Cleanup.
- Software distribution and Cleanup.
- Minimum charge of 4 workstation setups.

### *7.8.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Room Rental.
- Any software required other than core applications.
- Changes to Room configuration will be done with Time and Materials Rates.


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## 7.9 Training Room Daily Rental

### *7.9.1 Products or Services Provided within the Fee*

Training Room daily rental includes:

- Rental of the Room.
- Rental of the Workstation Hardware in the room.
- No more than 12 workstations plus 1 workstation for the instructor.
- Note: if non-core applications are required, the room must be rented for a full day prior to the required date for setup.

### *7.9.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Set-up charges for the workstations.
- Computer Projector.


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## 7.10 Price Schedule

(Price per unit)

| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Desktop Daily Rental | $ 150.00 | $ 150.00 | $ 150.00 | $ 150.00 | $ 150.00 | $ 150.00 |
| Desktop Monthly Short Term Rental | $ 400.00 | $ 400.00 | $ 400.00 | $ 400.00 | $ 400.00 | $ 400.00 |
| Desktop Weekly Rental | $ 200.00 | $ 200.00 | $ 200.00 | $ 200.00 | $ 200.00 | $ 200.00 |
| Printer Daily Rental | $ 80.00 | $ 80.00 | $ 80.00 | $ 80.00 | $ 80.00 | $ 80.00 |
| Printer Weekly Rental | $ 160.00 | $ 160.00 | $ 160.00 | $ 160.00 | $ 160.00 | $ 160.00 |
| Printer Monthly Rental | $ 320.00 | $ 320.00 | $ 320.00 | $ 320.00 | $ 320.00 | $ 320.00 |
| Rental Video Conferencing - First hour | $ 154.05 | $ 154.05 | $ 154.05 | $ 154.05 | $ 154.05 | $ 154.05 |
| Rental Video Conferencing - Line/Hour | $ 35.56 | $ 35.56 | $ 35.56 | $ 35.56 | $ 35.56 | $ 35.56 |
| Rental Video Conferencing - Room/Hour | $ 106.68 | $ 106.68 | $ 106.68 | $ 106.68 | $ 106.68 | $ 106.68 |
| Projector Day Rental | $ 250.00 | $ 250.00 | $ 250.00 | $ 250.00 | $ 250.00 | $ 250.00 |
| Laptop Daily Rental | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 |
| Laptop Monthly Rental | $ 450.00 | $ 450.00 | $ 450.00 | $ 450.00 | $ 450.00 | $ 450.00 |
| Laptop Weekly Rental | $ 250.00 | $ 250.00 | $ 250.00 | $ 250.00 | $ 250.00 | $ 250.00 |
| Training Room Daily Rental | $ 602.38 | $ 602.38 | $ 602.38 | $ 602.38 | $ 602.38 | $ 602.38 |
| Training Rm setup fee - specialty S/W | $ 113.12 | $ 113.12 | $ 113.12 | $ 113.12 | $ 113.12 | $ 113.12 |
| Training Rm setup fee - per std w/s | $ 47.64 | $ 47.64 | $ 47.64 | $ 47.64 | $ 47.64 | $ 47.64 |



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# 8 NETWORK ACCESS

## 8.1 General Provisions

User ID Services represent a variety of Services that are provided to or based on a specific User ID.

## 8.2 Internet Access

### *8.2.1 Products or Services Provided within the Fee*

The following are included in the price:

- Access to the Internet through a T1 connection or faster.
- Site Logging.
- Access to HTTP and FTP Services.
- Site and service blocking according to ATCO Corporate Requirements.

### *8.2.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Specialty reporting.
- User monitoring/investigations.

### *8.2.3 Exceptions Handling*

- All exceptions are subject to charges based with Time and Materials Rates.

## 8.3 Remote Access Service (RAS)

### *8.3.1 Products or Services Provided within the Fee*

The following are included in the price:

- Access to ATCO's Intranet.
- Maximum connection time during prime time (8am - 5pm): 2 hours.
- Maximum connection time during non-prime time: 3 hours.
- Documentation for ATCORAS setup.


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- CSC is the single point of contact for ATCORAS support and problem resolution.
- Support of the ATCO I-Tek ATCORAS core infrastructure (7x24).
- CSC provides configuration review for all workstation (7x24).
- Unidentifiable workstation problems are supported only during ATCO I-Tek Business Hours.
- Support is provided for standard workstations.
- Workstation technician support is provided in the Edmonton and Calgary campuses and on ATCO I-Tek owned devices only.
- Maximum connection speed 56kb, subject to the quality of line.
- UserID security administration.
- Maximum 1 connection to ATCORAS per UserID.
- Minimum 3 month commitment of the service.
- Full monthly fee will be charged for the month that the user registered.

### *8.3.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded in the price:

- Unidentifiable workstation problems are supported only during prime time.
- Support is provided for non-standard workstations and charged with Time and Materials Rates to configure the workstation for ATCORAS.
- Workstation technician support is only provided in the Edmonton and Calgary campuses, and users are responsible for the workstation delivery to the campus site for configuration support.
- Users are responsible for the workstation delivery to the campus site.
- Remote locations will incur additional long distance phone charges to dial into either Edmonton or Calgary for the ATCORAS service.

### *8.3.3 Exceptions Handling*

If the connection time exceeds the maximum connectivity time, ATCO I-Tek reserves the right to:

- Work with the Client to find an alternate solution to meet the business need.
- Automatically disconnect the user from the dial-in session.
- Remove the user's ATCORAS access.


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- Bill for the exceeded connection time.

## 8.4 Virtual Private Networking (VPN)

### *8.4.1 Products or Services Provided within the Fee*

- VPN Digital Security fob.
  - 1 fob per user.
- VPN Client software.
- Support for Core Architecture (i.e., - is the ATCO I-Tek network running and is the VPN gateway at the core running).
- Virus Protection Software for MSA Clients only.
- Installation Documentation.

### *8.4.2 Products or Services not Provided within the Fee (Additional charges will apply)*

- Connection to the Internet using an ISP (Internet Service Provider).
- Service Level Guarantees for end-to-end connectivity.
  - ISP will not provide Service Levels for the Internet.
  - ATCO I-Tek can not provide Service Levels for the Internet.
- Installation Fees for ISP.
- Virus Protection Software for non-MSA Clients.
- Firewall protection.
- Support for Client-owned workstations.
- Guarantees that the VPN Client Software will work on Client-owned workstation.
- Replacement of lost or damaged fob is subject to a $200 fee (subject to change by vendor).

## 8.5 VPN Remote Branch

This service refers to a virtual private network connection across the Internet from a remote office to the ATCO Corporate network.

### *8.5.1 Products or Services Provided within the Fee*

The following are included in the price:

- Central network connection equipment:


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The network and security devices used to interface the Internet based connection into the ATCO Corporate network are included.

All software, hardware, and security maintenance is included.

Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

- Remote branch VPN gateway

  Creates the secure, encrypted tunnel across the Internet to the ATCO Corporate network.

  Protects the connected devices in the remote office from malicious access on the Internet.

  Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

### *8.5.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The Internet service provider (ISP) investigation, installation, setup, and monthly fee.
- Local area network connections.
- Availability of the connection across the Internet cannot be guaranteed.
- Internal wiring and electrical facilities necessary for the installation in the remote office.
- Travel time and associated costs incurred by ATCO I-Tek to install the service.

## 8.6 VPN Firewall

This Service refers to a virtual private network connection from a small office shared with four or less devices that use the VPN – remote client service to connect to the ATCO Corporate network. A firewall/router devices with four ports is supplied to connect four or less devices.

### *8.6.1 Products or Services Provided within the Fee*

The following are included in the price:

- Central Network Connection Equipment

  The network and security devices used to interface the Internet based connection into the ATCO Corporate network are included.



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All software, hardware, and security maintenance is included. Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard

- Remote Office Firewall/Router

  Creates the secure, encrypted tunnel across the Internet to the ATCO Corporate network. Protects the connected devices from malicious access on the Internet.

  Software, hardware, and security maintenance are included.

### *8.6.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The Internet service provider (ISP) investigation, setup, and monthly fee.
- Local area network connections.
- The installation and maintenance of the service is not included and is offered at Time and Materials Rates.
- Internal wiring and electrical facilities necessary for the installation in the remote office.
- Travel time and associated costs incurred by ATCO I-Tek to install the service.
- Printing from mainframe applications is excluded but is available as an additional service.
- Network based printing. Availability of the connection across the internet.

## 8.7 Terminal Server Service

This Service refers to a device connected on the local area network that interfaces dialup ports to the ATCO Corporate network.

This Service is available in 1, 4, 8, 20 port configurations at differing prices.

### *8.7.1 Products or Services Provided within the Fee*

The following are included in the price:

- Central Network Connection Equipment

  The network and security devices used to interface the terminal server connection into the ATCO Corporate network are included.

  All software, hardware, and security maintenance is included.


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Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

- Terminal Server

  This device provides the protocol translation mechanism that translates dial protocols into TCP/IP for transmission across the ATCO Corporate network.

  Software, hardware, and security maintenance are included.

#### *8.7.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Support for the Terminal Server is excluded but available as a Time and Material Rate.
- Modems and telecommunication lines used for the dial mechanism.
- Installation and any associated travel.
- Internal wiring and electrical facilities necessary for the installation in the remote office.
- Travel time and associated costs incurred by ATCO I-Tek to install the Service.

### 8.8 Asymmetric Digital Subscriber Line (ADSL) Light

This Service refers to a wide area network data connection from a remote office local area network to the ATCO Corporate network. The Service utilizes a telecommunications carrier service based on differing speeds to the remote office and from the remote office to the corporate network. The speed from the office will vary from 256Kbps to 800 Kbps. The speed to the office from the corporate network will vary from 1Mbps to 3 Mbps.

The amount of data transferred on the Service during each month is a factor in the cost of the service. ADSL light includes 5GB of data transfer each month. Exceeding this amount for two consecutive months will require the client to move to the ADSL unlimited Service.

#### *8.8.1 Products or Services Provided within the Fee*

The following are included in the price:

- Central Network Connection Equipment

  The network and security devices used to interface the ADSL connection into the ATCO Corporate network are included.

  All software, hardware, and security maintenance is included.



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Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

- Remote Office Router

  This device provides the connection point from the remote office local area network to the telecommunications ADSL facility to the ATCO Corporate network.

  The underlying telecommunication facility is included.

  All software, hardware, and security maintenance is included.

  Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

#### *8.8.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The installation charge from the telecommunications carrier.
- Internal wiring and electrical facilities necessary for the installation in the remote office.
- Travel time and associated costs incurred by ATCO I-Tek to install the Service.

### 8.9 ADSL Unlimited

This Service refers to a wide area network data connection from a remote office local area network to the ATCO Corporate network. The Service utilizes a telecommunications carrier service based on differing speeds to the remote office and from the remote office to the corporate network. The speed from the office will vary from 256Kbps to 800 Kbps. The speed to the office from the corporate network will vary from 1Mbps to 3 Mbps.

The amount of data transferred on the service during each month is a factor in the cost of the Service. ADSL Unlimited includes an unlimited amount of data transfer.

#### *8.9.1 Products or Services Provided within the Fee*

The following are included in the price:

- Central Network Connection Equipment

  The underlying telecommunication facility is included.

  The network and security devices used to interface the ADSL connection into the ATCO Corporate network are included.

  All software, hardware, and security maintenance is included.



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Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

- Remote Office Router

  This device provides the connection point from the remote office local area network to the telecommunications ADSL facility to the ATCO Corporate network.

  The underlying telecommunication facility is included.

  All software, hardware, and security maintenance is included.

  Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

#### *8.9.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The installation charge from the telecommunications carrier.
- Internal wiring and electrical facilities necessary for the installation in the remote office.
- Travel time and associated costs incurred by ATCO I-Tek to install the Service.

### 8.10 Network Connectivity

This Service provides local area network connectivity to the ATCO Corporate network for devices that are approved by ATCO I-Tek but not owned and operated by ATCO I-Tek. This includes process control or Category 6 devices.

#### *8.10.1 Products or Services Provided within the Fee*

The following are included in the price:

- Local area network switch port
- This device provides the interface point into the ATCO Corporate network
- All software, hardware, and security maintenance is included
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are included
- Hosted on Windows platform.

#### *8.10.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:



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- Any security devices like firewall or intrusion detection equipment required to ensure the security of the ATCO Corporate network are excluded.
- Any new or additional wide area network equipment required to support the addition of the network connected device to the corporate network is excluded.
- Cabling from the device to the network connection point is excluded.

## 8.11 User ID Services

### *8.11.1 Products or Services Provided within the Fee*

The following is included in the price:

- Unique User ID with password (includes both Primary and Secondary User ID's).
- Access to the Windows domain to enable access to file, print, e-mail and scheduling Services.
- Electronic mail and scheduling Services including e-mail storage up to 50 MB per user.
- Standard Windows Profile.
- Standard Unix Profile as required.
- RACF User Profile.
- Access to the ATCO Intranet.
- User Documentation on Password Use best practices.

### *8.11.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded in the price:

- All access Services can be limited to clients logging onto an ATCO I-Tek standard workstation that is connected to the ATCO Network.
- Storage on Servers and Mainframe are charged separately.
- Internet Access Services are charged separately.
- Remote Access Services (RAS) are charged separately.
- E-mail storage Services, above the 50 megabytes included in the User ID category, are charged separately.
- User ID investigation Services are charged separately.


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## 8.12 File Server Storage

Data stored on the network file servers is assigned to User IDs. These items can be, but are not limited to, shared drives, personal network drives, and electronic mail.

### *8.12.1 Products or Services Provided within the Fee*

The following are included in the price:

- Operational Backup and Recovery.
- Storage on the file server.
- Maintenance, Enhancements & Support for the Standard File Server Environment & Servers.

### *8.12.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded in the price:

- Data moving, cleanup or archiving Services will be billed Time and Materials Rates .
- Where a user has a terminated status, the company will continue to receive charges for these Services until ATCO I-Tek has been notified to either delete/remove the service or move data to another user.
- Disaster recovery Services.

## 8.13 E-mail – 50 Megabytes Additional

### *8.13.1 Products or Services Provided within the Fee*

Subscription to bands of 50Megabyte blocks for all e-mail over and above the standard 50 Megabytes in the User ID Rate includes:

- Microsoft Exchange database maintenance and tuning.
- Operational Backup and recovery

## 8.14 Citrix Terminal Server

Clients can login from remote sites that have slow network connections and run their applications.


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### *8.14.1 Products or Services Provided within the Fee*

The following are included in the price:

- ATCO I-Tek is responsible for supporting connectivity to the Citrix server and availability of the hosted applications.
- All software, hardware, and security maintenance is included.
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

### *8.14.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- ATCO I-Tek does not support non-MSA hardware.
- ATCO I-Tek does not support the internet connection provided by Client's Internet Service Provider.

## 8.15 Blackberry Service

The Blackberry solution allows for an encrypted wireless real-time calendar and email synchronization with ATCO's business email environment.

ATCO I-Tek provides full support for product capability including:

- Wireless e-mail
- Voice support
- Wireless calendaring
- Wireless Internet
- Attachment capability

### *8.15.1 Products or Services Provided within the Fee*

The following are included in the price:

- ATCO I-Tek provides the infrastructure to link Microsoft Exchange servers and Microsoft Outlook to the Blackberry servers.
- ATCO I-Tek maintains both server and desktop software.
- ATCO I-Tek provides procurement and asset management of Blackberry devices.
- ATCO I-Tek does not lease, support or spare Blackberry devices. ATCO I-Tek will liaison with vendor, at Time and Materials Rates, for Blackberry device acquisition and support.



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- Support of synchronization between ATCO's Microsoft Exchange environment and Blackberry servers is standard.

### *8.15.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Monthly voice and data costs from 3rd party service provider.
- Support of 3rd party wireless network E-mail accounts.

## 8.16 Video Conferencing

The ATCO I-Tek options will be based on a standard videoconference room System and a standard support agreement.

***Definitions***

***Standard Videoconference Room System***

The equipment supplied will be two 32" television monitors, a Polycom Viewstation 512 or equivalent, second microphone, wide angle lens, network interface device NT1, and a 2 Business Day replacement policy for the listed equipment for a period of three years. The equipment is required to use ISDN services for connectivity.

***Standard Support Agreement***

The agreement only applies to the standard videoconference room System and entitles the user to the following Services:

- A five-minute telephone response during regular Business Hours to a reported trouble. An analyst will assess the situation and either correct the problem or recommend an alternative.
- Apply vendor maintenance regularly so that the latest approved software is available on the videoconferencing unit and that all updates have been installed.
- Advise the Client with operational procedures.
- Monitor to verify that the equipment is operating within expected parameters.
- Coordination of repairs. If the videoconferencing unit fails, ATCO I-Tek will provide a replacement unit within two Business Days until the system is repaired under the equipment warranty period of three years.


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***Service Choices***

### *8.16.1 Lease the videoconferencing equipment and enter into a support agreement.*

The service is only available at locations that have ISDN and LAN connectivity.

#### *8.16.1.1 Products or Services not Provided within the Fee (Additional charges will apply)*

- Installation of the equipment.
- Additional material required for the setup.
- Custom configurations that are Client requested.
- Moving the equipment at the Client request.
- Training.
- Travel costs associated with the setup.
- Cabling costs.
- ISDN monthly circuit cost.
- Long Distance charges.

All of the exclusions would be provided to the Client at Time and Materials Rates.
In the event of early withdrawal the client will be required pay a penalty based on the present value of the minimum lease payments.

### *8.16.2 The client already has a Standard Videoconference Room System and would like support.*

The service is only available at locations that have ISDN and LAN connectivity.

#### *8.16.2.1 Products or Services not Provided within the Fee (Additional charges will apply)*

- The installation of the hardware.
- Additional material required for the setup.
- Custom configurations that are Client requested.
- Moving the equipment at the Client request.
- Training.
- Travel costs associated with the setup.
- Cabling cost.


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- ISDN monthly circuit cost.
- Long distance charges.

### *8.16.3 Client chooses Time and Materials Rates only. All Client request would be charged at the current support rates*

The Client would be charged for:

- Original configuration of the equipment.
- Additional material required for the setup.
- Custom configurations that are Client requested.
- Moving the equipment at the Client request.
- Training.
- Travel costs associated with the setup/repair.
- Cabling Costs.
- ISDN monthly circuit costs.
- Long distance charges.
- 5-minute response to trouble is unavailable. Commercially reasonable efforts on requests with up to 24 hours to respond to requests.
- Software updates.
- Operational questions a client may have.
- Regular equipment maintenance.
- Coordination of repairs.

If the Client requests any of the above items, they will be charged at Time and Materials Rates. It is recommended that the Client enter at minimum a standard support term if they choose the purchase option. The standard support term can be cancelled with a 3-month notice at no penalty.

Note 1: All capital purchases including custom configurations will be evaluated on a per site basis.

Note 2: At locations that do not have access to ISDN services, switched 56KB data services may be substituted.


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## 8.17 Price Schedule

(Price per unit)

| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| E-mail 50 Megabytes Additional | $ 4.50 | $ 4.00 | $ 3.60 | $ 3.60 | $ 3.60 | $ 3.60 |
| File Server Storage (per gigabyte) | $ 55.00 | $ 55.00 | $ 55.00 | $ 55.00 | $ 55.00 | $ 55.00 |
| Distributed Archive Tape | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 |
| Distributed Retrieval Tape | $ 55.00 | $ 55.00 | $ 55.00 | $ 55.00 | $ 55.00 | $ 55.00 |
| Long Term Archive | $ 0.55 | $ 0.55 | $ 0.55 | $ 0.55 | $ 0.55 | $ 0.55 |
| Long Term Archive - 1st Month | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 | $ 3.15 |
| Internet Access | $ 13.91 | $ 13.91 | $ 13.91 | $ 13.91 | $ 13.91 | $ 13.91 |
| Remote Access Service (RAS) | $ 23.27 | $ 55.00 | $ 100.00 | $ 100.00 | $ 100.00 | $ 100.00 |
| VPN - Remote Client | $ 32.79 | $ 32.79 | $ 32.79 | $ 32.79 | $ 32.79 | $ 32.79 |
| VPN - Remote Branch | $ 775.50 | $ 775.50 | $ 775.50 | $ 775.50 | $ 775.50 | $ 775.50 |
| Network Firewall | $ 335.44 | $ 335.44 | $ 335.44 | $ 335.44 | $ 335.44 | $ 335.44 |
| Terminal Server Service 1 Port | $ 117.88 | $ 117.88 | $ 117.88 | $ 117.88 | $ 117.88 | $ 117.88 |
| Terminal Server Service 4 Port | $ 165.44 | $ 165.44 | $ 165.44 | $ 165.44 | $ 165.44 | $ 165.44 |
| Terminal Server Service 8 Port | $ 193.36 | $ 193.36 | $ 193.36 | $ 193.36 | $ 193.36 | $ 193.36 |
| Terminal Server Service 20 Port | $ 253.33 | $ 253.33 | $ 253.33 | $ 253.33 | $ 253.33 | $ 253.33 |
| Network Connectivity for Terminal Server | $ 35.35 | $ 35.35 | $ 35.35 | $ 35.35 | $ 35.35 | $ 35.35 |
| ADSL Light w/ Terminal Capability | $ 1,504.47 | $ 1,504.47 | $ 1,504.47 | $ 1,504.47 | $ 1,504.47 | $ 1,504.47 |
| ADSL Unlimited w/ Terminal Capability | $ 2,062.83 | $ 2,062.83 | $ 2,062.83 | $ 2,062.83 | $ 2,062.83 | $ 2,062.83 |
| ADSL Light | $ 1,395.90 | $ 1,395.90 | $ 1,395.90 | $ 1,395.90 | $ 1,395.90 | $ 1,395.90 |
| ADSL Unlimited | $ 1,954.26 | $ 1,954.26 | $ 1,954.26 | $ 1,954.26 | $ 1,954.26 | $ 1,954.26 |
| Network Connectivity | $ 35.35 | $ 35.35 | $ 35.35 | $ 35.35 | $ 35.35 | $ 35.35 |
| UserID Services | $ 15.21 | $ 15.21 | $ 15.21 | $ 15.21 | $ 15.21 | $ 15.21 |
| UserID Serv w/ limited ATCO Domain usage | $ 10.59 | $ 10.59 | $ 10.59 | $ 10.59 | $ 10.59 | $ 10.59 |
| Terminal Server Service (Citrix) | $ 37.22 | $ 37.22 | $ 37.22 | $ 37.22 | $ 37.22 | $ 37.22 |
| Wireless Blackberry Service Connectivity | $ 31.27 | $ 31.27 | $ 31.27 | $ 31.27 | $ 31.27 | $ 31.27 |
| Right Fax (plus variable long distance) | $ 21.55 | $ 21.55 | $ 21.55 | $ 21.55 | $ 21.55 | $ 21.55 |
| Video Conferencing Lease w/ Support | $ 816.60 | $ 816.60 | $ 816.60 | $ 816.60 | $ 816.60 | $ 816.60 |
| Substation | $ 398.09 | $ 398.09 | $ 398.09 | $ 398.09 | $ 398.09 | $ 398.09 |



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# 9 VOICE

## 9.1 General Provisions

Voice Services provides the ability to meet both standard Voice requirements as well as specialized requirements of Call Centres. This includes Services such as sets, lines, voice mail, enhanced features, call centre trunking, agent seats. These Services are available in the Edmonton and Calgary Campus locations and remote offices that have been integrated into the ATCO I-Tek voice network.

### *9.1.1 Products or Services Provided within the Fee*

The following are included in the price:

- Management of Contracts with Telecommunication(s) service providers.
- Infrastructure to support standard Voice Services.

### *9.1.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Special equipment such as headsets & adapters will be an additional charge to the Client.
- Cellular and wireless equipment or Services for this equipment will be an additional charge to the Client.

## 9.2 Centrex Telephone

This Service provides a basic business telephone set for use on the telecommunication carriers Centrex based telephony service.

### *9.2.1 Products or Services Provided within the Fee*

The following are included in the price:

- The telephone set, routine maintenance and technology refresh are included.

### *9.2.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The installation, cabling, Centrex line and feature costs.
- Telephone add-on modules, headsets.


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## 9.3 Call Centre

A Call Centre is a business unit where trained agents typically process a high volume and wide variety of Client inquiries, questions, and requests. While all Call Centre are similar in purpose and functionality, each has unique requirements for Voice Services based on their core business. The result is that each Call Centre requires specialized Services that are priced specifically for that business unit, in addition to normal Voice Services.

### *9.3.1 Products or Services Provided within the Fee*

The following are included in the price:

- Infrastructure to support Voice Services.
- Basic call handling, processing, messaging, and reporting capability.

### *9.3.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Enhancements, predictive dialer technology, recording systems, or any new telephony management applications.
- Advanced call treatment and reporting.
- Additional messaging requirements.
- The alteration of any existing Voice Services to meet the unique requirements of a Call Centre.

### *9.3.3 Exceptions Handling*

The following are exceptions to the price:

- Project service labour rates will be charged for development, maintenance, enhancements, or upgrade projects.
- New service rates will be calculated and applied after any Changes are made to standard service offerings.



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## 9.4 Call Center Symposium Application

This Service provides the centralized call flow control, monitoring, reporting, agent assignment and supervision applications used within call centers. It will integrate closely with the other call center Services.

### *9.4.1 Products or Services Provided within the Fee*

The following are included in the price:

- This is the software that provides the centralized call flow control, monitoring, reporting, agent assignment and supervision functionality required for the call center.
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.
- Hosted on Windows platform.

### *9.4.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The design, programming, and configuration of the application.
- Changes to existing applications.
- The hardware used to deliver the applications to the caller and the call center organization are separate Services

## 9.5 Call Center Symposium Server

This Service provides the hardware utilized by the call center Symposium Core application. It is the delivery mechanism for the centralized call flow control, monitoring, reporting, agent assignment and supervision applications used within call centers. It will integrate closely with the other call center Services

### *9.5.1 Products or Services Provided within the Fee*

The following are included in the price:

- Call center Symposium servers
- This is the hardware for the call center Symposium Core application.
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.
- Hosted on Windows platform.


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### *9.5.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The Symposium Core application software.

## 9.6 Call Center Call Pilot Applications

This Service provides messaging and announcements for call answering applications used within call centers. It will integrate closely with call processing operating systems like Nortel Symposium. The message must be made available to callers through ports and is therefore, closely associated with the call center Call Pilot Ports Service.

### *9.6.1 Products or Services Provided within the Fee*

The following are included in the price:

- Call Pilot Server
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

### *9.6.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The programming, recording, and configuration of the announcements and messages.
- Changes to existing announcements and messages.
- The voice ports used to deliver the announcements and messages to the caller are a separate Service.

## 9.7 Call Center Call Pilot Ports

This Service provides the delivery mechanisms for the call center Call Pilot Applications messaging and announcements. The number of concurrent callers accessing the application determines the number of ports required. It will integrate closely with call processing operating systems like Nortel Symposium.

### *9.7.1 Products or Services Provided within the Fee*

The following are included in the price:


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- Call Pilot server
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

#### *9.7.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The programming, recording, and configuration of the announcements and messages.
- Changes to existing announcements and messages using the ports.
- The application containing the announcements and messages to the caller are a separate Service.

### 9.8 Call Center Readerboard

This Service provides a customizable, 32 X 128 visual display of real time call centre statistics like average speed of answer and number of calls waiting. It is integrated closely with the Nortel Symposium call processing operating systems.

#### *9.8.1 Products or Services Provided within the Fee*

The following are included in the price:

- Call center readerboard server
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

#### *9.8.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The programming and configuration of the displays and messages.
- Changes to existing displays and messages.
- Installation and cabling required for the readerboard.

### 9.9 Call Centre Trunking

#### *9.9.1 Products or Services Provided within the Fee*

- The telephone System capacity that ATCO I-Tek provides in order to fulfill Call Centre requirements for incoming and outgoing call volumes in Edmonton and Calgary is measured in trunking channels. Incoming and outgoing calls processed through the Edmonton trunks, Calgary trunks, and


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the Edmonton/Calgary tie lines will be monitored and counted. The number of trunk channels used during the peak hours of the month will be charged to the Call Centre. The Call Centre will have the ability to set a maximum on the number of trunk channels used. Any incoming calls over the maximum established by the Call Centre will receive a busy signal.

## 9.10 Call Centre Seat (Max)

### *9.10.1 Products or Services Provided within the Fee*

The following is included in the price:

- A Voice Call Centre Seat is a charge based on the number of Agent Licenses purchased by the Call Centre.

## 9.11 Call Centre Set Operating Lease

### *9.11.1 Products or Services Provided within the Fee*

The following is included in the price:

- A Telephone set that is configured to utilize Call Centre functionality for call processing and handling.

## 9.12 Custom Call Routing Scripting (CCR)

### *9.12.1 Products or Services Provided within the Fee*

- The programming of call handling software to meet the Clients needs.
- Project service labour rates will be charged for development, maintenance, enhancements, or upgrade projects.
- If required, new service rates will be calculated and applied after any Changes are made to standard service offerings.

## 9.13 Custom Music-on-Hold License

### *9.13.1 Products or Services Provided within the Fee*

- A license to play music to a single caller on hold in a phone queue.


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#### *9.13.2 Products or Services not Provided within the Fee (Additional charges will apply)*

- Music from a third party provider and the maintenance for the recording.

#### *9.13.3 Exceptions Handling*

- A separate license is required for each simultaneous caller who receives music on hold in the phone queue

### 9.14 Recorded Announcement License

#### *9.14.1 Products or Services Provided within the Fee*

- The right to play an announcement to a single Client in a phone queue.

#### *9.14.2 Exceptions Handling*

- A separate license is required for each simultaneous caller who receives an announcement in the phone queue. Licenses are provided based on Service Level requirements and are negotiated for each requirement.

### 9.15 Recorded Announcement Route

#### *9.15.1 Products or Services Provided within the Fee*

- The hardware where the recorded announcement to be played over the phone System is stored.

### 9.16 Supervisor License

#### *9.16.1 Products or Services Provided within the Fee*

- A license to monitor a defined number of Agents for a Call Centre.

### 9.17 Dedicated OPX

#### *9.17.1 Products or Services Provided within the Fee*

- A telephone circuit that is used to connect a telephone set at a remote location to a campus PBX. The circuit is dedicated to that telephone set at the remote


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location. Prices will be determined based on site-specific requirements and reviewed on a site by site basis.

## 9.18 Dedicated Tie Lines

### *9.18.1 Products or Services Provided within the Fee*

- Circuits between PBX switches at two locations. These circuits provide the capability to dial between the locations by entering an access code followed by a local resident on the "called" PBX. Prices will be determined based on site-specific requirements and reviewed on a site by site basis.

## 9.19 Remote Centre Voice Network

### *9.19.1 Products or Services Provided within the Fee*

- The trunking rates charged by the Telecommunications Service Provider to provide connection between a PBX switch located at a site other than the two major campuses (Edmonton and Calgary) and the Public Switched Telephone Network (PSTN). Prices will be determined based on site-specific requirements and reviewed on a site by site basis.

## 9.20 Telecom Circuit Fees

### *9.20.1 Products or Services Provided within the Fee*

- This service is used to provide a vehicle to direct circuit charges from the Telecommunications Service Provider to the Client.

## 9.21 Telecom Fees

### *9.21.1 Products or Services Provided within the Fee*

- This service is used to provide a vehicle to direct charges that are not directly attributed to circuits. A line item in this service might contain an amalgamation of several charges into 1 line item.


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## 9.22 Voice Long Distance Direct

### *9.22.1 Products or Services Provided within the Fee*

The following is included in the price:

- Preferred Client rates apply to locations with Services provided by the subcontracted Telecommunications Service Provider.
- Access to long distance calling to the PSTN.
- Contract administration.
- Invoice administration.
- Reporting.
- Operator access.

### *9.22.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- No administration fee will be applied to long distance.
- Credit cards (calling cards) are managed directly by the Clients.

## 9.23 Voice Installs, Moves, Adds & Changes (IMAC's)

### *9.23.1 Products or Services Provided within the Fee*

- Any action requested by a Client that involves the alteration of location or configuration of a set, modem, or fax.

### *9.23.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Any wiring that may need to take place will be charged at Time and Materials Rates.
- Any travel required will be charged at Time and Materials Rates.

Project IMAC's, defined as 5 or more IMAC's to be done concurrently, are excluded from the price. The price for the Project IMAC's will be on an estimated basis, as described in the "Exceptions Handling" category.


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### *9.23.3 Exceptions Handling*

Project Voice Installs, Moves, Adds & Changes, concurrent IMAC's of 5 or more, are to be estimated on an incident by incident basis. The Project move will include Project Management charges to reflect the need to ensure that all the required IMAC's are done concurrently and on time.

## 9.24 Voice Line Charges

### *9.24.1 Products or Services Provided within the Fee*

- The local that appears on each set, modem, fax, ACD(Automatic Call Distribution) queue, script, or other service that provides a connection path to another unit within the local campus or PSTN calling area. More than one line can be present within any of the categories.

## 9.25 Voice Feature -Voicemail Remote Notify

This Service provides a notification that you have received a voice mail into the corporate voice mail System. The notification can be a voice call, pager notification, or ATCO I-Tek Corporate email message

### *9.25.1 Products or Services Provided within the Fee*

The following are included in the price:

- Voice mail remote notify server

  This is the System that hosts the operating system and application that delivers the notification Service

- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard

### *9.25.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Basic voice mail is a prerequisite for this service.
- Voice mail desktop is a prerequisite for email notification.
- Installation of the software on the Client’s workstation.
- The Service is restricted to the local calling area.
- A separate voice line may also be required in special situations.


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## 9.26 Voice Feature –Voice Mail Fax

This Service provides an incoming fax capability through the Microsoft Outlook email application on a standard ATCO I-Tek provided personal computer. Fax messages are displayed in a standard Inbox format.

### *9.26.1 Products or Services Provided within the Fee*

The following are included in the price:

- Voice mail fax server

  This is the System that hosts the operating system and application that delivers the fax.

- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

### *9.26.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Basic voice mail and voice mail desktop are prerequisites for this service.
- Installation of the software on the Client's workstation.
- A separate voice line is also required.

## 9.27 Voice Feature –Voice Mail Desktop

This Service provides access to the ATCO I-Tek provided corporate voice mail through the Microsoft Outlook email application on a standard ATCO I-Tek provided personal computer. Capability includes displaying a list of voice mail messages in an inbox, outbox, deleted items, and sent items format.

### *9.27.1 Products or Services Provided within the Fee*

The following are included in the price:

- Voice mail server

  This is the System that hosts the operating system and application that delivers the voice mail Service.

- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support are standard.

### *9.27.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:



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- Basic voice mail is a prerequisite for this service.
- Installation of the software on the Client's workstation.

## 9.28 Voice Set

### *9.28.1 Products or Services Provided within the Fee*

- A basic business telephone set.
- All routine maintenance of device

### *9.28.2 Products or Services not Provided within the Fee (Additional charges will apply)*

- Add-ons will be an additional expense priced according to function.

## 9.29 Voice Set Features – Call Park

### *9.29.1 Products or Services Provided within the Fee*

- The ability to place a call on hold that can be answered on any set anywhere within the local campus area. This is typically used to answer calls, place them on hold, and then broadcast a request on a Public Address System for a person to answer a call on a specific line. The person answering can use any phone in the local campus area to dial in the identified line number to collect the call.

### *9.29.2 Products or Services not Provided within the Fee (Additional charges will apply)*

- The Public Address System is the responsibility of the Client.

## 9.30 Voice Set Features – Call Recording

The ability to record telephone conversations on a subset of locals defined by the Client.

### *9.30.1 Products or Services Provided within the Fee*

Management, support, and training on the System and short-term storage of the recordings.

- Support.
- Training.


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#### *9.30.2 Products or Services not Provided within the Fee (Additional charges will apply)*

- Project service labour rates will be charged for development, maintenance, enhancements, or upgrade projects.
- Service rates will be calculated and applied based on the Client's requirements.
- Long term storage.
- Software: required to allow client access to stored recordings on file

##### *9.30.2.1 Exceptions Handling*

- The Client may withdraw from the 48-month contract at any time during the effective Term upon 30 days written notice and pay an early withdrawal penalty based on the following formula: a) Withdrawal within the first 12 months of the effective Term: # of Channels * Channel cost per month * Number of remaining months in the first year; b) Withdrawal in the remaining 36 months of the effective Term: 2/3 * # of Channels * Channel cost per month * Number of remaining months in effective Term.

### 9.31 Voice Set Features – Line Appearance

#### *9.31.1 Products or Services Provided within the Fee*

- The ability to configure a subset of Telephone Sets with the same local across the subset. One Telephone Set will be charged for a "Voice Line Charge" service, and the others will each receive "Voice Set Features - Line Appearance" charges.

### 9.32 Voice Set Features – Speed Call Manager

#### *9.32.1 Products or Services Provided within the Fee*

- The ability to create, edit and audit "Speed Call Lists". Speed Call Lists are tables that attach a 2-digit code to a 10-digit telephone number. Users can call the 10-digit telephone number by pressing the Speed Dial key on their telephone set and entering the 2-digit code to complete the dialing of the call.


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## 9.33 Voice Set Features – Speed Call User

### *9.33.1 Products or Services Provided within the Fee*

- Access to Speed Call List.

## 9.34 Voice Set Features – Visual Call Waiting

### *9.34.1 Products or Services Provided within the Fee*

- Display of an incoming number while the user is on-line with a Client.

## 9.35 Voice Set Features – Voice Advanced Mail

### *9.35.1 Products or Services Provided within the Fee*

- A voice mail box with the capacity to accept faxes to one local with telephone set access.

## 9.36 Voice Set Features – Voice Basic Mail

### *9.36.1 Products or Services Provided within the Fee*

- A voice mail box to one local with telephone set access.


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## 9.37 Price Schedule

(Price per unit)

| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Call Centre Symposium Application | Variable | Variable | Variable | Variable | Variable | Variable |
| Call Centre Symposium Server | Variable | Variable | Variable | Variable | Variable | Variable |
| Call Centre Call Pilot Applications | Variable | Variable | Variable | Variable | Variable | Variable |
| Call Centre Call Pilot Ports | Variable | Variable | Variable | Variable | Variable | Variable |
| Call Centre Readerboard | Variable | Variable | Variable | Variable | Variable | Variable |
| Call Centre Trunking | $ 83.57 | $ 83.57 | $ 83.57 | $ 83.57 | $ 83.57 | $ 83.57 |
| Call Centre Seat | $ 22.91 | $ 22.91 | $ 22.91 | $ 22.91 | $ 22.91 | $ 22.91 |
| Call Centre Set | $ 26.01 | $ 26.01 | $ 26.01 | $ 26.01 | $ 26.01 | $ 26.01 |
| Music-On-Hold | $ 2.34 | $ 2.34 | $ 2.34 | $ 2.34 | $ 2.34 | $ 2.34 |
| Recorded Announcement | $ 7.93 | $ 7.93 | $ 7.93 | $ 7.93 | $ 7.93 | $ 7.93 |
| Recorded Announcement Route | $ 34.32 | $ 34.32 | $ 34.32 | $ 34.32 | $ 34.32 | $ 34.32 |
| Call Centre Supervisor | $ 4.45 | $ 4.45 | $ 4.45 | $ 4.45 | $ 4.45 | $ 4.45 |
| Voice Install, Move, Add, Change | $ 64.96 | $ 64.96 | $ 64.96 | $ 64.96 | $ 64.96 | $ 64.96 |
| Voice Line Charge | $ 24.98 | $ 24.98 | $ 24.98 | $ 24.98 | $ 24.98 | $ 24.98 |
| Modem Line | $ 24.98 | $ 24.98 | $ 24.98 | $ 24.98 | $ 24.98 | $ 24.98 |
| Voice Set Charge | $ 15.89 | $ 15.89 | $ 15.89 | $ 15.89 | $ 15.89 | $ 15.89 |
| Voice Feature - Call Park | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 |
| Voice Feature - Call Recording | $ 44.64 | $ 44.64 | $ 44.64 | $ 44.64 | $ 44.64 | $ 44.64 |
| Voice Feature - Line Appearance | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 |
| Voice Feature - SC Manager | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 | $ 2.20 |
| Voice Feature - SC User | $ 1.10 | $ 1.10 | $ 1.10 | $ 1.10 | $ 1.10 | $ 1.10 |
| Voice Feature - Visual Call Waiting | $ 1.10 | $ 1.10 | $ 1.10 | $ 1.10 | $ 1.10 | $ 1.10 |
| Voice Feature - Voice Mail Advanced | $ 10.17 | $ 10.17 | $ 10.17 | $ 10.17 | $ 10.17 | $ 10.17 |
| Voice Feature - Voice Mail Basic | $ 8.50 | $ 8.50 | $ 8.50 | $ 8.50 | $ 8.50 | $ 8.50 |
| Voice Feature - Voice Mail Desktop | $ 3.60 | $ 3.60 | $ 3.60 | $ 3.60 | $ 3.60 | $ 3.60 |
| Voice Feature - Voice Mail Fax | $ 13.34 | $ 13.34 | $ 13.34 | $ 13.34 | $ 13.34 | $ 13.34 |
| Voice Feature - Voice Mail Remote Notify | $ 3.00 | $ 3.00 | $ 3.00 | $ 3.00 | $ 3.00 | $ 3.00 |
| Voice Feature -VM Extra Time (10min inc) | $ 5.07 | $ 5.07 | $ 5.07 | $ 5.07 | $ 5.07 | $ 5.07 |
| Centrex Set | $ 23.08 | $ 23.08 | $ 23.08 | $ 23.08 | $ 23.08 | $ 23.08 |
| PBX Trunk Port | $ 157.27 | $ 157.27 | $ 157.27 | $ 157.27 | $ 157.27 | $ 157.27 |
| Agency Switch | $ 198.67 | $ 198.67 | $ 198.67 | $ 198.67 | $ 198.67 | $ 198.67 |



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# 10 WIDE AREA NETWORK

## 10.1 General Provisions

The Wide Area Network (WAN) connects a remote site into the ATCO Group of Companies (ATCO Group) campus network. There are a variety of ways to connect a site to the ATCO Group network. The technology required will depend on the location of the site, the connection facilities available between the remote site, the central network and the Client's requirements. The prices stated here are available in Alberta, except where noted otherwise. Availability of all WAN Services offered are dependent upon the capabilities of the telecommunication service provider(s).

### *10.1.1 Products or Services Provided within the Fee*

The following are included in the price:

- Remote site hardware such as router(s), Data Service Unit(s) (DSU)/Channel Service Unit(s) (CSU), or analog modems only.
- The core hardware to provide the service are data circuits, router(s), Data Service Unit(s) (DSU)/Channel Service Unit(s) (CSU), or analog modems only.
- Network hardware and software tools used for WAN management.
- Maintenance for hardware and software by a third party vendor.
- Hardware and software service support.
- Telecommunication supplier circuit charges at the remote site(s).
- Telecommunication supplier circuit charges at the core (campus).

### *10.1.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Long distance tolls will be a Specified Expense of telecommunication costs by month by site as invoiced by the telecommunication service provider.

### *10.1.3 Exceptions Handling*

The following exception will apply:

- Any one-time setup charge from the telecommunication service provider for new and enhanced site Services will be applied as a Specified Expense.


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## 10.2 Virtual WAN General Provisions

A line that connects a remote site into the ATCO Group network through a Telecommunication Company's network cloud. The data flows from the remote site through mutually exclusive lines that are shared with other Clients of the Telecommunication Company and then into the ATCO Group's network.

### *10.2.1 Products or Services Provided within the Fee*

The following is included in the price:

- Rates for Virtual WAN sites include support of standard protocols only.

## 10.3 56K Virtual WAN

### *10.3.1 Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of data to the ATCO Group network to/from a site utilizing a 56 thousand bits per second bandwidth.

## 10.4 112K Virtual WAN

### *10.4.1 Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of data to the ATCO Group network to/from a site utilizing a 112 thousand bits per second bandwidth.

## 10.5 128K Virtual WAN North of 60

### *10.5.1 Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of data to the ATCO Group network to/from a site utilizing a 128 thousand bits per second bandwidth.
- This service is only available in the Yukon and Northwest Territories which is north of 60 degrees latitude.
- Two Primary Virtual Connections (PVC), one to each campus site, for purposes of redundancy.


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## 10.6 256K Virtual WAN

### *10.6.1 Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of data to the ATCO Group network to/from a site utilizing a 256 thousand bits per second bandwidth.

## 10.7 384K Virtual WAN

### *10.7.1 Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of data to the ATCO Group network to/from a site utilizing a 384 thousand bits per second bandwidth.

## 10.8 512K Virtual WAN

### *10.8.1 Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of data to the ATCO Group network to/from a site utilizing a 512 thousand bits per second bandwidth.

## 10.9 768K Virtual WAN

### *10.9.1 Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of data to the ATCO Group network to/from a site utilizing a 768 thousand bits per second bandwidth.

## 10.10 1.5M Virtual WAN

### *10.10.1Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of data to the ATCO Group network to/from a site utilizing a 1.5 million bits per second bandwidth.

## 10.11 10 Megabit Ethernet LAN Extension

### *10.11.1Products or Services Provided within the Fee*

The following is included in the price:



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- 10MB High Speed Access (shared) at the campus core.
- 10MB High Speed Access (shared) at the remote location.
- 1 Cisco 2514 Router located at the remote location.

#### *10.11.2Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- One time installation costs by both ATCO I-Tek and/or a telecommunication service provider.
- Sites outside of Edmonton and/or Calgary.

### 10.12 ISDN – General Provisions

The Integrated Service Data Network (ISDN) is a digital communication protocol for voice and data. ISDN can carry voice and/or data from the ATCO Group's network to a site depending on the equipment at the site. Typically, this service would not be implemented to sites that would incur long distance toll charges.

### 10.13 ISDN 128K

#### *10.13.1Products or Services Provided within the Fee*

The following is included in the price:

- The service provides transportation of voice and/or data to the ATCO Group network to/from a site utilizing a 128 thousand bits per second bandwidth.

### 10.14 Multi-ISDN 256K

#### *10.14.1Products or Services Provided within the Fee*

The following is included in the price:

- The service uses multiple ISDN lines to transport voice and/or data to the ATCO Group network to/from a site utilizing a 256 thousand bits per second bandwidth.

### 10.15 Multi-ISDN 384K

#### *10.15.1Products or Services Provided within the Fee*

The following is included in the price:

- The service uses multiple ISDN lines to transport voice and/or data to the ATCO Group network to/from a site utilizing a 384 thousand bits per second bandwidth.



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## 10.16 Multi-ISDN 512K

### *10.16.1Products or Services Provided within the Fee*

The following is included in the price:

- The service uses multiple ISDN lines to transport voice and/or data to the ATCO Group network to/from a site utilizing a 512 thousand bits per second bandwidth.

## 10.17 WAN Dedicated Networks

A specific line dedicated to provide service between a remote site into the ATCO Group network.

## 10.18 4 Wire Loop

### *10.18.1Products or Services Provided within the Fee*

The following is included in the price:

- Continuous connection between two sites.
- Cable mileage is limited to approximately 4km of existing site within Alberta.
- 256K to 768K bandwidth.
- Routers at each site.
- Line Drivers at each site.

## 10.19 Megastream

### *10.19.1Products or Services Provided within the Fee*

- ATCO I-Tek support charges include usage fees for equipment.

## 10.20 Microwave (Dedicated)

### *10.20.1Products or Services Provided within the Fee*

The following is included in the price:

- Hardware to mount and dismount microwave system at each end.
- Hardware to span connection from microwave system to LAN location.
- Monthly equipment fees for line drives located on Client premise.


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### *10.20.2Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- The microwave towers owned by the Client.
- Telecommunication supplier circuit charges at the remote site.
- There is no service guarantee since the microwave service is not managed by ATCO I-Tek

## 10.21 Price Schedule

(Price per site per month)

| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| 56K Virtual WAN | $ 1,466.77 | $ 1,466.77 | $ 1,466.77 | $ 1,466.77 | $ 1,466.77 | $ 1,466.77 |
| 112K Virtual WAN | $ 2,211.57 | $ 2,211.57 | $ 2,211.57 | $ 2,211.57 | $ 2,211.57 | $ 2,211.57 |
| 128K Virtual WAN NORTH OF 60 | $ 4,470.26 | $ 4,470.26 | $ 4,470.26 | $ 4,470.26 | $ 4,470.26 | $ 4,470.26 |
| 256K Virtual WAN | $ 2,758.67 | $ 2,758.67 | $ 2,758.67 | $ 2,758.67 | $ 2,758.67 | $ 2,758.67 |
| 384K Virtual WAN | $ 3,109.60 | $ 3,109.60 | $ 3,109.60 | $ 3,109.60 | $ 3,109.60 | $ 3,109.60 |
| 512K Virtual WAN | $ 3,298.17 | $ 3,298.17 | $ 3,298.17 | $ 3,298.17 | $ 3,298.17 | $ 3,298.17 |
| 768K Virtual WAN | $ 3,559.17 | $ 3,559.17 | $ 3,559.17 | $ 3,559.17 | $ 3,559.17 | $ 3,559.17 |
| 10Mb Ethernet - Local - 3 YR | $ 3,319.09 | $ 3,319.09 | $ 3,319.09 | $ 3,319.09 | $ 3,319.09 | $ 3,319.09 |
| 10 Mb Ethernet - Remote | $ 3,877.50 | $ 3,877.50 | $ 3,877.50 | $ 3,877.50 | $ 3,877.50 | $ 3,877.50 |
| Multi ISDN 256K | $ 1,839.19 | $ 1,839.19 | $ 1,839.19 | $ 1,839.19 | $ 1,839.19 | $ 1,839.19 |
| 384K Virtual WAN | $ 3,109.60 | $ 3,109.60 | $ 3,109.60 | $ 3,109.60 | $ 3,109.60 | $ 3,109.60 |
| Multi ISDN 512K | $ 2,480.64 | $ 2,480.64 | $ 2,480.64 | $ 2,480.64 | $ 2,480.64 | $ 2,480.64 |
| T1 in Grande Prairie | $ 2,295.48 | $ 2,295.48 | $ 2,295.48 | $ 2,295.48 | $ 2,295.48 | $ 2,295.48 |
| ISDN Virtual WAN | $ 571.50 | $ 571.50 | $ 571.50 | $ 571.50 | $ 571.50 | $ 571.50 |
| ISDN Circuit | $ 81.69 | $ 81.69 | $ 81.69 | $ 81.69 | $ 81.69 | $ 81.69 |
| 4 Wire Loop | $ 981.39 | $ 981.39 | $ 981.39 | $ 981.39 | $ 981.39 | $ 981.39 |
| Microwave (Dedicated) | $ 1,370.74 | $ 1,370.74 | $ 1,370.74 | $ 1,370.74 | $ 1,370.74 | $ 1,370.74 |
| VPN Remote Branch Onsite Spare | $ 103.40 | $ 103.40 | $ 103.40 | $ 103.40 | $ 103.40 | $ 103.40 |
| | | | | | | |



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# 11 WORKSTATION SERVICES

## 11.1 General Provisions

The Workstation Services are divided into separate rates for Workstation, Laptop and Terminal. There are three standard rates within each of these categories: Support, Network and Hardware. These will be applied to all devices. Equipment specifications listed are ATCO I-Tek's current specifications. Equipment specifications are subject to change without notice as technology changes.

## 11.2 Printer Hardware

Three types of printers are available. The main distinguishing features of printer capacity are memory size, duplexing capability, reliability, and pages per minute and installed network cards. Printers that fall outside the parameters of "Standard", "Low Volume", or "High Volume" will be priced individually.

### *11.2.1 Products or Services Provided within the Fee*

The following is included in the price:

- Printer hardware.
- Printer installation.

### *11.2.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Duplex option for standard, low volume and all color printers.

## 11.3 High Volume Black and White Printer

### *11.3.1 Products or Services Provided within the Fee*

The following is a summary of ATCO I-Tek's current specifications.
Specifications are subject to change without notice as technology changes.

- 32 MB Ram memory.
- Jet Direct card.
- 24 pages per minute.
- Duplex printing.
- 3 paper trays (letter/legal/ledger).


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## 11.4 High Volume Colour Printer

### *11.4.1 Products or Services Provided within the Fee*

The following is a summary of ATCO I-Tek's current specifications. Specifications are subject to change without notice as technology changes.

- Memory: 64 MB Ram.
- Network: Jet Direct Card.
- Technology: Laser.
- Pages Per Minute: 16ppm.
- Duplex: standard.
- Paper Handling: 2 Trays (Letter).
- Printer Installation.

## 11.5 Low Volume Black and White Printer

### *11.5.1 Products or Services Provided within the Fee*

The following is a summary of ATCO I-Tek's current specifications. Specifications are subject to change without notice as technology changes.

- Memory: 8 MB Ram memory.
- Network: Stand Alone.
- Pages Per Minute: 10 ppm.
- Paper Handling: 2 paper trays (letter/legal).

### *11.5.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Duplex printing.


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## 11.6 Low Volume Colour Printer

### *11.6.1 Products or Services Provided within the Fee*

The following is a summary of ATCO I-Tek's current specifications. Specifications are subject to change without notice as technology changes.

- Memory: 4Mb Desktop.
- Network: Optional.
- Technology: InkJet.
- Pages Per Minute: Desktop: 11ppm Black and White, 3ppm Colour or Portable:11ppm Black and White, 3ppm Colour.
- Duplex: N/A.
- Paper Handling: Desktop: 2 Trays (Letter) or portable: N/A.
- Printer Installation.

## 11.7 Standard Colour Printer

### *11.7.1 Products or Services Provided within the Fee*

The following is a summary of ATCO I-Tek's current specifications. Specifications are subject to change without notice as technology changes.

- Memory: 12 MB Ram.
- Network: Jet Direct Card.
- Technology: InkJet.
- Pages Per Minute: 11ppm Black and White, 9ppm Colour.
- Duplex: N/A.
- Paper Handling: 2 Trays (Letter).
- Printer Installation.

## 11.8 Standard Printer

### *11.8.1 Products or Services Provided within the Fee*

The following is a summary of ATCO I-Tek's current specifications. Specifications are subject to change without notice as technology changes.

- Memory: 16 MB Ram memory.


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- Network: Jet Direct card.
- Pages Per Minute: 17 ppm.
- Duplex: Optional duplex printing with incremental charge.
- Paper Handling: 2 paper trays (letter/legal).

#### *11.8.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Optional duplex printing with incremental charge.

### 11.9 Workstation Hardware

ATCO I-Tek's lease rates will be determined at the beginning of each calendar year. The lease rate will be determined at the beginning of the year and will remain in place until the end of that calendar year.

#### *11.9.1 Products or Services Provided within the Fee*

The following is included in the price:

- Maintenance and warranty of equipment.
- Replace as part of the standard refresh program. (Including 1 cascade per workstation as part of the refresh program).

#### *11.9.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Cascades (when not considered as part of the refresh program), moves and changes.
- All hardware additions to standard machine and installations will be charged Time and Materials Rates.

#### *11.9.3 Exceptions Handling*

Process Control machines are outlined in Appendix A – Out of Scope

### 11.10 Laptop Hardware Operating Lease

#### *11.10.1 Products or Services Provided within the Fee*

The following is included in the price:


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- Operational lease of workstation hardware.
- Hardware maintenance and support Services.
- The target for delivery of a standard laptop, subject to equipment availability from vendors, will be within 15 Business Days of the request.

The minimum specifications for a new or replacement laptop will be maintained and updated by ATCO I-Tek on a regular basis. Specifications will be made available at the time of request for the new laptop.

#### *11.10.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Moves/adds/changes.
- All support related items other than hardware.
- Special applications requested by the Client will be charged Time and Materials Rates to build and install.
- Network connection and SLA on site support.

### 11.11 Monitor 17 inch

#### *11.11.1 Products or Services Provided within the Fee*

The following is included in the price:

- 17” tube size.

### 11.12 Monitor 19 inch

#### *11.12.1 Products or Services Provided within the Fee*

The following is included in the price:

- 19” tube size.

### 11.13 Monitor 21 inch

#### *11.13.1 Products or Services Provided within the Fee*

The following is included in the price:

- 21” tube size.


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## 11.14 Monitor 15 inch or smaller - Discontinued

### *11.14.1 Products or Services Provided within the Fee*

The following is included in the price:

- 15” tube size.

## 11.15 PC Hardware Operating Lease

### *11.15.1 Products or Services Provided within the Fee*

The following is included in the price:

- Operational lease of workstation hardware.
- Hardware maintenance and support Services.
- The target for delivery of a standard Desktop, subject to equipment availability from vendors, will be within 15 Business Days of the request.

The minimum specifications for a new or replacement Desktop will be maintained and updated by ATCO I-Tek on a regular basis. This document will be made available at the time of request for the new Desktop.

### *11.15.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Moves/adds/changes.
- All support related items other than hardware.
- Special applications requested by the client will be charged Time and Materials Rates to build and install.
- Network connection and SLA on site support.

## 11.16 Terminal Hardware Operating Lease

### *11.16.1 Products or Services Provided within the Fee*

This service is no longer offered as there are no control unit terminals in service nor are they an offered service.


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## 11.17 Workstation Software

ATCO I-Tek has and will maintain a list of CORE software and versions.

### *11.17.1 General Provisions*

- Product support and training in the use of software.

## 11.18 Software Distribution Fee

### *11.18.1 Products or Services Provided within the Fee*

The following are included in the price:

- Distribution/installation of software product on standard workstation or laptop.
- Removal of software when requested or an upgrade occurs.

### *11.18.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Software Integration with the Core suite of software applications within the standard workstation environment will be charged Time and Materials Rates.
- Software integration and installation of software patches to the installed version of software will be charged Time and Materials Rates.
- Cost of the Software license fee will be a Specified Expense.
- Upgrades to a newer version of software.

### *11.18.3 Exceptions Handling*

The following exception will apply:

- ATCO I-Tek reserves the right to deny the installation of any software product that may compromise the quality or effectiveness of any service in the networked environment. All exceptions must be dealt with through the ATCO Group Standards Exception Process.

## 11.19 Workstation Support

### *11.19.1 Products or Services Provided within the Fee*

The workstation support rates include all Services relating to support of the standard workstation including:



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- Client support.
- Core software installation and support.
- The act of removing the workstation at the end of its lifecycle.
- Maintenance and support of LAN wiring.
- Maintaining and supporting configuration and equipment in the network closet.
- Minor upgrades in Core Software that do not cause major rework of current standard workstation builds

A list of standard CORE software products included in the workstation support rate will be maintained and updated by ATCO I-Tek on a regular basis. The list of all software considered part of the Core suite will be distributed to all MSA clients when updates and changes occur.

### *11.19.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Hardware fees.
- All moves and changes.
- Wiring for new locations will be charged Time and Materials Rates.
- Any Major upgrades in Core Software that would cause major rework of current standard workstation builds.

### *11.19.3 Exceptions Handling*

- Any support efforts when related to Client Type A or Dual Boot (w/ Multi-Partition configuration) activities will be charged Time and Materials Rates.

## 11.20 Laptop Support Low

### *11.20.1 Products or Services Provided within the Fee*

The following is included in the price:

- ATCO I-Tek Standard Laptop Build.
- Support for the workstation that has 4 or less workstation software applications above Core applications.
- Support for the Core suite of software applications.


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### *11.20.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- NCC (Network Challenged Client) Build.
- Dual Boot with Multi Partition configuration (the build and support are excluded). Refer to Appendix A – Out of Scope for further details on Dual Boot machines.

### *11.20.3 Exceptions Handling*

The following exception will apply:

- Any non-standard operating system builds will be charged this fee and all support related to the non-standard configuration of the workstation will be incrementally billed Time and Materials Rates.

## 11.21 Laptop Support Medium

### *11.21.1 Products or Services Provided within the Fee*

The following is included in the price:

- ATCO I-Tek Standard Laptop Build.
- Support for the workstation that has 5-8 workstation software applications above core applications.
- Support for the Core suite of software applications.
- Default for stand-alone devices will be Medium support.

### *11.21.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- NCC (Network Challenged Client) Build.
- Dual Boot with Multi Partition configuration (the build and support are excluded). Refer to Appendix A – Out of Scope for further details on Dual Boot machines.

### *11.21.3 Exceptions Handling*

The following exception will apply:


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- Any non-standard operating system builds will be charged this fee and all support related to the non-standard configuration of the workstation will be incrementally billed Time and Materials Rates.

## 11.22 Laptop Support High

### *11.22.1 Products or Services Provided within the Fee*

The following is included in the price:

- Support for the workstation that has more than 8-workstation software application above the core suite of applications.
- ATCO I-Tek Standard Laptop Build
- NCC (Network Challenged Client) Build will be considered High Support.
- Support for the Core Suite of software applications.

### *11.22.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Dual Boot with a multi-partition configuration (the build and support of that build are excluded).

### *11.22.3 Exceptions Handling*

The following exception will apply:

- Any non-standard operating system builds will be charged this fee and all support related to the non-standard configuration of the workstation will be incrementally billed Time and Materials Rates.

## 11.23 PC Support Low

### *11.23.1 Products or Services Provided within the Fee*

The following is included in the price:

- ATCO I-Tek Standard PC Build.
- Support for the workstation that has 4 or less workstation software applications above the Core suite of software applications.
- Support for the Core suite of software applications.


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### *11.23.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- NCC (Network Challenged Client) Build.
- Dual Boot with Multi Partition configuration (the build and support of that build are excluded). Refer to Appendix A – Out of Scope for further details on Dual Boot machines.

### *11.23.3 Exceptions Handling*

The following exception will apply:

- Any non-standard operating system builds will be charged this fee and all support related to the non-standard configuration of the workstation will be incrementally billed Time and Materials Rates.

## 11.24 PC Support Medium

### *11.24.1 Products or Services Provided within the Fee*

The following is included in the price:

- ATCO I-Tek Standard PC Build.
- Support for the workstation that has 5-8 workstation software applications above core applications.
- Support for the Core suite of software applications.
- Default for stand alone devices will be Medium support.

### *11.24.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- NCC (Network Challenged Client) Build.
- Dual Boot with Multi Partition configuration (the build and support are excluded). Refer to Appendix A – Out of Scope for further details on Dual Boot machines.

### *11.24.3 Exceptions Handling*

The following exception will apply:



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- Any non-standard operating system builds will be charged this fee and all support related to the non-standard configuration of the workstation will be incrementally billed Time and Materials Rates.

## 11.25 PC Support High

### *11.25.1 Products or Services Provided within the Fee*

The following is included in the price:

- Support for the workstation that has more than 8-workstation software application above the core suite of software applications or any Multi-Partition Configuration.
- ATCO I-Tek Standard Workstation Build
- NCC (Network Challenged Client) Build will be considered High Support.

### *11.25.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Dual Boot with Multi Partition configuration (the build and support of that build are excluded). Refer to Appendix A – Out of Scope for further details on Dual Boot machines.

### *11.25.3 Exceptions Handling*

The following exception will apply:

- Any non-standard operating system builds will be charged this fee and all support related to the non-standard configuration of the workstation will be incrementally billed Time and Materials Rates.

## 11.26 Out of Scope Equipment

Any out of scope equipment will be administered in accordance with Appendix A to Schedule D.

## 11.27 Printer Support – High

### *11.27.1 Products or Services Provided within the Fee*

This Printer Support Category is for High Volume Colour or Black and White printers.

The following is included in the price:



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- Support of “High” printer
- Support of printer queues.
- Printer software integration for Core products.

#### *11.27.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Printer supplies like paper and toner.
- Printer software integration for Non-Core products

### 11.28 Printer Support – Low

#### *11.28.1 Products or Services Provided within the Fee*

This Printer Support Category is for Low Volume Colour or Black and White printers.

The following is included in the price:

- Support of “Low” printers.
- Support of printer queues.
- Printer software integration for Core products.

#### *11.28.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Printer supplies like paper and toner.
- Printer software integration for Non-Core products

### 11.29 Printer Support – Standard

#### *11.29.1 Products or Services Provided within the Fee*

This Printer Support Category is for Standard Volume Colour or Black and White printers and all Stand Alone printers.

The following is included in the price:

- Support of “Standard” printers.
- Support of printer queues.
- Printer software integration for Core products.


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### *11.29.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following are excluded from the price:

- Printer supplies like paper and toner.
- Printer software integration for Non-Core products

## 11.30 Workstation Move/Addition/Change

### *11.30.1 Products or Services Provided within the Fee*

The service includes one of the following:

- Cascade (when not considered part of the refresh cycle) or move of a workstation.
- Addition of a single component to an existing workstation.

### *11.30.2 Products or Services not Provided within the Fee (Additional charges will apply)*

The following is excluded from the price:

- Any wiring that may need to take place will be charged at Time and Materials Rates.
- Any travel required will be charged at Time and Materials Rates.
- All software configuration and installation is additional.
- The cost of hardware where hardware is less than $1000 in any hardware upgrades will be a Specified Expense.
- The cost of hardware where hardware is more than $1000 in any hardware upgrades have a lease determined based on the life of the machine it was installed in.
- Adds/moves scheduled after regular ATCO I-Tek Business Hours at the request and authorization of the Client will be charged on a Time and Materials Rates basis.

Project Moves, defined as 5 or more workstations required to be moved concurrently, are excluded from the price. The price for the Project Move will be on an estimated basis, as described in the "Exceptions Handling" category.

### *11.30.3 Exceptions Handling*

Only hardware that is purchased from ATCO I-Tek may be installed on a workstation. Project Workstation Move/Addition/Changes, concurrent moves of 5



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or more workstations, are to be estimated on an incident by incident basis. The Project move will include Project Management charges to reflect the need to ensure all workstations are moved concurrently and on time.


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## 11.31 Price Schedule

Price per device per month

| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| B & W Printer High Volume | $ 100.00 | $ 100.00 | $ 100.00 | $ 100.00 | $ 100.00 | $ 100.00 |
| B & W Printer Low Volume | $ 28.00 | $ 28.00 | $ 28.00 | $ 28.00 | $ 28.00 | $ 28.00 |
| B & W Printer Medium Volume | $ 48.00 | $ 48.00 | $ 48.00 | $ 48.00 | $ 48.00 | $ 48.00 |
| B & W Printer Medium Volume w/duplex | $ 68.00 | $ 68.00 | $ 68.00 | $ 68.00 | $ 68.00 | $ 68.00 |
| Colour Printer High Volume | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 |
| Colour Printer Medium Volume | $ 50.00 | $ 50.00 | $ 50.00 | $ 50.00 | $ 50.00 | $ 120.00 |
| Colour Printer High Volume | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 | $ 120.00 |
| Monitor CRT – 17 inch | $ 8.00 | $ 8.00 | $ 8.00 | $ 8.00 | $ 8.00 | $ 8.00 |
| Monitor CRT – 19 inch | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 |
| Monitor CRT – 21 inch | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 |
| Monitor LCD – 15 inch: 2004 or older model | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 |
| Monitor LCD – 17 inch: 2004 or older model | $ 24.00 | $ 24.00 | $ 24.00 | $ 24.00 | $ 24.00 | $ 24.00 |
| Monitor LCD – 19 inch: 2004 or older model | $ 29.00 | $ 29.00 | $ 29.00 | $ 29.00 | $ 29.00 | $ 29.00 |
| Monitor LCD – 20 inch: 2004 or older model | $ 42.00 | $ 42.00 | $ 42.00 | $ 42.00 | $ 42.00 | $ 42.00 |
| Monitor LCD – 17 inch: 2005 or newer model | $ 18.00 | $ 18.00 | $ 18.00 | $ 18.00 | $ 18.00 | $ 18.00 |
| Monitor LCD – 19 inch: 2005 or newer model | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 |
| Monitor LCD – 20 inch: 2005 or newer model | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 | $ 32.00 |
| Laptop H/W Operating Lease | $ 142.50 | $ 142.50 | $ 142.50 | $ 142.50 | $ 142.50 | $ 142.50 |
| Laptop H/W Slim Operating Lease | $ 182.93 | $ 182.93 | $ 182.93 | $ 182.93 | $ 182.93 | $ 182.93 |
| Laptop Support High | $ 198.41 | $ 198.41 | $ 198.41 | $ 198.41 | $ 198.41 | $ 198.41 |
| Laptop Support Low | $ 125.08 | $ 125.08 | $ 125.08 | $ 125.08 | $ 125.08 | $ 125.08 |
| Laptop Support Medium | $ 161.27 | $ 161.27 | $ 161.27 | $ 161.27 | $ 161.27 | $ 161.27 |
| PC H/W Operating Lease | $ 81.12 | $ 81.12 | $ 81.12 | $ 81.12 | $ 81.12 | $ 81.12 |
| PC H/W Operating Lease - High Performance | $ 183.50 | $ 183.50 | $ 183.50 | $ 183.50 | $ 183.50 | $ 183.50 |
| PC Support Low | $ 106.03 | $ 106.03 | $ 106.03 | $ 106.03 | $ 106.03 | $ 106.03 |
| PC Support Medium | $ 132.22 | $ 132.22 | $ 132.22 | $ 132.22 | $ 132.22 | $ 132.22 |
| PC Support High | $ 158.41 | $ 158.41 | $ 158.41 | $ 158.41 | $ 158.41 | $ 158.41 |
| Printer Support High Volume | $ 76.37 | $ 76.37 | $ 76.37 | $ 76.37 | $ 76.37 | $ 76.37 |
| Printer Support Medium Volume | $ 65.00 | $ 65.00 | $ 65.00 | $ 65.00 | $ 65.00 | $ 65.00 |
| Printer Support Low Volume | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 | $ 20.00 |



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Price per incident

| DESCRIPTION | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Software Distribution Fee | Variable | Variable | Variable | Variable | Variable | Variable |
| Workstation Move/Add/Change | $ 61.42 | $ 61.42 | $ 61.42 | $ 61.42 | $ 61.42 | $ 61.42 |



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## 12 FORECAST VOLUMES

Prices are based on the following volume categories (excluding ATCO I-Tek) and non MSA Clients as of September 1, 2004

| Service Category | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| PC H W Operating Lease | 2,105 | 2,113 | 2,132 | 2,132 | 2,132 | 2,132 |
| Laptop H W Operating Lease | 671 | 670 | 672 | 672 | 672 | 672 |
| **Category Total** | **2,776** | **2,783** | **2,804** | **2,804** | **2,804** | **2,804** |
| | | | | | | |
| Monitor CRT - 17 inch | 2,039 | 2,041 | 2,071 | 2,071 | 2,071 | 2,071 |
| Monitor CRT - 19 inch | 4 | 4 | 4 | 4 | 4 | 4 |
| Monitor CRT - 21 inch | 138 | 138 | 138 | 138 | 138 | 138 |
| Monitor LCD - 17 inch: 2004 or older model | 123 | 123 | 123 | 123 | 123 | 123 |
| Monitor LCD - 19 inch: 2004 or older model | 62 | 62 | 62 | 62 | 62 | 62 |
| Monitor LCD - 20 inch: 2004 or older model | 31 | 31 | 31 | 31 | 31 | 31 |
| **Category Total** | **2,397** | **2,399** | **2,429** | **2,429** | **2,429** | **2,429** |
| | | | | | | |
| Colour Printer High Volume | 18 | 18 | 18 | 18 | 18 | 18 |
| Colour Printer Maximum Volume | 9 | 9 | 9 | 9 | 9 | 9 |
| Colour Printer Medium Volume | 4 | 4 | 4 | 4 | 4 | 4 |
| B & W Printer High Volume | 82 | 82 | 82 | 82 | 82 | 82 |
| B & W Printer Low Volume | 66 | 66 | 66 | 66 | 66 | 66 |
| B & W Printer Medium Volume | 214 | 214 | 214 | 214 | 214 | 214 |
| B & W Printer Medium Volume w duplex | 139 | 139 | 139 | 139 | 139 | 139 |
| **Category Total** | **532** | **532** | **532** | **532** | **532** | **532** |



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| Service Category | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| | | | | | | |
| MVS (ADABAS) CPU Minutes | 97,315 | 84,983 | 84,983 | 84,983 | 84,983 | 84,983 |
| MVS (IMS ADABAS Batch) CPU Minutes | 106,765 | 89,959 | 89,959 | 89,959 | 89,959 | 89,959 |
| MVS (Non-IMS ADABAS Batch) CPU Minutes | 29,030 | 41,815 | 41,815 | 41,815 | 41,815 | 41,815 |
| MVS (CICS) CPU Minutes | 3,091 | 2,789 | 2,789 | 2,789 | 2,789 | 2,789 |
| MVS (DB2) CPU Minutes | 10,655 | 18,731 | 18,731 | 18,731 | 18,731 | 18,731 |
| MVS (IMS) CPU Minutes | 45,638 | 46,511 | 46,511 | 46,511 | 46,511 | 46,511 |
| MVS (TSO) CPU Minutes | 6,356 | 5,770 | 5,770 | 5,770 | 5,770 | 5,770 |
| **Category Total** | **298,850** | **290,558** | **290,558** | **290,558** | **290,558** | **290,558** |
| | | | | | | |
| 10Mb Ethernet - Local - 3 YR | 4 | 4 | 4 | 4 | 4 | 4 |
| 10 Mb Ethernet - Remote | 2 | 2 | 2 | 2 | 2 | 2 |
| **Category Total** | **6** | **6** | **6** | **6** | **6** | **6** |
| | | | | | | |
| 256K Virtual WAN | 2 | 2 | 2 | 2 | 2 | 2 |
| 56K Virtual WAN | 7 | 7 | 7 | 7 | 7 | 7 |
| 768K Virtual WAN | 2 | 2 | 2 | 2 | 2 | 2 |
| **Category Total** | **11** | **11** | **11** | **11** | **11** | **11** |
| | | | | | | |
| ADSL Light | 24 | 24 | 24 | 24 | 24 | 24 |
| ADSL Unlimited | 11 | 11 | 11 | 11 | 11 | 11 |
| **Category Total** | **35** | **35** | **35** | **35** | **35** | **35** |
| | | | | | | |
| Network Connectivity for Terminal Server | 29 | 29 | 29 | 29 | 29 | 29 |
| Wireless Blackberry Service | 64 | 64 | 64 | 64 | 64 | 64 |



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| Service Category | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Connectivity | | | | | | |
| ISDN Circuit | 9 | 9 | 9 | 9 | 9 | 9 |
| **Category Total** | **102** | **102** | **102** | **102** | **102** | **102** |
| | | | | | | |
| Terminal Server Service 1 Port | 11 | 11 | 11 | 11 | 11 | 11 |
| Terminal Server Service 4 Port | 7 | 7 | 7 | 7 | 7 | 7 |
| Terminal Server Service 8 Port | 1 | 1 | 1 | 1 | 1 | 1 |
| **Category Total** | **19** | **19** | **19** | **19** | **19** | **19** |
| | | | | | | |
| VPN - Remote Client | 292 | 302 | 311 | 311 | 311 | 311 |
| VPN - Remote Branch | 7 | 7 | 7 | 7 | 7 | 7 |
| **Category Total** | **299** | **309** | **318** | **318** | **318** | **318** |
| | | | | | | |
| Internet Access | 1,676 | 1,691 | 1,715 | 1,715 | 1,715 | 1,715 |
| Centrex Set | 57 | 57 | 57 | 57 | 57 | 57 |
| **Category Total** | **1,733** | **1,748** | **1,772** | **1,772** | **1,772** | **1,772** |
| | | | | | | |
| Recorded Announcement | 34 | 34 | 34 | 34 | 34 | 34 |
| Recorded Announcement Route | 8 | 8 | 8 | 8 | 8 | 8 |
| **Category Total** | **42** | **42** | **42** | **42** | **42** | **42** |
| | | | | | | |
| Call Centre Trunking | 7 | 7 | 7 | 7 | 7 | 7 |
| PBX Trunk Port | 2 | 2 | 2 | 2 | 2 | 2 |
| **Category Total** | **9** | **9** | **9** | **9** | **9** | **9** |
| | | | | | | |
| Voice Feature - Voice Mail Advanced | 1 | 1 | 1 | 1 | 1 | 1 |



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| Service Category | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Voice Feature - Voice Mail Basic | 797 | 791 | 793 | 793 | 793 | 793 |
| Voice Feature - Voice Mail Desktop | 2 | 2 | 2 | 2 | 2 | 2 |
| Voice Feature - Voice Mail Fax | 2 | 2 | 2 | 2 | 2 | 2 |
| Voice Feature - Voice Mail Remote Notify | 4 | 4 | 4 | 4 | 4 | 4 |
| Voice Feature -VM Extra Time (10min inc) | 3 | 3 | 3 | 3 | 3 | 3 |
| **Category Total** | **809** | **803** | **805** | **805** | **805** | **805** |
| | | | | | | |
| Voice Feature - Call Park | 195 | 189 | 189 | 189 | 189 | 189 |
| Voice Feature - Line Appearance | 1,140 | 1,143 | 1,145 | 1,145 | 1,145 | 1,145 |
| Voice Feature - SC Manager | 117 | 119 | 121 | 121 | 121 | 121 |
| Voice Feature - SC User | 333 | 329 | 329 | 329 | 329 | 329 |
| Voice Feature - Visual Call Waiting | 101 | 102 | 103 | 103 | 103 | 103 |
| **Category Total** | **1,886** | **1,882** | **1,887** | **1,887** | **1,887** | **1,887** |
| | | | | | | |
| Voice Line | 2,474 | 2,472 | 2,491 | 2,491 | 2,491 | 2,491 |
| Modem Line | 241 | 231 | 226 | 226 | 226 | 226 |
| Voice Set | 1,933 | 1,936 | 1,954 | 1,954 | 1,954 | 1,954 |
| **Category Total** | **4,648** | **4,639** | **4,671** | **4,671** | **4,671** | **4,671** |
| | | | | | | |
| **Single Category Items** | | | | | | |
| MVS DASD Gigabyte Months | 136 | 136 | 136 | 136 | 136 | 136 |
| MVS Tape Gigabyte Months | 1,086 | 1,086 | 1,086 | 1,086 | 1,086 | 1,086 |
| MVS HSM Tape Gigabyte Months | 181 | 181 | 181 | 181 | 181 | 181 |
| 1.5M Virtual WAN | - | - | - | - | - | - |
| Distributed Archive Tape | 4 | 4 | 4 | 4 | 4 | 4 |



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| Service Category | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Email Service | 8,983 | 9,485 | 10,111 | 10,111 | 10,111 | 10,111 |
| Server Storage | 2,253 | 2,354 | 2,510 | 2,510 | 2,510 | 2,510 |
| UserID Services | 3,150 | 3,159 | 3,183 | 3,183 | 3,183 | 3,183 |
| Long Term Archive | 538 | 538 | 538 | 538 | 538 | 538 |
| Long Term Archive - 1st Month | 64 | 64 | 64 | 64 | 64 | 64 |
| Remote Access Service | 211 | 185 | 170 | 170 | 170 | 170 |
| Right Fax (plus variable long distance) | 90 | 90 | 90 | 90 | 90 | 90 |
| Terminal Server Service (Citrix) | 93 | 93 | 93 | 93 | 93 | 93 |
| Call Centre Set | 35 | 35 | 35 | 35 | 35 | 35 |
| Video Conferencing Lease w Support | 3 | 3 | 3 | 3 | 3 | 3 |
| 4 Wire Loop | 7 | 7 | 7 | 7 | 7 | 7 |
| Microwave (Dedicated) | 4 | 4 | 4 | 4 | 4 | 4 |
| Substation | 2 | 2 | 2 | 2 | 2 | 2 |
| Voice Feature - Call Recording | 7 | 7 | 7 | 7 | 7 | 7 |
| T1 in Grande Prairie | 2 | 2 | 2 | 2 | 2 | 2 |

Email Storage increments reduced from 100MB to 50 MB in 2005



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# INFORMATION TECHNOLOGY

# MASTER SERVICES AGREEMENT

## Schedule E – Special Terms

# SCHEDULE E - SPECIAL TERMS

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# 1.0 Introduction

## *1.1 Overview*

The purpose of this schedule is to document special terms that may be negotiated between any of the ATCO Group of Companies and ATCO I-Tek. In general, the intent of the Master Services Agreement is for ATCO I-Tek to provide the same Services to all participating Customers, based on the same terms and conditions. However, should the need arise for special terms with any one of the companies, those terms would be documented herein.

# INFORMATION TECHNOLOGY

# MASTER SERVICES AGREEMENT

## Schedule F – Asset Transfer

# SCHEDULE F – ASSET TRANSFER

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# 1.0 Introduction

## *1.1 Overview*

The purpose of this document is to identify the hardware assets that will be transferred from the ATCO operating companies to ATCO I-Tek as part of this agreement.

# 2.0 Hardware Assets

As of the effective date the Client will transfer the majority of hardware assets being used by the Client in its business, including but not limited to:

> mainframes, minicomputers, file, application and printer servers, workstations, personal computers and other desktop equipment, peripherals, routers, hubs and other related network communications equipment, telephone/voice systems and related equipment.

The Client will retain those assets, which are out of scope (Scada; AMR Systems).

A detailed list of the above mentioned hardware assets will be provided within three months of the commencement date and will include:

a) The fair market value of these resources which was completed as of the effective date of the contract by an independent third party provider ("I.T. Equipment Transfer Amount") and

b) All equipment is considered to be in good working order and is free from material defects and problems as of the effective transfer date.

## *2.1 Payment of Hardware Assets*

As of the effective date, ATCO I-Tek will provide the Client with resource usage credits monthly, on their invoice until such time as the "IT Equipment Transfer Amount" is complete. These proceeds will be deemed partial payment of the final IT Equipment Transfer Amount.

Upon the finalization of the detailed hardware list, ATCO I-Tek shall issue the Client a payment in the amount of the I.T. Equipment Transfer Amount less the credit proceeds paid to the client as of the effective date

# Schedule G

# Termination Transition Plan

## 1. Detailed Termination Transition Plan

Upon a notice of termination being given under this Agreement, a detailed Termination Transition Plan shall be prepared at the Client's sole cost and expense pursuant to a Statement of Work, and shall include each of the following items:

(a) Name of Party to whom the Services shall be transitioned

(b) Scope Statement

(c) Format and Form of Deliverables

(d) Transition Team Members including steering committee

(e) List of Software used by Client at the date of termination

(f) List of Hardware used by Client at the date of termination

(g) List of 3rd party contracts used by Client at the date of termination

(h) Review of Statements of Work in effect at the date of termination

(i) Detailed project plan

(j) Detailed Training Requirements

(k) Fees Schedule

(l) Client responsibilities during the Transition Assistance Period

(m) ATCO I-Tek responsibilities during the Transition Assistance Period

(n) Change Implementation

(o) Acceptance Process

(p) Authorization signatures

## 2. Client Data

Upon termination of this Agreement for any reason, ATCO I-Tek shall convert (to industry standard file formats) and make available to Client, or as Client directs, all Client Data in the possession, custody or control of ATCO I-Tek, and if no direction is provided by Client to ATCO I-Tek, the same shall be delivered up to Client within one hundred eighty (180) days following termination of this Agreement. Client shall pay for

any required conversion services (in the event Client Data is stored in a proprietary or confidential file format) at the Time and Materials Rate.

**3. Return of Client Property**

At the end of the Transition Assistance Period, or earlier, where appropriate in the circumstances, ATCO I-Tek shall return to the Client (in the format mutually agreed to in the Termination Transition Plan) all property belonging to Client including without limitation Client Systems, Documentation, Client Data, Client Know-How, IP Rights, IT Assets, and all other property owned by the Client.

**4. Return of ATCO I-Tek Property**

At the end of the Transition Assistance Period, or earlier, where appropriate in the circumstances, the Client will return to ATCO I-Tek all property belonging to ATCO I-Tek including without limitation ATCO I-Tek Systems, Documentation, ATCO I-Tek Know-How, IP Rights and IT Assets, and all other property owned by ATCO I-Tek.

**5. Training**

During the Transition Assistance Period, ATCO I-Tek shall provide training related to the Systems and Services to be transferred to the Client or its third party service provider as outlined in the Termination Transition Plan or in a Statement of Work.

**6. Third Party Software**

During the term of the Agreement, ATCO I-Tek will use commercially reasonable efforts to license third party software in such a way as to enable Client use of these third party licenses, held by ATCO I-Tek and required to run Client Systems, both during the term of the Agreement as well as after termination, pursuant to the terms of the Termination Transition Plan (including pursuant to a sublicense from ATCO I-Tek apart from any other Services).

**7. Consulting**

During the Transition Assistance Period, where appropriate in the circumstances, ATCO I-Tek shall provide consulting services related to the Systems or Services to be transferred to the Client or its third party service provider as outlined in the Termination Transition Plan or in a Statement of Work.

# AMENDING AGREEMENT

This Amending Agreement is dated effective as of the 2 day of May, 2005 (the "Effective Date") by and between:

ATCO I-Tek Inc.
("ATCO I-Tek")

- and -

ATCO Electric Ltd.
(the "Client")

**WHEREAS:**

A. The Client and ATCO I-Tek entered into an Information Technology Renewal Master Services Agreement dated effective January 1, 2005 (the "Renewal MSA ") under which ATCO I-Tek agreed to provide certain data processing and other services to Client;

B. The Client and ATCO I-Tek wish to amend certain terms of the Renewal MSA;

C. The parties have agreed, as of the Effective Date, to the amendments contemplated in this Amending Agreement and wish to document those amendments formally as set forth herein.

In consideration of the mutual covenants and agreements set forth herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

## 1. DEFINITIONS

a) Defined Terms. For the purposes of this Amending Agreement, the capitalized terms shall have the same meaning as defined in the Renewal MSA unless expressly indicated otherwise herein.

b) Number and Gender. All words importing the singular number include the plural and vice versa and all words importing gender include the masculine, feminine and neuter gender.

c) Schedules. The following Schedule is attached to and incorporated into this Amending Agreement by reference and is deemed to be a part hereof:

Schedule A AMENDMENTS

## 2. AMENDMENT

a) Amendment. The Renewal MSA is amended by the addition of the representation set forth in Schedule A, and by the replacement of the expressly listed provision of the Renewal MSA identified on Schedule A with the expressly indicated replacement provision set out in Schedule A.

b) Effective Date. All rights and obligations as between the parties and relating to this Amendment shall be effective and adjusted as at the Effective Date.

c) Regulatory. Notwithstanding anything to the contrary in this Amending Agreement, this Amending Agreement is subject to Client obtaining any necessary regulatory approvals, if applicable.

d) Confirmation of Remaining Provision. Except as expressly set forth in this Amending Agreement, the terms, conditions and covenants of the Renewal MSA shall remain in full force and effect.

## 3. MISCELLANEOUS

a) Binding Effect. This Amending Agreement shall be binding upon and enure to the benefit of the parties hereto and their respective successors and assigns.

b) Counterparts. This Amending Agreement may be executed in one or more counterparts, and delivered by facsimile, each of which shall be deemed an original and all of which taken together shall constitute a single agreement.

c) No Waiver. The failure of any Party to insist upon strict performance of a covenant hereunder or of any obligation hereunder, irrespective of the length of time for which such failure continues, shall not be a waiver of such Party's right to demand strict compliance in the future. No consent or waiver, express or

implied, to or of any breach or default in the performance of any obligation hereunder shall constitute a consent or waiver to or of any other breach or default in the performance of the same or of any other obligation hereunder.

**IN WITNESS WHEREOF,** the parties hereto have caused this Amending Agreement to be duly executed and delivered as of the Effective Date.

**ATCO Electric Ltd.**

Per: _____

Name: O.G. (Owen) Edmondson
Title: Vice-President

**ATCO I-Tek Inc.**

Per: _____

Name: R.L. (Bobbi) Lambright
Title: President

## SCHEDULE "A"

## AMENDMENTS

The Renewal MSA is amended as follows:

Section 8.2 shall be deleted from the Renewal MSA and replaced with the following:

## ARTICLE 8
## CHARGES AND PAYMENTS

### 8.2 Charges

In consideration of the provision by ATCO I-Tek to Client of the Services, Client shall pay to ATCO I-Tek the charges set forth in Schedule D and in any applicable Statement of Work. Client shall also pay all of ATCO I-Tek's charges with respect to any services other than the Services, including those referred to in section 2.7.

# Statement of Work

Master Services Agreement (MSA):

ATCO I-Tek Business Services Ltd. and ATCO Electric

*Change in Deposit Interest – Company 05, 06 & 08*

Statement of Work Number: **P1467**

**Provided to: North of 60 Companies**

**Provided by: ATCO I-Tek Business Services Ltd.**

*ATCO I-Tek has redacted certain information from the enclosed document and replaced vendor specific names and products with generic descriptions. The redacted and replaced information is the confidential information of ATCO I-Tek and ATCO I-Tek prohibits its disclosure to any person. The disclosure of such confidential information would cause damage to ATCO I-Tek, and in some circumstances would compromise the security of ATCO's computing environment.*

*ATCO I-Tek permits* Yukon Electrical Company Limited *to disclose the remaining information contained in the attached document strictly as part of their current respective application before the* Yukon Public Utilities Board - 2008-2009 General Rate Application. *This permission is granted subject to the condition that the use of the disclosed information shall be restricted to this specific filing and shall not be used by any person for any other purposes.*

Document Version 1.0

Date Created: March 03, 2004
Last Modified: March 03, 2004
Prepared by: Duane Kotun

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## STATEMENT OF CONFIDENTIALITY

This document is the proprietary and confidential information and property of **ATCO I-Tek Business Services Ltd.** (the "Supplier") and is governed by the obligations of non-disclosure and non-use in the Master Services Agreement between the Supplier and **ATCO Electric** (the "Client"). Without limiting the foregoing, by accepting possession of this document, you, and any third party agents, consultants or contractors engaged by you, agree to keep the contents of this document in strict confidence, and not use, duplicate, or disclose its ideas or contents for any purpose other than evaluating the ability of the Supplier to provide the services described herein, and for the purposes permitted under the Master Services Agreement, unless otherwise agreed to in writing by the Supplier.

Without limiting the foregoing, disclosure of any of this information to any third party would be disclosure of trade secrets of the Supplier or other parties (including scientific, technical, commercial or financial information) supplied in confidence and would (i) prejudice significantly the competitive position of the Supplier, (ii) interfere significantly with the contractual and other negotiations of the Supplier, and (iii) result in material harm to the Supplier.

### Revision History

| Revision Number | Revised By | Revision Date | Summary of Changes |
|---|---|---|---|
| 1.0 | D. Kotun | Mar. 3, 2004 | Create document |
| | | | |
| | | | |
| | | | |
| | | | |



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**Statement of Work**

*Change in Deposit Interest – Company 05, 06 & 08*

# 1 Project Overview

ATCO Electric (Yukon Electric) "The Client" has requested a change to the Deposit Interest rate for companies 05, 06 & 08 respectively. The increase will be from 1.5% to 2.50%, effective February cycle 01, 2004 for Company 05. Companies 06 and 08 will see a change from 2.77% to 2.71%.

## *1.1 Scope*

This Statement of Work is valid until March 2004.

# 2 Timing

In the event that the Client requests that ATCO I-Tek change the priority of current project work, the Client acknowledges that ATCO I-Tek may be required to adjust its resource allocation prior to the commencement of or while working on this project. In this instance, this Statement of Work may be impacted and the Client may incur additional costs to complete the project objectives, or may be required to alter the completion date of this project.

This project is tentatively scheduled to commence and be completed in February 2004.

# 3 Estimated Costs

## *3.1 Budget*

The labour figures identified below have been calculated using hourly units.

| | |
|---|---|
| Change programs to reflect the new Deposit Interest rate | $433.35 |
| TOTAL ESTIMATED COSTS | $433.35 |

The "Total Costs" of $433.35 is the estimated project cost.

Actual costs to complete the project will be invoiced to ATCO Electric as outlined in the Invoicing section below.

# 4 Invoicing

All ATCO I-Tek Business Services Ltd. labour charges will be invoiced at Time and Materials Rates as per the Master Services Agreement.



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All ATCO I-Tek charges and any ATCO I-Tek Business Services Ltd. non-labour charges will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

# 5 Change Control Process

Requests for changes or additions to the scope and costs identified in this document must be received in writing. Consideration of requests for any changes or additions shall not imply acceptance of such requests. Instead, each request will be considered based on the following criteria:

- The perceived value of the request within the context of the entire project
- The business implications of the requested change
- The effect of the change on project quality and project objectives
- An assessment of the complexity level and risk associated with the request
- The estimated expense of the request and the impact of the additional costs on the originally approved project budget.

If the change request receives approval to proceed, this Statement of Work will be amended, as will the Project Plan, and work will then proceed on addressing the change as part of the project.



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# 6 Authorization

Our signatures below signify that we have reviewed this document, and have provided authorization for work to proceed on the project as described in this document.

| APPROVER | DATE |
|---|---|
| [REDACTED: EMPLOYEE NAME] | |

| APPROVER | DATE |
|---|---|
| [REDACTED: EMPLOYEE NAME] | |



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# Statement of Work
# Short Form

| I-Tek Reference Number: PD00583 | Date Statement of Work Created: 24-Feb-06 | Client: ☒ Yukon Electric ☐ Yukon Energy ☐ Northland Utilities Ltd. (NWT) ☐ Northland Utilities Ltd. (Yellowknife) |
|---|---|---|
| Client Reference Number: | Description: Annual Schedule | Initiator(s): [REDACTED: EMPLOYEE NAME] |

| PMTR Number *(if applicable)*: | Ticket Number *(if applicable)*: | ☐ Notify Finance |
|---|---|---|

| Areas Impacted: | Request Type: | | |
|---|---|---|---|
| ☒ Applications | ☐ Parameter Changes | ☐ Account Update |
| ☐ Technologies | ☐ Policy Changes | ☒ Reports/Extracts |
| ☐ Call Center and Billing Services | ☐ Process Changes | ☐ Work Queue |
| ☐ Customer Choice | ☐ Functionality Changes | ☐ Other: _____ |

| Work Location: | Approval Required By (Date): 10-Mar-06 |
|---|---|
| 5 AC Edmonton | Scheduled Implementation Date: TBD after approval |

| Charge Allocation: ☒ ENHANCEMENT ☐ MAINTENANCE | MSA Impact: ☒ NO ☐ YES (PTO for detail) |
|---|---|

**Description of Service/ Information Requested:** ☐ SEE ATTACHED

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The North of 60 (N60) Companies has requested ATCO I-Tek to provide an estimate for generating [REDACTED: REPORT&EXTRACT NAME] annually for Companies 04, 05, 06, and 08. This report is currently generated on an ad hoc.

**Service/ Response Delivered:**

ATCO I-Tek will generate the scheduled report [REDACTED: REPORT&EXTRACT NAME]annually (5th business day of the year) for Companies 04, 05, 06, and 08 upon approval of this SOW.

**Report/Extract Name**

The report name (Street and Outdoor Light Audit) will remain unchanged.

**Report/Extract Number**

The report number [REDACTED: REPORT&EXTRACT NAME] will remain unchanged.

**Report/Extract Frequency**

[REDACTED: REPORT&EXTRACT NAME] will be generated annually (5th business day of the year).

**Report/Extract Format**

The report format will remain unchanged.

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.
*** Fixed Fees**
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Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement and as indicated in the ESTIMATE section above.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

ATCO I-Tek

# Statement of Work
# Short Form

**Report/Extract Location**

The report is distributed via [REDACTED: VENDOR PRODUCT]. A hard-copy report is sent to the following locations:

- Co 02 report (Co 06/08): Distribution Clerk/Report Management/Box 076
- Co 05 report (Co 04/05): Whitehorse Billing Dept/Box 576 – this would get mailed to Whitehorse with all the other reports directed to Box 576.

The estimate contained in this SOW will expire in 3 months from the Approval Required By Date indicated above.

*** Time & Material**

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*** Fixed Fees**

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ATCO I-Tek

# Statement of Work
# Short Form

**ESTIMATE*** ☒ Yukon Electric 25% ☒ Yukon Energy 25%
☒ Northland Utilities Ltd. (NWT) 25% ☒ Northland Utilities Ltd. (Yellowknife) 25%

| Deliverables | Estimate |
|---|---|
| Applications: Requirements and analysis | 128 |
| Design, construction and unit testing | 140 |
| **Total** | **$ 268.00** |

☐ Included in MSA ☒ Time & Material ☐ Do Not Invoice Client

**Services Commenced Prior to Approval (as per RFS):** ☒ NO ☐ YES

**Reason for Not Invoicing Client:**

**Description of MSA Impact:**

**Reason for Rejection/ Cancellation/ On Hold (if applicable):**

**STATEMENT OF WORK AUTHORIZATION:**

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| [REDACTED: EMPLOYEE NAME] | [REDACTED: EMPLOYEE NAME] 03-Mar-06 |
| Please print your name Date | Please print your name Date |

☐ APPROVED ☐ REJECT ☐ CANCEL ☐ ON HOLD

**SERVICE IMPLEMENTED:** **Date Implemented:**

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| [REDACTED: EMPLOYEE NAME] | [REDACTED: EMPLOYEE NAME] |
| Please print your name Date | Please print your name Date |

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# Statement of Work
# Short Form

| I-Tek Reference Number: | Date Statement of Work Created: | Client: |
|---|---|---|
| PD00584 | 03-Mar-06 | ☒ Yukon Electric<br>☒ Yukon Energy<br>☒ Northland Utilities Ltd. (NWT)<br>☒ Northland Utilities Ltd. (Yellowknife) |
| **Client Reference Number:** | **Description:** | **Initiator(s):** |
| | Change Sec Dep Intl | [REDACTED: EMPLOYEE NAME] |

| PMTR Number *(if applicable)*: | Ticket Number *(if applicable)*: | ☐ Notify Finance |
|---|---|---|

| Areas Impacted: | Request Type: | | |
|---|---|---|---|
| ☒ Applications | ☐ Parameter Changes | ☒ Account Update |
| ☐ Technologies | ☐ Policy Changes | ☐ Reports/Extracts |
| ☐ Call Center and Billing Services | ☐ Process Changes | ☐ Work Queue |
| ☐ Customer Choice | ☐ Functionality Changes | ☐ Other: _____ |

| Work Location: | Approval Required By (Date): 10-Mar-06 |
|---|---|
| 5 AC Edmonton | Scheduled Implementation Date: 01-Mar-06 |

| Charge Allocation: | MSA Impact: |
|---|---|
| ☐ ENHANCEMENT | ☐ NO |
| ☒ MAINTENANCE | ☐ YES (PTO for detail) |

**Description of Service / Information Requested:** ☐ SEE ATTACHED

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The North of 60 (N60) Companies has requested ATCO I-Tek to update the annual interest rates on deposits for Companies 04, 05, 06 and 08 as per government legislation.

**Service / Response Delivered:**

ATCO I-Tek will update the interest rates on deposits as defined below:

- Company 04 (Yukon Energy Corporation) – change to 3.00% from 2.25
- Company 05 (Yukon Electrical Company Limited – change to 3.00% from 2.25
- Company 06 (Northland Utilities (NWT) Limited ) – change to 3.37% from 2.54
- Company 08 (Northland Utilities (Yellowknife) Limited) – change to 3.37% from 2.54

*** Time & Material**
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*** Fixed Fees**
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ATCO I-Tek

# Statement of Work
# Short Form

**ESTIMATE*** ☒ Yukon Electric 25% ☒ Yukon Energy 25%
☒ Northland Utilities Ltd. (NWT) 25% ☒ Northland Utilities Ltd. (Yellowknife) 25%

| Deliverables | Estimate |
|---|---|
| Update annual interest rates on deposits | 200.00 |
| | |
| | |
| **Total** | **$ 200.00** |

☐ Included in MSA ☒ Time & Material ☐ Do Not Invoice Client

**Services Commenced Prior to Approval (as per RFS):** ☐ NO ☒ YES

**Reason for Not Invoicing Client:**

**Description of MSA Impact:**

**Reason for Rejection/ Cancellation/ On Hold (if applicable):**

**STATEMENT OF WORK AUTHORIZATION:**

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| **[REDACTED: EMPLOYEE NAME]** | **[REDACTED: EMPLOYEE NAME]** 03-Mar-06 |
| Please print your name Date | Please print your name Date |

☐ APPROVED ☐ REJECT ☐ CANCEL ☐ ON HOLD

**SERVICE IMPLEMENTED:** **Date Implemented:** 01-Mar-06

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| **[REDACTED: EMPLOYEE NAME]** | **[REDACTED: EMPLOYEE NAME]** 03-Mar-06 |
| Please print your name Date | Please print your name Date |

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# Statement of Work
# Short Form

| I-Tek Reference Number: PD00622 | Date Statement of Work Created: 26-Jun-06 | Client: ☒ Yukon Electric ☒ Yukon Energy ☒ Northland Utilities Ltd. (NWT) ☒ Northland Utilities Ltd. (Yellowknife) |
|---|---|---|
| **Client Reference Number:** | **Description:** Change GST to 6% | **Initiator(s):** REDACTED: EMPLOYEE NAME |

| PMTR Number *(if applicable)*: P1474 | Ticket Number *(if applicable)*: | ☐ Notify Finance |
|---|---|---|

| Areas Impacted: | Request Type: | | |
|---|---|---|---|
| ☒ Applications | ☐ Parameter Changes | ☐ Account Update | |
| ☐ Technologies | ☐ Policy Changes | ☐ Reports/Extracts | |
| ☐ Call Center and Billing Services | ☐ Process Changes | ☐ Work Queue | |
| ☐ Customer Choice | ☐ Functionality Changes | ☒ Other: Rate change GST to 6% | |

| Work Location: | Approval Required By (Date): 27-Oct-06 |
|---|---|
| 5 AC Edmonton | Scheduled Implementation Date: 04-Jul-06 |
| **Charge Allocation:** ☒ ENHANCEMENT ☐ MAINTENANCE | **MSA Impact:** ☒ NO ☐ YES (PTO for detail) |

**Description of Service/ Information Requested:** ☐ SEE ATTACHED

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As of July 1st 2006, the GST will be reduced from 7% to 6% as per federal government decision.

The CRA guidelines (http://www.cra-arc.gc.ca/agency/budget/2006/gstrateqa-e.html) established that invoices issued on or after July 1st, 2006 will apply GST of 6%, regardless when the service was provided.

N60 has requested ATCO I-Tek to transition from 7% to 6% rate of GST for July 1, 2006.

Scenarios to address are:

1) Normal Billing – Customers billed for a consumption period that will cross June 30.
2) Cancel and Re-bill.

**Approach:**

**1) Normal Billing – Customers billed for a consumption period that will cross June 30:**

- GST is payable on the earlier of the day the payment is made and the day the invoice is issued. Invoices issued and dated after July 1, 2006 for goods and services performed before and/or after that date will be subject to a 6% GST rate on the total amount.
- Normal billing charges may be calculated on an account prior to July 1, 2006 but not statemented until after that date. Based on ATCO I-Tek's interpretation of the CRA guidelines, all charges calculated prior to July 1, 2006 which have **not** been statemented as of that date with a GST calculation of 7% will be cancelled and recharged at a 6% GST rate.

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
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ATCO I-Tek

# Statement of Work
# Short Form

- If there is an undue delay in issuing an invoice, GST becomes payable when the invoice would have been issued if there had been no delay. If the value of supply is not ascertainable therefore a delay occurs in calculating a charge, this is considered normal business practice and does not fall under the definition of "undue delay". GST is payable when the value becomes ascertainable. Therefore charges which cannot be calculated as of July 1, 2006 or charges which are unstatemented as of that date, do not fall under the definition of "undue delay".

**2) Cancel and Re-bill:**

The following outlines ATCO I-Tek's interpretation of the CRA guidelines regarding cancel/re-bills:

- A cancel of a charge pertaining to a transaction which was calculated at a GST rate of 7% will also be cancelled using the GST rate of 7%.
- A re-charge processed on or after July 1, 2006 pertaining to a charge which was cancelled with a GST rate of 7%, will be re-charged at a GST rate of 6%.
    - If the re-charge results in a credit or a debit to the customer, the net adjustment is the difference between the charge that was cancelled at a rate of 7% and the re-charge at a rate of 6%.
- A charge period adjustment processed on or after July 1, 2006 pertaining to a charge which was calculated with a GST rate of 7% will be adjusted at a GST rate of 6%.

**Solution Recommendation:**

ATCO I-Tek recommends changing the GST unit price amount from 7% to 6% on July 1, 2006 with an effective date equal to each company's most recent GST production effective date. All charges calculated on or after July 1, 2006 will be calculated at a GST rate of 6%.

All valid distribution charges (including both recurring and one time charges) which have **not** been statemented as of July 1, 2006 with a GST calculation of 7% will be cancelled and re-charged at a 6% GST rate. This is to align with the CRA guidelines which states that invoices issued and dated after July 1, 2006 for goods and services performed before and/or after that date will be subject to a 6% GST rate on the total amount. Charges which are unstatemented as of July 1, 2006 represent normal business practices therefore do not fall under the definition of "undue delay".

a) GST is calculated on distribution charges at the time the charge is created on each account's charge cycle. Distribution charges may be calculated prior to July 1, 2006 but not statemented until after that date.

b) These cancel/re-charges will be reflected in existing Revenue reporting.

c) In order to manage accounts that will not automatically system charge at the new GST rate the following steps will be undertaken:

d) After the last billing cycle of June and prior to the first billing cycle of July 2006, ATCO I-Tek will provide the following extracts from the Master File to N60 for manual review and determination of the appropriate course of action:

- a list of accounts that have been charged reconnect or connect fees with 7% GST that have not yet statemented.
- a list of any unstatemented fees and adjustments which appear on the payment history (PA) screen. This will include cut off for non-payment (CONP) fees, manual revenue (TC65) adjustments, and other miscellaneous charges. The client will review these and manually adjust any accounts which have a transaction which has GST calculated at 7%.
- a list of Contract Consolidated Billing accounts which have billed but have not statemented.
- a list of accounts where the primary account NOBILLED and a sub-account exists which has lights.

e) Any adjustments required on the accounts listed on the extracts provided will be done via a ontime input file containing the appropriate refund of GST transactions (TC50 OP9) or will be manually adjusted by the clients.

f) The clients will also manually handle accounts which have transactions sitting on the Carry file which may have 7% GST calculations, but which have not yet statemented, if there are any such transactions. NOTE: The client has indicated that turn-off transactions on the carry file are not complete, so final bills will not be produced from them.

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ATCO I-Tek

# Statement of Work
# Short Form

**Assumptions:**

- The approach outlined is to be effective both to the ATCO-CIS Distribution System and Old CIS
- Interpretation of CRA guidelines will be assessed by ATCO's taxation group to confirm consensus with approach outlined in RFS Response
- No on-line transactions which calculate GST exist, so the actual rate change will be made on Tuesday, July 4, 2006, prior to July Cycle 1 Billing on July 5, 2006.
- It is anticipated that accounts which appear on the [REDACTED: REPORT&EXTRACT NAME] High Low Register and [REDACTED: REPORT&EXTRACT NAME] Error Register reports do not require any special processing. If any special processing is required, it will be handled manually by the clients.
- Transaction and account testing is not required by the clients (e.g. cancel/rebills, regular cycle bills, turn ons, etc).

**Service / Response Delivered:**

The following services will be performed by ATCO I-Tek for this SOW:

1) Perform impact assessment
2) Design rate change
3) Perform and test rate changes
4) Client informed of test results to provide approval to elevate rate change
5) Run a set of test extracts to identify charges on accounts that will need to be manually adjusted, and to verify extract formats and data elements
6) Incorporate client feedback into extracts
7) After the final June cycle runs, provide the supporting data extracts to identify charges that will need to be manually adjusted by the client
8) Prepare a one-time file containing appropriate refund of GST transactions (TC50 OP9) to execute after the rate change and before the 1st billing cycle of July to adjust accounts
9) Post implementation support

The following services will be performed by N60 for this SOW:

1) Confirm consensus of CRA guidelines with approach outlined in this SOW-SF
2) Provide direction on charges that cannot be cancelled
3) Perform some manual adjustments via keyplus
4) Review extracts and Carry file in order to make appropriate manual adjustments to accounts that cannot be managed by the system

The estimate contained in this SOW will expire in 3 months from the Approval Required By Date indicated above.

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.
*** Fixed Fees**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement and as indicated in the ESTIMATE section above.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

ATCO I-Tek

# Statement of Work
# Short Form

**ESTIMATE*** ☒ Yukon Electric 25% ☒ Yukon Energy 25%
☒ Northland Utilities Ltd. (NWT) 25% ☒ Northland Utilities Ltd. (Yellowknife) 25%

| | **Estimate** |
|---|---|
| Applications: Requirements and analysis | 700 |
| Design, construction and testing | 2,500 |
| User acceptance testing | 600 |
| Production implementation and post implementation support | 1,400 |
| CPU charges | 1,700 |
| **Total** | **$6,900** |

☐ Included in MSA ☒ Time & Material ☐ Do Not Invoice Client

**Services Commenced Prior to Approval (as per RFS):** ☐ NO ☒ YES

**Reason for Not Invoicing Client:**

**Description of MSA Impact:**

**Reason for Rejection/ Cancellation/ On Hold (if applicable):**

**STATEMENT OF WORK AUTHORIZATION:**

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| Please print your name Date | Please print your name Date |

☐ APPROVED ☐ REJECT ☐ CANCEL ☐ ON HOLD

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ATCO I-Tek

June 30, 2006

**Attention: Doug Tenney, General Manager**

The Yukon Electrical Company Limited
Head Office
P.O. Box 4190
100, 1100 – First Avenue
Whitehorse, Yukon Y1A 3T4

COPY

Dear Mr. Tenney:

**Re: Notice of Replacement of Existing CIS for North of 60 Companies**

The purpose of this letter is to inform you of ATCO I-Tek Business Services' offer to extend your current Statement of Work for billing services until December 31, 2007, from the current end date of December 31, 2006. Current terms and pricing would remain in place, subject to a CPI adjustment effective January 2007.

The current service arrangement will no longer be available after December 31, 2007 as we intend to retire the CIS system now serving the North of 60 Companies at that time. By extending the existing SOW, we are providing you with 18 months written notice as per Section 2 of the Statement of Work AE062, *Provision of Service for the North of 60 Companies (Amended May 15, 2003).*

We will be pleased to work with you and your representatives to investigate the best solution to meet the business requirements of the North of 60 Companies.

As you know, some work is already underway to identify and evaluate system options to meet your billing needs. A key component of that process will be to evaluate the current business processes related to your billing service to reflect the functionality of your replacement system and the overall business solution you select.

We will work with your people to develop a new Statement of Work related to replacing your current billing system and the related service arrangement, including implementation and transition requirements.

Please contact me to advise of your decision with respect to the offer to extend your existing SOW. If you agree with the proposed approach I will draw up the necessary amendment documentation.

ATCO I-Tek Business Services is committed finding the best CIS option for all parties and working with your team to ensure a seamless implementation and transition to the new system.

Sincerely,

Stephen Chan
Director, Business Development and Corporate Services

cc: Sett Policicchio, President, ATCO Electric
R. L. (Bobbi) Lambright, President, ATCO I-Tek
Wendy Scramstad, Supervisor Customer Service, The Yukon Electrical Company Limited
Barry Fossbakken, Supervisor Client Support, Information Technology Services, ATCO Electric

10035 – 105 Street, Edmonton, Alberta T5J 1C8
Tel: 780-420-7875 Fax: 780-420-3157
www.atcoitek.com

ATCO I-Tek

August 3, 2007

**Attention: Jerome Babyn, General Manager**

COPY

The Yukon Electrical Company Limited
Head Office
P.O. Box 4190
100, 4100 – First Avenue
Whitehorse, Yukon Y1A 3T4

Dear Mr. Babyn:

**Re: Notice of Statement of Work Extension for Provision of Services for North of 60 Companies (AE062)**

The purpose of this letter is to inform you of ATCO I-Tek Business Services' offer to extend your current Statement of Work for billing services until June 30, 2008, from the current end date of December 31, 2007. Current terms and pricing would remain in place, subject to a CPI adjustment effective January 2008.

On June 30, 2006 a letter was sent to Doug Tenney requesting that we extend the Statement of Work from December 31, 2006 to December 31, 2007. It was agreed at that time that the current terms and pricing would remain in place, subject to a CPI adjustment effective January 2007. Doug Tenney formally accepted this offer on August 3, 2006.

As part of the billing solution currently being completed there is the need to develop a new Statement of Work for the ongoing provision of service for the North of 60 Companies. The effort to create this Statement of Work will be completed in conjunction with the implementation of the new billing system. Upon transition to the new billing system the new agreement will take effect.

Please contact me to advise of your decision with respect to the offer to extend the existing Statement of Work.

Sincerely,

Vivian Cheng
Vice-President, Business Solutions & Applications

cc: Sett Policicchio, President, ATCO Electric
R. L. (Bobbi) Lambright, President, ATCO I-Tek
Wendy Scramstad, Supervisor Customer Service, The Yukon Electrical Company Limited
Barry Fossbakken, Supervisor Client Support, Information Technology Services, ATCO Electric
Duane Kotun, Manager, Distribution Accounts

10035 - 105 Street, Edmonton, Alberta, Canada T5J 1C8
Tel: 780-420-7875 Fax: 780-420-7746
www.atcoitek.com

**NORTHLAND UTILITIES ENTERPRISES LTD.**
An ATCO Company

March 18, 2003

ATCO I-Tek
10035 – 105 Street
Edmonton, Alberta
T5J 1C8

**Attention: Phil Schmidt, Client Relationship Manager**

Dear Phil:

**Re: Extension of the Statement of Work for Provision of Service for North of 60 Companies**

It is apparent that there is a great deal of uncertainty regarding options for replacing the CIS system currently used by the North of 60 Companies before the expiration of the existing service agreement in December 2004. Due to upcoming regulatory filing requirements and the needs of Yukon Energy, an external user of the system, we are respectfully requesting an extension of the existing terms and conditions of the contract until December 2006. We recognize that prior to that date a replacement system may be identified by I-Tek which meets our needs and expect that the contract extension would include a clause making such a change possible.

Please advise us in writing by April 15th 2003 whether the requested contract extension will be granted. It is imperative that we resolve this issue as soon as possible.

We wish to thank you for your anticipated co-operation in helping us address this very important issue for our customers and shareowners.

Please contact me at (780) 420-7893 if you have any question.

Yours truly,

Tracy Breault, CA
Supervisor Financial Services
Northland Utilities Enterprises Ltd.

cc: D. Morgan, Northland Utilities (NWT) Limited
J. Babyn, Northland Utilities (Yellowknife) Limited
P. Goguen, Northland Utilities Enterprises Ltd
W. Scramstad, Yukon Electrical Company Limited
R. Spencer, ATCO Electric
S. Sharuga, ATCO I-Tek

# Statement of Work

Master Services Agreement (MSA):
ATCO I-Tek Business Services Ltd. and ATCO Electric

***Provision Of Service For North of 60 Companies***

**Statement of Work Number: AE062**

**Amended May 15, 2003**

**For: ATCO Electric Limited**

**Provided by: ATCO I-Tek Business Services Ltd.**

Document Version 2.0

Date Created: July 4, 2002
Last Modified: May 14, 2003
Prepared by: Phil Schmidt

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# 1 Introduction

## *1.1 Amendment May 15, 2003*

Statement of Work AE062 effective February 1, 2002, has been amended to include the following:

(1) Updated ATCO I-Tek confidentiality and copyright clauses

(2) Added clause to include an option to replace the existing CIS prior to December 31, 2006

(3) Changed the Term ending date from December 31, 2004 to December 31, 2006

(4) Updated the Pricing, Fee Schedule to reflect the 2003 rates

(5) Updated the Pricing, Time and Materials Fee Schedule to be consistent with the existing Utilities contracts Time and Materials Fee Schedule.

## *1.2 Purpose*

The purpose of this Statement of Work is to identify the Services, Pricing and Term of Service which will be provided to the North of 60 companies on behalf of ATCO Electric using CIS. Services shall be provided to

- Northland Utilities (NWT)
- Northland Utilities (Yellowknife)
- Yukon Energy
- Yukon Electric

It is not a comprehensive list of all business policies or detailed procedures.

The Services described herein are directly related to the Client's provision of electricity distribution services, electric energy and meter data management.

## *1.3 Replacement of Existing CIS*

In the event that ATCO I-Tek Business Services Ltd. identifies the need to replace the existing CIS prior to December 31, 2006 with a new CIS that meets the needs of the Client companies, and the cost of such new CIS is deemed to be competitive in the marketplace, ATCO I-Tek Business Services Ltd. will prepare a Statement of Work for the fees associated with implementing the new CIS for the Client as well as the ongoing fees. Upon receiving written approval from the Client, not to be



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unreasonably withheld, ATCO I-Tek Business Services Ltd. will take steps to implement the new CIS.

## 1.4 *How this Document is Organized*

The Supplier's service offering is described in the sections in Appendix A as follows:

- Account Management: The support services the Supplier provides to the Client to assist with the Client's management of Accounts.
- Revenue Management: The services the Supplier provides to manage charges and adjustments including calculations, quality assurance and how bills are prepared.
- Receivables Management: The services the Supplier provides related to payments, credit adjustments and credit-related activities for accounts receivable.
- Financial Management: The services the Supplier provides for balances and controls internal accounts and Services, provides financial reporting and other Services related to the Client's third party accounts.
- Consulting and Special Services: A description of other Services the Supplier can provide to the Client.
- Administration: How the Supplier and the Client work together to deliver the services described herein.

## 1.5 *Standard vs. Optional Services*

This document describes standard Services and optional Services provided by the Supplier.

Pricing for standard Services is included in this Statement of Work.

Pricing for optional Services may also be described herein, or, will be defined by the Client and the Supplier in an additional Statement of Work or Change of Service Request.

The section(s) where costs are defined in the Fee Schedule are noted throughout this document as indicated below. More than one fee schedule may apply to one service, e.g., when multiple work areas are involved or if a systems or printing fee also applies.

*Fee Schedule: Base Billing Services + Pass Through Charges*



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## 1.6 Assumptions

The Client provides all wires-related products, services and energy and the Client is solely responsible for billing Customers for these products and services.

The Supplier provides these services using CIS to manage the Accounts. The Client is responsible for making the necessary arrangements with ATCO Electric Ltd. to ensure the availability of CIS for this purpose.

The Supplier provides behind-the-scenes billing support to the Client. The Client is the primary and direct contact for all communications with Customers unless otherwise described herein, e.g., when the Supplier sends credit notices directly to Customers.

The Services described herein are based on Client policies and system parameters in effect at the time of signing. Changes to these policies or parameters may require a Statement of Work or Change of Service Request.

The Supplier will coordinate directly with the Client to provide the services described herein.

All services described herein are provided in written or verbal English only.

## 1.7 Definitions

Capitalized terms used in this schedule which are not otherwise defined in this schedule shall have the meanings ascribed to them in the General Terms and Conditions.

**Account:** means the Customer's account for the service provided by the Client including basic Customer information (e.g., name), information on the service provided (e.g. residential electricity) and statementing information, (e.g., cycle and frequency).

**Agents:** A company authorized by a Customer to manage their day to day affairs with Client.

**AMR:** Automated Meter Reading

**CIS:** The Customer Information System used to manage the Client's accounts. Commonly referred to as 'old CIS', the system is a text-screen, mainframe based system.

**Client:** For this Statement of Work, means the companies that have contracted the Supplier, through the ATCO Electric Master Services Agreement, to provide the services described herein. The companies include:

- Northland Utilities (NWT)



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- Northland Utilities (Yellowknife)
- Yukon Energy
- Yukon Electric

**Company Use Accounts**: Accounts set up for Client for their own use, e.g., for electricity required to operate a substation or other company facility.

**DataCap:** Hardware and software used by ATCO Electric to capture and download meter reads.

**Distributor:** The company that delivers energy to a site. Also referred to as a wires service provider (WSP).

**Distribution Charges:** Charges from Client to the Customer for the distribution and transmission of electricity to a site.

**Field Orders:** CIS generated orders requesting Client to do work at a specified site.

**Idle Service:** A site that is not connected.

**Mass:** means over twenty-five.

**Pre-authorized Payment Plan (PPP):** a feature that allows Customers to have funds automatically withdrawn from their bank account to pay their bills.

**Services:** The services provided to the Client by the Supplier related to this Statement of Work.

**Site:** the location where electricity service is provided to a Customer.

**Supplier:** ATCO I-Tek Business Services

**Wires Service Provider:** Client.

# 2 Term

ATCO I-Tek Business Services will commence performance of the Services effective February 1, 2002 and shall provide the services for a term ending December 31, 2006.

ATCO I-Tek Business Services will provide ATCO Electric with 18 months written notice of renewal options.



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# 3 Pricing

The Client shall pay ATCO I-Tek Business Services the following rates for Services:

## Base Billing Services

| | | |
|---|---|---|
| Monthly Base Fee | $1.23 | Per Service Account (S/A) |

## Incremental Billing Services

| | | |
|---|---|---|
| Additional Processing of S/A | $0.62 | Per S/A |
| Additional Single-sided Pages | $0.09 | Per Page |
| Additional Inserts | $0.03 | Per Insert |
| Additional Folds | $0.0005 | Per Inserted Fold |
| Billing Specialist | $51.45 | Per Billable Hour |
| Incremental Maintenance Analyst | $129.00 | Per Billable Hour |

## Additional Services

| | | |
|---|---|---|
| Price Schedule Value Changes | $1000.00 | Price Schedule Table Change Request |
| Fax or E-mail | $0.21 | Per Transaction |
| Letter Printing | $0.21 | Per Page |
| Additional Statement Copies | $1.29 | Per Statement/Month |

## Time and Materials Rates

Specialized labor rates other than identified above will be defined in the Statement of Work or Change of Service Request.

## Pass Through Charges

| | | |
|---|---|---|
| Postage, Envelopes, Paper, Long Distance Phone Charges, Courier Charges, Archiving Costs | Fee Charged | Monthly Pass Through |

| | | |
|---|---|---|
| **System Processing Fee** | $14.92 | Per CPU Minute |



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## 3.8 Base Billing Services

Billing Services includes the provision of 'basic services' which includes billing services, CIS maintenance and processing and CMS Maintenance and processing.

Base Billing Services includes:

- Daily balancing of controls and bill check to verify accuracy of the billing run and the calculations of bills
- Monthly reconciliations to FIS
- Transfer of cash through inter-company payments
- Issue of refund cheques
- Create and input VPF for all companies
- Handle bill messaging and inserts
- Review and monitor transactions that error off system

ATCO I-Tek Business Services will provide up to **175** hours per month for Billing Services. Hours in excess of 175 in any one calendar month will be charged at the Incremental Billing Specialist rate.

### Maintenance

ATCO I-Tek Business Services will provide up to 160 hours of system maintenance per month. Hours in excess of 160 in any one calendar month will be charged at the incremental Maintenance Analyst rate.

### Printing

Includes the following for each service account:

- One, single page, double-sided bill per month including printing of bill messages and folding and inserting into the envelope.
- One copy of standard system generated reports. Additional printing will incur an incremental charge as set our in the Additional Services section.

### Processing

Includes:

- System (mainframe) processing of each service account once per month
- Additional processing will incur charges as per the Incremental Billing Services Fee



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**Minimum Monthly Fee**

The minimum monthly charge for Base Billing Services will be the greater of the above charges or $30,000.00 per month.

## 3.9 Incremental Billing Services Fee

### 3.9.1 Additional Processing Of Service Accounts

If a service account requires system processing more than once per month, this fee applies to each subsequent occurrence.

### 3.9.2 Additional Single-Sided Pages

Applies to each additional page and includes inserting and folding.

### 3.9.3 Inserts and Folds

Fee includes the inserting of Client-supplied inserts into envelopes. If the insert requires folding, the fold fee will also be charged.

### 3.9.4 Hourly Rates

These rates apply to services outlined above where an hourly rate is denoted or when the number of hours exceeds the specified maximum

### 3.9.5 Billing Specialist

Applies to Billing Services in excess of 175 hours in any one calendar month.

### 3.9.6 Incremental Maintenance Analyst

Applies to maintenance in excess of 160 hours in any one calendar month.

## 3.10 Additional Services

### 3.10.1 Price Schedule Value Changes

This fee is for the provision of services related to changing unit price values in a price schedule, e.g., changing a flat fee from $5 to $7 or a usage fee from $.05 / kWh to $.06 / kWh, as described in Schedule A-Definition of Services and as shown below.

Example:

*Fee Schedule: Price Schedule Value Changes*

The fee is charged for each individual request. If individual changes are combined into a single request, one price schedule change request will be assessed.



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Consultation required by the Client during the price schedule change is charged at the Time and Materials rates.

### 3.10.2 Fax or E-mail

This fee applies to faxing or e-mailing account information to either the Client, a Customer or an authorized agent of the Customer.

### 3.10.3 Letter Printing

This fee applies to any system-generated letter sent to the Customer. Postage and envelopes are billed separately as a Pass Through Charge.

### 3.10.4 Additional Statement Copies

This fee applies when the Supplier, at a Customer's request, prepares and sends an additional copy of a statement to the Customer or an authorized agent of the Customer.

## 3.11 Time and Materials Rates

Labour is charged on an hourly basis for the following types of Services:

(a) Statements of Work and Change of Service Requests,

(b) Development or modification and delivery of training required when changes to the Client's business practices or service offerings and staff necessitate,

(c) For other services required and not elsewhere defined.

## 3.12 Pass Through Charges

The Supplier, on behalf of the Client, can contract for Services as authorized by the Client and pass the charges onto the Client. A management fee of fifteen (15%) percent may be assessed on any Pass-Through Changes. These services are described in Appendix A-Description of Services.

Example:

*Fee Schedule: Pass Through Charges*



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## 3.13 System Processing Fee

This fee is charged for mainframe processing required for incremental services, e.g., additional reporting.

This fee also applies to mainframe processing required as a result of Statements of Work or Change of Service Requests.

This fee does not apply to processing for basic services that are included in the base charges.



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# 4 PROJECT STATEMENT OF WORK SIGN-OFF

Our signatures below signify that we have the authority to commit to the terms of this document on behalf our respective companies and have reviewed this document, and have found it to be a complete and true representation of our business and project requirements. We understand that if our requirements change or if we have additional requirements, the changes and additions will be evaluated and must be approved through the standard Change Control Process and may require a Statement of Work or Change of Service Request.

| APPROVER | DATE |
|---|---|
| Bobbi Lambright<br>President<br>ATCO I-Tek Ltd. | May 15, 2003 |
| Owen Edmondson<br>Vice President, Finance<br>ATCO Electric Ltd. | July 25 03 |



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# Appendix A – Description of Services



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# Appendix B – Statement Samples



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ATCO I-Tek

# Statement of Work
# Short Form

| I-Tek Reference Number: | Date Statement of Work Created: | Client: |
|---|---|---|
| **PD00646** | **08-Aug-06** | ☒ Yukon Electric<br>☒ Yukon Energy<br>☐ Northland Utilities Ltd. (NWT)<br>☐ Northland Utilities Ltd. (Yellowknife) |
| **Client Reference Number:** | **Description:**<br>**Change Sec Dep Intl** | **Initiator(s):**<br>**REDACTED: EMPLOYEE NAME** |

| PMTR Number *(if applicable)*: P1031 | Ticket Number *(if applicable)*: | ☐ Notify Finance |
|---|---|---|

| Areas Impacted: | Request Type: | | |
|---|---|---|---|
| ☒ Applications | ☒ Parameter Changes | ☐ Account Update | |
| ☐ Technologies | ☐ Policy Changes | ☐ Reports/Extracts | |
| ☐ Call Center and Billing Services | ☐ Process Changes | ☐ Work Queue | |
| ☐ Customer Choice | ☐ Functionality Changes | ☐ Other: _____ | |

| Work Location: | Pricing Valid Until: | N/A |
|---|---|---|
| 5 AC Edmonton | Approval Required By (Date): | N/A |
| | Scheduled Implementation Date: | 08-Aug-06 |

| Charge Allocation: | MSA Impact: |
|---|---|
| ☐ ENHANCEMENT | ☒ NO |
| ☒ MAINTENANCE | ☐ YES (PTO for detail) |

**Description of Service / Information Requested:** ☐ SEE ATTACHED

*ATCO I-Tek has redacted certain information from the enclosed document and replaced vendor specific names and products with generic descriptions. The redacted and replaced information is the confidential information of ATCO I-Tek and ATCO I-Tek prohibits its disclosure to any person. The disclosure of such confidential information would cause damage to ATCO I-Tek, and in some circumstances would compromise the security of ATCO's computing environment.*

*ATCO I-Tek permits Yukon Electrical Company Limited to disclose the remaining information contained in the attached document strictly as part of their current respective application before the Yukon Public Utilities Board - 2008-2009 General Rate Application. This permission is granted subject to the condition that the use of the disclosed information shall be restricted to this specific filing and shall not be used by any person for any other purposes.*

The North of 60 (N60) Companies have requested ATCO I-Tek to update the annual interest rates on deposits for companies 04 and 05, as per government legislation.

**Service / Response Delivered:**

ATCO I-Tek will update the interest rates on deposits as defined below:

- Company 04 (Yukon Energy Corporation) –change to 4.00% from 3.00%
- Company 05 (Yukon Electrical Company Limited) – change to 4.00% from 3.00%

The interest rate changes were implemented effective August 8, 2006.

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.
*** Fixed Fees**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement and as indicated in the ESTIMATE section above.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

ATCO I-Tek

# Statement of Work
# Short Form

**ESTIMATE*** ☒ Yukon Electric 50% ☒ Yukon Energy 50%
☐ Northland Utilities Ltd. (NWT) ____% ☐ Northland Utilities Ltd. (Yellowknife) ____%

| Deliverables | Estimate |
|---|---|
| Requirements and Analysis | $360.00 |
| Design, Construction and Unit Testing | $120.00 |
| Production Implementation | $ 24.00 |
| Test Environment Charge | $176.00 |
| **Total** | **$ 680.00** |

☐ Included in MSA ☒ Time & Material ☐ Do Not Invoice Client

**Services Commenced Prior to Approval (as per RFS):** ☐ NO ☒ YES

**Reason for Not Invoicing Client:**

**Description of MSA Impact:**

**Reason for Rejection/ Cancellation/ On Hold (if applicable):**

**STATEMENT OF WORK AUTHORIZATION:**

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| REDACTED: EMPLOYEE NAME | REDACTED: EMPLOYEE NAME |
| Please print your name | Please print your name |
| Date | August 21, 2006 Date |

☒ APPROVED ☐ REJECT ☐ CANCEL ☐ ON HOLD

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# Statement of Work

*N60 Billing System Replacement Project*

*Phase I: Solution Evaluation*

Project Number: PD00673

Provided to: The North of 60 Companies
c/o ATCO Electric Ltd.

Provided by: ATCO I-Tek Business Services Ltd.

*ATCO I-Tek has redacted certain information from the enclosed document and replaced vendor specific names and products with generic descriptions. The redacted and replaced information is the confidential information of ATCO I-Tek and ATCO I-Tek prohibits its disclosure to any person. The disclosure of such confidential information would cause damage to ATCO I-Tek, and in some circumstances would compromise the security of ATCO's computing environment.*

*ATCO I-Tek permits Yukon Electrical Company Limited to disclose the remaining information contained in the attached document strictly as part of their current respective application before the NWT Public Utilities Board - 2008-2009 General Rate Application. This permission is granted subject to the condition that the use of the disclosed information shall be restricted to this specific filing and shall not be used by any person for any other purposes.*

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## STATEMENT OF CONFIDENTIALITY

This document is the proprietary and confidential information and property of ATCO I-Tek Business Services Ltd. (the "Supplier") and is governed by the obligations of non-disclosure and non-use in the Master Services Agreement (the "MSA") between the Supplier and ATCO Electric Ltd. (the "Client"). Without limiting the foregoing, by accepting possession of this document, you, and any third party agents, consultants or contractors engaged by you, agree to keep the contents of this document in strict confidence, and not use, duplicate, or disclose its ideas or contents for any purpose other than evaluating the ability of the Supplier to provide the services described herein, and for the purposes permitted under the Master Services Agreement, unless otherwise agreed to in writing by the Supplier.

Without limiting the foregoing, disclosure of any of this information to any third party would be disclosure of trade secrets of the Supplier or other parties (including scientific, technical, commercial or financial information) supplied in confidence and would (i) prejudice significantly the competitive position of the Supplier, (ii) interfere significantly with the contractual and other negotiations of the Supplier, and (iii) result in material harm to the Supplier.

### Revision History

| Version Number | Revised By | Revision Date | Summary of Changes |
|---|---|---|---|
| 1.0 | ATCO I-Tek | September 21, 2006 | Original Document |
| 2.0 | ATCO I-Tek | October 16, 2006 | Client feedback incorporated |
| 3.0 | | | |
| 4.0 | | | |
| 5.0 | | | |

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# 1 Document Purpose

The purpose of this Statement of Work (SOW) is to describe the deliverables with the associated estimated costs that will be provided by ATCO I-Tek under the terms and conditions outlined in the ATCO I-Tek Business Services Master Services Agreement, with respect to the evaluation of the replacement of the current billing system utilized by four northern electric companies.

# 2 Executive Summary

The Old CIS Billing System is currently utilized by the following northern electric companies:

- Northland Utilities (Yellowknife) Limited part of the ATCO Group of Companies – located in Yellowknife, North West Territories
- Northland Utilities (NWT) Limited part of the ATCO Group of Companies – located in Hay River, North West Territories
- Yukon Electrical Company Limited part of the ATCO Group of Companies – located in the Yukon Territory
- Yukon Energy Corporation – located in the Yukon Territory

The three ATCO Group of Companies are referred to as the North of 60 Companies (N60). Any new billing system will be offered for use to Yukon Energy possibly allowing for lower costs for all.

For the N60 companies, the billing system plays a key role in allowing them to meet legislated/regulatory obligations and business requirements. For each of the companies, it is essential that billing and revenue reporting information be properly maintained to ensure timely, consistent and accurate information is available for both internal and external use.

The Old CIS provides the following business functions; customer and account management, service orders maintenance, billing, accounts receivable and general ledger management, credit and collections, payment remittances processing, meter reading management, organization support and query and reporting.

The Old CIS Billing System was a vendor application built over 30 years ago that has been in use by the utility companies in ATCO since late 1979. With the evolvement of information technology over the last 30 years, the cost of maintaining and operating the old technology platform has become increasingly high. The N60 companies want to evaluate alternatives before having to justify passing the high cost to the small customer base.

The purpose of this Statement of Work is to present the scope and estimated costs for the Supplier to work with the Client to provide analysis of available options to replace the current Old CIS Billing System. This analysis will provide information that will allow the evaluation of a potential in-house solution, as well as available third-party solutions against the current system based on business functionality,

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technical feasibility, one time project costs, as well as ongoing operating and support costs and vendor support.

The project is expected to commence June 2006 and be complete by the November 10, 2006 for an estimated cost of $89,586.

# 3 Assumptions

The following is a list of assumptions the Supplier has made in developing this Statement of Work:

- Supplier and Client resources will be available upon the project start date.
- The Client will remain an active participant in performing the work associated with this Statement of Work and will commit appropriate resources.
- The Client will make subject matter experts available to the Supplier a minimum of eight to sixteen hours per week.

# 4 Project Overview

The Old CIS Billing System was originally purchased in the late 1970s to provide customer care and billing functionality to all of the utilities in the ATCO Group of Companies. Over the years, the ATCO utility companies have significantly enhanced and customized the functionality of the Old CIS Billing System due to changes in business requirements. The application program code has been supported in-house for over 25 years.

As business requirements changes, the system architecture and underlying technologies can reach their limitation making enhancements to meet the business requirements no longer viable. This was the case with the utility business model changes for the Alberta deregulation of electric and gas utilities. Old CIS could not be enhanced to accommodate the complexity of the changes and resulted in ATCO Gas and ATCO Electric moving from the Old CIS Billing System to a new customer care and billing system. The Old CIS Billing System is now only used by the N60 companies and Yukon Energy Corporation.

The information technologies have evolved significantly over the last 30 years. The IT industry no longer builds applications using the technologies, such as sequential file for master data storage and processing, duplicated shadow database and non-relational database management system which is currently used by Old CIS. As a result, the support costs for retaining these technologies have become increasingly high due to the diminishing number of applications sharing the costs of the dated technologies and supporting tools.

In addition, Old CIS handled the billing of over one million customer accounts prior to ATCO Gas and ATCO Electric moving to a new customer care and billing system. Now Old CIS only handles approximately 30,000 accounts for the four northern

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electric companies. The small customer base will also make the justification of the increasing support costs difficult.

The Old CIS Billing System has the following business functionality:

- Customer and Account Management - facilities necessary for managing customer, account, and service location activities
- Service Order Maintenance – tracks information of all service orders initiated by customers, employees, and the system
- Billing – calculates bill usage and applies pricing schedules to the bill usage as well as supports billing adjustments and cancel/re-bill of prior period billings for each account
- Invoice Production - produces individual or consolidated invoices on cycle or off cycle
- Accounts Receivable Management – manages the accounts receivable for both the individual account and summarized at different levels
- General Ledger Management – electronically provides financial data to N60 companies' financial systems
- Credit & Collections –manages activities related to deposits, credit tracking, and collections for delinquent customer accounts
- Payment Remittances Management – records payments, credit/debit transactions, returned cheques, and posts payments and transactions to accounts
- Meter Management – manages all in-stock and in-service meters
- Meter Reading Management – collects meter readings, calculates measured usage and validates meter reading and measured usage
- Price Schedule Administration – provides facility to maintain test and production price schedules as well as facility to perform generic testing of price changes
- Query/Reporting – provides scheduled production reports and ad hoc requests for information
- System Administration – provides facility for clients to maintain system parameters that controls system operations

This phase of the project will focus on evaluation of alternatives for the replacement of Old CIS.

# 5 Work Location

- Edmonton, Alberta, ATCO Centre, 10035 – 105 Street

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# 6 Effective Dates

In the event that the Client requests that the Supplier change the priority of current project work, the Client acknowledges that the Supplier may be required to adjust its resource allocation prior to the commencement of or while working on this project. In this instance, the Project Plan developed to support this Statement of Work may be impacted and the Client may incur additional costs to complete the project objectives, or may be required to alter the completion date of this project.

# 7 Approach

The project will consist of seven main activities:

- Requirements Gathering
- Market Investigation & Evaluation of Third-Party Solutions
- Estimation of Integration Required for Each Viable Third-Party Solution
- High-Level Estimation of In-House Solution
- Estimation of Remaining Status Quo on Old CIS
- Evaluation of Potential Solutions
- N60 Management's Recommendation and Preparation of Implementation Estimate

## *7.1 Requirements Gathering*

The N60 Client will define the business requirements for the N60 companies. The Supplier will assist the Client to define the processes for the evaluation of the new billing system alternatives and the criteria for comparison and rating of the alternatives. The Supplier will define the technical requirements.

## *7.2 Market Investigation & Evaluation of Third-Party Solutions*

The Supplier will conduct a market investigation to identify vendor products that best align with the N60 group of companies' business requirements and the ATCO environment. The Supplier will contact the vendors and request that vendors with solutions under consideration provide information on their products and services.

The Supplier and the Client will assess the vendor information as to how well their billing solution meets the requirements and evaluation criteria. The Supplier will document comparisons between companies consisting of the following categories:

- Location – head office location and vendor contact information.
- Description – a brief overview of the type of billing system available.
- System – the type of system or platform the billing system operates on.

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- Functionality – a brief list of functionality and applications the company offers.
- History – a summary of the company's beginning, number of employees, and focal point of their business.
- Customers – outline of the number of customers serviced and their locations.
- Partners – the level of integration with other companies.
- Certification – the level of skilled technical support within the company.
- Implementation – the level and detail of assistance in the transition.
- Support Desk – the technical availability, times, and procedures.
- Case Studies – customer situation and successful billing solution.

The Supplier will contact each vendor, and request a one-day on-site demonstration of their product and address any questions. This session will be attended by both the Client and the Supplier.

After the product demonstration sessions, the Client and the Supplier will perform a high level comparison and rating of major system functions, the system flexibility, the ease of use, the ease of operation, and the underlying technologies. The vendor products will be short-listed.

For each viable short-listed solution, the Client and the Supplier will request each vendor to conduct a one week in-depth Fit Analysis, documenting any customization requirements and providing associated cost. Any chargeable expenses incurred by the vendors will be submitted to the Client.

The Client and the Supplier will attend at least one site visit and, if necessary, one vendor visit to settle a tie between vendor products. The vendor visit, if required, will allow the Client and the Supplier to meet the implementation team and determine their collective expertise and other intangibles that will affect their ability to provide a successful solution.

## *7.3 Estimation of ATCO-Tek Cost for Implementing Vendor Products*

For each short-listed third-party vendor product identified, the Client and the Supplier will work in conjunction with the third party vendors to determine system interfaces, data conversion and hardware and software requirements to implement the solution. ATCO I-Tek and the third parties will develop a cost estimate for the one-time implementation cost as well as on-going operating cost.

## *7.4 Estimation of In-House Solution*

In addition to evaluating third-party solutions, the Supplier will estimate the cost to implement ATCO CIS to support business functions for the N60 companies as well as the on-going operating cost.

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### *7.5 Estimation of Remaining Status Quo on Old CIS*

The Supplier will estimate the cost of continue operating Old CIS, taken into consideration other applications under the same technology platform may be removed at different timeframe.

### *7.6 Comparison of Potential Solutions*

The Client and the Supplier will evaluate the short-listed vendor products, the in-house solution, as well as remaining status quo on Old CIS, based on the following criteria:

- Fit Analysis – Out of the box fit to the business requirements
- Customization Items – Evaluation of customization approach to meet functional gaps in out of the box solution
- Interfaces – Development of interfaces with existing applications
- Total Vendor Costs – Includes out of the box, customization and vendor implementation costs
- Technical Solution – Evaluation of each alternative and how it will integrate and be supported into the ATCO technical environment
- Total Project Costs – Vendor costs and ATCO I-Tek implementation costs dependant for each potential solution
- Ongoing O&M Costs – Operations and maintenance support costs for each potential solution
- Other Important Evaluation Factors – Comparison of client defined critical factors that would impact decision making

## 8 Scope Statement

### *8.1 In Scope*

The scope of this project hereunder includes only the specific tasks and deliverables performed by ATCO I-Tek in delivering the services set forth in this proposal. The full scope of this proposal is included in section seven (7) of this document.

### *8.2 Out of Scope*

The full scope of this proposal is included in section seven (7) of this document.

## 9 Deliverables

The following deliverables will be provided by the Client:

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- Business Requirements
- Product Evaluation Criteria (with support from Supplier as per Section 7.1)

The following deliverables will be provided by the vendors:

- Vendor Information
- Vendor Production Information
- Vendor Product Demonstration
- Vendor Fit Analysis
- Vendor Product Customization and Cost
- Vendor Product Interfaces
- Vendor Implementation Cost

The following deliverables will be provided by ATCO I-Tek:

- Potential Vendor Products Research
- Vendor Evaluation Report, including Functional and Technical Evaluations
- ATCO I-Tek Implementation and ongoing Cost Estimates for Vendor Solutions
- Cost Estimate for In-House Solution Implementation
- Cost Estimate for Remaining Status Quo on Old CIS
- Comparison of Potential Solutions

# 10 Issues

None identified.

# 11 Risks

The following risks have been identified while conducting investigation into this request:

- There may not an alternative that will meet the client business plan and business constraints.

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# 12 Estimated Costs

The Fees described in this Estimated Costs/Budget section are estimates only, and the actual Fees charged by the Supplier may be different from the estimates provided herein. The Client agrees to pay the actual Fees charged by the Supplier for the Services, pursuant to this Statement of Work.

Estimated costs will be valid until November 10,.2007.

## *12.1 One Time Cost Estimate*

The figures identified in the budget below have been calculated using hourly units.

| Deliverable | One Time Fee |
|---|---|
| 7.1 Requirements Gathering | $6,432 |
| 7.2 Market Investigation & Evaluation of Third-Party Solutions (assuming three viable solutions/vendors) | $28,144 |
| 7.2 Travel Pass-Through Costs (assuming three viable solutions/vendors with site visits and vendor visits, attended by two Supplier representatives) | $8,736 |
| 7.3 Estimation of ATCO-Tek Cost for Implementing Vendor Solutions | $5,360 |
| 7.4 Estimation of In-House Solution | $4,736 |
| 7.5 Estimation of Remaining Status Quo on Old CIS | $2,000 |
| 7.6 Comparison of Potential Solutions | $7,000 |
| **Deliverables Subtotal** | **$62,408** |
| Project Management @ 8% | $4,993 |
| **Phase 1 Project Subtotal** | **$67,401** |
| Contingency @ 10% | 6,740 |
| **Total with Contingency** | **$74,141** |

[Third party vendor names and product names that can identify the vendor are redacted]

| Vendor Costs | One Time Fee |
|---|---|
| 7.2 Market Investigation & Evaluation of Third-Party Solutions (Vendor Onsite Visit) | |
| Vendor #1 - Cost Incurred Aug. 8-11, 2006 | $6,258 |
| Vendor #2 - Cost Incurred Aug. 14-17, 2006 | $9,187 |
| **Total** | **$15,445** |

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| |
|---|
| ATCO I-Tek's Weighed Hourly Rate for medium size or medium complexity project is $130/hour.<br><br>The composition of the Weighed Hourly Rate for medium size or medium complexity projects, is as follows: |

| | |
|---|---|
| Project Manager Rate : | 8% |
| Consultant Rate: | 17% |
| A4 System Analyst Rate: | 26% |
| A3 System Analyst Rate: | 33% |
| A2 System Analyst Rate: | 16% |

# 13 Project Schedule

The following is the schedule of the estimated time frame for all stages of this SOW:

| Deliverable | Estimated Completion Date |
|---|---|
| 7.1 Requirements Gathering | August 18, 2006 |
| 7.2 Market Investigation & Evaluation of Third-Party Solutions (assuming three viable solutions/vendors) | October 13, 2006 |
| 7.3 Estimation of ATCO-Tek Cost for Implementing Vendor Solutions | September 30, 2006 |
| 7.4 Estimation of In-House Solution | October 20, 2006 |
| 7.5 Estimation of Remaining Status Quo on Old CIS | October 20, 2006 |
| 7.6 Comparison of Potential Solutions | November 10, 2006 |

# 14 Invoicing

**Project Charges**

All the Supplier's labour charges and fees, including fees described herein, will be invoiced in accordance with the MSA.

In the event a Payment Schedule is attached hereto which provides for the payment of Fees on certain dates, or upon the completion of certain milestones, to the extent the Payment Schedule is inconsistent with the MSA, the Payment Schedule shall govern.

Labour charges will be invoiced at Time and Materials Rates as per the schedule below or the Master Services Agreement (Schedule C).

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All ATCO I-Tek charges and any ATCO I-Tek Business Services Ltd., non-labour charges, will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

All rates are subject to annual CPI increases in accordance with the MSA.

| Time Material Rates | |
|---|---|
| **Resource** | **Hourly Rate** |
| Analyst 1 | 89.77 |
| Analyst 2 | 103.11 |
| Analyst 3 | 118.87 |
| Analyst 4 | 133.45 |
| Consultant | 147.99 |
| Project Manager | 177.10 |

# 15 Change Control Process

Requests for changes or additions to the project particulars identified in this document must be received in writing. Using the Supplier's Project Change Control process, each request will be considered based on the following criteria:

- The perceived value of the request within the context of the entire project and its business implications
- The effect of the change on the entire project
- An assessment of any issues and risks associated with the request

Changes will be implemented upon approval from the project manager and the key client. Approval of changes or additions to the project will be facilitated through a Project Change Addendum. The Project Change Addendum addends the approved Project Plan or Statement of Work and supersedes all terms that are consistent with a term or provision contained in the Project Plan or Statement of Work. Once a Project Change Addendum is approved, the Project Manager will adjust the project schedule or other supporting project documents as required and work will proceed.

# 16 Acceptance Criteria

- Not Applicable

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# 17 Project Management

On acceptance of this Statement of Work, the Supplier will develop a Project Plan as part of its standard project initiating process to identify how the project team will meet the project objectives and control the assigned budget. The cost for developing this plan has been included in the estimated costs of this Statement of Work.

The project plan will be shared with key Client stakeholders for sign off prior to executing work.

[Redacted Client Project Manager and Supplier Project Manager]

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# 18 Authorization

Our signatures below signify that we have the authority to commit to the terms of this document on behalf our respective companies. We have reviewed this document, and have found it to be a complete and true representation of our business and project requirements. We understand that if our requirements change or if we have additional requirements, the changes and additions will be evaluated and must be approved in writing.

[Redacted approvers]

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# Statement of Work
# Short Form

| I-Tek Reference Number: | Date Statement of Work Created: | Client: |
|---|---|---|
| **PD00719** | **25-Jan-07** | ☒ Yukon Electric<br>☒ Yukon Energy<br>☒ Northland Utilities Ltd. (NWT)<br>☒ Northland Utilities Ltd. (Yellowknife) |
| **Client Reference Number:** | **Description:**<br>**Footed A/R for Auditor** | **Initiator(s):**<br>**REDACTED: EMPLOYEE NAME** |

| PMTR Number *(if applicable)*: | Ticket Number *(if applicable)*: | ☐ Notify Finance |
|---|---|---|
| P1096/P9026 | | |

| Areas Impacted: | Request Type: | | |
|---|---|---|---|
| ☒ Applications | ☐ Parameter Changes | ☐ Account Update | |
| ☐ Technologies | ☐ Policy Changes | ☒ Reports/Extracts | |
| ☒ Call Center and Billing Services | ☐ Process Changes | ☐ Work Queue | |
| ☐ Customer Choice | ☐ Functionality Changes | ☐ Other: _____ | |

| Work Location: | Approval Required By (Date): N/A |
|---|---|
| 5 AC Edmonton | Scheduled Implementation Date: 15-Jan-07 |

| Charge Allocation: | MSA Impact: |
|---|---|
| ☒ ENHANCEMENT | ☒ NO |
| ☐ MAINTENANCE | ☐ YES (PTO for detail) |

**Description of Service / Information Requested:** ☐ SEE ATTACHED

*ATCO I-Tek has redacted certain information from the enclosed document and replaced vendor specific names and products with generic descriptions. The redacted and replaced information is the confidential information of ATCO I-Tek and ATCO I-Tek prohibits its disclosure to any person. The disclosure of such confidential information would cause damage to ATCO I-Tek, and in some circumstances would compromise the security of ATCO's computing environment.*

*ATCO I-Tek permits Yukon Electrical Company Limited to disclose the remaining information contained in the attached document strictly as part of their current respective application before the Yukon Public Utilities Board - 2008-2009 General Rate Application. This permission is granted subject to the condition that the use of the disclosed information shall be restricted to this specific filing and shall not be used by any person for any other purposes.*

For audit purposes, a footed A/R report is prepared annually by a representative in the ATCO Group corporate office for the North of 60 companies. For 2006 year end, this representative was not available to provide the reports. As a result, the North of 60 companies requested that ATCO I-Tek confirm the required reports and make them available for audit purposes.

Footed A/R reports are required for each of the following North of 60 companies:

- Yukon Electrical
- Yukon Energy
- Northland Utilities Yellowknife
- Northland Utilities Hay River

**Service / Response Delivered:**

The following services and deliverables will be performed by ATCO I-Tek for this SOW:

- Confirm no existing report available and provide direction for submitting this request
- Create 4 ad hoc reports labeled as "PRTPXXX" and titled "FOOTING OF A/R AS OF DECEMBER 31, 2006", one for each of the following companies, listing selected accounts from the Master file with statuses of 03, 23, 33, 43, 08, 18, 06; and sorted by cycle:

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.
*** Fixed Fees**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement and as indicated in the ESTIMATE section above.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

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  - Yukon Electrical
  - Yukon Energy
  - Northland Utilities Yellowknife
  - Northland Utilities Hay River
- Generate a print request to print the reports at printer

Testing and/or balancing the reports is out-of-scope for this statement of work.

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.
*** Fixed Fees**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement and as indicated in the ESTIMATE section above.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

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**ESTIMATE*** ☒ Yukon Electric 25% ☒ Yukon Energy 25%
☒ Northland Utilities Ltd. (NWT) 25% ☒ Northland Utilities Ltd. (Yellowknife) 25%

| Deliverables | Estimate |
|---|---|
| Confirm no existing report available and provide direction for submitting this request | $ 55.00 |
| Requirements and Analysis | $135.00 |
| Creation of ad hoc reports and generation of print jobs | $755.00 |
| Test Environment Charges | $310.00 |
| **Total** | **$1,255.00** |

☐ Included in MSA ☒ Time & Material ☐ Do Not Invoice Client

**Services Commenced Prior to Approval (as per RFS):** ☐ NO ☒ YES

**Reason for Not Invoicing Client:**

**Description of MSA Impact:**

**Reason for Rejection/ Cancellation/ On Hold (if applicable):**

**STATEMENT OF WORK AUTHORIZATION:**

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| REDACTED: EMPLOYEE NAME | REDACTED: EMPLOYEE NAME |
| Please print your name Date | Please print your name Date |

☒ APPROVED ☐ REJECT ☐ CANCEL ☐ ON HOLD

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# Statement of Work
# Short Form

| I-Tek Reference Number: | Date Statement of Work Created: | Client: |
|---|---|---|
| PD00767 | 28-May-07 | ☒ Yukon Electric<br>☒ Yukon Energy<br>☐ Northland Utilities Ltd. (NWT)<br>☐ Northland Utilities Ltd. (Yellowknife) |
| **Client Reference Number:** | **Description:** Change Budget Value | **Initiator(s):** REDACTED |

| | | |
|---|---|---|
| **PMTR Number** *(if applicable)*: P1654 | **Ticket Number** *(if applicable)*: | ☐ **Notify Finance** |

| Areas Impacted: | Request Type: | | |
|---|---|---|---|
| ☒ Applications | ☐ Parameter Changes | ☐ Account Update | |
| ☐ Technologies | ☐ Policy Changes | ☐ Reports/Extracts | |
| ☐ Call Center and Billing Services | ☐ Process Changes | ☐ Work Queue | |
| ☐ Customer Choice | ☐ Functionality Changes | ☒ Other: Budget Amount Adjustment | |

| | |
|---|---|
| **Work Location:** | **Approval Required By (Date):** N/A |
| 5 AC Edmonton | **Scheduled Implementation Date:** July 4, 2007 (Cycle 01 July) |
| **Charge Allocation:** ☐ ENHANCEMENT ☒ MAINTENANCE | **MSA Impact:** ☒ NO ☐ YES (PTO for detail) |

**Description of Service/ Information Requested:** ☐ SEE ATTACHED

*ATCO I-Tek has redacted certain information from the enclosed document and replaced vendor specific names and products with generic descriptions. The redacted and replaced information is the confidential information of ATCO I-Tek and ATCO I-Tek prohibits its disclosure to any person. The disclosure of such confidential information would cause damage to ATCO I-Tek, and in some circumstances would compromise the security of ATCO's computing environment.*

*ATCO I-Tek permits Yukon Electrical Company Limited to disclose the remaining information contained in the attached document strictly as part of their current respective application before the Yukon Public Utilities Board - 2008-2009 General Rate Application. This permission is granted subject to the condition that the use of the disclosed information shall be restricted to this specific filing and shall not be used by any person for any other purposes.*

Yukon Electrical requested ATCO I-Tek to perform a one-time adjustment to the budget amount for active residential and commercial budget customers for Yukon Electrical and Yukon Energy services. The budget amount is to be increased by $20.00 for all active budget customers.

**Current Situation:**

Yukon Electrical and Yukon Energy budget amounts currently are set in consideration of a government sponsored rate subsidy program. The government sponsored rate subsidy program is ending and therefore budget amounts on active budget accounts need to be increased. Increasing budget amounts will help reduce the potential for budget customers to have large debit balances at the end of the budget year, resulting from termination of the subsidy program.

**Solution Approach:**

ATCO I-Tek will identify Yukon Electrical and Yukon Energy active budget accounts. ATCO I-Tek will process record correction transactions to increase the budget amount on all accounts by $20.00.

Yukon Electrical will participate in testing the process by confirming the success of the record correction transactions on test environment accounts.

Upon approval of test results, ATCO I-Tek will prepare the record correction transactions for processing in the CIS billing system on July 4, 2007, cycle 01 billing date.

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.
*** Fixed Fees**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement and as indicated in the ESTIMATE section above.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

ATCO I-Tek

# Statement of Work
# Short Form

**Service and Deliverables:**

The following services and deliverables will be provided by ATCO I-Tek for this Statement of Work:

- Update the budget amount on all Yukon Electrical and Yukon Energy budget accounts with a status of 03 or 23 by a one time flat amount of $20
- Provide test samples to Yukon Electrical for their review and approval to proceed
- Upon approval from Yukon Electrical, implement the change to production to be in effect for cycle 01 billing, July 2007
- Provide post implementation support

**Yukon Electrical Deliverables:**

- Provide confirmation of test results by review of sample accounts
- Provide approval to proceed for July 2007 cycle 01 billing

**Estimated Project Schedule:**

| Deliverable | Responsibility | Estimated Delivery Date |
|---|---|---|
| Approve SOW | Yukon Electrical | PPTA |
| Implement Services and Deliverables for PD00767 | I-Tek | July 4, 2007 |

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement.
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*** Fixed Fees**
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Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

**ESTIMATE*** ☒ Yukon Electric 100% ☐ Yukon Energy ____%
☐ Northland Utilities Ltd. (NWT) ____% ☐ Northland Utilities Ltd. (Yellowknife) ____%

| Deliverables | Estimate |
|---|---|
| Applications: Requirements and analysis | $ 135.00 |
| Produce & Deliver Query | $ 830.00 |
| Production implementation and post implementation support | $ 260.00 |
| Test Environment Charges | $ 430.00 |
| **Total** | **$1,655.00** |

☐ Included in MSA ☒ Time & Material ☐ Do Not Invoice Client

**Services Commenced Prior to Approval (as per RFS):** ☐ NO ☒ YES

**Reason for Not Invoicing Client:**

**Description of MSA Impact:**

**Reason for Rejection/ Cancellation/ On Hold (if applicable):**

**STATEMENT OF WORK AUTHORIZATION:**

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| REDACTED: EMPLOYEE NAME | [REDACTED: EMPLOYEE NAME] |
| Please print your name Date | Please print your name Date |

☒ APPROVED ☐ REJECT ☐ CANCEL ☐ ON HOLD

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ATCO I-Tek

# Statement of Work
# Short Form

| I-Tek Reference Number: PD00773 | Date Statement of Work Created: July 10, 2007 | Client: ☒ Yukon Electric ☐ Yukon Energy ☐ Northland Utilities Ltd. (NWT) ☐ Northland Utilities Ltd. (Yellowknife) |
|---|---|---|
| **Client Reference Number:** | **Description:** List of all PPP cust | **Initiator(s):** REDACTED: EMPLOYEE NAME |

| PMTR Number *(if applicable)*: P1661 | Ticket Number *(if applicable)*: | ☐ Notify Finance |
|---|---|---|

| Areas Impacted: | Request Type: | | |
|---|---|---|---|
| ☒ Applications | ☐ Parameter Changes | ☐ Account Update | |
| ☐ Technologies | ☐ Policy Changes | ☒ Reports/Extracts | |
| ☐ Customer Care and Billing Services | ☐ Process Changes | ☐ Work Queue | |
| ☐ Customer Choice | ☐ Functionality Changes | ☐ Other: _____ | |

| Work Location: | Pricing Valid Until: | N/A |
|---|---|---|
| 3 AC Edmonton | Approval Required By (Date): | N/A |
| | Scheduled Implementation Date: | File Provided July 3, 2007 |

| Charge Allocation: | MSA Impact: |
|---|---|
| ☐ ENHANCEMENT | ☒ NO |
| ☒ MAINTENANCE | ☐ YES (PTO for detail) |

## Description of Service / Information Requested:

☐ SEE ATTACHED

*ATCO I-Tek has redacted certain information from the enclosed document and replaced vendor specific names and products with generic descriptions. The redacted and replaced information is the confidential information of ATCO I-Tek and ATCO I-Tek prohibits its disclosure to any person. The disclosure of such confidential information would cause damage to ATCO I-Tek, and in some circumstances would compromise the security of ATCO's computing environment.*

*ATCO I-Tek permits Yukon Electrical Company Limited to disclose the remaining information contained in the attached document strictly as part of their current respective application before the Yukon Public Utilities Board - 2008-2009 General Rate Application. This permission is granted subject to the condition that the use of the disclosed information shall be restricted to this specific filing and shall not be used by any person for any other purposes.*

Yukon Electric is requesting ATCO I-Tek's assistance to provide them with an electronic file in excel format, listing all company 05 residential customers on the Preauthorized Payment Plan (PPP) as of July 3, 2007. Yukon Electric requires the account number and customer name to be provided on the listing.

Yukon Electric requires the electronic file containing records of residential PPP customers by July 11, 2007; to facilitate a draw scheduled for July 16, 2007.

## Service / Response Delivered:

The following services and deliverables will be performed by ATCO I-Tek for this SOW:

1. perform a query of the current customer information/billing system to identify residential accounts for Company 05, Yukon Electric, where the account is on the Preauthorized Payment Plan effective July 3, 2007. Criteria used for selecting accounts is as follows:
    a. account has a status of 03 (active) or 23 (active – initial bill not yet billed)
    b. rate code assigned to the account begins with a "1"
    c. active (not end-dated) preauthorized payment plan information is available for the account

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
Monthly fees will be invoiced as per Schedule C – Fee Schedule of the Master Services Agreement.
Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.
*** Fixed Fees**
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Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

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# Statement of Work
# Short Form

2. provide an excel spreadsheet with a separate record (row) for each company 05 residential account on PPP identified in the query, per the following:
    a. provide the account number and the customer name for each record (row)
    b. customer names listed that start with "/" represent customer names that are prefaced with a cent sign (¢) in the customer information/billing system

*** Time & Material**
The one time fees for services under this RFS Response will be payable upon completion of the services outlined above.
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Any ATCO I-Tek Business Services Ltd. non-labour charges and any third party charges associated with this RFS Response will be invoiced as a Pass-Through Expense as per the Master Services Agreement.
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# Statement of Work
# Short Form

**ESTIMATE*** ☒ Yukon Electric 100 % ☐ Yukon Energy ____ %
☐ Northland Utilities Ltd. (NWT) ____ % ☐ Northland Utilities Ltd. (Yellowknife) ____ %

| Deliverables | Estimate |
|---|---|
| Perform a query and provide an excel spreadsheet identifying Company 05 residential accounts on the preauthorized payment plan | $350.00 |
| **Total** | **$ 350.00** |

☐ Included in MSA ☒ Time & Material ☐ Do Not Invoice Client

**Services Commenced Prior to Approval (as per RFS):** ☐ NO ☒ YES

**Reason for Not Invoicing Client:**

**Description of MSA Impact:**

**Reason for Rejection/ Cancellation/ On Hold (if applicable):**

**STATEMENT OF WORK AUTHORIZATION:**

| **Client:** | **ATCO I-Tek:** |
|---|---|
| Sign | Sign |
| [REDACTED: EMPLOYEE NAME] | [REDACTED: EMPLOYEE NAME] |
| Please print your name Date | Please print your name Date |

☒ APPROVED ☐ REJECT ☐ CANCEL ☐ ON HOLD

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August 13, 2007

Vivian Cheng **SENT VIA EMAIL**
Vice –President, Business Solutions & Applications
ATCO I-Tek
10035-105 Street
Edmonton, Alberta
T5J 1C8

**Re: Statement of Work Extension for Provisions of Services for North of 60 Companies**

Dear Mrs. Cheng:

Thank-you for your letter of August 3rd confirming ATCO I-Tek's intention to extend the current Statement of Work for billing services until June 30, 2008. We accept your offer to extend the Statement of Work until the current CIS system is retired using the existing terms and pricing subject to a CPI adjustment effective January 1, 2008.

Yours truly,
THE YUKON ELECTRICAL COMPANY LIMITED
An **ATCO** Company

*Original copy signed.*

Jerome Babyn
General Manager

Cc Sett Policicchio, President ATCO Electric
R.L. (Bobbi) Lambright, President, ATCO I-Tek
Wendy Scramstad, Supervisor Customer Service, The Yukon Electrical Company Limited
Barry Fossbakken, Supervisor Client Support, ATCO Electric
Duane Kotun, Manger, Distribution Accounts
James Grattan, Manager Regulatory and Special Projects, ATCO Electric
Craig Steinbach, Manager Customer Service, The Yukon Electrical Company Limited

# N60 Billing System Replacement

Provided to: The North of 60 Companies
Project: PD00673

Date Created: May 28, 2007
Last Modified: August 1, 2008

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### Revision History

| Version Number | Revised By | Revision Date | Summary of Changes |
|---|---|---|---|
| 1.0 | Leo Bonanni | June 18, 2007 | Original Document |
| 2.0 | Leo Bonanni | July 19, 2007 | Change of Authorization |
| 3.0 | | | |
| 4.0 | | | |
| 5.0 | | | |

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# 1 Document Purpose

The purpose of this Statement of Work (SOW) is to describe the activities and deliverables, with the associated estimated costs, that will be provided by ATCO I-Tek under the terms and conditions outlined in the ATCO I-Tek Business Services Master Services Agreement, with respect to the implementation of the ATCO CIS Integrated Utility Billing System (ATCO CIS) for The North of 60 Companies (N60).

# 2 Executive Summary

[Third party vendor names and product names that can identify the vendor are redacted]

Commencing mid 2006 and through February 2007, ATCO I-Tek and N60 performed a market investigation and analysis to evaluate vendor products which provide Customer Care and Billing functionality to companies with similar profiles as N60.

A high level comparison and rating was performed on products proposed by Vendor #1 and Vendor #2. An evaluation was also performed on the ATCO Electric's parent company solutions, ATCO CIS to provide a complete picture. To view the evaluation report, please refer to document **"N60 Billing System Replacement Project; Phase I Solution Evaluation"**.

Based on the evaluation of business functionality, technical feasibility and total cost (one-time and on-going) of each solution, N60 selected ATCO-CIS as the product to provide their Customer Care and Billing functionality.

The implementation project will commence with a planning and scoping phase. The purpose of this exercise is to gather the detailed requirements for N60 and perform an in-depth fit-gap analysis against the functionality of ATCO CIS to determine any enhancements that must be made to ATCO CIS to support N60.

The planning and scoping exercise will be completed by July 31. At this time, ATCO I-Tek will be able to provide with certainty the implementation date for N60 based on the result of the analysis.

ATCO I-Tek and N60 will continue with the major implementation activities defined in this SOW to implement ATCO CIS for N60.

The total cost of this project is estimated at $1,096,000 and with the implementation date to be determined by July 31, 2007.

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# 3 Assumptions

This SOW has been prepared with the following assumptions. If the assumptions change, the Supplier has the right to change the SOW as necessary.

- The Yukon Energy Corporation will be included within the N60 Implementation.
- ATCO I-Tek Business Services Ltd. will continue to provide on-going services to N60 as outlined in the **"Provision of Service for North of 60 Companies"**. ATCO I-Tek and N60 will also review this agreement prior to implementation to ensure that all the services currently provided will continue to be relevant.
- N60 will be able to provide sufficient resources during the development, conversion, testing and implementation phases.

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# 4 Project Overview

The Old CIS Billing System was a vendor product built over 30 years ago and was purchased in the late 1970s to provide customer care and billing functionality to all of the utilities in the ATCO Group of Companies. Over the years, the ATCO utility companies have significantly enhanced and customized the functionality of Old CIS due to changes in business requirements. The application has been supported parent company for over 25 years.

As business requirements change, the system architecture and underlying technologies can reach their limitation making enhancements to meet the business requirements no longer viable. This was the case with the utility business model changes imposed by the deregulation of electric and gas utilities in Alberta. Old CIS could not be enhanced to accommodate the complexity of the changes and resulted in ATCO Gas and ATCO Electric commissioning a new customer care and billing system; ATCO CIS. Old CIS is now only used by N60.

Technologies used by Old CIS have evolved over the last 25 years. The IMS Data Base Management System (DBMS) and the supporting tools used by Old CIS are rarely used by business applications developed over the last 20 years. Business applications for the ATCO Group using the same technology platform as Old CIS have been replaced over the years due to business requirements. If N60 becomes the only user of Old CIS technologies, N60 will bear the entire licensing costs for IMS and the supporting tools.

The N60 Senior Management decided to look for alternatives to Old CIS and has outlined their basic philosophy for selecting Old CIS replacement. The Old CIS replacement system must provide no less functionality than Old CIS and the one-time implementation cost and the on-going operating cost must be most economical.

Based on this philosophy, ATCO CIS has been selected by N60 to replace Old CIS and other satellite systems such as Magtape Billing used to accommodate Consolidated Billing.

The back office services currently provided by ATCO I-Tek to N60 will continue, however, there is an activity scheduled to review all services provided to ensure they are still relevant upon the implementation of ATCO CIS.

ATCO CIS is substantially more robust and comprehensive than Old CIS. N60 staff will require significant training for understanding and using ATCO CIS effectively.

# 5 Work Location

The Implementation Project activities will be conducted mostly in the ATCO I-Tek Office in Edmonton the ATCO Centre. Some of the activities such as user training and post implementation user support may be conducted in Whitehorse as required.

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# 6 Approach

## 6.1 Implementation Methodology Approach

### 6.1.1 Planning and Scoping

To initially determine the ATCO CIS enhancements required to support N60, ATCO I-Tek will conduct a planning and scoping exercise. The N60 subject matter expert will provide detailed requirements for N60 to ATCO I-Tek for a fit-gap analysis.

ATCO Electric utilizes ATCO CIS as their distribution billing system. ATCO Electric and N60 have many similar requirements and processes and this project will leverage these similarities as much as possible. However, it is anticipated there will be some differences imposed by a different regulatory authority, environmental conditions, geographic conditions, etc. To effectively conduct the fit-gap analysis, ATCO Electric's ATCO CIS configuration will be used as the base for the prototype to test certain key elements of ATCO CIS and to examine the results in sufficient detail to determine the enhancements required.

After the ATCO CIS prototype has been configured for N60, key element testing can be undertaken by N60. The differences in business requirements for each of the N60 companies must be identified and included in the testing. In addition to online testing, cycle testing (i.e. charging and statementing) will occur using the ATCO Electric ATCO CIS testing process.

The planning and scoping exercise will rely heavily on re-using existing ATCO Electric processes and environment supplemented with N60 data. An example of this approach is to assign a N60 rate to an ATCO Electric Service Account to confirm that the current rate calculations will support N60 requirements and to also examine the statementing results.

Through this rigorous and comprehensive testing, current N60 business requirements and processes not supported by ATCO CIS can be identified and discussed with N60 to determine the suitable solution strategy. N60 will determine whether to enhance ATCO CIS or changing current processes or requirements.

Once decisions are made by N60, ATCO I-Tek will proceed with confirming the project cost and determining the implementation date.

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The following illustrates the broad testing proposed to confirm ATCO CIS functionality will support N60.

| Activity | Validation |
|---|---|
| N60 Rates Setup | • Rate Setup Limitations<br>• Residential Rates<br>• Commercial Rates<br>• Street and Sentinel Lights<br>• Generic Rate Testing Results |
| Customer Management | • Record Customer Data<br>• Specify Consolidated Accounts<br>• Specify Statement Accounts<br>• On-line Viewing |
| Account Management | • Set up service accounts<br>• Request Security Deposits<br>• Setup Pre-authorized Payment Plan<br>• Set-up Budget Payment Plan<br>• Process Equipment Installs<br>• On-line Viewing |
| Receivable Management | • Process Payments<br>• Returned Items<br>• Process Credit/Debit Adjustments<br>• Process Refunds<br>• Transfer Accounts Receivable<br>• On-line Viewing |
| Charge Calculations | • Usage Calculations<br>• Charge Calculations<br>• Estimate Calculations<br>• Manual Charges<br>• Street and Sentinel Light Charges<br>• Cancel and Rebill<br>• Final Charges<br>• On-line Viewing |
| Statementing | • Statement Generation<br>• Statement Formatting<br>• Consolidated Billing<br>• Budget Plan Statements<br>• Global Messaging<br>• Account Messaging<br>• Late Payment Charges<br>• On-line Viewing |
| Credit and Collections | • Manage Deposits |

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| Activity | Validation |
|---|---|
| | • Calculate Interest<br>• Refund Deposits<br>• Transfer Deposits |
| Balancing and Controls | • Balance and Control Accounts Receivables<br>• Balance and Control Deposits<br>• Balance And Control Remittances<br>• Balance and Control write-Offs |

### 6.1.2 Data Conversion

ATCO I-Tek will resurrect the data conversion programs that were used to convert ATCO Electric from Old CIS to ATCO CIS. The target environment for the conversion has undergone changes since ATCO Electric was converted, therefore, it is expected that changes to the data conversion software will require modifications.

ATCO I-Tek and N60 will need to collaborate extensively during this phase to ensure the data is converted correctly.

The following assumptions are used in providing scope for the Data Conversion activity.

- All N60 Companies will be converted at the same time
- Accounts receivable with current, 30, 60 and 90 balances will be extracted from Old CIS and loaded into ATCO CIS
- 13 billing periods of meter readings, measured and billed consumption will be extracted from Old CIS and loaded into ATCO CIS
- 13 billing periods of charges, adjustments and payments will be extracted from Old CIS and loaded into ATCO CIS
- Only open credit and collection cases will be extracted from CMS and loaded into ATCO CIS.
- Outdoor lights data will be extracted from Old CIS and loaded into ATCO CIS
- One year of Price Schedule history will be extracted from Old CIS and loaded into ATCO CIS

**Conversion Design**

Normally, a conversion design stage would analyze the existing Old CIS data in order to develop an approach to convert the existing data for use by ATCO CIS. This includes "scrubbing" plans for existing Old CIS data, a data transformation plan and plus any additional data required (i.e. a plan for generating or manually entering data not maintained by Old CIS or kept in another system).

Since ATCO Electric has already been through the conversion process, ATCO I-Tek will re-use the same approach for N60. The approach to data conversion is to

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execute the data conversion process and then make modifications based on the conversion results.

### Data Mapping

The purpose of this activity is to correlate data from the organization's current CIS to ATCO CIS. Data transformation specifications will be defined, manual entry of data will be defined and generated data will be defined.

Since ATCO Electric has already been through the conversion process, ATCO I-Tek will re-use the data mapping for N60. The last data conversion for ATCO Electric was for Farms & REA in 2000. However, due to the changes to ATCO CIS data structure over the years, existing data mapping will require review and new data mapping specifications will be required.

### Data Conversion Software Modification

The purpose of this activity is to create software programs to extract data from the existing database as well as software programs to load the data into the database for the new application.

ATCO I-Tek will resurrect the data conversion programs that were used to convert ATCO Electric from Old CIS to ATCO CIS. The CIS master file has not changed since ATCO Electric was converted to ATCO CIS, therefore, the assumption is that the software program to extract data from Old CIS will not require modification.

However, ATCO CIS has gone through Alberta utility industry deregulation and business requirement changes since then, ATCO CIS data structure has changed. It is expected that the data conversion software will require modifications.

### Data Scrubbing

The responsibility of scrubbing data within Old CIS is the responsibility of N60. ATCO I-Tek will provide supporting lists, error reports, etc to assist N60.

ATCO I-Tek will provide data scrubbing guidelines and procedures to N60.

### Data Extraction and Data Loading

The purpose of this activity will be to actually execute the conversion process. The end-to-end process constitutes extracting data from Old CIS and loading the data into ATCO CIS, distributing error reports and reconciliation reports to clients for verification, ensuring that data was loaded correctly, etc.

### Data Conversion Control Items

Control balancing will be done for the entire conversion effort.

For the control items identified below, the following table outlines the responsible parties and steps involved leading to the completion date of the Deliverables.

The data conversion control items are:

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- Sites
- Statement Accounts
- Customers
- Service Accounts
- Accounts Receivable (current, 30, 60, 90 day balances)
- Budget Payment Plans converted (quantity and amounts)
- Security Deposits Converted (quantity and amounts)

**Data Conversion Acceptance Testing**

The responsibility of validating the data conversion is the responsibility of N60. ATCO I-Tek will provide supporting lists, error reports, etc to assist N60.

### 6.1.3 ATCO CIS Enhancements

Upon completion of the planning and scoping phase, ATCO I-Tek will make enhancements to ATCO CIS as required.

### 6.1.4 System Interfaces

This activity will test interfaces to other systems to ensure they meet N60 requirements. The following interfaces will be tested:

- Oracle Financials
- Itron Premier Plus 4

### 6.1.5 System Test

ATCO I-Tek will conduct the System Test to verify the configuration and enhancements made to ATCO CIS for N60.

ATCO I-Tek will complete an end-to-end test of ATCO CIS and all of the interfaces. This will ensure that the entire system performs according to both functional and technical specifications and to identify potential bottlenecks in system performance.

### 6.1.6 User Acceptance Testing

Acceptance Test is the stage in which N60 will confirm or accept the readiness of ATCO CIS. In addition, this stage ensures that ATCO CIS (technology) is fully integrated with the organization (people and processes).

ATCO I-Tek will support N60 to identify business scenarios (e.g., scripts, test conditions, test data) required to test the application.

N60 will execute the user acceptance test plan that will test the integration of ATCO CIS business processes, organization and system modifications developed within other stages of the project.

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### 6.1.7 Implementation Planning

Implementation Planning provides the analysis and planning required to incorporate ATCO CIS into the N60 organizations and ATCO I-Tek. This includes:

- Determine workflows and procedures for each organization
- Determine Training Strategy
- Technical infrastructure planning
- Analyze roll-out strategy

### 6.1.8 Implementation Development

The purpose of this phase is to develop the required material that will be delivered to the appropriate audience to ensure a smooth transition to ATCO CIS. This includes:

- Procedure development
- Policy development
- Job design
- Development of ATCO CIS User Manual
- Development of cutover activities

### 6.1.9 Implementation

The purpose of this phase is to implement ATCO CIS for N60. This phase is concluded when the integrated solution has been accepted by N60 and is delivered as a fully operational system. This phase includes:

- Training Delivery
- Data Conversion
- Implementation/Roll-Out

## 6.2 ATCO CIS Configuration Approach

To meet the multiple company requirements of N60, the “Statement Company” and “Service Company” structure in addition to the consolidated billing structure will be utilized.

### 6.2.1 Company Configuration

The key business requirements for each of the N60 companies are:

- Provide for separate revenue, receivable and usage reporting
- Provide for separate statement logo and different bill stock
- Provide for separate price schedules and billing parameters
- Restrict information access security to the company level

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## Statement Company

Statement Company holds the rules and parameters for payment processing and allocation, credit and collection rules for each Statement Company. Data access security can also be set by Statement Company.

## Service Company

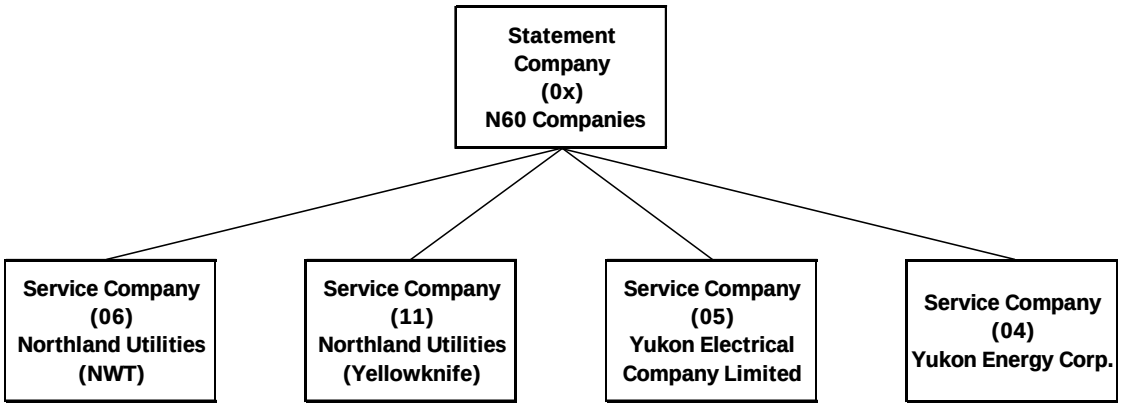
Service Company facilitates the reporting of revenue, receivable and usage separated for each Service Company. It also holds the price schedules, billing and usage validation rules and parameters and late pay fee calculation method for each Service Company. Data access security can also be set by Service Company.

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To meet the key business requirements, ATCO CIS provides two options for company configuration.

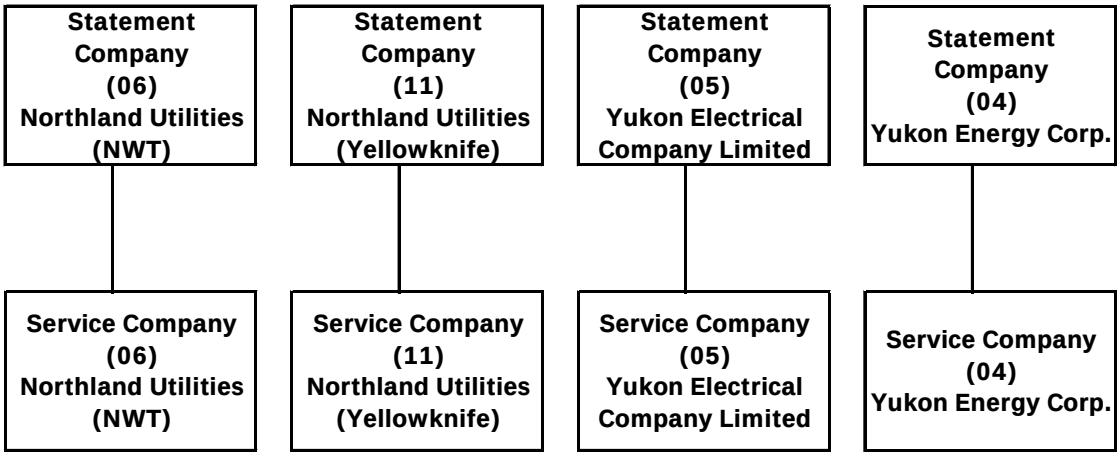
## Option 1 – One Statement Company and Four Service Companies

In this configuration option, each of the four N60 companies will be setup as a Service Company and one Statement Company will be setup for managing the overall group. Each Service Company will inherent the business parameters from the Statement Company.




## Option 2 – Four Statement Companies and Four Service Companies

In this configuration option, there will be one Statement Company and one Service Company for each N60 company. Each Statement Company will have a unique set of business parameters.




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## Company Configuration Options (relative comparison)

| Requirement | Option 1 | Option 2 |
|---|---|---|
| Provide for separate revenue, receivable and usage reporting for each N60 Company | yes | Yes |
| Provide for different price schedules, calculation methods and pro-ration parameters for each N60 Company | yes | Yes |
| Provide for different business rules and parameters for usage validation for each N60 Company | yes | Yes |
| Provide for different business rules and parameters for payment processing and allocation, credit and collection for each N60 Company | no | Yes |
| Enhancement Effort to meet N60 requirements | significant | Minimal |
| Provide for different data access security for each N60 Company | yes | Yes |
| Configuration effort | 1 time | 4 times |
| Data Conversion Effort | same | Same |
| Database Setup Effort | same | Same |
| Production Setup (batch jobs, job schedules, etc) effort | 1 setup | 4 times<br>One setup per Statement Company |
| Production Monitoring Effort | 1 set of jobs | 4 times<br>4 sets of jobs |
| On-going Daily Balance and Control | Combined | One per Statement Company |

## Recommended Option

Option 2 is the preferred configuration option because it meets the key requirements, provides for maximum flexibility and requires minimal enhancements to support N60.

The Statement Company numbers for the N60 companies will be:

- 04 Yukon Energy Corporation
- 05 Yukon Electrical Company Ltd
- 06 Northland Utilities (NWT) Ltd
- 11 Northland Utilities (Yellowknife) Ltd

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### 6.2.2 Business Rules and Parameters Configuration

- Company business rules and parameters
- Statement Company business rules and parameters
- Service Company business rules and parameters
- Code Table values
- Credit and Collection business rules and parameters
- Batch jobs and batch job schedules

### 6.2.3 Consolidated Billing Account Configuration

To support consolidated billing, ATCO CIS separates the “Statement Account” from the “Service Account” to allow the grouping of multiple Service Accounts under one Statement Account for generating a consolidated statement. ATCO CIS also has the flexibility of having the Statement Account and the Service Account belonging to different companies.

#### Statement Account

Statement Account provides the capability of grouping multiple Service Accounts together for consolidated billing. The Statement Account is used to generate the statement or bill for the customer.

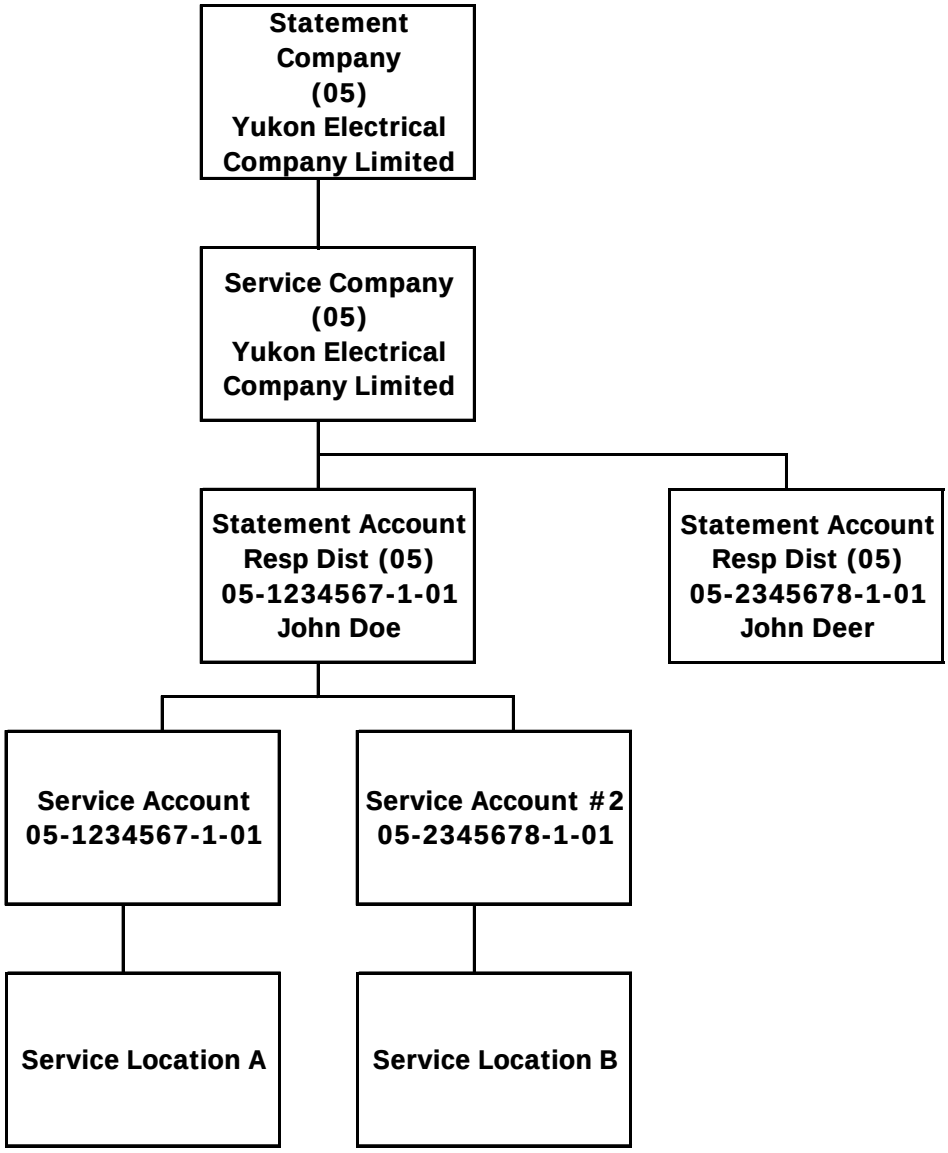
#### Service Account

Service Account holds the revenue, receivable and usage for each customer service account. Each Service Account must belong to a Service Company.

The purpose of a Statement Account is to consolidate Service Accounts together to produce one statement to the customer. At conversion, a Statement Account will be created for each N60 consolidated billing customer. All the Service Accounts in Old CIS that are grouped for consolidated billing will be connected to the appropriate Statement Account. Upon implementation, N60 will be able to add or remove Service Accounts from the Statement Account as required.

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The following diagram illustrates the configuration of a consolidated billing account.




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### 6.2.4 Meter Equipment Management Configuration

Currently, ATCO Electric manages the meter inventory for N60 using ATCO CIS. In ATCO CIS, the meters owned by ATCO Electric and each of the N60 companies are not differentiated. Financial responsibilities are settled outside of ATCO CIS.

Old CIS also requires the meter inventory data in order to perform selected functions (i.e. Meter Install). Since the meter inventory is not differentiated by company, a complete copy of the ATCO Electric's in-stock meters is duplicated in Old CIS. Each day a two-way interface keeps Old CIS and ATCO CIS in synchronization. An interface file is sent to Old CIS to update the inventory data. Old CIS also sends an interface file to ATCO CIS when meters are installed, removed or exchanged.

ATCO CIS currently has business rules in place that prevents meters to be shared among companies.

ATCO CIS must be enhanced to accommodate N60 Equipment Inventory. . The effort to enhance ATCO CIS for Meter Equipment changes is not included in this estimate.

The following two options are presented to manage the Equipment Inventory for N60. Both options will require enhancements to ATCO CIS and for both options, the interface between Old CIS and ATCO CIS will no longer be required.

**Option 1 – Transfer Equipment Inventory to each N60 Company**

| Process | Approach |
|---|---|
| Meter Purchase | • ATCO Electric will continue to negotiate with various meter suppliers and bulk purchase meters for N60 companies.<br>• During design phase, the most optimum method to designate Meter Ownership will be designed.<br>• ATCO CIS will be enhanced to record Meter Ownership |
| Meter Sample Groups | • ATCO Electric will continue to manage Meter Sample Groups.<br>• ATCO Electric will continue to assign all meters to the various sample groups as they currently do.<br>• ATCO CIS will be enhanced to allow Sample Groups to include meters from multiple companies. |
| Meter Recalls | • ATCO Electric will continue to manage Meter Recalls<br>• ATCO CIS will be enhanced to allow the recall process to include meters from multiple companies. |
| Assign Meter Ownership to In-Stock and In-Service Meters | • It is assumed all in-service meters belong to the company providing service to that site.<br>• Assign Meter Ownership to all in-stock meters that belong to Northland Utilities (Hay River), Northland Utilities (Yellowknife), Yukon Electrical Company Limited and |

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| Process | Approach |
|---|---|
| | Yukon Energy Corporation. ATCO Electric will be designated owner of all other meters.<br>• The N60 ATCO CIS Implementation Project will record the Meter Ownership as directed. |
| Meter Moves | • The process for installing, removing and salvaging meters will be reviewed to ensure Meter Ownership is accommodated properly |
| On-line Meter Viewing | • Selected windows will be enhanced to show Meter Ownership |
| Reports | • Selected reports will be enhanced to show Meter Ownership |

**Option 2 – Share Meters between Companies**

Option 2 is similar to Option 1, however, ATCO CIS will be enhanced to allow sharing of meters between companies.

**Preferred Configuration Option**

Option 1 is the preferred configuration option because it meets the key requirements and provides for lower one-time and on-going costs.

During the Planning and Scoping phase the ATCO Electric Meter Shop will be consulted to ensure Option1 presents no significant impacts to their operations.

## 6.3 Route Management and Meter Reading

Currently, N60 has an arrangement with ATCO Gas for using the Computer Aided Dispatch (CAD) application to support the N60 Route Management and Meter Reading. ATCO Gas has implemented Stage I of the Work Management Project and will decommission CAD in 2008.

During the Planning and Scoping phase, N60 will review the Route Management and Meter Reading support provided by ATCO CIS and determine if the ATCO CIS functionality is sufficient to meet their requirements. If ATCO CIS does not meet the requirements, ATCO CIS will need to be enhanced or N60 will need to make arrangements with ATCO Gas for the use of Work Management functionality.

The effort to enhance ATCO CIS or Work Management is not included in this estimate.

## 6.4 Review of Master Services Agreement (MSA)

The services provided to N60 are recorded in Statement of Work "**Provision of Service for North of 60 Companies**". These services are based on the operational support surrounding the Old CIS system. With the implementation of ATCO CIS, all services currently provided must be reviewed to ensure they are still relevant and also determine if additional services must be provided due to ATCO CIS functionality and complexity.

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# 7 Scope Statement

## 7.1 In Scope

The scope of the Implementation Services hereunder includes only the specific Deliverables set forth in this Statement of Work.

Enhancements to ATCO CIS include:

- Application functionality limited to:
  - Price & Tax module for Northland Utilities NWT Territorial Support Rider calculation
  - Statementing for each N60 Company
- Testing by ATCO I-Tek for above enhancements

## 7.2 Out of Scope

For clarity, the following items are not in the scope of this Statement of Work:

- Implementation items not identified in this proposal are not included
- Any modifications required to ATCO CIS or ATCO Gas' Work Management System required to support Route and Meter Reading
- Any modifications required to ATCO CIS for Meter Equipment Management
- Any modifications required to ATCO CIS Credit Module
- Requested changes after the Post Implementation Support period are not included.
- Delivery of communication program to N60 customers, regulators, etc.
- Delivery of communication program to N60 staff.
- Preparation and delivery of training program to N60 staff.
- Preparation of N60 business policies
- Preparation of N60 business process changes and job descriptions
- Preparation of User Procedure manual

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# 8 Deliverables

## 8.1 Deliverable # 1 – Scoping and Planning Document

### Description

The Scoping and Planning Document will identify all required enhancements to be made to ATCO CIS in order to support N60.

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Design rates for ATCO CIS | CC&B | |
| Perform generic Rate Testing | CC&B | |
| Review Rates Design | | ATCO Electric |
| Approve Rates | | ATCO Electric |
| Load Rates into ATCO CIS | CC&B | |

## 8.2 Deliverable # 2 – N60 Rates Loaded into ATCO CIS

### Description

Engineer Old CIS N60 rates for compatibility with ATCO CIS and manually load N60 rates into ATCO CIS. Only current rates and expired rates no older than 13 months will be loaded. This includes rates and riders.

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Design rates for ATCO CIS | CC&B | |
| Perform generic Rate Testing | CC&B | |
| Review Rates Design | | ATCO Electric |
| Approve Rates | | ATCO Electric |
| Manually Load Rates into ATCO CIS | CC&B | |

## 8.3 Deliverable # 3 - ATCO CIS Company Configuration for N60

### Description

ATCO CIS will be configured for N60 operation. The configuration includes:

- N60 business rules
- N60 business parameters
- N60 Code Table values
- Batch jobs modified for N60

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- N60 Job schedules for batch processes
- Reports defined to Express Delivery
- Reports Defined To SAR (Sysout Archival + Retrieval) Report Database

The baseline business rules and business parameters will be those from ATCO Electric.

| ID | Type | Company |
|---|---|---|
| 04 | Statement Company | Northland Utilities (Yellowknife) Ltd. |
| 05 | Statement Company | Yukon Electrical Company Limited |
| 06 | Statement Company | Northland Utilities (NWT) Limited |
| 11 | Statement Company | Yukon Energy Corporation |
| | | |
| 04 | Service Company | Northland Utilities (Yellowknife) Ltd. |
| 05 | Service Company | Yukon Electrical Company Limited |
| 06 | Service Company | Northland Utilities (NWT) Limited |
| 11 | Service Company | Yukon Energy Corporation |

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Baseline definition of business rules | Applications | |
| Baseline definition of business parameters | Applications | |
| Review business rules | | N60 |
| Review business parameters | | N60 |
| Approve business rules | | N60 |
| Approve business parameters | | N60 |
| Configure ATCO CIS with approved business rules | Applications | |
| Configure ATCO CIS with approved business parameters | Applications | |

## 8.4 Deliverable # 4 – Meter Equipment Management Configuration

### Description

ATCO CIS configured to differentiate meters that belong to N60 companies. Currently ATCO CIS has business rules in place that prevents meters to be shared among companies.

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Confirm configuration option | | N60 |
| Configure ATCO CIS as per selected option | Applications | |

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## 8.5 Deliverable # 5 – Data Conversion from Old CIS to ATCO CIS

### Description

ATCO CIS data will be extracted from Old CIS and loaded into ATCO CIS. To support the conversion, control reports, error reports and utility reports will be generated.

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Conversion Design | Applications | |
| Data Mapping | Applications | N60 |
| Data Conversion Software modifications | Applications | |
| Data Scrubbing | | N60 |
| Data Extraction and Data Loading | Applications | |
| Generate Control Items | Applications | |
| Validate Controls | | N60 |
| Data Conversion Acceptance Testing | | N60 |

The responsibility of scrubbing data within Old CIS is the responsibility of N60. ATCO I-Tek will provide supporting lists, error reports, etc to assist N60.

ATCO I-Tek will provide a data scrubbing guidelines and procedures to N60.

## 8.6 Deliverable # 6 – System Test

### Description

ATCO I-Tek will complete an end-to-end test of ATCO CIS and all of the interfaces. This will ensure that the entire system performs according to both functional and technical specifications and to identify potential bottlenecks in system performance.

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Conduct System Test | Applications | |

## 8.7 Deliverable # 7 – User Acceptance Testing

### Description

N60 will prepare test scripts and a user acceptance test plan that will test the integration of ATCO CIS business processes, organization and system modifications developed within other stages of the project.

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### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Develop Test Scenarios | | N60 |
| Develop Test Plan | | N60 |
| Prepare Test Environment | Applications | |
| Execute User Acceptance Test | | N60 |

## 8.8 Deliverable # 8 – Updated Provision of Service for N60 Companies

### Description

ATCO I-Tek and N60 need to review the services that will be provided to N60 after ATCO CIS is implemented for N60. The review should generate a new agreement.

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Review existing Services | Business Development | N60 |
| Determine new Services required | Business Development | N60 |
| Develop policies (if required) | Business Development | N60 |
| Prepare new Services Agreement | Business Development | |
| Acceptance of new Agreement | | N60 |

## 8.9 Deliverable # 9 – Implementation Planning

### Description

The purpose of this phase is to allow ATCO I-Tek and N60 to plan for the activities that will be required to prepare their respective organizations for the integration of ATCO CIS within their organization.

- ATCO I-Tek will train the N60 trainer on the use of ATCO CIS and the N60 trainer will train N60 staff.

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Determine workflows and procedures for each organization | CC&B | N60 |
| Determine Training Strategy | CC&B | N60 |
| Technical infrastructure planning | I-Tek | N60 |
| Analyze roll-out strategy | I-Tek | N60 |

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## 8.10 Deliverable # 10 – Implementation Development

### Description

The purpose of this phase is to develop the required material that will be delivered to the appropriate audience to ensure a smooth transition to ATCO CIS. This includes:

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Procedure development for each respective organization | CC&B | N60 |
| Job design for each respective organization | CC&B | N60 |
| Training development | | N60 |
| Development of cutover activities | I-Tek | N60 |

## 8.11 Deliverable # 11 – Implementation

### Description

The purpose of this activity is to migrate from Old CIS to ATCO CIS and begin operation of ATCO CIS in a production environment.

### Roles and Responsibilities

| Activity | I-Tek | Client |
|---|---|---|
| Training Delivery | | N60 |
| Data Conversion | I-Tek | |
| Validate Data Conversion | I-Tek | N60 |
| Implementation/Roll-Out | I-Tek | N60 |

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# 9 Issues

There are no issues identified at this time.

# 10 Risks

There are no risks identified at this time.

# 11 Estimated Costs

The Fees described in this section are estimates only, and the actual fees charged by the Supplier may be different from the estimates provided herein. The Client agrees to pay the actual Fees charged by the Supplier for the Services, pursuant to this Statement of Work.

## 11.1 One Time Cost Estimate

The figures identified in the budget below have been calculated using 2007 hourly rates.

| Phase / Activity | Estimate |
|---|---|
| **ATCO CIS Product Configuration** | |
| Company Setup, Business Rules and Parameters | $172,000 |
| Production Job and Schedule Setup | $62,500 |
| **Data Conversion** | |
| Data Mapping | $2,600 |
| Data Extraction Software & Loading | $78,100 |
| Data Conversion, Loading Data and Testing | $283,600 |
| **Testing Support** | |
| Test Scenario Development | $40,000 |
| System Testing and UAT Testing Support | $80,000 |
| Test Result Validation | $40,000 |
| **Bill Format and Print** | |
| Bill Format and Print | $76,200 |
| Additional Customized Reports | $10,000 |
| **Interfaces** | $49,000 |
| **Application Hosting** | |
| Application Packaging and Distribution | $1,540 |
| Access Security Setup | $10,400 |

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| Phase / Activity | Estimate |
|---|---|
| **Project Administration** | |
| Project Management | $150,000 |
| User Training (train the trainer) | $20,000 |
| Expenses (e.g. Travel) | $20,000 |
| **Total I-Tek Implementation Estimate** | **$1,095,940** |

| ATCO I-Tek Prorated Hourly Rate | |
|---|---|
| ATCO I-Tek's prorated hourly rate for large or high complexity project is $140/hour. | |
| The prorated hourly rate for User Acceptance Testing is $110/hour. | |
| The allocation of the project estimate for large size or high complexity projects, excluding user acceptance testing, is as follows: | |
| Project Manager: | 8% |
| Consultant: | 26% |
| A4 System Analyst: | 24% |
| A3 System Analyst: | 28% |
| A2 System Analyst: | 14% |

## 11.2 On-Going Fee Estimate

The on-going fees are based on the services that will be provided N60 by ATCO I-Tek after ATCO CIS is implemented. These fees will be part of the Updated Provision of Service for North of 60 Companies review process.

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# 12 Invoicing

## One Time Charges

All the Supplier's charges and fees, including fees described herein, will be invoiced in accordance with the MSA.

In the event a Payment Schedule is attached hereto which provides for the payment of Fees on certain dates, or upon the completion of certain milestones, to the extent the Payment Schedule is inconsistent with the MSA, the Payment Schedule shall govern.

Labour charges will be invoiced at Time and Materials Rates as per the Master Services Agreement (Schedule C).

Test Environment Fees will be charged based on labour charges. For this project, the fees will be assessed at 35% (can be changed per SOW upon approval from Finance) of total labour.

All ATCO I-Tek charges and any ATCO I-Tek Business Services Ltd., non-labour charges, will be invoiced as a Pass-Through Expense as per the Master Services Agreement.

All rates are subject to annual CPI increases in accordance with the MSA.

## On going Charges

All ATCO I-Tek charges will be invoiced as per the Master Services Agreement (schedule C). In the event the charge is not part of schedule C then the charge will be as per the schedule included.

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# 13 Deliverable Schedule

Commencing in May, ATCO I-Tek in conjunction with N60 will conduct a planning and scoping exercise. The purpose of this activity is to test certain key elements of ATCO CIS beginning with N60 rate schedules to determine the magnitude of enhancements required to ATCO CIS.

By July 31, 2007 ATCO I-Tek will complete the planning and scoping exercise and will be able to provide with certainty the implementation date for N60 and a more detailed project schedule.

**N60 Interim Implementation Schedule**

| Start | End | |
|---|---|---|
| **May** | **TBD** | **Data Conversion and ATCO CIS Configuration**<br>Start ATCO CIS Prototype Company Business Rules Review and Configuration<br>Generate Data Scrubbing Reports and Start Data Scrubbing |
| **May** | **July 13** | **Test-Analyze**<br>Engineer N60 Rates into ATCO CIS Structure<br>Conduct generic rate testing<br>Assess Customer Management<br>Assess Account Management<br>Assess Receivables Management<br>Assess Charge Calculations<br>Assess Statemating<br>Assess Revenue Reporting<br>Assess Credit and Collections<br>Assess Balancing & Controls<br>Assess ATCO CIS Online viewing<br>Assess N60 Meter Management Configuration |
| **July 16** | **July 31** | **Analyze and Develop Schedule**<br>Assess test results and determine impacts<br>Determination of resolutions to gap analysis<br>Confirm project cost<br>Provide implementation schedule to N60 |

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# 14 Change Control Process

Requests for changes or additions to the scope and particulars identified in this document must be received in writing on the Project Change Request Form using ATCO I-Tek's Project Change Control process. ATCO I-Tek will estimate each Change Request and the ATCO I-Tek Project Manager will determine cost and schedule impacts. If necessary, the Change Requests will be escalated to the Steering Committee/Project Sponsor(s) for final approval or rejection. Consideration of requests for any changes or additions shall not imply acceptance of such requests.

In response to the Change Request, ATCO I-Tek will provide an impact assessment of the following areas:

- The perceived value of the request within the context of the entire project
- The business implications of the requested change
- The effect of the change on project quality and project objectives
- The effect of the change on project schedule
- An assessment of the complexity level and risk associated with the request
- The estimated expense of the request and the impact of the additional costs on the originally approved project budget

If the Change Request receives approval to proceed by the designated client representative(s), implementation of the approved change will be facilitated through a Project Change Addendum. This Addendum supplements the approved Statement of Work and Project Plan. Once the Project Change Addendum is approved, the ATCO I-Tek Project Manager will adjust the project schedule and/or other related project documents as required and work will proceed.

# 15 Acceptance Criteria

Acceptance Testing will confirm the readiness of ATCO CIS. The following criteria will be used to quantify acceptance.

N60 will examine the results of the following activities and provide written approval to accept ATCO CIS within their organization:

- Data is migrated successfully from Old CIS to ATCO CIS. All balancing and control figures are acceptable and any deviations are explainable.
- ATCO CIS is configured as requested by N60. The configuration parameters and business rules will be evident through the successful completion of test scenarios.
- All required enhancements have been completed and tested successfully.

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- All system interfaces have been tested successfully.

# 16 Acceptance Sign-off

Upon completion of the acceptance tests in respect of each applicable Deliverable, or if no acceptance tests are applicable, then within the Review Period, as the case may be, the Client shall complete and deliver to the Supplier an Acceptance Notice in a form to be provided by the Supplier.

# 17 Project Management

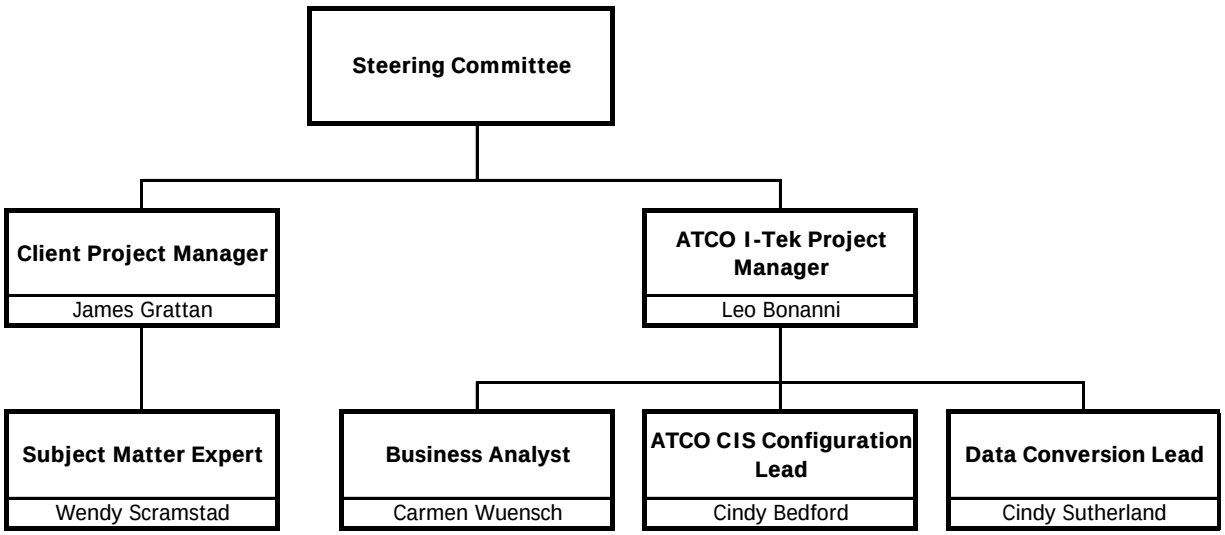
On acceptance of this Statement of Work, the Supplier will develop a Project Plan as part of its standard project initiating process to identify how the project team will meet the project objectives and control the assigned budget. The cost for developing this plan has been included in the estimated costs of this Statement of Work.

The project plan will be shared with key Client stakeholders for sign off prior to executing work.

The Client Project Manager for the project described under this Statement of Work is James Grattan.

The Supplier Project Manager for the project described under this Statement of Work is Leo Bonanni.

## 17.1 Project Organization Structure




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## 17.2 Project Roles and Responsibilities

| Role | Responsibility |
|---|---|
| **Project Sponsor** | • committed to the completion of the project on time and on budget<br>• provides project support at the highest organizational level<br>• approves Statement of Work<br>• provides strategic direction<br>• approves changes to project schedule and budget<br>• maintains close contact with the Steering Committee |
| **Steering Committee** | • committed to the completion of the project on time and on budget<br>• creates the environment for organizational and business process change<br>• makes recommendations regarding budget and schedule changes to the Project Sponsor<br>• communicates expectations and critical decisions<br>• approves commitment of appropriate project resources<br>• provides direction for resolution of issues |
| **N60 Client Manager** | • accountable to the N60 Steering Committee for the successful implementation of the project<br>• ensures commitment of appropriate N60 resources as per the project schedule<br>• works closely with the ATCO I-Tek Project Manager to resolve change requests, decision requests and issues<br>• manages N60 deliverables and schedule<br>• escalates issues to the Steering Committee<br>• evaluates the impacts of change requests, decision requests and issues and makes recommendations to the N60 Steering Committee |

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| Role | Responsibility |
|---|---|
| **N60 Subject Matter Expert** | • is committed to the completion of the project on time and on budget<br>• responsible for understanding the organization change impacts<br>• manages commitment of appropriate business experts as per the project schedule<br>• provides business services direction on business process and procedures<br>• assumes responsibility for the ultimate quality of user acceptance testing<br>• assumes responsibility for the ultimate quality of the business processes and procedures<br>• assumes responsibility for the ultimate quality of the training material<br>• manages resolution of business services related issues<br>• escalates issues to the N60 Client Manager<br>• reports status to the N60 Client Manager |
| **ATCO I-Tek Project Manager** | • accountable to the N60 Steering Committee for the successful implementation of the project<br>• ensures commitment of appropriate ATCO I-Tek resources as per the project schedule<br>• works closely with the N60 Client Project Manager to resolve change requests, decision requests and issues<br>• manages ATCO I-Tek deliverables and schedule<br>• accountable for the overall quality of the Deliverables<br>• accountable for managing the overall project schedule and budget<br>• evaluates the impacts of change requests, decision requests and issues and makes recommendations to the N60 Steering Committee<br>• escalates issues to the Steering Committee<br>• reports status to the N60 Steering Committee |

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| Role | Responsibility |
|---|---|
| **Business Analyst** | • committed to the completion of the project on time and on budget<br>• responsible for understanding the organization change impacts<br>• responsible for the quality of business process deliverables<br>• provides extensive information about currently installed processes<br>• provides extensive information about how processes operate in the new system<br>• develops and documents business processes and procedures<br>• assumes responsibility for the support of user acceptance testing<br>• working with the IT Systems Analysts, translates business knowledge into project specifications and requirements<br>• working with the IT Systems Analysts, is responsible for the configuration of the application<br>• escalates issues to the ATCO I-Tek Project Manager<br>• reports status to the ATCO I-Tek Project Manager |
| **Team Leads** | • committed to the completion of the project on time and on budget<br>• accountable for the successful completion of deliverables on schedule and on budget<br>• accountable to the quality of IT Deliverables<br>• provides and reviews cost estimates for deliverables<br>• provides the project schedule for deliverables<br>• monitors schedule and budget to the assigned deliverables<br>• responsibility for the overall design, coding and unit testing of the application<br>• assigns deliverables to system analysts<br>• manages resolution of IT related issues |

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| Role | Responsibility |
|---|---|
| | • escalates issues to the ATCO I-Tek Project Manager<br>• reports status to the ATCO I-Tek Project Manager |

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# 18 Authorization

Our signatures below signify that we have the authority to commit to the terms of this document on behalf our respective companies. We have reviewed this document, and have found it to be a complete and true representation of our business and project requirements. We understand that if our requirements change or if we have additional requirements, the changes and additions will be evaluated and must be approved in writing.

| Approver | Date |
|---|---|

James Grattan
Client Project Manager
North 60 Companies

| Approver | Date |
|---|---|

Shirley A'Hearn
Senior Manager, Utility Billing & Settlement
ATCO I-Tek Inc.

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**CW-YECL-30**

**Issue:** Forecast Operations and Maintenance Expenses

**Reference:** Schedules 5.1

**Preamble:** CW requires further information to fully understand and assess the forecast operating and maintenance expenses for the test years

**Request:**

(a) Please split each line item in Schedule 5.1 to labour, contractor and materials & supplies and indicate the percentage escalation or inflation applied to each of these categories in each actual and each test year.

(b) Please expand Schedule 5.1 to include forecast amounts for each line item for 2003 through 2007. Please provide explanations for any variances between forecast and actual greater than 10 .

(c) Please provide additional information regarding the higher than normal increases in 2008 and or 2009 to the following line items on Schedule 5.1

(i) 64600 - Diesel Generation - increases in 2008 and 2009

(ii) 84600 Diesel Maintenance - increase in 2008

(iii) 87300 Maintenance - increases in 2008 and 2009

(iv) 87400 Underground Maintenance increase in 2008

(v) 87800 Street Light Maintenance increase in 2008

(vi) 70100 Public Information Administration increase in 2008

(vii) 71100 Customer Applications and Service Orders increase for 2008

(viii) 71300 Customer Billing and Accounting increases in 2008 and 2009

(ix) 71400 - Revenue Collections increase for 2009

(x) 72100 Administrative increase for 2008

(xi) 72300 Insurance increase for 2008

(xii) 72500 Employee Expenses increase for 2009

(xiii) 72600 Training and Safety increase for 2008

**Response:**

(a) This level of detail is not required in order to assess the reasonableness of Yukon Electrical's forecast expenditures. Yukon Electrical also observes that this level of detail is beyond the level agreed to in Alberta for the major Alberta Electric Utilities in their Minimum Filing Requirements.

Please refer to CW-YECL-25(c) Attachment 1 for the breakdown of Schedule 5.1 by function. For wage inflation please refer to CW-YECL-25(b) Attachment 1. The 2003-2007 actual and 2008-2009 test years increase in labour costs can be found in YEC-YECL-8(n). For 2003-2007 actual non-labour cost increases relate to both changes in price and volume. The inflation versus base level change split is not available. For the 2008-2009 test years a 5 rate of inflation was applied where applicable to other expenses.

(b) Please refer to CW-YECL-4(b). There are no approved forecasts as 2003-2007 was not a test period. As such the information requested can not be provided.

(c) Please refer to Schedule 5.2 for additional information.

**CW-YECL-31**

**Issue:** Property Taxes

**Reference:** Page 6-1

**Request:**

(a) Please expand the table on page 6-1 to include actual property taxes for 2003 through 2005.

(b) Please provide an explanation for the increase in forecast property taxes for the 2008 and 2009 test years.

**Response:**

(a)

| | 2003 Actual | 2004 Actual | 2005 Actual | 2006 Actual ( 000's ) | 2007 Actual | 2008 Test | 2009 Period |
|---|---|---|---|---|---|---|---|
| **Property Taxes** | 222 | 226 | 229 | 230 | 235 | 249 | 261 |

(b) Please refer to YUB-YECL-19 as below.

The primary cause of property tax increases is due to the City of Whitehorse's 2008 budget forecast of 7.5 increase in property taxes in 2008 and 4 in 2009.

**CW-YECL-32**

**Issue:** Return on Equity

**Reference:** Foster Associates Report p. 4, l. 105 p. 6, l. 150

**Preamble:** In the referenced sections, Ms. McShane discussed two distinct approaches to setting a rate of return on common equity by regulatory Boards and Commissions in Canada. One method could be described as determining a benchmark rate of return adjusting capital structure in accordance with risk profile and the second would be acceptance of the specific regulated company's actual capital structure for regulatory purposes, or deeming a capital structure that adequately protects bondholders while determining a company-specific rate of return.

**Request:**

(a) In this application, is Ms. McShane advocating the first method, the second method or some blending of the two methods? Please explain.

(b) What method did Ms. McShane advocate in her appearance before the NWTPUB in the proceeding leading to Decision 13-2007?

**Response:**

(a) As stated on page 5, Ms. McShane utilized the first approach and estimated a capital structure that fully reflects the business risks of Yukon Electrical as lying at the upper end of a range of 47.5-52.5 . At a common equity ratio of 52.5 , Ms. McShane recommended, for the express purposes of this hearing, adopting the benchmark return on equity derived in the EUB's Generic Cost of Capital Decision, as adjusted for changes in interest rates or 8.75 .

However, as stated on page 36, lines 944-945, a common equity ratio of 52.5 represents a material departure from the actual common equity ratio of approximately 40 that has been historically maintained and would require a material equity infusion by shareholders to bring the actual equity ratio up to

52.5 . However, the 8.75 benchmark return on equity is viewed as relatively low and it is unlikely that investors would invest additional equity in order to have the opportunity to earn an inadequate return. As a result, Ms. McShane recommended YECL move to an equity ratio of 47.5 with the difference between a 47.5 equity ratio and the 52.5 ratio that would fully compensate for YECL's business risks be reflected in an incremental equity risk premium of 0.50 . Ultimately, her recommendation reflects the second approach.

(b) In the proceeding leading to Decision 13-2007, Ms. McShane used the second approach of varying both capital structures and risk premiums. In that case, Ms. McShane was asked to evaluate the reasonableness of NTPC's forecast actual capital structures for the two test years. While Ms. McShane found that the forecast common equity ratios were reasonable, they did not equate NTPC with a benchmark Canadian utility and it was therefore necessary to adjust the benchmark return on equity to fully compensate for NTPC's total risk relative to the benchmark.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**CW-YECL-33**

**Issue:** Return on Equity

**Reference:** Foster Associates Report page 8, lines 208-213

**Preamble:** Ms. McShane states: The generic return on equity established by the EUB in Decision 2004-052 and adjusted automatically each year in subsequent Orders is virtually identical to benchmark ROEs adopted by other Canadian regulators, including the National Energy Board and, implicitly, by the Public Utilities Board of the Northwest Territories when it established the allowed ROE for Northwest Territories Power Corporation in Decision 13-2007 (August 29, 2007).

**Request:**

What does Ms. McShane mean by the NWTPUB implicitly adopted a benchmark ROE? How does this differ from explicit adoption?

**Response:**

In Decision 13-2007, the NWT PUB established a return on equity for NTPC for 2007 08 of 9.25 . The allowed return on equity of 9.25 expressly included a 50 basis point upward adjustment to compensate for the relatively higher risk of NTPC. As noted at page 43 of the decision, the 50 basis point additional risk premium was adopted for NTPC in relation to the return on equity applicable to a benchmark utility. From these findings, it may be reasonably inferred that the PUB considered a return on equity of 8.75 (at a long-term Canada bond yield of 4.50-4.65 ) to be equivalent to a benchmark return on equity. It should be noted that the NWT PUB did not specify the long Canada yield in its decision. However, the range of 4.50-4.65 represents the range of forecasts for 2007 08 provided by the experts in the proceeding.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**CW-YECL-34**

**Issue:** Return on Equity

**Reference:** Foster Associates Report page 8, footnote 5

**Preamble:** Ms. McShane states: In my opinion, as well as that of Yukon Electrical, the EUB benchmark return on equity is below the level commensurate with the comparable returns standard. The EUB as well as the NEB have initiated proceedings to determine whether their automatic adjustment mechanisms continue to produce a fair return. In the ATCO Utilities' view (with which I concur), as filed with the AUC on April 4, 2008, the automatic adjustment mechanism does not produce a fair return. Nevertheless, until such time as the issue has been reviewed by the AUC, Yukon Electrical is prepared to accept the EUB benchmark as a point of departure for establishing its allowed ROE for 2008 and 2009.

CW wishes to understand YECL's position regarding the process to reconsider 2008 return on Equity and capital structure initiated in AUC Decision 2008-051.

**Request:**

(a) Does acceptance of the EUB 'benchmark' as a point of departure for establishing its allowed ROE for 2008 and 2009 mean that Yukon Electrical will or will not revise its evidence if the AUC process is concluded prior to the October hearing?

(b) If Yukon Electrical does propose revising its evidence based on the process initiated by AUC Decision 2008-051, will Yukon Electrical revise other portions of its application based on other changed circumstances prior to the hearing?

(c) If Yukon Electrical does propose revising its return on capital evidence and the AUC process is not concluded prior to the hearing, does Yukon Electrical propose that Ms. McShane's recommendations be accepted as a benchmark until such time as the AUC process is concluded?

(d) If the AUC process results in a significantly different benchmark ROE for 2009 than for 2008, will YECL accept the 2008 ROE for 2009?

(e) Aside from Ms. McShane's and ATCO's opinion, is it possible that the AUC process could result in a lower benchmark ROE? Should the Board reduce YECL's ROE if this is the outcome of the AUC process?

**Response:**

(a) Yukon Electrical does not plan to revise its evidence as a result of the AUC process. The AUC's recently issued schedule does not anticipate a hearing until February 2009.

(b) Yukon Electrical does not plan to revise its cost of capital evidence.

(c) Yukon Electrical proposes that Ms. McShane's recommendations be implemented as filed for both 2008 and 2009.

(d) Yukon Electrical is proposing reliance on the requested ROE for the purpose of final rates for both 2008 and 2009, irrespective of the outcome of the recently initiated generic cost of capital proceeding. It is not proposing a placeholder ROE subject to the outcome of the AUC proceeding. In future proceedings before the YUB, Yukon Electrical may consider the outcome of the Alberta generic decision in formulating future ROE proposals.

(e) It is always possible that the outcome could be lower, although the available evidence does not support such an outcome. No, the Board should not reduce YECL's allowed ROE if the outcome of the AUC proceeding is a lower ROE than reflected in its existing adjustment mechanism. Yukon Electrical is proposing that the requested ROE be approved for final 2008 and 2009 rates, not as a placeholder.

**CW-YECL-35**

**Issue:** Return on Equity

**Reference:** Foster Associates Report, page 36, lines 956-963 and Section 8, Attachment 1-1, Section 5, page 3 of 3

**Preamble:** Ms. McShane states: In this regard, Canadian utility returns compare unfavourably to the returns that are being allowed for U.S. utilities. The average return on equity that has been allowed by state regulators for U.S. electric and gas utilities over the period 2005-2008Q1 has been approximately 10.4 , approximately 1.5 percentage points higher than the corresponding allowed returns for Canadian utilities. The returns allowed by the Federal Energy Regulatory Commission for (lower risk) transmission operations have been in the approximate range of 10.75-13.8

**Request:**

(a) Is Section 8, Attachment 1-1, Section 5, page 3 of 3 the source of Ms. McShane's comparison between Canadian and U.S. allowed utility returns? If yes, where is the corresponding yearly data for FERC regulated transmission operations? Please identify the utilities and transmission operations that comprise the U. S. and Canadian samples and identify which utilities and transmission operations are federally and state provincially regulated.

(b) By transmission operations, does Ms. McShane mean electric transmission utilities or are natural gas pipelines included in Ms. McShane's FERC sample? If pipelines are not included, what are the corresponding allowed returns for interstate pipelines?

(c) Please provide for the same time period as Section 8, Attachment 1-1, Section 5, page 3 of 3, the allowed and achieved returns for each entity in the Canadian and American samples.

(d) For each entity in the two samples, please identify which utilities and transmission operations in this sample operate in a fully regulated environment, which utilities are subject to incentive regulation schemes and which utilities are deregulated and the extent to which they are deregulated.

(e) What are the prospective 2008 and 2009 (if available) returns for state-regulated U.S. gas and electric utilities and for FERC-regulated transmission operations

**Response:**

(a) Schedule 5, page 3 of 3 is the source for the Canadian and US returns referenced in lines 956 to 961. The returns allowed by the FERC for transmission operations referenced at lines 961-963 covered the period May 2005 to February 2008 and are presented below:

| Date | Company | Docket Number | Approved ROE |
|---|---|---|---|
| 5 25 2005 | Public Service Company of New Mexico | ER05-741-000 | 10.80 |
| 5 31 2005 | American Electric Power Service Corp | ER05-751-000 | 12.00 |
| 6 24 2005 | Westar Energy Inc | ER05-925-000 | 11.50 |
| 8 23 2005 | City of Vernon, California | ER00-2019-016 | 10.72 |
| 12 30 2005 | Michigan Electric Transmission Co | ER06-56-00 | 12.38 |
| 7 14 2006 | International Transmission Corp | ER06-1006-000 | 12.38 |
| 8 7 2006 | Central Maine Power Company | ER06-963-000, ER06-963-001 | 10.72 |
| 10 31 2006 | ISO New England | ER04-157-004, ER04-714-001 | 10.90 |
| 7 24 2007 | Baltimore Gas & Electric | ER07-576 | 10.80 |
| 11 16 2007 | Pepco Holdings | ER08-10-000 | 10.80 |
| 2 29 2008 | Potomac-Appalachian Highline Trans. (PATH) | ER08-386-000 | 13.80 |
| 2 29 2008 | SoCal Edison: DPV2 & Tepachapi Projects | ER08-375-000 | 11.50 |
| 2 29 2008 | SoCal Edison: Rancho Vista Project | ER08-375-000 | 11.50 |

The requested information on the Canadian companies is contained on pages 1 and 2 of Schedule 5. The US company data are compiled by Regulatory Research Associates, now part of SNL, and include all major state-level final rate decisions issued between January 1990 and March 30, 2008 for investor-owned

electric and gas utilities. The data comprise 492 electric utility and 402 gas utility decisions. These data are proprietary. The summary pages from the relevant issue are attached as CW-YECL-35(a) Attachment 1.

(b) The referenced FERC regulated operations are electric transmission only. Please see the response to part (a) for the companies included. There are relatively few litigated interstate gas pipeline cases in which allowed ROE has been determined. The table below provides those of which Ms. McShane is aware dating from 1994.

| Company | Date Issued | ROE | Equity Ratio |
|---|---|---|---|
| Ozark Gas Transmission | 07 07 94 | 12.00 | 47.68 |
| Panhandle Eastern | 02 05 96 | 12.13 | 59.97 |
| Williams Gas Transmission | 12 19 96 | 13.46 | 64.29 |
| Iroquois Gas Transmission | 07 29 98 | 12.38 | 35.21 |
| Northwest Pipeline | 06 01 99 | 12.22 | 55.00 |
| Trunkline Gas Company | 01 12 00 | 12.56 | 59.08 |
| Transcontinental Gas Pipeline | 03 17 00 | 12.40 | 60.20 |
| Enbridge Pipelines (KPC) | 09 10 02 | 11.83 | 40.50 |
| Williston Basin | 07 03 03 | 12.48 | 58.98 |
| High Island Offshore System | 01 24 05 | 11.22 | 49.20 |
| Kern River Gas Transmission | 10 19 06 | 11.20 | 38.01 |

(c) The data on allowed ROEs for the individual companies in the U.S. state regulated sample are proprietary. The allowed ROEs for the individual Canadian companies are, as indicated in response to (a), provided in Schedule 5. Ms. McShane has not compiled the achieved returns for the regulated operations of either the U.S. or Canadian companies. These data are not readily accessible.

(d) Ms. McShane has not reviewed each individual U.S. utility decision to determine which are subject to incentive mechanisms or which operate in restructured or unrestructured environments, given the number of decisions that are covered by the Regulatory Research Associates data base. The allowed ROEs for U.S. utilities are for those portions of the business that remain fully regulated. In other words, if an electric utility operates in an environment where generation is

competitive, the allowed ROE is for the regulated wires operation. With respect to Canadian utilities, the following companies on Schedule 5, page 1 are subject to incentive mechanisms: FortisBC, the Ontario Electricity Distributors, Enbridge Gas, Gaz Metro, Terasen Gas, Union Gas, and all of the NEB-regulated pipelines except Westcoast. The Alberta and Ontario electric utilities operate in a restructured environment.

(e) The prospective allowed ROEs for the U.S. utilities are equal to the recently allowed ROEs; they are not subject to automatic adjustment formulas and would not change until such time as the utility applies for a change in rates. An update to Schedule 5, page 3 of 3, would show that the average ROE adopted for U.S. utilities during the first two quarters of 2008 was 10.47 .

# SPECIAL REPORT

April 2, 2008

## MAJOR RATE CASE DECISIONS--JANUARY-MARCH 2008

For the first three months of 2008, the average electric equity return authorization by state commissions was 10.32% (nine determinations), compared to the 10.36% average in calendar-2007. The average gas equity return authorization for the first quarter of 2008 was 10.44% (6 determinations), compared to the 10.24% average in calendar-2007.

After reaching a low in the late-1990's and early-2000's, the number of equity return determinations for energy companies has generally increased over the last several years. In fact, the total number of electric and gas equity return determinations in 2007 was the largest since 1993. Increased costs, including environmental compliance expenditures, the need for generation and delivery infrastructure upgrades and expansion at many companies, and the expiration of restructuring-related rate freezes argue for a continuation of the increased level of rate case activity over the next several years. However, relatively low interest rates, competitive pressures, technological improvements, the use of multi-year settlements that do not specify return parameters, and a reduced number of companies due to mergers, may prevent the number of rate cases and equity return determinations from significantly increasing further. We note that electric industry restructuring in many states has led to the unbundling of rates, with state commissions authorizing revenue requirement and return parameters for delivery operations only (which we footnote in our chronology), thus complicating historical data comparability. The tables included in this study are extensions of those contained in the January 8, 2008 Regulatory Study entitled *Major Rate Case Decisions--January 2006-December 2007--Supplemental Study*. Refer to that report for information concerning individual rate case decisions that were rendered in 2006 and 2007.

The table on page 2 shows annual average equity returns authorized since 1990, and by quarter since 2001, in major electric and gas rate decisions, followed by the number of determinations during each period. The tables on page 3 present the composite industry data for items in the chronology of this and earlier reports, summarized annually since 1997, and quarterly for the most recent nine quarters. The individual electric and gas cases decided in the first three months of 2008 are listed on pages 4 and 5, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), return on equity (ROE), and percentage of common equity in the adopted capital structure. Next we indicate the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. Summary data for 2007 is also included for comparative purposes. Fuel adjustment clause and other rider-related rate changes are not reflected in this study.

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**Average Equity Returns Authorized January 1990 - March 2008**

| | | Electric Utilities | | Gas Utilities | |
|---|---|---|---|---|---|
| **Year** | **Period** | **ROE %** | **(# Cases)** | **ROE %** | **(# Cases)** |
| **1990** | Full Year | 12.70 | (44) | 12.67 | (31) |
| **1991** | Full Year | 12.55 | (45) | 12.46 | (35) |
| **1992** | Full Year | 12.09 | (48) | 12.01 | (29) |
| **1993** | Full Year | 11.41 | (32) | 11.35 | (45) |
| **1994** | Full Year | 11.34 | (31) | 11.35 | (28) |
| **1995** | Full Year | 11.55 | (33) | 11.43 | (16) |
| **1996** | Full Year | 11.39 | (22) | 11.19 | (20) |
| **1997** | Full Year | 11.40 | (11) | 11.29 | (13) |
| **1998** | Full Year | 11.66 | (10) | 11.51 | (10) |
| **1999** | Full Year | 10.77 | (20) | 10.66 | (9) |
| **2000** | Full Year | 11.43 | (12) | 11.39 | (12) |
| | 1st Quarter | 11.38 | (2) | 11.16 | (4) |
| | 2nd Quarter | 10.88 | (2) | 10.75 | (1) |
| | 3rd Quarter | 10.78 | (8) | --- | (0) |
| | 4th Quarter | 11.50 | (6) | 10.65 | (2) |
| **2001** | **Full Year** | **11.09** | (18) | **10.95** | (7) |
| | 1st Quarter | 10.87 | (5) | 10.67 | (3) |
| | 2nd Quarter | 11.41 | (6) | 11.64 | (4) |
| | 3rd Quarter | 11.06 | (4) | 11.50 | (3) |
| | 4th Quarter | 11.20 | (7) | 10.78 | (11) |
| **2002** | **Full Year** | **11.16** | (22) | **11.03** | (21) |
| | 1st Quarter | 11.47 | (7) | 11.38 | (5) |
| | 2nd Quarter | 11.16 | (4) | 11.36 | (4) |
| | 3rd Quarter | 9.95 | (5) | 10.61 | (5) |
| | 4th Quarter | 11.09 | (6) | 10.84 | (11) |
| **2003** | **Full Year** | **10.97** | (22) | **10.99** | (25) |
| | 1st Quarter | 11.00 | (3) | 11.10 | (4) |
| | 2nd Quarter | 10.54 | (6) | 10.25 | (2) |
| | 3rd Quarter | 10.33 | (2) | 10.37 | (8) |
| | 4th Quarter | 10.91 | (8) | 10.66 | (6) |
| **2004** | **Full Year** | **10.75** | (19) | **10.59** | (20) |
| | 1st Quarter | 10.51 | (7) | 10.65 | (2) |
| | 2nd Quarter | 10.05 | (7) | 10.54 | (5) |
| | 3rd Quarter | 10.84 | (4) | 10.47 | (5) |
| | 4th Quarter | 10.75 | (11) | 10.40 | (14) |
| **2005** | **Full Year** | **10.54** | (29) | **10.46** | (26) |
| | 1st Quarter | 10.38 | (3) | 10.63 | (6) |
| | 2nd Quarter | 10.68 | (6) | 10.50 | (2) |
| | 3rd Quarter | 10.06 | (7) | 10.45 | (3) |
| | 4th Quarter | 10.39 | (10) | 10.14 | (5) |
| **2006** | **Full Year** | **10.36** | (26) | **10.43** | (16) |
| | 1st Quarter | 10.27 | (8) | 10.44 | (10) |
| | 2nd Quarter | 10.27 | (11) | 10.12 | (4) |
| | 3rd Quarter | 10.02 | (4) | 10.03 | (8) |
| | 4th Quarter | 10.56 | (16) | 10.27 | (15) |
| **2007** | **Full Year** | **10.36** | (39) | **10.24** | (37) |
| **2008** | **1st Quarter** | **10.32** | (9) | **10.44** | (6) |

**CW-YECL-36**

**Issue:** Capital Structure and Cost of Capital

**Reference:** Foster Associates Report page 2, lines 42-47

**Preamble:** Ms. McShane states: Since the forecast average long-term Government of Canada bond yield for 2008-2009, at 4.5 , is virtually identical to the forecast relied on by the EUB to determine the allowed ROE for 2008, the application of the automatic adjustment formula produces a benchmark return on equity of approximately 8.75 for 2008-2009. The indicated benchmark return on equity of 8.75 would be applicable to Yukon Electrical at a common equity ratio of 52.5 .

**Request:**

(a) For comparison, what are the benchmark capital structures for electric distribution and electric transmission utilities set by the EUB in Decision 2004-052?

(b) In any other jurisdictions that employ benchmark rates of return, what are the benchmark capital structures for integrated electric utilities for distribution-only and transmission-only electric utilities?

**Response:**

(a) For taxable electric transmission and distribution utilities, the deemed common equity ratios were 33 and 37 respectively.

(b) There are no jurisdictions that have a benchmark capital structure for an integrated electric utility. In Ontario, the deemed capital structure adopted for Hydro One Transmission and for the electricity distributors could be considered benchmark capital structures for the two functions: both are deemed a common equity ratio of 40 . To Ms. McShane's knowledge, these are the only two jurisdictions which could be viewed as having adopted benchmark capital structures for electric utilities.

**CW-YECL-37**

**Issue:** Capital Structure and Cost of Capital

**Reference:** Foster Associates Report, page 10, lines 287 290

**Preamble:** Ms. McShane states: Based on these forecasts and a continuation of the current 50 basis point spread between 10- and 30-year Canada bond yields, I anticipate that the 30-year Canada bond yield will average 4.7 in 2009.

**Request:**

What is the actual current spread between 10- and 30-year Canada bond yields?

**Response:**

On July 16, 2008, the 10-year bond yield was 3.73 and the long-term Canada yield was 4.12 producing a current spread of 39 basis points.

**CW-YECL-38**

**Issue:** Capital Structure and Cost of Capital Risk Factors

**Reference:** Foster Associates Report, page 16, line 441 443

**Preamble:** Ms. McShane states: Business risk encompasses those market demand, supply and regulatory factors that expose the shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment.

**Request:**

(a) Has Yukon Electrical failed to achieve its required rate of return in any year during the 2003-2007 period? For required rate of return please use the last allowed rate of return for Yukon Electrical for 2003 and the AEUB benchmark rate of return for the 2004-2007 period as a proxy for allowed rate of return.

(b) Please summarize all the changes in market demand, supply and regulatory factors from the 2003-2007 period and the 2008 9 test years that would either increase or decrease the risk profile of Yukon Electrical.

**Response:**

(a) Yukon Electrical has not had an allowed ROE set since the negotiated settlement for 1996 97, when it was set at 11.25 for both years. The actual ROEs for Yukon Electrical in 2003 to 2007 were as follows:

| Year | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| ROE | 10.54 | 10.20 | 9.04 | 10.69 | 10.70 |

The Alberta benchmark ROEs for the years 2004-2007 can be found under AltaLink, ATCO Electric and FortisAlberta on Ms. McShane's Schedule 5, page 2 of 3. For purposes of determining whether Yukon Electrical over or under-earned from 2003-2007, the only valid comparison is between the actual ROEs in the

table above and the 11.25 negotiated for 1996 97. The Alberta benchmark ROEs do not represent Yukon Electrical's allowed ROE.

(b) Ms. McShane has analyzed the risks and capital structure requirements from first principles. Her evaluation did not include an analysis of changes in business risk.

**CW-YECL-39**

**Issue:** Capital Structure and Cost of Capital Risk Factors

**Reference:** Foster Associates Report, page 16, line 441 443

**Preamble:** Ms. McShane states: Supply and physical (operating) risks faced by an integrated electric utility comprise the risk of under-earning due to the inability to deliver electricity, or the inability to recover costs associated with the acquisition or delivery of electricity.

**Request:**

(a) On a retrospective basis, has Yukon Electrical faced any supply constraints in past years?

(b) On a prospective basis, what specific supply risks has Ms. McShane identified in her discussion referenced at page 20, line 534 page 21, line 562 that would increase Yukon Electrical's total risk during the test years?

(c) When evaluating the supply risk of YECL, has Ms. McShane included all the supply risks of YEC or just the supply risk of generation owned by YECL?

**Response:**

(a) Yukon Electrical has not experienced any supply constraints in past years.

(b) Ms. McShane has not evaluated the supply risks from the perspective of increases during the test period, but rather in a relative (to other utilities) sense. Moreover, the analysis of risk is not limited to the test period; it is assessed over the longer-term, as the capital structure and ROE reflect longer-term risks. Some aspects of YECL's supply and physical risks are ongoing, e.g., the severe climate, isolated nature of the smaller communities served which in turn necessitates the continued presence of generation assets. One factor was identified that will decline over time, e.g. exposed distribution line is being moved underground.

(c) Ms. McShane has evaluated the supply and physical risks of the company's operations in their entirety, not just the supply risk of generation owned by Yukon Electrical.

**CW-YECL-40**

**Issue:** Capital Structure and Cost of Capital

**Reference:** Foster Associates Report, page 16, line 456 page 17, line 459

**Preamble:** Ms. McShane states: The regulatory framework in which a utility operates is, next to the basic demand risks, the most significant aspect of risk to which shareholders in a regulated firm are exposed. The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

**Request:**

(a) What references have been made in the financial community respecting the YPUB's regulation of Yukon Electrical? Does the financial community regard the YPUB as increasing Yukon Electrical's regulatory risk or as decreasing its risk?

(b) Does Ms. McShane concur with these comments (if any) on Yukon Electrical's regulatory environment?

(c) Does Ms. McShane's comment at page 21, lines 571 - 573 that On balance, the regulatory environment in the Yukon has been even-handed and reasonable in its approach mean that, retrospectively, Yukon Electrical's regulatory risk has not added to its overall business risk?

(d) Does Ms McShane's comment at page 21, lines 575 - 576 that Nevertheless regulatory decisions can also have a negative impact on utilities. mean that she expects that the Board's decision as a result of this process will increase Yukon Electrical's business risk? If yes, what decisions might the Board make that will have a negative impact on Yukon Electrical?

(e) Does a fully regulated environment create a more or less risky environment than partial or full deregulation? Please discuss the variation of risk along the regulation deregulation spectrum.

**Response:**

(a) Ms. McShane is not aware of any comments by the financial community regarding the YPUB's regulation of Yukon Electrical.

(b) Please see response to (a)

(c) The reference means that there is no particular element of the regulatory model in the Yukon that would cause Yukon Electrical to face materially higher or lower regulatory risks than the typical Canadian utility.

(d) No. As stated at page 21, lines 578-580, Ms. McShane has no reason to conclude that, based on current policies and practice, that Yukon Electrical, similar to other regulated utilities in North America, will not be provided a reasonable opportunity to recover its capital investment. Nevertheless, the regulator cannot provide a guarantee that the capital investment will be recovered. The regulator can not provide a guarantee that long-term economic conditions will permit the full recovery of the invested capital, it does not make energy policies that can impact on the ability to recover the invested capital, and it cannot bind the decisions of future regulators.

(e) Ms. McShane does not know of any regulatory environment in North America which could be described as fully deregulated. To her knowledge, all of the electric distribution and transmission and gas distribution businesses remain fully regulated. With respect to a partially deregulated environment compared to a fully regulated environment, the correct response depends on the specific circumstances of the particular regulatory environments. For example, a wires utility operating in a partially deregulated market where there was either no obligation to purchase power on behalf of customers or where the recovery of the cost of power purchased on behalf of customers was ensured would be less risky than a wires utility who has an obligation to purchase but no assurance of recovery of the costs of power purchased.

All other things equal, the wires utility with no obligation to provide power or with full assurance of power cost recovery would be less risky than a fully regulated integrated (i.e., with regulated generation) utility, as generation is considered to be fundamentally riskier than distribution or transmission. Although generally regulated wires utilities are regarded as less risky than regulated integrated

utilities, the specific circumstances need to assessed. For example, it would be difficult to know whether a fully regulated integrated utility is more risky than a regulated wires utility which has no assurance of power cost recovery without having full information about the two, e.g., the contractual terms under which the wires utility purchases power, the type of generation that the integrated utility operates and other available regulatory protections afforded to either company if any.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**CW-YECL-41**

**Issue:** Capital Structure

**Reference:** Foster Associates Report, page 20, lines 635-639

**Preamble:** Ms. McShane states: Approximately 12 of Yukon Electrical's rate base is comprised of generation assets (approximately 90 of which is diesel). The presence of generation assets in rate base generally increases the business risk of Yukon Electrical relative to a pure distribution utility, as the operational risks associated with generation exceed those of wires operations.

**Request:**

(a) What percentage of YECL's total supply is represented by these generation assets in rate base?

(b) Does YECL own transmission assets? If yes, what percentage of the rate base is comprised by transmission assets?

(c) Are transmission rate base assets considered more or less risky than generation assets? Please refer to the benchmark deemed capital structure of transmission only electric utilities in jurisdictions that employ a benchmark rate of return?

**Response:**

(a) Approximately 90 of Yukon Electrical's power is purchased, with the remainder comprised of 2.7 hydro generation and 7.3 diesel generation. See Schedule 3.2 of Yukon Electrical's application.

(b) Yes. Per depreciation schedules 7.2, 7.3 & 7.4 Yukon Electrical has a very small amount of transmission substation equipment. It represents approximately 1 of Yukon Electrical's property, plant, and equipment.

(c) Transmission operations are considered less risky than generation operations. To date in Canada only Alberta has set deemed capital structures for both regulated transmission and regulated (or semi-regulated; i.e., Heritage assets subject to PPAs) generation operations. The common equity ratios for transmission operations were set lower than for generation operations.

## CW-YECL-42

**Issue:** Capital Structure

**Reference:** Foster Associates Report, page 24, lines 635-639

**Preamble:** Ms. McShane states: With respect to the recent Northwest Territories Power Corp. (NTPC) decision, for the 2007 08 test year, the Public Utilities Board of the Northwest Territories adopted a common equity ratio of 48.86 and an incremental equity risk premium of 0.50 for NTPC, a higher business risk utility than Yukon Electrical.

**Request:**

(a) Please confirm that Ms. McShane references NWTPUB Decision 13-2007 previously mentioned at page 8 of the Foster Associates Report.

(b) In Decision 13-2007, the NWTPUB states at page 34, The Board considers, with the eventual retirement of the high cost sinking fund debt, the coverage ratios and the financial risk of the utility would likely improve. Therefore, the capital structure accepted by the Board should not be viewed as solely reflecting NTPC's business risks but rather as one that takes into account NTPC's particular circumstances with respect to high cost debt. Do the same circumstances of the cost debt being higher than the cost equity apply to YECL?

**Response:**

(a) Confirmed.

(b) No.

**CW-YECL-43**

**Issue:** Cost of debt

**Reference:** Application page 8-2, lines 10-14 and Schedule 8.2

**Preamble:** YECL states: The cost of debt includes the weighted average cost of all long term advances from Yukon Electrical's parent company. The cost of issuing the debt is included in the overall embedded costs. Yukon Electrical's forecast embedded cost of debt of 6.60 for the test period is based on Foster and Associates, Inc.'s 4.55 Long Canada Bond yield forecast, a 200 basis point spread and 5 basis points for issue costs.

**Request:**

(a) Is the 200 basis points based on the discussion at page 12, line 330 to page 13, line 375 of the Foster Associates Report? If not, or if YECL has supplementary evidence in support of a 200 basis points spread, please provide.

(b) On what does YECL base its issuance costs of 5 basis points? Please provide evidence or documentation that this is an appropriate estimate of issuance costs during the test years.

(c) Is the long Canada plus 200 basis points formula a notional prospective cost of debt rather than an actual prospective cost of debt?

(d) Are all other debt issues, other than Issues T and U, in Schedule 8.2 the actual costs of these issues?

**Response:**

(a) The 200 basis point spread is based on:

(i) Yukon Electrical's affiliated company, ATCO Gas, filed a 2008-2009 GRA using a 200 basis point spread. In that proceeding, ATCO Gas in response to IR, UCA-AG-67(b) Supplemental (filed March 12, 2008) stated:

*"(b) At the time of preparation of the rate application, it was the general consensus of our financial advisors that the financial markets were very volatile due to the sub prime credit crisis and that credit spreads were anticipated to go much higher than current levels being seen in the market at that time. While the ultimate impact of the sub prime crisis could not be known with certainty, the consensus of the financial advisors was that it would be significant and in the range of 200 basis points. The impact of the sub prime crisis continues to have a significant impact on the markets today and is expected to have a significant impact going forward. It is a common belief in the financial community that the impact on credit spreads has not yet peaked. The increase in credit spreads is evident in the response to CAL-AG 24(a) where the average historical spread for CU Inc.'s 30 year bonds was approximately 90 basis points as seen in June, 2007, and has jumped to approximately 130 basis points towards the end of 2007. Further, as of March 10, 2008 CU Inc.'s 30 year debenture spread is 154 basis points over long Canada bonds. This confirms the trend of increasing spreads and higher volatility that the financial advisors were predicting and because of the opinion that the crisis is not yet over, it is reasonable to assume a 200 basis point spread over the average long Canada bond rate for ATCO Gas' forecasted debenture rates."*

(ii) The data in response to (c) below supports the forecast 200 basis point spread, given the increasing spreads since mid 2007.

(b) CU Inc. issues debentures to the public and incurs issue costs. Based on a 100 million issue of debentures in each test year, CU Inc.'s estimated issue costs for each issue are as follows:

| **Type of Cost** | **Amount** |
|---|---|
| | ( ) |

| | |
|---|---|
| Underwriting fees (1) | 500,000 |
| Filing fees (2) | 15,000 |
| Rating agency annual fees and issue fees | 150,000 |
| Legal costs | 20,000 |
| Audit | 10,000 |
| Printing and other | 5,000 |
| Total | 700,000 |

Notes:
(1) 0.5 of amount issued.
(2) Based on a shelf prospectus and one pricing supplement per year. As a shelf prospectus has a two year life, one half of the shelf prospectus filing fees is included in the estimate. The estimate also assumes no additional filing fees are payable on sales to Alberta or B.C. purchasers.

For a 100 million 30 year issue with a coupon rate of 6.55 and issue costs of 700,000, the embedded rate would be 6.60 , or 5 b.p. above the coupon interest rate.

Yukon Electrical is forecasting that it will issue a 2,150,000 debenture in 2008 and a 5,200,000 debenture in 2009. The issue costs for each issue are forecast to be 15,000 and 36,000, respectively.

The gross proceeds of a CU Inc. issue is advanced to Yukon Electrical's parent, ATCO Electric Ltd., on the understanding that it will reimburse CU Inc. for its pro-rata share of the issue costs incurred by CU Inc. ATCO Electric, in turn, advances funds to Yukon Electrical on the same understanding i.e., that Yukon Electrical will reimburse ATCO Electric for its pro-rata share of the issue costs incurred by ATCO Electric.

In the case of ATCO Electric, the interest rate on the debenture it issues to CU Inc. is the same coupon interest rate as on the CU Inc. debentures issued to the public. ATCO Electric pays CU Inc. its pro-rata share of CU Inc.'s issue costs at the time the debenture is issued. ATCO Electric then amortizes the issue costs on a monthly basis over the term of the debenture.

In the case of Yukon Electrical, this monthly amortization is considered to be administratively inefficient, given the relatively small sums involved ( 50 and 100 per month, respectively). It is considered to be more efficient for the issue

costs to be rolled into the interest rate and be paid to ATCO Electric over the life of each debenture. Accordingly, the coupon interest rate on the Yukon Electrical debenture is set equal to the embedded rate (i.e., the debenture interest rate plus an amount to cover issue costs).

(c) This is Yukon Electrical's best estimate of the actual prospective cost of debt to CU Inc. that will be mirrored down to Yukon Electrical through its parent company ATCO Electric.

(d) Confirmed. It should be noted that Issues T and U are in Schedule 8.3 and do not appear in Schedule 8.2.

**CW-YECL-44**

**Issue:** Cost of debt

**Reference:** Application page 8-2, lines 10-14 and Schedule 8.2

**Preamble:** Ms. McShane states: In turn, Yukon Electrical should contribute its fair share toward the maintenance of the debt ratings through its own capital structure and return on equity. It would be inequitable for customers to receive the benefits of debt costs that reflect an A(high) A debt rating while the common equity ratio (or equity thickness) is only adequate, for example, for a (notional) BBB rating.

**Request:**

(a) In providing an A(high) A debt rating to CU Utilities, haven't the bond rating agencies already factored in the actual capital structures and returns on equity of YECL and its CU affiliates when determining CU's corporate bond rating? If not, why haven't the bond rating agencies taken YECL's financial performance into account when rating CU Utilities?

(b) Isn't Ms. McShane's proposition that Yukon Electrical should contribute its fair share toward the maintenance of the (CU) debt ratings through its own (thicker) capital structure and (higher) return on equity (brackets added) equivalent to extra compensation to CU for floating YECL's debt?

**Response:**

(a) Yes, in addition to other factors such as the degree of diversification. With specific respect to Yukon Electrical, it is too small to have a material impact on the overall performance of CU Inc., and thus its ROEs and capital structure are not likely to impact the debt ratings. That fact does not alter the principle cited in the preamble to the question.

(b) No, Ms. McShane's recommendations are based on the proposition that the combined capital structure and ROE adopted for Yukon Electrical should be consistent with its fundamental business risks, which are in part a function of its size, and the actual debt ratings of CU Inc.

**CW-YECL-45**

**Issue:** Capital Additions Forecasting accuracy

**Reference:** Schedule 9.1

**Preamble:** CW wishes to better understand YECL capital expenditure forecasting accuracy.

**Request:**

(a) Please expand Schedule 9.1 to also include actual and forecast plant additions for 2003 and 2004 and also forecast additions for 2005 to 2007.

(b) Please provide explanations for any variances between forecast and actual greater than 10 .

**Response:**

(a) There were no approved forecasts for 2003-2007 as these were not test years. Please refer to CW-YECL-45(a) Attachment 1 for actual additions from 2003-2007.

(b) Yukon Electrical does not have an approved forecast for 2003 2007 and cannot provide variances.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Plant Additions**
**( 000s)**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 |
|---|---|---|---|---|---|---|---|
| 1 | Work in progress, beginning of year | | 363 | 609 | 934 | 427 | 871 |
| 2 | **Generation:** | | | | | | |
| 3 | Generating Plants | | 597 | 925 | 825 | 638 | 476 |
| 4 | | | 597 | 925 | 825 | 638 | 476 |
| 5 | **Billing:** | | | | | | |
| 6 | New N60 Billing Systems | | - | - | - | - | 480 |
| 7 | | | - | - | - | - | 480 |
| 8 | **Distribution:** | | | | | | |
| 9 | New Extensions | | 1,344 | 1,837 | 1,923 | 2,433 | 3,106 |
| 10 | Distribution Improvements | | 1,567 | 1,660 | 2,899 | 2,858 | 2,070 |
| 11 | Street and Sentinel Lights | | 796 | 848 | 172 | 943 | 908 |
| 12 | Meters | | 37 | 46 | 17 | 77 | 37 |
| 13 | Transformers and Regulators | | 393 | - | 7 | - | 20 |
| 14 | | | 4,137 | 4,391 | 5,018 | 6,311 | 6,141 |
| 15 | **General property and equipment:** | | | | | | |
| 16 | Tools, Instruments & Equipment | | 25 | 48 | 59 | 55 | 48 |
| 17 | Office Furniture & Equipment | | 1 | 24 | 12 | 6 | 10 |
| 18 | Office Computer Equipment | | 12 | 235 | 5 | 3 | 0 |
| 19 | Communication Equipment | | 1 | 5 | 7 | 9 | 57 |
| 20 | Transportation Equipment | | 25 | 2 | 160 | 158 | 513 |
| 21 | Land and Buildings | | 51 | 53 | 30 | 136 | 84 |
| 22 | | | 115 | 367 | 273 | 367 | 712 |
| 23 | Miscellaneous Other | | - | - | | - | - |
| 24 | **Total capital expenditures** | | 4,849 | 5,683 | 6,116 | 7,316 | 7,809 |
| 25 | Less: Transfers to rate base | S.8.6 L.3 | (4,603) | (5,358) | (6,623) | (6,872) | (7,645) |
| 26 | Work in progress, end of year | S.8.5 L.5 | 609 | 934 | 427 | 871 | 1,035 |

**CW-YECL-46**

**Issue:** Capital Additions 2008 and 2009 Forecast

**Reference:** Pages 9-1 to 9-28

**Preamble:** CW wishes to better understand the 2008 & 2009 forecast capital additions.

**Request:**

(a) Generation Plants are forecast to cost 3,124,000 in 2009. Please provide detailed cost estimates for the Carcross New 1.5 MW Power Plant

(b) Distribution New Extensions are forecast to be 3,141,000 in 2008. Please provide detailed cost estimates for the Mountain Air Subdivision, the Hamilton Blvd Main Infrastructure Extension, Whitehorse Copper Phase II 2008, CoW Stan McGowan Subdivision, and the Selkirk FN Mino Connect.

(c) Distribution New Extensions are forecast to be 2,962,000 is 2009. Please provide detailed cost estimates for the Miscellaneous U G Services Various Subdivisions, Whistle Bend Subdivision, and Arkell Infill.

(d) Distribution Improvements are forecast to be 2,967,000 in 2008. Please provide detailed cost estimates for the Tagish Road Rebuild, Marsh Lake Reliability Fix, Yukon Electrical Tie Between 1st Street and 6th Avenues, and the Pelly Crescent to Grey Mountain H Frames

(e) Distribution Improvements are forecast to be 2,532,000 in 2009. Please provide detailed cost estimates for the Tagish Section to Tagu, the Hillcrest Conversion, Lambert Street DQ Alley, and Teslin Klondike Alley.

(f) Regarding Street and Sentinel Lighting, please provide detailed cost estimates for the CoW Hamilton Blvd. Extension Lighting in 2008 and the Miscellaneous Projects and Mountainview Other in 2009

(g) AMR Installation is forecast to be 330,000 and 3,855,000 for 2008 and 2009 respectively. Please provide the business case and detailed cost estimates. How many units are to be installed each year? Please provide a cost benefit analysis and indicate where the meter reading savings occur in the test years and thereafter.

**Response:**

(a) Below is the estimate information for the proposed new Carcross generator. The project scope is as follows:

- 1.5MW generator, self contained double walled environmentally approved fuel storage both intergraded and separate. The project also included a secure pad, step up transformation, grid interface material, protection, and automated system synchronizations.
- A quote from a third party vendor for the generator was estimated at 1.4M.
- The additional 0.6M is the estimate for the fuel system, substation upgrades (including ground grid and foundation), step up transformer, and automation as mentioned above. This portion of the estimate is based on similar type of work conducted by Yukon Electrical in other communities it serves.
- Total project costs 2.0M.

(b) The cost for Large Underground subdivisions are estimated based on a historic number of approximately 5,000 - 6,000 per lot for underground service. Variables are: the size of the subdivisions, digging conditions and proximity to main power lines and therefore estimates are adjusted accordingly. These per lot estimates are used in forecasting future subdivision costs. Overhead subdivisions would have a lower unit cost per lot again depending on lot size etc. Please refer to CW-YECL-46(b) Attachment 1 for estimating details for specific 2008 new extensions.

(c) Please refer to CW-YECL-46(b) Attachment 1 for estimate details for specific New Extensions in 2009.

(d) In regard to Distribution Improvements average costs for a km of line or a typical alley are used after the section of line is identified via justifications explained in other responses In addition similar projects from past years are reviewed and used as a baseline for estimating if appropriate. Please refer to CW-YECL-46(b) Attachment 1 for details on specific Distribution Improvement projects for 2008.

(e) Please refer to CW-YECL-46(b) Attachment 1 for specific Distribution Improvement projects for 2009.

(f) The Hamilton extension includes regularly placed street lighting located at standard distances. The approximate cost of street lighting can be determined on this basis. The length of the road was known so the number of lights could be determined. Detailed design, including the exact location of intersections, will be done a few months prior to construction in order to allow time to procure materials. For miscellaneous projects Yukon Electrical monitors the state of its aging infrastructures and designates portions of the system that have reached the end of their useful life for replacement. Yukon Electrical employs a number of approaches including ongoing testing and monitoring to ensure that such facilities are replaced in a systematic manner, as needed. Annual patrols identify which lights areas are most in need of work and then the specific locations are planned for change out.

(g) Please refer to the business case, YUB-YECL-15(c) Attachment 1.

NEW EXTENSIONS

1 Mountain Air Subdivision

| | | |
|---|---|---|
| Material | 191 | k |
| Labour | 109 | k |
| Metering | 52 | k |
| Other | 30 | k |
| Total | 382 | k |

2 Hamilton Blvd Infrastructure Extension 2008

| | | |
|---|---|---|
| Material | 160 | k |
| Labour | 117 | k |
| Other | 23 | k |
| Total | 300 | k |

trenching by customer

3 City of Whitehorse Stan McGowan Subdivision 2008

| | | |
|---|---|---|
| Material | 75 | k |
| Labour | 123 | k |
| Other | 17 | k |
| Total | 215 | k |

4 Whitehorse Copper Phase II (2008)

| | | |
|---|---|---|
| Material | 84 | k |
| Labour | 119 | k |
| Other | 22 | k |
| Total | 225 | k |

5 Selkirk First Nations Minto Connect (2008)
100-3 phase structures at 3500 structure

| | | |
|---|---|---|
| Material | 160 | k |
| Labour | 130 | k |
| Other | 60 | k |
| Total | 350 | k |

6 Arkell Subdivision (Infill 2009)
106 lots at 6100 per lot
650 k

7 Misc Underground subdivisions (2009)
various locations - 36 lots at 6100 lot

220 k
also based on historic actuals

8 Whistle Bend Subdivision (2009)
This estimate is based on a portion of the costs to be preliminary infrastructure design work including substation prep
190 k

DISTRIBUTION IMPROVEMENTS

1 Tagish road Rebuild 2008
very similar to Tagish rebuild in 2006 adjusted for minor differences (Length of line etc.)
180 k

2 Marsh Lake Rebuild 2008
Type of work similar to project undertaken in 2006 adjusted for differences
180 k

3 Pelly Crescent to Grey Mountain H Frames

| | |
|---|---|
| 3km of new line | 116 k |
| Other | 31 k |
| Brushing | 53 k |
| | 200 k |

4 Tagish to Taku (2009)
Similar work to Tagish work in 2006 and 2008
200 k

5 Hillcrest Conversion 2009
18 transformer at 5500 transformer
33 poles at 4500 pole
250 k

6 Lambert Street - DQ Alley 2009
Historical cost of similar alleys in the City such as 1st Ave.
300 k

7 Teslin - Klondike Alley 2009

Based on similar work undertaken
200 k

8 Yukon Electrical Tie between 1st and 6th Ave. 2008
This project was estimated based on a similar project in 2006(1st Ave Conv) adjusted for known differences.
400 k

STREET LIGHTING

1 Hamilton Blvd Extension Lighting 2008
Approximately 20 lights at 10k light
200 k

2 Miscellaneous Projects 2009
Based on historic infill lighting projects
23 lights at 10k light
230 k

3 Mountain View 2009
based on 10K per light
250 k

**CW-YECL-47**

**Issue:** Capital Additions North 60 New Billing Systems

**Reference:** Pages 9-11, 9-17

**Preamble:** CW wishes to better understand the 2007 actual and 2008 forecast capital costs for the North 60 New Billing System.

**Request:**

(a) Please provide a copy of the business case and any other documentation that explains the purpose of the North 60 New Billing System.

(b) Please explain the basis of the allocation of 480,000 (32 of the total project cost) to 2007 while 1,008,000 (68 of the total project cost) is allocated to 2008. What was the CWIP treatment of this project?

(c) Why is Yukon Electrical including these costs in rate base when it contracts for Billing Service with ATCO I-Tek (as per Schedule 5.3, line 11)? Shouldn't these costs be included in ATCO I-Tek charges?

**Response:**

(a) Please refer to YUB-YECL-16(b) Attachment 1.

(b) The billing system conversion began in 2007 with a forecast completion in 2008. The 480,000 reflects the costs incurred by Yukon Electrical through to December 31, 2007. In accordance with Generally Accepted Accounting Principles (GAAP), the billing system conversion project was treated as work in progress as of December 31, 2007.

(c) Yukon Electrical has contracted ATCO I-Tek to operate and maintain all aspects of the billing system from the receipt of monthly meter reads through to the customer receiving their monthly bill. In addition to these back office functions, Yukon Electrical has a small front line staff of Whitehorse based Customer Service Advisors (CSA's) who respond to customer requests and inquiries. The costs to complete the conversion are being capitalized by Yukon Electrical and are not part of the ongoing operating and maintenance fee charged by ATCO I-Tek.

**LE-YECL-1**

**Reference: Section 1**

**Requests:**

Page (P) 1-3, Line (L) 5: The said 5.9 and 5.1 increases for 2008 and 2009 respectively appear to be inconsistent with the information presented in Schedule 1.1, probably because revenues from Rider F are not shown. Please provide a more complete schedule.

**Response:**

Please refer to revised Schedule 2.1, Line 53 of the Application for the calculation of the rate increases.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**LE-YECL-2**

**Reference:** Section 1

**Requests:**

P 1-5, L 9: Income Tax rates have changed at various times during the 10 years between the last test years and the current test years, please explain why this deferral account is required now when it was not previously required.

**Response:**

This deferral account is required now as these income tax rates are not under the control of the company and are not reasonably forecastable. This is one of the criteria outlined on page 1-5 of the Application that Yukon Electrical is using in determining whether or not a deferral account is required.

As no deferral account for income tax rates was sought and approved as part of the 1996-1997 GRA and given that Yukon Electrical cannot implement a deferral account without Board approval, Yukon Electrical has been required to manage through the intervening years between GRAs without a deferral account on income tax rates.

**LE-YECL-3**

**Reference: Section 1**

**Requests:**

P 1-5, L 22: When filing this GRA it appears that YECL was aware that YEC was planning to file a phase I GRA later in 2008, and that a joint Phase II hearing would need to take place soon after that. Given the high fixed costs of hearings, which are ultimately paid by ratepayers, please justify why YECL has chosen a path which appears to anticipate 3 separate hearings instead of one consolidated hearing for joint YECL and YEC Phase I and Phase II proceedings. Please show how the ratepayers would benefit from the apparently more costly process adopted.

**Response:**

It is critical to understand that Yukon Electrical and YEC are two separate and distinct companies and are run as such.

Yukon Electrical has a responsibility to its shareowners as well as its customers to run the company efficiently. A measure that Yukon Electrical has run the company effectively would be the avoidance of any rate increases since the 1996-1997 proceeding[1]. To this end, it is important for Yukon Electrical to file any general rate application in a timely manner that will allow for a decision prior to the end of the first test year. It was not possible in discussion with YEC for a joint Phase I filing to be coordinated to meet this timeframe.

It is also important to note that given Yukon Electrical and YEC are two separate and distinct companies with separate and distinct issues, it is not clear that significant savings would be realized from a consolidated hearing.

[1] The impact of increases or decreases in the actual price of diesel fuel as compared to the 1997 GRA forecast have been flowed through to customers via the Rider F mechanism.

## LE-YECL-4

**Reference: Section 1**

**Requests:**

Organizational Chart: Please provide a similar charts with FTEs for 1997, the last test year examined by the Yukon Utilities Board (the Board), and for 2007.

**Response:**

The last approved test period was 1996 1997. Information provided in response to information requests is in accordance with Board Order 2008-05, which confirmed that Yukon Electrical is not required to provide information prior to 2003 to test the revenue requirement. Please refer to CW-YECL-8(d) Attachment 1.

## LE-YECL-5

**Reference: Section 2**

**Requests:**

P 2-2, L 2: Please provide schedule 2.1 including in each year any additional revenue recoveries such as from Rider F.

**Response:**

There are no additional revenue recoveries beyond those already provided in Schedule 2.1 of the Application. The Diesel Fuel Price Rider (Rider F) accounts for the difference between the actual and final approved forecast fuel prices and either a recovery from or refund to customers. The actual Rider F fuel variance is detailed on Schedule 4.1 line 5.

**LE-YECL-6**

**Reference:** Section 2

**Requests:**

P 2.2, L 17: Please explain how YECL has dealt with UPC in light of recent significant increases in the price of heating fuel, noting that heating with fuel oil is now more expensive than electric heating at present rates. What is the forecasted increase, if any, in UPC (and more particularly in winter) for residential and general service customers?

**Response:**

While Yukon Electrical recognizes the volatility in the price of oil, it is unable to confirm the statement that heating with fuel oil is now more expensive than electric heating at present rates as now and present rates are relative terms. Please refer to YCS-YECL-9 as well YEC-YECL-2(h) for further comments on the forecast UPC as well as factors that might influence it on a go forward basis.

**LE-YECL -7**

**Reference:** Section 2

**Requests:**

P 2-4, L 3: If residential UPC is expected to remain flat why does an increase in customers of 1.9 result in only a 1.3 in sales?

**Response:**

Yukon Electrical would like to clarify that The growth is mainly driven by customer additions partially offset by a decrease in residential UPC .

The small decrease in residential UPC from 9,825 kWh customer in 2007 to 9,766 kWh customer in 2008 is mainly due to the use of a weather normalized UPC for the test period.

**LE-YECL-8**

**Reference: Section 3**

**Requests:**

P 3-1, L 4: Given that YEC has in previous proceedings before the Board indicated that they expect rates to go down as a result of power service to the Sherwood Copper's Minto Explorations mine at Minto why has YECL assumed that purchased power costs will remain flat? What work has YECL done to determine if this is a valid assumption?

**Response:**

Yukon Electrical is not aware of the magnitude of the rate reduction that is being proposed by YEC. Once this matter has been determined by the YUB then in accordance with Yukon Electricals deferral account treatment for purchase power it will pass on the changes to customers.

## LE-YECL-9

**Reference: Section 3**

**Requests:**

P 3-2, L 13: This paragraph discusses the diesel contingency fund and the fact that diesel generation may be on the margin on the WAF system in some months of the year. Schedule 3.2 does not indicate a significant change in forecasted diesel generation by YECL on the WAF system. What is the connection to a decrease in forecasted hydro generation from Fish Lake hydro, please explain.

**Response:**

For purposes of the test years, Yukon Electrical's WAF grid diesel plants are expected to act only as stand-by plants. If WAF diesel should be on the margin due to the connection of the Minto Mine, Yukon Electrical has assumed YEC's larger diesel units will be run to meet the additional WAF system demand.

When diesel is on the margin on the WAF system, the existing mechanisms of the Diesel Contingency Fund result in a financial adjustment if Yukon Electrical or YEC actual hydro generation is higher or lower from long term averages.

## LE-YECL-10

**Reference:** Section 4

**Requests:**

P 4-1, L 4: This table does not provide the actual diesel costs incurred in 2006 and 2007 as it does not include costs recovered through Rider F. Can YECL confirm that this is the ***Fuel Expense*** as per line 6 of Schedule 4.1 rather than the diesel ***Fuel Costs*** as shown in line 4 of Schedule 4.1?

**Response:**

Confirmed.

## LE-YECL-11

**Reference:** Section 4

**Requests:**

P 4-2, L 12: What is the price of oil on a dollars per barrel basis that corresponds to the forecasted diesel fuel prices in each of 2008 and 2009? Has the price of oil increased since the forecasts were prepared? Is a revision to this GRA now required?

**Response:**

The forecasted diesel fuel prices were not based on any index to the price of a barrel of oil. The price of oil has increased since this application was prepared. A revision to this GRA and all that that entails is certainly not required due to the mechanisms incorporated into the longstanding deferral account in place for differences between actual and forecast diesel prices.

## LE-YECL-12

**Reference: Section 4**

**Requests:**

Schedule 4.2: Please explain how fuel can be purchased for standby purposes at rates far lower than for primary power generation. If these figures are not the fuel purchase costs, please provide the forecasted fuel purchase costs.

**Response:**

Fuel cannot be purchased at a lower price for a standby plant as compared to an operating plant. However the filling of fuel tanks and purchase frequency is generally far less at standby plants than it is at operating plants. This means that existing fuel inventories at standby plants include fuel that was purchased at a lower price in the past and has not been used to date.

**LE-YECL-13**

**Reference: Section 4**

**Requests:**

What actions has YECL undertaken to improve the heat rates in each of these communities? Are any actions planned for 2008-2009?

**Response:**

Heat rates have remained relatively flat over the years for the plants operated by Yukon Electrical. Heat rates do vary based on which units are running (when and for how long), how old the unit is and where it is in its maintenance cycle. Anomalies are investigated if and when they occur. Yukon Electrical has incorporated the following in order to improve heat rates:

- Utilize integrated Glycol systems designed to minimize idle time before engine goes to rated speed.
- Yukon Electrical has installed a second distribution feeder in some communities to allow existing (smaller) units to be able to pick up load after an outage.
- Yukon Electrical considers heat rates when purchasing new generating units.
- Sizing units appropriate to the load in a given community, if appropriate.

**LE-YECL-14**

**Reference: Section 4**

**Requests:**

What actions has YECL undertaken to investigate other forms of power generation to reduce or to stabilize costs? If no investigations have been undertaken please explain why. Are any actions planned for 2008-2009?

**Response:**

Yukon Electrical has been having discussions with some of its diesel served customers on exploring micro-hydro opportunities. In fact, Yukon Electrical has a confidential Memorandum of Understanding with one customer group on a microhydro project. Initial data collection on water flows has been completed and the project will move to the next stage of pre-feasibility. In the past Yukon Electrical has worked with customers and their consultants regarding the incorporation of wind energy into the diesel production mix.

Yukon Electrical also monitors other jurisdictions such as the Northwest Territories to ascertain if there are alternate sources of generation for diesel communities. To date Yukon Electrical is not aware of any non grid connected generation alternative that has proven financially beneficial or that meets the reliability standards that are required in the jurisdictions it has looked at.

Yukon Electrical is participating in the development of a Yukon Government Energy Strategy and has provided input to government officials into its thoughts on how the strategy may best serve Yukoners.

Yukon Electrical participates in seminars, workshops and conferences when appropriate to learn more about technologies such as wind and solar and to determine if break throughs have been made that will allow for successful conversion of diesel communities.

In addition Yukon Electrical takes advantage of any grid extension that could remove customers from diesel onto hydro such as it is doing in Pelly Crossing.

Yukon Electrical has not included any costs in its revenue requirement for research and development looking at new technologies. Yukon Electrical will, however, continue to support worthwhile initiatives being pursued by qualified groups and lend its expertise as necessary. If there are viable solutions and alternatives being put forward, Yukon Electrical is always prepared to review the information for applicability in serving its diesel communities.

**LE-YECL-15**

**Reference: Section 4**

**Requests:**

Are there any plans to implement any alternative sources of power? Please explain.

**Response:**

Please refer to LE-YECL-14.

**LE-YECL-16**

**Reference: Section 4**

**Requests:**

What demand side management (conservation and efficiency improvement) programs has YECL undertaken to reduce consumption in these communities and therefore costs to all Yukon ratepayers? If no programs have been undertaken please explain why. Are any programs planned for 2008-2009?

**Response:**

Yukon Electrical has taken the approach that education and providing information to consumers is the practical and cost effective focus of its efforts regarding promoting efficiency and conservation in the communities it serves. Yukon Electrical makes available a variety of printed material to assist customers in energy planning. These include:

- Managing Electricity Costs
- Make Your Home Powersmart
- Guide to Conservation

These same publications are also available on Yukon Electrical's website.

Yukon Electrical works closely with the Energy Solution Center (ESC) in a number of ways including the following:

- Providing information and data that is helpful to ESC in developing their energy programs for Yukoners.
- Yukon Electrical includes bill inserts comprised of materials that ESC wants to get out to the public.

- Yukon Electrical refers its customers to the ESC for assistance with home audits etc.

Yukon Electrical also places ads in Yukon newspapers that provide conservation tips to customers.

Yukon Electrical proposes to update its energy management publications and information on its website and continue to make the information available to its customers throughout the test period. Yukon Electrical will also continue to work with the ESC and the Government of the Yukon with respect to their various initiatives.

## LE-YECL-17

**Reference: Section 5**

**Requests:**

P 5-2, L 17: Please provide labour inflation data for Canada as a whole, Alberta, British Columbia, and Yukon for 2003 to 2007. If similar data for electric utilities is available from the Canadian Electrical Association, or similar organization, please provide that.

**Response:**

LE-YECL-17 Attachment 1 is a report from Alberta Finance and Enterprise that provides the information requested. It is important to note that the numbers reflected in the report do not necessarily show market adjustments that can occur to base salaries but rather it would show the economic increases that have been afforded to the various sectors in Alberta and Canada.

In regard to labor inflation data from CEA for the electric utility sector Yukon Electrical was not able to locate such data. However, LE-YECL-17 Attachment 2 is a CEA report on the labor market in the Electrical Utility sector. It serves as further information as to why labour cost increases are and will continue to be a likely reality in the industry.

# Economic Spotlight

**ALBERTA FINANCE AND ENTERPRISE**
**Budget and Fiscal Planning**
July 7, 2008

## WAGE UPDATE

### 2008 WAGE SETTLEMENTS

In the first five months of 2008, Alberta's negotiated wage settlements averaged 3.8% (Table 1). 57% of the employees covered by the settlements were from the private sector. Private sector wage settlements averaged 5.7% compared to 1.2% in the public sector. In January, a province-wide agreement was struck between all 62 school authorities and the Alberta's Teachers' Association. However, most of the 34,000 employees covered under the agreement are not included in Table 1 as each region needed to ratify the agreement separately and the data were not available to be included in the most recent wage settlements information.

Nationally, negotiated wage settlements have averaged 3.2% in the first four months of 2008. Settlements averaged 3.1% in the public sector and 3.6% privately.

**Table 1:**
**Trends in Negotiated Wage Settlements**

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008YTD[c] |
|---|---|---|---|---|---|---|---|
| **Alberta: Negotiated Wage Settlements** [a] | | | | | | | |
| **All Industries** | | | | | | | |
| Number of Employees | 84,047 | 74,942 | 96,232 | 62,282 | 51,091 | 54,518 | 12,221 |
| Wage Settlement (percent) | 5.0 | 3.1 | 3.4 | 3.2 | 2.7 | 4.7 | 3.8 |
| **Public Sector** | | | | | | | |
| Number of Employees | 68,298 | 49,435 | 59,237 | 38,965 | 31,981 | 24,158 | 5,194 |
| Wage Settlement (percent) | 5.3 | 3.6 | 3.5 | 3.2 | 3.6 | 3.2 | 1.2 |
| **Private Sector** | | | | | | | |
| Number of Employees | 15,749 | 25,507 | 36,995 | 23,317 | 19,110 | 30,360 | 7,027 |
| Wage Settlement (percent) | 3.4 | 2.3 | 3.1 | 3.2 | 1.1 | 5.8 | 5.7 |
| **Canada: Negotiated Wage Settlements** [b] | | | | | | | |
| **All Industries** | | | | | | | |
| Number of Employees | 985,195 | 628,970 | 847,410 | 1,356,270 | 830,875 | 797,455 | 196,600 |
| Wage Settlement (percent) | 2.8 | 2.5 | 1.8 | 2.3 | 2.5 | 3.3 | 3.2 |
| **Public Sector** | | | | | | | |
| Number of Employees | 760,060 | 469,350 | 468,350 | 1,157,200 | 636,130 | 375,160 | 147,280 |
| Wage Settlement (percent) | 2.9 | 2.9 | 1.4 | 2.2 | 2.6 | 3.4 | 3.1 |
| **Private Sector** | | | | | | | |
| Number of Employees | 225,135 | 159,620 | 379,060 | 199,070 | 194,745 | 422,295 | 49,320 |
| Wage Settlement (percent) | 2.6 | 1.2 | 2.3 | 2.5 | 2.2 | 3.1 | 3.6 |

[a] Source: Alberta Employment and Immigration
[b] Source: Human Resources and Social Development Canada
[c] Data on negotiated wage settlements for Canada are Jan-Apr; Data for Alberta are Jan-May.

On an industry basis, the most notable increases in wage settlements were recorded in the transportation and warehousing (7.5%) and manufacturing (5.8%) industries (Table 2).

**Table 2. Negotiated Wage Settelements Selected Industries, Alberta**

| ( change) | 2006 | 2007 | 2008YTD |
|---|---|---|---|
| Construction | 6.4 | 5.9 | 5.7 |
| Mining, oil and gas | 3.7 | 7.1 | - |
| Public Admin | 3.8 | 6.1 | 5.3 |
| Transportation | 3.4 | 4.5 | 7.5 |
| Manufacturing | 3.3 | 4.7 | 5.8 |
| Trade | 3.4 | 4.5 | - |
| Health | 3.1 | 4.7 | - |
| Education | 3.7 | 1.8 | 1.0 |
| **Total** | | | |

**Source: Employment and Immigration**
**Jan-May**

## AVERAGE WEEKLY EARNINGS[1] and LABOUR INCOME

In the first four months of 2008, Alberta's average weekly earnings (AWE), which include overtime, increased by 5.2%, following growth of 4.5% in 2007 and 4.9% in 2006. This is above national AWE growth of 3.0% over the same period. Inflation in Alberta averaged 3.3% over the first four months of the year, compared to 1.7% nationally (Table 3).

Total labour income, which is also influenced by employment growth, posted growth of 8.8% in the first quarter of 2008 compared to the same period last year. This is down from 11.5% in 2007 and 15.4% in 2006. Nationwide, labour income increased by 5.4% in the first quarter of 2008. Employment in Alberta is up 3.2% through April compared to the same period last year.

**Table 3:**
**Trends in Wage and Inflation**

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008YTD[a] |
|---|---|---|---|---|---|---|---|
| **Average Weekly Earnings Growth (including overtime)** | | | | | | | |
| Alberta | 2.3% | 1.4% | 3.0% | 5.2% | 4.9% | 4.5% | 5.2% |
| Canada | 2.1% | 1.4% | 2.1% | 3.2% | 3.0% | 3.2% | 3.0% |
| **Inflation (in percent)** | | | | | | | |
| Alberta | 3.4% | 4.4% | 1.4% | 2.1% | 3.9% | 5.0% | 3.3% |
| Canada | 2.2% | 2.8% | 1.8% | 2.2% | 2.0% | 2.2% | 1.7% |
| **Labour Income (% chg)** | | | | | | | |
| Alberta | 3.3% | 4.5% | 9.7% | 14.0% | 15.4% | 11.5% | 8.8% |
| Canada | 3.3% | 3.9% | 5.7% | 5.8% | 6.6% | 6.3% | 5.4% |

Source: Statistics Canada.
[a] Data on average weekly earnings and inflation are Jan-Apr; labour income data are Jan-Mar.

Growth in AWE has been strong across the board in the first four months of 2008 (Table 4). Growth has been strongest in utilities, oil and gas, health care and transportation.
Nationally, AWE increased by 3.0% in the first

**Table 4. Average Weekly Earnings Selected Industries, Alberta**

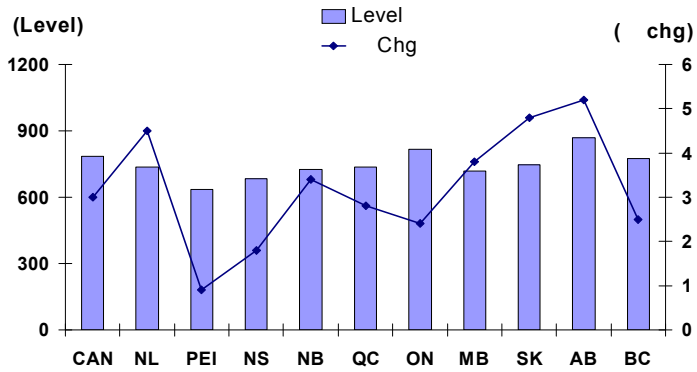
| ( change) | 2006 | 2007 | 2008YTD |
|---|---|---|---|
| Transportation | 1.8 | 5.6 | 6.7 |
| Health | 5.2 | 5.3 | 6.7 |
| Oil and Gas | 2.6 | 3.2 | 9.0 |
| Utilities | 3.0 | 4.4 | 11.6 |
| Construction | 3.6 | 5.4 | 4.5 |
| Manufacturing | 3.7 | 3.9 | 4.6 |
| Public Admin | 3.9 | 4.1 | 5.9 |
| Education | 4.4 | 3.5 | 6.5 |
| **Total** | **4.9** | **4.5** | **5.2** |

**Source: Statistics Canada**
**Jan-Apr**

[1] Average weekly earnings is defined as total dollars earned divided by the number of people who worked during a specified time period.

four months of 2008. AWE in Saskatchewan grew the second fastest in country, second to Alberta, with growth of 4.8% (Chart 1). Newfoundland and Manitoba also posted solid gains in wages, both growing by around 4.0%. Alberta continues to have the highest AWE level among the provinces, averaging at $867.50 this year. This is followed by Ontario at $816.80.

**Chart 1. Average Weekly Earnings By Province, 2008 YTD**




Economics and Statistics
For further information, call Bryce van Sluys 427-8345 Mary MacGregor 427-8790

# PROVIDING RELIABLE ENERGY IN A TIME OF CONSTRAINTS: A NORTH AMERICAN CONCERN

Canadian Electricity Association

**April 2008**

Canadian Electricity Association canadienne de l'électricité



The voice of Canadian Electricity. La voix de l'électricité canadienne.

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Canadian Electricity Association
Association canadienne de l'électricité
www.canelect.ca

# Providing Reliable Energy in a Time of Constraints: A North American Concern

## Executive Summary

The North American electricity market is facing significant constraints today and for the foreseeable future that could negatively impact the reliability of the North American market. In terms of generation resources, government initiatives to control carbon and other emissions and to show preferential treatment to emerging technologies over conventional technologies, as well as uncertainty in regulatory processes, could lead to supply constraints in certain regions. Further, the lack of sufficient transmission investment over the last few decades has resulted in constraints on certain portions of the North American transmission grid, while the construction of a growing array of smaller projects has raised new concerns about the sufficiency of transmission capacity to accommodate a differently configured supply system. These issues and labour supply shortages are raising concerns about the long-term security of the North American electricity market. The economic health of both our countries requires the attention of decision-makers in both Canada and the United States to address these issues.

Given the close and extensive relationship between the U.S. and Canada, measures to address constraints should be considered in the context of the North American energy market. The North American electricity system, which interconnects Canadian and U.S. electricity markets, is among the most integrated and reliable in the world and combines a diversity of fuel sources, extensive transmission interconnects and two-way trading that benefits both countries. The integration between these two countries provides the framework for greater trade and greater market opportunities between our countries.

Increased integration of the U.S./Canadian marketplace and coordinated actions between the countries will enable Canada and the United States to provide reliable energy in a time of constraints. CEA believes that the following measures would reduce constraints across the North American market:

- Working cooperatively to increase generation supply, including both mature and emerging technologies;
- Enhancing the cross-border transmission grid by increasing transmission capacity, implementing bi-national transmission reliability rules, building transmission for new generation, and ensuring critical infrastructure protection;
- Avoiding barriers to cross-border electricity trade;
- Promoting demand-side measures and energy efficiency/conservation;
- Coordinating strategies to address environmental concerns; and
- Managing labour shortages.

As major players in the global energy market whose economies turn on a robust and reliable energy sector, both Canada and the U.S. must ensure a reliable energy supply in the future. Such energy reliability can be built on the existing energy trading relationship and the opportunities for enhanced trade between the countries. The continued emphasis on the integrated U.S. and Canadian energy markets provides an excellent means to ensure energy reliability for both countries and avoid constraints on the system. In both Canada and the U.S., long-term growth and the need to replace aging assets will require large - scale technology projects alongside smaller-scale emerging technology projects. Making generation, transmission and labour constraints a North American concern makes sense from both an economic and a political perspective.

## I. Market Overview: The Integrated U.S./Canadian Electricity Market

The diversity of the Canadian and U.S. electricity systems, the different balances of conventional and emerging technologies in our various regional generation mixes, and the differing market demands region by region over days, weeks, and seasons, have prompted a level of trade that benefits electricity consumers in every region across the continent. When linked across the international border, our diverse systems have created opportunities for efficiencies in regional systems management, reduced environmental impact, and improved reliability; these are vital achievements for all concerned.

### A. Details of the Integrated Market

The map of the North American Transmission Grid below offers a clear visual indicator of the extent of current integration. Electricity trade occurs at a range of points across the Canada-U.S. border, as shown on page 3, reflecting the largely north-south nature of the Canadian grid, as it is integrated with the more dense web of transmission infrastructure in the U.S.

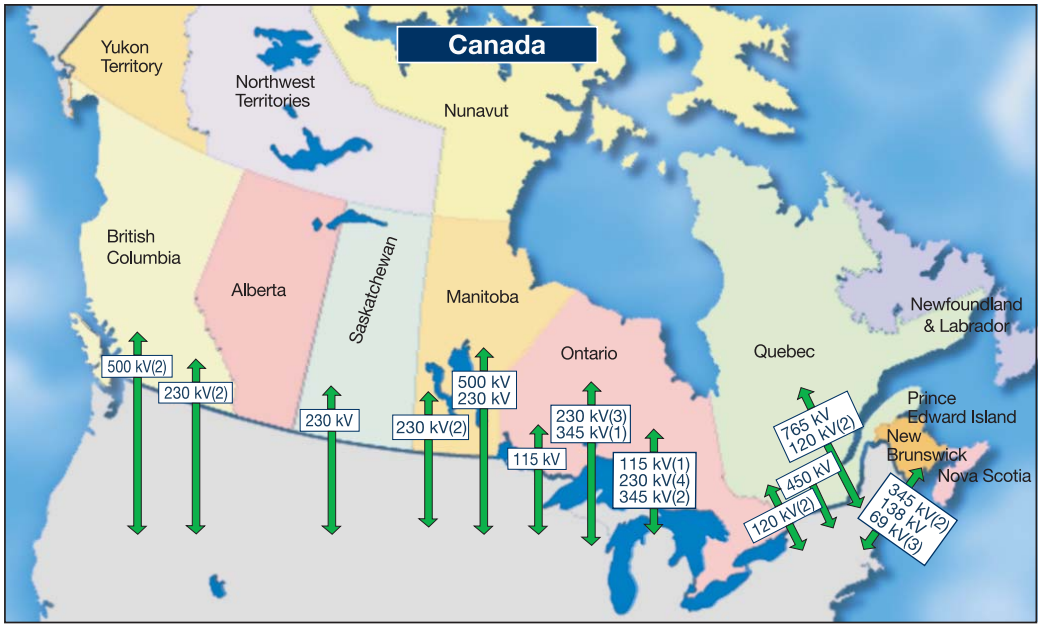
## North American Transmission Grid




Map copyright CEA. Lines shown are 345kV and above. There are numerous interconnections between Canada and the U.S. under 345kV that do not appear on this map.

Cross-border trade enables market participants to take advantage of diversity between the Canadian and U.S. electricity systems. The diversity and complementarity of our systems are first demonstrated by the different balances of various mature and emerging technologies in our generation mixes. These differences primarily reflect availability of resources, as different geographic regions have access to different input resources. The pie charts show the generation mixes for Canada and the U.S.

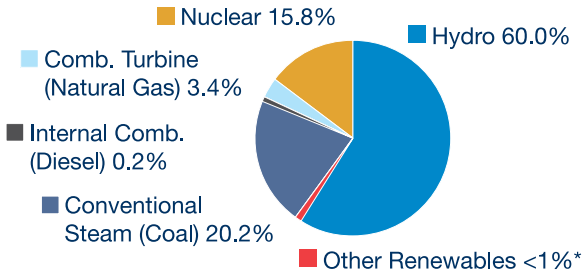
## Major Transmission Interconnections between Canada and the U.S.




Note: The numbers indicate the voltage of the power lines from each province to the states.
If there is more than one line with a given voltage, the number of lines is indicated in parentheses.
Source: NEB, Canadian Electricity Association and Natural Resources Canada.

## Electricity Generation by Fuel Source in Canada and the U.S., 2006

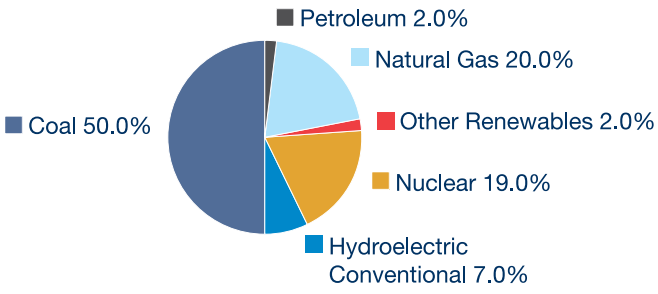
### Canada
**Net Electricity Generation, 2006**




Total = 584.4 TWh

Source: Statistics Canada
Survey 2151

### U.S.
**Net Electricity Generation, 2006**




Total = 4,065 TWh

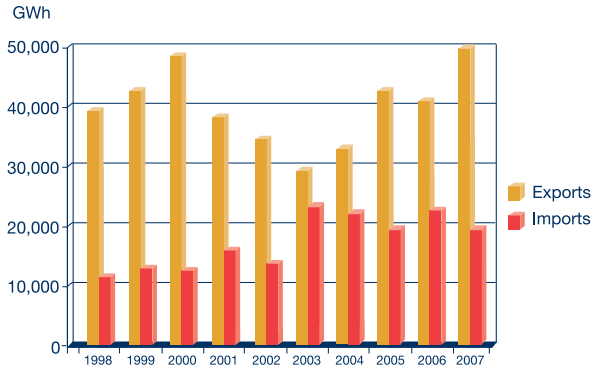
Source: Energy Information Administration
Electricity Power Annual

*2006 data was unavailable at the time of publication.
Numbers are based on 2005 data.

Electricity is now established as a key and growing part of the larger energy trade between the two countries, and it is increasingly two-way. Electricity trade between Canada and the U.S. stems primarily from two sources. First, generators in Canada are key suppliers to particular U.S. markets. In addition, generators in both countries take advantage of the trading relationship (for example the interaction between the competitive markets of Ontario, NYISO and MISO) to optimize the performance of their respective asset portfolios, which contributes to lower electricity costs and higher overall system efficiency and reliability. The bar graph demonstrates the extent of this two-way trading relationship.

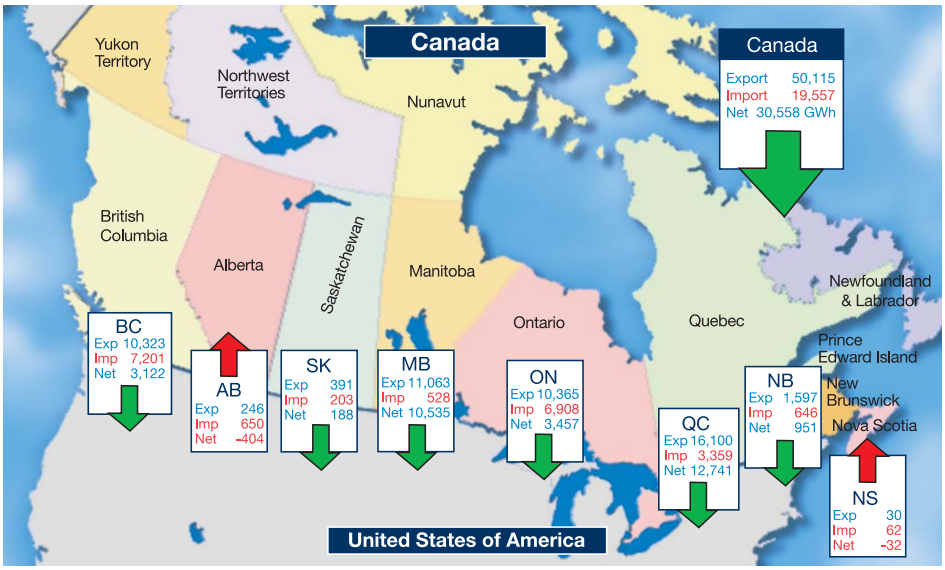
The quantity of electricity exported from Canada has typically been 6 to 10 percent of production. At the same time, electricity imports to Canada have increased over time. The fundamental point is that the market is a borderless one, and supply meets demand north to south or south to north as that market requires, to the advantage of consumers across the continent. Robust competitive wholesale markets in both the U.S. and Canada rely on integrated U.S./Canadian markets. As the markets continue to open, the importance of cross-border trade will only increase.

**Electricity Exports from Canada and Imports from the U.S., 1998-2007**




Source: NEB Electricity Exports and Imports, Monthly Statistics, various years.

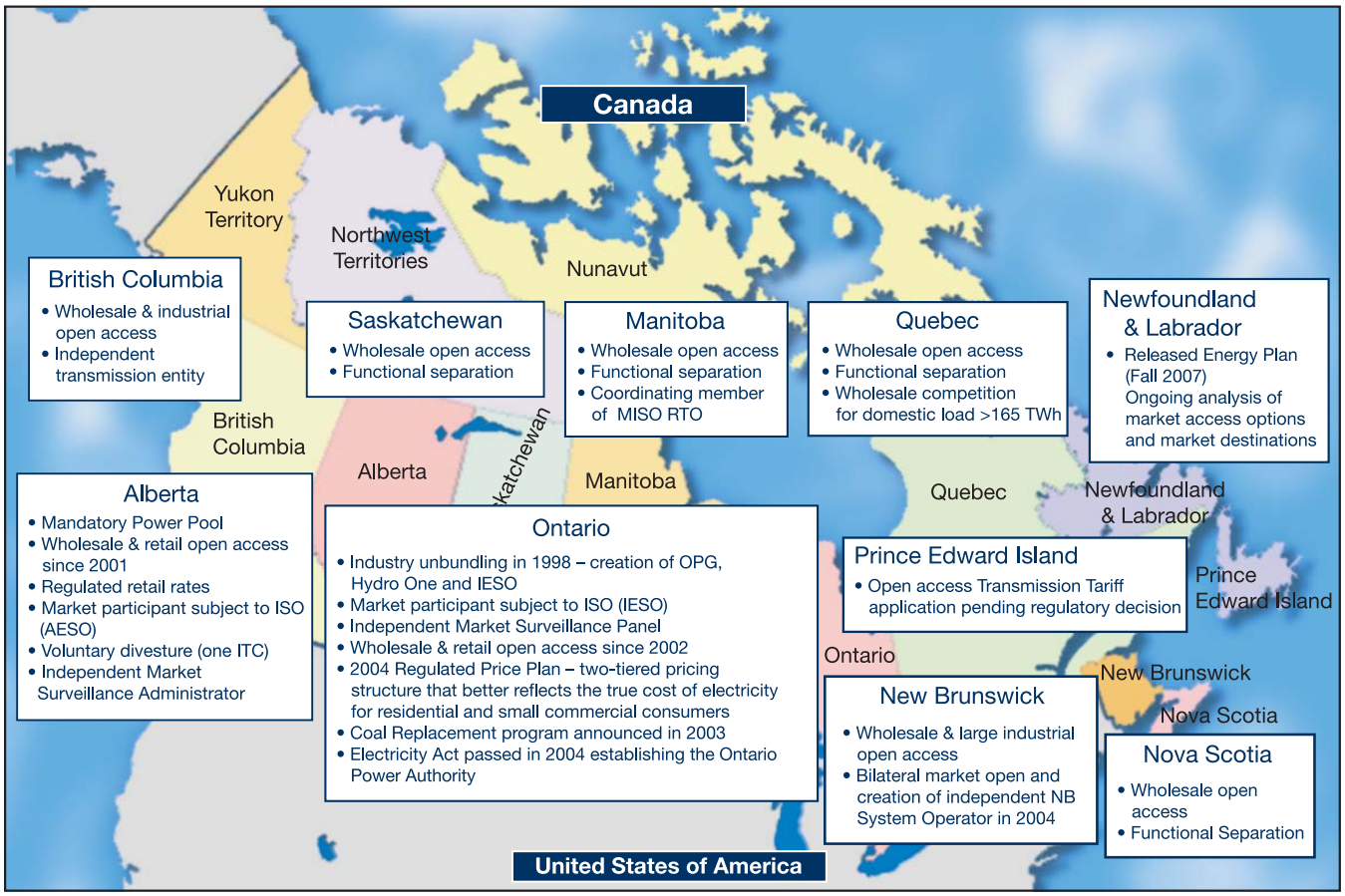
## Exports and Imports between Canada and the U.S., 2007




Source: NEB Electricity Exports and Imports, January 2007 to December 2007.

Restructuring of the electricity industry has followed a similar pace in both Canada and the U.S., although the drive to open markets in both countries appears to have stopped. Currently, approximately 50 percent of Canadian retail customers are in open markets (although regulated rates remain available to retail customers in both Ontario and Alberta). The map on page 5 describes market restructuring in Canada.

**Market Restructuring in Canada, 2008**




## II. Setting the Stage: Constrained Resources in the North American Electricity Market

Canada and the United States enjoy the most significant trading relationship in the world. On a daily basis, that trading relationship exceeds $1.3 billion in value, a significant portion of which is energy. Canada is America's largest supplier of energy, accounting for 94% of natural gas imports, nearly 100% of electricity imports, and more crude and refined oil products than any other foreign supplier. And in terms of electricity trade, in 2006, the U.S. imported 36.4 million megawatt hours from Canada and exported 18.5 million megawatt hours to Canada. More important to the U.S./Canada relationship, such electricity trade enhances the reliability of each country's transmission system, allows for the sale of surplus power, and mitigates risk by providing for power during times of emergency outages or periods of high electricity demand.

But the electricity market is facing significant constraints, today, and for the foreseeable future, that could hurt that trading relationship, and those constraints need the attention of decision-makers in both Canada and the United States. If not designed carefully various policies and government initiatives, such as those to control carbon emission, other emissions and those to mandate emerging technologies could lead to supply constraints in certain regions. Further, the lack of sufficient transmission investment over the last few decades has resulted in constraints on certain portions of the North American transmission grid, while the construction of a growing array of smaller projects has raised new concerns about the sufficiency of transmission capacity to accommodate a differently configured supply system. These issues and labour supply shortages are raising concerns about the long-term security of the North American electricity market.

**A. Constraints in Generation Supply**

Both Canada and the U.S. are experiencing growing economies and rising populations, with consequential increases in electricity demand. With such increases, as well as the retirement of aging or environmentally-underperforming facilities, increases in generation capacity will be required in our respective countries. Both the U.S. and Canada project the need to increase generation capacity by approximately 25 percent by 2025 to satisfy demand.

This need for new generation capacity in both Canada and the U.S., however, comes at a time when public concern about environmental issues is high. Mature generation sources such as coal, large hydro, or nuclear, remain important components of the North American energy supply mix, and measures to address environmental issues must not limit North America's ability to ensure reliable and adequate generation capacity through their use. For example, Canada and the US are both pursuing aggressive measures to address climate change that can have fundamental effects on generation supply choices. In both countries, some advocates suggest that the solutions to climate change are all associated with emerging technologies. Too often the roles for more mature technologies in a carbon constrained future are glossed over. Diversifying the generation portfolio is good for ensuring sufficient generation capacity in both countries, but limiting the options available will lead to constraints in generation supply – and ironically this could have an adverse impact on the environment.

**B. Transmission Constraints**

The North American transmission grid is experiencing constraints in several markets, and constraints will likely increase unless adequate investment in transmission capacity is advanced in the near-term. In the North American Electric Reliability Corporation's ("NERC") 2007 Long-Term Reliability Assessment, NERC maintains that significant investment in transmission is required in many areas of North America as projected transmission additions lag behind demand growth and new resource additions. According to this assessment, the total number of transmission miles is projected to increase by 8.8 percent in the U.S. and 4.8 percent in Canada over the next ten years. While this is more than a 30 percent increase in proposed transmission miles since last year's assessment, NERC maintains that more investment is still required, as each peak season puts more and more strain on the transmission system.

Adding to an already congested system is the growth of renewable resources and the need for transmission infrastructure to integrate these resources. As NERC noted in its Long-Term Assessment, such resources are often remotely located, requiring significant transmission links often over challenging terrain. Transmission is thus the enabling link to renewable generation and must be constructed in anticipation and in advance of renewable generation resources.

While the integrated U.S./Canadian electricity market enjoys the benefits of cross-border trade, constraints along the border and within large regional markets inhibit trade growth. Several examples exist of supply potentially available to constrained regions that cannot access the markets because of transmission congestion. This is true across the Canada/US border, particularly in the Pacific Northwest, Manitoba and bordering states, and in the northeast. Increases in electricity demand without corresponding increases in transmission investment will further inhibit this important trading opportunity.

**C. Labour Constraints**

The complex and expansive North American electricity system is facing significant labour force challenges in the years ahead. An aging workforce and pending retirements could have dramatic impacts on an industry already challenged by increasing demand and technology change. And these constraints are being felt in both Canada and the United States.

The Canadian utility industry currently employs 98,000 people. According to the *Canadian Electricity Human Resources Sector Study*, commissioned by CEA in 2004, almost 40 percent of the electricity sector's non-support staff will be eligible to retire by 2014. Retirement estimates show that the sector will need more than 17,000 people in technical positions in the next 8 years.

The problem is no different in the U.S.. According to the NERC Long-Term 2007 Assessment, the industry workforce is aging. At the same time, by 2015, there will

be a 25 percent increase in demand for industry workers. In a recent study performed by the U.S. Department of Energy, that agency projects, with anticipated retirements, the U.S. industry could see a potential workforce shortage of electrical line-workers of nearly 20 percent of the current workforce. And the situation is not much better for electric power and transmission engineers.

New construction and modifications to all aspects of the electricity systems in Canada and the U.S. are required, involving new technologies and a substantial increase in the workforce to accommodate such construction and modifications. However, the shrinking industry workforce is putting in jeopardy the ability of the industry to respond to increasing generation and transmission needs. In addition, training requirements pose a new set of challenges to the industry. The evolution of technologies in the electricity sector is constant, with developments such as increased distributed generation, the introduction of new software-based technology systems, and "green" technologies. These new technologies have created the need for new training and skills development, and "re-skilling" of the existing and future labour forces versed in both "old" and "new" technologies. A shortage of properly trained and skilled labour could have serious repercussions for the electricity sector, leading to reduced reliability, increased cost of production, infrastructure project delays, and decreased safety and productivity due to less experienced employees and worker shortages.

## III. Measures to Address Constraints in the North American Electricity Market

The current energy trading relationship between the United States and Canada can be enhanced to expand cross-border trade, stimulate infrastructure investment, and develop efficient and sustainable technologies. This will provide the foundation for greater trade and greater market opportunities between our two countries. Increased integration of the U.S./Canadian marketplace will also help to reduce any uncertainty regarding energy supply in North American energy markets by relieving constraints between and within our two counties. In the following sections, the Canadian Electricity Association reviews a number of measures that we believe would relieve current and future constraints for both Canada and the United States.

### A. Increasing Generation Supply

In terms of future generation investment, solutions will necessarily reflect the availability of resources, the viability of new technologies, regulatory and policy regimes, and to a lesser extent the availability of government incentives. Currently, in the U.S., coal is the predominant fuel source. In Canada hydroelectric power is the dominant generation technology. We anticipate that more coal and nuclear power plants will be constructed in the U.S. to take advantage of the incentives in the Energy Policy Act of 2005 and that new capacity in a range of technologies – but especially hydroelectricity and nuclear – will be added in the Canadian marketplace.

These differing fuel opportunities in our respective countries allow for a diversity of supply that enhances the U.S./Canada bilateral trading relationship. In the United States, 51% of electricity generation needs are met by coal-fired generation facilities, 20% by nuclear and 20% by natural gas, with hydroelectric capacity and other renewables accounting for the remaining 9% of generation capacity. In contrast, 60% of Canadian electricity generation capacity is hydropower, 24% is conventional thermal power, and 16% is nuclear. The availability and utilization of a range of supply options – different fuels, different technologies - will be fundamental to a cost-effective, reliable, and secure North American electricity system.

#### 1. Mature Generation

Mature generation technologies supply much of the generation needs in the U.S. and in Canada. Governmental mandates that impose restrictions on continued use of mature generation technologies for various reasons could therefore result in constraints in available generation capacity. Notwithstanding recent fuel price volatility and environmental concerns such as climate change, conventional fuel sources will continue to remain important in meeting our respective demand requirements. The challenge is to use these supplies in a manner with the least environmental impact.

Given our common electricity market and our common air-shed, CEA supports a bi-national cooperative approach to research and development to enhance our mature generation supply. Cooperative cross-border measures

between U.S. and Canadian interests could help ensure an adequate and sustainable electricity supply in the future. This is true, for example, with regard to clean coal technologies, where companies in both the U.S. and Canada have expressed interest in siting large-scale clean coal units. Companies in both the U.S. and Canada have announced plans to invest in advanced coal generation facilities, relying on technologies such as integrated gasification combined cycle and supercritical circulating fluidized bed. Such companies will utilize applicable U.S. and Canadian incentives to overcome the relatively high capital costs of these facilities, at least in the near-term.

A bi-national approach to an electricity market also helps to minimize the effects of constraints in fuel supply. U.S. reliance on natural gas may prove problematic in the future, as natural gas prices continue to rise and the availability of supplies continues to fall. Low water years can have a significant impact on Canadian utilities that generate the majority of their electricity using hydroelectric facilities. The bi-national nature of the electric grid, however, provides the necessary diversity of supply to avoid shortages in electricity supply, even if there are shortages in fuel supply.

There are also opportunities to promote nuclear facilities on a bi-national basis. While no nuclear facility has been built in the U.S. in recent years, the Energy Policy Act of 2005 contains numerous incentives to spur investment in nuclear facilities. In fact, the Energy Information Agency (EIA) projects that nine gigawatts of new nuclear capacity will be built as a result of the incentives in the Energy Policy Act. In Canada, although no new nuclear plants have been built in the country since 1986, there is an explicit commitment to new build nuclear in Ontario, and strong interest in Alberta and New Brunswick. While nuclear may not be an option in every jurisdiction, due to specific policy decisions (such as in British Columbia, where the construction of nuclear generation facilities is prohibited), it remains a key part of the generation portfolio across the continent – now and in the future.

**2. Emerging Technologies**

Concerns regarding emissions, land and water impacts, and the sustainability of fuel supply are serving to promote the development of alternative generation technologies. Canada and the U.S. have an opportunity to work together to help secure an energy future while responding to environmental and sustainability concerns. For example, Canada will continue to have most of its electricity met by hydroelectric facilities, while hydroelectric power exported from Canada will continue to serve as essential resource in major portions of the U.S. Wind generation continues to grow in importance, both in recognition of its benefits as a contributor to fuel diversity and because of its low-emission energy production. And new technology opportunities continue to gain profile – for instance the Electric Power Research Institute is now projecting significant tidal energy potential in both the U.S. and Canada.

The U.S. EIA estimates that renewable generation, including combined heat and power generation, will grow by 2.1 percent per year, from 385 billion kilowatt hours in 2006 to 631 billion kilowatt hours in 2030. In terms of renewable generation potential in Canada, the Clean Air Renewable Energy Coalition, a group of corporate and environmental organizations and municipal governments, estimates that Canada's potential for low-impact renewable sources (defined by them as excluding large hydropower) is between 122 million and 398 billion kilowatt hours. And with respect to additional hydroelectricity production, Natural Resources Canada estimates a potential of 182,832 megawatts, with 34,371 megawatts considered practical for future development by electric utilities. Capturing this renewable potential will help to ensure an adequate – and environmentally preferable – electricity supply in the North American market.

In recent years, alternative generation investment in both Canada and the U.S. has increased significantly. For example, with respect to wind energy generation, Canada saw a doubling of its capacity during 2006, from 684 megawatts to 1,341 megawatts. According to the American Wind Energy Association, wind energy installations in the U.S. now number 16,818 megawatts and produce enough electricity on a typical day to power the equivalent of 4.5 million homes. Investments in this and other technologies are expected to grow in the coming years.

Efforts to diversify our current energy supply by promoting emerging technologies are important to helping ensure reliable and environmentally-sound energy. However, where technology support initiatives arbitrarily pick winners and losers among a range of technologies, such initiatives can result in more harm than good. And where such technology initiatives serve to exclude certain technologies from other jurisdictions (such as defining "renewable technologies" to

exclude large hydropower), the benefits from cross-border trade are compromised. Additionally, as new technology opportunities arise, it is important to ensure that they can be incorporated in an effective and efficient manner without compromising system integrity. CEA believes that our respective markets would benefit from common definitions of environmentally preferable power choices (renewable or otherwise) and from common approaches to supporting them.

**B. Enhancing the Cross-Border Transmission Grid**

In its most recent reliability assessment, NERC highlights the need for increased transmission capacity. In both the U.S. and Canada, transmission investment has seriously lagged behind generation investment. In order to effectively take advantage of the diversity of the bi-national generation market, there needs to be adequate transmission capacity across the border.

**1. Increasing Transmission Capacity**

Promoting the construction of the transmission necessary to relieve existing constraints on the North American grid and to ensure available transmission capacity with respect to new generation supply will help ensure a secure supply of electricity in the North American market in the future. A bi-national cooperative approach to encouraging the construction of such new transmission capacity would help to relieve constraints along the U.S./Canadian border, as well as help to assure the adequacy of electricity supply in the U.S. and Canada.

Opportunities to ease transmission congestion must first be identified. The U.S. Department of Energy recently designated two National Interest Electric Transmission Corridors, reflecting regions with significant transmission constraints or congestion problems. These National Corridor designations were based on an earlier National Electric Transmission Congestion Study. In the Study, DOE identified as a conditional congestion area the Montana-Wyoming area. Noting the significant potential of expanded generation in Alberta, DOE concluded that the U.S. would be unable to take advantage of such potential absent expansion of the transmission capacity in this part of the U.S. Encouraging the development of generation capacity in Alberta will require enhanced grid connections in the Montana-Wyoming area and between this area and Canada.

A cooperative approach between the U.S. and Canadian industries requires the identification of factors that could inhibit transmission construction, and identification of solutions to address such barriers to construction. One such barrier may be public opposition to the construction of new transmission lines, coupled with extensive regulatory processes for the approval of such lines. Transmission reinforcements may be more acceptable in regions where new generation construction is politically or logistically infeasible. The solution to regulatory delays would involve greater certainty in the process for siting transmission lines. Moreover, establishing this greater certainty in the process for transmission siting, by including, for example, a transparent and rigorous process and appropriate and clear deadlines, would allow for increased construction of beneficial transmission facilities within the North American transmission system.

Other measures should also be considered to promote investment in transmission infrastructure. First, action may need to be taken to ensure adequate returns. Rates of return on capital invested in transmission facilities are often too low, serving to discourage investment in such facilities. CEA believes that regulatory approaches that increase rates of return for transmission facilities would encourage greater investment in such facilities. To that end, Provincial (and State) regulators should observe FERC's lead in providing higher rates of return for investments in transmission infrastructure. In addition, measures to identify opportunities for merchant transmission facilities in our two countries could also be explored. Moreover, tax measures that would facilitate more investment in the development of new transmission infrastructure at key bottlenecks across the continental marketplace could be implemented. For example, aligning capital cost allowance rates with the useful life of the asset would encourage greater transmission investment. The U.S. Congress recognized the importance of tax incentives to encourage the construction of transmission facilities by including provisions in the Energy Policy Act that treat transmission facilities as 15-year property and provide an 8-year period for recognition of gains following the disposition of transmission property.

Opportunities for bi-national cooperation for both investment in advanced transmission technologies and transmission R&D – either through government programs, industry support, or government-industry partnerships – should also be explored to take advantage of the bi-national interest in a reliable and efficient transmission system. Advancements

have been made in transmission technologies both to reinforce the grid and to improve the management of the grid. Improvements to grid management, such as the utilization of real-time data and cooperation between balancing authorities in the development of consistent scheduling protocols and sharing of reserves, have allowed for the more efficient use of the existing transmission infrastructure. Nevertheless, in the absence of higher rates of return, there may not be sufficient incentives for such improvements to the transmission grid, or for the necessary research and development to pursue advanced transmission technologies.

**2. Implementing Bi-National Transmission Reliability Rules**

With the highly integrated North American transmission grid in mind, the U.S. Congress developed and passed reliability legislation that allows for the creation of an Electric Reliability Organization ("ERO") that can operate on an international basis. The ERO model ensures a balance of interests that protects the organization from being unduly subject to any one stakeholder or government, while respecting the sovereign right of authorities in each country to assure themselves that the interests of their citizens are protected through oversight and remand functions. And because only the ERO – as opposed to individual regulatory or legislative bodies – can develop reliability standards with continental application, the reliability system can be run effectively on an international basis.

The ERO's ability to operate effectively on an international basis requires close cooperation among the relevant governmental authorities. The need for this close cooperation led to the establishment of the Bilateral Electric Reliability Oversight Group ("Bilateral Group"), which is comprised of the Federal-Provincial-Territorial Working Group, the Federal Energy Regulatory Commission ("FERC" or "Commission") and the U.S. Department of Energy. The Bilateral Group developed the "Terms of Reference for Bilateral Electric Reliability Oversight Group" ("Terms of Reference"), which identified the appropriate cooperative approaches for the governments to ensure the effective operation of the ERO. Moreover, the Bilateral Group released the "Principles for an Electric Reliability Organization That Can Function On An International Basis" ("Bilateral Principles") to assist FERC in developing rules that would allow the ERO to operate effectively on an international basis. Both the Commission's Final Rules and the NERC ERO submission ultimately approved by FERC were consistent with the Bilateral Principles, thereby ensuring that the reliability organization ultimately approved by the relevant regulatory authorities will be able to operate effectively on an international basis.

On July 20, 2006, FERC certified NERC as the ERO in the U.S. FERC then issued a final rule approving 83 of NERC's proposed 107 Reliablity Standards on March 16, 2007. And on April 19, 2007, FERC approved NERC's compliance program, the pro forma delegation agreements, and the eight Delegation Agreements between NERC and the eight Regional Entities. NERC has been recognized as an ERO in the Province of Ontario and by the National Energy Board, and is working with the other Provinces to ensure that the reliability standards are mandatory and enforceable in the North American grid as a whole.

Looking ahead, it is important that the relevant regulatory authorities respect the integrity of the international organization, whose responsibility is to develop standards that reflect the interests and concerns of both Canadian and U.S. entities. General guidance from governmental authorities in addressing issues of concern regarding certain standards can be useful to the ERO in revisiting certain standards. However, specific and detailed directives from a governmental authority with respect to those same standards could limit the ERO's ability to effectively balance the interests and concerns of the North American utility industry and could limit the ERO's ability to craft a revised standard that would receive approval from the other governmental authorities. In fact, CEA had expressed such concern in recent comments to FERC, based on FERC proposals to require certain changes to Reliability Standards outside the NERC standards development process. An effective international ERO turns upon cooperation across the board in the agreed-upon standard-setting process.

**3. Transmission for New Generation**

Renewable generation, such as wind, is often located in remote locations, requiring new transmission to reach load. A number of recently announced proposed transmission projects are designed to connect this new generation to the grid. Such new generation offers significant benefits to the North American electricity system, but also brings with it challenges presented by generation technologies that are often less predictable.

In its Long-Term Assessment, NERC projects that wind generation will become a significant portion of the generation mix. NERC recommends that any mandate to build renewable generation be accompanied by active support for the development of, and investment in, the transmission infrastructure required to reliably integrate those resources into the bulk power system. NERC further recommends that planning be utilized to address issues relating to the intermittent nature of such resources.

CEA believes that building new transmission at an early stage is essential to the advancement of renewable generation resources. Addressing issues relating to queuing processes and other regulatory challenges will also help to promote renewable resources and avoid future transmission constraints. To further promote such generation, cross-border cooperative efforts in planning transmission investments should be studied.

A bi-national approach to transmission infrastructure could also maximize the benefits of generation diversity, particularly as it relates to greater wind development. For example, Canadian hydroelectric generation systems could act as a "battery," providing potential services through their ability to store surplus energy, returning it when required as a dispatchable product, resulting in balancing of prices in the energy markets. This would require additional transmission capabilities beyond that justified on a firm basis.

**4. Ensuring Critical Infrastructure Protection**

Since the terrorist attacks in the United States on September 11, 2001, the electricity industry has become better prepared for both physical and cyber attacks on the electricity infrastructure. Cyber attacks are of particular concern given the electricity industry's growing dependence on e-commerce and electronic controls. Moreover, the potential for physical threats to the electric infrastructure remains a reality.

In January 2000, following the successful Y2K transition, CEA members formed the Critical Infrastructure Protection Working Group (now the Security and Infrastructure Protection Committee) in order to coordinate activities, share best practices, and interface with the Canadian federal government. In its first year-and-a-half of activities, it established an effective information sharing Intranet site, implemented methods for coordinating activities with NERC and other partners, developed and implemented an Early Warning System for threats to electricity infrastructure, and worked closely with the federal government. The Early Warning System developed by the Working Group is a model being looked at by other sectors as a fast and efficient method of communicating information in times of high alert.

The North American electric power industry is currently working through NERC to develop approaches for safeguarding the North American bulk electric power system. This work culminated in the development of cyber security standards approved by the NERC Board of Trustees and submitted to the relevant governmental authorities for approval as Reliability Standards; FERC recently approved these standards. Such bi-national cooperation provides for an effective approach to ensuring the protection of North American electricity infrastructure and accordingly, should be encouraged.

**C. Avoiding Barriers to Cross-Border Electricity Trade**

CEA members are an integral component of the North American transmission grid, and the interconnected nature of our systems has allowed for the development of an important trading relationship with U.S. market participants. Efficient and rational supply choices in our respective countries can help to reduce constraints in the North American electricity market. Such supply choices require on-going monitoring to avoid or eliminate measures that might create seams within and between electricity markets. Identification and elimination of operational or business obstacles will help to ensure efficient and effective market decisions, helping to ensure a secure electricity market.

Seams affect electricity markets where the rules and conditions on either side of jurisdictional boundaries constrain the economic transfer capacity or flow of energy. Differences in market rules or operating and scheduling practices that inhibit the ability to economically trade energy or capacity between regions impact market liquidity. System operating practices, transmission access scheduling, certain pricing models, and rate pancaking are all examples of market rules and conditions that could result in inefficiencies in trade between regions. And without market liquidity, price discovery and long-term hedging of pricing become more difficult tasks. Measures that harmonize differing market rules and transmission scheduling and pricing systems improve market liquidity and enhance cross-border trade.

Addressing such barriers to trade requires an understanding of the differing regulatory responsibilities applicable to electricity markets. In Canada, electricity regulation is predominantly within the jurisdiction of the provinces, with a Government of Canada role in regulation of energy exports and facilities that span international borders. In contrast, in the United States, interstate electricity markets are regulated primarily by FERC. As such, different approaches to electricity markets may develop. Policymakers and regulators should work cooperatively among themselves and with industry to identify the impediments to efficient cross-border trade and to identify appropriate measures to address any barriers to trade. And governmental authorities, as well as industry, need to be mindful of the potential for additional barriers to robust electricity markets in working to address seams issues between electricity markets. Coordinated approaches to addressing seams issues will allow for greater efficiency and enhanced reliability in electricity markets.

CEA is presently participating in a U.S. Court of Appeals proceeding reviewing the impact of a FERC order on capacity imports over the Canada/U.S. border. The order, unless reversed, may have the effect of eliminating all capacity imports over a particular cross-border interconnection. CEA is participating in the proceeding to urge the Court to consider the impact of such an order on cross-border sales of capacity. Barriers to trade, such as this FERC order, would serve to limit the effectiveness of cross-border markets, particularly the ability of such markets to respond to potential supply shortages in the future.

### D. Promoting Demand Side Measures and Energy Efficiency / Conservation

Adequate generation and transmission capacity are critical to both eliminating and avoiding constraints in the North American electricity market. Focusing solely on the supply side of the grid, however, misses opportunities for employing demand-side measures to address generation or transmission constraints. Investment in demand-side measures – particularly energy efficiency/conservation and distributed generation – can help to reduce the need for new generation or transmission facilities. Demand-side measures have been implemented both in Canada and the U.S. in response to various policy directives, but are likely to increase in importance, particularly where fuel prices continue to remain volatile and challenges to certain generation persist.

Demand-side measures can help to address constraints in generation supply. For example, according to a recent report issued by the U.S. Federal Energy Regulatory Commission on demand response, demand response and advanced metering programs have grown significantly in recent years. According to the report, demand response lowered the consumption of electricity by 1.4 percent to 4.1 percent during periods of peak demand in 2006.

Demand-side measures can also help to relieve transmission constraints. In its National Transmission Grid Study, the U.S. Department of Energy concluded that targeted energy efficiency/conservation and distributed generation could reduce electricity loads on the transmission system, alleviate bottlenecks, and delay the need for construction of new transmission facilities. But measures to relieve transmission constraints can often occur in places other than where the constraint exists. For example, transmission constraints in the U.S. caused by the Lake Erie Loop Flow could be relieved through distributed generation or efficiency measures taken in Canada, or vice versa. (Phase shifters may also help address this constraint). Bi-national coordination in incenting, planning and deploying demand-side measures could thus prove an effective means of addressing transmission constraints on the international grid.

### E. Coordinating Strategies to Address Environmental Concerns

The climate change debate remains a continuing challenge for both the U.S. and Canada, but one that could benefit from cross-border dialogue. Canada and the U.S. have taken different approaches to the issue of climate change. Canada is a signatory to the Kyoto Protocol, while the U.S. is not. Nevertheless, recent proposed approaches in Canada and the U.S., as well as the involvement of each country in the Asia Pacific Partnership on Clean Development and Climate, suggest opportunities for coordinated approaches to deal with climate change.

The Canadian government has identified short-term and long-term measures to address climate change. In the short-term, the Canadian government continues to advocate a target-setting approach based on emissions

intensity for the 2010-2020 period. Longer term, the Canadian government commits to achieving an absolute reduction in greenhouse gas emissions between 45 and 65% from 2003 levels by 2050. Mature low-emission technologies such as hydropower and nuclear as well as new and emerging technologies (such as wind and carbon capture and storage) will be encouraged to help meet these targets.

Measures to mandate GHG reductions are currently being considered in the U.S. Congress. In fact, the Lieberman-Warner Climate Security Act of 2007, which would establish a cap and trade system, recently passed the Senate Committee on Environment and Public Works. These measures suggest opportunities for a coordinated approach between the two countries that would recognize the unique characteristics of North American energy production. As decision-makers begin to look at the post-2012 period, a coordinated and complementary approach becomes all the more important. In both countries there are a number of initiatives already at play at the state/provincial level to address climate change.

In particular, the NAFTA partners could work together on a coordinated approach to setting targets for emission reductions and possibly an integrated system for trading GHG emissions. As with energy trading, GHG emissions trading between Canada and the U.S. could offer significant benefits to both countries – building on already strong regional markets through new trading opportunities. And by providing businesses with the flexibility that trading provides, the NAFTA partners could help companies identify the most cost-effective options to reduce emissions.

As a first step towards this, a North American GHG registry could be established to monitor GHG emissions, and their reductions. Established protocols both for reporting emissions and for reporting emissions reduction would offer interested businesses across North America access to a uniform mechanism for the credit market. Such protocols could also encourage additional investments in greenhouse gas reduction measures. Finally, eligibility for a much broader range of projects for credits could encourage more businesses to participate in the registry.

In a similar fashion, other air issues would benefit from a coordinated approach and CEA encourages ongoing discussions that work towards bilateral solutions to these issues. Joint initiatives are an effective means of addressing concerns facing our common air-shed.

**F. Managing Labour Shortages**

Trained and experienced workers are essential to ensure the long-term stability of Canada's electricity supply. To address this significant challenge, efforts must be made to build the skills base of domestic workers, ensure that trained and skilled workers are able to work and flourish in their area of expertise, and attract and retain skilled foreign workers, especially within and between Canada and the U.S. markets.

Statistics indicate that the primary sources of power system engineering graduates – universities – are not graduating a sufficient number of engineers. And recent data shows a decline in the number of students enrolled in the power systems engineering disciplines, further exacerbating the problem. Efforts to encourage interest in power systems engineering and related disciplines must be made, both at the university level and at earlier stages. In fact, in a U.S. Department of Energy work force study, DOE suggests promoting math and science education in high school, or even grade school, to help prepare students for the more rigorous electrical engineering programs at the university level.

Increasing participation of under-represented groups and expanding and improving skills training and apprenticeship funding are also steps that could be taken to develop a skilled, educated and adaptable workforce. For example, in Canada, the Hydro Northern Training and Employment initiative was launched as a result of two proposed Manitoba Hydro hydroelectric projects in Northern Manitoba. This initiative is training and preparing over 1,000 Aboriginal residents for 800 Manitoba Hydro construction and related employment opportunities. Another example of a pro-active industry-Aboriginal partnership is BC Hydro's Aboriginal Employment and Education Strategy, established as a long term approach to building internal awareness and conducting recruitment outreach with Aboriginal communities in British Columbia.

In terms of training and apprenticeship programs, governments could help to promote the quality, efficiency and availability of apprenticeships, skills training programs, student aid and scholarships to help the industry meet its labour needs. Tax credits for employers hiring an apprentice

would also help to promote apprenticeships in the future. The government could also help to defer the financial hardships faced by apprentices while pursuing apprenticeship programs. Further, programs like "Trade Up," developed by Bruce Power and the Power Workers Union and comprised of a student guide, lesson plans, information on trades, and hands-on learning activities, promotes skilled trade careers in the electricity sector and encourages teachers, counsellors, parents and students to consider apprenticeships as an option.

To broaden their candidate pool, U.S. and Canadian utilities are increasingly turning to internationally trained workers, and are developing programs to ensure their successful integration. But barriers to retaining foreign-trained workers remain, including inhibitive security clearances and visa restrictions, foreign credential recognition, requirements for domestic work experience, and lack of relevant language skills. To address the qualification issue, Manitoba Hydro has been actively involved with the Internationally-Educated Engineers Qualification Program at the University of Manitoba, which allows immigrants with engineering credentials obtained outside of Canada to meet part of the licensing requirements for professional engineering practice in Manitoba. The Canadian federal government could support the establishment of internationally-educated qualification programs in educational institutions throughout Canada. In terms of foreign credential recognition, CEA supports the establishment of a comprehensive pre-qualification process for foreign-trained workers in their country of origin. CEA further recommends the easing of visa restrictions and better aligning the Immigration Point System with Canadian labour market information. Reducing the barriers to hiring foreign-trained workers, including cross-border hiring between Canada and the U.S., will help our respective countries prepare for the challenge of ensuring a healthy North American electricity system. Additionally, initiatives undertaken by organizations such as the Electricity Sector Council to assess the labour issues and investigate potential solutions are also a valuable resource in addressing the labour challenge.

**Conclusion**

A number of factors have led to concerns about constraints in the North American energy market, including a lack of adequate investment in generation and transmission assets, as well as a potential labour shortage. Given the interconnected nature of the North American grid and the strong trading relationship between Canada and the United States, it would be sensible to make constraints a North American concern and to focus on solutions that take advantage of our existing trading relationship and means for enhanced trade. Cooperative cross-border measures for developing increased generation supply could help to ensure an adequate, reliable and sustainable electricity supply in the future. Adequate transmission capacity across the border would allow market players to take advantage of the diversity of the bi-national generation market. The identification and elimination of operational or business obstacles will help to ensure efficient and effective market decisions, necessary for a reliable electricity system. Cooperative approaches to demand-side measures and energy efficiency could help to reduce our reliance on fossil fuels and relieve constraints on the transmission grid. Coordinated approaches to addressing climate change could help to identify the most cost-effective options to reduce emissions for both countries. And to manage possible labour shortages in the future, cooperative approaches can be taken to build the skills base of domestic workers, ensure that trained and skilled workers are able to work and flourish in their area of expertise, and attract and retain skilled foreign workers.

The U.S./Canada integrated electricity market provides the framework for greater trade and greater market opportunities between our countries, thereby addressing constraints and enhancing energy reliability for both Canada and the U.S.. That reliability has been the foundation of our common economic well-being. Ensuring its long-term stability is in our common interest.

**LE-YECL-18**

**Reference: Section 5**

**Requests:**

P 5-2, L 20: Does YECL advertise all available openings locally? Please explain. Over the past two years how many and which YECL positions have been filled from within the ATCO organization and how many and which from outside ATCO? Which positions were filled from within Yukon?

**Response:**

Yukon Electrical posts the majority of job vacancies internally including in ATCO Electric. If no interest is expressed internally then jobs are then advertised locally either through newspaper ads or through employee discussions and interaction within the community. In addition to the traditional advertising strategies Yukon Electrical participates in career fairs and initiatives and programs that have been used successfully in its parent company.

In response to the question on the filling of vacancies Yukon Electrical offers the following:

**2004**

Three positions were filled from the ATCO organization in Alberta and one position was filled from outside of the Yukon and ATCO.

**2005**

Six positions were filled from the ATCO organization, four positions were filled from the local market and one position was filled external to the Yukon.

**2006**

Two positions were filled from the ATCO organization, three positions were filled in the local market and one position was filled external to the Yukon.

**2007**

Three positions were filled from the ATCO Organization and four positions were filled from the local market.

**2008 (YTD)**

One position was filled from the ATCO organization, two positions were filled external to the Yukon and one position was filled from the local market.

The above numbers are for both replacement and new positions and do not include temporary or summer student positions that are typically filled from the local market.

Yukon Electrical has three distinctive markets from which it draws on for employees. For trades and some management positions the ATCO organization serves as the primary market. For entry level positions and some administrative positions the local market is the main pool of resources. On occasion some trade positions can be filled from the local market however this sector has become increasingly difficult to recruit regardless of the market place. The third market is typically the external Yukon market and is drawn upon when the first two markets are unable to produce the required positions.

## LE-YECL-19

### Reference: Section 5

### Requests:

P 5-3, L 15: Please provide the annual inflation rates for Canada, Alberta, British Columbia, and Yukon for 1998 to 2007. Please explain why Alberta inflation rates should be applied to Yukon.

### Response:

Please refer to table below.

**Consumer Price Index (CPI) All-items, 2002 100**

| | Canada | | Alberta | | British Columbia | | Whitehorse | |
|---|---|---|---|---|---|---|---|---|
| | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change |
| 1998 | 91.3 | *n/a* | 89.2 | *n/a* | 93.4 | *n/a* | 94.3 | *n/a* |
| 1999 | 92.9 | *1.8* | 91.4 | *2.5* | 94.4 | *1.1* | 95.3 | *1.1* |
| 2000 | 95.4 | *2.7* | 94.5 | *3.4* | 96.1 | *1.8* | 97.5 | *2.3* |
| 2001 | 97.8 | *2.5* | 96.7 | *2.3* | 97.7 | *1.7* | 99.3 | *1.8* |
| 2002 | 100.0 | *2.2* | 100.0 | *3.4* | 100.0 | *2.4* | 100.0 | *0.7* |
| 2003 | 102.8 | *2.8* | 104.4 | *4.4* | 102.2 | *2.2* | 101.9 | *1.9* |
| 2004 | 104.7 | *1.8* | 105.9 | *1.4* | 104.2 | *2.0* | 103.0 | *1.1* |
| 2005 | 107.0 | *2.2* | 108.1 | *2.1* | 106.3 | *2.0* | 105.3 | *2.2* |
| 2006 | 109.1 | *2.0* | 112.3 | *3.9* | 108.1 | *1.7* | 106.8 | *1.4* |
| 2007 | 111.5 | *2.2* | 117.9 | *5.0* | 110.0 | *1.8* | 109.5 | *2.5* |

figures are not available for Yukon
Source: Statistics Canada

The Alberta Inflation rate of 5 has been used in Yukon Electrical's application as;

- Yukon Electrical's parent company ATCO Electric operates in Alberta and services received by Yukon Electrical by its parent company are therefore Alberta based.
- Yukon Electrical purchases many of its specialty line materials from Alberta.
- Transportation services typically come from or through Alberta.
- The majority of the trade conducted by Yukon Electrical comes from or goes through Alberta.

## LE-YECL-20

**Reference: Section 5**

**Requests:**

Schedule 5.1, L 31 & 32: Why are operating costs for meter reading and customer billing increasing substantially at a time when YECL is spending very significant capital on new AMR metering and a decrease in meter reading staff is forecasted?

**Response:**

In regard to meter reading costs, revised Schedule 5.1 show a decrease in 2007 from 464k to 436k in 2008, due to the off loading of some of the meter reading in the rural areas from journeymen linemen to lower paid Field Service Representatives. The increase in 2009 is as a result of inflation. Savings from the AMR conversion project are not expected in 2009 except as noted with meter testing, as 2009 is the implementation year for this project and Yukon Electrical does not anticipate meter reading savings as meters are being converted. Monthly meter reading will still be necessary during this period. The business case for AMR supports long term cost savings for customers. Please refer to YUB-YECL-15(c) Attachment 1.

In regard to customer billing and accounting costs on Schedule 5.1 these are not impacted by the AMR project. Please refer to Schedule 5.2 for variance explanations on this activity.

**LE-YECL-21**

**Reference: Section 5**

**Requests:**

Schedule 5.1, L 33 & 34: Why is a very significant increase in Revenue Collections and Collection of Delinquent Accounts being forecasted?

**Response:**

Revenue Collection cost increases as a result of a new credit card usage program being proposed by Yukon Electrical as an added customer benefit in 2009.

The Collection of Delinquent Accounts costs are increasing due to inflation as shown on Schedule 5.2

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## LE-YECL-22

**Reference:** Section 5

**Requests:**

Schedule 5.3: The affiliate costs from 2006 to 2009, a period of 3 years, increase by 31 (more than 9 per year). Please justify why this should be greater than even Alberta's rate of inflation.

**Response:**

The affiliate cost increases from 2006-2009 are a result of new and additional services being provided since 2006. Adjusted for these new and additional services, affiliate cost increases in the period 2006-2009 have been modest, as follows:

| | **( 000)** |
|---|---|
| At 2009 - Affiliate Costs | 1,189 |
| Adjusted for New and Additional Services | |
| - After Hours answering commencing in 2007 | 26 |
| - Increase in billing system services as a result of implementing ATCOCIS refer to YUB-YECL16 (b) Attachment 1 | 130 |
| - Increase in regulatory and financial reporting costs to account for increased regulatory requirements, which are levelized over the test period, as well as increased financial reporting requirements such as the pending implementation of IFRS. | 50 |
| 2009 Affiliate Costs Adjusted for New and Additional Services | 983 |
| 2006 Affiliate Costs | 909 |
| Increase Over 2006 Affiliate Costs | 74 |
| Three Year Increase | 8.14 |
| Annual Increase | 2.71 |

As a result, the increase in the 2006 affiliate costs when looking at the 2006 level of service is less than 3 per annum which is less than Alberta's rate of inflation.

It is also important to note that services provided by affiliates in the test period, after including the new and additional services, are provided by only 1.67 FTEs as outlined in the Organization Chart (Section 1, Attachment 1).

## LE-YECL-23

**Reference:** Section 7

**Requests:**

Schedule 7.4, L 24 & 25: Please explain the practical implications of the negative net salvage values of 60 and 70 respectively.

**Response:**

The applied for depreciation rates include provision for the recovery of the service value of the utility assets. Service value is normally defined in regulatory circles as being the original cost of the assets less the estimated net salvage value of the assets when removed from regulated service. Net salvage includes the estimated salvage proceeds realized from the sale of assets to third parties or proceeds realized from the reuse within the utilities less the estimated costs of removal and site restoration. Often the estimated costs of removal and restoration exceed the expected salvage proceeds. In such circumstances, the utility is left with a net negative salvage estimate to recover through rates.

In the case of the -60 and -70 identified above, Yukon Electrical is estimating that the net cost of retirement (after netting estimating salvage proceeds) equals 60 and 70 of the original cost of the assets. Therefore the depreciation rates as identified on Schedule 7.4 result in the recovery of 160 and 170 respectively of the original installed costs.

## LE-YECL-24

**Reference:** Section 7

**Requests:**

P 7: On this page it is stated that historical data to 2007 was used in the study. On pages 27 30 examples of IOWA survivor curves are presented, and actual YECL statistics are presented on pages 47 to 99 in tabular and graphical format. With few exceptions the actual experience bears no resemblance to the IOWA curves chosen to represent them, so how can they be judged to better represent the service lives of YECL plant compared to the formerly used straight line depreciation method?

**Response:**

It should be noted that the depreciation rates as applied for resulting from the Gannett Fleming study are based on a straight-line method of depreciation. There is no change in this application to the continued use of straight line depreciation. The currently approved depreciation rates are also based on the estimated retirement dispersion as represented by IOWA curves.

The selection of average service life is based on a number of considerations as follows:

- The historic trends of retirements based on a mortality study;
- Review of the company operating and maintenance practices as determined from interviews with operational and engineering staff;
- Management polices with regard to the replacement of assets;
- Industry trends with regard to technological and manufacturing trends;
- Gannett Fleming professional judgment and experience; and
- The currently approved lives of the company
- The currently approved lives of peer companies

As such, there are a number of factors in addition to the historic retirement trends that are considered by Gannett Fleming in the selection of the appropriate IOWA curve upon which to base the calculation of depreciation rates.

**LE-YECL-25**

**Reference:** Section 7

**Requests:**

Much of the YECL plant would appear to be at or approaching the steep portion of the IOWA curves in terms of service life. Does this not mean that the use of the IOWA curves will result in a significant increase in depreciation expense in the years to come compared to the continued use of the straight line method?

**Response:**

No. The current depreciation rates are also based on the use of a retirement dispersion represented by IOWA curves. Both the current and applied for depreciation rates are calculated using straight-line depreciation.

Please also refer to YUB-YECL-23 for a more detailed discussion of the depreciation rate calculation process, as seen below.

The calculation of depreciation accrual rates for mass property assets requires the selection of a depreciation method, a grouping procedure and a basis upon which to apply the depreciation rates. In the circumstance of YEC, Gannett Fleming has recommended the continuation of the straight line method of depreciation, the equal life group procedure for grouping of assets and the application of the parameters on a remaining life basis. As the selection of these depreciation calculation parameters underpins the booked amount of accumulated depreciation, Gannett Fleming does not recommend changes to these policies unless a significant tolling issue results from the continued use of the practices.

Each of these required depreciation policy selections is discussed below.

Methods of Depreciation. Depreciation, in public utility regulation, is the loss in service value not restored by current repairs or covered by insurance. The determination of annual depreciation accrual rates must consider the amount of service value which an

asset or group of assets will lose during the year in which the rates are to be applied. Most assets render service on a relatively uniform basis during each year of life that is the usefulness of an asset does not change over the period of time that the asset is in service. In such circumstances use of a straight line method of depreciation is appropriate. Other methods of depreciation such as the declining balance method (which assumes that an asset is more useful in its early years than later in its life) or sum of the years digits (which assumes an exponential raise in the usefulness of an asset over its life) are not generally accepted for rate making purposes, although they can be used for financial disclosure or income tax purposes.

Grouping Procedures. When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group.

In the average service life procedure, the rate of annual depreciation is based on the average life or average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life. In this procedure, the accrued depreciation is based on the average service life of the group and the average remaining life of each vintage within the group derived from the area under the survivor curve between the attained age of the vintage and the maximum age.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

A simplistic example highlighting the differences in the two procedures is presented on the following page. The example assumes an account with two assets, each costing with an original cost of 1,000 for total investment of 2,000. The example also assumes that one of the assets has a life estimate of 5 years and the second has a 15

life expectancy. As such the asset balance from years 1 through 5 is 2,000 and 1,000 for the years 6 through 15. The average service life for the account would be determined by taking the average of the 5 and 15 year life estimates for an average of 10 years.

In the following example, using the average service life procedure where the rate of annual depreciation is based on the average life or average service life of the group, the rate applied to the surviving balances of the group's cost balance is calculated as follows:

| | | | | |
|---|---|---|---|---|
| 100 | (original Cost) | 0 | (No salvage has been assumed) | 10 years (Average Service Life) |
| 10 | | | | |

Therefore the annual accrual for years 1 through 5 is 200 ( 2,000 account balance X 10 ). In the years 6 through 15, following the 1,000 retirement at the end of year 5 the annual accrual is 100 ( 1,000 X10 )

In the equal life group procedure, the property group is subdivided according to service life with each group being depreciated over its specific estimate. As such in the example the annual accrual is developed specifically for each of the two groups, and the requirement for each group is summed to determine the overall expense for the account. As such for years 1 through 5 the annual accrual is determined as follows:

| | | | |
|---|---|---|---|
| | 1,000 (Cost of the first group) | 5 years (life of the first group) | 200 |
| Plus | 1,000 (cost of the second Group) | 15 years (life of the second group) | 67 |
| | 267 ( 200 | 67) | |

In the years 6 through 15 following the retirement of the first asset, the depreciation is 67, being the appropriate amount for the asset remaining in service.

It should be noted that in the example, both procedures result in the full collection of the entire 2,000 investment and the accumulated depreciation balances are zero after the

retirement of the second asset. However, using the ASL procedure, if all of the accumulated depreciation is allocated to the first asset, there has been no collection for the second asset at the end of the fifth year. In contrast, when using the ELG procedure an appropriate amount ( 67 X5 years) has been collected towards the recognition of the consumption of the service value of the second asset in addition to fully depreciating the first asset by the time of retirement.

**Example providing the differences in the ASL and ELG Procedures**

| | | Average Service Life (ASL) | | Equal Life Group (ELG) | |
|---|---|---|---|---|---|
| Year | Asset Balance | Annual Accrual | Accumulated Deprn | Annual Accrual | Accumulated Deprn |
| 1 | 2000 | 200 | 200 | 267 | 267 |
| 2 | 2000 | 200 | 400 | 267 | 534 |
| 3 | 2000 | 200 | 600 | 267 | 801 |
| 4 | 2000 | 200 | 800 | 267 | 1068 |
| 5 | 2000 | 200 | 0(1) | 267 | 335(2) |
| 6 | 1000 | 100 | 100 | 67 | 402 |
| 7 | 1000 | 100 | 200 | 67 | 469 |
| 8 | 1000 | 100 | 300 | 67 | 536 |
| 9 | 1000 | 100 | 400 | 67 | 603 |
| 10 | 1000 | 100 | 500 | 67 | 670 |
| 11 | 1000 | 100 | 600 | 66 | 736 |
| 12 | 1000 | 100 | 700 | 66 | 802 |
| 13 | 1000 | 100 | 800 | 66 | 868 |
| 14 | 1000 | 100 | 900 | 66 | 934 |
| 15 | 1000 | 100 | 0 | 66 | 0 |
| Total | | 2000 | | 2000 | |

(1) Calculated as follows: 800 200 - 1,000 (retirement of first asset)
(2) Calculated as follows: 1,068 267 - 1,000 (retirement of the first asset)

Gannett Fleming views that the ELG procedure better aligns the consumption of the service value of the assets to the resultant depreciation expense. Furthermore, the ELG does result in enhanced generational equity between the users of the two assets. However, the ELG procedure does result in an increased level of depreciation expense early in the account's life.

While some interveners and regulators have not been willing to approve the ELG procedure, given the high level of depreciation expense early in the asset's life, many a number of regulators have allowed the procedure.

Application Basis. Once a method of depreciation (i.e. straight-line) and a grouping procedure (i.e. the ELG procedure) have been established the actual depreciation rate calculation can be made. Use of the whole life basis develops the annual and calculated depreciation calculations assuming that the current depreciation parameters

have been in place from age zero of an asset's life through to the end of the maximum age of the asset account's life. Use of the whole life basis results in new plant additions being properly depreciated on the basis of the most current estimated depreciation parameters. These calculations are presented in Table 1 of the Gannett Fleming report.

As there have been changes in both the assets average service life and net salvage estimates over the many years of the asset accounts life, and given that not all assets retire at the precise timing estimated in depreciation studies, a variance between the calculated and booked accumulated depreciation amounts exists, as presented in table 2 of the Gannett Fleming report. In order to adjust for the variance between the calculated and actual amounts of accumulated depreciation, table 2 of the Gannett Fleming report amortizes the variance over the estimated composite remaining life of the account.

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## LE-YECL-26

**Reference: Section 8**

**Requests:**

P 8-2, L 12: Foster Associates evidence at page 37, including footnote 34, indicates that for a return on equity of 9.25 (0.5 premium) the applicable cost of debt to be the long-term Canada bonds plus 130 basis points. Please explain how YECL can both expect a premium on its return on rate base *plus* a 70 basis point premium on its debt?

**Response:**

Yukon Electrical is not requesting an additional risk premium on its cost of debt. The 6.15 cost of debt cited at page 37 of the Foster Associates evidence is the cost of new debt based on the indicated spreads at the end of March 2008, which was approximately 160 basis points above the 4.55 long-term Canada yield for a new 30-year CU Inc. debt issue. The footnote on page 37 incorrectly reported the November 30, 2007 indicated spread of 130 basis points, rather than the March 2008 spread. The 6.60 cost of debt at page 8-2 of the Application is the cost of new debt forecast by the Company for the test period. While both estimates are derived based on the forecast long Canada yield of 4.55 , the resulting costs of debt are applicable to different time periods. Yukon Electrical's forecast cost of new debt anticipates an increase in the spread over long Canada bonds at which CU Inc. would be able to issue.

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## LE-YECL-27

**Reference:** Section 8

**Requests:**

P 8-3, L 1: Please explain each of the charges to the reserve for injuries and damages in 2006 and 2007.

**Response:**

| | | ( 000's) | |
|---|---|---|---|
| **Description** | **Reason for failure** | **2006** | **2007** |
| Watson Lake diesel unit 4 | Cylinder head burnt causing damage to the exhaust valve | | 22 |
| Pelly diesel unit 3 | Injector failure led to oil and lubricant failure and an engine rebuild was required | | 51 |
| Watson Lake diesel unit 5 | Premature cylinder failure | 26 | |
| Watson Lake diesel units 1&6 | Premature failure of piston liners | 25 | |
| | | 51 | 73 |

**LE-YECL-28**

**Reference: Section 8**

**Requests:**

P 8-3, L 9: The year over year growth rates of 11 , 30.5 , and 36 from 2006 through 2009 is out of line with customer growth rates of under 2 . Why are we suddenly seeing this large wave of capital expenditures in the test years? Why not in previous years or deferrals to subsequent years?

**Response:**

Customer growth rates can not be tied to overall capital expenditures. For example the amount forecast to be spent in the test years on customer new extensions is 3.141m in 2008 and 2.962m in 2009 which is similar to past years expenditures. Another important aspect is that although a customer extension may be similar in capital cost to another, it may be very different from a load perspective. That is why Yukon Electrical prepares a detailed sales forecast which incorporates the differences in load characteristics.

Three significant capital expenditures are proposed and supported by business cases which demonstrate significant benefits to customers are;

Billing System Conversion 1,488k

Automatic Meter Reading 4,185k

Stand-by generator in Carcross 2,000k

Once the costs of these projects are removed from the overall capital forecast the trending is very similar to the recent previous non test year capital expenditures.

**LE-YECL-29**

**Reference:** Section 8

**Requests:**

Schedules 8.2 and 8.3: Please provide the Canada long-term (30 year) bond yields and the Canadian year over year consumer price index inflation rate for each year in which debt capital was supplied from ATCO to YECL.

**Response:**

In accordance with Board Order 2008-5, information dating back to 1989 is not required to test the revenue requirement in the test period. However, to be helpful, given that long term debt issued since the 1996-1997 GRA does impact the revenue requirement YECL will provide the information requested since the 1996 97 proceeding.

| Year of Debt Issue [1] | CPI [2] | Long Canada Bond Yield |
|---|---|---|
| 1999 | 1.8 | 5.72 |
| 2000 | 2.7 | 5.71 |
| 2001 | 2.5 | 5.77 |
| 2002 | 2.2 | 5.67 |
| 2004 | 1.8 | 5.11 |
| 2005 | 2.2 | 4.38 |
| 2006 | 2.0 | 4.26 |

[1] There was no debt issued in 1996, 1997, 1998 and 2003

[2] Please note that the annual CPI rate bears no relation to the yield on Long Term Canada Bonds in any given year.

## LE-YECL-30

**Reference:** Section 8

**Requests:**

Schedules 8.2 and 8.3: Please provide a federal government inflation forecast and long-term Canada bond yield forecast for 2008 and 2009.

**Response:**

| | 2008 | 2009 |
|---|---|---|
| Federal Government CPI Inflation Forecast | 1.5 | 1.9 |
| Long Term Canada Bond Yield Forecast | 4.2 | 4.225 |

Please note that the annual CPI rate bears no relation to the yield on Long Term Canada Bonds in any given year.

**LE-YECL-31**

**Reference: Section 8**

**Requests:**

Schedule 8.9, L 7: It would seem likely that O&M lag in 2006 and 2007 must have been substantially lower than the 19 days indicated on the table since a study has shown it was only 5 days now. To who did the benefits of the actual lower working capital requirements flow in 2006 and 2007 (and in prior years)?

**Response:**

Working Capital is a requirement to operate the business and is approved by the YUB as part of the utilities revenue requirement. The 19 days for O&M lag is consistent with the 1996 97 GRA and as such was approved in setting rates at that time. To the extent that business processes have improved cash flows over time, to lower this requirement, is a benefit to the ratepayer. This benefit can only be realized by having a GRA whereby rates are revised.

**LE-YECL-32**

**Reference: Section 8**

**Requests:**

P 3, L 72: Is ATCO YECL's only shareholder?

**Response:**

Yes, Yukon Electrical is a wholly-owned subsidiary of ATCO Electric Ltd., which is, in turn, a wholly-owned subsidiary of CU Inc.

**LE-YECL-33**

**Reference: Section 8**

**Requests:**

P 3, L 72: Does YECL have debt with any organization other than ATCO?

**Response:**

No. CU Inc., parent of ATCO Electric Ltd., raises all debt from the market on behalf of Yukon Electrical as well as other subsidiaries of CU Inc..

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**LE-YECL-34**

**Reference: Section 8**

**Requests:**

P 3, L 76-78: Please explain the additional costs associated with increasing debt.

**Response:**

As the proportion of debt in the capital structure increases, the risk of default rises, and debt investors require a higher rate to compensate them for that increased risk, and or more stringent terms and conditions attached to the debt issuance. Equity investors, whose interest is residual to that of the debt holders, require a higher return as the debt ratio rises, as their ability to achieve a compensatory return is less certain.

**LE-YECL-35**

**Reference: Section 8**

**Requests:**

P 7, L 184-192: Is inflation rate a business risk? How does it affect the cost of capital?

**Response:**

Yes. Inflation is a business risk because higher than expected inflation may result in actual costs being higher than was anticipated and was provided for in rates. All other things equal (supply demand for capital, risk aversion), higher expected inflation raises the cost of capital.

**LE-YECL-36**

**Reference: Section 8**

**Requests:**

P 8, L 229: Is the interest rate being referred to here the long-term (30 year) Government of Canada bonds?

**Response:**

Yes.

**LE-YECL-37**

**Reference: Section 8**

**Requests:**

P 10, L 272: What has been the 10-year and 30-year government of Canada bond yields in each year from 1998 to 2007?

**Response:**

The requested average yields are presented in the table below:

| | 10-Year Canada | Long-term (30-Year) Canada |
|---|---|---|
| 1998 | 5.30 | 5.59 |
| 1999 | 5.55 | 5.72 |
| 2000 | 5.89 | 5.71 |
| 2001 | 5.48 | 5.77 |
| 2002 | 5.27 | 5.67 |
| 2003 | 4.78 | 5.31 |
| 2004 | 4.55 | 5.11 |
| 2005 | 4.04 | 4.38 |
| 2006 | 4.21 | 4.26 |
| 2007 | 4.25 | 4.30 |

**LE-YECL-38**

**Reference: Section 8**

**Requests:**

P 11, L 287: Please explain how adding 0.10 interest rate for each quarter of 2009 (starting on January 1) to a 2008 interest rate of 3.7 will result in an average 10-year bond return of 4.2 in 2009 rather than 3.95 ?

**Response:**

The forecast for 2009 was not determined as suggested in the request.

As stated at page 10, commencing at line 277, due to the absence of a consensus 2009 forecast for the 10-year Canada yield, the 2009 forecast was based on the quarterly consensus forecasts for U.S. 10-year Treasury bond. The Blue Chip *Financial Forecasts* (May 1, 2008) anticipated 10-year Treasury bond yields of:

| | |
|---|---|
| 1st Quarter 09 | 4.0 |
| 2nd Quarter 09 | 4.1 |
| 3rd Quarter 09 | 4.3 |

With a further 0.1 increase in the 4th quarter, the 4th quarter 10-year yield would be 4.4 , for an annual average of 4.2 .

The 10-year Canada bond yield was estimated to be approximately the same as the forecast 10-year U.S. yields, given that, as noted at lines 283-285, the available consensus forecasts show that the Canadian and U.S. rates are expected to track closely, with the 10-year Canada bond slightly higher (10 basis points) than the 10-year Treasury by 2010.

**LE-YECL-39**

**Reference: Section 8**

**Requests:**

P 13, L 367: Is it your assertion that YECL would be rated BBB by all bond rating agencies?

**Response:**

No. As indicated at page 14, lines 370-372, on a true stand-alone basis, Yukon Electrical would not be able to obtain investment grade debt ratings (BBB- or better) given its small size.

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## LE-YECL-40

### Reference: Section 8

### Requests:

P 14, L 373: Is it your assertion that ratepayers would be worse off if served by another utility (such as Yukon Energy) rather than YECL?

### Response:

Ms. McShane's point was that Yukon Electrical's ratepayers benefit from their affiliation with ATCO Electric and CU Inc., because CU Inc can raise debt capital at a lower cost than Yukon Electrical could on its own and passes that lower cost on to Yukon Electrical (and its ratepayers). CU Inc. has among the highest credit ratings of all investor-owned utilities in Canada and thus incurs lower costs of debt than the preponderance of investor-owned Canadian utilities. As a result, the cost of debt to Yukon Electrical's rate payers is lower than it would otherwise be if it were owned by virtually any other investor-owned utility in Canada.

## LE-YECL-41

**Reference:** Section 8

**Requests:**

P 19, L 501: YECL's sales forecast in Section 2 of the Application makes no reference to GDP being used. Why is GDP relevant given YECL's forecasting technique is more practical and direct?

**Response:**

Ms. McShane references growth in GDP in the context of assessing the business risk of YECL. In assessing the business risk of a utility, market demand factors, including the service territory's economic diversity and strength, are of great importance. (Page 16, lines 445-448) Examination of GDP by industry and over time permits a standard basis of comparison among various utilities.

## LE-YECL-42

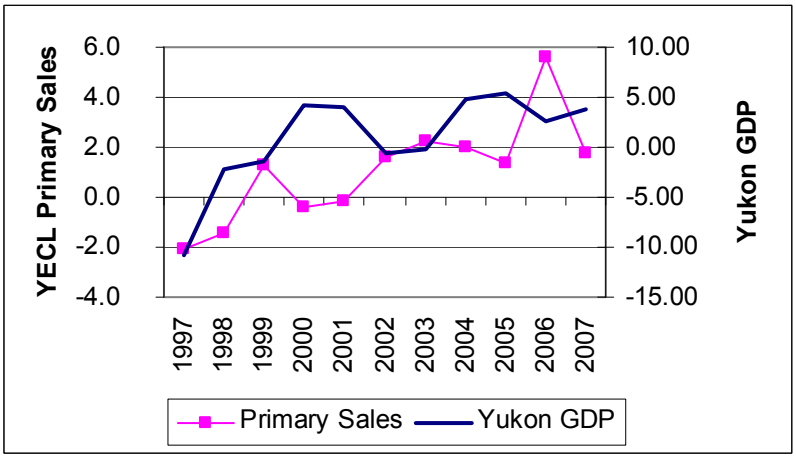
**Reference: Section 8**

**Requests:**

P 19, L 513: Contrary to the assertion in the discussion the primary sales listed in Schedule 3.1 of YECL's application does not show volatility, but rather steady growth. Can any impact on YECL primary sales from the said variation in GDP be shown?

**Response:**

Ms. McShane disagrees with the premise of the question. Schedule 3.1 shows purchased power actuals for 2006 and 2007 and forecasts for 2008 and 2009. The graph below compares real GDP growth rates in the Yukon and Yukon Electrical primary sales growth rates from 1997-2007. While there may be no direct year-by-year correlation between Yukon GDP and Yukon Electrical sales over this period, both series exhibit volatility.



**LE-YECL-43**

**Reference:** Section 8

**Requests:**

P 20, L 525: YECL has in the past participated in energy conservation programs and the Energy Solutions Centre has been in operation for many years. Other utilities across Canada have aggressive energy efficiency programming too. What evidence is there that YECL cannot take efficiency and conservation adequately into account, based on their experience since 1991, when preparing their forecasts?

**Response:**

As stated at pages 2-1 to 2-3 of the Application, Yukon Electrical incorporates information on average use per customer (UPC) in developing its residential sales forecasts. The decline in average UPC for Whitehorse residential customers over the period 1997-2007 of approximately 8 reflects the impact of increased efficiency and conservation on the Company's sales. Nevertheless, increasing emphasis on energy efficiency, conservation and reducing peak load increases the risk of lost sales and, therefore, the risk to the Company's earnings, as the recovery of fixed costs is tied to the amount of electricity sold. The recent trend towards revenue decoupling in both the electric and gas industries in North America is partly a reflection of the recognition of the increased risk and partly a recognition of the need to remove disincentives for utilities to support conservation efforts.

For example, in April 2007, the New York Public Service Commission's ordered the 11 largest electric and natural gas utilities in the state to establish revenue-decoupling mechanisms to separate sales from revenues. In its order the Commission stated that it had experience using decoupling mechanisms to achieve two primary objectives: to remove utility opposition to customer investments and efforts to reduce energy consumption; and to **reduce the risk to utilities of lost fixed cost revenue recoveries, such as during multi-year rate plans,** or for utilities facing significant financial challenges. ( Potential Electric and Gas Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed

Generation, Case Nos. 03-E-0640 and 06-G-0746, April 2007, N.Y.S.P.C., page 8, emphasis added)

## LE-YECL-44

**Reference:** Section 8

**Requests:**

P 20, L 534: Given the variety of power sources (including multiple diesel generators) in the communities being served what risks are there that are not already covered by the reserve for injuries and damages?

**Response:**

The existence of the reserve for injuries and damages does not alter the fundamental supply and physical risks faced by Yukon Electrical. Moreover, the reserve for injuries and damages is not intended to be a catch-all for unbudgeted expenditures related to the supply of power. The reserve for injuries and damages is primarily intended to replace third party insurance for sudden and accidental failures where the cost of third party insurance is prohibitively high or third party insurance is not available. The reserve for injuries and damages is intended to cover expenditures that are significant and of low probability of occurrence.

## LE-YECL-45

**Reference: Section 8**

**Requests:**

P 20, L 541: Please confirm that YECL's Stewart Crossing diesel plant can and does provide back-up power generation to the Mayo Dawson City grid as opposed to back-up generation for Stewart Crossing only.

**Response:**

Not Confirmed. The design of the system does not allow this diesel plant to feed into the Mayo-Dawson grid. In addition, given the size of this unit is 150kW, it could not provide any reasonable backup for the grid.

## LE-YECL-46

**Reference:** Section 8

**Requests:**

P 21, L 553: Please describe any unanticipated repairs that are not covered by the reserve for injuries and damages as described in the examples on page 8-3 of YECL's application.

**Response:**

Ms. McShane references the potential unanticipated impacts of repair (in terms of both time and expenditures) . The referenced impacts relate, for example, to regularly scheduled overhauls or repairs undertaken as part of Yukon Electrical's normal course of business, where the costs may exceed the amounts forecast. The nature of diesel engines, in particular, can lead to unbudgeted labour and parts costs associated with unscheduled and scheduled repairs. The reserve for injuries and damages is primarily intended to replace third party insurance for sudden and accidental failures where the cost of third party insurance is prohibitively high as well as the deductible for insured losses or third party insurance is not available.

**LE-YECL-47**

**Reference: Section 8**

**Requests:**

P 26, L 689: Are Northwest Territories Power Corporation and Yukon Energy lower risk utilities than YECL?

**Response:**

No.

**LE-YECL-48**

**Reference: Section 8**

**Requests:**

P 33-35, Section VIII: Various references are made to bond rating agency comments (dated 2003 and 2004) about low allowed return on equity for Canadian electric utilities. Please provide Canadian PUB decisions on allowed return on equity for these years. How do YECL's returns for these years compare?

**Response:**

The referenced comments from the bond rating agencies cover the period 2003-2007. The various Canadian PUB decisions on approved return on equity are publicly available from the respective PUB websites. The approved ROEs for individual utilities, dating back to 1990, are found on Ms. McShane's Schedule 5, page 2 of 3. Yukon Electrical's most recent allowed ROE was established as a result of a negotiated settlement at 11.25 for 1996 and 1997. The actual ROEs in 2003 and 2004 were 10.2 and 9.9 . These amounts have been updated from the 11.2 and the 10.81 shown on Schedule 8.1 in the application to correctly account for long-term debt costs.

## LE-YECL-49

**Reference: Section 8**

**Requests:**

P 35, L 928: Is it your view that YECL should be treated differently than other Canadian electrical utilities?

**Response:**

No, in Ms. McShane's view, all Canadian utilities, including Yukon Electrical, should be allowed a return which meets the fair return standard.

**LE-YECL-50**

**Reference: Section 9**

**Requests:**

P 9-16: Will the rebuild of Fish Lake Unit 1 generator result in an increase in generator capacity?

**Response:**

No, the output capacity of the generator at Fish Lake 1 will not increase as a result of the refurbishing taking place.

## LE-YECL-51

**Reference: Section 9**

**Requests:**

P 9-18 to 9-20: When poles are being replaces are taller ones put in their place to increase clearance over the taller trees adjacent to the ROW?

**Response:**

Generally poles are replaced like for like, height is determined by the type of terrain and the electrical and potential communication attachments that it will support. Pole replacement is not a solution to address brushing issues and access to the power line infrastructure. It also does not eliminate the fire hazards associated with vegetation under the power lines.

**E-YECL-52**

**Reference: Section 9**

**Requests:**

P 9-21: (See also question 20) Please describe the operational efficiencies and other benefits of the AMR meters being proposed?

**Response:**

Please refer to the business case for more details, YUB-YECL-15(c) Attachment 1.

**LE-YECL-53**

**Reference: Section 9**

**Requests:**

P 9-22: Will the new wheel (turbine?) proposed for unit 2 increase its capacity?

**Response:**

No, the new turbine at Fish Lake 2 is being manufactured to the same specification as the original turbine.

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## LE-YECL-54

**Reference: Section 9**

**Requests:**

P 9-23 & 24: Will the new PLCs for the Destruction Bay and Old Crow diesel plants improve their heat rates or result in other cost savings?

**Response:**

Yukon Electrical's diesel plants already have PLC's (although obsolete) so there is no impact on heat rate.

PLC's are meant to save costs associated with manual restoration and automatic dispatching of units. However there are no incremental cost savings in Yukon Electrical's application as PLC's have been in place for some time.

## LE-YECL-55

**Reference: Section 9**

**Requests:**

P 9-25: The distribution improvements list seems to suggest that YECL has been deferring upgrades for some time pending an appearance before the Board, please explain.

**Response:**

As the utility infrastructure ages and as part of the ongoing business cycle of Yukon Electrical it identifies projects that are required to provide safe reliable and cost effective service to it's customers. As part of it's review Yukon Electrical considers costs and revenues to determine if an adjustment to it's revenue requirement is necessary. The application that is before the YUB is Yukon Electrical's best forecast as to what is required to continue to provide high quality service to it's customers.

Yukon Electrical does not defer upgrades that are required for the safety and reliability of its system.

**UCG-YECL-1**

**Reference: Sales and Revenue**

**Requests:**

Please provide the amount of income from demand charges for 2007 and proposed 2008, 2009. Provide total of demand charges for each year.

**Response:**

Yukon Electrical is not able to provide the amount of income from demand charges for 2007 as the billing system's reporting does not report at that level of detail.

The proposed 2008 and 2009 income from demand charges will not be available until such time as the Phase II Rate Design is completed.

**UCG-YECL-2**

**Reference: Sales and Revenue**

**Requests:**

Please provide the amount of income from energy charges for 2007 and proposed 2008 & 2009. Provide total of energy charges for each year.

**Response:**

Yukon Electrical is not able to provide the amount of income from energy charges for 2007 as the billing system's reporting does not report at that level of detail.

The proposed 2008 and 2009 income from energy charges will not be available until such time as the Phase II Rate Design is completed.

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**UCG-YECL-3**

**Reference: Sales and Revenue**

**Requests:**

Please provide the amount of income from YEC shortfall rider R for 2007 and proposed 2008, 2009. Provide total of YEC shortfall rider R for each year.

**Response:**

Yukon Electrical has interpreted the request for Rider R income to mean the 14.93 YEC Revenue Shortfall Rider J based on the description of YEC shortfall rider .

Please refer to Schedule 2.1, L44 of the filing for the amount of income from the YEC Revenue Shortfall (Rider J) for 2007, 2008 and 2009.

| | |
|---|---|
| 2007 | 5,017,000 |
| 2008 | 5,028,000 |
| 2009 | 5,067,000 |

There is no difference on what will be collected on existing or proposed rates for the Rider J as it is applied against base rates and this Application proposes to address Yukon Electrical's forecast shortfall via Riders G and R. The base rates will not change until such time as a Phase II Application and proceeding takes place and the Board approves new base rates.

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## UCG-YECL-4

**Reference: Sales and Revenue**

**Requests:**

Please provide the amount of income from Fuel Adjustment Rider J for 2007 and proposed 2008, 2009. Provide total of Fuel Adjustment Rider J for each year.

**Response:**

Yukon Electrical has interpreted the request for Rider J income to mean Rider F based on the description of Fuel Adjustment Rider .

As detailed on Schedule 4.1 line 5, the 2007 fuel variance was 3,172,000.

The fuel variance for 2008 and 2009 is not known at this time. The variance will be derived based on the difference between actual fuel prices in 2008 and 2009 vs. the final approved forecast prices.

## UCG-YECL-5

### Reference: Sales and Revenue

### Requests:

Please provide and explain any other income from each year 07-09.

### Response:

Please refer to Schedule 2.2 of the Application.

The Other Income breakdown is as follows:

| | Actual 2007 | Test 2008 | Test 2009 |
|---|---|---|---|
| Penalty Revenue | 5 | 5 | 5 |
| Rent - Office & Buildings | 111 | 114 | 114 |
| BC Hydro Agreement | 32 | 32 | 33 |
| Miscellaneous | 15 | 15 | 15 |
| Per Schedule 2.2 Line 4 | 163 | 166 | 167 |

As well, Yukon Electrical does receive money from a third party for use of the common North of 60 billing system soon to be called ATCO-CIS:

| | Actual 2007 | Test 2008 | Test 2009 |
|---|---|---|---|
| CIS billing system recovery booked as recovery of O&M | 67 | 50 | 40 |

**UCG-YECL-6**

**Reference: Sales of Land or Property**

**Requests:**

Please provide all income from sale of lands or property of YECL since last GRA in 1996.

**Response:**

In accordance with Board Direction 2008-5 Yukon Electrical is not required to provide information prior to 2003 to test the revenue requirement in the test period. There has been no income from sale of lands since 2003.

**UCG-YECL-7**

**Reference: Sales of Land or Property**

**Requests:**

i Please provide all income from sale of lands or property of Alberta Power Ltd. since last GRA in 1996.
ii Please provide all income from sale of lands or property of Canadian Utilities Ltd.since last GRA in 1996.

**Response:**

i), ii) Yukon Electrical does not have knowledge of any sale of lands or property of Alberta Power or Canadian Utilities. If there were sales they do not have any impact on the revenue requirement put forward by Yukon Electrical in its current application.

**UCG-YECL-8**

**Reference: Sales of Land or Property**

**Requests:**

Please provide all income from sale of lands or property of ATCO since last GRA in 1996.

**Response:**

Yukon Electrical does not have knowledge of any sale of lands or property by ATCO. If there were sales they do not have any impact on the revenue requirement put forward by Yukon Electrical in its current application.

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## UCG-YECL-9

### Reference: Sales of Land or Property

### Requests:

Please provide all income from lease of lands or property of YECL and all of the above related affiliates.

### Response:

Yukon Electrical is not knowledgeable of any income obtained by affiliates for the lease of lands and properties. If there was income derived by affiliates it would not have an impact on the revenue requirement put forward by Yukon Electrical in its current application.

In regard to Yukon Electrical it does derive revenue from the lease of the top floor of its downtown office space and a bay at its service center, a small office space in Watson Lake, a cabin and house tied to the Fish Lake Hydro operations and a company owned home in Beaver Creek in the amount of approximately 114,000 annually. This revenue is included as other revenues on schedule 2.2 of its application. Most of these leases have been in place since 2003 and have always been recorded as other revenues.

The exception to the above is the lease of 2 company owned houses in Watson Lake that used to account for approximately 15,000 of other revenue annually. Since September 2006 these homes are now provided as a taxable benefit to the employees to deal with chronic retention and attraction issues.

**UCG-YECL-10**

**Reference: Affiliate or Inter-Party Transactions**

**Requests:**

Please confirm that YECL is a wholly-owned subsidiary of ATCO.

**Response:**

Not Confirmed. Yukon Electrical is a wholly-owned subsidiary of ATCO Electric Ltd.

**UCG-YECL-11**

**Reference: Affiliate or Inter-Party Transactions**

**Requests:**

Please confirm that the equity holder and the debt holder for YECL are one and the same.

**Response:**

Confirmed.

**UCG-YECL-12-1**

**Reference: Affiliate or Inter-Party Transactions**

**Requests:**

Please outline each related party transaction and reasons, for each test year.

**Response:**

Please refer to YEC-YECL-8(i) below:

As outlined in Section 1, Attachment 1, the Head Office personnel are from the following areas:

- Governance
- Human Resources
- Regulatory Support
- Financial Reporting
- Payroll
- Information Technology
- Materials Management

As such, the 1.67 FTE head office personnel are providing support for such things as:

- Phase I regulatory issues - this would cover support for the preparation and filing of:
    - Application
    - IRs
    - Evidence
    - Argument
    - Reply

This would also include providing witnesses at hearings;

- Financial reporting issues, such as ensuring impacts of GAAP pronouncements including IFRS are appropriately dealt with;
- Review of financial statements and reports;
- Administration of capital assets;
- Recruitment and training;
- Strategy and governance;
- Ordering of supplies and other material management matters;
- Payroll administration.

A number of these areas such as support for GRAs, administration of capital assets and IFRS impacts could be contracted out as is done by other utilities. However, given that the equivalent of only 1.67 FTEs is providing this wide-ranging support is described above, contracting out their services would be a difficult and ineffective option

For the other affiliate charges:

| **Affiliate Company** | **Service Provided** | **Description** |
|---|---|---|
| ATCO Electric | Metering Services | Assist with administration of metering inventory, (purchases & retirements) |
| ATCO Electric | After Hours Answering | Support relating to after hours answering service |
| ATCO Gas | Meter Services | Provision of data-cap hub site service enabling download of meter reads |
| ATCO I-tek | Information Technology | Support for all systems, office computers, software (Please refer to CW-YECL-29(b)) |
| ATCO I-tek Business Services | Filling System Services | Support for customer billing (Please refer to CW-YECL-29(b)) |

**UCG-YECL-12-2**

**Reference: Rate Base**

**Requests:**

Please confirm that Foster Associates was hired and paid by the YECL to provide rate base evidence.

**Response:**

Not confirmed. Foster Associates Inc. was hired to provide evidence on fair return, comprised of both an appropriate capital structure and return on equity [as per Section 8, Attachment 1, Page 1 of the Application].

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**UCG-YECL-13**

**Reference: Rate Base**

**Requests:**

Please provide tendering process for contract of providing rate base evidence, how decision was made to hire particular provider, and how much this contract cost.

**Response:**

As outlined in UCG-YECL-12-2, Foster Associates Inc., was hired to provide specific evidence on fair return specifically and not rate base matters generally. As well, there was no tendering process considered given Foster Associates' long history of testifying in regulatory proceedings throughout North America in general and in Alberta, Whitehorse and the Northwest Territories specifically.

As well, given that Yukon Electrical's parent company and affiliated companies have used Foster Associates in the past, familiarity with Yukon Electrical requirements was considered a definite benefit in the decision to use Foster Associates. An estimate for Foster Associates to provide this evidence and support through the GRA process is 100,000.

**UCG-YECL-14**

**Reference: Rate Base**

**Requests:**

Please confirm that Foster Associates are general providers of rate base evidence for YECL and related affiliates.

**Response:**

Again, Foster Associates provides evidence on fair return. Foster Associates has not been used by Yukon Electrical in the recent past dating back to prior to 1996, however Foster Associates have been used by related affiliates to provide similar fair return evidence.

**UCG-YECL-15**

**Reference: Rate Base**

**Requests:**

Please give YECL rationale why Board should accept this evidence from a company that was sole-sourced and paid for by the applicant.

**Response:**

This is evidence from a well respected, independent expert who has testified in more than 190 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of US and Canadian telephone companies, gas and pipelines and distributors and electric utilities. Ms. McShane's complete qualifications are outlined in Section 8, Attachment 1, Appendix A of the Application. The fact that the applicant paid for these services in no way impacts on the independence. Utilities routinely provide evidence from independent third party experts to support certain aspects of a company's revenue requirement. This is considered prudent in order to justify certain aspects of a utility's application and provide the regulator sufficient evidence to support just and reasonable rates being requested. The fact that this evidence is paid for by the applicant, in no way diminishes the evidence put forward.

**UCG-YECL-16**

**Reference: Rate of Return**

**Requests:**

Please confirm that YECL can and does use deferral costs to maximize rate of return for any given year.

**Response:**

This is certainly not confirmed.

Deferral accounts are not used to maximize return but instead deferral accounts are set up to protect the company from unforeseen costs beyond the control of management [as outlined on page 1-5, lines 18 and 19 of the Application] that are not being compensated for in its allowed return on equity. Deferral accounts are also set up to benefit customers in situations where the company reaps unforeseen savings from situations outlined on page 1-5, lines 18 and 19 of the Application.

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**UCG-YECL-17**

**Reference: Rate of Return**

**Requests:**

Please give and explain any deferral costs for each year since 2005 and how this has effected rate of return for each of the years.

**Response:**

The deferral amounts are explained in Sections 3 and 4 of the Application. The costs as outlined in the Application are:

| | ( 000) | | |
|---|---|---|---|
| | **2005** | **2006** | **2007** |
| Purchased Power - Rider J | 4,686 | 4,882 | 5,017 |
| Fuel Deferral - Rider F | 2,389 | 2,860 | 3,172 |
| Diesel Contingency Fund | -- | -- | -- |
| | 7,075 | 7,742 | 8,189 |

The existence of these deferral accounts has not affected rate of return for each of these years. The reason for this is that Yukon Electrical is not compensated in the allowed return, for the risks associated with fluctuations in these accounts.

**UCG-YECL-18**

**Reference: Operation and Maintenance Costs**

**Requests:**

For each of years 2007, 08 and 09 please **break-down each** of the various O&M costs (i.e. administration, labour, vacancy rate, non-labour, affiliate, taxes, depreciation, amortization of deferred costs, etc.) and give full explanation of any cost above three per cent of the preceding year.

**Response:**

Please refer to CW-YECL-25(c) Attachment 1 and also Schedule 5.2 for an explanation of O&M variances.

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## UCG-YECL-19

## Reference: Operation and Maintenance Costs

## Requests:

For each of years 2007, 08 and 09 please **break-down each** of the administration costs and give full explanation of any cost above three per cent of the preceding year.

## Response:

| Administration Costs Breakdown | Actual | Test Period | Test Period |
|---|---|---|---|
| | 2007 | 2008 | 2009 |
| Labour | 487 | 500 | 544 |
| Fringe | 116 | 103 | 108 |
| ATCO I-Tek | 331 | 353 | 370 |
| ATCO Electric Head Office | 160 | 227 | 209 |
| ATCO Gas Office Services | 14 | 15 | 16 |
| Business Travel | 4 | 21 | 22 |
| Telecommunications | 77 | 81 | 85 |
| Courier and Freight | 20 | 31 | 33 |
| Stationary, Office Supplies, and Printing | 27 | 43 | 45 |
| Other | 7 | 7 | 7 |
| Billing system third party revenues | (67) | (50) | (40) |
| **Total** | 1,176 | 1,331 | 1,399 |

The increase in labour in 2009 is mainly due to inflation as well as additional staff budgeted for variable pay. For ATCO I-Tek services please refer to YEC-YECL-11(b) for the ATCO I-Tek amounts as updated. The Head Office costs increase in 2008 is mainly due to increased Head office support for GRA filings as well as increased financial reporting requirements. Business travel costs have increased in 2008 due to inflation, additional professional development and management travel, as well as returning to normal levels. Courier and Freight as well as Stationary, Office Supplies and Printing are also increasing in 2008 due to inflation, and as well from lower than average costs in 2007 incurred.

**UCG-YECL-20**

**Reference: Capital Additions**

**Requests:**

i. Please give amounts for each test year to be invested on the new billing system.

ii. Please give amounts and year previously spent on this program.

iii. Please give tendering process for new billing system program.

iv. Please explain if this was sole-sourced, how such policy would be of benefit to ratepayers.

**Response:**

i-iv As detailed in the Application, Yukon Electrical spent 480,000 on the billing system conversion in 2007 and is forecasting to spend 1,008,000 in 2008. The billing system was not sole sourced. Please refer to the Business Case included in YUB-YECL-16(b) Attachment 1 that details the evaluation, analysis and selection process.

**UCG-YECL-21**

**Reference: Capital Additions**

**Requests:**

i. Please give amounts for each test year to be invested on the new meters initiative.

ii. Please give amounts and year previously spent on this program.

iii. Please give tendering process for new meters program.

iv. Please explain if this was sole-sourced, how such policy would benefit ratepayers.

**Response:**

i. Per pages 9-21 and 9-27 of the Application, Yukon Electrical is forecasting to invest 330,000 and 3,855,000 in 2008 and 2009 respectively on the AMR conversion. Please refer to YUB-YECL-15(c) Attachment 1 for a copy of the business case.

ii. As detailed on Schedule 5.2 of the Application line 96, Yukon Electrical expensed 19,000 in 2006 studying the feasibility of Two Way Automatic Communication System (TWACS) AMR. Please refer to YUB-YECL-15(c) Attachment 1 for a copy of the business case.

iii. As detailed in the business case, Yukon Electrical has chosen to proceed with Aclara to be the supplier of its AMR technology. This choice is predicated on Aclara being the same supplier that ATCO Electric uses in its AMR program. Given Yukon Electrical's small size and limited technical resources, it was not prepared to go it alone with a separate and distinct technology platform.

iv. Yukon Electrical believes the choice of Aclara will benefit ratepayers from a cost perspective as it the same technology that has been successfully implemented by its parent company in Alberta. Yukon Electrical will also have access to experienced ATCO Electric resources when it comes to trouble shooting issues associated with the implementation as well as other ongoing issues if and when they should occur.

**UCG-YECL-22**

**Reference: Capital Additions**

**Requests:**

Please explain how each of these investments is absolutely necessary for system function.

**Response:**

With respect to the billing system conversion, Yukon Electrical's detailed work in the business case confirmed the continued use of the legacy system was not economic and therefore replacement of the system is a prudent investment. Please refer to YUB-YECL-16(b) Attachment 1 for the business case the supports the decision to proceed with ATCO-CIS.

With respect to the AMR conversion, Yukon Electrical's detailed work in the business case shows there will be long term savings to ratepayers as well as a variety of other benefits that will arise as a result of the conversion from manual to automated meter reading. While a conversion to AMR is not absolutely necessary for system function, the business case detailed in YUB-YECL-15(c) Attachment 1 supports the recommendation to proceed.

**UCG-YECL-23**

**Reference: Capital Additions**

**Requests:**

Please explain how these investments will be cost-effective for ratepayers.

**Response:**

For the billing system conversion, please refer to the business case detailed in YUB-YECL-16(b) Attachment 1. For the AMR conversion, please refer to the business case detailed in YUB-YECL-15(c) Attachment 1.

**UCG-YECL-24**

**Reference: ROE Evidence**

**Requests:**

i. Please explain why capital structure of YECL should change from the normally accepted 40-60 split.

ii. Please give examples of other Canadian utilities' capital structure.

**Response:**

i. Ms. McShane's evidence evaluated the appropriate capital structure from first principles; her evidence explains in detail the rationale for the proposed capital structure.

ii. Please see Table 4 of Ms. McShane's evidence and Schedule 5, page 1 of 3.

**UCG-YECL-25**

**Reference: ROE Evidence**

**Requests:**

Please confirm that this change in YECL capital structure will increase both the rate of return and the debt interest for their parent company to the detriment of ratepayers.

**Response:**

This cannot be confirmed. The proposed capital structure includes a lower debt ratio and, thus, lower interest expense than would be the case with a 60 40 debt equity capital structure. Further, if a 60 40 debt equity capital structure had been proposed, the corresponding common equity returns would have been higher.

**UCG-YECL-26**

**Reference: ROE Evidence**

**Requests:**

Please explain how this new 47.5-52.5 capital structure split will have benefits for the YECL customers ratepayers.

**Response:**

Customers are best served when investors are provided an opportunity to earn a return that meets the fair return standard, as the utility will have the ability to raise capital on reasonable terms and conditions as required and to provide a level of service that meets customers' requirements and expectations.

**UCG-YECL-27**

**Reference: ROE Evidence**

**Requests:**

Please explain how raising the ROR an extra 5 basis points for the extra risk premium, cited by Foster evidence, benefits YECL customers ratepayers.

**Response:**

Please see response to UCG-YECL-26.

**UCG-YECL-28**

**Reference: ROE Evidence**

**Requests:**

Please provide YECL rationale for not including performance-based mechanisms in rate of return evidence.

**Response:**

The design of performance-based mechanisms is not part of expert evidence on the required rate of return.

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**UCG-YECL-29**

**Reference: Rate Base and Return**

**Requests:**

Please provide chart giving rate base s for each year since 1996 GRA.

**Response:**

Please refer to the revised Schedule 8.1 & 8.5 issued July 4, 2008 which provides this information since 2003. The last approved test period was 1996 1997. Information provided in response to information requests is in accordance with Board Order 2008-05, which confirmed that Yukon Electrical is not required to provide information prior to 2003 to test the revenue requirement.

**UCG-YECL-30**

**Reference: Rate Base and Return**

**Requests:**

Please provide chart giving rate of return percentage and amounts for each year since1996 GRA.

**Response:**

Please refer to YEC-YECL-39(c) for the regulated returns from 1998-2007, below;

The actual YECL regulated return is as follows:

| Year | Actual |
|---|---|
| 1998 | 9.65 |
| 1999 | 9.75 |
| 2000 | 10.09 |
| 2001 | 10.67 |
| 2002 | 10.98 |
| 2003 | 10.55 |
| 2004 | 10.20 |
| 2005 | 9.04 |
| 2006 | 10.69 |
| 2007 | 10.70 |

**UCG-YECL-31**

**Reference: Rate Base and Return**

**Requests:**

Please provide examples of rates of return for other utilities for each year since last 1996 GRA.

**Response:**

Please see Section 8, Attachment 1-1, Schedule 5.

**UCG-YECL-32**

**Reference: Rate Case Costs**

**Requests:**

Please explain rate case costs of 75K documented each year for the 2006 actual and 2007 forecast.

**Response:**

Per schedule 8.8 line 17, there are no rate case costs recorded in 2006. The 2007 Rate Case cost of 30k relates to initial preparation costs associated with the 2008-2009 GRA.

**UCG-YECL-33**

**Reference: Rate Case Costs**

**Requests:**

Please explain rate case costs of 86K documented each year for 2008 and 2009 test periods.

**Response:**

Please refer to Schedule 8.8 which shows rate case costs of 750k and write offs of 375k for both 2008 & 2009, and also page 8.5 of the application which explains the rate case reserve.

**UCG-YECL-34**

**Reference: Schedule 1.1**

**Requests:**

Please explain why diesel fuel costs escalate by almost double from 2007 actuals to test years, as diesel fuel price increases are covered under fuel adjustment rate rider.

**Response:**

Diesel fuel costs escalate in the test years as forecast fuel prices have been included in the revenue requirement rather than included in the fuel adjustment rider. Please refer to Schedule 2.1 line 48 to show the net rate increase if the fuel costs now in revenue requirement were being recovered through rider F.

**UCG-YECL-35**

**Reference: Schedule 1.1**

**Requests:**

Please explain escalation in depreciation for 2009 test year.

**Response:**

The increase in depreciation is due to the increase in capital expenditures in the test years.

Please refer to Schedule 8.6 line 15 which shows that net property and plant equipment is increasing as a result of capital expenditures.

**UCG-YECL-36**

**Reference: Schedule 1.1**

**Requests:**

Please explain why YECL can no longer sustain costs, so as to not increase rates, when this schedule clearly demonstrates a healthy forecasted increase in revenues.

**Response:**

Yukon Electrical has not had a rate increase since 1996 97. This demonstrates that Yukon Electrical has been very diligent in managing its costs and continues to do so. However increasing cost pressures such as inflation and the need for additional capital expenditures have precipitated the need for this general rate application and reasonable rate increases.

**UCG-YECL-37**

**Reference: Schedule 2.1**

**Requests:**

Please explain who the two wholesale customers are.

**Response:**

These sales are wholesale sales to YEC at their Marsh Lake Control structure and Johnsons Crossing locations.

**UCG-YECL-38**

**Reference: Schedule 3.2**

**Requests:**

Please explain what losses and company used means.

**Response:**

System loss (or losses) is the difference between the energy supplied at the system supply level (from Yukon Energy or a Yukon Electrical production plant) and the energy delivered at the customer level. Company use is electricity used at Yukon Electrical's downtown Whitehorse office, Service Complex, its electrical devices on the distribution system as well as for heating the standby generation units during the winter to ensure they are available for service.

**UCG-YECL-39**

**Reference: Schedule 4.1**

**Requests:**

Please explain why diesel fuel usage does not drop more for test year 2009 as Pelly is scheduled to go on-grid.

**Response:**

Per Schedule 4.2 line 29, the fuel usage in Pelly is forecasted to reduce from 482,000 litres in 2008 to 3,000 litres in 2009. Yukon Electrical forecasts 3000 litres per year for exercising the stand by plant on a monthly basis and for stand by service.

**UCG-YECL-40**

**Reference: Schedule 4.1**

**Requests:**

Please explain if any of the YECL diesel plants use cogeneration. If not why not.

**Response:**

No, Yukon Electrical does not have any plants that use cogeneration.

Yukon Electrical does however utilize waste heat distribution in most of our operating plants to primarily pre heat stand by units. In Old Crow the water jacket heat is used to heat the staff bunk house as well as the stand by generator.

In the community of Watson Lake, the waste heat is distributed through a municipally owned system to heat some government owned facilities.

## UCG-YECL-41

**Reference: Schedule 5.2 p1**

**Requests:**

Please explain 10 inflation index on Supervision and Engineering Diesel and 8 on Diesel Generation.

**Response:**

The 6,000 increase in Supervision and Engineering Diesel between 2008 and 2009 is mainly due to wage inflation. It is also due to changes in staffing in the supervisory positions as well as variable pay.

The 29,000 increase in Diesel Generation between 2008 and 2009 is detailed in Schedule 5.2 of the application.

**UCG-YECL-42**

**Reference: Schedule 5.2 p2**

**Requests:**

Please explain why Brushing costs proposed increase some 100 since 2005.

**Response:**

Yukon Electrical enhanced the brushing program starting in 2005 in order to address reliability concerns brought forward by customers throughout the Southern Lakes areas based on a number of significant wind storms.

Over the last two decades Yukon Electrical has constructed many new rural power line extensions throughout the southern lakes areas. Increased costs to the brushing program in some cases are due to these expansions as they have now grown up to the point that they now require brushing to maintain safety and reliability.

Yukon Electrical began to upgrade existing power line R.O.W widths since 2005 to current standards of 12.2 meters for single phase lines and 15 meters for three phase lines in order to improve system reliability and also to reduce the risks of wildfires caused by contacts with energized lines.

For further information please refer to YUB-YECL-11(a) below.

> YECL's brushing program is best described as maintenance of power line right of ways (ROW's) by the removal of vegetation and second growth trees within the right of way. Each year brushing requirements are identified through patrols of lines completed by operational staff, customer input, trouble areas identified through outage and reliability data.
>
> YECL uses a number of methods to complete the brushing requirements including community based contract crews supervised by YECL staff, Qualified Utility Arborists and Utility Tree Trimmers, Bucket truck aerial trimmers, and Hydro Axe Mowers. In most cases usable fuel wood greater than 4 in diameter is stacked along the right of way for use of property owners and general public.

The debris and vegetation are removed by burning when possible or chipping with a wood chipper.

YECL uses a number of local contractors to complete the brushing requirements. Three Whitehorse based companies are used mainly with support from contract crews supplied by First Nations within the smaller rural communities around Yukon.

In recent years YECL has enhanced the brushing program to include the widening of many existing R.O.W'S to upgrade R.O.W widths to today's standards. The brushing program also includes the identification and removals of Danger Trees from outside of the R.O.W. Danger Trees are trees which are dead or leaning into the R.O.W. Danger Trees also include trees that have damaged root systems from a previous high wind event, they pose an obvious risk to falling on the line.

**UCG-YECL-43**

**Reference: Schedule 5.2 p2**

**Requests:**

Please explain why main reason for increases from 07 to 08 is inflation costs of some 5 to 8 for Brushing, Maintenance and Underground Maintenance.

**Response:**

The increases in both of these activities are as a result of increased labour costs due to inflation, community skills premium, and the associated fringe benefit increases. In addition, there is inflation for material and other non labour items that contribute to the variance.

**UCG-YECL-44**

**Reference: Schedule 5.2 p3**

**Requests:**

Please explain why Street Light Maintenance increase some 75 from 2005.

**Response:**

There are a number of reasons why there have been cost increases in the street light maintenance activity. Some of these include;

- Number of Lights increase annually
- Increase in the cost of light replacement and related material
- Aging streetlight system
- Type of lights being maintained more decorative lights in the system
- Inflationary pressures on fringe and labour
- Please refer to revised Schedule 5.2 Lines 122-127 for further variance explanation.

**UCG-YECL-45**

**Reference: Schedule 5.2 p3**

**Requests:**

Please explain why IT costs are listed twice from 2007 to 2008, once on p.3 Public Information and once on Schedule 5.3 Administration Expense ATCO I-Tek.

**Response:**

IT charges are not listed twice as the IT costs in Public Information are for Yukon Electrical's web page design and maintenance. Where as the IT costs in Schedule 5.3 are for Yukon Electrical's computer systems, software and services provided by ATCO I-Tek.

## UCG-YECL-46

**Reference: Schedule 5.2 p3**

**Requests:**

Please explain why Supervision staffing levels would have to increase when a new billing system is being implemented to improve efficiency.

**Response:**

There is no change in Customer Service Advisor (CSA) staffing levels, supervisory or otherwise, as a result of the conversion from the legacy billing system to ATCO-CIS. The 12,000 increase in the supervisory expense between 2008 and 2009 is due to a change in the staffing mix where the supervisor customer accounting was seconded to the billing conversion project in 2008 and replaced by a less senior staff member. Yukon Electrical will return to its pre-conversion staffing mix once the conversion is completed. Please refer to YUB-YECL-16(b) Attachment 1 for the reasons why the new billing system in being implemented.

**UCG-YECL-47**

**Reference: Schedule 5.2 p4**

**Requests:**

Most increases on this schedule in test years are due to inflation. Please give rationale for such an inflation increase.

**Response:**

Please refer to page 5-2 to 5-3 of the Application. As well, please refer to LE-YECL-19 for an explanation as to why the Alberta inflation rate is appropriate for YECL.

Also, please refer to CW-YECL-24 for further support for the labour inflation increases.

**LE-YECL-19:**

Please refer to table below.

**Consumer Price Index (CPI) All-items, 2002 100**

| | Canada | | Alberta | | British Columbia | | Whitehorse | |
|---|---|---|---|---|---|---|---|---|
| | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change |
| 1998 | 91.3 | *n/a* | 89.2 | *n/a* | 93.4 | *n/a* | 94.3 | *n/a* |
| 1999 | 92.9 | *1.8* | 91.4 | *2.5* | 94.4 | *1.1* | 95.3 | *1.1* |
| 2000 | 95.4 | *2.7* | 94.5 | *3.4* | 96.1 | *1.8* | 97.5 | *2.3* |
| 2001 | 97.8 | *2.5* | 96.7 | *2.3* | 97.7 | *1.7* | 99.3 | *1.8* |
| 2002 | 100.0 | *2.2* | 100.0 | *3.4* | 100.0 | *2.4* | 100.0 | *0.7* |
| 2003 | 102.8 | *2.8* | 104.4 | *4.4* | 102.2 | *2.2* | 101.9 | *1.9* |
| 2004 | 104.7 | *1.8* | 105.9 | *1.4* | 104.2 | *2.0* | 103.0 | *1.1* |
| 2005 | 107.0 | *2.2* | 108.1 | *2.1* | 106.3 | *2.0* | 105.3 | *2.2* |
| 2006 | 109.1 | *2.0* | 112.3 | *3.9* | 108.1 | *1.7* | 106.8 | *1.4* |
| 2007 | 111.5 | *2.2* | 117.9 | *5.0* | 110.0 | *1.8* | 109.5 | *2.5* |

figures are not available for Yukon
Source: Statistics Canada

The Alberta Inflation rate of 5 has been used in Yukon Electrical's application as;

- Yukon Electrical's parent company ATCO Electric operates in Alberta and services received by Yukon Electrical by its parent company are therefore Alberta based.
- Yukon Electrical purchases many of its specialty line materials from Alberta.
- Transportation services typically come from or through Alberta.
- The majority of the trade conducted by Yukon Electrical comes from or goes through Alberta.

**CW-YECL-24:**

(a&b) Yukon Electric has done a number of things to determine what is required to attract and retain employees in the brisk labor market. In the past the Yukon was considered an attractive place for employees within the ATCO Group to move to and job postings were often met with several applications from qualified individuals. In the last two years or so Yukon Electric has faced several situations whereby there have been no applications for critical positions. When Yukon Electrical would talk to individuals in other jurisdictions about why they would not consider a position in the Yukon it was apparent that the compensation package being offered was no longer competitive. As a result Yukon Electrical was left with several vacancies in critical positions and it was putting a strain on the remaining resources. People were getting tired and burned out taking on additional responsibilities and some were talking of leaving the company. This was the compelling evidence that Yukon Electrical had that demanded an aggressive course of action.

One of the significant advantages that Yukon Electric has is its affiliation with the ATCO Group. Yukon Electric has access to a number of human resource professionals who provide expert advice to Yukon Electrical. Therefore Yukon Electric does not have to spend unnecessary dollars on studies as it is able to utilize the work that has been done in ATCO Electric. This is of great benefit to customers.

ATCO Electric identified that it also had difficulties in attracting and retaining trade positions especially in its northern communities. They implemented a Community Skills Premium in many of the northern communities. Because ATCO Electric is a major market for Yukon Electrical to hire trades people from

Yukon Electric implemented a similar program. It was also a fact that based on recruiting efforts externally outside of ATCO that there was either a very limited or no response. It was only after the implementation of the Community Skills Premium and other benefits that vacancies began to be filled.

In addition to the above a salary study was done in preparation for the collective bargaining negotiations in the Northland companies in 2007. Yukon companies were surveyed and the results have shown that Yukon Electrical is behind in several wage range categories.

Yukon Electrical will be entering collective bargaining with it employees association this fall and will be updating its wage data. Due to the sensitive nature of negotiations Yukon Electric is hesitant to provide any data on the record at this time. However Yukon Electric will at a minimum be following the general settlement components provided by both ATCO Electric and Northland Utilities in order to remain competitive.

At the same time that the survey on salaries was being undertaken information was also being requested on what type of 'northern benefits' employers are providing to employees. Although some information was provided it was apparent through further discussions with participating companies that not all compensation was being disclosed because they saw the information as competitively sensitive. CW-YECL-24(a) Attachment 1 is an excerpt of the survey conducted by Sierra Systems on behalf of the company. Also attached is information provided in ATCO Electric's 2007-8 GTA Towers Perrin Review Attachment 2, Compensation Planning Outlook Attachment 3 as well Yukon Electrical is filing an update to the Compensation Planning Outlook as Attachment 4.

Below are some of the benefits that Yukon Electrical was told employers were offering but did not wish to include in the survey:

- Unlimited personal use of company vehicles including fuel
- Payment of travel flight to anywhere in the world once and in some cases twice per year.

- Bonuses for moving and contributions towards mortgages based on years of service.
- Profit sharing arrangements.
- Years of service bonuses

There were many creative ways that employers throughout the north compensate employees in an effort to attract and retain them. It is not easy to do an apples to apples comparison as employers see the information as competitively sensitive.

For Yukon Electric it makes sense that it follows the lead of ATCO Electric as it is the largest market where trades employees come from and transfer to.

**UCG-YECL-48**

**Reference: Schedule 5.2 p4**

**Requests:**

Please explain why there will be a cost increase to implement new ATCO-CIS billing system from 2007 to 2008.

**Response:**

Please refer to YUB-YECL-16(b) Attachment 1.

**UCG-YECL-49**

**Reference: Schedule 5.2 p4**

**Requests:**

Please explain why costs are schedule to increase for impact on new ATCO-CIS billing system from 2008 to 2009 when conversion is to be completed by 2008 and the general purpose of this system is to produce efficiencies.

**Response:**

Please refer to YUB-YECL-16(b) Attachment 1.

**UCG-YECL-50**

**Reference: Schedule 5.2 p4**

**Requests:**

For Revenue Collections please explain how accepting credit cards will increase costs.

**Response:**

The reason for the cost increase in revenue collections is that there is a fee charged by the credit card company for each transaction or bill payment made by the customer. For the purposes of this application Yukon Electrical assumed a rate of 1.9 from the credit card companies.

**UCG-YECL-51**

**Reference: Schedule 5.2 p 5**

**Requests:**

Please explain why YECL proposes to charge 750,000 for this application and then charge again on Administrative costs from 2007-2008 due to increased head office support for these regulatory processes.

**Response:**

Yukon Electrical is not proposing to charge 750,000 for this application and then again on administrative costs.

The rate case costs of 750,000 outlined on page 8-5 of the Application relate to the forecast for external costs and some minor internal costs relating to both the Phase I and Phase II applications. These external costs relate to intervener costs as well as Yukon Electrical's external costs for legal counsel and costs for consultants such as Foster Associates Inc. and Gannett Fleming. As such, these costs are not included on Schedule 5.2 as these head office support costs on Schedule 5.2 relate to Yukon Electrical's internal costs including internal staffing required to support these applications.

**UCG-YECL-52**

**Reference: Schedule 5.2 p 5**

**Requests:**

Please explain why Administrative Corporate cost increase from 2007-2008 due to absence of credits for regulatory awards when corporate lawyer was paid full costs for last regulatory process and this particular application has not been awarded yet.

**Response:**

Costs increase from 2007 to 2008 are as a result of Yukon Electrical being credited or refunded in 2007 for costs incurred in prior years for regulatory proceedings it had intervened in.

As such, this credit does not relate to either of Yukon Electrical's last regulatory process or to this application. There are no such credits forecast in 2008.

**UCG-YECL-53**

**Reference: Schedule 5.2 p 5**

**Requests:**

Please explain why Employee Expenses are proposed to increase some 280 since 2005.

**Response:**

Employee expenses have increased 136,000 or 78 since 2005. As provided in the variance explanation on line 218 of Schedule 5.2 the increase in Employee Expenses is due the increase of northern travel benefits from one flight out to two flights for employees and eligible dependants. This initiative has been undertaken by Yukon Electrical to be competitive with similar programs being offered by ATCO Electric, Northland Utilities and some local businesses. It is a key component in Yukon Electric's attraction and retention strategy.

Also please refer to Article 31.00 in CW-YECL-25(b) Attachment 1 for further information.

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**UCG-YECL-54**

**Reference: Schedule 5.2 p 5**

**Requests:**

Please explain why YECL proposes such an inflationary increase in audit fees in test years.

**Response:**

The total increase in this account is 7,000 in 2008 and 5,000 in 2009. The detailed explanation for these increases is:

| | **( 000)** |
|---|---|
| 2007 Audit Legal Fees and Special Studies | 88 |
| Increase in Audit Fees | 2 |
| Internal Labour Costs Associated with the Collective Bargaining Agreement for 2009-2010 | 5 |
| 2008 Audit Legal Fees and Special Studies | 95 |
| Increase in Audit Fees | 3 |
| Increase in Legal Fees | 2 |
| 2009 Audit Legal Fees and Special Studies | 100 |

Given that audit fees are 45,000 in 2007 the increases of 2,000 in 2008 and a further 3,000 in 2009 are not unreasonable as compared to inflation increases of approximately 5 .

**UCG-YECL-55**

**Reference: Schedule 5.3**

**Requests:**

Please explain why After Hours Answering costs are to be charged twice, once in Supervision-87000 and again in Affiliate Company-712000.

**Response:**

There was a typographical error in schedule 5.3. It should read 87000 Supervision instead of 72100 Administrative. The dollar amounts shown are correct.

**UCG-YECL-56**

**Reference: Schedule 5.3**

**Requests:**

Please explain why IT to ATCO affiliate costs proposed increase 165 since 2003.

**Response:**

The I-Tek costs as updated from the benchmark study (please refer to YEC-YECL-11 (b)) have increased from 228,000 in 2003 to 324,000 in 2009 an increase of 62 over 6 years.

This increase occurred in the period prior 2006 mainly due to the implementation of Oracle Financials in 2004. Charges have remained flat since 2006.

**UCG-YECL-57**

**Reference: Schedule 5.3**

**Requests:**

Please explain why Billing system service from ATCO affiliate proposed to increase 150 from 2005 if this new system is to be cost-effective.

**Response:**

Billing System Services as updated for the benchmark study (please refer to YEC-YECL-11 (b)) have increased from 339,000 in 2005 to 448,000 in 2009, an increase of 32 over 4 years. This increase is primarily due to the implementation of ATCOCIS in 2008.

**UCG-YECL-58**

**Reference: Schedule 5.3**

**Requests:**

Please explain any Affiliate Company cost increase greater than 3 from 2007-2008 and from 2008-2009.

**Response:**

Please refer to UCG-YECL-58 Attachment 1.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Affiliate Charges included in Operations and Maintenance**
**( 000s)**

| Line No. | O M Category | Affiliate Company | Services Provided | Cross Ref. | Actual 2007 | Test Period 2008 | Te |
|---|---|---|---|---|---|---|---|
| 1 | Details of Affiliate Costs in Operations and Maintenance | | | | | | |
| 2 | 87500 - Meters and Meter Testing | ATCO Electric | Metering Services | Note 1 | 32 | 40 | |
| 3 | | | | | | | |
| 4 | 72100 - Administrative | ATCO Electric | After Hours Answering | | 28 | 26 | |
| 5 | 71200 - Meter Reading | ATCO Gas | Meter Services | Note 2 | 37 | 39 | |
| 6 | | | | | | | |
| 7 | 72100 - Administrative Expenses | ATCO Gas | Office Services | Note 3 | 14 | 15 | |
| 8 | | | | | | | |
| 9 | 72100 - Administrative Expenses | ATCO I-Tek | Information Technology | Note 4 | 331 | 329 | |
| 10 | | | | | | | |
| 11 | 71300 - Customer Billing and Accounting | ATCO I-Tek Business Services | Billing System Services | Note 5 | 366 | 416 | |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | Details of Head Office Costs | | | | | | |
| 15 | 72100 - Administrative Expenses | ATCO Electric | Governance | Note 6 | 22 | 24 | |
| 16 | 72100 - Administrative Expenses | | Human Resources | Note 7 | 67 | 87 | |
| 17 | 72100 - Administrative Expenses | | Health and Safety | | 19 | - | |
| 18 | 72100 - Administrative Expenses | | Regulatory Phase II | Note 8 | - | 12 | |
| 19 | 72100 - Administrative Expenses | | Financial Reporting and Regulatory Phase I | Note 9 | 26 | 87 | |
| 20 | 72100 - Administrative Expenses | | Payroll | Note 10 | 6 | 9 | |
| 21 | 72100 - Administrative Expenses | | Use of Systems | Note 11 | 8 | 5 | |
| 22 | 72100 - Administrative Expenses | | information Technology | Note 12 | 3 | 2 | |
| 23 | | | Total Head Office Fees | | 151 | 226 | |
| 24 | | | | | | | |
| 25 | | | | | | | |
| 26 | | | | | | | |
| 27 | 72100 - Administrative Expenses | ATCO Electric | Material Management | | 9 | - | |
| 28 | | | | | | | |
| 29 | | | | | | | |
| 30 | | | | | | | |
| 31 | | | | | | | |
| 32 | Total Affiliate Costs included in Operations and Maintenance | | | | 968 | 1,091 | |

33 Note 1 - The increase of 8 in 2008 is mainly due to a lower than average level of support required in 2007, as well as inflation.
Due to the materiality of the application being disclosed in 000's the increase of 2 in 2009 is not considered significant.
Note 2 - Due to the materiality of the application being disclosed in 000's the increase of 2 in 2008 is not considered significant.
Note 3 - Due to the materiality of the application being disclosed in 000's the increase of 1 in 2008 is not considered significant.
Note 4 - The test period forecast has been updated to reflect the benchmark study as per YEC-YECL-11 (b)
Note 5 - The test period forecast has been updated to reflect the benchmark study as per YEC-YECL-11 (b)
The increase in 2008 reflects the implementation of the ATCO-CIS billing system. The increase in 2009 reflects the full year impact of the ATCO-CIS billing system.
Note 6 - Due to the materiality of the application being disclosed in 000's the increase of 2 in 2008 is not considered significant.
Note 7 - The increase of 20 in 2008 is primarily due to increase support from HR relating to support for the Collective Agreement negotiations.
Note 8 - The increase of 12 in 2008 is due to support from head office in preparing regulatory rider applications.
Note 9 - The increase of 61 in 2008 is primarilydue to increased support for regulatory filings as well as increased financial reporting requirements
For further details please refer to YEC-YECL-08 (i).
Note 10 - Due to the materiality of the application being disclosed in 000's the increase of 3 in 2008 is not considered significant.
Note 11 - Due to the materiality of the application being disclosed in 000's the increase of 1 in 2009 is not considered significant.
Note 12 - Due to the materiality of the application being disclosed in 000's the increase of 1 in 2009 is not considered significant.

**UCG-YECL-59**

**Reference: Schedule 7.1**

**Requests:**

Please explain Depreciation Expense proposed increase of 130 since 2005.

**Response:**

The increase of 30 is due to the increase in Property, Plant and Equipment (PP&E). Since 2005, mid-year PP&E is forecast to increase by approximately 33 by 2009.

**UCG-YECL-60**

**Reference: Schedule 8.3**

**Requests:**

Please explain the reasons for proposed borrowing of T and U Series for each test year.

**Response:**

The borrowings are required to maintain the company's capital structure as proposed in the application and are used to finance the capital expenditures of 10 Million in 2008 and 13.5 Million in 2009 as not all of these expenditures can be financed by internally generated funds or contributions by utility customers.

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**UCG-YECL-61**

**Reference: Schedule 8.3**

**Requests:**

Please explain the projected interest rate of 6.55 .

**Response:**

The projected coupon rate of 6.55 comprises:

| | |
|---|---|
| Forecast long-term Canada Bond Yield for 2008-2009 [per Section 8 Attachment 1 page 2] | 4.55 |
| Spread between long Canada Bond Yield and Corporate Bonds | 2.00 |
| | 6.55 |

**UCG-YECL-62**

**Reference: Schedule 8.3**

**Requests:**

Please confirm these loans from affiliate, Canadian Utilities or ATCO.

**Response:**

These loans are with ATCO Electric Ltd.

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**UCG-YECL-63**

**Reference: Schedule 8.4**

**Requests:**

Please explain 300 increase in Other Post Employment Benefits from 2003 to 2009.

**Response:**

On Schedule 8.4, the mid year balance in OPEB increases from 190,000 in 2003 to 537,000 in 2009, an increase of less than 200 . The reason this balance increases is that for the years up to and including 2007, Yukon Electrical accounted for OPEB on the accrual basis. For those years the accrual required under GAAP was significantly higher than the actual cash payments made for OPEB.

For the test period, Yukon Electrical is proposing to move to the cash basis for accounting for OPEB which results in the charges equaling the cash payments.

**UCG-YECL-64**

**Reference: Schedule 8.5 8.6**

**Requests:**

Please explain proposed increases in Property, Plant and Equipment for each test year.

**Response:**

As outlined in Schedule 8.6, the increases in Property, Plant & Equipment are driven by Capital Additions. The details on the additions are outlined in Section 9 of the Application.

**UCG-YECL-65**

**Reference: Schedule 8.5 8.6**

**Requests:**

Please explain proposed increases in Accumulated Depreciation for each test year.

**Response:**

As outlined in Schedule 8.6, the increases in accumulated depreciation are driven by the annual depreciation expense. Details of the annual depreciation expense are provided in Section 7 of the Application.

**UCG-YECL-66**

**Reference: Schedule 8.7**

**Requests:**

Please explain why the costs of meter replacements are over 4million while the retirement of these same number of meters are less than 1 million.

**Response:**

The new meter replacements are electronic meters that are part of an Automated Meter Reading System. The legacy meters are old electro-magnetic meters that are not compatible with Automated Meter Reading.

**UCG-YECL-67**

**Reference: Schedule 8.8**

**Requests:**

Please explain this schedule in laymans terms.

**Response:**

This schedule outlines certain items where there is a timing difference between actual expenditures for these items and the expense customers pay in revenue requirement in a given year. To provide for rate stability it is deemed more equitable to write off certain expenses over a period of time rather than write off 100 of these costs in the year they were incurred.

Specifically Schedule 8.8 captures the following:

Rate Case Costs

These costs are typically incurred in one year but are included in revenue requirement over a two year period.

Diesel Plant Major Overhaul Costs

This account captures the cost of major overhauls in one year but are included in revenue requirement over the period between overhauls [e.g. if a diesel engine requires an overhaul every five years the costs would be included in revenue requirement over a five year period].

Fish Lake License Renewal Costs

The cost to renew this license would be included in revenue requirement over the term of the license.

For all of the above items that comprise deferred charges and credits, the amount included in revenue requirement each year is shown on Schedule 1.1, line 14. The balance remaining that has not yet been charged to customers is incorporated into the overall rate base amounts on Schedule 8.5, line 12.

**UCG-YECL-68**

**Reference: Schedule 8.10**

**Requests:**

Please explain large increase in utility expenses from 2007 to 2008.

**Response:**

The increase of 5,694 in utility expenses is detailed in Schedule 1-1 and is explained throughout the Application.

The main increases are for diesel fuel of 3,661 explained in Schedule 4.1, operation and maintenance expenses of 1,468 explained on Schedules 5.1 and 5.2 and an increase in the write-off of deferred costs of 465 explained in Schedule 8.8.

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**UCG-YECL-69**

**Reference: Schedule 8.11**

**Requests:**

Please explain what is meant by Contribution in Aid of Construction.

**Response:**

Contributions in Aid of Construction are financial contributions made by customers for new extensions that exceed the maximum allowable company investment identified in the Electrical Service Regulations and approved by the YUB.

**UCG-YECL-70**

**Reference: Schedule 9.1**

**Requests:**

Please explain Land and Buildings Additions for each test year.

**Response:**

Below are the lands and buildings additions for the test years.

2008

Upgrades to company houses in Watson Lake (siding and deck)

Cold storage shed for Marwell Service Complex yard and heating system improvements for Marwell Service Complex

New furnaces and siding work for downtown Whitehorse office

Asbestos removal and installation of gutters at the Fish Lake Unit 1 building

2009

Watson Lake house flooring

Old Crow bunk house replacement.

**UCG-YECL-71**

**Reference: Schedule B maximum company Investment (MCI)**

**Requests:**

Please compare YECL MCI with other private companies in other jurisdictions.

**Response:**

Yukon Electrical is not proposing any changes to the Maximum Company Investments included in Schedule B of the Electric Service Regulations as part of its Phase I Application. Please refer to the table below for a comparison of currently approved Maximum Company Investments with other utilities. This matter will be addressed as part of the pending Phase II Application.

| Rate Class | Northland Utilities Yellowknife | Yukon Electrical Yukon Energy | Northwest Territories Power Corporation | ATCO Electric | BC Hydro |
|---|---|---|---|---|---|
| Residential single | 1,500 per site | 900 per site | 1,500 per site | 980 per site | 1,900 per site |
| Residential multiple | 425 per site | 450 per site | 750 per unit | 980 per site | unknown |
| Small General Service | 175 per kW | 400 per kW | 250 per kW | 350 per kW | 425 per kW |
| Street Lights | Cost of installation | 700 per light | Cost of installation | 1,150 per light | 110 per light |
| Private Lights | 700 per light | 700 per light | No Investment | 915 per light | unknown |

## YCS-YECL-1

**Reference:** Section 2

**Requests:**

Page 2-4 Lines 2 to 7.
Residential: Can you explain why the projected residential sales increase is relatively flat? Why are you not considering customers switching over to electric space heating in your projections?

**Response:**

Please refer to YCS-YECL-09, CW-YECL-14(e) as well as YEC-YECL-2(h) for an explanation on how residential UPC was determined.

**YCS-YECL-2**

**Reference:** Section 3 Schedule 3-2

**Requests:**

About 20,000 MWh of energy comes from diesel generation, which is about 7 of your total generation and purchases. What steps are you taking to reduce your diesel generation in:
- Beaver Creek
- Watson Lake
- Burwash Landing Destruction Bay
- Old Crow

At what rate will YECL pay for power provided by an IPP in these diesel communities.

**Response:**

Factors and activities within our control in the communities listed above that have a positive impact on diesel fuel consumptions are:

- Monitoring and maintaining our generating units heat rates.
- Heat rates are considered when engine replacement is required.
- When adding or rebuilding existing infrastructure we deploy current construction standards such as larger wire size, ampact connections and voltage conversions ( 2400 to 14.4)
- Load balancing
- Reduce station service by using waste heat to keep stand by unit warm and to provide building heat.

Yukon Electrical does not have a YUB approved rate for IPP's at the present time. It may be appropriate as a starting point to consider the avoided cost of diesel fuel as one option for pricing of IPP energy. Yukon Electrical is also not aware of any legislation that

exists to allow sale of energy to the electrical grid by IPP's. Until the practices and policies are created in the Yukon, Yukon Electrical encourages IPP's to focus on off loading their own power requirements which in turn results in less fuel being burned at the central generation facility.

Yukon Electrical is open to discussions with any IPP who provides a safe, reliable and cost effective solution to offsetting diesel fuel usage in the communities served by Yukon Electrical.

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## YCS-YECL-3

**Reference:** Section 4

**Requests:**

p 4-1 Lines18-20
What is the 5-year average consumption of the stand-by diesel plants in Haines Junction, Carmacks, Carcross, Teslin and Ross River? Is it the Standby at the bottom of Schedule 4-2?

**Response:**

The five year average consumption of diesel fuel (2003-2007) at Yukon Electrical's stand by diesel plants as requested are as follows:

Haines Junction 4,733L

Carmacks 8,902L

Teslin 2,575L

Ross River 7,198L

YECL does not have a diesel plant at Carcross.

Standby is at the bottom of Schedule 4.2.

## YCS-YECL-4

**Reference:** Section 4

**Requests:**

p 4-3 Line 7
Is the forecast rate of 0.8933 still valid given the recent fuel increases? What are the new rates? In schedule 4-2 the fuel price increase between 2007 and 2008 is projected to be less than 10 and to be flat between 2008 and 2009. Can you give us a rationale for such low projected increases?

**Response:**

It is reasonable to assume that based upon current fuel prices that Yukon Electrical's forecast fuel price in its application appears low.

There are no new rates for fuel until such time as a compliance filing is produced with revised fuel rates.

The fuel prices for 2008 and 2009 were based on actual fuel costs in January of 2008 and Yukon Electrical felt this was the best information available at the time. In any event given the volatility in prices, whatever prices Yukon Electrical ultimately used would have varied from actuals, Yukon Electrical would not have forecast a 30 rise in fuel prices in less than half a year.

Due to the volatility of the price of fuel, Yukon Electrical has had and continues to request a deferral account to capture differences in fuel prices as they are not reasonably forecastable.

## YCS-YECL-5

**Reference:** Section 4

**Requests:**

Schedule 4-1 Line 1
What is causing the total diesel generation to drop from 2007 and on? What measures do you have to reduce this further?

**Response:**

The forecast information in line 1 of 4-1 reflects the anticipated reduction in fuel purchased and consumed to supply energy to the community of Pelly Crossing. Yukon Electrical has forecast the interconnect to the WAF Hydro Grid on November 1, 2008.

In regard to future reductions of diesel generation, Yukon Electrical will continue to analyze and optimize fuel consumption via:

- On going engine and generator maintenance and rebuilds as per manufacture specifications.
- Engine generator optimization by analyzing heat rates and Programmable Logic Control opportunities.
- Yukon Electrical has participated in a recent conference hosted by ATCO Electric focused on isolated generation practices and efficiencies. This, Prime Power Diesel Inter-Utilities Conference is affiliated with Canadian Off Grid Utilities Associations, the conference took place in May of 2008.

## YCS-YECL-6

**Reference:** Section 4

**Requests:**

Schedule 4-2 Watson Lake is the largest consumer of diesel and therefore has the biggest impact for diesel reduction. What steps are you taking to make these reductions? Do you have a power smart type program in place? Are you requesting any proposals for IPP's.

**Response:**

Yukon Electrical in conjunction with the Town of Watson Lake operates a district heating system utilizing the waste heat from the power plant to heat several buildings in Watson Lake. This has allowed for the displacement of heating fuel for these building which has been a significant offset to carbon emissions in Watson Lake. There are no power smart type programs in place in Watson Lake at the present time. However the Energy Solutions Centre may have programs that are beneficial to Watson Lake customers.

Yukon Electrical also monitors other jurisdictions such as the Northwest Territories to ascertain if there are alternate sources of generation for diesel communities. To date Yukon Electrical is not aware of any non grid connected generation alternative that has proven financially beneficial or that meets the reliability standards that are required in the jurisdictions it has looked at. Yukon Electrical does note, however, that it has in the recent past worked with the Town of Watson Lake's consultants on the feasibility of interconnecting a bio-fuel power plant.

Yukon Electrical is participating in the development of a Yukon Government Energy Strategy and has provided input to government officials into its thoughts on how the strategy may best serve Yukoners.

Yukon Electrical participates in seminars, workshops and conferences when appropriate to learn more about technologies such as wind and solar and to determine if break throughs have been made that will allow for successful conversion of diesel communities.

Yukon Electrical has not included any costs in its revenue requirement for research and development looking at new technologies however Yukon Electrical will continue to support worthwhile initiatives being pursued by qualified groups and lend its expertise as necessary. If there are viable solutions and alternatives being put forward, Yukon Electrical is prepared to review the information for applicability in serving its diesel communities.

## YCS-YECL-7

**Reference:** Section 5.1

**Requests:**

a) Where is the fuel consumption due to vehicle use shown in the table?

b) How much of the cost are associated with fuel consumption for vehicle use?

c) What measures are being done to reduce this consumption? Specifically, what is your anti-idling campaign structure? Please outline any programs that you have within your corporate structure to promote energy efficiency and waste reduction with your staff?

d) Do you have any hybrids, energy-efficient, or small-sized cars for, say, for your meter-readers and your administrative staff? What are your plans to increase the total efficiency of your vehicle fleet and your operation?

e) What kind of program do you have within your company to reduce waste of energy and otherwise?

**Response:**

(a) The fuel costs are charged to the vehicle pool which in turn is allocated to capital and O&M according to the usage of the vehicles. These costs are allocated to the appropriate activities identified in Schedule 5.1.

(b) The approximate cost of fuel used by Yukon Electrical's fleet is as follows;

- 2005 - 127k, consumption in litres 132,000
- 2006 - 144k, consumption in litres 144,000
- 2007 - 148k, consumption in litres 143,000

(c) Please refer to YCS-YECL-08.

(d) No we currently do not have any hybrids.

- However our parent company is currently piloting the use of a Hybrid 5 ton bucket truck, as our larger units consume a proportionally high amount of fuel. ATCO Electric (AE) is one of the first Utilities in western Canada to order this type of vehicle. Yukon Electric will monitor the success of this program to determine if it is applicable during replacement of a similar vehicle in it's fleet.
- We are attempting to reduce weight and size of the service trucks by moving from service bodies to a pack rat box bin configurations. These bin configurations allow us to keep most items within the box of the truck which reduces wind drag in comparison to the service body type.
- Depending on the use of the vehicle, we are reducing the pay load weight and size by replacing tons with ton trucks. This allows us to reduce the engines size as well. We have recently purchased two ton trucks in a Flex Fuel configuration.
- Hybrids and or smaller vehicles will be considered in all of Yukon Electrical's vehicle purchasing decisions.

(e) Please refer to YCS-YECL-08
In addition other activities include the following:

- Scheduled maintenance on heating and cooling system in our office buildings.
- Replacement of down town office furnaces with energy efficient units.
- Buildings are equipped with programmable thermostats and motion sensing light switches throughout both Whitehorse buildings.
- Service complex has undergone a complete energy audit and assessment. We are examining and budgeting to implement the recommendations within the assessment. We are scheduling to have the same assessment done on our downtown office.
- Have worked with the City of Whitehorse on a pilot program to install timed dimmers in street lights in the downtown and subdivisions. The lights would dim in off peak hours to conserve energy.
- Monitor other pilot projects and initiatives through out the industry via our parent company and the CEA.
- Yukon Electrical is participating in a pilot project with two LED streetlights

## YCS-YECL-8

**Reference:** Carbon Emissions

**Requests:**

YCS is concerned that YECL is not considering your impact on the environment in your bottom line. How do you account for your carbon emissions? Do you have a carbon emissions offset program? How do you pay to offset your carbon emissions?

**Response:**

Yukon Electrical is very concerned with its impact on the environment and has undertaken a number of initiatives to minimize its footprint on the environment. Yukon Electrical tracks its net generation and then converts the information to Net CO2 emissions per tonne and also CO2 Emission intensity (Kg kwh). This information has been used in corporate reports in the past. This is how the emissions are accounted for.

In addition Yukon Electrical in conjunction with the Town of Watson Lake operates a district heating system utilizing the waste heat from the power plant to heat several buildings in Watson Lake. This has allowed for the displacement of heating fuel for these building which has been a significant offset to carbon emissions in Watson Lake.

Yukon Electrical has implemented a recycling reuse program in all of its facilities. This has a societal benefit to the overall reduction on the carbon emissions.

Yukon Electrical strives to minimize waste throughout its operations. Used transformers are shipped to approved recyclers. Other materials targeted in reuse, recycle and recovery programs include:

Lube oil
Transformer oil
Lead acid batteries
Copper
Structural steel
Paper and cardboard

Bottles and cans
Toner cartridges

In addition Yukon Electrical has implemented a reduced idling practice for its fleet operations. Employees are encouraged to limit idling while conducting field operations.

Yukon Electrical considers the fuel efficiency of vehicles that are purchased for its fleet and has even reduced the weight of its service vehicles in an effort to improve fuel efficiency. When replacing diesel units for its power plants fuel efficiency of the units is also a consideration in an effort to improve the overall heat rates in the specific plant.

Yukon Electrical conducts Environmental audits on a predetermined basis to ensure that it is in compliance with regulations and develops action plans to implement audit recommendations.

Yukon Electrical has not included any costs in its revenue requirement to pay to offset its carbon emissions however have developed internal practices that it feels are helpful to the environment.

## YCS-YECL-9

**Reference:** Demand Side Management

**Requests:**

During the last year we've seen an unprecedented escalation in fuel prices to the point that electricity based space heating has become cheaper than oil-source heating. Existing
and new customers are changing over to electric baseboard heating to this price signal. Could you outline what in this application deals this trend?

**Response:**

Although the cost of fuel has been significant over the past number of months there have been other factors that have provided a price signal to customers that would actually encourage customers to use less electricity such as the loss of 50 of the Rate Stabilization Fund. Therefore Yukon Electrical has not seen a significant number of customers converting to Electric heat from fossil fuels. In fact the energy use per customer as shown in section 2 of Yukon Electrical application demonstrate that energy usage has remained relatively flat for many years despite ever changing market conditions.

Yukon Electrical has also seen that several customers are converting to pellet stoves for heating which has little or no impact on electric usage. The cost for conversion to change heat sources can be significant for customers and there are those who still believe that fuel costs may actually go down in the near future. Therefore based on a number of external factors it is not expected that the average use per customer will be impacted in any significant way in the test years and Yukon Electrical believes its sales forecast is reasonable.

**YCS-YECL-10**

**Reference:** IPP

**Requests:**

Net Metering: You presently have a purchase agreement with the Northern Research Institute (Yukon College) to buy renewable energy from their system. You had also had a net-metering arrangement with the Kris Selzer resident in the past. How will you facilitate renewable energy purchase from future proponents? Price are you offering for the purchase of renewable energy from customers who produce it?

A fossil-free future for the Yukon:

How are you planning for a fossil-free future for the Yukon?

**Response:**

Yukon Electrical has been working cooperatively with customers who want to generate small amounts of power and potentially feed excess energy back on to the grid. To date no customer has generated excess energy onto the grid as the self generation has only met some internal energy requirements.

In terms of the concept of Net Metering Yukon Electrical is monitoring what is happening in Alberta with new Micro Generator Regulations and hopes to benefit from the learnings of the initiative before embarking on a project in the Yukon.

Yukon Electrical does not have a rate that would allow it to pay customers for energy delivered to the grid. Yukon Electrical does have a design for Net-Metering as well as interconnection standards.

In regard to Distributed Generation (DG) and Independent Power Producers (IPP), Yukon Electrical offers the following views:

From a needs perspective, it is Yukon Electrical's understanding that the Yukon Energy Corporation has surplus hydro generation and is continuing to make secondary sales

available. Therefore, the need for additional generation, DG or otherwise, is not readily apparent.

Yukon Electrical is not philosophically opposed to the interconnection of DG or independent power producers (IPP's) to the power grid. However, we believe there are a number of questions that need to be answered. Some of these questions are:

- Should DG or independent power producers be included in the overall system planning? Is the Yukon jurisdiction and market large enough to support this approach?

- Is the inclusion of DG or IPP's the most appropriate solution to address the need for new generation?

- Does the inclusion of DG or IPP's improve or negatively impact system reliability and or power quality based on the unique power systems that exist in the Yukon?

- Has the regulatory and legislative framework for the interconnection of DG or IPP's been established in the Yukon?

Yukon Electrical believes that DG and IPP's under the right conditions may be included in overall system planning and that the choice of a particular generation solution should be in the economic interests of rate payers and should result in the safe and reliable delivery of power to customers.

With respect to the establishment of a regulatory and legislative framework, Yukon Electrical believes that this is a critical step that has yet to take place.

Should there be an interest in pursuing this topic further; Yukon Electrical would be pleased to discuss it with the YUB, government as well as industry leaders.

Throughout its IR responses Yukon Electrical has demonstrated its commitment to the environment and will continue to explore opportunities that provide even further benefits to its customers and the environment. Yukon Electrical is also participating in the development of an Energy Strategy by the Yukon Government and believes that this process may be helpful in setting the stage for energy planning in the Yukon.

## YEC-YECL-1

**Reference:** Overall Revenue Requirement

**Requests:**

(a) Please provide a copy of Schedule 1.1 as updated July 4, 2008 that includes:

i. A column showing the last approved test year forecasts.

ii. Columns showing the percentage year over year changes by line item for each year starting in 2004.

iii. A column showing, by line item, the average annual actual percent increase for the years 2003 to 2007 inclusive.

iv. A column showing, by line item, the percentage change for test year 2009 compared with actual 2007.

(b) Please provide all internally generated reports or documents prepared for or by senior management or otherwise in 2007 or 2008 which discusses in any way with the possibility of not proceeding with the GRA for the 2008 test year or the 2008 and 2009 test years.

(c) Please provide a detailed explanation as to why YECL is deferring to Alberta based factors in preparing its revenue requirement application. (e.g. Alberta ROE formula, Alberta inflation rate, etc.)

(d) In YECL's view should YEC use these same factors in preparing its General Rate Application? If not, why not.

(e) Please produce all internally generated documents including any reports done by or for senior management or otherwise in 2005, 2006 and 2007 which discusses in any manner how YECL could avoid bringing a GRA in 2005, 2006 or 2007, including any discussion as to how O&M expenses or capital additions could be curtailed in those years to avoid a GRA

**Response:**

(a) i) The last approved test period was 1996 1997. Information provided in response to information requests is in accordance with Board Order 2008-05, which confirmed that Yukon Electrical is not required to provide information prior to 2003 to test the revenue requirement.

ii- iv) Please refer to YEC-YECL-01 Attachment 1.

(b) Yukon Electrical prepares a three year business plan each year. As part of its ongoing review of its costs and revenues, management must determine if a General Rate Application (GRA) is required to continue to deliver safe, reliable and cost effective service to its customers while still meeting the needs of its shareowners. Yukon Electrical also is cognizant of the costs of going forward with a GRA and, therefore, considers all aspects of its business plan before proceeding with a regulatory filing. Internally generated documents and reports are confidential and proprietary and are only used by management in fulfillment of its obligations to manage the company.

(c) Please refer to LE-YECL-19 which, in part, states;

In regard to why the Alberta Inflation rate of 5 has been used in YECL's application we offer the following information:

- YECL's parent company ATCO Electric operates in Alberta and services received by YECL by its parent company are therefore Alberta based.
- YECL purchases many of its specialty line materials from Alberta.
- Transportation services typically come from or through Alberta.

The majority of the trade conducted by YECL comes from or goes through Alberta.

(d) Yukon Electrical does not participate in Yukon Energy Corporations (YEC) business planning process, nor does it have responsibility for the operation of YEC. Therefore Yukon Electrical does not offer a view on what factors or indicators YEC should use in operating it's business.

(e) Please refer to YEC-YECL-1(b). In addition, no O&M and Capital projects can be curtailed as they relate to the safe and reliable operation of the system. In some cases capital projects such as Automatic Meter Reading can be deferred until a business case is complete. However, if the project proves beneficial to customers it should proceed or be brought forward through the regulatory process to the YUB for approval, as is the case with Yukon Electrical's current application.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Utility Revenue Requirement**
**( 000s)**

| Description | Cross Ref. | Actual 2003 | Actual 2004 | Change 2004 | Actual 2005 | Change 2005 | Actual 2006 | Change 2006 | Actual 2007 | Change 2007 | Test Per 2008 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | | | |
| Retail revenues | S.2.1 L.45 | 35,163 | 36,221 | 3.0 | 37,109 | 2.5 | 39,115 | 5.4 | 40,177 | 2.7 | 45, |
| Other revenue | S.2.2 L.6 | 692 | 696 | 0.6 | 757 | 8.8 | 760 | 0.4 | 784 | 3.2 | |
| **Total Revenues** | | 35,855 | 36,917 | 3.0 | 37,866 | 2.6 | 39,875 | 5.3 | 40,961 | 2.7 | 46, |
| **Costs** | | | | | | | | | | | |
| Purchase power | S.3.1 L.13 | 20,562 | 21,111 | 2.7 | 21,681 | 2.7 | 23,239 | 7.2 | 23,647 | 1.8 | 23, |
| Diesel Fuel | S.4.1 L.6 | 1,942 | 2,030 | 4.5 | 2,014 | -0.8 | 2,026 | 0.6 | 2,054 | 1.4 | 5, |
| Operations and maintenance | S.5.1 L.49 | 6,008 | 6,469 | 7.7 | 6,755 | 4.4 | 6,969 | 3.2 | 7,290 | 4.6 | 8, |
| Property Taxes | Page 6-1 | 223 | 226 | 1.3 | 230 | 1.8 | 230 | 0.0 | 235 | 2.2 | |
| Depreciation | S.7.1 L.4 | 3,355 | 3,481 | 3.8 | 3,727 | 7.1 | 3,901 | 4.7 | 4,171 | 6.9 | 4, |
| Amortization of contributions | S.8.11 L.8 | (847) | (901) | 6.4 | (962) | 6.8 | (1,008) | 4.8 | (1,092) | 8.3 | ( |
| Amortization of deferred costs credits | S.8.8 L.7 | 75 | 75 | 0.0 | - | -100.0 | - | 0.0 | 187 | 0.0 | |
| Return on rate base | S.8.1 L.5,10,15,20,25,30 | 3,180 | 3,186 | 0.2 | 3,093 | -2.9 | 3,484 | 12.6 | 3,614 | 3.7 | 3, |
| Income taxes | S.10.1 L.30 | 1,357 | 1,240 | -8.6 | 1,328 | 7.1 | 1,034 | -22.1 | 855 | -17.3 | |
| **Total Costs** | | 35,855 | 36,917 | 3.0 | 37,866 | 2.6 | 39,875 | 5.3 | 40,961 | 2.7 | 46, |

## YEC-YECL-2

**Reference:** Sales and Revenue Forecast

**Requests:**

(a) Please provide Schedule 2.1, as updated July 4, 2008, broken out separately for each of the following rate zones:

- WAF
- Large Diesel [Watson Lake]
- Small Diesel [diesel served communities other than Watson Lake and Old Crow]
- Old Crow

(b) Is the sales forecast method the same as used in YECL's last General Rate Application? If not, please enumerate any differences and provide an explanation for why the forecasting method was changed.

(c) Please describe YECL's method for reviewing its sales and revenue forecasts. How frequently are forecasts prepared? Who reviews and approves the forecasts?

(d) Please describe YECL's method for evaluating the accuracy of its forecasts. Does YECL have accuracy targets or tolerance ranges? How frequently are actual sales and revenues compared against forecasts?

(e) Provide a detailed variance schedule including the forecast and actual amounts of the customers, energy sales and revenues indicated for the years 1996 to 2007, and for the first six months of 2008, for each customer class broken out separately for WAF, Watson Lake, other diesel served communities other than Old Crow.

(f) Please discuss the impact on the utility's costs, return on rate base and net income if actual sales exceed the GRA forecasts and if actual sales are lower than the GRA forecasts. Indicate the expected impact on return on rate base and net income for 2009 if actual WAF sales are 10 more than forecast, compared with 10 less than forecast.

(g) With respect to the customer additions forecasts for the residential customer class, does the forecast consider only known residential property developments or does it also consider population growth forecasts? If so please provide the source of the population growth forecasts. If not, please explain why population growth forecasts are not considered.

(h) With respect to the use per customer (UPC) for residential customers, please explain why a three year average was used? In YECL's view does this method adequately capture the potential for increased use per customer due to increased saturation of home electronics?

(i) With respect to the commercial customer sales forecast, please describe in detail how the Whitehorse 2007 UPC was adjusted to remove load specifically attributable to the Canada Winter Games (including the forecast without this adjustment).

(j) For each test year (2008 and 2009), how many new commercial customers were forecast in Whitehorse and what is the average UPC assumed for these new customers in each test year? Provide for each year starting in 2003 until 2007 the number of new commercial customers in Whitehorse and the average UPC each year for these new customers. Please provide any analysis that YECL has done of normalized UPC trends since 2003 for existing Whitehorse commercial customers, i.e., trends excluding impacts from new customers.

(k) With respect to the 2009 UPCs are the UPCs the same as used for the 2008 test year or do they incorporate the 2008 year?

(l) With respect to the commercial customer revenue forecast, please explain in detail why the average revenue per kW.h is lower in 2008 and 2009 than in 2006 and 2007, and why commercial class revenues decline in 2008 despite growth in MWh sales.

(m) At page 2-2, it is stated that UPC was normalized for Whitehorse and Watson Lake. However, the Attachments show UPC normalized for various other communities. Please explain, and confirm the approach used for determining normalized UPC for these other communities.

(n) Please identify the variables being compared in each of the regression analyses (e.g., Section 2, Attachments 2, 4, etc. to 30) and explain with examples how this

analysis was used in the forecasts provided for Whitehorse residential normalized UPC for any given year (e.g., 2007) and for the test years. Please provide any assessments as to sensitivity of such regressions as between different months or seasons.

(o) Please provide details on the peak load forecasting methodology for each rate zone (see a above) including for each rate zone peak forecast and load factor assumed for each customer class.

(p) Using the initial business plans approved by senior management and or YECL's board in each year in question - - what were YECL's forecasts in the 2006 business plan, and how did those forecasts compare to actual 2006 results. Please provide the same information for 2007 and 2008.

(q) Please provide, for each rate zone and rate class:

- the current run-out rate being charged, the 1997 GRA diesel fuel price used to determine such run out rates, the comparative costs at the time of the 1997 GRA for heating with electricity versus alternative oil or propane fuels, and estimates of current comparative costs today for heating with electricity versus alternative oil or propane fuels; and

- the adjusted run out rate that would apply to reflect current diesel fuel prices applicable to diesel generation in each rate zone (as applicable in the latest Rider F filing of YEC YECL).

(r) Please comment on the run out rate assumptions adopted for YECL's test year sales forecasts, and the sensitivity of such forecasts to updated run out rates to reflect current fuel prices.

**Response:**

(a) Please refer to YEC-YECL-02(a) Attachment 1.

(b) Yukon Electrical's sales forecast methodology for the 2008 2009 GRA is fundamentally the same as it was for the 1996 1997 GRA. Two differences are (1) regression was used for all WAF and Watson Lake area residential customers as compared to just Whitehorse residential customers in 1996 1997, and (2) the commercial sales regression for Whitehorse excluded the one time impacts of the 2007 Canada Winter Games. These changes were incorporated into the 2008 2009 forecast methodology in order to complete as accurate a forecast as possible.

(c) Yukon Electrical's GRA sales and revenue forecast methodology is detailed in its Application. It was approved by the General Manager as well as head office personnel as part of the overall GRA Application.

(d) Yukon Electrical reviews its GRA sales and revenue forecast. Yukon Electrical strives to prepare as accurate a forecast as possible. Yukon Electrical does not have an accuracy target or tolerance range.

(e) In accordance with Board Order 2008-05, information prior to 2003 is not required in order to test the revenue requirement in the test period. As 2003-2007 are non-test years, no forecast is available. Please refer to part (a) Attachment 1 for actual (2003 2007) and forecast sales (2008 - 2009) in the WAF, Large Diesel (Watson Lake), Small Diesel (excluding Old Crow) and Old Crow. Yukon Electrical's Application is based on the best information at the time of the filing that does not include partial year actuals for 2008. Partial year results are not reflective of full year performance.

(f) In general terms, production, purchased power, distribution and customer accounting costs will rise if actual sales exceed the forecast and they will fall if actual sales are lower than forecast. Please refer to YEC-YECL-02(f) Attachment 1 for an analysis of the impact on return on rate base and net income if actual 2009 WAF sales are 10 more than forecast compared with 10 less than forecast.

(g) The forecast considered known residential developments that give rise to residential housing construction. Yukon Electrical has previously examined Whitehorse population numbers as compared to residential customer additions and has found no correlation between the two. For purposes of forecasting the test years 2008-2009, known residential property developments is the most direct and accurate indication of customer additions especially in the current environment of limited serviced lot availability which is impacting the forecast growth rate in 2009.

(h) Yukon Electrical believes the use of a three year average is a reasonable approach to forecast for the test period. With respect to the potential for increased UPC due to increased saturation of home electronics, the UPC data included in the filing does not support this hypothesis.

Further to the issue of forecast UPC, Yukon Electrical believes the 37 bill increase price signal associated with the termination of the Government's Rate Stabilization Fund will have a far greater impact on future UPC[1]. Yukon Electrical also believes the Yukon Government's recently announced Good Energy rebate program (refer to YEC-YECL-2(h) Attachment 1) will immediately result in downward pressure on UPC that has not been reflected in Yukon Electrical's forecast.

(i) Please refer to the following response to CW-YECL-9 for a description of how Yukon Electrical addressed the issue of one time sales associated with the Canada Winter Games.

**CW-YECL 9 Response:**

(a) (i) the addition of a small number of larger retail stores 1.3

(ii) a new housing complex located near Yukon College 0.2

(iii) the one time sales associated with the Canada Winter Games 0.6

(iv) colder than average weather 0.2

[1] 37 bill increase based on a residential customer consuming 750 KWh per month as of March 2007. 50 of the RSF was terminated on July 1, 2007 with the remaining 50 of the RSF slated for termination on July 1, 2008. On May 21, 2008, the Yukon Government announced that it was extending the termination date of the remaining coverage of the RSF from July 1, 2008 to July 1, 2009.

(v) other growth items .8

(b) As the larger retail stores and housing complex were in place throughout 2007, they will not influence the growth rate between 2007 and 2008 or the growth rate between 2008 and 2009. The load associated with these customers was incorporated into the test years via the overall customer numbers and UPC. The one time sales associated with the 2007 Canada Winter Games will have a negative impact on growth between 2007 and 2008, but no impact on the growth between 2008 and 2009. The remaining other growth items that resulted in a .8 growth rate between 2006 and 2007 will have some impact on the growth rate between 2007 and 2008 as these customers would have been connected at various points during 2007 and forecast to be in place throughout 2008. The load associated with these customers was incorporated into the test years via the customer numbers and UPC.

When looking at the absolute growth rates between 2007 and 2008, it is also important to note that 2007 was colder than the normal weather and Yukon Electrical used a weather normalized methodology for forecasting its commercial UPC in Whitehorse. Adjusting for the exclusion of one time Canada Winter Games impacts for the test periods and a colder 2007 year, results in an overall growth rate of 1.2 in total commercial energy in 2008 relative to 2007.

(c) As the one time sales associated with the Canada Winter Games related to (1) a temporary tent structure that hosted the opening and closing ceremonies as well as a festival as well as (2) a small number of hotels that opened in February and March of 2007 when they traditionally are closed during the non-tourist season, none of these sales are permanent.

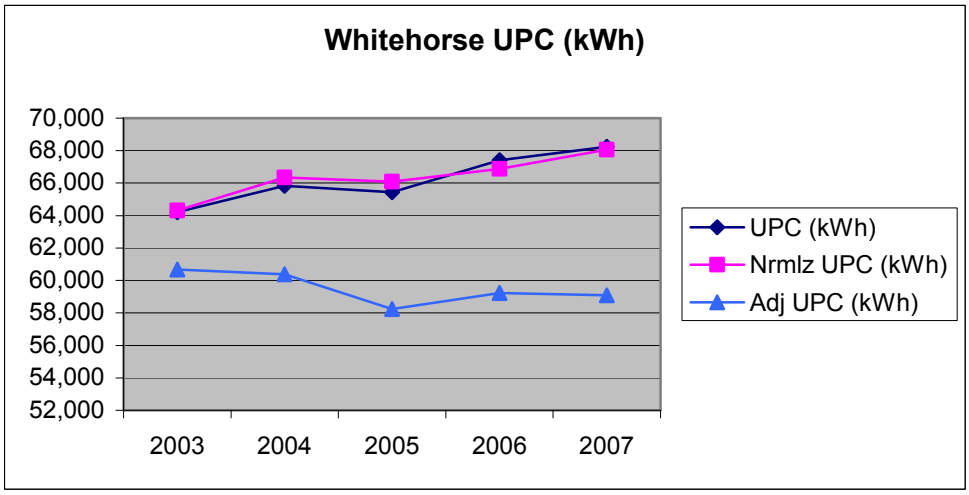
(j) Yukon Electrical is forecasting 17 new commercial customer additions in Whitehorse in 2008 with an overall average UPC of 68,689 kWh year and 21 new commercial additions in 2009 with an overall average UPC of 30,286 kWh year, assuming the customer is on the system for a full year. The decrease from 2008 to 2009 lower is due to a larger number of small load commercial customers forecast to be connected to the system in 2009.

Yukon Electrical's billing system does not allow it to easily track the UPC of new commercial customers and their associated UPC. Yukon Electrical has, however, tracked the impact of the 24 largest new commercial customers that have connected and remained connected to the distribution system since 2003.

Yukon Electrical's analysis of commercial UPC trend since 2003:

| Whitehorse Commercial | 2003 (kWh) | 2004 (kWh) | 2005 (kWh) | 2006 (kWh) | 2007 (kWh) |
|---|---|---|---|---|---|
| **Total UPC** | 64,208 | 65,827 | 65,434 | 67,414 | 68,246 |
| **Normalized UPC** | 64,309 | 66,335 | 66,090 | 66,887 | 68,054 |
| **Adjusted UPC** | 60,682 | 60,380 | 58,244 | 59,237 | 59.087 |

Adjusted UPC excludes the 24 largest load customers that have come onto and remained on the distribution system since 2003 as well as the 1 time sales associated with the Canada Winter Games. Yukon Electrical is unable to perform the regressions to weather normalize the Adjusted UPC due to difficulty in obtaining monthly UPC data for these customers which is required to do the calculation.




This analysis shows that once you remove the largest 24 customers connected since 2003, the UPC for all remaining customers has decreased marginally since 2003.

(k) The 2009 forecast UPCs are the same as those used for 2008.

(l) As Yukon Electrical's system does not separate actual revenue into demand and energy revenue, it is difficult to pinpoint the exact reason why revenue per kWh is lower in 2008 and 2009 as compared to 2007. The difference could be partially explained by the fact that more commercial customers had a higher billed demand as a result setting demand peaks in February and March of 2007 when there were extreme cold temperatures as well as the impact of the Canada Winter Games. These peak measured demands would have set the peak demand (ratchet) that commercial customers would have been billed on for the next 12 months.

(m) For greater clarity, all of the communities for which there was an attachment were normalized. For the remaining communities, UPC was not normalized. In summary, for commercial, only Whitehorse's UPC was normalized. For residential, the following communities had their UPC normalized: Whitehorse,

Carmacks, Carcross, Haines Junction, Teslin, Ross River, Tagish, Marsh Lake, Deep Creek, Takhini River, Lower Post, Upper Liard and Watson Lake.

(n) Please refer to YUB-YECL-4 Attachments 1-30 for the Attachments in Excel format. The regression analysis was used to calculate the normalized value of the average UPC for each community. As indicated in the attachments, in each community, the average UPC was regressed on the corresponding HDD, using 1994-2007 monthly data. Since HDD data for each individual community was not available, HDD in Whitehorse and Watson Lake was used, depending on the proximity of the community in question to Whitehorse and Watson Lake. The monthly normalized UPC values were then calculated by multiplying the coefficient of HDD from the regression equation by the difference between the actual HDD and the normal HDD (please see the attachments in Excel format and the column labelled Normalized UPC (kWh) ).

For example, for Whitehorse residential (Attachment 1) Normalized UPC (kWh) for January 2007 was calculated to be 1,352 kWh and December 2007 was calculated to be 927 kWh. The normalized monthly UPCs for 2007 total 10,472 kWh. This is the normalized UPC for 2007 for Whitehorse residential customers. To mitigate the undue impact of one high low year on the forecast, YECL used a three-year average normalized UPC in each community as a forecast for 2008 and 2009. This calculation is found in the column labelled 3-Yr Average Mthly Normal UPC (kWh) and, for this example, the average is 10,524 kWh.

As described above, the regression equation was used for several communities to obtain the annual average normalized UPC, which was then used (last 3-year average) to arrive at the UPC forecast for those communities for the test period. For the remaining communities, their average UPC for the test period was based on a simple 3-year historical average UPC. As such, a sensitivity analysis by month and season cannot be provided.

(o) For the purposes of forecasting commercial billing demand, the methodology was the same for all rate zones. A 3-year average (not peak) monthly billing load

factor was applied to the energy forecast to derive a total monthly billing demand for each commercial rate. Please refer to the table below for a summary of each commercial rate's Billing Demand forecast and assumed load factor.

**Yukon Electrical Company Limited**

**Commercial Forecast Billing Load Factor and Billing Demand 2008 and 2009**

| Commercial Rate | Annual Avg Load Factor Forecast | 2008 Annual Avg Demand Forecast (kW) | 2009 Annual Avg Demand Forecast (kW) |
|---|---|---|---|
| 2160 - Hydro Non-Govt | 33% | 27,161 | 27,454 |
| 2170 - Hydro Govt-Muni | 37% | 4,280 | 4,323 |
| 2180 - Hydro Govt-Fed | 44% | 10,372 | 10,557 |
| 2260 - Small Diesel Non-govt | 31% | 764 | 598 |
| 2280 - Small Diesel Govt-Fed | 26% | 423 | 325 |
| 2360 - Large Diesel Non-Govt | 31% | 1,497 | 1,526 |
| 2370 - Large Diesel Govt-Muni | 32% | 381 | 389 |
| 2380 - Large Diesel Govt-Federal | 34% | 679 | 693 |
| 2460 - Old Crow Diesel Non-Govt | 33% | 127 | 127 |
| 2480 - Old Crow Diesel Govt-Fed | 24% | 206 | 206 |

(p) Materials provided to Yukon Electrical's Board are considered confidential. Yukon Electrical notes that this position is similar to that taken by Yukon Energy in its 2005 Required Revenues and Related Matters Application IR process wherein Yukon Energy responded to McMahon-YEC-1-19(b) as well as variety of other similar requests by interveners, by stating Materials provided to Yukon Energy's Board of Directors and minutes from the Board meetings are confidential.

(q) The current run out rates are as follows:

| **Rates**<br>**RESIDENTIAL** | Run out Rate<br>Energy 1,000 kWh<br>kWh |
|---|---|
| **1160 - Hydro Non-Govt** | 0.1045 |
| **1180 - Hydro Govt** | 0.1045 |
| **1260 - Small Diesel Non-Govt** | 0.1236 |
| **1280 - Small Diesel Govt** | 0.1236 |
| **1360 - Large Diesel Non-Govt** | 0.1045 |
| **1380 - Large Diesel Govt** | 0.1045 |
| **1460 - Old Crow Diesel Non-Govt** | 0.2577 |
| **1480 - Old Crow Diesel Govt** | 0.2577 |

| **Rates**<br>**COMMERCIAL** | Run out Rate<br>Energy 2,000 kWh<br>kWh |
|---|---|
| **2160 - Hydro Non-Govt** | 0.1045 |
| **2170 - Hydro Govt-Muni** | 0.1045 |
| **2180 - Hydro Govt-Fed** | 0.1045 |
| **2260 - Small Diesel Non-govt** | 0.1236 |
| **2280 - Small Diesel Govt-Fed** | 0.1236 |
| **2360 - Large Diesel Non-Govt** | 0.1045 |
| **2370 - Large Diesel Govt-Muni** | 0.1045 |
| **2380 - Large Diesel Govt-Federal** | 0.1045 |
| **2460 - Old Crow Diesel Non-Govt** | 0.2577 |
| **2480 - Old Crow Diesel Govt-Fed** | 0.2577 |

The 1997 GRA diesel fuel prices used to determine the run out rates:

| **Forecast Cost of Fuel ( L)** | |
|---|---|
| WAF | 29.78 |
| Large Diesel (Watson Lake) | 28.43 |
| Destruction Bay | 32.60 |
| Beaver Creek | 33.81 |
| Stewart Crossing | 32.90 |
| Pelly Crossing | 32.87 |

| | |
|---|---|
| Swift River | 31.52 |
| Old Crow | 77.02 |

Source: Table 3.3 1996 1997 GRA

Yukon Electrical does not have comparative costs at the time of the 1997 GRA for heating with electricity versus alternative oil or propane fuels nor does it have estimates of current comparative costs today for heating with electricity versus alternative oil or propane fuels.

With respect to the adjusted run out rate that would apply to reflect current diesel fuel prices applicable to diesel generation in each rate zone, Yukon Electrical notes that fuel prices have increased between 1997 and 2008 and, all things being equal, the run out rate would increase. The design of new run out rates from those that have been in place since 1997 will be addressed as part of the Phase II Application.

(r ) No change in the run out rates is expected during most if not all of the test period. For this reason, there is little or no sensitivity to updated run out rates.

**Small Diesel (Watson Lake) - Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Summary of Customers, Energy Sales and Revenue**

| Line No. | Description | Billed Actual 2003 | Billed Actual 2004 | Billed Actual 2005 | Billed Actual 2006 | Billed Actual 2007 | Test Period 2008 Existing | Test Period 2008 Proposed |
|---|---|---|---|---|---|---|---|---|
| 1 | **Residential** | | | | | | | |
| 2 | Customers (average during year) | 263 | 267 | 273 | 274 | 284 | 297 | |
| 3 | Sales in MWh | 2,106 | 2,147 | 2,174 | 2,274 | 2,387 | 2,332 | |
| 4 | MWh sales per customer | 8.0 | 8.0 | 8.0 | 8.3 | 8.4 | 7.8 | |
| 5 | Revenue ( 000s) | 259 | 264 | 268 | 279 | 294 | 294 | |
| 6 | Cents per KWh | 12.31 | 12.30 | 12.33 | 12.28 | 12.34 | 12.62 | |
| 7 | **Commercial** | | | | | | | |
| 8 | Customers (average during year) | 133 | 135 | 134 | 134 | 137 | 135 | |
| 9 | Sales in MWh | 3,157 | 3,190 | 2,942 | 3,023 | 2,533 | 3,005 | |
| 10 | MWh sales per customer | 23.7 | 23.7 | 21.9 | 22.5 | 18.5 | 22.2 | |
| 11 | Revenue ( 000s) | 487 | 494 | 462 | 471 | 484 | 462 | |
| 12 | Cents per KWh | 15.44 | 15.48 | 15.69 | 15.57 | 19.12 | 15.36 | |
| 13 | **Street lights** | | | | | | | |
| 14 | Sales in MWh | 97 | 107 | 110 | 112 | 112 | 115 | |
| 15 | Revenue ( 000s) | 22 | 24 | 24 | 25 | 25 | 25 | |
| 16 | Cents per KWh | 22.73 | 21.92 | 22.04 | 22.06 | 22.03 | 21.97 | |
| 17 | **Sentinel lights** | | | | | | | |
| 18 | Sales in MWh | 64 | 62 | 61 | 61 | 60 | 60 | |
| 19 | Revenue ( 000s) | 13 | 13 | 13 | 13 | 12 | 12 | |
| 20 | Cents per KWh | 20.77 | 20.78 | 20.77 | 20.76 | 20.78 | 20.71 | |
| 21 | **Total Company - Retail - Primary** | | | | | | | |
| 22 | Customers | 396 | 402 | 407 | 408 | 421 | 432 | |
| 23 | Sales in MWh | 5,423 | 5,506 | 5,287 | 5,470 | 5,091 | 5,511 | |
| 24 | Revenue ( 000s) | 782 | 794 | 767 | 787 | 816 | 793 | |
| 25 | Cents KWh | 14.41 | 14.42 | 14.50 | 14.39 | 16.02 | 14.40 | |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Impact on Utility Revenue Requirement for 10 Decrease in WAF Sales**

**( 000s)**

| Line No. | Description | Cross Ref. | 2009 Decrease 10 | Original Applicatio |
|---|---|---|---|---|
| 1 | **Revenues** | | | |
| 2 | Retail revenues | S.2.1 L.45 | 43,549 | 47,07 |
| 3 | Other revenue | S.2.2 L.12 | 827 | 82 |
| 4 | **Total Revenues** | | 44,376 | 47,90 |
| 5 | | | | |
| 6 | **Costs** | | | |
| 7 | Purchase power | S.3.1 L.13 | 21,031 | 23,49 |
| 8 | Diesel Fuel | S.4.1 L.6 | 5,299 | 5,29 |
| 9 | Operations and maintenance | S.5.1 L.49 | 9,317 | 9,31 |
| 11 | Property Taxes | Page 6-1 | 261 | 26 |
| 12 | Depreciation | S.7.1 L.4 | 4,837 | 4,83 |
| 13 | Amortization of contributions | S.8.11 L.8 | (1,028) | (1,02 |
| 14 | Amortization of deferred costs credits | S.8.8 L.7 | 652 | 65 |
| 15 | Return on rate base | S.8.1 L.5, 10, 15, 20 | 3,336 | 4,02 |
| 16 | Income taxes | S.10.1 L.30 | 671 | 1,04 |
| 17 | **Total Costs** | | 44,376 | 47,90 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Impact on Utility Revenue Requirement for 10 Increase in WAF Sales**
**( 000s)**

| Line No. | Description | Cross Ref. | 2009 Increase 10 | Original Application |
|---|---|---|---|---|
| 1 | **Revenues** | | | |
| 2 | Retail revenues | S.2.1 L.45 | 50,334 | 47,075 |
| 3 | Other revenue | S.2.2 L.12 | 827 | 827 |
| 4 | **Total Revenues** | | 51,161 | 47,902 |
| 5 | | | | |
| 6 | **Costs** | | | |
| 7 | Purchase power | S.3.1 L.13 | 25,779 | 23,494 |
| 8 | Diesel Fuel | S.4.1 L.6 | 5,299 | 5,299 |
| 9 | Operations and maintenance | S.5.1 L.49 | 9,317 | 9,317 |
| 11 | Property Taxes | Page 6-1 | 261 | 261 |
| 12 | Depreciation | S.7.1 L.4 | 4,837 | 4,837 |
| 13 | Amortization of contributions | S.8.11 L.8 | (1,028) | - 1,028 |
| 14 | Amortization of deferred costs credits | S.8.8 L.7 | 652 | 652 |
| 15 | Return on rate base | S.8.1 L.5, 10, 15, 20 | 4,670 | 4,026 |
| 16 | Income taxes | S.10.1 L.30 | 1,374 | 1,044 |
| 17 | **Total Costs** | | 51,161 | 47,902 |

Yukon Government

NEWS release

FOR RELEASE 08-192
August 5, 2008

## GOVERNMENT LAUNCHES REBATE PROGRAM TO HELP YUKONERS REDUCE ENERGY COSTS

WHITEHORSE The Yukon government is helping Yukoners reduce their energy costs by launching *Good Energy*, a comprehensive program which provides 100- 500 in cash rebates on a wide range of energy efficient products.

*Good Energy* is part of the Yukon government's effort to help Yukoners lower their energy costs, Energy, Mines and Resources Minister Brad Cathers said. This program supports Yukoners' move to energy efficient products which can lower their energy costs.

*Good Energy* rebates apply to a wide range of products, including high efficiency:

- kitchen and laundry appliances
- solar domestic hot water systems
- pellet and wood stoves
- oil and propane furnaces and boilers
- outboard boat motors

The products must meet specific energy efficiency requirements to be eligible for the rebate. A number of industry standards regarding efficiency are used, including Energy Star .

*Good Energy* is an expansion of the popular *Appliance Rebate Program* offered by the Energy Solutions Centre. Last year, that program had 589 participants (approximately 5 per cent of Yukon households) who received rebates for 676 appliances and 83 furnaces boilers. It is expected the expanded program will encourage even more Yukoners to choose the most energy efficient products possible when purchasing.

We all have options when it comes to reducing our energy bills, Cathers said. I encourage Yukoners to choose *Good Energy* when they are buying products for their homes and businesses.

Eligible *Good Energy* products are available at many Yukon retailers. Rebate forms and program information is available at Yukon retailers or at the Energy Solutions Centre. The Energy Solutions Centre can be contacted by calling 867-393-7063 or toll-free at 1-800-662-0408 ext. 7063, or by visiting www.esc.gov.yk.ca.

*Good Energy* runs until March 31, 2009.

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**Attachment** *Good Energy* eligible products, rebate amounts and eligibility criteria.

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| Category | Eligible energy efficient product | Rebate available | Eligibility Criteria |
|---|---|---|---|
| **Home Appliances** | Refrigerator | 200 non-hydro communities | Energy Star |
| | | 100 hydro communities | Energy Star |
| | Freezers | 200 non-hydro communities | Energy Star |
| | | 100 hydro communities | Energy Star |
| | Clothes Washers | 200 non-hydro communities | Energy Star |
| | | 100 hydro communities | Energy Star |
| | Dish Washers | 200 non-hydro communities | Energy Star |
| | | 100 hydro communities | Energy Star |
| **Heating Appliances** | Wood stoves | 300 | EPA 40 CFR Part 60 or CSA - B415.1-M92 approved |
| | Wood pellet stoves and boilers | 300 | ULC certified |
| | Heat recovery ventilators | 300 | Certified by the Home Ventilati Institute |
| | Oil furnaces and boilers | 500 - oil furnace boiler 85 efficiency | Energy Star 85 AFUE or better |
| | | 300 - oil furnace boiler 83 efficiency | Energy Star 83 AFUE or better |
| | Oil furnaces for Mobile Homes | 250 - 80.0 AFUE or better | 80.0 AFUE or better |
| | Propane furnaces and boilers | 500 - Propane furnace boiler 92 efficiency | Energy Star 92 AFUE or better |
| | | 300 - Propane furnace boiler 90 efficiency | Energy Star 90 AFUE or better |
| | Hot water heating | 500 - solar domestic hot water system | CAN CSA Standard |
| **Transportation** | Outboard motors | 250 - less than 30hp | California Air Resources Board (CARB) 3 star rating |
| | | 500 - 30hp or greater | |

Non-hydro communities: Beaver Creek, Burwash Landing, Destruction Bay, Old Crow, Pelly Crossing, Upper Liard and Watson Lake.

## YEC-YECL-3

**Reference:** Revenues

**Requests:**

(a) Please indicate whether YECL received any revenues from sales or rental of underground ducts or rental of pole space to third parties (e.g. telephone, cable) in Whitehorse?

(b) If so, please indicate the amount of revenues received in each year starting in 2003. Please also indicate whether these revenues were accounted for in the GRA Application and if so where. Where these revenues are earned as a result of an agreement with a third party, please provide a copy of this agreement.

(c) Provide a detailed schedule of the various types of other revenue as shown in Schedule 2.2, as updated on July 4, 2008 and their origins.

(d) Does YECL anticipate earning any other revenue or income that is not included in forecast revenues for 2008 and or 2009?

**Response:**

(a) Yukon Electrical receives joint use revenues from the rental of pole space to third parties.

(b) In accordance with Board Order 2008-5 information prior to 2005 was not required to test the reasonableness of the forecasts in the test period. These agreements have not been provided as these are commercial agreements with third parties and Yukon Electrical considers such agreements to be confidential.

(c) Please refer to YEC-YECL-03(c) Attachment 1.

(d) No.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Miscellaneous Revenue**

| Line No. | Description | Cross Ref. | Actual 2005 | Actual 2006 | Actual 2007 | Te |
|---|---|---|---|---|---|---|
| | Other Revenue Breakdown: | | | | | |
| | Penalty revenue | | 5 | 5 | 5 | |
| | Rent Office & Buildings | | 108 | 104 | 111 | |
| | BC Hydro Agreement | | 30 | 31 | 32 | |
| | Miscellaneous | | 4 | 8 | 16 | |
| | Per Schedule 2.2 Line 4 | | 147 | 148 | 164 | |

## YEC-YECL-4

**Reference:** Line Losses and Company Use

**Requests:**

(a) Please provide Schedule 3.2, as updated on July 4, 2008 (but also showing secondary sales and primary sales, and secondary and primary purchases), broken out separately for each of the following rate zones:

- WAF
- Large Diesel [Watson Lake]
- Small Diesel [diesel served communities other than Watson Lake and Old Crow]
- Old Crow

(b) Please explain in detail what is included in Losses and company use as this is described in Schedule 3.2? Does YECL have targets for line losses and company use? If so please describe.

(c) Please provide a schedule that separates out the line losses from company use for the test years and the years 2003 to 2007 and for each rate zone.

(d) Please describe the uses that are included in company use and describe YECL's processes for minimizing these uses.

(e) Please explain the factors affecting company use amounts each year and in each rate zone? Should company use amounts be expected to increase in proportion with overall sales, or should they be expected to be relatively fixed from year to year?

(f) Please provide a detailed variance schedule including the forecast and actual amounts for the first six months of 2008 for the same information required under a above [Schedule 3.2 for the various information as noted].

**Response:**

(a) Please refer to YEC-YECL-04(a) Attachment 1

(b) System loss (or losses) is the difference between the energy supplied at the system supply level (from Yukon Energy or a Yukon Electrical production plant) and the energy delivered at the customer level. Company use electricity is electricity used for Yukon Electrical's downtown Whitehorse office and Service Complex, electricity used to operate distribution system devices and electricity used in the winter to keep the standby units heated when they are in standby mode. Yukon Electrical attempts to minimize losses where it is practical.

(c) Yukon Electrical does not actively compile the company use electricity detailed in (b) above. Yukon Electrical notes the quantum of electricity used for company use would be very small in relation to the overall line losses for the company.

(d) Please refer to (b) above with respect to locations where company use electricity is consumed. Yukon Electrical's lights at its downtown Whitehorse and Service Complex facilities have motion detectors that turn the lights off when the rooms are not in use.

(e) Given company use electricity effectively relates to lights at Yukon Electrical's downtown Whitehorse and Service Complex offices, the ongoing operation of electrical devices on the distribution system and the heating of standby units, they will remain relatively consistent year to year.

(f) Yukon Electrical used the best information available at the time of the filing and did not use 2008 actual information to prepare the forecast. As such Yukon Electrical is not providing partial year 2008 information.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Schedule of Energy Losses**
**(MW.h )**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Sales and Losses** | | | | | | | | |
| 2 | Total energy sales (MWh) | S.2.1 L.39 | 254,635 | 262,483 | 268,105 | 285,205 | 291,752 | 287,255 | 279,497 |
| | WAF/MD - Primary | | 220,532 | 226,073 | 229,743 | 242,365 | 247,870 | 249,554 | 253,195 |
| | WAF/MD - Secondary | | 13,039 | 15,998 | 18,363 | 21,555 | 23,566 | 16,853 | 6,954 |
| | Large Diesel | | 12,918 | 13,007 | 12,900 | 12,885 | 13,269 | 13,579 | 13,746 |
| | Small Diesels | | 5,423 | 5,506 | 5,287 | 5,470 | 5,091 | 5,511 | 3,820 |
| | Old Crow | | 1,559 | 1,661 | 1,762 | 1,731 | 1,716 | 1,758 | 1,781 |
| | | | 253,471 | 262,245 | 268,056 | 284,007 | 291,512 | 287,255 | 279,497 |
| | Unbilled Adjustment | | 1,164 | 238 | 49 | 1,198 | 240 | - | - |
| | | | 254,635 | 262,483 | 268,105 | 285,205 | 291,752 | 287,255 | 279,497 |
| 3 | Losses and company used - (MWh) | | 14,836 | 17,284 | 15,723 | 18,591 | 18,087 | 17,810 | 17,329 |
| | WAF/MD - Primary | | 12,921 | 14,809 | 13,117 | 15,289 | 15,243 | 15,299 | 15,564 |
| | WAF/MD - Secondary | | 764 | 1,048 | 1,048 | 1,360 | 1,449 | 1,033 | 427 |
| | Large Diesel | | 566 | 730 | 742 | 1,142 | 855 | 823 | 833 |
| | Small Diesels | | 454 | 577 | 597 | 675 | 426 | 502 | 349 |
| | Old Crow | | 131 | 120 | 219 | 126 | 113 | 152 | 155 |
| | | | 14,836 | 17,284 | 15,723 | 18,591 | 18,087 | 17,810 | 17,329 |
| 4 | Losses - | | 5.8 | 6.6 | 5.9 | 6.5 | 6.2 | 6.2 | 6.2 |
| | WAF/MD - Primary | | 5.9% | 6.6% | 5.7% | 6.3% | 6.1% | 6.1% | 6.1% |
| | WAF/MD - Secondary | | 5.9% | 6.6% | 5.7% | 6.3% | 6.1% | 6.1% | 6.1% |
| | Large Diesel | | 4.2% | 5.3% | 5.4% | 8.1% | 6.1% | 5.8% | 5.8% |
| | Small Diesels | | 7.2% | 8.9% | 9.6% | 10.9% | 6.8% | 8.7% | 8.5% |
| | Old Crow | | 7.8% | 6.8% | 11.2% | 6.9% | 6.1% | 7.8% | 7.8% |
| 5 | Total generation and purchases (MWh) | | 269,471 | 279,767 | 283,828 | 303,796 | 309,839 | 305,065 | 296,826 |
| 6 | **Sources - MWh** | | | | | | | | |
| 7 | Hydro generation - WAF | | 4,948 | 5,799 | 6,239 | 8,216 | 9,025 | 6,192 | 6,192 |
| 8 | Hydro grid standby diesel generation - WAF MD | S.4.1 L.1 | 27 | 14 | 8 | 39 | 131 | 44 | 44 |
| 9 | Diesel generation | S.4.1 L.1 | 21,486 | 21,974 | 21,799 | 22,125 | 22,203 | 21,883 | 20,433 |
| | Large Diesel | | 13,505 | 13,738 | 13,642 | 14,116 | 14,124 | 14,148 | 14,322 |
| | Small Diesels | | 6,291 | 6,466 | 6,195 | 6,197 | 6,226 | 5,767 | 4,118 |
| | Old Crow | | 1,690 | 1,771 | 1,963 | 1,812 | 1,853 | 1,967 | 1,993 |
| | | | 21,486 | 21,974 | 21,799 | 22,125 | 22,203 | 21,883 | 20,433 |
| 10 | Purchases - WAF MD | S.3.1 L.4 | 243,010 | 251,980 | 255,782 | 273,416 | 278,480 | 276,946 | 270,156 |
| | WAF/MD - Primary | | 229,971 | 235,982 | 237,419 | 251,861 | 254,914 | 260,093 | 263,202 |
| | WAF/MD - Secondary | | 13,039 | 15,998 | 18,363 | 21,555 | 23,566 | 16,853 | 6,954 |
| | | | 243,010 | 251,980 | 255,782 | 273,416 | 278,480 | 276,946 | 270,156 |
| 11 | | | 269,471 | 279,767 | 283,828 | 303,796 | 309,839 | 305,065 | 296,826 |
| 12 | **Sources -** | | | | | | | | |
| 13 | Hydro generation - WAF | | 1.8 | 2.1 | 2.2 | 2.7 | 2.9 | 2.0 | 2.1 |
| 14 | Diesel generation | | 8.0 | 7.9 | 7.7 | 7.3 | 7.2 | 7.2 | 6.9 |
| | Large Diesel | | 5.0% | 4.9% | 4.8% | 4.6% | 4.6% | 4.6% | 4.8% |
| | Small Diesels | | 2.3% | 2.3% | 2.2% | 2.0% | 2.0% | 1.9% | 1.4% |
| | Old Crow | | 0.6% | 0.6% | 0.7% | 0.6% | 0.6% | 0.6% | 0.7% |
| | | | 8.0% | 7.9% | 7.7% | 7.3% | 7.2% | 7.2% | 6.9% |
| 15 | Purchases - WAF MD | | 90.2 | 90.1 | 90.1 | 90.0 | 89.9 | 90.8 | 91.0 |
| | WAF/MD - Primary | | 85.3% | 84.3% | 83.6% | 82.9% | 82.3% | 85.3% | 88.7% |
| | WAF/MD - Secondary | | 4.8% | 5.7% | 6.5% | 7.1% | 7.6% | 5.5% | 2.3% |
| | | | 90.2% | 90.1% | 90.1% | 90.0% | 89.9% | 90.8% | 91.0% |
| | | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

## YEC-YECL-5

**Reference:** Fish Lake Hydro Generation

**Requests:**

(a) Please provide the actual Fish Lake hydro generation over each of the last 10 years used to calculate the forecast test year generation forecasts described on page 3-1. Please discuss if the 10 year average was adjusted to remove any one time, non-recurring generation outages.

(b) Please provide a schedule showing the number of hours the Fish Lake hydro generation was unavailable due to planned maintenance or capital works and due to any unplanned outages for each of the 10 years used to develop the test year generation forecasts. Please provide an estimate of the generation energy lost as a result of those outages.

(c) Please provide a schedule that shows the forecast generation at Fish Lake from the last General Rate Application and the actual generation for the same period.

(d) At page 3-2, when discussing the Diesel Contingency Fund (DCF), it is stated: For the purposes of this filing, Yukon Electrical has updated its annual forecast of hydro generation to 6.2 GW.h. Provide the long term average hydro generation by month last approved by the Board in the 1996 1997 GRA for YECL's DCF account. Explain fully the proposed basis for seeking a change today in this long term average hydro generation used for YECL's DCF account, and indicate the proposed average hydro generation by month. Confirm that the DCF has no application to YECL so long as WAF diesel is not on the margin.

(e) Please provide a schedule showing Fish Lake energy generation for all years to date, and the long term average annual and monthly energy generation based on this long term record. Indicate any adjustments needed to this record, and these averages, to address one-time events not relevant to estimating long-term average energy capability.

(f) Please provide, for each test year, the specific adjustments referenced at page 3-1 for estimated downtime in the test period, for required rebuilds Please provide more details on the estimated downtime in the test period for required rebuilds at Fish Lake. Please provide the number of hours it is expected to be unavailable and the expected lost generation.

(g) Please indicate what changes, if any, are expected to Fish Lake average annual energy and peak output capability by month after the rebuilds are completed.

(h) What are the causes of potential fluctuations of costs in the operation of Fish Lake Facility?

(i) Identify any options that YECL has examined to reflect in rates the downtime required for Fish Lake rebuilds (beyond the option adopted of increasing rates in the test years for the added purchase power needed due to this short term event). How does YECL propose to credit customers if the rates resulting from this GRA are in place beyond 2009 and Fish Lake generation returns to long term average levels once the rebuilds are complete? Has YECL examined the option of including the short term costs for added purchase power in the costs for the rebuild and amortizing these costs over the life of the project? If not, why not?

(j) Please provide a variance schedule including the forecast and actual amounts of Fish Lake generation for the first six months of 2008.

**Response:**

(a) Please refer to YUB-YECL-5 Attachment 1.

(b) Please refer to YUB-YECL-5 Attachment 4. Energy lost due to the outages over the past 10 years is estimated to be 0.6 GWhr

(c) Please refer to YUB-YECL-5 Attachment 4. This information is sufficient for testing the forecast.

(d) The last approved test period was 1996 1997. Information provided in response to information requests is in accordance with Board Order 2008-05, which confirmed that Yukon Electrical is not required to provide information prior to

2003 and or 2005 to test the revenue requirement. Yukon Electrical is proposing to use 6.2GWh as the forecast for the test years based on down time that is required to complete necessary work on the Fish Lake system. It is not meant to be a long term average. In regard to the Diesel contingency fund deferral account, Yukon Electrical is proposing that it remain in place if Diesel is on the margin and confirms that it would not be triggered as long as WAF Diesel is not on the margin.

(e) Please refer to YUB-YECL-5(a) Attachment 1. There are no adjustments to the record to address one time events.

(f) Yukon Electrical estimates the down time to be 6 weeks per test year for the required upgrades at Fish Lake Hydro. This equates to 0.8 GWh of lost generation per test year.

(g) Yukon Electrical forecasts no additional energy output on the Fish Lake Hydro System due to these rebuilds.

(h) Causes that can contribute to the potential operational cost fluctuations of Fish Lake Hydro include, grid outages, line outages, equipment failure, impact due to the environment (trees, beavers) as well as significant changes in water levels, and ice conditions.

(i) Yukon Electrical is connected to the WAF grid. As such the small amount of purchase power, required due to the down time for the repairs on Fish Lake, are most economically captured by additional purchases from YEC. Although some options were considered, these were not seen as being cost effective. Yukon Electrical takes the risks associated with differences in the energy output of Fish Lake of being higher or lower than the long term average outside of the test period. In addition, Yukon Electrical is taking the risk on the availability of Fish Lake being less than forecast during the test period. Yukon Electrical believes that the forecast represents the best information that it had at the time of filling the application. Yukon Electrical has not considered including added purchase power costs in the capital cost of the Fish Lake rebuilds as typically energy costs are expensed.

(j) Yukon Electrical used the best information available at the time of filing its application and as such is not providing partial year 2008 information.

## YEC-YECL-6

**Reference:** Generation

**Requests:**

(a) Describe, for each rate zone (WAF, Large Diesel, Small Diesel and Old Crow) the firm capacity and firm energy capabilities of each generation source.

(b) Describe the criteria YECL uses in calculating firm energy and firm capacity.

**Response:**

(a) Please refer to YUB-YECL-10(a) Attachment 1. Yukon Electrical is unaware of what is meant by firm energy capabilities . Please refer to revised Schedule 4.2 which shows the actual and forecasted generation by community.

(b) Yukon Electrical removes the largest unit capacity from the community. The total capacity remaining is what Yukon Electrical uses for the community's firm capacity.

## YEC-YECL-7

**Reference:** Sales Forecasts

**Requests:**

(a) Please provide an update, using 2008 and 2009 forecasts, to the response to CI-YEC YECL-35 from the 1993 94 General Rate Application.

(b) Please provide a copy of the forecast wholesale power purchase and Rider J forecast information by month and year that YECL provided to YEC for planning purposes each year from 2003 to 2008, and provide a schedule indicating the variances between the forecast and actual amounts

**Response:**

(a) Please refer to CW-YECL-19 Attachment 1.

(b) Yukon Electrical does not consider that this information is relevant to the testing of the sales forecast however given that this information has been provided to YEC previously please refer to YEC-YECL-7 Attachment 1. Please note that information relating to 2008 has not been provided as Yukon Electrical used the best information available at the time of the filing and did not use 2008 actual information to prepare the forecast.

## YECL Purchased Power

| | Jan-03 | Feb-03 | Mar-03 | Apr-03 | May-03 | Jun-03 | Jul-03 | Aug-03 | Sep-03 | Oct-03 | Nov-03 | Dec-03 | 2003 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | | | | | | | | | | | | | |
| **Primary** | 23,441,211 | 19,065,686 | 21,694,556 | 17,855,827 | 16,710,125 | 16,544,769 | 15,388,323 | 15,850,537 | 18,248,933 | 19,164,285 | 23,096,773 | 22,909,834 | 229,970,859 |
| **Secondary** | 1,001,900 | 972,980 | 1,013,290 | 775,590 | 628,460 | 568,590 | 815,295 | 561,665 | 1,089,180 | 1,354,815 | 2,035,630 | 2,221,710 | 13,039,105 |
| **Total** | 24,443,111 | 20,038,666 | 22,707,846 | 18,631,417 | 17,338,585 | 17,113,359 | 16,203,618 | 16,412,202 | 19,338,113 | 20,519,100 | 25,132,403 | 25,131,544 | 243,009,964 |
| **Provided to YEC** | | | | | | | | | | | | | |
| **Primary** | 24,314,488 | 21,838,564 | 20,616,461 | 17,738,249 | 16,221,034 | 14,965,971 | 14,475,104 | 14,534,154 | 15,976,638 | 18,048,511 | 20,908,553 | 24,057,913 | 223,695,640 |
| **Secondary** | 865,000 | 860,000 | 840,000 | 820,000 | 845,000 | 615,000 | 435,000 | 535,000 | 860,000 | 1,000,000 | 1,070,000 | 1,115,000 | 9,860,000 |
| **Total** | 25,179,488 | 22,698,564 | 21,456,461 | 18,558,249 | 17,066,034 | 15,580,971 | 14,910,104 | 15,069,154 | 16,836,638 | 19,048,511 | 21,978,553 | 25,172,913 | 233,555,640 |
| **Variance** | | | | | | | | | | | | | |
| **Primary** | -873,277 | -2,772,878 | 1,078,095 | 117,578 | 489,091 | 1,578,798 | 913,219 | 1,316,383 | 2,272,295 | 1,115,774 | 2,188,220 | -1,148,079 | 6,275,219 |
| **Secondary** | 136,900 | 112,980 | 173,290 | -44,410 | -216,540 | -46,410 | 380,295 | 26,665 | 229,180 | 354,815 | 965,630 | 1,106,710 | 3,179,105 |
| **Total** | -736,377 | -2,659,898 | 1,251,385 | 73,168 | 272,551 | 1,532,388 | 1,293,514 | 1,343,048 | 2,501,475 | 1,470,589 | 3,153,850 | -41,369 | 9,454,324 |

| | Jan-04 | Feb-04 | Mar-04 | Apr-04 | May-04 | Jun-04 | Jul-04 | Aug-04 | Sep-04 | Oct-04 | Nov-04 | Dec-04 | 2004 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | | | | | | | | | | | | | |
| **Primary** | 25,502,296 | 19,557,960 | 23,331,043 | 17,793,205 | 17,114,100 | 16,604,160 | 16,036,315 | 17,074,790 | 17,968,625 | 18,367,113 | 22,434,043 | 24,198,075 | 235,981,725 |
| **Secondary** | 1,850,335 | 1,457,605 | 2,001,440 | 1,929,785 | 1,159,055 | 909,675 | 649,190 | 712,065 | 760,770 | 1,378,860 | 1,736,695 | 1,452,945 | 15,998,420 |
| **Total** | 27,352,631 | 21,015,565 | 25,332,483 | 19,722,990 | 18,273,155 | 17,513,835 | 16,685,505 | 17,786,855 | 18,729,395 | 19,745,973 | 24,170,738 | 25,651,020 | 251,980,145 |
| **Provided to YEC** | | | | | | | | | | | | | |
| **Primary** | 24,588,446 | 22,093,104 | 20,853,877 | 17,953,454 | 16,413,882 | 15,142,488 | 14,646,626 | 14,709,141 | 16,168,910 | 18,261,273 | 21,144,387 | 24,325,660 | 226,301,247 |
| **Secondary** | 995,000 | 960,000 | 940,000 | 920,000 | 945,000 | 715,000 | 535,000 | 635,000 | 960,000 | 1,100,000 | 1,170,000 | 1,215,000 | 11,090,000 |
| **Total** | 25,583,446 | 23,053,104 | 21,793,877 | 18,873,454 | 17,358,882 | 15,857,488 | 15,181,626 | 15,344,141 | 17,128,910 | 19,361,273 | 22,314,387 | 25,540,660 | 237,391,247 |
| **Variance** | | | | | | | | | | | | | |
| **Primary** | 913,850 | -2,535,144 | 2,477,166 | -160,249 | 700,218 | 1,461,672 | 1,389,689 | 2,365,649 | 1,799,715 | 105,840 | 1,289,656 | -127,585 | 9,680,478 |
| **Secondary** | 855,335 | 497,605 | 1,061,440 | 1,009,785 | 214,055 | 194,675 | 114,190 | 77,065 | -199,230 | 278,860 | 566,695 | 237,945 | 4,908,420 |
| **Total** | 1,769,185 | -2,037,539 | 3,538,606 | 849,536 | 914,273 | 1,656,347 | 1,503,879 | 2,442,714 | 1,600,485 | 384,700 | 1,856,351 | 110,360 | 14,588,898 |

| | Jan-05 | Feb-05 | Mar-05 | Apr-05 | May-05 | Jun-05 | Jul-05 | Aug-05 | Sep-05 | Oct-05 | Nov-05 | Dec-05 | 2005 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | | | | | | | | | | | | | |
| **Primary** | 26,263,044 | 21,545,246 | 20,645,685 | 17,521,588 | 17,832,112 | 16,462,502 | 17,291,923 | 16,373,196 | 17,656,716 | 20,361,133 | 21,823,317 | 23,642,228 | 237,418,690 |
| **Secondary** | 1,395,100 | 1,253,640 | 1,581,250 | 2,059,975 | 1,435,345 | 1,316,480 | 981,460 | 1,173,005 | 1,375,970 | 1,914,200 | 2,150,765 | 1,725,690 | 18,362,880 |
| **Total** | 27,658,144 | 22,798,886 | 22,226,935 | 19,581,563 | 19,267,457 | 17,778,982 | 18,273,383 | 17,546,201 | 19,032,686 | 22,275,333 | 23,974,082 | 25,367,918 | 255,781,570 |
| **Provided to YEC** | | | | | | | | | | | | | |
| **Primary** | 25,008,519 | 21,729,949 | 21,315,145 | 18,211,020 | 17,061,195 | 16,165,950 | 16,394,446 | 16,488,000 | 16,661,660 | 18,660,658 | 21,627,481 | 24,887,991 | 234,212,014 |
| **Secondary** | 1,295,000 | 1,260,000 | 1,140,000 | 1,120,000 | 1,145,000 | 915,000 | 735,000 | 935,000 | 1,260,000 | 1,300,000 | 1,470,000 | 1,575,000 | 14,150,000 |
| **Total** | 26,703,519 | 23,289,949 | 22,755,145 | 19,531,020 | 18,306,195 | 17,380,950 | 17,529,446 | 17,623,000 | 18,021,660 | 20,160,658 | 23,297,481 | 26,762,991 | 251,362,014 |
| **Variance** | | | | | | | | | | | | | |
| **Primary** | 1,254,525 | -184,703 | -669,460 | -689,432 | 770,917 | 296,552 | 897,477 | -114,804 | 995,056 | 1,700,475 | 195,836 | -1,245,763 | 3,206,676 |
| **Secondary** | 100,100 | -6,360 | 441,250 | 939,975 | 290,345 | 401,480 | 246,460 | 238,005 | 115,970 | 614,200 | 680,765 | 150,690 | 4,212,880 |
| **Total** | 954,625 | -491,063 | -528,210 | 50,543 | 961,262 | 398,032 | 743,937 | -76,799 | 1,011,026 | 2,114,675 | 676,601 | -1,395,073 | 4,419,556 |

| | Jan-06 | Feb-06 | Mar-06 | Apr-06 | May-06 | Jun-06 | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | | | | | | | | | | | | | |
| **Primary** | 26,459,105 | 21,270,630 | 23,943,184 | 19,880,399 | 17,900,058 | 17,056,913 | 16,845,219 | 17,589,345 | 19,060,100 | 19,385,580 | 27,030,230 | 25,439,850 | 251,860,613 |
| **Secondary** | 2,428,605 | 1,658,130 | 1,846,700 | 2,085,510 | 1,583,480 | 1,306,270 | 1,257,420 | 1,217,280 | 1,545,110 | 1,835,720 | 2,185,990 | 2,605,160 | 21,555,375 |
| **Total** | 28,887,710 | 22,928,760 | 25,789,884 | 21,965,909 | 19,483,538 | 18,363,183 | 18,102,639 | 18,806,625 | 20,605,210 | 21,221,300 | 29,216,220 | 28,045,010 | 273,415,988 |
| **Provided to YEC** | | | | | | | | | | | | | |
| **Primary** | 25,893,679 | 23,700,295 | 21,961,998 | 19,587,473 | 17,427,155 | 16,249,522 | 15,721,835 | 16,043,169 | 17,533,735 | 19,609,287 | 22,485,129 | 25,648,809 | 241,862,086 |
| **Secondary** | 1,976,676 | 1,819,242 | 1,679,300 | 1,539,359 | 1,451,895 | 1,416,910 | 1,323,615 | 1,323,615 | 1,586,006 | 1,749,271 | 1,947,522 | 2,186,589 | 20,000,000 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total** | 27,870,356 | 25,519,537 | 23,641,298 | 21,126,831 | 18,879,050 | 17,666,432 | 17,045,450 | 17,366,784 | 19,119,741 | 21,358,558 | 24,432,651 | 27,835,398 | 261,862,086 |
| **Variance** | | | | | | | | | | | | | |
| **Primary** | 565,426 | -2,429,665 | 1,981,186 | 292,926 | 472,903 | 807,391 | 1,123,384 | 1,546,176 | 1,526,365 | -223,707 | 4,545,101 | -208,959 | 9,998,527 |
| **Secondary** | 451,929 | -161,112 | 167,400 | 546,151 | 131,585 | -110,640 | -66,195 | -106,335 | -40,896 | 86,449 | 238,468 | 418,571 | 1,555,375 |
| **Total** | 1,017,354 | -2,590,777 | 2,148,586 | 839,078 | 604,488 | 696,751 | 1,057,189 | 1,439,841 | 1,485,469 | -137,258 | 4,783,569 | 209,612 | 11,553,902 |

| | **Jan-07** | **Feb-07** | **Mar-07** | **Apr-07** | **May-07** | **Jun-07** | **Jul-07** | **Aug-07** | **Sep-07** | **Oct-07** | **Nov-07** | **Dec-07** | **2007** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | | | | | | | | | | | | | |
| **Primary** | 25,615,830 | 24,427,490 | 24,549,624 | 20,404,392 | 18,365,168 | 16,725,774 | 17,737,590 | 17,577,792 | 19,157,382 | 20,338,590 | 22,454,087 | 27,560,328 | 254,914,047 |
| **Secondary** | 2,715,720 | 2,421,000 | 2,287,980 | 2,428,320 | 1,822,210 | 1,471,420 | 1,498,680 | 1,155,800 | 1,489,180 | 1,786,430 | 2,362,810 | 2,126,420 | 23,565,970 |
| **Total** | 28,331,550 | 26,848,490 | 26,837,604 | 22,832,712 | 20,187,378 | 18,197,194 | 19,236,270 | 18,733,592 | 20,646,562 | 22,125,020 | 24,816,897 | 29,686,748 | 278,480,017 |
| **Provided to YEC** | | | | | | | | | | | | | |
| **Primary** | 29,350,554 | 21,976,263 | 22,446,876 | 21,317,485 | 16,259,635 | 17,878,034 | 17,786,235 | 16,201,125 | 18,747,677 | 18,903,344 | 23,804,665 | 24,055,493 | 248,727,385 |
| **Secondary** | 2,307,977 | 1,790,344 | 2,163,437 | 2,400,802 | 1,637,745 | 1,378,427 | 1,104,111 | 1,101,518 | 1,345,278 | 2,043,186 | 2,508,722 | 2,119,135 | 21,900,682 |
| **Total** | 31,658,531 | 23,766,607 | 24,610,313 | 23,718,286 | 17,897,380 | 19,256,461 | 18,890,346 | 17,302,643 | 20,092,954 | 20,946,530 | 26,313,387 | 26,174,628 | 270,628,067 |
| **Variance** | | | | | | | | | | | | | |
| **Primary** | -3,734,724 | 2,451,227 | 2,102,748 | -913,093 | 2,105,533 | -1,152,260 | -48,645 | 1,376,667 | 409,705 | 1,435,246 | -1,350,578 | 3,504,835 | 6,186,662 |
| **Secondary** | 407,743 | 630,656 | 124,543 | 27,518 | 184,465 | 92,993 | 394,569 | 54,282 | 143,902 | -256,756 | -145,912 | 7,285 | 1,665,288 |
| **Total** | -3,326,981 | 3,081,883 | 2,227,291 | -885,574 | 2,289,998 | -1,059,267 | 345,924 | 1,430,949 | 553,608 | 1,178,490 | -1,496,490 | 3,512,120 | 7,851,950 |

**YECL Rider J ( 000's )**

| | **Jan-03** | **Feb-03** | **Mar-03** | **Apr-03** | **May-03** | **Jun-03** | **Jul-03** | **Aug-03** | **Sep-03** | **Oct-03** | **Nov-03** | **Dec-03** | **2003** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | 570 | 498 | 397 | 212 | 349 | 348 | 333 | 323 | 340 | 340 | 397 | 437 | 4,544 |
| **Provided to YEC** | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a |
| **Variance** | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a |

| | **Jan-04** | **Feb-04** | **Mar-04** | **Apr-04** | **May-04** | **Jun-04** | **Jul-04** | **Aug-04** | **Sep-04** | **Oct-04** | **Nov-04** | **Dec-04** | **2004** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | 471 | 430 | 400 | 403 | 347 | 354 | 355 | 336 | 344 | 356 | 395 | 428 | 4,619 |
| **Provided to YEC** | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a |
| **Variance** | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a |

| | **Jan-05** | **Feb-05** | **Mar-05** | **Apr-05** | **May-05** | **Jun-05** | **Jul-05** | **Aug-05** | **Sep-05** | **Oct-05** | **Nov-05** | **Dec-05** | **2005** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | 530 | 404 | 402 | 396 | 360 | 347 | 349 | 340 | 366 | 359 | 413 | 421 | 4,687 |
| **Provided to YEC** | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a |
| **Variance** | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a | n a |

| | **Jan-06** | **Feb-06** | **Mar-06** | **Apr-06** | **May-06** | **Jun-06** | **Jul-06** | **Aug-06** | **Sep-06** | **Oct-06** | **Nov-06** | **Dec-06** | **2006** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | 492 | 434 | 454 | 411 | 366 | 370 | 365 | 346 | 368 | 378 | 425 | 473 | 4,882 |
| **Provided to YEC** | 479 | 448 | 415 | 383 | 355 | 335 | 328 | 336 | 360 | 390 | 430 | 485 | 4,744 |
| **Variance** | -13 | 14 | -39 | -28 | -11 | -35 | -37 | -10 | -8 | 12 | 5 | 12 | -138 |

| | **Jan-07** | **Feb-07** | **Mar-07** | **Apr-07** | **May-07** | **Jun-07** | **Jul-07** | **Aug-07** | **Sep-07** | **Oct-07** | **Nov-07** | **Dec-07** | **2007** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actuals** | 516 | 465 | 499 | 441 | 371 | 375 | 378 | 350 | 364 | 377 | 436 | 445 | 5,017 |
| **Provided to YEC** | 533 | 420 | 429 | 413 | 341 | 369 | 366 | 346 | 389 | 373 | 453 | 460 | 4,892 |
| **Variance** | 17 | -45 | -70 | -28 | -30 | -6 | -12 | -4 | 25 | -4 | 17 | 15 | -125 |

## YEC-YECL-8

**Reference:** Operations and Maintenance Expense Labour Costs

**Requests:**

(a) Please provide a version of Schedule 5.1, as updated July 4, 2008, that separates labour costs from non-labour costs.

(b) For the actual years 2003 through 2007 and the 2008 and 2009 test years, please provide a schedule that shows total labour costs; the portion capitalized as part of capital projects (if any) and the total labour costs included in O&M.

(c) Please provide a schedule that shows the number of full time equivalent positions (FTEs) for the actual years 2003 through 2007 and the test years 2008 and 2009.

(d) Please provide a copy of the 2008-2009 collective agreement or wages negotiated by ATCO Electric and its employee association (as referenced at line 20 of page 5-2).

(e) Will all YECL employees be covered by the 2009-2010 collective agreement with YECL's employee association or are there any positions that are excluded from the collective agreement? If there are excluded positions please indicate the number of excluded positions, the average wage increase assumed for those positions in each test year and the justification for the assumed wage increase.

(f) Please provide the actual vacancy rate for each year from 2003 through 2007.

(g) Please provide a schedule that compares the existing YECL wages, the forecast YECL wages including the 9.5 average job class wage increase proposed for the 2009 test year and the 2008-2009 wages negotiated between ATCO Electric and its employee association. Provide the equivalent information for the last GRA test year (1997) as well as for the years 2003 to 2007.

(h) Please provide a detailed explanation as to why Yukon ratepayers should have to pay equivalent wages to what ATCO negotiated in Alberta. Has such an approach been approved by the Public Utilities Board of the NWT for YECL's sister company in the NWT?

(i) Please provide an explanation and justification for the head office personnel allocated to YECL (Section 1 Attachment 1).

(j) Please provide an explanation and justification for YECL-based personnel with responsibilities for sister companies having such high allocations to YECL and low allocations to sister companies as shown in Section 1 Attachment 1. Provide the equivalent information for the last GRA test year (1997) as well as for the years 2003 to 2007.

(k) Please provide a detailed listing (names and responsibilities) of all head office personnel allocated to YECL. Please provide a detailed justification for why head office personnel have been allocated to YECL (Section 1 Attachment 1).

(l) Please explain and justify the increase in YECL based FTEs in Section 1 Attachment 1. Provide the equivalent information for the last GRA test year (1997) as well as for the years 2003 to 2007.

(m) In order to avoid or reduce such an extraordinary revenue requirement increase in the test years, what consideration has been given to staff reductions in the test years? Please provide any internally generated documents, including any reports prepared by, or for, senior management discussing in any way this possibility.

(n) For the actual years 2003 through 2007 and the 2008 and 2009 test years, please describe any changes to employee benefits and provide a schedule that shows the following:

i. Total FTEs.
ii. Base wages.
iii. Increases in wage costs due to cost of living increases.
iv. Increases in wage costs due to step or merit increases.
v. Fringe benefit costs.
vi. Northern Living Allowance.
vii. Costs related to the additional travel benefits discussed at page 5-2
viii. Costs related to the increases in 2008 and 2009 for job classifications that are in demand and difficult to fill as described on page 5-2.
ix. Other earnings.

**Response:**

(a) This level of detail is not required in order to test the reasonableness of Yukon Electrical's forecast expenditures. Yukon Electrical also observes that this level of detail is beyond the level agreed to in Alberta for the major Alberta Electric Utilities in their minimum Filing Requirements. Yukon Electrical has provided this information on a functional basis. Please refer to CW-YECL-25(c) Attachment 1.

(b) The following is a breakdown of total labour costs. The 'Other' category is one that is mainly for labour associated with inventory and vehicle pools and is then charged to O&M and Capital based on usage.

| | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|
| | | | | ( 000's) | | | |
| **O M** | 2,694 | 2,756 | 3,047 | 3,168 | 3,344 | 3,864 | 4,250 |
| **Capital** | 673 | 736 | 727 | 894 | 978 | 1,150 | 1,244 |
| **Other** | 116 | 193 | 101 | 135 | 132 | 197 | 211 |
| | 3,483 | 3,685 | 3,875 | 4,197 | 4,454 | 5,211 | 5,706 |

(c) Please refer to the following table of full time equivalent positions.

| | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Forecast 2008 | Forecast 2009 |
|---|---|---|---|---|---|---|---|
| **FTEs** | 43.8 | 45.9 | 47.3 | 46.7 | 50.0 | 54.2 | 56.4 |

(d) Please refer to YUB-YECL-8(a) Attachment 1.

(e) Out of Scope positions (9 employees) are not included in the collective agreement. Please refer to CW-YECL-25 for definition of out of scope. Please refer to page 1-3 (assumptions) of Yukon Electrical's application for average out of scope wage increases for the test years. The increases for out of scope positions partially follow in scope increases as well as the increases estimated to be provided by Yukon Electrical's parent company as Yukon Electrical's out of scope employees are on a similar compensation program as that of its parent company. Yukon Electric recognizes that out of scope positions generally attract increased responsibility and accountability. Out of Scope positions are not paid overtime and salary compression between in scope and out of scope positions

can occur. All of these must be taken in to consideration when setting out of scope compensation and in order to address quality leadership as well as attraction and retention requirements of the company.

(f) Vacancy rates are calculated based on an approved complement for FTEs. As such vacancy rates are not applicable given that there were no Board approved FTEs for this period.

(g) Please refer to YUB-YECL-8(g) Attachment 1.

(h) Yukon Electric is an ATCO Group Company and is owned by ATCO Electric. Over the years Yukon customers have benefited from the expertise and economies of scale that have been provided by the ATCO Group. Many of Yukon Electrical's employees and managers have come from the ATCO Group and this represents a significant market for Yukon Electrical employees that would otherwise not be available to the Company. Without a similar or even an enhanced compensation package Yukon Electrical would not be able to attract or retain many of the employees it now has. In a tightening labour market, which is only expected to become more challenging' it is a significant benefit to be able to have a market such as the ATCO Group to draw on. The ability to seek advice and learn from a larger affiliated utility is an advantage to all customers served by Yukon Electrical.

Northland Utilities has not yet received a decision on its current GRA applications before the Public Utilities Board of the Northwest Territories (PUB). However, in past GRA decisions, the salary compensation approved as part of the revenue requirement by the board was based on ATCO Electric, Yukon Electrical, and in some cases local market salary benchmarks. The requested salary levels are required in order to be competitive in the marketplace.

(i) As outlined in Section 1, Attachment 1, the Head Office personnel are from the following areas:

- Governance
- Human Resources
- Regulatory Support
- Financial Reporting
- Payroll

- Information Technology
- Materials Management

As such, the 1.67 FTE head office personnel are providing support for such things as:

- Phase I regulatory issues - this would cover support for the preparation and filing of:
    - Preparation of Application, Information Responses and Updates if any;
    - Preparation and review of rebuttal evidence (if required);
    - Review of Intervenor Evidence and preparations of IR's, review of IR Responses
    - Presentation of company witnesses;
    - All aspects of Rider applications;
    - Preparation and review of Argument and Reply; and
    - Annual Report on Finances.
- Financial reporting issues, such as ensuring impacts of GAAP pronouncements including IFRS are appropriately dealt with;
- Review of financial and management reports;
- Administration of capital assets;
- Recruitment and training;
- Strategy and governance;
- Ordering of supplies and other material management matters;
- Payroll administration.

A number of these areas such as support for GRAs, administration of capital assets and IFRS impacts could probably be contracted out, as is done by certain other utilities. However, given that the equivalent of only 1.67 FTEs are providing the wide ranging support functions described above, contracting out such services would be a difficult and ineffective option

(j) There are only two Yukon Electrical based positions identified in Attachment 1 Section 1 that have responsibility for sister companies. The General Manager and the Administrative Assistant.

The Administrative Assistant provides support to sister companies for incident and stewardship reporting as well as some minor administration functions. The amount allocated is based on an estimate of hours to be spent working on sister company activities as well as looking at the historical hours spent.

The General Manager spends most of his time in the Yukon and the Yukon is his home base. This can vary based on activity in the various companies however generally that is the case. The sister companies have managers who spend time with key local key parties and participate in community based activities. In Yukon Electrical the General Manager has these responsibilities.

Yukon Electrical is a larger company that demands the majority of the time of the General Manager and the allocation of time reflects this fact and is representative of the reality of time spent with each company.

(k) The specific identification of head office personnel is not required to test the revenue requirement in the test period. The responsibilities and the detailed justification for the 1.67 head office FTEs allocated to YECL are provided in (i) above.

(l) The last approved test period was 1996 1997. Information provided in response to information requests is in accordance with Board Order 2008-05, which confirmed that Yukon Electrical is not required to provide information prior to 2003 and or 2005 to test the revenue requirement.

Please refer to CW-YECL-8(d) Attachment 1 as well below are the summary of the justifications for the additions to Yukon Electrical staff since 2003. There were no additions or reductions to FTE's in 2004 and 2006.

<u>2005</u>

**Receptionist** Yukon Electrical added this position to support customer service operations. The position had been temporary in the past, however volume of customer calls and workload of other front office employees warranted the

addition. This position also provides back up for the Customer Service Advisors and the Operations Group as required.

2007

**Planned Maintenance and HS E Coordinator** Yukon Electrical identified several needs in its planned program and Health and Safety program. The Planned Maintenance Program and Health, Safety and Environment Coordinator is responsible to develop, update, budget and implement a variety of Yukon Electrical's programs for the inspection and maintenance of distribution and hydro generation assets, including replacement and improvement programs. This position is also responsible for taking the lead in preparing Yukon Electrical's annual Heath, Safety and Environment Plan, including an Emergency Response Plan, that will result in the company working towards meeting all HSEMS Best Practices. This position will take the lead within the management team in identifying and securing internal as well as external resources to manage the field work associated with the above noted programs.

**Engineering Assistan**t Yukon Electrical due to increased work loads and volume of work identified a need in its engineering department. The addition of an Engineering Assistant (EA) is critical to provide support with the design, estimating, project management and customer interaction necessary to implement the company's capital business plan. The EA will be trained to use engineering programs, construction and metering standard necessary to provide safe and reliable service to customers. This position will also provide backup for other EA's as required.

The increasing power line additions and aging infrastructure have demanded that additional resources be added to not only effectively manage projects but also to meet in service dates required by customers.

**Apprentice Lineman** Yukon Electrical as part of its ongoing comprehensive attraction and retention strategy hired an apprentice Lineman to supplement Construction and Operations activities. This position continues to assist with challenges related to Journeyman Lineman attraction. Overall, the increase in the line complement in Yukon Electrical will assist with the reduction of and dependency on contractors and the associated costs in the completion of operation and maintenance, and capital work.

2008

**Engineer in Training** As part of the ATCO Electric Engineering Program Yukon Electrical was fortunate to be provided with an Engineer in Training (EIT). This position will provide engineering support to Yukon Electrical Engineering Services Group. By being included in this program, Yukon Electrical is hopeful that it will assist with recruitment of Engineers for the company in the future.

**Operations Support** The addition of an Operation Support person is due to an ever-increasing industry dependency on data to support the operations, maintenance and construction of Yukon Electrical distribution and generation assets and increased administrative requirements in our processes in order to manage the operations department.

**Lineman Serviceman Journeyman** Qualified linemen although difficult to attract are an absolute requirement to the operation of the power system. A number of changes have impacted the Operations Department significantly over the past few years. The most significant is the creation of a functional line crew focused on capital work. This has depleted the operational manpower compliment which is a major driver to adding this position. In addition the power system itself has grown significantly, simply more wires and infrastructure to operate. This can be supported by unprecedented capital expenditure of the past 2 or 3 constructions seasons.

Other contributing factors are the increased commitment by staff to Health and Safety programs and processes such as tail boards, job planning and associated documentation requirements.

It is expected that over time the strategy of adding line positions to Yukon Electrical's compliment will reduce its current dependency on contract crews.

**Supervisor Corporate Communications** This position was eliminated and external resources are completing the work associated with the roll.

2009

**Field Service Representative** The addition of an FSR is one component of a multiple solution approach being implemented by Yukon Electrical to meet

increased workloads, reduce long-term costs, and address attraction and retention issues. A Field Service Representative can be trained and take on non-critical low hazard tasks to the operations group in 6 to 12 months. For a journeyman lineman it takes a minimum of 4 years.

**Draftsperson** At the present time, Yukon Electrical does not have a drafts person on staff and presently out sources most of its drafting requirements with the exception of some minor in house drafting by its surveyor. The costs for the draftsperson are largely capital and will replace current third part charges required to complete drafting. Due to the important nature of completing as build drawings, switching maps as well as providing critical backup to the second person of the two person distribution survey and drafting team the Draftsperson position is required. This position will also be expected to assist with survey activities required to be undertaken by Yukon Electrical in the delivery of service to customers.

**Meter Reader** Due to Automated Meter Reading 1 Meter Reader position is being eliminated.

(m) Yukon Electrical disagrees with the characterization of the revenue requirement as extraordinary. Yukon Electrical has not been before the regulator for 12 years and its revenue requirement is not out of line with inflation during this time. In addition there are other cost pressures being driven by the market such as labour and increased supplier costs that are beyond Yukon Electrical's control. As well increasing capital expenditures to provide benefits to customers and long term savings are also drivers.

Please refer to YEC-YECL-1(b). Labour requirements are considered along with every other aspect of Yukon Electrical's business planning requirements to provide safe, reliable and cost effective service to its customers. Staff reductions are not a viable option at this time.

(n) For 2008 and 2009, a temporary community skills premium has been introduced for hard to fill technical and trades positions only. As well an additional northern travel benefit has been introduced for 2009. Both these are for attraction and retention purposes and necessary to keep skilled electrical trades positions filled in the north.

| | | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test 2008 | Test 2009 |
|---|---|---|---|---|---|---|---|---|
| i | FTE's | 43.8 | 45.9 | 47.3 | 46.7 | 50.0 | 54.2 | 56.4 |
| | | | | | **( 000 s)** | | | |
| ii | Base Wages | 2,847 | 3,042 | 3,246 | 3,470 | 3,691 | 4,034 | 4,532 |
| iii | Cost of Living Increases | 120 | 128 | 104 | 111 | 109 | 169 | 412 |
| iv | Step Increases [1] | n a | n a | n a | n a | n a | n a | n a |
| v | Fringe Benefits | 340 | 341 | 434 | 442 | 744 | 1,032 | 1,109 |
| vi | Northern Living Allowance | 410 | 427 | 445 | 453 | 470 | 569 | 590 |
| vii | Additional Travel Benefits | - | - | - | - | - | - | 80 |
| viii | Community Skills Premium | - | - | - | - | - | 285 | 220 |
| ix | Other Earnings | 76 | 82 | 119 | 111 | 120 | 140 | 153 |

[1] Step increases are not tracked separately and are included in cost of living increases.

## YEC-YECL-9

**Reference:** Operations and Maintenance Expense Non-Labour Costs Requests

**Request:**

(a) Please provide a schedule similar to Schedule 5.1, as updated July 4, 2008, that separates non-labour costs into ongoing operational and administrative activities and new programs or projects.

(b) Please describe in more detail YECL's budgeting process for non-labour costs. When and how often are budgets prepared? Who reviews and approves the budgets? How are budgets monitored?

(c) Please provide the sources and justification for the use of a 5 Alberta based inflation rate for non-labour costs in the test years. Please provide a detailed explanation as to why Yukon ratepayers should be required to pay an Alberta-based inflation rate.

(d) Please provide the actual inflation rate for Yukon and for Alberta for each of the past 5 years.

(e) Have increases in non-labour cost tracked consistently with actual Alberta inflation rate for the years from 2004 to 2007. Please provide the necessary detailed information for each year.

**Response:**

(a) Please refer to CW-YECL-25(c) Attachment 1 as well as Schedule 5.2 for explanations of variances which describe new programs planned by Yukon Electrical for the forecast years.

(b) For GRA forecasts for non-labour costs are generally a function of past years activity with inflation according to the assumptions outlined on page 1-3 of the application. As well the accounts and activities are reviewed for any anticipated circumstances or changes in operations that may cause exception to the normal activity for the upcoming year that must be considered. The forecast is reviewed

and approved by the senior Yukon Electrical management and ultimately by head office.

(c) The actual inflation rate in Alberta for 2007 was 5 . Given the continued strong economy in Alberta and the potential for a weakening dollar, a rate of 5 was used for the test period. Please refer to (d) below for an explanation of why an Alberta based inflation rate is appropriate.

(d) Please refer to LE-YECL-19 (below):

**Consumer Price Index (CPI) All-items, 2002 100**

| | Canada | | Alberta | | British Columbia | | Whitehorse | |
|---|---|---|---|---|---|---|---|---|
| | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change |
| 1998 | 91.3 | *n/a* | 89.2 | *n/a* | 93.4 | *n/a* | 94.3 | *n/a* |
| 1999 | 92.9 | *1.8* | 91.4 | *2.5* | 94.4 | *1.1* | 95.3 | *1.1* |
| 2000 | 95.4 | *2.7* | 94.5 | *3.4* | 96.1 | *1.8* | 97.5 | *2.3* |
| 2001 | 97.8 | *2.5* | 96.7 | *2.3* | 97.7 | *1.7* | 99.3 | *1.8* |
| 2002 | 100.0 | *2.2* | 100.0 | *3.4* | 100.0 | *2.4* | 100.0 | *0.7* |
| 2003 | 102.8 | *2.8* | 104.4 | *4.4* | 102.2 | *2.2* | 101.9 | *1.9* |
| 2004 | 104.7 | *1.8* | 105.9 | *1.4* | 104.2 | *2.0* | 103.0 | *1.1* |
| 2005 | 107.0 | *2.2* | 108.1 | *2.1* | 106.3 | *2.0* | 105.3 | *2.2* |
| 2006 | 109.1 | *2.0* | 112.3 | *3.9* | 108.1 | *1.7* | 106.8 | *1.4* |
| 2007 | 111.5 | *2.2* | 117.9 | *5.0* | 110.0 | *1.8* | 109.5 | *2.5* |

figures are not available for Yukon
Source: Statistics Canada

The Alberta Inflation rate of 5 has been used in Yukon Electrical's application as;

- Yukon Electrical's parent company ATCO Electric operates in Alberta and services received by Yukon Electrical by its parent company are therefore Alberta based.
- Yukon Electrical purchases many of its specialty line materials from Alberta.
- Transportation services typically come from or through Alberta.
- The majority of the trade conducted by Yukon Electrical comes from or goes through Alberta.

(e) Generally Yukon Electrical's experience is that non labour inflation has on average been at least as high as Alberta in recent years. Although equivalent information is not shown for Alberta and is not available for 2004, the data and experience that Yukon Electrical have had supports an average non-labour inflation rate of above the rate of 5 used in this application. Please refer to the table below:

**Material Cost**

The table below shows the variation in the cost of line material over the last three years. The variation of some material has been very significant. For example, in the case of transformers, the increase can be in excess of 40 , however for this example Yukon Electrical used an overall estimate of material costs.

**Contractor Costs**

Yukon Electrical chose two of its largest and most utilized contractors in 2005, 2006, and 2007 to reflect the inflation increases.

**Average Cost Escalations**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| **Material** | 7.79 | 8.74 | 11.10 |
| **Contractor** | 4.75 | 5.21 | 3.98 |
| **Average** | 6.27 | 6.98 | 7.54 |

## YEC-YECL-10

**Reference:** Pelly Crossing Fuel Deferral Account

**Requests:**

(a) Please describe in detail any capital works that YECL must undertake in order to connect Pelly Crossing to the main grid and provide an update on the expected timing and in-service dates for these capital works.

(b) Please provide a detailed explanation as to what the uncertainties are with respect to connecting Pelly Crossing to the main grid effective November 1, 2008, and identify all steps taken, or to be taken, by YECL to address each such uncertainty.

(c) Please confirm that YECL's proposed Pelly Crossing fuel deferral account will in effect shift to ratepayers all risks and costs related to delays in YECL's connection to the new Carmacks-Pelly Crossing transmission line.

(d) Please provide a detailed explanation as to why YECL's customers, rather than YECL, should be at risk through the proposed deferral account for YECL's ability to plan and execute the required capital works to connect Pelly Crossing to the main grid at the earliest possible date.

(e) Does YECL have a deferred cost or deferral account accounting policy? If so please provide a copy of the policy.

(f) Please indicate when YECL connected Stewart Crossing to the Mayo-Dawson grid, and explain any delays encountered in this regard after the grid had come into service.

**Response:**

(a) The scope of this project has changed since the original filing of Yukon Electrical's Rate Application. On July 18, 2008, one of YEC's consultants suggested the second 138kv to 25kv transmission substation proposed near the community of Pelly Crossing was being reviewed. An alternate interim interface

point and configuration has been proposed. Details are: from the interface tie between YEC and Yukon Electrical that Yukon Electrical will have an Oil Sectionalized Switch (OSS) to sectionalize from and synchronize to the grid when required. Yukon Electrical will then step the voltage down to the current community distribution voltage of 2400V. A short distribution line (approx. 800 metres) will be built to reach the community's existing distribution system. In addition some work will be undertaken to prepare the existing power plant for standby operation. Construction of the tie is tentatively scheduled to commence by the third week of August 2008 with final connection to the grid forecast for November 1, 2008.

(b) Yukon Electrical is confident that no delays will occur in its in service date if YEC is able to provide the power line required for the grid connection by Yukon Electrical by October 1, 2008. To address this uncertainty Yukon Electrical has been meeting with YEC regarding the project on an on going basis.

(c) Not confirmed as Yukon Electrical has not previously had this risk. If customers in Pelly are not connected to the grid by November 1, 2008 because of delays by either YEC and or Yukon Electrical then additional fuel costs will be incurred. The deferral account is a reasonable approach to recover costs that are not under the control of the company. Yukon Electrical plans to have the infrastructure in place by September 30, 2008. Commissioning of the line and final connection activity will occur once the line is available from YEC.

(d) This deferral account was intended to address the uncertainty of the transmission portion of the project from Carmacks to Pelly. This is by far the larger component of the project and is not controllable by Yukon Electrical.

(e) The typical criteria for the consideration of a deferral account that must be met are shown in Yukon Electrical Application page, 1-5, as follows:

That costs are:

1. Not under the control of the company and are not reasonably forecastable or:

2. An error in forecasting could produce a loss or gain of a substantial magnitude.

Yukon Electrical is of the view that the Pelly grid connection project as it relates to potential fuel cost increases meets the criteria.

(f) Yukon Electrical completed the distribution component of the interconnection on Oct 5, 2005. Grid power was supplied by Yukon Energy via its substation on or about October 17, 2005. While there were no construction related delays after Stewart Crossing was connected to the grid, Yukon Electrical did need to work through a number of commissioning issues for a short period of time after the grid was made available.

**YEC-YECL-11**

**Reference:** Affiliate Costs

**Requests:**

(a) Please describe in detail the fully allocated cost methodology referenced on pages 5-3 and 5-4 of the Application. Provide specific calculations and ratios.

(b) Please elaborate on the benchmarking process related to ATCO I-Tek and ATCO I-Tek Business Services described on page 5-4 of the Application. When is the referenced ATCO report to be filed with the AUC?

(c) Please provide a detailed explanation as to why a report prepared by ATCO to be ruled upon by the AUC should be used by the YUB in setting Yukon-based rates.

(d) Please provide Schedule 5.3 for affiliate costs as estimated in the 1996 97 GRA. Identify and explain any material changes in cost allocation methods since that time.

**Response:**

(a) Please refer to YEC-YECL-11(a) Attachment 1 for a complete description of the fully allocated cost methodology .

The specific calculations are as follows:

| Head Office Costs | Labour | Fringe 12 | 2008 Overhead 60 | Other | Total |
|---|---|---|---|---|---|
| Governance | 14 | 2 | 8 | | 24 |
| Human Resources | 5 | 6 | 30 | | 87 |
| Regulatory | 7 | 1 | 4 | | 12 |
| Financial Reporting | 51 | 6 | 30 | | 87 |
| Payroll | 5 | 1 | 3 | | 9 |
| Information Technology | 1 | -- | 1 | | 2 |
| Use of Systems | -- | -- | -- | 5 | 5 |
| | 129 | 16 | 76 | 5 | 226 |
| Materials Management Balance Sheet | 24 | 3 | 15 | 15 | 42 |

| Head Office Costs | Labour | Fringe 12 | 2009 Overhead 60 | Other | Total |
|---|---|---|---|---|---|
| Governance | 15 | 2 | 9 | | 26 |
| Human Resources | 52 | 6 | 32 | | 90 |
| Regulatory | 5 | -- | 1 | | 3 |
| Financial Reporting | 42 | 5 | 26 | | 73 |
| Payroll | 6 | 1 | 3 | | 10 |
| Information Technology | 1 | -- | 1 | | 2 |
| Use of Systems | -- | -- | -- | 7 | -- |
| | 118 | 14 | 71 | 7 | 210 |
| Materials Management Balance Sheet | 27 | 3 | 16 | | 46 |

(b) This collaborative process was put in place to determine the Fair Market Value of the services being charged by ATCO I-Tek. The collaborative process involved the ATCO Utilities as well as interested parties. An independent consultant was selected to prepare a benchmark report for the years 2003-2007 and an Evergreen Strategy to cover the process for the years subsequent to 2007. This benchmark report provided the market value for the prices to be charged by ATCO I-Tek.

This report was filed with the Alberta Utilities Commission on February 21, 2008.

This application has not yet been approved, however, the report has been signed off by the Customer Group agreeing that:

> *"The report satisfies and meets the Terms of Reference established pursuant to the Commission's decision and directions…"* [ATCO Utilities, February 21, 2008 Application, page 2 of 3]

As such, Yukon Electrical now submits that the results of this report be incorporated into Yukon Electrical's application and has attached detailed schedules (please refer to YEC-YECL-11(b) Attachments 2 and 3) incorporating the updated prices from this report. The results of this are as follows:

| **I-Tek** | **2008** | **2009** |
|---|---|---|
| Costs per Application | 353 | 370 |
| Updated for Benchmarking | 329 | 324 |
| Reduction in I-Tek Costs | 24 | 46 |

| **ITBS** | **2008** | **2009** |
|---|---|---|
| Costs per Application | 434 | 484 |
| Updated for Benchmarking | 416 | 448 |
| Reduction in ITBS Costs | 18 | 36 |

These reductions will be incorporated into a compliance filing relating to this proceeding.

The market price for ITBS costs was based on the 2003 market price adjusted for inflation for those components that are inflation sensitive which is typically labour. This approach is consistent with the Evergreen Strategy approach.

(c) This collaborative process set out to establish the fair market price for the services being provided by ATCO I-Tek. This has been a lengthy process involving customer groups and the ATCO Utilities. It is apparent that this would be a costly and time consuming process if separately undertaken by Yukon Electrical. As such, Yukon Electrical is utilizing the work done by ATCO Utilities and Customers Groups in Alberta and proposing to use the fair market price set for the larger southern utilities as a reasonable approach to setting the fair market price for Yukon Electrical.

(d) In accordance with Board Order 2008-5, it is not required to provide this information prior to 2003 to test the revenue requirement in the test period.

The details of affiliate costs have been provided in Schedule 5.3 (as updated on July 4, 2008). There has been no change to the cost allocation method (that has been tested and approved as part of ATCO Electric's proceedings) since 2003 however it is important to note that the overhead rate included in the charge has reduced to 60 effective 2007 from 70 charged in 2006 and prior.

| ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL | Provision of Services to or from Affiliates |
|---|---|
| **Original Issue Date:** Nov 2, 2001 | **Revision Date:** April 10, 2007 **Number:** G.5 |
| **PREPARED BY:** D. Freedman | **APPROVED BY:** Dennis DeChamplain |

## PURPOSE

To provide guidelines for the charging of work performed for or received from affiliates within the ATCO Group.

## POLICY

All transactions with affiliates are governed by the ATCO Group Inter-affiliate Code of Conduct.

For Profit Services

Services provided to Affiliates on a For Profit Basis shall not be charged at less than the Fair Market Value for those servIces. Services received from Affiliates on a For Profit Basis shall not be paid for at more than Fair Market Value. Consultation with the Compliance Officer should occur prior to the determination of Fair Market Value for services to be provided or received on a For Profit Basis.

A prudence review of these services may be required when deemed appropriate by management and or the Compliance Officer. In demonstrating that Fair Market Value was paid or received pursuant to a For Profit Affiliate Service arrangement, the Utility, subject to any prior or contrary direction by the EUB, may utilize any method to determine Fair Market Value that it believes appropriate in the circumstances. These methods may include, without limitation: competitive tendering, competitive quotes, benchmarking studies, catalogue pricing, replacement cost comparisons or recent market transactions.

The Utility shall bear the onus of demonstrating that the methodology or methodologies utilized in determining the Fair Market Value of the subject goods or services was appropriate in the circumstances.

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Shared Services

Shared Services provided to or received from Affiliates on a Cost Recovery Basis are permitted, unless an approved regulated rate exists for the services, in which case the regulated rate will be charged. in the event that the service provided represents a major on-going transaction, or a collection of related minor transactions that are significant in their totality, a review, involving the Compliance Officer, should be performed as to whether the service pricing is appropriate.

Financial transactions with Affiliates A Utility shall ensure that any loan, investment, or other financial support provided to a Non-Utility Affiliate is provided on terms no more favorable than what that Non-Utility Affiliate would be able to obtain as a standalone entity from the capital markets.

Sharing employees A Utility may share employees on a Cost Recovery Basis with an Affiliate provided that the employees to be shared:

i) do not have access to Confidential information;
ii) do not routinely participate in making decisions with respect to the provision of Utility Services or how Utility Services are delivered;
iii) do not routinely deal with or have direct contact with customers of the Utility; and
iv) are not routinely involved in operating, planning or managing the business of the Utility (subject to certain exceptions per the Code).

Transferring of employees A Utility may transfer employees to or from an Affiliate, provided **any** employee transferred by the Utility who had access to Confidential Information shall execute a confidentiality agreement with respect to such Confidential Information prior to the transfer.

Sharing of assets - The plant, assets and equipment of a Utility shall be separated in ownership and separated physically from the plant, assets and equipment of other Non-Utility Affiliates. Utility Affiliates may share ownership and may physically share office space, equipment, rights-of-way and other assets on a Cost Recovery Basis.

Where operational efficiencies between Utilities that are Affiliates can be obtained through the use of common facilities (such as shared warehousing or field offices). combined purchasing power or through the use of other cost saving procedures, individual assets or groups of assets used in Utility operations (such as equipment, plant inventory, spare parts or similar assets) may be transferred in the ordinary course of business between Utilities on a Cost Recovery Basis.

Occasional Services: A Utility may receive, or provide, one-off, infrequent or occasional services to or from an Affiliate on a Cost Recovery Basis, without a service agreement. The service(s) must be documented by way of a work order, purchase order or similar instrument.

Emergency Services: In the event of an emergency, a Utility may share services and resources with an Affiliate without a service agreement on a Cost Recovery Basis. The service(s) must be documented by way of a work order, purchase order or similar instrument.

Master Service Agreement or Contract

A Master Service Agreement or Master Service Contract (both referred to as MSC for purposes of this policy) must be developed with each affiliate, governing all services with the affiliate, which are not charged on the basis of regulated rates. All services with the affiliate counter party that the MSC applies to can be brought under that MSC by way of a schedule to the MSC. A copy of all agreements with affiliates should be forwarded to the Compliance Officer for record keeping. Note that a service agreement is not required for occasional or emergency services. in the event that these services become material as to value, frequency or use of resources, (as determined by management or the Compliance Officer), a service agreement shall be entered into.

Recoveries

Recoveries for work performed for affiliates will be recorded as revenue to ATCO Electric, not as a reduction to operating expenses.

| ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL | Provision of Services to or from Affiliates |
|---|---|
| **Original Issue Date:** Nov 2, 2001 | **Revision Date:** April 10, 2007 **Number:** G.5 |
| **PREPARED BY:** D. Freedman | **APPROVED BY:** Dennis DeChamplain |

**DEFINITIONS**

**Affiliate:** Means with respect to any Utility:

i) an affiliate as defined in the Alberta Business Corporations Act;

ii) a unit or division within the Utility or any Body Corporate referred to in clause (i) above;

iii) a partnership, joint venture, or Person in which the Utility or any Body Corporate referred to in clause (i) above has a controlling interest or that is otherwise subject to the control of the Utility or such Body Corporate;

iv) any partnership, joint venture, or Person deemed by the EUB to be an affiliate of the Utility for the purpose of this Code of Conduct; and

v) an agent or other Person acting on behalf of any Body Corporate, operating division, partnership, joint venture or Person referred to in clauses (i) to (iv) above.

**Cost Recovery Basis:** Means with respect to:

i) the use by one Affiliate of another Affiliate's personnel, means the fully burdened costs of such personnel for the time period they are used by the Affiliate, including salary, benefits, vacation, materials, disbursements and all applicable overheads;

ii) the use by one Affiliate of another Affiliate's equipment, means an allocated share of capital and operating costs appropriate for the time period utilized by the Affiliate;

iii) the use by a Utility of an Affiliate's services, means the complete costs of providing the service, determined in a manner acceptable to the Utility, acting prudently;

iv) the use by an Affiliate of a Utility's services, means the complete costs of providing the service, determined in a manner acceptable to the Utility, acting prudently; and

v) the transfer of equipment, plant inventory, spare parts or similar assets between Utilities, means the net book value of the transferred assets.

| ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL | Provision of Services to or from Affiliates |
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**Direct Labour Costs:** The number of hours worked on a project times an employee's hourly wage, or the portion of the annual salary attributable to the services provided.

**Direct Costs of Goods and** Services: The actual amount paid to the vendor for supplies and services used in the provision of services to an affiliate.

**Direct Cost of Material:** The unit cost of material used in the provision of services to an affiliate based on the average cost from the Materials Management System.

**Direct Cost of Vehicle and Equipment Charges:** The charges for vehicles and equipment used in the provision of services to affiliates should be based on the hours used times the hourly charge out rate. The hourly charge out rate will include capital and related costs.

**Fair Market Value:** The price reached in an open and unrestricted market between informed and prudent parties, acting at arms length and under no compulsion to act.

**For** Profit Services: Any service that relates to a core business provided on a for-profit bases:

i) by a Utility to a Non-Utility Affiliate, other than a Utility Service; or
ii) by a Non-Utility to a Utility.

**Fringe Benefits:** The costs incurred by the employer in providing benefits to the employee. These costs include: CPP, Pension, Employment Insurance, Workers' Compensation, Alberta Health Care.

**Non-Preset Labour:** Employees who are not preset and must submit a daily timesheet in order to distribute their salary to the appropriate accounts.

**Preset Labour:** Employees whose salaries are distributed on a preset basis to the same accounts.

| ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL | Provision of Services to or from Affiliates |
|---|---|
| **Original Issue Date:** Nov 2, 2001 | **Revision Date:** April 10, 2007 **Number:** G.5 |
| **PREPARED BY:** D. Freedman | **APPROVED BY:** Dennis DeChamplain |

**Payroll Burden:** An incremental charge that is included in an employee's hourly charge out rate to cover payment for statutory holidays and vacation pay.

**Overhead:** A general loading charge applied to all Labour Costs for the recovery of corporate costs.

**PROCEDURE**

A. Determination of Cost Recovery Basis.

Charges for services should be done on an actual cost basis providing it is cost effective and reasonable to track the cost of services provided. In the event cost tracking is not used, the cost allocation methodology used must fairly allocate costs based on reasonable and appropriate criteria. Whether cost tracking is used or not, the following amounts must be incorporated in the determination of fully burdened costs:

1. Labour Charges In addition to the Direct Labour Costs, the following amounts should be included:

Payroll Burden of 16.3 for employees on timesheets. The payroll system will apply the burden for all Non-Preset Labour. The burden rate is not to be applied when an annual salary is used in the determination of the Direct Labour costs. A separate calculation of burden will be made for Preset Labour charged on an hourly basis.

Fringe Benefits Fringe Benefits are determined by the financial system on a monthly basis.

For non-construction projects an Overhead rate of 60 will be applied to labour charges, including payroll burden where applicable as defined above. An additional Overhead rate of 20 will be applied to the labour charges including payroll burden for construction projects.

Other charges as discussed below must be included as applicable.

2. Other Charges which may or may not apply, depending on the service performed include:

   Direct cost of Goods and Services.

   Direct Cost of Material a handling and restocking charge will be applied to the direct cost of materials. Contact Financial Reporting for the current rate to be applied. The MSC should contain a provision that allows for this rate to be varied by ATCO Electric as required.

   Direct Cost of Vehicle and Equipment Operating Costs Contact Financial Reporting for the current rates to be applied. The MSC should contain a provision that allows for this rate to be varied by ATCO Electric as required.

   Financing, operating costs and depreciation should be recovered if the provision of service to an Affiliate involves the use of ATCO Electric's utility assets. Contact Financial Reporting for assistance in determining these amounts.

   Financing costs associated with a delay in compensation for a material portion of the agreement may be required. Contact Financial Reporting for assistance in determining these amounts.

3. If the agreement involves the disposal of an asset, then fair market value will be exchanged for the asset. If the sale of an asset occurs between regulated affiliates, Fair Market Value will not be less than the Net Book Value of the assets. Statutory requirements for regulatory approval of sales of utility property, other than in the ordinary course of business, will be met.

| ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL | Provision of Services to or from Affiliates |
|---|---|
| **Original Issue Date:** Nov 2, 2001 | **Revision Date:** April 10, 2007 **Number:** G.5 |
| **PREPARED BY:** D. Freedman | **APPROVED BY:** Dennis DeChamplain |

B. Finalizing the Agreement

1. The standard MSC is to be used for all agreements with non-regulated affiliates. In the event that a modification to the format of the MSC is required, approval must be obtained from the Compliance Officer.

2. Where an MSC is required, a new MSC must be developed or the existing MSC amended to incorporate new services or changes to pre-existing services. The amendment can be incorporated through the revision to Schedules of the MSC, with appropriate approvals from all parties to the agreement, as well as an approval date.

   The new or amended agreement must clearly indicate an effective date. Contact the Compliance Officer for assistance with respect to this.

3. Discussion with Financial Reporting should occur regarding how the revenue is to be collected, and any new account numbers required for the tracking of revenues and costs associated with the agreement. Generally affiliate revenues should be processed through debit notes which have a standard settlement date. Other collection methods may require a bill to be generated or different procedures to be put in place.

C. Compliance Records

Records shall be maintained in a manner sufficient to support a third party audit of the state of compliance with the ATCO Group Inter-Affiliate Code of Conduct and retained for a period of at least six years.

**YUKON ELECTRICAL COMPANY LIMITED**
**IT Operating Plan**

| | Service | Activity | Acct. | Co. No. | Units | | | | Price | | | | Dollars | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Actual 2006 | Actual 2007 | Test Year 2008 | Test Year 2009 | Actual 2006 | Actual 2007 | Test Year 2008 | Test Year 2009 | Actual 2006 | Actual 2007 | Test Year 2008 | Test Year 2009 |
| Hardware | B & W Printer Low Volume | 72100 | 550606 | 05 M | 12.0 | 12.0 | 12.0 | 12.0 | 28.00 | 28.00 | 33.46 | 31.95 | 336.00 | 336.00 | 401.52 | 383.40 |
| | B & W Printer Medium Volume | 72100 | 550606 | 05 M | 22.0 | 12.0 | 15.0 | 15.0 | 48.00 | 48.00 | 44.02 | 42.04 | 1,056.00 | 576.00 | 660.30 | 630.60 |
| | B & W Printer Medium Volume w duplex | 72100 | 550606 | 05 M | 51.0 | 24.0 | 34.0 | 34.0 | 68.00 | 60.00 | 44.02 | 42.04 | 3,468.00 | 1,440.00 | 1,496.68 | 1,429.36 |
| | Colour Printer Maximum Volume | 72100 | 550606 | 05 M | 10.0 | | - | - | 155.00 | 155.00 | 116.65 | 111.40 | 1,550.00 | - | - | - |
| | Laptop H W Operating Lease | 72100 | 550606 | 05 M | 70.0 | 86.0 | 100.0 | 100.0 | 135.00 | 120.00 | 128.40 | 123.26 | 9,450.00 | 10,320.00 | 12,840.00 | 12,326.00 |
| | Laptop Support High | 72100 | 550606 | 05 M | 24.0 | 24.0 | 24.0 | 24.0 | 204.50 | 211.96 | 155.96 | 166.10 | 4,908.00 | 5,087.04 | 3,743.04 | 3,986.40 |
| | Laptop Support Low | 72100 | 550606 | 05 M | 46.0 | 54.0 | 54.0 | 54.0 | 128.25 | 131.61 | 121.05 | 128.92 | 5,899.50 | 7,106.94 | 6,536.70 | 6,961.68 |
| | Laptop Support Medium | 72100 | 550606 | 05 M | | 8.0 | 30.0 | 30.0 | | 171.26 | 124.92 | 133.04 | - | 1,370.08 | 3,747.60 | 3,991.20 |
| | Monitor CRT - 17 inch | 72100 | 550606 | 05 M | 294.0 | 130.0 | 130.0 | 130.0 | 8.00 | 8.00 | 9.14 | 7.77 | 2,352.00 | 1,040.00 | 1,188.20 | 1,010.10 |
| | Monitor CRT - 19 inch | 72100 | 550606 | 05 M | 63.0 | | | | 18.00 | 29.50 | 30.86 | 33.16 | 1,134.00 | - | - | - |
| | Monitor CRT - 21 inch | 72100 | 550606 | 05 M | 24.0 | 12.0 | 12.0 | 12.0 | 31.00 | 29.50 | 14.54 | 12.36 | 744.00 | 354.00 | 174.48 | 148.32 |
| | Monitor LCD - 17 inch 2004 older | 72100 | 550606 | 05 M | 12.0 | 6.0 | 6.0 | 6.0 | 24.00 | 22.00 | 25.52 | 21.69 | 288.00 | 132.00 | 153.12 | 130.14 |
| | Monitor LCD - 19 inch 2005 | 72100 | 550606 | 05 M | | 264.0 | 430.0 | 430.0 | | 15.00 | 28.36 | 24.11 | - | 3,960.00 | 12,194.80 | 10,367.30 |
| | PC H W Operating Lease | 72100 | 550606 | 05 M | 315.0 | 327.0 | 327.0 | 327.0 | 81.12 | 80.00 | 72.03 | 69.15 | 25,552.80 | 26,160.00 | 23,553.81 | 22,612.05 |
| | PC Support High | 72100 | 550606 | 05 M | 36.0 | 37.0 | 37.0 | 37.0 | 162.91 | 168.13 | 125.12 | 133.25 | 5,864.76 | 6,220.81 | 4,629.44 | 4,930.25 |
| | PC Support High | 72100 | 550606 | 05 M | | (2.0) | - | - | | 28.69 | 125.12 | 133.25 | - | (57.38) | - | - |
| | PC Support Low | 72100 | 550606 | 05 M | 215.0 | 207.0 | 207.0 | 207.0 | 108.44 | 110.74 | 103.66 | 110.40 | 23,314.60 | 22,923.18 | 21,457.62 | 22,852.80 |
| | PC Support Medium | 72100 | 550606 | 05 M | 64.0 | 83.0 | 100.0 | 100.0 | 135.67 | 139.44 | 106.73 | 113.67 | 8,682.88 | 11,573.52 | 10,673.00 | 11,367.00 |
| | PC Support Medium | 72100 | 550606 | 05 M | | (3.0) | - | - | | 28.70 | 106.73 | 113.67 | - | (86.10) | - | - |
| | Printer Support High Volume | 72100 | 550606 | 05 M | 10.0 | | - | - | 76.37 | 80.00 | 109.40 | 116.51 | 763.70 | - | - | - |
| | Printer Support Low Volume | 72100 | 550606 | 05 M | 12.0 | 12.0 | 12.0 | 12.0 | 20.00 | 21.00 | 32.39 | 34.50 | 240.00 | 252.00 | 388.68 | 414.00 |
| | Printer Support Medium Volume | 72100 | 550606 | 05 M | 73.0 | 36.0 | 36.0 | 36.0 | 65.00 | 68.00 | 64.01 | 68.17 | 4,745.00 | 2,448.00 | 2,304.36 | 2,454.12 |
| | SSL Secure Remote Access | 72100 | 550606 | 05 M | | 2.0 | 14.0 | 14.0 | | 32.79 | 32.79 | 32.79 | - | 65.58 | 459.06 | 459.06 |
| | Tablet PC H W Operating Lease | 72100 | 550606 | 05 M | 12.0 | | - | - | 17.82 | 185.00 | 170.59 | 163.77 | 213.84 | - | - | - |
| | VPN - Remote Client | 72100 | 550606 | 05 M | 12.0 | 1.0 | 1.0 | 1.0 | 53.52 | 15.00 | 32.79 | 32.79 | 642.24 | 15.00 | 32.79 | 32.79 |
| | VPN - Remote Client | 72100 | 550606 | 05 M | 92.0 | 45.0 | 45.0 | 45.0 | 32.79 | 32.79 | 32.79 | 32.79 | 3,016.68 | 1,475.55 | 1,475.55 | 1,475.55 |
| | XEROX Printer Support | 72100 | 550606 | 05 M | 10.0 | 24.0 | 24.0 | 24.0 | 65.00 | 65.00 | 64.01 | 68.17 | 650.00 | 1,560.00 | 1,536.24 | 1,636.08 |
| User Fees | Email Storage (50mb blocks) | 72100 | 550607 | 05 A | 2,621.0 | 3,333.0 | 4,000.0 | 4,500.0 | 4.50 | 3.10 | 1.92 | 1.34 | 11,794.50 | 10,332.30 | 7,680.00 | 6,030.00 |
| | Internet Service | 72100 | 550607 | 05 M | 257.0 | 252.0 | 260.0 | 260.0 | 14.20 | 14.20 | 21.79 | 21.79 | 3,649.40 | 3,578.40 | 5,665.40 | 5,665.40 |
| | Internet Service | 72100 | 550607 | 05 M | 5.0 | | | | 5.00 | 14.20 | 21.79 | 21.79 | 25.00 | - | - | - |
| | Rightfax Service | 72100 | 550607 | 05 M | 4.4 | | - | - | 0.04 | 22.00 | 21.25 | 21.25 | 0.18 | - | - | - |
| | Server Storage | 72100 | 550607 | 05 A | 484.8 | 703.6 | 800.0 | 800.0 | 55.00 | 38.00 | 24.16 | 18.12 | 26,664.00 | 26,736.80 | 19,328.00 | 14,496.00 |
| | Server Storage - Migrated | 72100 | 550607 | 05 A | 0.4 | 0.2 | 0.3 | 0.3 | 14.65 | 14.65 | 14.65 | 14.65 | 5.86 | 2.93 | 4.40 | 4.40 |
| | Temporary Credit- File Storage Archiving | 72100 | 550607 | 5 A | | 2.0 | | | | (23.35) | | | - | (46.70) | - | - |
| | Terminal Server Service (citrix) | 72100 | 550607 | 05 M | 48.0 | 48.0 | 48.0 | 48.0 | 38.00 | 38.00 | 41.72 | 41.72 | 1,824.00 | 1,824.00 | 2,002.56 | 2,002.56 |
| | UserID Serv w limited ATCO Domain usage | 72100 | 550607 | 05 M | | 12.0 | 12.0 | 12.0 | | 10.81 | 16.84 | 16.84 | - | 129.72 | 202.08 | 202.08 |
| | UserID Services | 72100 | 550607 | 05 M | 573.0 | 605.0 | 615.0 | 615.0 | 15.53 | 15.53 | 16.84 | 16.84 | 8,898.69 | 9,395.65 | 10,356.60 | 10,356.60 |
| | UserID Services | 72100 | 550607 | 05 M | | | | | | 15.53 | 16.84 | 16.84 | - | - | - | - |
| | Distributed DR (Infrastructure) | 72100 | 550607 | 05 M | | 605.0 | 615.0 | 615.0 | | 15.95 | 15.88 | 15.88 | - | 9,649.75 | 9,766.20 | 9,766.20 |
| | Distributed DR (Infrastructure) | 72100 | 550607 | 5 | 523.0 | | | | 15.35 | | | | 8,028.05 | | - | - |
| | Wireless Blackberry Service Connectivity | 72100 | 550607 | 05 M | | 7.0 | 22.0 | 22.0 | | 31.27 | 29.95 | 29.95 | - | 218.89 | 658.90 | 658.90 |
| Service Requests | Express Request Service Fee | 72100 | 550608 | 5 A | 4.0 | 3.0 | 4.0 | 4.0 | 125.77 | 132.50 | 58.02 | 61.79 | 503.08 | 397.50 | 232.08 | 247.16 |
| | Software | 72100 | 550608 | 05 A | 8.0 | 8.0 | 18.0 | 18.0 | 329.59 | Variable | Variable | Variable | 2,636.72 | 1,426.00 | 3,200.00 | 3,360.00 |
| | Hardware | 72100 | 550608 | 05 A | 3.0 | 12.0 | 12.0 | 12.0 | 712.20 | Variable | Variable | Variable | 2,136.60 | 1,709.00 | 3,200.00 | 3,360.00 |
| | Software Integration Pkging Labour | 72100 | 550608 | 05 A | 1.0 | | - | - | 118.59 | 124.93 | 105.50 | 112.36 | 118.59 | - | - | - |
| | Software Distribution Fee | 72100 | 550608 | 05 A | 5.0 | 18.0 | 38.0 | 38.0 | 118.45 | 124.79 | 158.24 | 168.53 | 592.25 | 2,246.22 | 6,013.12 | 6,404.14 |
| | Software Support Labour | 72100 | 550608 | 05 A | 2.5 | 2.0 | 2.0 | 2.0 | 118.59 | 124.93 | 105.50 | 112.36 | 296.48 | 249.86 | 211.00 | 224.72 |
| | Voice Install, Move, Add, Change | 72100 | 550608 | 05 A | | 1.0 | 1.0 | 1.0 | | 71.01 | 61.72 | 65.73 | - | 71.01 | 61.72 | 65.73 |
| | Hardware Install Move Add Change Labour | 72100 | 550608 | 05 A | 7.0 | 20.0 | 20.0 | 20.0 | 118.59 | 124.93 | 126.33 | 134.54 | 830.13 | 2,498.60 | 2,526.60 | 2,690.80 |
| OFin ASP | Discoverer Maint. on License Purchase | 72100 | 550613 | 05 M | 84.0 | 97.0 | 97.0 | 97.0 | 13.37 | 13.37 | 13.37 | 14.24 | 1,123.08 | 1,296.89 | 1,296.89 | 1,381.28 |
| | Discrete Mfg Read Maint. on License Purchase | 72100 | 550613 | 05 M | | 22.0 | 22.0 | 22.0 | | 19.14 | 19.14 | 20.38 | - | 421.08 | 421.08 | 448.36 |
| | Discrete Mfg Update Maint. on License Purchase | 72100 | 550613 | 05 M | | | - | - | | 50.02 | 50.02 | 53.27 | - | - | - | - |
| | Financials Read Maint. on License Purchase | 72100 | 550613 | 05 M | | | - | - | | 19.14 | 19.14 | 20.38 | - | - | - | - |
| | Financials Update Maint. on License Purchase | 72100 | 550613 | 05 M | 48.0 | 61.0 | 61.0 | 61.0 | 50.02 | 50.02 | 50.02 | 53.27 | 2,400.96 | 3,051.22 | 3,051.22 | 3,249.47 |
| | iExpense Maintenance on License Purchase | 72100 | 550613 | 05 M | 303.0 | 284.0 | 300.0 | 300.0 | 0.85 | 0.85 | 0.85 | 0.91 | 257.55 | 241.40 | 255.00 | 273.00 |
| | iProcurement Maintenance on License Purchase | 72100 | 550613 | 05 M | 93.0 | 19.0 | 19.0 | 19.0 | 0.89 | 0.89 | 0.89 | 0.95 | 82.77 | 16.91 | 16.91 | 18.05 |
| | Mobile Supply Chain Maint. on License Purchase | 72100 | 550613 | 05 M | | | - | - | | 19.95 | 19.95 | 20.25 | - | - | - | - |
| | Order Management Maint. on License Purchase | 72100 | 550613 | 05 M | 84.0 | 53.0 | 60.0 | 60.0 | 0.04 | 0.04 | 0.04 | 0.04 | 3.36 | 2.12 | 2.40 | 2.40 |
| | Project Acct Read Maint. on License Purchase | 72100 | 550613 | 05 M | | | - | - | | 19.14 | 19.14 | 20.38 | - | - | - | - |
| | Project Acct Update Maint. on License Purchase | 72100 | 550613 | 05 M | 36.0 | 36.0 | 36.0 | 36.0 | 50.02 | 50.02 | 50.02 | 53.27 | 1,800.72 | 1,800.72 | 1,800.72 | 1,917.72 |
| | Project Management Maint. on License Purchase | 72100 | 550613 | 05 M | 30.0 | 22.0 | 22.0 | 22.0 | 10.61 | 10.61 | 11.10 | 11.93 | 318.30 | 233.42 | 244.20 | 262.46 |
| | Purchasing Read Maint. on License Purchase | 72100 | 550613 | 05 M | | | - | - | | 19.14 | 20.02 | 21.51 | - | - | - | - |
| | Purchasing Update Maint. on License Purchase | 72100 | 550613 | 05 M | 60.0 | 53.0 | 53.0 | 53.0 | 50.02 | 50.02 | 50.02 | 53.27 | 3,001.20 | 2,651.06 | 2,651.06 | 2,823.31 |
| | Ofin Storage - DASD | 72100 | 550613 | 05 A | 168.4 | 278.4 | 360.0 | 360.0 | 55.00 | 38.00 | 21.72 | 16.29 | 9,262.00 | 10,579.20 | 7,819.20 | 5,864.40 |
| | Ofin Storage - DASD Network attached | 72100 | 550613 | 05 A | | | | | | 38.00 | 21.72 | 16.29 | - | - | - | - |
| | Ofin Storage - Local | 72100 | 550613 | 05 A | 39.0 | 20.8 | 20.8 | 20.8 | 22.00 | 15.00 | 7.60 | 5.70 | 858.00 | 312.00 | 158.08 | 118.56 |

**YUKON ELECTRICAL COMPANY LIMITED**
**IT Operating Plan**

| | Service | Activity | Acct. | Co. No. | Units Actual 2006 | Units Actual 2007 | Units Test Year 2008 | Units Test Year 2009 | Price Actual 2006 | Price Actual 2007 | Price Test Year 2008 | Price Test Year 2009 | Dollars Actual 2006 | Dollars Actual 2007 | Dollars Test Year 2008 | Dollars Test Year 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | OFin Hosting & Support | 72100 | 550613 | 05 A | 12.0 | 12.0 | 12.0 | 12.0 | 4,674.64 | Variable | Variable | Variable | 56,095.68 | 59,572.00 | 61,000.00 | 62,000.00 |
| | Ofin Disaster Recovery | 72100 | 550613 | 05 A | 12.0 | 12.0 | 12.0 | 12.0 | 287.01 | Variable | Variable | Variable | 3,444.12 | 3,444.00 | 3,500.00 | 3,600.00 |
| | OFin Unused License Charge | 72100 | 550613 | 05 A | 42.0 | 39.0 | 45.0 | 45.0 | 13.05 | Variable | Variable | Variable | 548.10 | 422.00 | 500.00 | 500.00 |
| **WAN** | VPN Remote Branch - connection service | 72100 | 550603 | 05 M | 24.0 | 24.0 | 24.0 | 24.0 | 775.50 | 775.50 | 790.51 | 790.51 | 18,612.00 | 18,612.00 | 18,972.24 | 18,972.24 |
| | Network Telecom Fee | 72100 | 550603 | 0 m | | 1.0 | | | | 200.00 | | | - | 200.00 | - | - |
| | VPN - Small Offices | 72100 | 550603 | 05 M | | 11.4 | 12.0 | 12.0 | | 140.00 | 142.41 | 142.41 | - | 1,596.00 | 1,708.92 | 1,708.92 |
| **XEROX** | Lease Xerox | 72100 | 550611 | 05 A | 31.0 | | 4.0 | 4.0 | 229.66 | Variable | Variable | Variable | 7,119.46 | 8,465.00 | 8,500.00 | 8,600.00 |
| | Service Xerox | 72100 | 550611 | 05 A | 41.0 | 38.0 | 48.0 | 40.0 | 77.84 | Variable | Variable | Variable | 3,191.44 | 8,129.00 | 8,000.00 | 8,000.00 |
| | Consumables Xerox | 72100 | 550611 | 05 A | | 50.0 | - | - | | Variable | Variable | Variable | - | - | - | - |
| **CIS COS** | MVS (IMS) CPU Minutes | 71300 | 550301 | 05 A | 318.9 | | - | - | 13.47 | 13.47 | 6.58 | 6.38 | 4,295.58 | - | - | - |
| | MVS (CICS) CPU Minutes | 71300 | 550301 | 05 A | 0.2 | | - | - | 10.50 | 8.50 | 6.13 | 5.95 | 2.10 | - | - | - |
| **ATCO-CIS Access** | MVS (CICS) CPU Minutes | 71300 | 550301 | 05 A | | | - | - | | 8.50 | 6.13 | 5.95 | - | - | - | - |
| | MVS (DB2) CPU Minutes | 71300 | 550301 | 05 A | - | | - | - | 10.49 | 8.50 | 6.13 | 5.95 | - | - | - | - |
| | MVS (ADABAS) CPU Minutes | 72100 | 550602 | 05 A | 59.7 | | - | - | 13.47 | 13.47 | 7.49 | 7.27 | 804.16 | - | - | - |
| **Timesharing (TSO)** | MVS (IMS ADABAS Batch) CPU Minutes | 72100 | 550602 | 05 A | 49.6 | | - | - | 13.46 | 13.47 | 7.49 | 7.27 | 667.62 | - | - | - |
| | MVS (TSO) CPU Minutes | 72100 | 550602 | 05 A | | | - | - | | 8.50 | 7.49 | 7.27 | - | - | - | - |
| | MVS DASD Gigabyte Months | 72100 | 550602 | 05 A | | | - | - | | 50.00 | 6.55 | 6.35 | - | - | - | - |
| | MVS Form Type 1000 | 72100 | 550602 | 05 A | | | - | - | | 14.35 | 15.00 | 14.55 | - | - | - | - |
| | MVS HSM Tape Gigabyte Months | 72100 | 550602 | 05 A | - | | - | - | 3.15 | 2.18 | 0.43 | 0.42 | - | - | - | - |
| | MVS Print Pages | 72100 | 550602 | 05 A | 6.4 | | - | - | 108.27 | 108.27 | 41.85 | 40.59 | 692.93 | - | - | - |
| | MVS (ADABAS) CPU Minutes | 72100 | 550612 | 05 A | | 77.9 | 77.9 | 77.9 | | 13.47 | 7.49 | 7.27 | - | 1,049.31 | 583.47 | 566.33 |
| | MVS (IMS ADABAS Batch) CPU Minutes | 72100 | 550612 | 05 A | | 47.7 | 47.7 | 47.7 | | 13.47 | 7.49 | 7.27 | - | 642.52 | 357.27 | 346.78 |
| | MVS (Non-IMS ADABAS Batch) CPU Minutes | 72101 | 550612 | 05 A | 3.9 | 1.1 | 1.1 | 1.1 | 10.50 | 8.50 | 6.58 | 6.38 | 40.95 | 9.35 | 7.24 | 7.02 |
| | MVS (CICS) CPU Minutes | 72100 | 550612 | 05 A | | 1.4 | 1.4 | 1.4 | | 8.50 | 6.13 | 5.95 | - | 11.90 | 8.58 | 8.33 |
| | MVS (DB2) CPU Minutes | 72100 | 550612 | 05 A | | 7.6 | 7.6 | 7.6 | | 8.50 | 6.13 | 5.95 | - | 64.60 | 46.59 | 45.22 |
| | MVS (IMS) CPU Minutes | 72100 | 550612 | 05 A | | 436.1 | 436.1 | 436.1 | | 13.47 | 6.58 | 6.38 | - | 5,874.27 | 2,869.54 | 2,782.32 |
| **Mainframe** | MVS (TSO) CPU Minutes | 72100 | 550612 | 05 A | 28.3 | 34.6 | 34.6 | 34.6 | 10.50 | 8.50 | 6.13 | 5.95 | 297.15 | 294.10 | 212.10 | 205.87 |
| | MVS DASD Gigabyte Months | 72100 | 550612 | 05 A | 0.3 | 0.5 | 0.5 | 0.5 | 72.90 | 50.00 | 6.55 | 6.35 | 21.87 | 25.00 | 3.28 | 3.18 |
| | MVS Form Type 1000 | 72100 | 550612 | 05 A | 0.3 | 0.1 | 0.1 | 0.1 | 9.00 | 6.56 | 15.00 | 14.55 | 2.70 | 0.66 | 1.50 | 1.46 |
| | MVS Form Type 1000 | 72100 | 550612 | 05 A | 6.1 | 0.4 | 0.4 | 0.4 | 31.93 | 6.91 | 15.00 | 14.55 | 194.77 | 2.76 | 6.00 | 5.82 |
| | MVS Form Type 1000 | 72100 | 550612 | 05 A | | 16.0 | 16.0 | 16.0 | | 28.03 | | | - | 448.48 | - | - |
| | MVS Form Type 1000 | 72100 | 550612 | 05 A | | 1.0 | 1.0 | 1.0 | | 31.93 | | | - | 31.93 | - | - |
| | MVS HSM Tape Gigabyte Months | 72100 | 550612 | 05 A | | | - | - | | 2.18 | 0.43 | 0.42 | - | - | - | - |
| | MVS Print Pages | 72100 | 550612 | 05 A | | 17.6 | 17.6 | 17.6 | | 108.27 | 41.85 | 40.59 | - | 1,905.55 | 736.56 | 714.38 |
| | MVS Tape Gigabyte Months | 72100 | 550612 | 05 A | 6.0 | 6.3 | 6.3 | 6.3 | 3.15 | 2.18 | 0.43 | 0.42 | 18.90 | 13.73 | 2.71 | 2.65 |
| | Maint. & Enhancement Labour Hours | 72100 | 550604 | 05 A | | | - | - | | 125.23 | 130.08 | 138.54 | - | - | - | - |
| | Software Enhancements | 72100 | 550608 | 5 A | | 2.0 | 2.0 | 2.0 | | 827.20 | | | - | 1,654.40 | - | - |
| | Other Mainframe Application Expenses | 72100 | 550604 | 05 A | 12.0 | | | | 10.70 | Variable | Variable | Variable | 128.40 | - | | - |
| **Distributed Applications** | Distributed Applications Service fees | 72100 | 550610 | 05 A | 24.0 | 24.0 | 24.0 | 24.0 | 956.99 | Variable | Variable | Variable | 22,967.76 | | - | - |
| | ATCO I-Tek Maint. & Enh. Costs | 72100 | 550604 | 05 A | | 24.0 | 24.0 | 24.0 | | Variable | Variable | Variable | - | 23,285.00 | 24,000.00 | 24,000.00 |
| | ATCO I-Tek- Additional Application Expenses | 72100 | 550604 | 05 A | 31.0 | | n a | n a | 0.15 | Variable | Variable | Variable | 4.65 | | - | - |
| | **TOTAL** | | | | | | | | | | | | **311,133.81** | **331,051.73** | **329,488.41** | **323,562.42** |

**YUKON ELECTRICAL COMPANY LIMITED**
**2008 - 2009 GENERAL RATE APPLICATION**

| **2006** | | | Actual | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| Base Billing Services | | Rate | | | | | | | | | | | | | |
| | Volume | | 15,122 | 15,479 | 15,485 | 15,501 | 15,521 | 15,558 | 15,586 | 15,607 | 15,647 | 15,666 | 15,679 | 15,705 | 186,556 |
| | Cost | 1.34 | 20,160 | 20,742 | 20,750 | 20,771 | 20,798 | 20,848 | 20,885 | 20,913 | 20,967 | 20,992 | 21,010 | 21,950 | 250,787 |
| Additional Services | | | | | | | | | | | | | | | |
| | Volume | | 45 | 47 | 60 | 58 | 66 | 62 | 38 | 31 | 38 | 34 | 92 | 62 | 633 |
| | Cost | 0.66 | 30 | 31 | 40 | 38 | 44 | 41 | 25 | 20 | 25 | 22 | 61 | 41 | 418 |
| Rate Rider Changes | | | | | | | | | | | | | | | |
| | Volume | | - | - | - | - | - | | - | - | - | - | - | - | |
| | Cost | | | 474 | | 1,021 | 1,152 | | 133 | 1,021 | 282 | | 2,673 | 500 | 7,256 |
| Postage | | | | | | | | | | | | | | | |
| | Volume | | 12,727 | 13,031 | 13,084 | 13,649 | 11,873 | 13,855 | 13,093 | 12,433 | 13,702 | 12,555 | 13,096 | 14,416 | |
| | Cost | 0.55 | 7,000 | 7,167 | 7,196 | 7,507 | 6,530 | 7,620 | 7,201 | 6,838 | 7,536 | 6,905 | 7,203 | 7,929 | 86,632 |
| Paper - Utility Bill and Collection Forms | | | 840 | 661 | 928 | 679 | 639 | 699 | 671 | 628 | 702 | 721 | 698 | 700 | 8,566 |
| | | | 28,030 | 29,075 | 28,914 | 30,016 | 29,163 | 29,208 | 28,915 | 29,420 | 29,512 | 28,640 | 31,645 | 31,120 | 353,658 |

| **2007** | | | Actual | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| Base Billing Services | | Rate | | | | | | | | | | | | | |
| | Volume | | 15,046 | 15,723 | 15,746 | 15,764 | 15,772 | 15,805 | 15,834 | 15,863 | 15,904 | 15,940 | 15,971 | 16,018 | 189,386 |
| | Cost | 1.40 | 21,600 | 22,012 | 22,044 | 22,070 | 22,081 | 22,127 | 22,168 | 22,208 | 22,266 | 22,316 | 22,359 | 23,285 | 266,536 |
| Additional Services | | | | | | | | | | | | | | | |
| | Volume | | 79 | 86 | 74 | 179 | 80 | 61 | 51 | 101 | 87 | 51 | 44 | 56 | 949 |
| | Cost | 0.69 | 55 | 59 | 51 | 124 | 55 | 42 | 35 | 70 | 60 | 35 | 30 | 39 | 655 |
| Rate Rider Changes | | | | | | | | | | | | | | | |
| | Volume | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | Cost | - | 600 | (246) | | | 1,069 | (713) | - | 1,402 | - | - | 535 | (600) | 2,047 |
| Postage | | | | | | | | | | | | | | | |
| | Volume | | 13,091 | 13,940 | 12,455 | 13,905 | 12,327 | 13,975 | 12,667 | 13,284 | 13,896 | 12,685 | 14,096 | 13,520 | |
| | Cost | 0.55 | 7,200 | 7,667 | 6,850 | 7,648 | 6,780 | 7,686 | 6,967 | 7,306 | 7,643 | 6,977 | 7,753 | 7,436 | 87,914 |
| Paper - Utility Bill and Collection Forms | | | 600 | 989 | 633 | 734 | 685 | 1,061 | 753 | 643 | 665 | 956 | 619 | 625 | 8,963 |
| | | | 30,055 | 30,481 | 29,578 | 30,576 | 30,670 | 30,203 | 29,923 | 31,629 | 30,634 | 30,284 | 31,296 | 30,785 | 366,114 |

**YUKON ELECTRICAL COMPANY LIMITED**
**2008 - 2009 GENERAL RATE APPLICATION**

| 2008 | | | Forecast | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| Base Billing Services | | Rate | | | | | | | | | | | | | |
| | Volume | | 15,121 | 15,802 | 15,825 | 15,843 | 15,851 | 15,884 | 15,913 | 15,942 | 15,984 | 16,020 | 16,051 | 16,098 | 190,334 |
| Old CIS | Cost | 1.47 | 21,483 | 23,229 | 23,263 | 23,289 | 23,301 | | | | | | | | 114,565 |
| ATCO-CIS | Cost | 1.72 | | | | | | 27,320 | 27,370 | 27,420 | 27,492 | 27,554 | 27,608 | 27,689 | 192,453 |
| Printing | Cost | 0.11 | | | | | | 1,747 | 1,750 | 1,754 | 1,758 | 1,762 | 1,766 | 1,771 | 12,308 |
| Additional Services | | | | | | | | | | | | | | | |
| | Volume | | 53 | 74 | 55 | 62 | 72 | - | - | - | - | - | - | - | 316 |
| | Cost | 0.72 | 38 | 53 | 40 | 45 | 52 | - | - | - | - | - | - | - | 228 |
| Rate Rider Changes | | | | | | | | | | | | | | | |
| | Volume | | - | - | - | - | - | - | - | | | | | | - |
| | Cost | - | - | 700 | | | 700 | | | 700 | - | | 700 | - | 2,800 |
| Postage | | | | | | | | | | | | | | | |
| | Volume | | 13,156 | 14,010 | 12,517 | 13,975 | 12,389 | 14,045 | 12,730 | 13,350 | 13,965 | 12,748 | 14,166 | 13,588 | 160,639 |
| | Cost | 0.53 | 6,973 | 7,425 | 6,634 | 7,407 | 6,566 | 7,444 | 6,747 | 7,076 | 7,401 | 6,756 | 7,508 | 7,202 | 85,139 |
| Paper - Utility Bill and Collection Forms | | | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 9,000 |
| | | | 29,244 | 32,157 | 30,687 | 31,491 | 31,369 | 37,261 | 36,617 | 37,700 | 37,401 | 36,822 | 38,332 | 37,412 | 416,493 |

| 2009 | | | Forecast | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| Base Billing Services | | Rate | | | | | | | | | | | | | |
| | Volume | | 15,197 | 15,881 | 15,904 | 15,922 | 15,930 | 15,963 | 15,993 | 16,022 | 16,064 | 16,100 | 16,131 | 16,178 | 191,285 |
| Base Billing | Cost | 1.72 | 26,139 | 27,315 | 27,355 | 27,386 | 27,400 | 27,456 | 27,508 | 27,558 | 27,630 | 27,692 | 27,745 | 27,826 | 329,010 |
| Printing | Cost | 0.11 | 1,672 | 1,747 | 1,749 | 1,751 | 1,752 | 1,756 | 1,759 | 1,762 | 1,767 | 1,771 | 1,774 | 1,780 | 21,040 |
| Additional Services | | | | | | | | | | | | | | | |
| | Volume | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | Cost | 0.73 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Rate Rider Changes | | | | | | | | | | | | | | | |
| | Volume | | - | 700 | - | - | 700 | - | - | 700 | - | - | 700 | - | 2,800 |
| | Cost | - | | | | | | | | | | | | | - |
| Postage | | | | | | | | | | | | | | | |
| | Volume | | 13,222 | 14,080 | 12,580 | 14,045 | 12,451 | 14,115 | 12,794 | 13,417 | 14,035 | 12,812 | 14,237 | 13,656 | 161,444 |
| | Cost | 0.55 | 7,272 | 7,744 | 6,919 | 7,725 | 6,848 | 7,763 | 7,037 | 7,379 | 7,719 | 7,047 | 7,830 | 7,511 | 88,794 |
| Paper - Utility Bill and Collection Forms | | | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 750 | 9,000 |
| | | | 35,833 | 37,556 | 36,773 | 37,612 | 36,750 | 37,725 | 37,054 | 37,449 | 37,866 | 37,260 | 38,099 | 37,867 | 447,844 |

## YEC-YECL-12

**Reference:** Operation and Maintenance Costs Schedule 5.1, 5.2 and 5.3

**Requests:**

(a) Provide a detailed schedule for the past five years of the labour, lubricants, consumables, engine maintenance and overhaul costs that are included in the production expenses. Include in the schedule any other cost categories that need to be identified in order to analyzes the total production costs.

**Response:**

(a) A detailed break out of actual product types used in production expenses is not available. However please refer to YEC-YECL-12(a) Attachments 1 and 2 for a breakdown of the production expenses by Hydro, Diesel, and Diesel overhauls.

| | | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|
| **HYDRO** | | | | | | | | |
| | **O M** | | | | | | | |
| | Fringe | 4 | 5 | 5 | 4 | 12 | 11 | 12 |
| | Labour | 49 | 55 | 57 | 47 | 69 | 73 | 79 |
| | Other | 27 | 16 | 23 | 44 | 56 | 44 | 71 |
| | | 80 | 76 | 85 | 95 | 136 | 127 | 162 |
| **DIESEL** | | | | | | | | |
| | **O M** | | | | | | | |
| | Fringe | 31 | 48 | 51 | 52 | 116 | 118 | 128 |
| | Labour | 354 | 403 | 421 | 452 | 470 | 579 | 650 |
| | Other | 408 | 386 | 325 | 345 | 359 | 385 | 404 |
| | | 793 | 836 | 797 | 849 | 945 | 1,082 | 1,181 |
| | **Overhauls** | | | | | | | |
| | Labour | 17 | 25 | 24 | 16 | 18 | 31 | 19 |
| | Fringe | 1 | 2 | 2 | 1 | 3 | 3 | 2 |
| | Contract Services & material | 303 | 275 | 247 | 226 | 193 | 318 | 217 |
| | Other | 9 | 9 | 25 | 8 | 16 | 32 | 20 |
| | | 330 | 311 | 298 | 251 | 230 | 385 | 257 |
| **TOTAL PRODUCTION** | | 1,203 | 1,223 | 1,181 | 1,196 | 1,312 | 1,594 | 1,600 |

**YECL GENERATING PLANTS OVERHAULS**

| Description | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test 2008 | Test 2009 |
|---|---|---|---|---|---|---|---|
| Stewart Unit 3 Overhaul | 9,333 | | | | | | |
| W. Lake Unit 6 Generator Fire | 51,543 | | | | | | |
| W. Lake Unit 2 Overhaul | 24,103 | | | | | | |
| Beaver Creek Unit 2 Overhaul | 58,546 | | | | | | |
| Beaver Creek Unit 3 Overhaul | 5,101 | | | | | | |
| Pelly Unit 2 Overhaul | 22,053 | | | | | | |
| D. Bay Unit 1 Overhaul | 43,906 | | | | | | |
| Old Crow Unit 2 Overhaul | 31,946 | | | | | | |
| W. Lake Unit 6 Overhaul | 21,317 | (11,492) | | | | | |
| W. Lake Unit 1 Overhaul | 24,508 | 107,758 | | | | | |
| 2003 WL2 Overhaul | 37,564 | | | | | | |
| W. Lake Unit 5 Overhaul | | 8,566 | | | | | |
| D. Bay Unit 2 Overhaul | | 30,645 | | | | | |
| Pelly Unit 3 Overhaul | | 6,570 | | | | | |
| W. Lake Unit 3 Overhaul | | 168,748 | | | | | |
| Beaver Creek Unit 2 Overhaul | | | 30,062 | | | | |
| Beaver Creek Unit 3 Overhaul | | | 73,327 | | | | |
| Stewart Unit 2 Injectors | | | 4,295 | | | | |
| Old Crow Unit 2 Overhaul | | | 102,281 | | | | |
| W. Lake Unit 4 Overhaul | | | 54,589 | | | | |
| D. Bay Unit 1 Overhaul | | | 19,690 | | | | |
| Pelly Unit 3 Overhaul | | | 14,157 | (309) | | | |
| W. Lake Unit 5 Overhaul | | | | 7,226 | | | |
| W. Lake Unit 6 Overhaul | | | | 66,531 | | | |
| W. Lake Unit 6 Overhaul | | | | 2,397 | | | |
| W. Lake Unit 1 Overhaul | | | | 53,563 | | | |
| Pelly Unit 3 Overhaul | | | | 10,345 | | | |
| Beaver Creek Unit 1 Overhaul | | | | 41,354 | 900 | | |
| W. Lake Unit 2 Overhaul | | | | 70,038 | 69,781 | | |
| Beaver Creek Unit 2 Overhaul | | | | | 73,513 | | |
| Pelly Unit 2 Overhaul | | | | | 25,135 | | |
| W. Lake Unit 4 Overhaul | | | | | 11,581 | | |
| Old Crow Unit 2 Overhaul | | | | | 27,184 | | |
| W. Lake Plant Injectors | | | | | 21,608 | | |
| W. Lake Unit 3 Overhaul | | | | | | 85,000 | |
| W. Lake Unit 6 Overhaul | | | | | | 140,000 | |
| D. Bay Unit 1 Overhaul | | | | | | 60,000 | |
| Old Crow Unit 3 | | | | | | 70,000 | |
| D. Bay Unit 2 Overhaul | | | | | | 30,000 | |
| W. Lake Unit 1 Overhaul | | | | | | | 155,000 |
| W. Lake Unit 5 Overhaul | | | | | | | 18,000 |
| Beaver Creek Unit 2 Overhaul | | | | | | | 38,000 |
| Old Crow Unit 1 | | | | | | | 46,000 |
| **Total Overhauls** | **329,921** | **310,795** | **298,400** | **251,145** | **229,701** | **385,000** | **257,000** |

**YEC-YECL-13**

**Reference:** O&M Expense

**Requests:**

(a) Please provide a detailed breakdown of production expenses for YECL from 1996 to 2009 and explain in detail the relationships between generation levels and these production O&M expenses.

(b) Please provide a detailed breakdown of transmission and distribution expenses for YECL from 1996 to 2009 and provide a detailed explanation for major changes.

(c) Please provide a detailed breakdown of YECL's Public Information expenditures for the years 2005 to 2009 and provide a detailed explanation for major changes.

(d) Please provide a detailed breakdown of Commercial expenses for 1996 to 2009 and provide a detailed explanation for major changes.

(e) Please provide a detailed breakdown of Administration and General Expenditures from 1996 to 2009 and provide a detailed explanation for any significant variances.

(f) Please compare 1996 and 1997 actual O and M expenditures and forecast 2008 and 2009 O&M expenditures and explain in detail the reasons for any variances greater than 10 .

**Response:**

(a) In accordance with Board Order 2008-5 information prior to 2003 is not required to test the revenue requirement in the test period. Please refer to YEC-YECL-12(a) Attachments 1 and 2. Generation levels in relationship to O&M production expenditures are such that the proper staffing along with efficient planning and execution of maintenance, will result in minimum O&M cost per KwH produced over the long run. Yukon Electrical operates it's generation business in such a manner to produce the best possible ratio of cost per KwH while balancing the needs for proper standards for safety and reliability.

(b) In accordance with Board Order 2008-5 information prior to 2003 is not required to test the revenue requirement in the test period. Please refer to CW-YECL-25(c) Attachment 1 and Schedule 5.1. In 2004, extreme wind and snow storms caused an increase in line maintenance. For 2005 - 2009 descriptions of major changes please refer to Schedule 5.2.

(c) For 2005 - 2009 description of major changes please refer to Schedule 5.2.

(d) In accordance with Board Order 2008-5 information prior to 2003 is not required to test the revenue requirement in the test period. Please refer to CW-YECL-25(c) Attachment 1 and Schedule 5.1. For descriptions of major changes please refer to Schedule 5.2.

(e) In accordance with Board Order 2008-5 information prior to 2003 is not required to test the revenue requirement in the test period. Please refer to CW-YECL-25(c) Attachment 1 and Schedule 5.1. The increase from 2004 to 2005 is due to regulatory intervention and employee relocation costs incurred. For 2005 - 2009 significant variance explanations please refer to Schedule 5.2.

(f) In accordance with Board Order 2008-5 information prior to 2003 is not required to test the revenue requirement in the test period. As such it is not necessary to provide variances explanations for actual 1996 and 1997 O&M costs.

## YEC-YECL-14

**Reference:** Parent Charges

**Requests:**

(a) Provide a detailed accounting of parent charges. Please provide a detailed explanation of what the parent charges are for and why Yukon ratepayers should be required to pay for such charges.

**Response:**

(a) Parent charges equate to the head office charges referred to on Schedule 5.3 Lines 14 23. Schedule 5.3 is a detailed breakdown of the costs. The detailed explanation of services received for these costs is contained in Yukon Electrical's Master Service Contract. Please refer to CW-YECL-28 and CW-YECL-29.

Yukon ratepayers should be required to pay for such services as these services are required to operate the business. Please refer to YEC-YECL-8(i) for a complete explanation and justification of these head office costs.

## YEC-YECL-15

**Reference:** Administration Costs

**Requests:**

(a) Provide a schedule detailing the costs included in each of the administration cost categories.

**Response:**

(a) Please refer to UCG-YECL-19 below:

| Administration Costs Breakdown | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|
| Labour | 487 | 500 | 544 |
| Fringe | 116 | 103 | 108 |
| ATCO I-Tek | 331 | 353 | 370 |
| ATCO Electric Head Office | 160 | 227 | 209 |
| ATCO Gas Office Services | 14 | 15 | 16 |
| Business Travel | 4 | 21 | 22 |
| Telecommunications | 77 | 81 | 85 |
| Courier and Freight | 20 | 31 | 33 |
| Stationary, Office Supplies, and Printing | 27 | 43 | 45 |
| Other | 7 | 7 | 7 |
| Billing system third party revenues | (67) | (50) | (40) |
| **Total** | 1,176 | 1,331 | 1,399 |

The increase in labour in 2009 is mainly due to inflation as well as additional staff budgeted for variable pay. For ATCO I-Tek services please refer to YEC-YECL-11(b) for the ATCO I-Tek amounts as updated. The Head Office costs increase in 2008 is mainly due to increased Head office support for GRA filings as well as increased financial reporting requirements. Business travel costs have increased in 2008 due to inflation, additional professional development and management travel, as well as returning to normal levels. Courier and Freight as well as Stationary, Office Supplies and Printing are also increasing in 2008 due to inflation, and as well from lower than average costs in 2007 incurred.

## YEC-YECL-16

**Reference:** Diesel Fuel Costs

**Requests:**

(a) Please provide a copy of Schedule 4.1, as updated July 4 2008, that provides the information separated by rate zone. Please explain the rationale for using January 1, 2008 prices as the forecast for the test years.

(b) Please provide a copy of each Rider F filing with the YUB since 2003. Explain the basis for fuel price forecasts adopted by YECL in the June 30, 2008 Rider F filing.

(c) Please compare the diesel fuel prices used by YECL in the latest Rider F filing (June 30, 2008) with the diesel fuel prices assumed in the GRA. Update Schedule 4.1 for the test years to reflect the June 30, 2008 Rider F fuel price forecasts, and provide this information broken out by rate zone.

(d) Please provide the actual diesel fuel prices paid by community and overall rate zone (similar to Schedule 4.2) for June 2008. Update, for the test years, Schedule 4.2 to reflect YECL's current fuel price forecasts for these years.

**Response:**

(a) Please refer to YEC-YECL-16(a) Attachment 1. The rational for using the January prices was that these prices were the prices at the time of finalizing the forecast. Given the volatility of the oil commodity on the world oil market, speculation on future prices would not add value to this process as any changes in fuel prices are dealt with through the fuel Rider F.

(b) Please refer to YEC-YECL-16(b) Attachment 1. The basis for the fuel price forecast adopted by Yukon Electrical in the June 30, Rider F filing, was the same basis as was used in the application. That is, the price used was based on the price at the time Rider F was filed.

(c) The comparison of the June 30, 2008 Rider F filing diesel price and the GRA price is as follows:

| | | (Cents litre) | | |
|---|---|---|---|---|
| | | | 30-Jun-08 Rider F | |
| **Rate Zone** | **Community** | **GRA** | **Fuel Price** | **Difference** |
| Large Diesel | Watson Lake | 87.48 | 125.00 | 37.52 |
| Small Diesel | Beaver Creek | 81.52 | 125.00 | 43.48 |
| Small Diesel | Destruction Bay | 83.13 | 125.00 | 41.87 |
| Old Crow | Old Crow | 193.41 | 125.00 | (68.41) |
| Small Diesel | Stewart Crossing | | | - |
| Small Diesel | Pelly Crossing | 89.33 | 125.00 | 35.67 |
| Small Diesel | Swift River | 92.44 | 125.00 | 32.56 |
| Hydro | Standby | 70.00 | 125.00 | 55.00 |

Please refer to YEC-YECL-16(c) Attachment 1 for the version of Schedule 4.1 requested.

(d) 2008 actuals are not required to test the application and will not be provided.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Diesel Generation and Fuel Summary - Breakdown by Rate Zone**
**( 000s)**

| Line No. | Description | Cross Ref. | Rate Zone | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 |
|---|---|---|---|---|---|---|---|---|---|
| | | | Large Diesel WAF | 13,532 | 13,751 | 13,650 | 14,156 | 14,255 | 14,192 |
| | | | Old Crow | 1,690 | 1,771 | 1,962 | 1,811 | 1,853 | 1,967 |
| | | | Small Diesel | 6,291 | 6,466 | 6,195 | 6,197 | 6,226 | 5,767 |
| 1 | Total Diesel Generation (MWh) | S.3.2 L.8 & 9 | | 21,513 | 21,988 | 21,807 | 22,164 | 22,334 | 21,927 |
| | | | Large Diesel WAF | 3.83 | 3.82 | 3.79 | 3.80 | 3.79 | 3.82 |
| | | | Old Crow | 3.60 | 3.50 | 3.56 | 3.64 | 3.52 | 3.56 |
| | | | Small Diesel | 3.47 | 3.43 | 3.45 | 3.51 | 3.46 | 3.50 |
| 2 | Fuel heat rate (KWh per litre) | | | 3.69 | 3.66 | 3.66 | 3.69 | 3.67 | 3.71 |
| | | | Large Diesel WAF | 3,537 | 3,599 | 3,602 | 3,726 | 3,763 | 3,716 |
| | | | Old Crow | 479 | 520 | 558 | 514 | 528 | 552 |
| | | | Small Diesel | 1,813 | 1,886 | 1,796 | 1,767 | 1,797 | 1,647 |
| 3 | Litres of fuel (000s) | | | 5,828 | 6,004 | 5,956 | 6,007 | 6,088 | 5,915 |
| | | | Large Diesel WAF | 1,486 | 1,715 | 2,397 | 2,773 | 2,931 | 3,249 |
| | | | Old Crow | 557 | 635 | 786 | 809 | 883 | 1,067 |
| | | | Small Diesel | 805 | 934 | 1,220 | 1,305 | 1,412 | 1,399 |
| 4 | Fuel costs ( 000s) | | | 2,848 | 3,284 | 4,403 | 4,886 | 5,226 | 5,715 |
| | | | Large Diesel WAF | (483) | (695) | (1,369) | (1,716) | (1,848) | - |
| | | | Old Crow | (190) | (229) | (360) | (417) | (479) | - |
| | | | Small Diesel | (232) | (331) | (661) | (727) | (845) | - |
| 5 | Fuel Variance | | | (906) | (1,254) | (2,389) | (2,860) | (3,172) | - |
| | | | Large Diesel WAF | 1,002 | 1,020 | 1,028 | 1,058 | 1,083 | 3,249 |
| | | | Old Crow | 366 | 406 | 427 | 392 | 405 | 1,067 |
| | | | Small Diesel | 573 | 603 | 559 | 577 | 567 | 1,399 |
| 6 | Fuel Expense | S.1.1 L.8 | | 1,942 | 2,030 | 2,014 | 2,026 | 2,054 | 5,715 |
| | | | Large Diesel WAF | 42.01 | 47.65 | 66.55 | 74.44 | 77.90 | 87.43 |
| | | | Old Crow | 116.37 | 122.11 | 140.99 | 157.36 | 167.16 | 193.41 |
| | | | Small Diesel | 44.42 | 49.53 | 67.92 | 73.82 | 78.55 | 84.93 |
| 7 | Average cost (cents per litre) | L.4 L.3 | | 48.87 | 54.70 | 73.93 | 81.34 | 85.84 | 96.61 |

The Yukon Electrical Company Limited
An *ATCO* Company

July 10, 2008

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from 1.233 cents per kW.h to 1.860 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after August 1, 2008.

Due to actual fuel prices being significantly higher than fuel prices provided for in rates, the diesel fuel price variance has continued to increase over the past 3 months driving the deficit owing from ratepayers to the companies up to $505,000 at the end of June 2008. This variance will continue to grow with current and rising fuel prices at the existing Rider F rate of 1.233 cents per kWh.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level until the completion of the General Rate Applications. At this point the Rider will be adjusted accordingly.

Yours sincerely,

The Yukon Electrical Company Limited

Jerome Babyn
General Manager

Yukon Energy Corporation

for David Morrison
President and CEO

Encl.

**The Yukon Electrical Company Limited**
**Yukon Energy Corporation**
**Rider F Calculation**
**As At June 30, 2008**
**(Forecast Implementation Date in CIS = August 1, 2008)**

**The Yukon Electrical Company Limited**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | | |
|---|---|---|---|---|---|---|
| Due From (To) Customers - as at June 30, 2008 | | | | | | 504,626 |
| Jul-08 | Estimated Net | | | 150,000 | | |
| Aug-08 | 32.88 | 125.00 | 446,954 | 411,723 | | |
| Sep-08 | 33.94 | 125.00 | 438,421 | 399,243 | | |
| Oct-08 | 33.98 | 125.00 | 473,011 | 430,541 | | |
| Nov-08 | 34.16 | 125.00 | 502,146 | 456,157 | | |
| Dec-08 | 35.00 | 125.00 | 607,319 | 546,617 | | |
| Jan-09 | 33.43 | 125.00 | 504,558 | 462,026 | | |
| Feb-09 | 34.28 | 125.00 | 508,574 | 461,370 | | |
| Mar-09 | 35.38 | 125.00 | 490,743 | 439,826 | | |
| Apr-09 | 32.88 | 125.00 | 427,616 | 393,940 | | |
| May-09 | 33.73 | 125.00 | 400,548 | 365,579 | | |
| Jun-09 | 33.40 | 125.00 | 406,044 | 371,918 | | |
| Jul-09 | 34.92 | 125.00 | 400,198 | 360,507 | | |
| Sub total | | | | 5,249,447 | | 5,249,447 |
| **YECL Shortfall** | | | | | | **5,754,073** |

**Yukon Energy Corporation**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | Secondary Sales Adjmt | |
|---|---|---|---|---|---|---|
| Due From (To) Customers - as at June 30, 2008 | | | | | | - |
| Jul-08 | Estimated Net | | | | (45,000) | |
| Aug-08 | 59.95 | 95.05 | 22,630 | 7,943 | (33,443) | |
| Sep-08 | 59.95 | 95.05 | 24,800 | 8,705 | (44,257) | |
| Oct-08 | 59.95 | 95.05 | 19,207 | 6,742 | (55,273) | |
| Nov-08 | 59.38 | 88.95 | 49,497 | 14,635 | - | |
| Dec-08 | 59.40 | 89.18 | 51,456 | 15,323 | - | |
| Jan-09 | 59.42 | 89.34 | 52,850 | 15,812 | - | |
| Feb-09 | 59.34 | 88.52 | 57,831 | 16,876 | - | |
| Mar-09 | 59.34 | 88.52 | 57,829 | 16,876 | - | |
| Apr-09 | 59.95 | 95.05 | 21,195 | 7,439 | - | |
| May-09 | 59.95 | 95.05 | 19,332 | 6,786 | (58,592) | |
| Jun-09 | 59.95 | 95.05 | 22,321 | 7,835 | (47,841) | |
| Jul-09 | 59.95 | 95.05 | 24,026 | 8,433 | (30,126) | |
| Sub total | | | | 133,405 | (314,531) | (181,126) |
| **YEC Shortfall** | | | | | | **(181,126)** |

**Combined YEC/YECL shortfall** **5,572,947**

2008 - 2009 Forecast Retail Sales (KwH's) August 1, 2008 - July 31, 2009

| | | |
|---|---|---|
| YECL | 271,179,000 | |
| YEC | 28,466,374 | |
| Total | | 299,645,374 |

**Rider F rate** Price per KWH (cents) to recover 100% of shortfall to July 31, 2009 **1.860**

April 16, 2008

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from .9638 cents per kW.h to 1.233 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after May 1, 2008.

Due to actual fuel prices being significantly higher than fuel prices provided for in rates, the diesel fuel price variance has increased over the past 4 months driving the deficit owing from ratepayers to the companies up to $224,616 at the end of March 2008. This variance will continue to grow with current and rising fuel prices at the existing Rider F rate of .9638 cents per kWh.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to April 2009. As in the past, the Companies commit to review the variables impacting Rider F on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Jerome Babyn
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

# The Yukon Electrical Company Limited
# Yukon Energy Corporation
# Rider F Calculation
# As At March 31, 2008
# (Forecast Implementation Date in CIS = May 1, 2008)

**The Yukon Electrical Company Limited**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | |
|---|---|---|---|---|---|
| Due From (To) Customers - as at March 31, 2008 | | | | | 224,616 |
| Apr-08 | Estimated Net | | | 250,000 | |
| May-08 | 33.73 | 96.56 | 446,685 | 280,651 | |
| Jun-08 | 33.40 | 96.56 | 417,188 | 263,478 | |
| Jul-08 | 34.92 | 96.56 | 420,249 | 259,050 | |
| Aug-08 | 32.88 | 96.56 | 414,012 | 263,633 | |
| Sep-08 | 33.94 | 96.56 | 433,963 | 271,764 | |
| Oct-08 | 33.98 | 96.56 | 470,103 | 294,197 | |
| Nov-08 | 34.16 | 96.56 | 547,955 | 341,932 | |
| Dec-08 | 35.00 | 96.56 | 618,229 | 380,612 | |
| Jan-09 | 33.43 | 96.56 | 576,926 | 364,217 | |
| Feb-09 | 34.28 | 96.56 | 514,615 | 320,494 | |
| Mar-09 | 35.38 | 96.56 | 522,506 | 319,693 | |
| Apr-09 | 32.88 | 96.56 | 451,015 | 287,227 | |
| Sub total | | | | 3,896,946 | 3,896,946 |
| **YECL Shortfall** | | | | | **4,121,562** |

**Yukon Energy Corporation**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | Secondary Sales Adjmt | |
|---|---|---|---|---|---|---|
| Due From (To) Customers - as at March 31, 2008 | | | | | | - |
| Apr-08 | Estimated Net | | | (45,000) | - | |
| May-08 | 59.95 | 88.66 | 17,992 | 5,166 | (37,201) | |
| Jun-08 | 59.95 | 88.66 | 21,219 | 6,092 | (30,665) | |
| Jul-08 | 59.95 | 88.66 | 23,017 | 6,608 | (19,236) | |
| Aug-08 | 59.95 | 88.66 | 21,644 | 6,214 | (21,576) | |
| Sep-08 | 59.95 | 88.66 | 23,794 | 6,831 | (28,553) | |
| Oct-08 | 59.95 | 88.66 | 18,087 | 5,193 | (35,660) | |
| Nov-08 | 59.38 | 81.70 | 46,124 | 10,295 | (44,710) | |
| Dec-08 | 59.40 | 82.00 | 48,198 | 10,890 | (48,235) | |
| Jan-09 | 59.42 | 82.21 | 49,749 | 11,336 | (54,111) | |
| Feb-09 | 59.34 | 81.23 | 53,996 | 11,818 | (51,142) | |
| Mar-09 | 59.34 | 81.26 | 54,246 | 11,890 | (47,667) | |
| Apr-09 | 59.95 | 88.66 | 20,189 | 5,796 | (48,644) | |
| Sub total | | | | 53,128 | (467,400) | (414,272) |
| **YEC Shortfall** | | | | | | **(414,272)** |

**Combined YEC/YECL shortfall** **3,707,290**

2008-2009 Forecast Retail Sales (kwh's) - May 1, 2008 - April 30, 2009

| | | |
|---|---|---|
| YECL | 271,266,000 | |
| YEC | 29,304,299 | |
| Total | | 300,570,299 |

**Rider F rate** - price per kwh (cents) to recover 100% of shortfall to April 30, 2009 **1.233418745**

The Yukon Electrical Company Limited
An *ATCO* Company

November 20, 2006

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Acting Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of a decrease in the automatic fuel price adjustment rider (Rider F) from 1.2799 cents per kW.h to .9638 cents per kW.h based on the attached forecast. The decrease will be effective for bills rendered on or after December 1, 2006.

Rider F collections since March 1, 2006 have reduced the accumulated deficit for fuel price variance down from $657,000 so that as of October 31, 2006, the Companies are owed approximately $35,000 in cumulative fuel price variance shortfalls. We expect to incur, on average, charges of approximately $245,000 per month in excess of the forecast fuel prices currently included in rates. This monthly fuel variance is forecast to be offset by a favorable Secondary Sales rate variance averaging $19,000 per month for a combined variance of $226,000 per month.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to November 2007. As in the past, the Companies commit to review the situation on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Doug Tenney
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

WHITEHORSE 2007
JEUX DU CANADA GAMES
OFFICIAL SUPPLIER - FOURNISSEUR OFFICIEL



WHITEHORSE 2007
JEUX DU CANADA GAMES

**The Yukon Electrical Company Limited**
**Yukon Energy Corporation**
**Rider F Calculation**
**As At October 31, 2006**
**(Forecast Implementation Date in CIS = December 1, 2006)**

**The Yukon Electrical Company Limited**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | |
|---|---|---|---|---|---|
| Due From (To) Customers - as at October 31, 2006 | | | | | 34,538 |
| Nov-06 | Estimated Net | | | 74,500 | |
| Dec-06 | 33.26 | 83.56 | 568,107 | 285,767 | |
| Jan-07 | 33.00 | 83.56 | 607,281 | 307,041 | |
| Feb-07 | 34.00 | 83.56 | 561,654 | 278,356 | |
| Mar-07 | 33.48 | 83.56 | 479,987 | 240,377 | |
| Apr-07 | 33.84 | 83.56 | 454,098 | 225,778 | |
| May-07 | 34.18 | 83.56 | 428,642 | 211,663 | |
| Jun-07 | 33.58 | 83.56 | 442,714 | 221,268 | |
| Jul-07 | 33.32 | 83.56 | 411,906 | 206,942 | |
| Aug-07 | 32.79 | 83.56 | 458,014 | 232,534 | |
| Sep-07 | 32.90 | 83.56 | 453,359 | 229,672 | |
| Oct-07 | 33.97 | 83.56 | 447,008 | 221,671 | |
| Nov-07 | 33.50 | 83.56 | 519,092 | 259,857 | |
| Sub total | | | | 2,995,427 | 2,995,427 |
| **YECL Shortfall** | | | | | **3,029,965** |

**Yukon Energy Corporation**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | Secondary Sales Adjmt | |
|---|---|---|---|---|---|---|
| Due From (To) Customers - as at October 31, 2006 | | | | | | - |
| Nov-06 | Estimated Net | | | (50,000) | - | |
| Dec-06 | 59.95 | 78.68 | 11,374 | 2,130 | (25,766) | |
| Jan-07 | 59.95 | 78.68 | 12,083 | 2,263 | (27,665) | |
| Feb-07 | 59.95 | 78.68 | 11,114 | 2,082 | (25,518) | |
| Mar-07 | 59.95 | 78.68 | 10,802 | 2,023 | (23,373) | |
| Apr-07 | 59.95 | 78.68 | 10,167 | 1,904 | (19,081) | |
| May-07 | 59.95 | 78.68 | 9,765 | 1,829 | (15,380) | |
| Jun-07 | 59.95 | 78.68 | 10,793 | 2,021 | (11,997) | |
| Jul-07 | 59.95 | 78.68 | 12,559 | 2,352 | (9,232) | |
| Aug-07 | 59.95 | 78.68 | 11,657 | 2,183 | (10,977) | |
| Sep-07 | 59.95 | 78.68 | 12,861 | 2,409 | (15,320) | |
| Oct-07 | 59.95 | 78.68 | 9,557 | 1,790 | (18,669) | |
| Nov-07 | 59.95 | 78.68 | 10,763 | 2,016 | (23,430) | |
| Sub total | | | | (24,997) | (226,408) | (251,404) |
| **YEC Shortfall** | | | | | | **(251,404)** |
| **Combined YEC/YECL shortfall** | | | | | | **2,778,560** |

2006 - 2007 Forecast Retail Sales (kwh's) - December 1, 2006 - November 30, 2007

| | | | |
|---|---|---|---|
| | YECL | 260,000,000 | |
| | YEC | 28,301,881 | |
| | Total | | 288,301,881 |
| **Rider F rate** | - price per kwh (cents) to recover 100% of shortfall to November 30, 2007 | | **0.963767648** |

**The Yukon Electrical Company Limited**
An ***ATCO*** Company

February 7, 2006

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Acting Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90 and due to the increases in diesel fuel prices, The Yukon Electrical Company Limited and Yukon Energy Corporation are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from 0.7909 cents per kW.h to 1.2799 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after March 1, 2006.

As of January 31, 2006, the Companies are owed approximately $635,000 in cumulative fuel price variance shortfalls. We also expect to incur, on average, approximately $240,000 per month in charges in excess of the forecast fuel prices currently included in rates.

As described in Yukon Energy's 2005 Revenue Requirements Application, this is the first Rider F calculation that includes a component for the variance between the forecast and actual secondary sales rates. As the actual 2005 rate was higher than the forecast rate, a favourable variance of $18,761 was created to offset the cumulative negative fuel variance. Between February 2006 and February 2007, a favourable secondary sales variance of approximately $211,000 has been forecast.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to February 28, 2007. As in the past, the Companies commit to review the situation on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Doug Tenney
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

**The Yukon Electrical Company Limited**
**Yukon Energy Corporation**
**Rider F Calculation**
**As At January 31, 2006**
**(Forecast Implementation Date in CIS = March 1, 2006)**

**The Yukon Electrical Company Limited**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | |
|---|---|---|---|---|---|
| Due From (To) Customers - as at January 31, 2006 | | | | | 675,363 |
| Feb-06 | Estimated Net | | | 50,000 | |
| Mar-06 | 33.48 | 85.92 | 479,987 | 251,695 | |
| Apr-06 | 33.84 | 83.75 | 454,098 | 226,627 | |
| May-06 | 34.18 | 83.84 | 428,642 | 212,877 | |
| Jun-06 | 33.58 | 83.03 | 442,714 | 218,936 | |
| Jul-06 | 33.32 | 84.12 | 411,906 | 209,241 | |
| Aug-06 | 32.79 | 83.20 | 458,014 | 230,874 | |
| Sep-06 | 32.90 | 82.87 | 453,359 | 226,529 | |
| Oct-06 | 33.97 | 82.36 | 447,008 | 216,329 | |
| Nov-06 | 33.50 | 85.08 | 519,092 | 267,759 | |
| Dec-06 | 33.26 | 84.94 | 568,107 | 293,624 | |
| Jan-07 | 33.00 | 83.18 | 612,509 | 307,372 | |
| Feb-07 | 34.00 | 83.35 | 561,654 | 277,151 | |
| Sub total | | | | 2,989,012 | 2,989,012 |
| **YECL Shortfall** | | | | | **3,664,375** |

**Yukon Energy Corporation**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | Secondary Sales Adjmt | |
|---|---|---|---|---|---|---|
| Due From (To) Customers - as at January 31, 2006 | | | | | | (39,554) |
| Feb-06 | Estimated Net | | | (10,000) | (33,620) | |
| Mar-06 | 0.5995 | 80.00 | 21,231 | 16,858 | (29,913) | |
| Apr-06 | 0.5995 | 72.06 | 20,409 | 14,584 | (13,821) | |
| May-06 | 0.5995 | 72.06 | 19,520 | 13,949 | (10,914) | |
| Jun-06 | 0.5995 | 72.06 | 21,602 | 15,437 | (8,921) | |
| Jul-06 | 0.5995 | 72.06 | 24,449 | 17,471 | (7,134) | |
| Aug-06 | 0.5995 | 72.06 | 22,837 | 16,319 | (7,227) | |
| Sep-06 | 0.5995 | 72.06 | 24,852 | 17,759 | (10,856) | |
| Oct-06 | 0.5995 | 72.06 | 19,473 | 13,916 | (13,050) | |
| Nov-06 | 0.5995 | 72.06 | 20,682 | 14,779 | (17,004) | |
| Dec-06 | 0.5995 | 72.06 | 22,730 | 16,243 | (19,363) | |
| Jan-07 | 0.5995 | 72.06 | 24,383 | 17,424 | (20,241) | |
| Feb-07 | 0.5995 | 72.06 | 22,773 | 16,274 | (19,211) | |
| Sub total | | | | 181,014 | (211,274) | (30,260) |
| **YEC Shortfall** | | | | | | **(69,815)** |

**Combined YEC/YECL shortfall** **3,594,561**

2006 - 2007 Forecast Retail Sales (kwh's) - March 1, 2006 - February 28, 2007

| | | |
|---|---|---|
| YECL | 252,400,000 | |
| YEC | 28,453,016 | |
| Total | | 280,853,016 |

**Rider F rate** - price per kwh (cents) to recover 100% of shortfall to February 28, 2007 **1.279872601**

June 15, 2005

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Mr. Brian Morris, Chair

Dear Sir,

Pursuant to Section 8 of OIC 1995/90 and due to the increases in diesel fuel prices, The Yukon Electrical Company Limited and Yukon Energy Corporation are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from $ 0.5867 per kW.h to $ 0.7909 per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after July 1, 2005.

The Companies are currently owed approximately $290,742 in cumulative price variance shortfalls and also expect to incur, on average, approximately $155,000 per month in charges in excess of the forecast fuel prices currently recovered from rates.

The Companies also note that any change to the 2005 Yukon Energy diesel price arising from a decision by the YUB regarding Yukon Energy's 2005 Revenue Requirement and Related Matters Application will impact the 2005 fuel variance as of January 1, 2005. As well, the possible use of Rider F to normalize the revenue from Secondary Sales customers will impact the determination of the rider. The impact arising from a Board decision on these matters is expected to be small in relation to the size of the Rider calculated. However, until a decision is rendered by the Board, no impacts will be included in the current determination of Rider F but rather will be included once an Order has been rendered.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to June 30, 2006. As in the past, the Companies commit to review the situation on an ongoing basis to ensure the balance in the account is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Doug Tenney
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

**The Yukon Electrical Company Limited**
**Yukon Energy Corporation**
**Rider F Calculation**
**June 1, 2005**

**The Yukon Electrical Company Limited**

| | | Fuel Price in Rates (Cents) | Forecast Fuel Price (Cents) | Forecast Litres | Monthly Shortfall | |
|---|---|---|---|---|---|---|
| Due (to) from customers May 31, 2005 | | | | | | 284,507.85 |
| Anticipated shortfall | | | | | | |
| June | 2005 | Estimated Net Variance after collections | | | $ 40,000.00 | |
| July | 2005 | 33.32 | 65.09 | 417,523 | $ 132,633.40 | |
| August | 2005 | 32.79 | 64.18 | 415,423 | $ 130,390.77 | |
| September | 2005 | 32.90 | 64.30 | 441,969 | $ 138,760.98 | |
| October | 2005 | 33.97 | 66.20 | 448,083 | $ 144,410.20 | |
| November | 2005 | 33.50 | 65.78 | 467,751 | $ 150,967.78 | |
| December | 2005 | 33.26 | 65.10 | 511,936 | $ 162,987.42 | |
| January | 2006 | 33.00 | 64.76 | 580,908 | $ 184,517.01 | |
| February | 2006 | 34.00 | 66.52 | 517,562 | $ 168,308.95 | |
| March | 2006 | 33.48 | 65.57 | 482,610 | $ 154,906.21 | |
| April | 2006 | 33.84 | 66.27 | 439,921 | $ 142,644.69 | |
| May | 2006 | 34.18 | 66.92 | 404,413 | $ 132,417.15 | |
| June | 2006 | 33.58 | 65.51 | 416,900 | $ 133,092.32 | |
| **Total** | | | | | | $ 1,816,036.89 |
| Due (to) from customers June 30, 2006 | | | | | | $ 2,100,544.74 |

**Yukon Energy Corporation**

| | | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | |
|---|---|---|---|---|---|---|
| Due (to) from customers May 31, 2005 | | | | | | 6,234.00 |
| Anticipated shortfall | | | | | | |
| June | 2005 | Estimated Net Variance after collections | | | $ (11,000.00) | |
| July | 2005 | 32.78 | 66.15 | 18,867 | $ 6,295.92 | |
| August | 2005 | 32.78 | 66.15 | 18,971 | $ 6,330.62 | |
| September | 2005 | 32.78 | 66.15 | 19,940 | $ 6,653.98 | |
| October | 2005 | 32.78 | 66.15 | 16,315 | $ 5,444.32 | |
| November | 2005 | 32.78 | 66.15 | 17,383 | $ 5,800.71 | |
| December | 2005 | 32.78 | 66.15 | 18,957 | $ 6,325.95 | |
| January | 2006 | 32.78 | 66.15 | 21,313 | $ 7,112.15 | |
| February | 2006 | 32.78 | 66.15 | 18,655 | $ 6,225.17 | |
| March | 2006 | 32.78 | 66.15 | 20,477 | $ 6,833.17 | |
| April | 2006 | 32.78 | 66.15 | 20,339 | $ 6,787.12 | |
| May | 2006 | 32.78 | 66.15 | 19,025 | $ 6,348.64 | |
| June | 2006 | 32.78 | 66.15 | 20,909 | $ 6,977.33 | |
| Total | | | | | | 66,135.09 |
| Due (to) from customers June 30, 2006 | | | | | | 72,369.09 |
| Combined YEC/YECL shortfall | | | | | | 2,172,913.82 |

| | | |
|---|---|---|
| Forecast KWH - July 1, 2005 - June 30, 2006 | | |
| YECL | 246,627,980 | |
| YEC | 28,098,569 | |
| 2005 - 2006 planned kwh's - July 1, 2005 - June 30, 2006 | | 274,726,550 |
| Price per kwh (cents) to recover 100% of shortfall to June 30, 2006 | | 0.790936961 |

February 10, 2003

Yukon Utilities Board
P.O. Box 6070
Whitehorse, Yukon
Y1A 1A3

Attention: Mr. Brian Morris, Chair

Dear Sir,

Pursuant to Section 8 of OIC 1995/90 and due to the increases in diesel fuel prices, The Yukon Electrical Company Limited and Yukon Energy Corporation are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from 0.2214 per kW.h. to 0.5867 per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after March 1, 2003.

The Companies are currently owed approximately $412,671 in cumulative price variance shortfalls and also expect to incur on average approximately $87,000 per month in charges in excess of the forecast fuel prices.

Based on the attached forecast, the Companies expect Rider F to continue through to February 28, 2004. As in the past, the Companies commit to review the situation on an ongoing basis to ensure there is no over-collection from customers.

Yours sincerely,

The Yukon Electrical Company Limited

Paul Goguen
General Manager

Yukon Energy Corporation

Don Willems
President and CEO

Encl.

**The Yukon Electrical Company Limited**
**Yukon Energy Corporation**
**Rider F Calculation**

**The Yukon Electrical Company Limited**

| | | January 31, 2003 Fuel Price in Rates | Actual Fue Price | Forecast Litres | Monthly Shortfall | |
|---|---|---|---|---|---|---|
| Balance as of Jan 31, 03 | | | | | | 243,296.59 |
| Anticipated shortfall | | | | | | |
| Feb | 2003 | 32.79 | 49.54 | 415,423 | 69,583.35 | |
| March | 2003 | 32.90 | 48.75 | 441,969 | 70,052.09 | |
| April | 2003 | 33.97 | 49.34 | 448,083 | 68,870.36 | |
| May | 2003 | 33.50 | 49.86 | 467,751 | 76,524.06 | |
| June | 2003 | 33.26 | 48.77 | 511,936 | 79,401.27 | |
| July | 2003 | 33.00 | 48.42 | 580,908 | 89,576.01 | |
| August | 2003 | 34.00 | 47.66 | 517,562 | 70,698.97 | |
| Sept | 2003 | 33.48 | 47.75 | 482,610 | 68,868.45 | |
| Oct | 2003 | 33.84 | 49.33 | 439,921 | 68,143.76 | |
| Nov | 2003 | 34.18 | 48.90 | 404,413 | 59,529.59 | |
| December | 2003 | 33.58 | 48.37 | 416,900 | 61,659.51 | |
| January | 2004 | 33.32 | 48.06 | 417,523 | 61,542.89 | |
| Feb | 2004 | 32.79 | 49.54 | 415,423 | 69,583.35 | |
| Total | | | | | | 914,033.67 |
| Due (to) from customers February 28, 2004 | | | | | | 1,157,330.26 |

**Yukon Energy Corporation**

| | Fuel Price in Rates | Forecast Fuel Price | Forecast Litres | Monthly Shortfall | |
|---|---|---|---|---|---|
| Due From (To) Customers - Actual Balance as at January 31, 2003 | | | | | 169,375 |
| Feb-03 | 32.78 | 49.52 | 367,393 | 61,502 | |
| Mar-03 | 32.78 | 49.52 | 342,231 | 57,289 | |
| Apr-03 | 32.78 | 49.52 | 316,400 | 52,965 | |
| May-03 | 32.78 | 43.00 | 32,503 | 3,322 | |
| Jun-03 | 32.78 | 43.00 | 35,629 | 3,641 | |
| Jul-03 | 32.78 | 43.00 | 35,295 | 3,607 | |
| Aug-03 | 32.78 | 43.00 | 37,324 | 3,815 | |
| Sep-03 | 32.78 | 43.00 | 41,156 | 4,206 | |
| Oct-03 | 32.78 | 43.00 | 32,791 | 3,351 | |
| Nov-03 | 32.78 | 49.52 | 36,072 | 6,038 | |
| Dec-03 | 32.78 | 49.52 | 38,026 | 6,366 | |
| Jan-04 | 32.78 | 49.52 | 44,577 | 7,462 | |
| Feb-04 | 32.78 | 49.52 | 38,837 | 6,501 | |
| Total | | | | | 220,066.06 |
| Due (to) from customers February 28, 2004 | | | | | 389,441.06 |
| Combined YEC/YECL shortfall | | | | | 1,546,771.32 |
| 2003 - 2004 planned kwh's - March 1 - Feb 28 | | | | | |
| YECL | | | | 235,387,745 | |
| YEC | | | | 28,248,437 | |
| Total | | | | | 263,636,182 |
| Price per kwh (cents) to recover 100% of shortfall to Feb 28, 2004 | | | | | 0.586706769 |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Diesel Generation and Fuel Summary Breakdown by Rate Zone - June 30, Rider F Prices**
**( 000s)**

| Line No. | Description | Cross Ref. | Rate Zone | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 |
|---|---|---|---|---|---|---|---|---|---|
| | | | Large Diesel WAF | 13,532 | 13,751 | 13,650 | 14,156 | 14,255 | 14,192 |
| | | | Old Crow | 1,690 | 1,771 | 1,962 | 1,811 | 1,853 | 1,967 |
| | | | Small Diesel | 6,291 | 6,466 | 6,195 | 6,197 | 6,226 | 5,767 |
| 1 | Total Diesel Generation (MWh) | S.3.2 L.8 & 9 | | 21,513 | 21,988 | 21,807 | 22,164 | 22,334 | 21,927 |
| | | | Large Diesel WAF | 3.83 | 3.82 | 3.79 | 3.80 | 3.79 | 3.82 |
| | | | Old Crow | 3.60 | 3.50 | 3.56 | 3.64 | 3.52 | 3.56 |
| | | | Small Diesel | 3.47 | 3.43 | 3.45 | 3.51 | 3.46 | 3.50 |
| 2 | Fuel heat rate (KWh per litre) | | | 3.69 | 3.66 | 3.66 | 3.69 | 3.67 | 3.7 |
| | | | Large Diesel WAF | 3,537 | 3,599 | 3,602 | 3,726 | 3,763 | 3,716 |
| | | | Old Crow | 479 | 520 | 558 | 514 | 528 | 552 |
| | | | Small Diesel | 1,813 | 1,886 | 1,796 | 1,767 | 1,797 | 1,647 |
| 3 | Litres of fuel (000s) | | | 5,828 | 6,004 | 5,956 | 6,007 | 6,088 | 5,915 |
| | | | Large Diesel WAF | 1,486 | 1,715 | 2,397 | 2,773 | 2,931 | 4,645 |
| | | | Old Crow | 557 | 635 | 786 | 809 | 883 | 690 |
| | | | Small Diesel | 805 | 934 | 1,220 | 1,305 | 1,412 | 2,059 |
| 4 | Fuel costs ( 000s) | | | 2,848 | 3,284 | 4,403 | 4,886 | 5,226 | 7,394 |
| | | | Large Diesel WAF | (483) | (695) | (1,369) | (1,716) | (1,848) | - |
| | | | Old Crow | (190) | (229) | (360) | (417) | (479) | - |
| | | | Small Diesel | (232) | (331) | (661) | (727) | (845) | - |
| 5 | Fuel Variance | | | (906) | (1,254) | (2,389) | (2,860) | (3,172) | - |
| | | | Large Diesel WAF | 1,002 | 1,020 | 1,028 | 1,058 | 1,083 | 4,645 |
| | | | Old Crow | 366 | 406 | 427 | 392 | 405 | 690 |
| | | | Small Diesel | 573 | 603 | 559 | 577 | 567 | 2,059 |
| 6 | Fuel Expense | S.1.1 L.8 | | 1,942 | 2,030 | 2,014 | 2,026 | 2,054 | 7,394 |
| | | | Large Diesel WAF | 42.01 | 47.65 | 66.55 | 74.44 | 77.90 | 125.00 |
| | | | Old Crow | 116.37 | 122.11 | 140.99 | 157.36 | 167.16 | 125.00 |
| | | | Small Diesel | 44.42 | 49.53 | 67.92 | 73.82 | 78.55 | 125.00 |
| 7 | Average cost (cents per litre) | L.4 L.3 | | 48.87 | 54.70 | 73.93 | 81.34 | 85.84 | 125.00 |

## YEC-YECL-17

**Reference:** Depreciation

**Requests:** Depreciation

(a) Please provide the retainer letter and any terms of reference given to Gannett Fleming with respect to the Depreciation Study as at December 31, 2007.

(b) Was Gannett Fleming directed to use the equal life group (ELG) method? Did YECL have any influence on Mr. Kennedy's decision to use the ELG method?

(c) Did YECL or Gannett Fleming consider the average service life (ASL) method? If not, why not? If yes, why was it rejected?

(d) Provide a detailed summary of any discussion with Mr. Kennedy on all matters discussed with him in relation to the ASL method including all discussion regarding the issue of YECL using a different depreciation method than YEC.

(e) With the aid of Gannett Fleming please provide an estimate of the YECL depreciation expense for the test years assuming the ASL method were approved by the YUB instead of the ELG method? Please indicate the impact on each test year depreciation if this method was adopted.

(f) With the aid of Gannett Fleming please provide a summary of regulated utilities in Canada who use depreciation rates based on the ELG method and utilities who use depreciation rates based on the ASL method.

(g) Please discuss YECL's accounting approach to future removal and site restoration costs. Indicate the impact on each test year depreciation expenses if the Board directs YECL to treat future removal and site restoration costs in the same way as it directed YEC to treat these costs in Order 2005-12.

(h) Please identify any asset lives used in the Depreciation Study that are less than the asset lives used (and approved by the YUB) for YEC for comparable assets (e.g. wood poles) in their last GRA, and provide an explanation and justification for each such shorter asset life adopted in the Depreciation Study filed in YECL's Application.

**Response:**

(a) Please refer to YEC-YECL-17(a) Attachment 1.

(b&c) YECL has incorporated the use of the Equal Life Group (ELG) procedure into the calculation of depreciation rates for a number of years. The use of the ELG has been approved by the Yukon Utilities Board ( YUB ) in these previous depreciation studies.

The ELG procedure is widely used, and in the opinion of Gannett Fleming, does provide a superior matching of the consumption of service value of utility assets to the depreciation expense component of the revenue requirement**.** In the depreciation study completed by Gannett Fleming on behalf of Yukon Energy Corporation the following is stated at page I-5:

> *"There are primarily two different approaches used by utilities in Canada and the United States in calculating depreciation, the equal life group procedure and the average service life procedure. Both procedures have been approved and adopted by regulatory authorities across North America. Although, in the opinion of Gannett Fleming, the equal life procedure is superior to the average service life procedure in matching depreciation expense with the loss of service value, the average life procedure is also a widely accepted method. The management of Yukon Energy directed Gannett Fleming to calculate annual and accrued depreciation using the average service life procedure in order to ensure toll stability" [emphasis added].*

As indicated above, Gannett Fleming recognizes that both the Average Service Life (ASL) and ELG procedures will result in the complete recovery of investment in utility assets, and both are widely used in regulatory jurisdictions throughout North America. However, given the prior approval of the use of the ELG procedure for Yukon Electrical by the YUB, the superiority of the ELG procedure, the wide acceptance of the ELG procedure, and the absence of any other business or economic considerations, the use of the ASL procedure was not considered appropriate by either Yukon Electrical or Gannett Fleming.

(d) Gannett Fleming did not discuss this specific issue with Yukon Electrical. The reasons for the depreciation procedures used in the YEC depreciation study are considered as confidential between Gannett Fleming and YEC, and were not discussed with Yukon Electrical. However, Gannett Fleming did notify Yukon Electrical that a depreciation study had been completed by Gannett Fleming for YEC that may have included different depreciation methods than those considered appropriate by Yukon Electrical.

Gannett Fleming notes that every depreciation study presents unique circumstances which may influence the selection of the depreciation parameters that are appropriate for that specific utility at the specific time the depreciation. Such is the case for both the current Yukon Electrical depreciation study and the study completed by Gannett Fleming for YEC.

(e) If the ASL method were approved by the YUB the forecast depreciation expense for 2008 would be 3,974,000, a reduction of 391,000 from the ELG method. The forecast for 2009 would be 4,418,000, a reduction of 419,000 from the ELG method. The General Provision would be reduced by 217,000 in 2008 and by 245,000 in 2009. The amortization of differences would be reduced by 176,000 in both years.

(f) The following are Canadian regulatory jurisdictions where Gannett Fleming is aware that the ELG procedure as been approved for use in the calculation of depreciation expense to be included in tolls:

- Alberta Utilities Commission most utilities regulated by the AUC incorporate the use of the ELG procedure.
- Saskatchewan Public Utilities Commission - has approved the ELG procedure in tolls for SaskEnergy.
- Yukon Utilities Board in previous studies for Yukon Electrical and YEC
- Nova Scotia Public Utilities Board in an application by Nova Scotia Power
- New Brunswick Board of Public Utility Commissioners in an application of NB Power for Distribution assets
- The Canadian Radio and Television Commission

(g) Yukon Electrical proposes to continue the previously approved method of providing for net salvage requirements wherein the estimated costs of net

salvage are recovered through depreciation expense over the period in which the asset is providing utility service. In this manner the customers who receive the benefit of the asset in utility service fund the costs associated with the asset, including the net salvage. This approach is widely accepted, in both previous Decisions of this Board and throughout North America. The method, as proposed in this application, is the method considered by Gannett Fleming to best comply with the depreciation objective to recover the service value of the asset over its estimated service life, and to best comply with regulatory fairness.

Section 8.1 of the Reasons for Decision associated with Board Order 2005-12 outlines the issues related to the treatment of net salvage costs related to Yukon Energy Corporation. At page 48 of the Reasons for Decision the Board states:

> *"The Board is of the view that if there is no longer a need for YEC to collect amounts for annual appropriation to the FRSR reserve, then consistent with section 3110 of the CICA Handbook, YEC should comply with GAAP and remove these charges from annual revenue requirements."*

This decision appears to be based on two critical facts related to YEC. Namely, that the company has recorded an Asset Retirement Obligation related to the legal requirement for the removal of facilities in compliance with Section 3110 of the CICA handbook, and secondly, that the company has recorded FRSR requirements into a separate balance sheet account. Neither of these facts is consistent with the circumstances of Yukon Electrical. Firstly, Yukon Electrical has not recorded any Asset Retirement Obligations in accordance with Section 3110 of the CICA handbook. Secondly, a separate FRSR fund (or even a separate balance sheet fund for net salvage) has not been developed for net salvage requirements. As such there is no FRSR fund to draw down as is the circumstance of YEC. Therefore, the circumstances relating to Board Decision 2005-12 are not consistent with the facts of this YEC application.

(h) Please refer to YEC-YECL-17(h) Attachment 1, which indicates the following results:

- Yukon Electrical has 6 accounts with an estimated average service life longer than YEC by at least 10 ;
- Yukon Electrical has 10 accounts with an estimated average service life shorter than YEC by at least 10
- The average service life estimate selected by both companies is within 10 in 8 accounts

The selection of average service life is based on a number of considerations as follows:

- The historic trends of retirements based on a mortality study;
- Review of the company operating and maintenance practices as determined from interviews with operational and engineering staff;
- Management polices with regard to the replacement of assets;
- Industry trends with regard to technological and manufacturing trends;
- Gannett Fleming professional judgment and experience; and
- The currently approved lives of the company
- The currently approved lives of peer companies.

In the circumstance of the 10 accounts where Yukon Electrical is recommending a life shorter than the average service life as currently approved for YEC, the following is a summary of the primary force that drove the average service life recommendation.

The average service life selection in Accounts 446.0 Accessory Electrical Equipment; 477.1 Distribution Substation Equipment, and 479.1 Line Transformers were based on the operational interviews. The actual mortality experience was limited and was not sufficient upon which to base the life estimation. The process used to select the average service life in these accounts was to develop a survivor curve (which resulted in only limited results), review of the currently approved average service life estimate and discussions with operational personal.

The average service life estimate for accounts 473 Poles, Towers and Fixtures; 478.1 Street Light and signal systems; and 478.2 Sentinel Lights was based on the mortality study of historic retirement patterns. While the mortality study of these accounts resulted in incomplete IOWA survivor curves, a period of significant retirement history was observed in each of the accounts. In these accounts the period of significant retirement history was followed by a period of limited plant being exposed to retirement activity. In these circumstances the period of reduced plant exposures was not ignored but the IOWA curves were fit through the period of meaningful plant exposures.

The average service life of account 482.0 Structures and Improvements was based on the mortality study which did develop a complete survivor curve. The results of the mortality study were confirmed by company operational staff.

With regard to the average service life selections for account 483.0 Office furniture and Equipment; account 485.0 Tools and Instruments; and account 486.0 Communications Equipment, reflect the increased digital nature of the assets. Gannett Fleming has witnessed a trend over the past few years of reductions to the average service lives of these accounts as mechanical equipment has been replaced by digital and often multifunctional assets. The digital nature of these assets has had a life shortening impact on these accounts.

In each of the above cases, Gannett Fleming did consider the average life estimate developed for YEC, as YEC was used as a peer company to which to compare the average service life recommendations. In the view of Gannett Fleming, while the lives for these accounts are shorter, they are within a reasonable band for which long life assets can be expended to last. As indicated in YEC-YECL-17(h) Attachment 1 there are also a number of accounts for which the Yukon Electrical average service life estimates are longer than the YEC estimates. However, in these accounts Gannett Fleming also felt that the life estimates were also within a band of reasonableness.

**YEC-YECL-17(a)**
**Attachment 1**
**Page 1 of 1**

## Kennedy, Larry E.

**From:** doug.baer@atcoelectric.com
**Sent:** December 21, 2007 5:20 PM
**To:** Kennedy, Larry E.
**Subject:** Yukon Electrical Depreciation Study

Larry,

As discussed we request that you conduct a complete depreciation study for the Yukon Electrical Company to be included in our 2008 general rate application. I will forward our data files to you early in the new year.

Have a great Christmas season!!

Doug Baer
(780) 420-8020
Fax (780) 420-7120

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Yukon Electrical Company Limited
Comparison of YECL Average Service Life Estimates to Those Approved for YEC

| YECL Account | | | | YEC Account | | |
|---|---|---|---|---|---|---|
| Account | Description | Estimated Survivor Curve | | Account | Description | Estimated Survivor Curve |
| 425.0 | Hydro Equipment | 30-R3 | | 140003.700 | Misc. Power Plant Equip | 30-R2 |
| 442.0 | Structures and Improvements | 40-R2.5 | | 140004.200 | Structures and Improvements | 40-R3 |
| 444.0 | Fuel Holders, Products and ACC | 35-R4 | Longer | 140004.403 | Fuel Holders, Products and ACC | 25-R2 |
| 445.0 | Gen. Equipment and Prime Movers | 27-R2.5 | | 140004.500 | Gen. Equipment and Prime Movers | 30-R2 |
| 446.0 | Accessory Electrical Equipment | 35-R3 | Shorter | 140003.600 | Accessory Electrical Equipment | 45-R3 |
| 447.0 | Misc. Power Plant Equipment | 35-R3 | Longer | 140004.700 | Misc. Power Plant Equipment | 30-R2 |
| 457.0 | Substation Equipment - Transmission | 40-R4 | | 140006.710 | Substation Equipment - Transmission | 40-R2.5 |
| 471.0 | Land Rights | 75-R3 | Longer | 140002.106 | Land Rights | 50-R2.5 |
| 473.0 | Poles, towers & Fixtures | 40-R3 | Shorter | 140008.300 | Poles and Fixtures | 45-R3 |
| 474.0 | Overhead Conductor | 40-R3 | | 140008.410 | Overhead Costs | 40-R2 |
| 474.1 | Overhead Services | 40-R3 | | 140008.410 | Overhead Costs | 40-R2 |
| 475.0 | Underground conduit | 50-R4 | Longer | 140008.510 | Underground Services | 40-R2.5 |
| 475.1 | Underground Services | 40-R4 | | 140008.510 | Underground Services | 40-R2.5 |
| 476.1 | Meters | N A | | 140008.610 | Meters | 30-R2 |
| 476.3 | AMR Meters | 25-S2 | | N A | | |
| 477.1 | Substation Equipment - Distribution | 35-R3 | Shorter | 140008.710 | Substation Equipment - Distribution | 40-R2 |
| 478.1 | Street Lights and Signal Systems | 25-R3 | Shorter | 140008.815 | Street Lights | 40-R2 |
| 478.2 | Sentinel Lights | 23-R2 | Shorter | 140008.961 | Sentinel Lights | 30-L2 |
| 479.1 | Line Transformers | 35-R3 | Shorter | 140008.905 | Line Transformers | 40-R2.5 |
| 482.0 | Structures and Improvements - General Plant | 32-R4 | Shorter | 140009.211 | Building and Improvements | 40-R2.5 |
| 483.0 | Office Furntiure and Equipment | 15-SQ | Shorter | 140009.202 | Office Furntiure and Equipment | 20-SQ |
| 483.2 | Computer Equipment and Acc. | 5-SQ | | 140009.320 | Computer Hardware | 5-SQ |
| 484.0 | Transportation and Mobile Equipment | 10-R0.5 | Longer | 140014.411 | Utility Vehicles | 7-L2 |
| 485.0 | Tools and Instruments | 15-SQ | Shorter | 140009.505 | Tools and Instruments | 20-SQ |
| 486.0 | Communications Equipment | 15-SQ | Shorter | 140009.605 | Communications Equipment | 20-L4 |
| 488.2 | Houses | 40-R3 | Longer | 140009.820 | Company Owned Houses | 30-R3 |

YECL has 5 accounts with an estimated average service life longer than YEC by at least 10
YECL has 11 accounts with an estimated average service life shorter than YEC by at least 10
The average service life estimate is within 10 in 8 accounts

**YEC-YECL-18**

**Reference:** Automated Meter Reading

**Requests:**

(a) Please provide the business case for conversion to AMR system, including any cost-benefit analysis undertaken.

(b) Please provide all internally generated documents including reports done for or by senior management to justify this capital project.

**Response:**

(a&b) Please refer to YUB-YECL-15(c) Attachment 1.

## YEC-YECL-19

**Reference:** New Customer Care and Billing System

**Requests:**

(a) Please provide the business case for the new customer care and billing system conversion including any cost-benefit analysis undertaken.

(b) Please provide all internally generated documents including reports done for or by senior management to justify this capital project.

(c) Please provide the amortization periods for the legacy systems that are being replaced with the new customer care and billing system.

**Response:**

(a) Please refer to YUB-YECL-16(b) Attachment 1.

(b) Please refer to YUB-YECL-16(b) Attachment 1.

(c) There is no amortization period for the legacy billing system as Yukon Electrical does not have any assets or accumulated amortization associated with the legacy system.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



## YEC-YECL-20

**Reference:** Johnson's Crossing

**Requests:**

(a) Please confirm the rate proposed to be charged for Johnson's Crossing.

(b) Please provide justification for rate and explain why it is fair and reasonable.

**Response:**

(a) As per Schedule 2.1 lines 32-37, there is no new rate proposed for Yukon Electrical's wholesale sales to Yukon Energy at Johnson's Crossing and the Marsh Lake Control Structure. Similar to retail rates, the wholesale rates of 20 cents per kWh and 6.84 cents a kWh will continue until such time as a Phase II Application is completed and new rates are approved by the Board. Yukon Electrical notes the Riders R and G were not proposed to be applicable to the wholesale rate charged by Yukon Electrical to Yukon Energy.

(b) Yukon Electrical and Yukon Energy jointly filed their 1996 1997 GRA that incorporated the Johnson's Crossing rate into their respective wholesale sales and purchased power revenue requirements. Both companies were effectively held whole. Since that point in time, Yukon Energy as part of its 2005 Required Revenues and Related Matters Application updated its purchased power forecast based on the above noted rates. (Please refer to Schedule 12, line 18 of Yukon Energy's 2005 Application where 38,000 was forecast for purchased power.) Until such time as a formal cost of service is completed for the wholesale as well as retail rates as part of a Phase II Application, the current approach of Yukon Electrical and Yukon Energy forecasting their respective revenues and expenses at the existing rates is fair and reasonable.

## YEC-YECL-21

**Reference:** Additions to Rate Base

**Requests:**

(a) With reference to any existing and applicable policy on capital expenditures, please provide a brief description and justification of all capital projects over 500,000 undertaken from 1996 to 2006 that will continue to have costs in rate base during 2008 or 2009, and indicate the amount of such costs in forecast rate base in 2008 and 2009.

(b) For each of the capital projects in (a) please provide the business case and all internally generated documents including reports done for or by senior management to justify this capital project.

(c) Please provide a continuity schedule for gross plant in service showing capital additions and disposals for each year (1996-2009).

(d) Please provide a continuity schedule for accumulated amortization, opening balance and fixed asset amortization.

**Response:**

(a&b) Please refer to YEC-YECL-25(a) Attachment 1 for summary of capital additions greater than 100,000.

(c&d) Please refer to YEC-YECL-21(c) Attachment 1.

**Yukon Electical**
**Continuity Schedule of Property, Plant and Equipment**
**( 000's)**

| Line No. | Description | Cross Ref. | Actual 1996 | Actual 1997 | Actual 1998 | Actual 1999 | Actual 2000 | Actual 2001 | Actual 2002 | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Property, Plant and Equipment** | | | | | | | | | | | | | | | |
| 2 | Balance at beginning of year | | 60,977 | 65,063 | 69,919 | 73,230 | 76,617 | 79,377 | 83,749 | 87,141 | 91,263 | 96,282 | 102,602 | 109,232 | 116,451 | 126,076 |
| 3 | Additions | S.9.1 L.25 | 4,437 | 5,240 | 4,316 | 4,598 | 3,441 | 4,736 | 3,893 | 4,603 | 5,358 | 6,623 | 6,872 | 7,645 | 9,975 | 13,544 |
| 4 | Retirement and disposals | S.8.7 L.20 | (351) | (384) | (1,005) | (1,211) | (681) | (364) | (501) | (481) | (339) | (303) | (242) | (426) | (351) | (1,165) |
| 5 | | S.7.2, 7.3 L.50 | 4,086 | 4,856 | 3,311 | 3,387 | 2,760 | 4,372 | 3,392 | 4,122 | 5,019 | 6,320 | 6,630 | 7,219 | 9,624 | 12,379 |
| 6 | Balance at end of year | S.7.2, 7.3 L.52 | 65,063 | 69,919 | 73,230 | 76,617 | 79,377 | 83,749 | 87,141 | 91,263 | 96,282 | 102,602 | 109,232 | 116,451 | 126,076 | 138,455 |
| 7 | Construction-in-progress | S.9.1 L.26 | 333 | 168 | 23 | 159 | 916 | 182 | 363 | 609 | 934 | 427 | 871 | 1,035 | 620 | 580 |
| 8 | Total Property, Plant and Equipment | S.8.5 L.2 | 64,730 | 69,751 | 73,207 | 76,458 | 78,461 | 83,567 | 86,778 | 91,872 | 97,216 | 103,029 | 110,103 | 117,486 | 126,696 | 139,035 |
| 9 | **Accumulated Depreciation** | | | | | | | | | | | | | | | |
| 10 | Balance at beginning of year | | 21,754 | 23,867 | 26,019 | 28,019 | 30,059 | 32,285 | 34,770 | 37,432 | 40,001 | 43,126 | 46,441 | 49,959 | 53,768 | 57,693 |
| 11 | Depreciation expense | S.7.1 L.4 | 2,407 | 2,650 | 2,795 | 2,873 | 3,023 | 3,110 | 3,244 | 3,355 | 3,481 | 3,727 | 3,901 | 4,171 | 4,365 | 4,837 |
| 12 | Depreciation capitalized | | 57 | 13 | 5 | 13 | 14 | 10 | 18 | 20 | 18 | 26 | 21 | 24 | 24 | 24 |
| 13 | Retirements and dismantling | | (351) | (511) | (800) | (846) | (811) | (635) | (600) | (806) | (374) | (438) | (404) | (386) | (464) | (1,240) |
| 14 | Balance at end of year | S.8.5 L.4 | 23,867 | 26,019 | 28,019 | 30,059 | 32,285 | 34,770 | 37,432 | 40,001 | 43,126 | 46,441 | 49,959 | 53,768 | 57,693 | 61,314 |
| 15 | Net Property, Plant and Equipment | | 40,863 | 43,732 | 45,188 | 46,399 | 46,176 | 48,797 | 49,346 | 51,871 | 54,090 | 56,588 | 60,144 | 63,718 | 69,002 | 77,720 |

## YEC-YECL-22

**Reference:** Contributions in Aid of Construction Requests**:**

**Requests:**

(a) Please provide a continuity schedule for YECL of Contributions in Aid of Construction for the years 1996 to 2009 segregating additions and amortizations.

(b) Please provide contributions from customers since 1996 (gross balance as of December 31, 2007).

(c) By component please confirm which component of the company's investment policy with regard to maximum utility investment was used to determine YECL's investment in each project.

(d) If the company's investment policy was not followed please provide a detailed explanation as to how YECL derived its investment.

**Response:**

(a&b) Please refer to YEC-YECL-22(a) Attachment 1.

(c) Yukon Electrical follows the current Electric Service Regulations (ESR), Schedule B Page 25, effective October 18, 2005. Prior to 2005 the Yukon Electrical followed the ESA effective March 19, 1996. Please refer to Attachment YEC-YECL-22(c) Attachment 1 and Attachment YEC-YECL-22(c) Attachment 2.

(d) Yukon Electrical follows the investment policy that has been approved by the Board.

**Yukon Electical**
**Continuity Schedule of Contributions in Aid of Construction**
**( 000's)**

| Description | Actual 1996 | Actual 1997 | Actual 1998 | Actual 1999 | Actual 2000 | Actual 2001 | Actual 2002 | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Contributions in Aid of Construction** | | | | | | | | | | | | | | |
| Prior Year Gross Contributions | 16,511 | 17,789 | 20,339 | 21,277 | 22,243 | 23,686 | 24,566 | 25,781 | 27,951 | 29,590 | 31,445 | 33,634 | 36,205 | 38,765 |
| Net Additions to property | 1,278 | 2,550 | 938 | 969 | 1,443 | 880 | 1,215 | 2,170 | 1,639 | 1,855 | 2,189 | 2,571 | 2,560 | 2,506 |
| Current Year Gross Contributions | 17,789 | 20,339 | 21,277 | 22,246 | 23,686 | 24,566 | 25,781 | 27,951 | 29,590 | 31,445 | 33,634 | 36,205 | 38,765 | 41,271 |
| **Accumulated Amortization** | | | | | | | | | | | | | | |
| Prior Year Accumulated Amortization | 3,834 | 4,459 | 5,091 | 5,808 | 6,542 | 7,304 | 8,088 | 8,899 | 9,746 | 10,647 | 11,609 | 12,617 | 13,709 | 14,672 |
| Net Amortization | 625 | 632 | 717 | 734 | 762 | 784 | 810 | 847 | 901 | 962 | 1,008 | 1,092 | 963 | 1,028 |
| Current Year Accumulated Amortization | 4,459 | 5,091 | 5,808 | 6,542 | 7,304 | 8,088 | 8,898 | 9,746 | 10,647 | 11,609 | 12,617 | 13,709 | 14,672 | 15,700 |
| **Net Contributions in Aid of Construction** | 13,330 | 15,248 | 15,469 | 15,704 | 16,382 | 16,478 | 16,883 | 18,205 | 18,943 | 19,836 | 21,017 | 22,496 | 24,093 | 25,571 |

## SCHEDULE B
## MAXIMUM COMPANY INVESTMENT

**1.** **(a)** **"Cost"** means the estimated cost of materials, labour, equipment, expenses, and any other direct costs incurred by the Company in extending Service to a Point of Delivery.

**(b)** **"Annual Cost"** means the estimated cost of generating and transmitting electric energy to the Customer, operating and maintaining the facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of facilities constructed to serve the Customers.

**2.** Subject to the provisions of paragraph 3 of this Schedule B, the maximum **cost** which the Company will incur to extend service to a point of delivery (herein referred to as the "Maximum Company Investment") shall be determined as follows:

**(a)** **Residential Service:**
900 per single family dwelling; and
450 per Multiple Dwelling Unit

**(b)** **General Service:**
400 per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated life is less than 25 years or seasonal the Company investment will be reduced proportionally, then the Maximum Company Investment shall be determined in the manner described in paragraph 3;

**c)** **Municipal Street Lighting:**
700 per light

**d)** **General Service Secondary:**
One half of one year of forecast retail sales revenues.

At the end of one year of service the Company will re-assess whether the customer's estimates of their consumption were accurate and will collect from the customer (or refund) any contributions, based on the Maximum Company Investment rules then in place in paragraph 2 or paragraph 3, that are required if the loads are significantly different than originally estimated.

**3.** The Maximum Company Investment for an extension of service not specified in paragraph 2, and the Maximum Company Investment in any extension of service, whether or not specified in paragraph 2, the Load characteristics of which are expected to vary materially from the average for that type of service, shall be determined on the basis of a detailed analysis of the **Annual Cost** of such extension and the revenue expected to be derived therefrom. If the **Annual Cost** of serving a customer is higher than the revenue expected to be received from such service, then the Maximum Company Investment shall be the **Cost** of the extension less the present value of the annual amounts over the expected life of the service by which the **Annual Cost** is expected to exceed the revenue.

## SCHEDULE B
## MAXIMUM COMPANY INVESTMENT

**1.** **(a)** **"Cost"** means the estimated cost of materials, labour, equipment, expenses, and any other direct costs incurred by the Utility in extending Service to a Point of Delivery.

**(b)** **"Annual Cost"** means the estimated cost of generating and transmitting electric energy to the Customer, operating and maintaining the facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of facilities constructed to serve the Customers.

**2.** Subject to the provisions of paragraph 3 of this Schedule B, the maximum **cost** which the Company will incur to extend service to a point of delivery (herein referred to as the "Maximum Company Investment") shall be determined as follows:

**(a)** **Residential Service:**
900 per single family dwelling; and
450 per Multiple Dwelling Unit

**(b)** **General Service:**
180 per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated life is less than 25 years or seasonal the Company investment will be reduced proportionally, then the maximum Company investment shall be determined in the manner described in paragraph 3;

**c)** **Municipal Street Lighting:**
700 per light.

**3.** The maximum Company investment for an extension of service not specified in paragraph 2, and the maximum Company investment in any extension of service, whether or not specified in paragraph 2, the Load characteristics of which are expected to vary materially from the average for that type of service, shall be determined on the basis of a detailed analysis of the **Annual Cost** of such extension and the revenue expected to be derived therefrom. If the **Annual Cost** of serving a customer is higher than the revenue expected to be received from such service, then

the maximum Company investment shall be the **Cost** of the extension less the present value of the annual amounts over the expected life of the service by which the **Annual Cost** is expected to exceed the revenue.

**YEC-YECL-23**

**Reference: Capital Plans**

**Requests:**

(a) Describe the system planning criteria used to develop YECL's capital plans.

(b) How far into the future does YECL prepare capital plans? What are these capital plans based on? Please provide a schedule showing YECL's capital plans by project for the next 5 years.

(c) Please describe how YECL's capital projects are prioritized.

(d) Please describe the age and condition assessments which lead to YECL's conclusion that lines need to be upgraded. What are the reliability statistics for these lines and how do these statistics compare to other lines on the system and the system average.

(e) Has a condition assessment study or other report documenting condition assessment been undertaken? If so, please provide copies of all relevant documents.

(f) Please provide YECL's multi year plan to upgrade and extend the life of major components.

**Response:**

(a) System Planning is driven primarily by load growth, existing infrastructure capacity, age, condition, access and operability, safety issues, other system risks and changes to standards and operating practices. Other components are coincidental load readings at substations and at specific breakers. One of the last key factors in this process is the development or redevelopment of the community or areas within the community. Factors influencing community development are the local economy, demand for and availability of residential, commercial and industrial property.

(b) Yukon Electrical develops a 3 year capital plan which it updates annually. Capital plans are based on a review of the overall system requirements as determined by the operations team utilizing information as provided below in (d) and (e). Yukon Electrical's two year forecast is provided in its application for the test years 2008 and 2009; with 2010 still under development.

(c) Once capital projects have been identified priorities are determined based on some of the following considerations:

- Customer needs- providing service to customers who wish to receive electrical service including a review of in service dates
- Safety benefits requirements- projects that will improve safety and or address unsafe situations
- Improves Reliability- the project improves reliability or addresses a reliability concern.
- Enhances customer service- projects that provide service benefits to customers.
- Age and obsolescence- projects that are required to support system integrity.
- Cost benefits- projects that provide a financial benefit to customers
- Replacement of infrastructure and equipment projects that are necessary to deliver service to customers.
- Meet legislative or legal requirements- projects that are required to address changes to codes, regulations or laws. Potential liability must also be taken into account.
- Environmental projects that will provide environmental benefits or that are required to meet environmental standards.

Projects are assessed against the considerations and completed based on facts, prudence, experience and professional judgement

(d) Age alone is not the deciding factor. The climbability of a pole, the ability to receive support or parts for a piece of equipment, accessibility to facilities and many other factors including those identified in (a) above are taken into account when evaluating an asset for rebuild or replacement.

Yukon Electrical does not track specifically its reliability statistics on a line or feeder basis but rather it tracks reliability on the system as a whole. Weekly Yukon Electrical's operations group meets with engineering to discuss the past weeks system performance. Of priority at these weekly meetings are all unplanned distribution outages or events which cause supply disruptions to customers. Events are recorded and trends are identified, ie: reoccurring failures of specific feeders, transformers or services. Trends are then investigated by researching the causes. Supporting information may be available by reviewing service interruption reports. Depending on the cause of the outages a determination is made to either immediately make corrections to the equipment or if the asset repairs can be put into the capital business planning cycle.

(e) On a regular basis Yukon Electrical completes assessments on its system. This is recorded in a number of reports, including: monthly substation reports annual line patrols, ground rod report forms, electrical equipment reports, hydro inspection reports, diesel plant inspection reports, safety audit reports, environmental audit reports, fleet inspection reports. All of these types of reports assist Yukon Electrical in determining the condition of its power system and equipment and provides information necessary to assist with Capital and O&M planning requirements. This information is too voluminous to provide as it would take up several file cabinets. Third party assessments have only been completed on specific components of the distributions system. Such as a Dam Safety Audit on the Fish Lake water way or the Fish Lake turbines inspections. YECL from time to time consults with other groups to assist with its capital planning and business planning needs.

(f) Yukon Electrical's multi year plan for Capital expenditures is provided in Section 9 of the Application. Final determination for 2010 capital expenditures is still under review and not available at this time.

**YEC-YECL-24**

**Reference:** Generation Plants

**Requests:**

(a) With reference to pages 9-5 and 9-6, Plant fuel systems required updating to current Canadian mandatory standards and codes. Please provide detailed information regarding which Canadian mandatory standards and codes are being complied with.

i. Please provide a list of the current Canadian mandatory standards and codes applicable to these projects. Please provide specific sections of Canadian mandatory standards and codes applicable to projects.

ii. Please provide an explanation regarding how the system improvements undertaken meet and comply with the Canadian mandatory standards and codes.

iii. Are any system improvements being undertaken which are not required to comply with mandatory standards and codes? If so, please provide list of such improvements and their justification.

.

**Response:**

(a) .

i. Attached are some of the generation standards relating to generation plants referenced by Yukon Electrical in it application (YEC-YECL-24 attachment 1).

ii. The system improvements undertaken by Yukon Electrical, regarding fuels systems, are driven by a variety of codes and standards as referenced in (i) above. Generally our system improvements are designed to minimize the risk of fire and fuel releases. Therefore alarm systems were installed, fuel

containment was upgraded, and automatic shut of valves were installed to name a few.

iii. Yes, system improvements are undertaken for a variety of reasons including age and obsolescence, environmental compliance, safety, improved reliability, and if required added capacity.

**Summary**
**Fuel Storage and Handling Documents**

| Issuing Agency | Document Number | Title of Document | Regulation | Referenced in Regulations | Reference Document (Guidelines/Protocols) | Design Standard | Explanatory Document | Explanation |
|---|---|---|---|---|---|---|---|---|
| American Petroleum Institute: | | | | | | | | |
| | API RP 651-97 | Cathodic Protection of Aboveground Petroleum Storage Tanks | | | x | | | |
| | API RP 652-97 | Lining of Aboveground Petroleum Storage Tank Bottoms | | | x | | | |
| | API 620 and 650 | Seismic Loads on Large Tanks | | | | x | | |
| | API Std 653-01 | Tank Inspection, Repair, Alteration, and Reconstruction | | | | x | | |
| | API RP 1632-96 | Cathodic Protection of Underground Storage Tank and Piping Systems | | | x | | | |
| | API Std 2610-94 | Design, Construction, Operation, Maintenance and Inspection of Terminal and Tank Facilities | | | | x | | |
| Canadian Council of Ministers of the | | | | | | | | |
| | CCME PN 1180 | Environmental Guideline for Controlling Emissions of Volatile - Organic Compounds from Aboveground Storage Tanks (1995) | | | x | | | for emmisions |
| | CCME PN 1299 | Canadian Environmental Quality Guidelines (1999) | | | x | | | soils remediation |
| | CCME | CWS for PHC Canada-wide Standards for Petroleum Hydrocarbons in Soil (2001) | | | x | | | soils remediation |
| Canadian General Standards Board: | | | | | | | | |
| | CAN/CGSB-3.2-99 | Fuel Oil, Heating | | | | | x | Canadian general Standards - fuel classification |
| Canadian Petroleum Products Institute: | | | | | | | | |
| | CPPI/PACE Report 87-1 | Impressed Current Method of Cathodic Protection of Underground Petroleum Storage Tanks | | | | | | |
| | CPPI (1995) | Using the CPPI Colour-Symbol System to Mark Equipment and Vehicles January 1990 for Product Identification | | x | | | | |
| | CPPI (2000) | Recommended Practices: Operation of Shop-Fabricated Aboveground Petroleum Storage Tank Systems | | | x | | | |
| Canadian Standards Association: | | | | | | | | |
| | CAN/CSA-B139-00 | Installation Code for Oil Burning Equipment | x | x | | | | |
| Environmental Protection Agency: | | | | | | | | |
| | EPA/530/UST-90/007 | Standard Test Procedures for Evaluating Leak Detection Methods: Statistical Inventory Reconciliation Methods | | | x | | | |
| | EPA 510-B-95-009 | Introduction to Statistical Inventory Reconciliation | | | x | | | |
| NACE International: | | | | | | | | |
| | NACE RP0169-2002 | Control of External Corrosion on Underground or Submerged Metallic Piping Systems | | x | x | | | |
| | NACE RP0285-2002 | Corrosion Control of Underground Storage Tank Systems by Cathodic Protection. | | x | x | | | |
| | NACE RP0193-2001 | External Cathodic Protection of On-Grade Carbon Steel Storage Tank Bottoms | | x | | | | |
| | NACE TM0101-2001 | Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Tank Systems | | x | x | | | |
| | NACE No. 10/SSPC- | PA6 Fiberglass-Reinforced Plastic (FRP) Linings Applied to Bottoms of Carbon Steel Aboveground Storage Tanks | | x | | | | |
| National Research Council: | | | | | | | | |
| | NRCC 38727 | National Fire Code of Canada (NFCC) - 1995 | x | | | | | establishes standards of fire safety |
| Steel Tank Institute: | | | | | | | | |
| | STI SP001-00 | Standard for Inspection of In-service Shop Fabricated Aboveground Tanks for the Storage of Flammable and Combustible Liquids. | | | x | | | |
| | STI R831-98 | Optional Recommended Practice for Control of Localized Corrosion Within Underground Steel Petroleum Storage Tanks. | | | x | | | |
| | STI R893-89 | Recommended Practice for External Corrosion Protection of Shop Fabricated Aboveground Tank Floors. | | | x | | | |
| | STI RP011-01 | Recommended Practice for Anchoring of Steel Underground Storage Tanks. | | | x | | | |
| Underwriters' Laboratories of | | | | | | | | standards - ULC certification seal |
| | ULC-S601-2000 | Aboveground Horizontal Shop Fabricated Steel Tanks | | x | | | | |
| | ULC-S601(A)-2001 | Shop Refurbishing of Aboveground Horizontal Shop Fabricated Steel Tanks | | x | | | | |
| | CAN/ULC-S602-1992 | Above ground Steel Tanks for Fuel Oil and Lubricating Oil | | x | | | | |
| | CAN/ULC-S603-1992 | Underground Steel Tanks | | x | | | | |
| | CAN/ULC-S603.1-1992 | Galvanic Corrosion Protection Systems for Underground Steel Tanks | | x | | | | |
| | ULC-S603(A)-2001 | Refurbishing of Underground Steel Tanks | | x | | | | |
| | ULC-S615-1998 | Underground Reinforced Plastic Tanks | | x | | | | |

**Summary**
**Fuel Storage and Handling Documents**

| Issuing Agency | Document Number | Title of Document | Regulation | Referenced in Regulations | Reference Document (Guidelines/Protocols) | Design Standard | Explanatory Document | Explanation |
|---|---|---|---|---|---|---|---|---|
| | ULC-S615(A)-1987 | Refurbishing of Underground Reinforced Plastic Tanks | | x | | | | |
| | ULC-S618-2000 | Magnesium and Zinc Anodes and Zinc and Copper/Copper Sulphate Reference Electrodes | | | x | x | | |
| | ULC-S630-2000 | Above ground Vertical Shop Fabricated Steel Tanks | | x | | | | |
| | ULC-S630(A)-2001 | Shop refurbishing of Aboveground Vertical Shop Fabricated Steel Tanks | | x | | | | |
| | CAN/ULC-S633-1999 | Flexible Underground Hose Connectors | | | | x | | |
| | CAN/ULC-S643-2000 | Above ground Shop Fabricated Steel Utility Tanks | | x | | | | |
| | CAN/ULC-S651-2000 | Emergency Valves | | | | x | | |
| | ULC-S653-1994 | Contained Above ground Steel Tank Assembles | | | | x | | |
| | ULC-S655-1998 | Above ground Protected Tank Assemblies | | | | x | | |
| | ULC-S656-2000 | Oil-Water Separators | | | x | | | |
| | ORD-C58.9-1997 | Secondary Containment Liners for Underground and Above ground Tanks | | | x | | | |
| | ORD-C58.10-1992 | Underground Jacketed Steel Tanks | | x | | | | |
| | ORD-C58.12-1992 | Leak Detection Devices (Volumetric Type) for Underground Storage Tanks | | | x | x | | |
| | ORD-C58.14-1992 | Leak Detection Devices (Nonvolumetric Type) for Underground Storage Tanks | | | x | x | | |
| | ORD-C58.15-1992 | Overfill Protection Devices for Flammable Liquid Storage Tanks | | | | x | | |
| | ORD-C58.19-1992 | Spill Containment Devices for Underground Tanks | | | | x | | |
| | ORD-C58.20-1996 | Special Corrosion Protection Underground Tanks | | | x | x | | |
| | ORD-C80.1-2000 | Aboveground Non-Metallic Tanks for Fuel Oil | | | | x | | |
| | ORD-C107.4-1992 | Ducted Flexible Underground Piping Systems | | | | x | | |
| | ORD-C107.7-1993 | Glass-Fibre Reinforced Plastic Pipe and Fittings | | | | x | | |
| | ORD-C107.12-1992 | Line Leak Detection Devices for Flammable Liquid Piping | | | | x | | |
| | ORD-107.14-1992 | Non Metallic Pipe and Fittings | | | | x | | |
| | ORD-C107.19-1992 | Secondary Containment of Underground Piping | | | | x | | |
| | ORD-C107.21-1992 | Under-Dispenser Sumps | | | | x | | |
| | ORD-C142.5-1992 | Above ground Concrete Encased Steel Tank Assemblies | | x | | | | |
| | ORD-C142.6-2000 | Storage Vaults | | | | x | | |
| | ORD-C142.13-1997 | Mobile Refueling Tanks | | | | x | | |
| | ORD-C142.15-2000 | Precast Concrete Tanks | | | | x | | |
| | ORD-C142.17-1998 | Above ground Special Purpose Relocatable Vertical Tanks | | | | x | | |
| | ORD-C142.18-1995 | Above ground Rectangular Steel Tanks | | | | x | | |
| | ORD-C142.19-1994 | Spill Containment Devices for Aboveground Tanks | | | | x | | |
| | ORD-C142.20-1995 | Above ground Secondary Containment Tanks | | | | x | | |
| | ORD-C142.22-1995 | Contained Above ground Vertical Steel Tank Assemblies | | | | x | | |
| | ORD-C536-1998 | Flexible Metallic Hose | | | | x | | |

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**5YEC-YECL-25**

**Reference:** Distribution Projects Undertaken Between 1996 and 2005

**Requests:**

(a) For projects greater than 100,000 and in a manner consistent with 1996 97 GRA question YUB-YEC YECL-1-35, please complete a table that details (1) project name and total expense capitalized, (2) project description, (3) rationale justification and (4) cost benefit for all distribution projects between January 1, 1996 and 2007. On an annual basis, please ensure that table provides the sum of all projects not included in this analysis that reconciles to the total distribution capitalized for a given year.

(b) For 1996 and 1997 please explain any discrepancies regarding forecast capital projects and actual results.

**Response:**

(a) Please refer to Yukon Electrical's summary of projects over 100k for years 1996 - 2009 in YEC-YECL-25(a) Attachment 1.

(b) Yukon Electrical's total capital forecast included in its 1996 1997 GRA was 9.774M for the test years 1996 97. The actual total capital expenditures for the 1996 and 1997 test years were 9.729M.

| PROJECT NUMBERS | COST | YEAR | PROJECT NAME | |
|---|---|---|---|---|
| | **Distribution New Extensions** | **70001** | | |
| C00760 | $901,000 | 1996-1997 | YTG McIntyre Logan Feeder | |
| C00787 $560,000 1996-1997 | $560,000 | 1996-1997 | YTG Copper Ridge Subdivision. Phase 2 | |
| C00788 | $295,000 | 1996-1997 | YTG Logan Substation | |
| C01061 | $209,000 | 1997-1998 | YTG Copper Ridge Mobile Home Park | |
| C01091 | $115,000 | 1997 | Commercial Customer | |
| C01113 | $128,000 | 1997-1998 | Commercial Customer | |
| C01152 | $105,000 | 1997-1998 | YTG Copper Ridge Infrastructure | |
| C01332 | $123,000 | 1998-1999 | YTG YHC Range Rd Mobile Home Complex | |
| C01484 | $342,000 | 1999-2000 | Yukon Electrical/Commercial Customer – Downtown U/G | |
| C01554 | $160,000 | 1999-2000 | Commercial Customer | |
| C01737 | $141,000 | 2000 | Commercial Customer | |
| C01775 | $110,000 | 2000-2001 | Commercial Customer | |
| C02211 | $176,000 | 2002-2003 | Commercial Customer | |
| C02273 | $142,000 | 2002-2003 | Commercial Customer | |
| C02290 | $352,000 | 2003 | YTG Copper Ridge Stage 9 | |
| C02488 | $442,000 | 2004-2005 | YTG Copper Ridge Stage 10 | |
| C02525 | $174,000 | 2004-2006 | Commercial Customer | |
| C02548 | $188,000 | 2005 | Commercial Customer | |
| Y10217 | $214,000 | 2005 | YTG Copper Ridge Stage 11 | |
| Y10236 | $234,000 | 2005-2006 | Commercial Customer | |

# CAPITAL PROJECTS OVER 100K 1996-2004 5

| PROJECT NUMBERS | COST | YEAR | PROJECT NAME | |
|---|---|---|---|---|
| Y10280 | $232,000 | 2005-2006 | Commercial Customer | |
| Y10312 | $201,000 | 2006 | YTG Canada Games Village | |
| Y10498 | $267,000 | 2006 | Commercial Customer | |
| Y10567 | $145,000 | 2006 | Commercial Customer | |
| Y10573 | $221,000 | 2006 | Commercial Customer | |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | **Distribution System Improvements** | **70004** | | |
| | Specific project identified to maintenance and improve system reliability or address issue or operating concerns | Rebuild, relocated, alter or enhance existing infrastructure. | Various reasons, generally the age and condition of existing infrastructure. Often capacity, location and design are factors as well. | System reliability and integrity are maintained and improvements incorporated where possible. |
| Y10626 | Watson Lake Danger tree removal | See generic Right of Way Widening business case. | | |
| Y10315 | YECL Watson Lake microwave line rebuild | See business case | | |
| Y10448 | Teslin Sub transformer replace | See business case | | |
| Y10036 | YECL Tagish Road Re-build | See business case | | |
| Y10501 | YECL First Avenue Conversion | See business case | | |
| Y10035 | Mayo Rd Rebuild 2006 | See business case | | |
| Y10557 | U/G Rebuild Justice Center to Whitehorse Star | See business case | | |
| Y10625 | Hawkins alley | See business case | | |
| Y10573 | CoW First Avenue Street Lights | See business case | | |
| Y10647 | Lambert St to 4th Ave and portions of 4$^{th}$ replacement | See business case | | |
| C02055 | Stewart Crossing Attachment to YEC system | See business case | | |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| Y10323 | Stewart Crossing Investment in YEC 3 phase substation | See business case | | |
| Y10006 | Pelly Transformer Platform bank/Phase Imbalance | See business case | | |
| Y10254 | YECL Marsh Lake Reg & OCR | See business case | | |
| C02132 – Y10011 | Riverdale Area Pole Changes | See business case | | |
| C02486 | Mayo Road Area System Improvements | See business case | | |
| Y10277 | Main Steel Alley | See business case | | |
| Y10341 | Cable replacement near PCSS | See business case | | |
| C02486-Y10035 | Mayo Road Rebuild | See Mayo Rd Rebuild 2006 business case | | |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| C02534<br>( $115,000)<br>2004 ~ 2005 | Ray Street 2004 underground rebuild | Install the electrical portion of the underground system in previously installed raceway. | Poles were aging. Some have no treatment or only treatment at the butts. Other issues due to shell rot or repeated climbing result in poles not being safe to work off of or add new services to. Reconstruction of a new overhead system would not be possible due to code restriction. Therefore YECL has to convert the overhead lines to an underground system. | A subsurface power system designed to new standards. Less potential of human interference or contact. Improved operability and maintenances due to new equipment and access. |
| C01988<br>( $118,000)<br>2001 ~ 2003 | YECL line relocate Alaska Hwy/ Laberge Rd | Rebuild existing powerline to accommodate road upgrade | Structures are old and conductor is small and has been damaged and repaired over the years due to trees and elements. | Increased ground clearance, increased capacity of main line out of LaBerge substation. Reduce long term brushing requirements. Reduce the difficulty of access to the line when performing routine line patrols and troubleshooting. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| C02487 – Y10001 ($225,000) 2004 | YECL Jubilee Mountain Cable Replacement | Build new single phase overhead line to replace 1950's existing 3 phase cable that was laying on the ground. Convert the 3 phase generator for one of the customers to a single phase system to avoid the need for a three phase line. | The existing three phase ground cable had numerous temporary splices causing reliability issues and had caused wildlife issues. The ground cable was also a health and safety hazard to staff and public. | Reliability, safety and replacement of deteriorating facilities. Standard contingency material for repair and restoration. |
| Y10004 ($ 157,000) 2004 | Gray Mountain Line Rebuild<br><br>Middle Section Near Gun Range | Change poles and associated hardware. Rebuild on the opposite side of the road to allow pre build and minimize the outages to the key customers served at the top of Grey Mountain. | This line feeds key communication towers such as radio and hospital pagers as well as infrastructure critical to EMO activities. Furthermore, the line is subject to extreme weather conditions. Poles are aging. Some have no treatment or only treatment at the butts. Other poles, due to shell rot or repeated climbing are not safe to work off of or add services to | Increased reliability to essential service communication sites. Replace deteriorating facilities |
| C02496 ($190,000) 2004 | Grey Mountain Line Rebuild – Bottom section | Change poles and associated hardware. Rebuild on the opposite side of the road to allow pre build and minimize the outages to the key customers served at the top of Grey Mountain. | This line feeds key communication towers such as radio and hospital pagers as well as infrastructure critical to EMO activities. Furthermore, the line is subject to extreme weather conditions. Poles are | Increased reliability to essential service communication sites. Replace deteriorating facilities. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | | | aging. Some have no treatment or only treatment at the butts. Other poles, due to shell rot or repeated climbing are not safe to work off of or add services to. | |
| C02311 ($224,000) 2003 | 3rd Avenue U/G Conversion<br><br>Boston Pizza to Ray Street. | Install the high voltage cables and ducts into this area and remove aging and deteriorating overhead infrastructure Tie into existing underground facilities on the north side of 2nd Avenue. | Poles are old. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add new services to. A new overhead system would not be able to meet code in the area that is zoned commercial and could be zero lot line. High voltage lines and transformers would be too close to roof, window and vents. | A subsurface power system designed to new standards. Less potential of human interference or contact. Improved operability and maintenances due to new equipment and access. Replace deteriorated facilities. Eliminate hazards. Comply with code |
| C02113 ($232,000) 2002 | Destruction Bay Alaska Highway Reroute | Move power line to maintain minimum clearances to driving surfaces and allow for Alaska Highway reconstruction. | The existing power line is on the highway Right of Way (ROW) and was in conflict with new highway reconstruction. | Accessible power line Right of Way. Comply with legislation (maintain minimum clearance to driving surface) Replace deteriorated facilities. |
| C02077 ($520,000) 2002 | Shipyard tie in completion | Build new underground lines/feeders and salvage obsolete overhead lines. | New feeders are required to connect distribution system to the new substation. | Strengthens 12 kV loop in downtown Whitehorse core allowing for improved operability and |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | | | | growth. |
| C02080 ($143,000) 2002 | Services Substation Tie | Tie in new 34KV feeders to connect Shipyard and Services substations. | To provide alternate feed between substations for continuity of service. | Allows us to serve existing customers from our new substation and connects substations for loop and alternate feed capabilities. |
| C02505 ($ 103,000) 2004 | Shipyard substation | Salvaged existing overhead substation and tie into system | Existing sub is on leased land (YTG) and the lease will not be renewed. City plan for area development requires its removal and the lines in the future development area to be removed | Allows us to serve existing customers from our new substation and connects substations for loop and alternate feed capabilities. |
| C02339 – Y10019 ($270,000) 2003-2004 | Powerline reroute Porter creek | Rebuild existing double circuit 34.5kV and 12.5 kv line that is aged and deteriorated and on unsecured Right of Way. | Replace aged and deteriorating facilities that are on unsecured Right of Way. | Security of supply to serve customers in Porter Creek area. Replaced aged and deteriorated main feeder facilities. |
| C02272 ($220,000) 2003-2004 | Distribution drawing upgrade | Digitize and update our manually drafted distribution maps, | Our maps consist of old manually drafted maps that were not easily updatable. Other maps are digitally drawn and updated in a program that only the draftsperson can access. By digitizing our old manual maps and getting key users a program to access the files they can then print the maps they need on a daily | Standardizes drafting process, map updates can be completed in less time. Enables the development of a layered map design, facility information in one format. Allows us to move toward a “data base” of easements, licenses, brushing plans, land base information and ultimately improves service to our customers. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | | | basis. | |
| C02158 ($180,000) 2003 | Keno City Distribution rebuild | Change poles and associated hardware / conductor. | Poles were aging (1950's vintage). Some have no treatment or only treatment at the butts. Other issues due to shell rot or repeated climbing result in poles not being safe to work off of or add new services to. | Reliability and safety. Replaced aged and deteriorated infrastructure in a remote community. |
| C01908 ($291,000) 2001 | 1st Avenue back alley from Elliott Street through to City Hall. | Install padmount transformers, underground primary cables and ducts into this area. Convert the customers' overhead secondary services to underground services. | Poles are old. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. In high traffic areas such as in the downtown area, poles and structure are often damaged by vehicular movement. Reconstruction of a new overhead system would be difficult and expensive in order to comply with code due to the high voltage lines and transformers being too close to roof, window, and vents. Therefore YECL has to convert the overhead lines to an underground system. | A subsurface power system designed to new standards. A safer system that has less potential of human interference or contact. Improved operability and maintenances due to new equipment and access. |
| C01843 | Haines Junction airport | String in 1/0 ACSR wire and | An ice storm in 1999 | Line rebuilt to heavy loading |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| ($124,000) 2000 | feeder reconductor | rebuild as required the line between the Airport and the Haines Junction substation. Remove old conductor | diminished the integrity of the #6 wire. The line in question was a double circuit YEC/YECL line between the airport and the Haines Junction substation. | standards. Restored line integrity and provided for future increased load. Addressed a safety concern. |
| C01821 ($631,000) 2000/2001 | YECL shipyards substation rebuild | Material required to construct Subsurface substation to replace existing overhead substation. | Original substation is an aged facility sitting on the riverbank on leased land that will not be renewed. | A subsurface power system designed to new standards. Less potential of human interference or contact. Improved operability and maintenances due to new equipment and access and addresses potential environmental concerns. |
| C01779 ($116,000) 2000 | Alley rebuild between Main Street and Elliott. | Install padmount transformers, underground primary cables and ducts into this area. Convert the customers' overhead secondary services to underground services | Poles are old. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. In high traffic areas such as in the downtown area, poles and structure are often damaged by vehicular movement. Reconstruction of a new overhead system would be difficult and expensive in order to comply with code due to the high voltage lines and transformers being too close to roof, window, and vents. | A subsurface power system designed to new standards. A safer system that has less potential of human interference or contact. Improved operability and maintenances due to new equipment and access. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | | | Therefore YECL has to convert the overhead lines to an underground system. | |
| C01754 ($152,000) 2000 | Old Crow distribution line rebuild | Install taller poles in locations where ground clearance is not to the minimum standards and in locations where the poles are aged and deteriorated. | Much of the older system is built with 35 ft poles. Ground clearance has diminished due to a variety of factors. (e.g. road surfaces changing) resulting in safety concerns. Balance load on the system. There are also aged and deteriorating infrastructure that requires replacement. | Meet minimum clearance requirements. Less stress on the generators due to improved load balancing, Improved reliability of our line and remove some risks of pole failure. |
| C01743 ($564,000) 2000-2001 | 34 kV / 12 kV line rebuild at north end of downtown underground feeders to tie into new Shipyards substation. | Install high voltage 750 and 500 MCM underground cables and ducts to connect new Shipyards substation to the system. | Required to link new Shipyards substation with Services substation. Fourth feeder from Shipyards to accommodate new growth.. | Fully linked and looped downtown substations infrastructure that removed aged and deteriorating lines from waterfront. Better accommodates load growth in the area. |
| C01612 ($105,000) 2000 | Haines Junction 2nd feeder | Add a second feeder breaker to the system to allow Yukon Electrical to split the town load for restoration purposes. | The diesel plant had trouble picking up the town's load during cold load pickup. A second feeder allows Yukon Electrical to pick up part of the town, stabilize the generator and then add the rest of the town's load. | Reliability and allows the plant to do what it was intended to do during restoration. |
| C01603 | Services substation to Two | Rebuild an aging and | This double circuit 34 kV and | Upgrade of a critical City of |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| ($132,000) 2001 | Mile Hill rebuild | deteriorating portion of the main double circuit 34 kV / 12 kV line between Service Substation and Two Mile Hill. Upgrade the wire size to 266 ACSR for both circuits. | 12 kV line has wire that is undersized for the amount of load that Yukon Electrical is required to serve in the area. | Whitehorse feeder. Meet load growth requirements in the area. |
| C01571 ($107,000) 1999 | Line rebuild for Carcross substation | Tie new Carcross substation to existing system with two new 25 kV lines. | The Carcross substation was required to be rebuilt and relocated. This work was necessary to tie the new substation to the existing system that feeds Carcross and Tagish. | Connects customers to new substation. |
| C01535 ($128,000) 1999-2001 | Alaska Highway / Carcross Corner OCRs upgrade and relocation | Upgrade and relocate the protective devices and their structures that are on the lines serving Carcross and Teslin. | Standardize structures. Upgrade protective equipment to current standards. Improved the operational capabilities of the devices. Address safety issues. | Provides improved operation of the system. Addresses safety concerns. Protective devices can now accommodate automation. Upgraded substandard equipment. |
| C01513 ($259,000) 1999-2000 | New Carcross substation | Replace an aged and obsolete substation that feed Carcross and Tagish with a new substation. | The existing substation has old and deteriorated poles and old timbers. Upgraded infrastructure required to accommodate load growth in the area. | Security of supply for Carcross and Tagish areas. Reliability and safety. Replace aging infrastructure. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| C01483 ($256,000) 1999 | YECL downtown underground rebuild CBC/NWTEL alley | Install padmount transformers, underground primary cables and ducts into this area. Convert the customers' overhead secondary services to underground services | Poles are old. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. In high traffic areas such as in the downtown area, poles and structure are often damaged by vehicular movement. Reconstruction of a new overhead system would be difficult and expensive in order to comply with code due to the high voltage lines and transformers being too close to roof, window, and vents. Therefore YECL has to convert the overhead lines to an underground system. | A subsurface power system designed to new standards. A safer system that has less potential of human interference or contact. Improved operability and maintenances due to new equipment and access. |
| C01331 ($210,000) 1998 | Nisutlin River Crossing | Build and install a cable tray with cables on the Nisutlin River Bridge in Teslin. Salvage old submarine cable. | The existing submarine cable that was put in by the US Army is old and deteriorating. Contingency in the event of failure was challenging due the type of cable and location (in the river). One of three phases had faulted restricting capacity and reliability. | Improved security of supply to customers on the other side of the bridge. Feed is now standard cable in proper raceway on bridge that can be repaired or replaced with greater ease. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| C01281 ($280,000) 1998 | YECL stage 1 downtown Whitehorse Underground | Install the transformers high voltage cables and ducts into this area. Convert the customers overhead secondary services to underground services. | Poles are old. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. In high traffic areas such as in the downtown area, poles and structure are often damaged by vehicular movement. Reconstruction of a new overhead system would be difficult and expensive in order to comply with code due to the high voltage lines and transformers being too close to roof, window, and vents. | A power system that we can operate and maintain. Eliminates a deteriorated system and meets current codes and regulations. A subsurface power system designed to new standards. Less potential of human interference or contact. Improved operability and maintenances due to new equipment and access |
| C01245 ($111,000) 1997 | Watson Lake airport U/G cable replacement | Replace old underground feed with a new underground feed on airport feeder. | Underground cable is old, deteriorated and direct buried. Failures have been frequent in the past. Original cable had been installed by US Army in 1940's | Improved reliability to a critical part of Watson Lake's infrastructure. Upgrades aged facilities. |
| C01124 (124,000) 1998 | Riverdale FH Collins School area voltage conversion. | Salvage the 2400V sub and convert the customer and lines to 12.5kV. | The schools, warm water wells, fish hatchery fed from a 2400v substation. This substation is surrounded by a 12.5kV system. By converting the customer transformers to 12.5kv we can salvage this old | Remove old substation equipment from the system. Provide uniform distribution voltage in the area. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | | | substation and its transformers. This would remove double circuit lines and simplify the system for operation and construction purposes. | |
| C01021 ($105,000) 1997 | Tagish line rebuild | Change poles, conductor and associated hardware on a portion of the Tagish line. | Poles are aging. Some have no treatment or only treatment at the butts. Other due to shell rot or repeated climbing are not safe to work off of or add services to. | Reliability and safety and replacement of aged and deteriorating infrastructure. |
| C00885 ($238,000) 1996 | McIntyre 34kv second feeder | Extend the 34kv line toward McIntyre subdivision to replace part of the loop underground system to the subdivisions in the area.. | One of the McIntyre subdivision's feeders has had multiple failures. The Logan substation has a 34 kV line in the area of McIntyre. We would build a line towards the Logan substation and replace the existing feeder into McIntyre with a more reliable feeder. | Reliability to the area. Replace failing infrastructure. Provide a loop or alternate feed to the residents in this area. |
| C00860 ($120,000) 1996-1997 | Tagish Bridge crossing reroute | Construct a raceway on the Tagish bridge to accommodate primary cable installation. | The existing overhead line was old and deteriorating, Restoration of the overhead river crossings are very challenging due the nature of their design. The area is also a known flyway for waterfowl | Security of supply to customers on the east side of the bridge. Feeder is now ducted standard raceway. Cable that can be repaired or replaced with greater certainty. Electrical hazard to waterfowl has been eliminated. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | | | and the overhead conductor is a proven hazard as Trumpeter Swans migrate through the area. | |
| C00780 ($146,000) 1996 | McCrae substation rebuild | Replace an aged and obsolete substation that feeds the McCrae / Country residential area south of Whitehorse. | The existing substation has old and deteriorated poles and old timbers. Upgraded infrastructure required to accommodate load growth in the area. | Security of supply for customers in the McCrae and country residential areas south of Whitehorse. Reliability and safety. Replace aging infrastructure. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | **GENERATION** | **90000** | | |
| Y10271 ($571,000) 2005 | Watson Lake Fuel system | See generic business case for fuel system upgrades | | |
| Y10030 – C02442 ($104,000) 2006 | Carmacks fuel system | See generic business case for fuel system upgrades | | |
| Y10423 ($111,000) 2005 | #2 Penstock Partial Replacement Unit #2 Fish Lake Hydro | Replace a section of the #2 wood stave penstock with steel. | The #2 wood stave penstock was installed in the 1950s and began to shift and break apart in 2004 due to ground erosion. This drove this partial replacement project. | More secure water source for unit #2. Catastrophic failure of penstock avoided. Mitigated environmental risk. |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| C02068/C02406 ($210,000) 2003-2005 | Stewart Crossing Interconnect conversion | Change the controls and programs for the plant to run as a standby plant after the interconnection to the Mayo Dawson grid. Control and communicate with the remote OSS to serve the community either from the grid or the plant. Upgrade the service and install heaters in the plant. | Automatic start up and synchronization of the plant to the distribution system in Steward Crossing if the transmission line fails. Consistent standard throughout Yukon Electrical's service territory. Take advantage of hydro benefits for the community. | Minimized outage time for the customers of Steward Crossing and reduces cost of responding to manually start and put the plant on line. Reduces dependency on diesel fuel and associated costs. |
| Y10033 – C02465 ($708,000) 2004 | Old Crow Fuel System | See generic business case for fuel system upgrades | | |
| C02380 ($100,000) 2003 | Fuel system upgrade Swift River | See generic business case for fuel system upgrades | | |
| C02375 ($118,000) 2003 | Fuel system upgrade Beaver Creek | See generic business case for fuel system upgrades | | |
| C01485 ($668,000) 1999 | Replace diesel engines 1 & 6 in Watson Lake | Replace existing units 1 & 6. with two new units. | Units have reached the end of their life (near 100,000hrs), and must be replaced to provide service to the community. | Reduced risk of failure. |
| C01355 ($106,000) 1998-1999 | 225KW mobile generator | Purchase mobile unit | Purchase unit to work in and around Whitehorse to minimize outages and help | Mobile generation will help with small isolated plant outages and with local small outages that would be |

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | | | with construction projects | too long for customers. |
| C01268 ($373,000) 1998 | Replacement Unit 3 Old Crow | Replace the smallest unit (1981 vintage), 220kW with a 500kW unit | Generator loading has grown to the point where Yukon Electrical has less than 110% capacity with the largest unit out of service. | Provide adequate generation in the community with the largest unit out of service. |
| C01197 ($542,000) 1997 | Mobile unit Haines Junction | Install a 1.5MW generator and a 480V-14.4kV/25kV step up bank. | Extended outages, lengthy restoration time. | Contingency supply for Haines Junction |
| C01016 ($194,000) 1997/98 | Diesel installation Watson Lake | Install used Detroit Diesel Series 60 generator set with an out-sourced used alternator. All modification and new equipment purchased are included. | Old unit failed | Need 500kw unit to handle peak loads and still have a good heat rate. |
| C01009 ($362,000) 1997/98 | Construct new plant in Swift River | Build new 2 unit plant complete with new building and controls and fuel tank. Install in Swift River and connect to the system. | Old plant and units are old (installed by the Army) 1950's. Had 3 old units in a very old building, poor fuel efficiency. Environmental issues with tank. Plant is not automated and to automate such old equipment, in an old building, in Swift was not prudent. Plant built off site and installed in Swift. | Reliable plant in an isolated community with no alternative power. Upgraded to code. |
| C00892 ($205,000) 1997 | Pelly Crossing | Replace Engine in Pelly Crossing isolated generation plant. | Engine had reached the end of it's service life, increased maintenance cost. | Reduce operation and maintenance. Provide adequate generation in the community with the largest unit out |

# CAPITAL PROJECTS OVER 100K 1996-2004 5

| PROJECT NUMBER | PROJECT NAME | DESCRIPTION | JUSTIFICATION | BENEFIT |
|---|---|---|---|---|
| | | | | of service. |
| C00773 ($232,000) 1997/98 | Pelly PLC and 2nd feeder | Add a second feeder breaker to the system and split the load just outside the plant yard. | Diesel plant has trouble picking up the load during the peak load season (winter). In the past extended outages have occurred. A second feeder would allow pick up of the town, and stabilize the generator before adding the remaining community load. | Reliability; allows the plant to do what it was intended to do during peak load (critical) times. |
| C00572 ($227,000) 1996 | Watson Lake Generator control | Install General Electric Fanuc Programmable Logic Control system. (PLC) | Engine and generator PLC's have evolved. Standards and technique of installing and operating this equipment have progressed as well. This equipment has more capabilities and functionality. | Increased reliability, operability, and trouble shooting capability. More advanced and sensitive generator / load monitoring and control. |

# ROW widening various locations

**Summary:** The previous standard of 3 m or 5m on either side of a power line has caused Yukon Electrical problems in the past and often does not allow the company proper access to its facilities. The new standard of 6.1m for single phase and 7.5m for three phase line has proven much better in other areas as well as Yukon. Wildfires, public safety, right of way access for maintenance vehicles and trouble shooting and reliability are the main drivers.

**Project Description:** Widen selected existing right of ways (ROW) to allow for access, wildfire reduction, and reliability.

**Costs Schedule:** Approximately 10,000 to 20,000 per km depending on several factors such as access, size of trees, density of trees, hand slash or mechanical, method of disposal, time of year, and location of work.

**Benefits:** Reliability, wildfire mitigation, accessibility for maintenance and emergency.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Experience with the wider right of ways in the Yukon has trended to fewer tree related outages.

**Business and Technology drivers:** Fewer tree related outages.

**Risks of proceeding:** None

**Risks of not proceeding:** Outages, public contacts or wildfire if tree falls on the line. Access and ability to trouble shoot create unsafe conditions to operate our system.

**Alternatives:** Status quo, narrow right of ways
Tree free right of ways not cost effective (for distribution power lines) or desired by communities.

**Recommendations:** Continue normal practice of widening ROW to improved standard.

**Priority:** Type A Eliminate Safety Hazards

**Summary**: These projects bring our diesel plant fuel system to compliance with current mandatory codes for Canada.

**Project Description:** This project consists standardizing all of Yukon Electrical's diesel plants with double wall tanks, berms and sumps (if required), fluid containment within plants and alarmed automatic shutoff valves.

**Costs Schedule:** Smaller plants (Beaver Creek, Destruction Bay, Haines Junction, Pelly Crossing, Stewart Crossing, Ross River, Carmacks, Teslin), Watson Lake and Old Crow.

**Benefits:** Mitigate the potential of fire and fuel spills comply with current code.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Code

**Business and Technology drivers:** New code, increased expectation on business to be responsible steward of environment.

**Risks of proceeding:** Cost overruns manage projects effectively

**Risks of not proceeding:** Increased costs of spills, increased number of spills, non-compliance with new code, environmental damage.

**Alternatives**

- For isolated diesel generation sites, no alternatives were identified.
- For grid diesel generation standby plants, remove plants.

**Recommendations:** Bring plant fuel containment and fuel systems up to the new code.

**Priority:** Type A Comply with new code.

# C02132 Y10011

**Summary:** Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add attachments too. When this occurs, the poles are changed.

This area is inaccessible. Many people have extended their yards. Brushing is difficult or impossible to do in this area. For these reasons and the fact that a trail exists in the area, Yukon Electrical has designed an underground primary and overhead secondary design. The trail gives us access and a ROW for our underground system.

**Project Description:** Build an underground primary system and salvage the overhead primary. Rebuild the overhead secondary system (Hybrid).

**Costs Schedule:** 201,000

**Benefits:** Reliability, safety of linemen and public; reduced long term brushing costs.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older. Access is very difficult and in some cases impossible. It can be very challenging to obtain permission brush to current standards.

**Business and Technology drivers:** Reliability and safety. Poles have deteriorated.

**Risks of proceeding:** Cost over runs effectively manage projects

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system.

**Alternatives:**
Over head relocation and rebuild to front lot configuration.
Total underground system conversion.

**Recommendations:** In this location underground primary is recommended and overhead secondary is recommended as the most cost effective solution.

**Priority:** Type A Avoid immediate effect of security of supply. Replace deteriorating facilities.

# Y10006

**Summary:** Phase imbalance is an issue in Pelly Crossing. Load balancing is critical is an isolated community with limited load and generation. 3 phase is to be extended into the community to allow for more flexibility. Also two step up banks will be salvaged and replaced with a 3 phase step up bank.

**Project Description:** Build a new 2400 delta 12.5 7.2kV step up bank. Extend three-phase into Jon Ra subdivision and extend three-phase into the 2400V section of town.

**Costs Schedule** 134,000.

**Benefits** Better loading (balanced loading) on our generation.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Load increases are in certain areas where only one phase is available.

**Business and Technology drivers:** Load increase.

**Risks of proceeding:** Cost overruns manage costs effectively

**Risks of not proceeding:** Shorter life on generators, less efficient generator operation

**Alternatives:** Convert entire town to 12.5 7.2kV system more costly. Install larger generators.

**Recommendations:** Extend phase wires into the community to allow for transferring of load now and in the future to ensure load is balanced.

**Priority:** Type A

# Y10254

**Summary:** Voltage lower than what we can serve our customers is being supplied by our Marsh Lake single phase sub. Our protective devices (OCRs) are not coordinating so they require upgrading.

The three phase 1950's regulator on the 34.5kv system does not regulate automatically.

**Project Description:** Install regulation on the Marsh Lake 14.4kv system and upgrade the OCR devices to coordinate better with the downstream devices. Build a platform for new 34.5kv regulator and salvage the old three phase regulator.

**Costs Schedule:** 202,000

**Benefits:** Serve customers on Marsh Lake distribution and customers on the 34.5kv distribution line with voltage within established parameters as well as improved line coordination.

**Resources and Funding Annual:** System improvement budget

**What has changed?** Loading has increased the voltage drop and caused coordination cold load pickup issues on the Marsh Lake system.

**Business and Technology drivers:** Increased load on system.

**Risks of proceeding**: Cost overruns manage costs effectively

**Risks of not proceeding:** Meeting minimum voltage requirements as established.

**Alternatives:** Adding regulators on individual feeder however to costly.

**Recommendations:** Add regulators on the 34kV main distribution. Upgrade protection to avoid coordination cold load pickup issues.

**Priority:** Type A Comply with legislation (minimum voltage levels) Replace deteriorating facilities.

**2002-2005**

# C02055 Y10008 Y10323

**Summary:** A transmission source is available to supply Stewart Crossing with hydro electricity as opposed to supplying the community with diesel generation. Continue to supply the community with three phase power via a new three phase interconnection with the transmission system and tie into the existing plant's town's 2400V delta system.

**Project Description:** Construct a three-phase 25kV grounded wye line from the transmission substation to the plant and then convert it to 3-phase 2400V delta. Upgrade interconnection line to current standards. Remotely control the interconnection point of the Stewart Crossing system to the transmission system. Contribute to a three phase substation being constructed by Yukon Energy.

| | | |
|---|---|---|
| **Costs Schedule:** | Distribution interconnection and system upgrade | 421,000 |
| | Three-phase substation contribution to Yukon Energy | 464,000 |

**Benefits:** Convert Stewart Crossing from a diesel generation community to a hydro electric supplied community while maintaining existing three phase availability.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Hydro electric grid source available from Yukon Energy.

**Business and Technology drivers:** Availability of hydro electricity.

**Risks of proceeding:**
Cost overruns manage costs effectively

**Risks of not proceeding**: Fuel price risk and the continuation of an operating plant as compared to a stand-by plant.

**Alternatives:** A single phase interconnection as opposed to a three phase interconnection. Incremental costs associated with a three phase substation offset by lower distribution system modifications as well as lower three-phase standby plant modification costs. Decision to proceed with a single phase solution would result in three phase power no longer being available to the community.

**Recommendations:** Maintain status quo with respect to three phase power availability in the community via a three-phase interconnection to the grid.

**Priority:** Type A Interconnect generation.

# C02486 Y10035 Y10504

**Summary** Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. When this occurs, the poles are changed. Historically this has been a high load growth feeder. Generally these poles were installed prior to 1969.

This is a main line supplied by a radial feeder. Yukon Electrical is also taking this opportunity to upgrade the wire to increase capacity.

**Project Description:** Change pole and associated hardware

**Costs Schedule:** 120,000 2005; 104,000 2006

**Benefits:** Reliability, safety.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older, load growth

**Business and Technology drivers:** Reliability and safety. Poles have deteriorated.

**Risks of proceeding:** Cost over runs effectively manage projects

**Risks of not proceeding Outages:** public contacts or wild fire if pole fails; unsafe conditions to operate our system.

**Alternatives**
Underground much more expensive
Concrete pole more expensive; would require many bucket trucks to work on poles
Composite poles new unproven technology; more expensive; would require many bucket trucks to work on poles
Steel poles - more expensive; would require many bucket trucks to work on poles

**Recommendations:** Continue normal utility practice of changing out pole when required.

**Priority:** Type A Avoid immediate effect of security of supply (old poles). Replace deteriorating facilities.

# Y10625

**Summary:** Infrastructure is aging. New developments in this area are zero lot lines.

**Project Description:** Change the overhead primary to underground primary. Leave the overhead secondary in place.

**Costs Schedule**: 100,000

**Benefits:** Reliability and safety.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older. A new condo on 4th and Hawkins required 3 phase power. .

**Business and Technology drivers:** Increased area power requirements; reliability and safety due to older poles; zoning regulation changes.

**Risks of proceeding**
Cost overruns manage project effectively

**Risks of not proceeding**
Outages, public contacts fire if pole fails; unsafe conditions to operate our system.

**Alternatives** Continue normal utility practice of changing out poles when required.

**Recommendations** Upgrade to underground due to restrictions in the alley.

**Priority** Type A Replace deteriorating facilities); comply with legislation (can't build and not create a code violation)

# Y10660

**Summary:** The Existing single phase line is across country, making it challenging to maintain and patrol when trouble shooting. The customer has requested a conversion from single phase to three phase. This conversion and construction is an opportunity to share costs in relocating the line to road side to improve access. It will also provide better load balancing at the substation and reduces the number of overhead road crossings on the Alaskan highway.

**Project Description:** Replace and relocate existing cross country line along road side.

**Costs Schedule:** 85,000

**Benefits:** Increased reliability and improved access. Three phase configuration has the ability to better balance the loading of the system and potential future growth in the area. Road side construction vs. cross country requires less future brushing.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Cadet Camps request for three phase power.

**Business and Technology drivers:** Present line is quite inaccessible for routine patrols, maintenance and trouble shooting.

**Risks of proceeding:** Cost over runs manage costs effectively

**Risks of not proceeding:** Missed opportunity to relocate cross country to roadside.

**Alternatives:** Convert the existing cross country line from single phase to three phase. Similar results but still inaccessible extra road crossing, balancing capability reduced, maintenance brushing is not decreased due to road side construction.

**Recommendations:** Proceed with project as planned.

**Priority:** Type A - Avoid immediate effect of security of supply (old poles). Replace deteriorating facilities.

# Y10647

**Summary:** Street light davits are rusted and are in need of replacement. Some have been damaged by vehicle contacts. Many have direct buried wires which have not been reliable in the past. Steel davits would be replaced with galvanized davits. Underground cables would be replaced with wire in conduit to ensure better protection of the wire and easier replacement if a failure should occur.

Take the opportunity to update to current lighting standards as appropriate.

**Project Description:** Replace davits and install new wires in duct.

**Costs Schedule:** 107,287

**Benefits:** Structurally sound light davits, designed to proper lighting levels in a busy downtown. Replaces aged and deteriorated infrastructure.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Lights have gotten older. Aged lights have rusted due to exposure to salt and water. Cables feeding the lights are failing due to age, frost, dig-ins, water ingress.

**Business and Technology drivers:** New lights will be galvanized, design to RTAC standard.

**Risks of proceeding:** Cost over runs manage project effectively.

**Risks of not proceeding:** Increased risk to a failure of a davit in a busy public area.

**Alternatives:** Status quo not an option due to safety concerns.

**Recommendations:** Replace aged davits with new galvanized davit and replace direct buried wires with wires in duct.

**Priority:** Type A Eliminate hazards (rusted out davits). Replace deteriorated facilities.

# Y10253

**Summary:** Poles are old and some are anchored to trees. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. When this occurs the poles are changed.

**Project Description:** Change pole and associated hardware. Rebuilding on the opposite side of the road will allow us to pre build the job and minimize the outages to the customers.

**Costs Schedule:** 190,000.

**Benefits:** Reliability, safety. Reposition the line from cross county to road side. Improved access when patrolling, maintaining or troubleshooting the line.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older, Tagish road has been realigned several times reducing the access to the line.

**Business and Technology drivers:** Reliability and safety. Poles have deteriorated. New design will remove frost issues by building to heavy loading standards.

**Risks of proceeding:**
Cost overruns manage costs effectively.

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system due to pole condition. Limited access to the line.

**Alternatives:** Underground much more expensive

**Recommendations:** Continue normal utility practice of changing out pole when required. Rebuild on opposite side of road to allow for safer construction and minimize outages.

**Priority:** Type A
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# Y10315

**Summary:** Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. When this occurs the poles are changed. Step down transformer was eliminated.

.**Project Description:** Change pole and associated hardware. Convert primary voltage from 2400V to 14400 V.

**Costs Schedule:** 105,000

**Benefits:** Reliability, safety, standard distribution voltage.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older

**Business and Technology drivers:** Voltage conversion.

**Risks of proceeding:** Cost over runs effectively manage projects

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system.

**Alternatives**
Underground significantly more expensive
Concrete pole more expensive; would require many bucket trucks to work on poles
Composite poles new unproven technology; more expensive; would require many bucket trucks to work on poles
Steel poles - more expensive; would require many bucket trucks to work on poles
Delay Conversion. Both practical and cost effective to coordinate conversion with other required work.

**Recommendations:** Continue normal utility practice of changing out pole when required. Convert from 2400V to 14400V.

**Priority:** Type A Avoid immediate effect of security of supply (old poles). Replace deteriorating facilities.)

# Y10820

**Summary:** Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. All these poles are climbed by both the power and communication utilities and are at the point where climbing them is a safety hazard. Rebuilding on the opposite side allows Yukon Electrical to replace the line with minimal outage to customers.

**Project Description:** Change pole and associated hardware

**Costs Schedule:** 136,000

**Benefits:** Reliability, safety.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older

**Business and Technology Drivers:** Reliability and safety. Poles have deteriorated.

**Risks of proceeding:** Cost overruns manage project effectively

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system.

**Alternatives:**
Underground much more expensive

**Recommendations:** Continue normal utility practice of changing out pole when required.

**Priority:** Type A Avoid immediate effect of security of supply. Replace deteriorating facilities

**Business Case: 4 Avenue Klondike Inn to Ogilvie St. - 2007**

# Y10330

**Summary**: Poles are old. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add attachments too.

City of Whitehorse will widen driving surface and add new bike lanes between Ogilvie St and 2nd Ave intersection. As well, it's likely they will extend their storm sewer system on a proposed shared easement with YECL on the Westmark Klondike property.

YECL will have to remove all poles within the project area as they will conflict with new alignments. System (including street lighting) will have to be rebuilt.

**Considerations:**

- There are 2 old and substandard padmount transformers within the project area; one old live front at the Westmark and the other is a radial only unit feeding McDonalds.
- Poles are in poor shape. Some have been changed out due to rot and at least 1 is dry rotted and stubbed. Structures and assets in the downtown core are subject to more vehicular traffic and tend to be damaged often, in some cases to the point of unplanned replacement.
- Line conductor undersized and of various sizes.
- Line is built about 1.5 meter offset from buried water and sanitary lines and in close proximity of NWTel ducted system, excavation is therefore challenging for both utilities.

**Project Description:** Convert overhead line on 4th Ave. from Klondike Inn to Ogilvie St. to underground. Provide loop feed to McDonalds and remove live front transformer at Klondike Inn. Reestablish alignment as per standard with other utilities.

**Costs Schedule:** 650,000

**Benefits:** Continuity of service, upgrade capacity, remove hazards (poles and live front transformers).

**Resources and Funding:** Annual system improvement budget

**What has changed?** Poles have gotten older development in area requires changes, live-front transformers and their associated equipment are getting older and are safety risk to employees.

**Business and Technology drivers:** Poles have gotten older. Facilities require rebuilding.

- There does not appear to be a viable overhead corridor available on either side of the street, we have a drawing supporting this conclusion.
- As the street is presently lit with lights on existing wood poles, the project would have to include all new lighting. Lighting calcs, due to new road width, calls for 12 meter Gal standards staggered on both sides of the street supplied via U G feeds.(RTAC Guidelines)
- A rebuild at this time enables us to partner with the City on the construction site, civil excavations specifically.

**Risks of proceeding:** Cost over runs manage project effectively

## Business Case: 4th Avenue Klondike Inn to Ogilvie St. - 2007

**Risks of not proceeding:** Opportune time to install underground with City's road works

**Alternatives:**

a) **Leave as is:**
Not possible as alignments conflict.

b) **Move line out into the street:**
Not possible for obvious reasons

c) **Move line closer to property lines:**
Not possible as NWTel duct bank, buried water line and buried sanitary line right next to it leaves no overhead line corridor.

d) **Move overhead line across the street :**
At 4.5 M offset PL (standard) poles from MSB to Dollar Store would be set touching back of curb, way too close to driving area. Poles from Dollar Store to Spook Crk would be on the driving surface.

e) **Rebuild to underground on same side as existing overhead line:**
Recommended, alignment must be 3 M off set water line per City Engineer.

f) **Rebuild to underground on opposite side of the street:**
Would be more expensive as distances are longer and we wouldn't be able to take advantage of existing conduit crossings on Second Avenue and Ray Street.

**Recommendations:** The recommendation is to rebuild to full underground standard on the same side of the road

**Priority:** Type A Replace deteriorating facilities; eliminate hazards

**Generic Business case - 2007**

# Overall Justification

**Summary:** Poles are aging; some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add service to. When this occurs the poles are changed. Generally these poles were installed around 1969. In sections that are cross country, access is extremely challenging especially during wind, ice and snow storms. This has been a trouble area in the past.

**Project Description:** Change poles and take opportunity to move the line to road side to reduce ongoing brushing requirements and increase access and visibility for planned maintenance and outage restoration.

**Costs Schedule:** 150,000 in budget for 3 years for 2 large sections and 2 smaller sections

**Benefits:** Reliability, accessibility, maintainability, reduced ongoing brushing, road side construction requires 7.5m R W vs. 15m cross country.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older and line requires replacing, access to the line has diminished.

**Business and Technology drivers:** Reliability and maintainability.

**Risks of proceeding:** Cost over run manage project effectively

**Risks of not proceeding:** Outages or wild fire if pole fails; unsafe conditions to operate our system. Poor accessibility and visibility when trouble shooting during unplanned outages.

**Alternatives:** Underground much more expensive
Rebuild line in the same place difficult to trouble shoot during emergency restoration and very poor access for operation and maintenance, continue to maintain 15m R W for vegetation.

**Recommendations:** Continue normal utility practice of changing out poles when required. Take the opportunity to move the line to road side for visibility and maintainability.

**Priority:** Type A Avoid immediate effect of security of supply (old poles); eliminate safety hazards

# Y10637

**Summary**: Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. When this occurs the poles are changed. Generally these poles were installed around 1969. This section is cross country and challenging to accessible during wind, ice and snow storms. .

**Project Description:** Change poles and take the opportunity to move the line to road side to reduce brushing and increase access for maintenance and trouble shooting.

**Costs Schedule**: 150,000

**Benefits:** Reliability, maintainability reduces future brushing.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older

**Business and Technology drivers:** Reliability and maintainability. Poles have deteriorated.

**Risks of proceeding:** Cost overruns manage project effectively

**Risks of not proceeding:** Outages, or wild fire if pole fails; unsafe conditions to operate our system. Poor accessibility and visibility to find problems when trouble shooting and restoring power.

**Alternatives**
Underground much more expensive
Rebuild line in the same place tough to find problems and very poor access for operation and maintenance.

**Recommendations:** Continue normal utility practice of changing out poles when required. Take the opportunity to move the line to road side for visibility during emergency restoration and maintainability.

**Priority:** Type A Avoid immediate effect of security of supply (old poles). Replace deteriorating facilities.

# Y10904 &Y10888

**Summary**: The foundations supporting the plant and fuel system are unstable and allow shifting due to changes in ground conditions. There is a safety concern (flash hazard) with unit breaker located inside the plant. There is a code violation with the existing step up transformer bank (less than 2.7m from live parts to ground level)

**Project Description:** Redesign and build plant and fuel tank foundations. Relocate unit breaker to outside of the plant and replace existing step up bank with a pad mount transformer. This will call for fence and grounding modifications. Build to new fuel containment standards.

**Costs Schedule:** 116,600 2007, Unit Breaker, Plant & Transformer 91,500 forecast for 2008

**Benefits:** Code compliance and improved reliability of this plant.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Tank and plant foundation are becoming more unstable, new safety procedures in regard to flash hazards.

**Business and Technology drivers:** National Fire Code, Canadian Council of Ministers on the Environment PN1326 requirements, physical stability of our standby plant, safety concerns for employees, risk of fuel spills.

**Risks of proceeding:** Cost overruns manage project effectively

**Risks of not proceeding:** Fuel spill due to no automated fuel spill detection or due to shifting tank and plant. Safety risks due to arc flash.

**Alternatives:** Remove generation and fuel system from substation and community.

**Recommendations:** Build two concrete pads for the unit and the tank. Replace platform transformer bank with a padmount unit. Replace unit breaker with an outdoor breaker on the 25kv system.

**Priority:** Type A Eliminate hazards comply with legislation (fuel containment)

# Y11125

**Summary:** Underground cable is old and direct buried. The risers and stress cones are tape type. Transformers are radial fed live-front transformers. This cable is unjacketed cable.

**Project Description:** Rebuild old underground system to current standards.

**Costs Schedule:** 175,000 in business plan

**Benefits:** Reliability and safety, contingency spare for new standards (Replacement of Live fronts with dead front transformers)

**Resources and Funding:** Annual system improvement budget

**What has changed?** Aged infrastructure; lack of availability of live front transformers; safety and operating standards.

**Business and Technology drivers:** Risk of failure is high due to type of cables and stress cones. Safety concerns on operating old live front transformers increase constantly.

**Risks of proceeding:** Cost overruns manage project effectively

**Risks of not proceeding:** Unplanned failure to infrastructure, potential for extended outages. (cable splices and elbow installation during outage)

**Alternatives:** Leave as is and accept the risk.

**Recommendations:** Replace old infrastructure with safe reliable facilities, current standards.

**Priority:** Type A Eliminate safety hazards; replace deteriorating facilities, avoid immediate effect of security of supply.

# Y11126

**Summary:** Brushing is difficult or impossible to do in this area. For this reason we have designed an underground primary that leave the overhead secondary configuration in place. This allows us to not change the customer's service drops and entrances. In this specific area, the overhead utilities are located on the property line adjacent to the street.

**Project Description:** Build an underground primary system and salvage the primary on the existing line.

**Costs Schedule:** 140,000 in business plan

**Benefits:** Reliability, Reduced bushing costs, and requirements

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older. Brushing is challenging and costly, at times impossible. Changes from country residential to residential lots have created conflicts between residence's trees and power lines.

**Business and Technology drivers:** Reliability and safety

**Risks of proceeding: Cost** over runs manage project effectively

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system, on going trim costs when attempting to brush.

**Alternatives:** Over head with new wood poles Building new line near road could cause conflicts with driveways and existing deep utilities. We would have a main line near the road and very likely service poles into each house (double the amount of poles.)

**Recommendations:** Relocating the primary over head underground.

**Priority:** Type A Avoid immediate effect of security of supply. Replace deteriorating facilities.

# Y11123

**Summary:** Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add attachments too. When this occurs the poles are changed. This line feeds critical communication infrastructure for the phone company, the hospital and radio stations.

**Project Description:** Rebuild the line.

**Costs Schedule:** 200,000

**Benefits:** Reliability and safety.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older. Added customers at the end of the line, (Mountain top communications site)

**Business and Technology drivers:** Reliability and safety. Poles have deteriorated.

**Risks of proceeding:** Cost overruns manage project effectively

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system.

**Alternatives:** Underground much more expensive

**Recommendations:** Continue normal utility practice of changing out pole when required.

**Priority** Type A Avoid immediate effect of security of supply (old poles). Replace Deteriorating facilities.

**Summary**: This existing 266 ACSR line is a main tie between two different substations that feed a large part of downtown. The age of poles and Yukon Electrical being unable to replace overhead lines with overhead lines in this area require the company to replace it with underground cables. Due to the criticality of this line, and to ensure optimal operating flexibility, we will replace the line with a 600 Amp tie line. Recent zero lot line condominium development in the area has accelerated the project.

**Project Description:** Replace the overhead line between 2nd and 6th avenue with an underground line under Strickland Street.

**Costs Schedule:** 400,000

**Benefits:** Maintain critical tie line

**Resources and Funding:** Annual system improvement budget

**What has changed?** Customer development in the area.

**Business and Technology drivers:** Reliability and safety.

**Risks of proceeding:**
Cost overruns manage project effectively

**Risks of not proceeding:** Outages, public contacts or fire if pole fails; unsafe conditions to operate our system. Clearance conflicts with customer development.

**Alternatives:** N A

**Recommendations:** Convert line to underground

**Priority:** Type A

**Summary:** Poles are old and some are anchored to trees. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add services to. When this occurs the poles are changed.

**Project Description:** Change pole and associated hardware. Rebuilding on the opposite side of the road will allow us to pre build the job and minimize the outages to the customers.

**Costs Schedule:** 180,000 estimate subject to a field check

**Benefits:** Reliability, safety. Reposition the line from cross county to road side. Improved access when patrolling, maintaining or trouble shooting the line.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older, Tagish road has been realigned several times reducing the access to the line.

**Business and Technology drivers:** Reliability and safety. Poles have deteriorated. New design will remove frost issues by building to heavy loading standards.

**Risks of proceeding:**
Cost overruns manage costs effectively.

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system due to pole condition. Limited access to the line.

**Alternatives:** Underground much more expensive

**Recommendations:** Continue normal utility practice of changing out pole when required. Rebuild on opposite side of road to allow for safer construction and minimize outages.

**Priority:** Type A

# Y11080

**Summary:** Connect Pelly Crossing diesel plant to the grid to ensure it can work islanded and in parallel with the grid.

**Project Description:** Install controls, logic and synchronizing to connect Pelly Crossing plant to the grid. Install heat in the plant to ensure units are in hot standby mode.

**Costs Schedule:** 150,000

**Benefits** Pelly plant can run the town if the WAF grid is out. Pelly plant can feed into the grid if additional generation is required.

**Resources and Funding** Annual system improvement budget

**What has changed?** Pelly distribution system will have a grid source

**Business and Technology drivers** Reduce diesel fuel requirement in the community. Keeping the existing plant allows for a contingency supply for this community similar to other communities that have been converted from isolated generation to grid power.

**Risks of proceeding:**
Cost overruns manage costs effectively
None: YEC agrees that this is the correct plan (we have email dated Dec. 17, 2007)

**Risks of not proceeding :** Diesel is used to supply Pelly Crossing rather than use grid hydro.

**Alternatives:** Remove diesel plant from the community and not have a standby plant (alternate source for 400 - 500kw of load.)

**Recommendations:** Connect this community to the grid in a similar manner to others in the Yukon.

**Priority:** Type A interconnect generation, add new customers to clean power. Type B - reduce adverse effects

# Y11098

**Summary:** A transmission source will be available to Pelly Crossing. The source is about 1km west of the existing plant. The transmission substation produces 25kV power. Yukon Electrical plans to bring the power into the community and then tie it into the plant town 2400V delta system or to the 12.5 7.2kv wye system.

**Project Description:** Build a 3 phase 25kV line from the source toward the existing power lines and convert it to 3 phase 2400V delta or 12.5kV 7.2kV wye. Tie control of Hydro-diesel separation point remotely.

**Costs Schedule:** 140,000

**Benefits:** Convert Pelly from a diesel community to a hydro electric supplied community.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Hydro electric power supply is coming to the area

**Business and Technology drivers:** Eliminate reliance of diesel power when economically possible.

**Risks of proceeding:** Cost overruns manage project effectively

**Risks of not proceeding:** Potential load growth is limited unless generators sizes are increased.

**Alternatives:** Do not connect to the grid, remain on diesel generation**.**

**Recommendations:** Tie the community to hydro electric power.

**Priority:** Type A Interconnect generation. Add new customers to clean energy source.

# Y05105

**Summary:** When we have a fault on our power system the ground potential can rise. This high voltage would be put onto NWTel's ground neutral and could cause safety concerns and equipment damage.

**Project Description:** Run a nonconductive fiber from NWTel's wires into our plants.

**Costs Schedule**: 102,000

**Benefits:** Ensure safety to NWTel people and their equipment and bring our system up to standard (Canadian Electrical Code C22.1-06.) Addresses concern from communications company.

**Resources and Funding:** Annual system improvement budget

**What has changed?** NWTel officially notified us of the concern on November 9, 2007.

**Business and Technology drivers:** Safety, adherence to Canadian Electrical Code

**Risks of proceeding:** Cost overruns manage projects effectively

**Risks of not proceeding:** Subject NWTel people and or equipment to high voltages (Electrocution**)**

**Alternatives:** Use Positrons or a similar device to isolate us from NWTel. These are large expensive devices that require maintenance. Fiber and the equipment to convert fiber to copper and copper to fiber are zero maintenance and cheaper.

**Recommendations:** Run non shielded fiber (non conductive) into our plants subs to isolate our ground from NWTel infrastructure.

**Priority:** Type A comply with legislation; eliminate hazards.

# Y11121

**Summary:** This line has reliability concerns due to frost and snow build up. This is due to wires slapping together when one or more wires lose their snow ice buildup. This is occurs in places where the wires are above one another. Therefore vertical corners need to be tightened or removed by straightening the line or replaced with flat corners.

**Project Description:** Remove verticals, change structure and build to heavy loading standards.

**Costs Schedule:** Phase I 180,000 in 2008; Phase 2 180,000 in 2009 (Squanga towards Teslin).

**Benefits:** Improved reliability, reduction of highway crossings.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Customer concerns regarding reliability**.**

**Business and Technology drivers:** Reliability.

**Risks of proceeding:** Cost over run manage project effectively.

**Risks of not proceeding:** Teslin community continues to raise the issues around power quality and the number of outages. Servicemen continue to remove ice off the line in adverse weather conditions.

**Alternatives:** Different over head options were evaluated such as different conductor, longer arms, shorter spans, adjust conductor tension.

**Recommendations:** Construct to heavy loading standard.

**Priority:** Type A Carry existing load with minimum level of reliability, service and voltage. Eliminate safety hazards (for servicemen removing ice). Replace deteriorating facilities.)

# Unassigned project number

**Summary**:
As a requirement of our 2007 Dam Safety Review and as recommended in the water licensing application, a control structure is required. This structure will manage water flow into Franklin Lake.

**Project Description:** Design and build a structure to deal with excess water.

**Costs Schedule**: 150,000 in 2009 and in 2010 capital forecast

**Benefits:** Requirement of Water License.

**Resources and Funding:** Annual system improvement budget

**What has changed?** The requirement to manage water differently as per the Water License renewal and the as identified by the Dam Safety Review.

**Business and Technology drivers:** Water license will not be renewed without it.

**Risks of proceeding:** Cost over run manage project efficiently.

**Risks of not proceeding:** Non compliance with water license.

**Alternatives :** None identified

**Recommendations:** Comply with recommendations and requirements as Water license and Dam Safety Review.

**Priority:** Type A comply with Water Board Dam safety review.

# Y11103

**Summary**: Third party inspections have concluded the generator requires significant maintenance and repair. From this preliminary field based inspection, the assumption is the core is becoming delaminated and the bearing needs to be refurbished at minimum. A more detailed summary of deficiencies and cost repaired can only be provided when the unit is taken out of service and dismantled.

**Project Description:** Remove generator and transport to qualified repair shop. Reinstall unit and commission.

**Costs Schedule:** 125,000 budgeted

**Benefits:** Continue to off load local distribution sub and feeder (S8358). Unit supplies into the WAF grid.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Unit has been in service since the 1950's.

**Business and Technology drivers:** Life Cycle maintenance.

**Risks of proceeding:** Cost overruns manage project effectively

**Risks of not proceeding:** Unit failed and unable to produce energy.

**Alternatives:** Run unit to failure with the risk un- repairable damage.

**Recommendations:** Take it out of service and complete repairs.

**Priority:** Type A - Avoid immediate effect of security of supply. Eliminate safety hazards. Replace deteriorated facilities.

# Y11099

**Summary:** Inspections by third parties have recommended that this unit needs to be replaced due to normal wear and tear. Holes in turbine could lead to catastrophic failure. The unit which runs 24 7 has been doing so since 1950's.

**Project Description**: Remove and replace the turbine and shaft in Unit 2

**Costs Schedule:** 60,000 in 2008, 130,000 in 2009

**Benefits:** Hydro electricity and continue to off load local distribution substation and feeder (S8358).

**Resources and Funding:** Annual system improvement budget

**What has changed?** Wheel is worn out, water license is being renewed.

**Business and Technology drivers:** Life Cycle Replacement

**Risks of proceeding:** None

**Risks of not proceeding:** Catastrophic failure of turbine, unable to supply grid.

**Alternatives:** Run to failure with the risk of major damages and loss generation.

**Recommendations:** Order wheel in 2008, 40 week delivery time, supplier is in Europe.

**Priority:** Type A - Avoid immediate effect of security of supply

**Summary:** Street light davits are rusted and may fail. Some have been damaged by vehicle and road maintenance equipment contacts. Many have direct buried wires which have not been reliable in the past. Steel davits would be replaced with galvanized davits. Underground cables would be replaced in ducting for better protection of the wire and easier replacement if a failure should occur in the future.

**Project Description:** Replace davits and install new wires in duct.

**Costs Schedule**: 230,000 in 2009

**Benefits:** Structurally sound light davits, designed to proper lighting levels in a busy downtown, hwy and residential neighborhoods. Replaces aged and deteriorated infrastructure. Design to RTAC guidelines.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Lights have gotten older. Aged lights have rusted due to exposure to salt and water, some light have been damaged. Cables feeding the lights fail due to age, frost, dig-ins, water ingress.

**Business and Technology drivers:** New standard is galvanized davits and ducted cableing.

**Risks of proceeding:** Cost over runs manage project effectively.

**Risks of not proceeding:** Increased risk to a failure of a davit.

**Alternatives:** Operate to failure; lights would remain in service until they failed. Replace randomly and at a higher cost per structure.

**Recommendations:** Replace aged davits with new galvanized davits and replace direct buried wires with wires in duct.

**Priority:** Type A Eliminate hazards (rusted out davits). Replace deteriorated facilities.

# Project number not assigned at this time

**Summary:** IDEC has discontinued the manufacturing of our existing Programmable Logic Controllers (PLC) FA-2J and FA-3S PLCs.

It is recommended we change out the IDEC PLCs to GE Fanuc 9030 PLC. Parts and technical support are getting difficult to obtain. Many of our existing plants were converted to GE PLCs over 10 years ago and for consistency Yukon Electrical proposes to standardize on this type of PLC.

**Project Description:** Replace 20 year old computer control system and wiring.

**Costs Schedule:** Budget estimate of 77,000

**Benefits:** Able to have parts and support for failures, expansion, changes

**Resources and Funding:** Annual system improvement budget

**What has changed?** Computers have gotten older, devices are not be made anymore

**Business and Technology drivers:** Manufacture has stopped making the product and will soon stop supporting it. It is important for us to continue to remotely operate and interrogate our plants for reliability purposes.

**Risks of proceeding:** GE Fanuc will be replaced with something else eventually.
Cost over runs manage cost effectively

**Risks of not proceeding:** Unable to replace failed component in the plant control system. Unable to change program or add additional components to the control system. Failure of control system that allows us to operate the plants.

**Alternatives:** Attempt to find alternate sources for obsolete system.

**Recommendations:** Continue the PLC change out program we stared over 10 yrs ago.

**Priority:** Type A replace deteriorating facilities. Type B Provide necessary equipment and facilities to operate.

# Project number not assigned
# At this time.

**Summary** Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add attachments too. When this occurs the poles are changed. Generally these poles were installed prior to 1969.

**Project Description** Change poles and associated hardware. When we rebuild on the opposite side of the road it allows us to pre build the job and minimize the outages to the customers.

**Costs Schedule:** 75,000 in business plan

**Benefits:** Reliability and safety.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older

**Business and Technology drivers:** Reliability and safety.

**Risks of proceeding :** Cost over runs manage job effectively

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system.

**Alternatives:**
Underground much more expensive

**Recommendations:** Continue normal utility practice of changing out pole when required and as identified. Rebuild on opposite side of road to allow for safer construction and minimize outages (if required).

**Priority:** Type A Avoid immediate effect of security of supply (old poles), Replace deteriorating facilities.

**Summary:** Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add attachments too. When this occurs the poles are changed. Generally these poles were installed prior to 1969.

**Project Description**: Change pole and associated hardware

**Costs Schedule:** 200,000

**Benefits:** Reliability, safety of linemen and public.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older

**Business and Technology drivers:** Reliability and safety. Poles have mostly or totally deteriorated.

**Risks of proceeding:** Cost over runs manage project effectively

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system.

**Alternatives**
Underground more expensive
Concrete pole more expensive; would require many bucket trucks to work on poles
Composite poles new unproven technology; more expensive; would require many bucket trucks to work on poles
Steel poles - more expensive; would require many bucket trucks to work on poles

**Recommendations:** Continue normal utility practice of changing out pole when required.

**Priority:** Type A Replace deteriorated facilities.

**Summary:** Poles are aging. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add attachments too. When this occurs the poles are changed. Generally these poles were installed prior to 1969.

The routing of this portion of line was constructed along the original access to the area; the access has since been changed. We now have limited or no road side access to portions of the line, structures are also on property annexed by lake front lot owners.

**Project Description;** Change poles and associated hardware and rebuilding the line on the opposite side of the road.

**Costs Schedule:** 200,000

**Benefits:** Safety, Reliability and improved access for maintenance, trouble shooting and restoration.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Infrastructure is in excess of 40 years old and access has become limited.

**Business and Technology drivers:** Reliability and safety.

**Risks of proceeding:** Cost over runs manage project effectively

**Risks of not proceeding:** Outages, public contacts or wild fire if pole fails; unsafe conditions to operate our system.

**Alternatives**
Underground much more expensive

**Recommendations:** Continue normal utility practice of changing out pole when required. Rebuild on opposite side of service road to allow for safer construction and minimize outages and construct in location for easy trouble shooting.

**Priority:** Type A

# Y10754

**Summary:** Old Crow does not have the 110 back up if the largest unit is out of service. The logical replacement size is 500kW and this unit will not fit into the existing building. A modular unit is recommended to replace unit at the end of it life cycle.

**Project Description:** Purchase and install a modular 500kW unit. Cooling system will tie into existing cooling system to keep all units on hot standby.

**Costs Schedule** 100,000 in 2009; 800,000 in 2010

**Benefits:** Reliability of generation in an isolated community.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Load has increased, engine has reached end of life cycle.

**Business and Technology drivers:** Yukon minimum requirement is to have 110 capacity with largest unit out of service.

**Risks of proceeding:** While load could decrease, it is not likely.

**Risks of not proceeding:** Long term outages to isolated community with no road access and risk of not meeting community's electrical needs.

**Alternatives:** Buy larger unit not efficient for the load we have
Buy a smaller unit better heat rate but does not meet long term needs of the community.

**Recommendations:** Buy a 500kW self-contained generator, engine, unit breaker and controls

**Priority:** Type A Avoid immediate effect of security of supply

# Project number has not been assigned.

**Summary:** IDEC has discontinued the manufacturing of our existing Programmable Logic Controllers (PLC) FA-2J and FA-3S PLCs.

It is recommended we change out the IDEC PLCs to GE Fanuc 9030 PLC. Parts and technical support will are getting difficult to obtain. Many of our existing plants were converted to GE PLCs over 10 yrs ago and for consistency Yukon Electrical proposes to standardize on this type of PLC.

**Project Description:** Replace 20 year old computer control system and wiring.

**Costs Schedule:** 77,000

**Benefits:** Able to have parts and support for failures, expansion, changes.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Computers have gotten older, devices are not be made anymore

**Business and Technology drivers:** Manufacture has stopped making the product and will soon stop supporting it. It is important for us to continue to remotely operate and interrogate our plants for reliability purposes.

**Risks of proceeding:** GE Fanuc will be replaced with something else eventually.
Cost over runs manage cost effectively

**Risks of not proceeding:** Unable to replace failed component in the plant control system; Unable to change program or add additional components to the control system.

**Alternatives:** None identified

**Recommendations:** Continue the PLC change out program.

**Priority:** Type Type A replace deteriorating facilities. Type B Provide necessary equipment and facilities to operate.

**2009**

**Summary:** In the YEC 20 yr Resource Plan, it was recommended that all communities over 1MW be equipped with local generation to serve the immediate area during grid or line failure. The Southern Lakes area, including Carcross and Tagish, fits this criteria Yukon Electrical plans to install a generator in near the Carcross substation. This generator would be no less than 1.5MW as this is adequate sizing for the cold load pick up of the area.

**Project Description:** Purchase a 1.5MW generator complete with a step up transformer and double wall fuel tanks on skids. Install generating equipment with auto synchronizing technology in the Carcross substation.

**Costs Schedule:** 2,000,000 in 2009 budget

**Benefits:** 100 generation redundancy for the residents of the communities of Carcross and Tagish during grid or distribution line outages. .

**Resources and Funding:** Annual system improvement budget

**What has changed?** It has been determined in the Yukon that for communities that have loads over 1MW that back up generation should be considered.

**Business and Technology drivers:**

- Back up diesel for community over 1MW.
- N-1 support for 170 line failure (support for Whitehorse area power supply)
- This configuration would result in similar diesel backup as that which exists for other communities served by Yukon Electrical such as Haines Junction, Teslin, Carmacks, Ross River and Stewart Crossing.

**Risks of proceeding:** Availability of a generating unit, delays in delivery.

**Risks of not proceeding:** Potential for an extended outage in the event the grid or distribution line outages.

**Alternatives:**

- Status quo - Communities of Carcross and Tagish remain without an alternate generating source.
- Grid source from Jake's Corner this feed has same source for first 20km of line and is estimated to be a more expensive option.

**Recommendations:** Install 1.5MW (or larger generator) to improve reliability during grid outages to Carcross Tagish area.

**Priority:** Type A Carry existing load with minimum level of reliability, service and voltage
Type B- Reduce adverse affects to customers affected by outages.

# Project number unassigned
# At this time.

**Summary:** Poles are old. Some have no treatment or only treatment at the butts. Others due to shell rot or repeated climbing are not safe to work off of or add service to. A new overhead system would not be able to meet code due to the high voltage lines and transformers being too close to roof, window, and vents. Due to zero lot line zoning, in many areas, no right of way is available for overhead power lines. In addition, there is less impact to animal and tree contacts. Therefore Yukon Electrical is required to convert the overhead lines to an underground system.

**Project Description:** Install the padmount transformers, high voltage cables, and ducts into this area. Convert customers' overhead secondary services to underground services.

**Costs Schedule:** 300,000 business plan

**Benefits:** Eliminates a deteriorated system and meets current codes and regulations.

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older. New code requires more space from buildings.

**Business and Technology drivers:** New code requirements since the line was built. Poles have gotten older. Facilities require rebuilding.

**Risks of proceeding:** Cost over runs manage project effectively

**Risks of not proceeding:** Unable to provide service to the next customer that comes along, system is not able to accommodate load growth.

**Alternatives:** Status quo not acceptable as system need upgrading

**Recommendations:** Build the underground system to ensure existing code violations are dealt with and future loads can be served without concern for public safety.

**Priority:** Type A Avoid immediate effect of security of supply, comply with legislation. Replace deteriorating facilities

# Project Number Unassigned

**Summary**: Poles are aging. Some have no treatment or only treatment at the butts, a number of poles are stubbed. Others due to shell rot or repeated climbing are not safe to work off of or add services to. When this occurs the poles are changed. In a number of locations access is limited. Generally these poles were installed by the Air Force in the 1950's.

This area is fed from the most heavily loaded line and substation (Mountainview - S8358). Moving the feed to the subdivision to another substation will allow us to off load this substation and line and allow us to minimize outages by giving us a second source into the area for the rebuild.

**Project Description**: Change pole and associated hardware, convert 12KV system to 25KV. In some areas the over head will need to be placed underground.

**Costs Schedule:** 250,000 in 2009 Business Plan and 250,000 in 2010 Business Plan

**Benefits:** Reliability and safety

**Resources and Funding:** Annual system improvement budget

**What has changed?** Facilities (poles) have gotten older. Substation loading will shift.

**Business and Technology drivers:** Reliability and safety.

**Risks of proceeding:** Cost over run manage project effectively

**Risks of not proceeding:** Outages, public contacts or fire if pole fails; unsafe conditions to operate our system.

**Alternatives**
Underground much more expensive only do if alignments and narrow road width force us.
Concrete pole more expensive; would require many bucket trucks to work on poles
Composite poles new unproven technology; more expensive; would require many bucket trucks to work on poles
Steel poles - more expensive; would require many bucket trucks to work on poles

**Recommendations:** Continue normal utility practice of rebuilding the infrastructure.

**Priority:** Type A Avoid immediate effect of security of supply (old poles). Replace deteriorating facilities

**YEC-YECL-26**

**Reference:** Distribution New Extensions

**Requests:**

(a) With reference to page 9-1 lines 7-9, please provide more information regarding the discussions undertaken by YECL with regard to developing its new extension capital forecast, i.e., provide a list the communities, developers, engineering firms and customers consulted with, when and how such consultation occurs and provide detailed summaries of discussion or input received and how this information was integrated into or influenced the extension capital forecast.

(b) With reference page 9-1 lines 9-11, please provide policy or standard by which YECL assesses the ability of infrastructure to accommodate proposed growth. Provide examples of the types of customer service requirements that are considered.

(c) With reference page 9-1 lines 11-13, please provide detailed information on how YECL develops its estimate for facilities required for new extensions which are inserted in the forecast.

(d) With reference to page 9-1, lines 12-14, please provide detailed information on the consideration given to historical customer additions. How are these integrated into the forecast?

**Response:**

(a) City of Whitehorse, YTG, First Nation Governments, and developers are consulted. Our employees are involved in the community organizations such as Chamber of Commerce and participate in a number of workshops, planning meetings, and Charrettes where development is the primary topic. In certain situations Yukon

Electrical initiates the dialog and in others the developer or his consultant contact Yukon Electrical. Most developers incorporate the cost of electrical service into their preliminary business plan or before securing financing for a project and as a result contact Yukon Electrical on an ongoing basis. Formal documentation is generally started when the customer requests a firm estimate and the work order package is created.

(b) Yukon Electrical reviews a number of customer service requirements in its system planning. Some of these include, but are not limited to: customer load requirements, voltage flicker due to motor starts, service size, service entrance location, harmonics from customer equipment, service voltage required, existing pole locations, in-service dates, easement requirements etc.

(c) Generally, Yukon Electrical's estimating process is as follows: After an on site meeting with the interested party a detailed preliminary sketch is completed. An engineered design is developed based on engineered standard prints. Yukon Electrical uses a comprehensive proprietary computer program to assist with design and estimating. An estimate is then created with consideration given to the customer requirements listed in (b) above as well as other variables that have an impact on the final costs, such as backhoe for difficult digging conditions, additional travel, accommodation, brushing, surveying, easement, licensing, permitting, supervision and contingency. If applicable, standard investment amounts are calculated as per Schedule B Maximum Company Investment Page 25 of Electrical Service Regulations, October 18 2005.

For longer term forecasts Yukon Electrical conducts high level engineering assessment of the project. It also relies on historical information regarding similar projects that have been undertaken. In some cases Yukon Electric may use an average cost per lot as a reasonable way to develop its new extension forecast. For large or special equipment that may be required for a project, Yukon Electrical may seek estimates from manufacturers suppliers to include in the overall project costs. Yukon Electrical will also consult, in some cases, with other industry

professionals who may have experience with similar types of work to assist in the estimating of the project.

(d) Yukon Electrical recognizes that there will be unidentified new extensions that come forward on an annual basis. Historical trends that have occurred have proven that this is a prudent cost to include in Yukon Electrical's new extension forecast.

## YEC-YECL-27

**Reference:** Distribution Improvements

**Requests:**

(a) With reference to Reference page 9-1 lines 17-19, please provide YECL's definition of an acceptable level of system performance.

(b) With reference to pages 9-1 and 9-2, can the four major categories of distribution improvement projects be categorized by order of necessity or priority? Which distribution improvement projects currently included in the capital plan fall within each of the four major categories. Which are type A and how many are type B?

(c) With reference to Reference page 9-2 lines 11-13, please file the analysis referred to and used in the capital forecast.

(d) How many outages have been attributed to system deficiencies from the period 1996-2007?

(e) Describe the review process undertaken with regard to outages. Please provide any documentation or reporting that is provided.

(f) How many customer complaints regarding power quality concerns have been received from 1996-present? How many are received annually?

(g) With reference page 9-2 lines 16-18, please provide options reviewed for each major distribution improvement forecast for the test period. Please provide summary of engineering input sought and received for each project. Is such input sought prior to determining optimal option or afterwards? What criteria is used to determine the optimal option for system improvements?

(h) Please provide options reviewed for projects over 500,000 that have been undertaken over the period from 1996-2005.

(i) With reference to page 9-12, please provide a detailed description of past problems caused by old standard clearance of 3m to 5m clearance.

(j) Please provide authority for the new standard clearance distance employed. What other jurisdictions use the new standard?

**Response:**

(a) An acceptable level of system performance can have many facets. Some of the ones that Yukon Electrical considers very important are as follows:

- For protection of the system, it is important that coordination between protective devices is provided to minimize the frequency and size of customer outages.
- For voltage, Yukon Electrical monitors the system to ensure that voltage is maintained to the appropriate levels as identified in Yukon Electrical's Construction Standards Manual, print H5 derived from CSA standards CAN 3- C235-83 table 3.
- Other codes, regulations, and standards that apply to the operation of power systems by electric utilities in Canada and the Yukon are complied with
- Outages are minimal or at an acceptable level based on reliability indices used by the company.
- That the system is capable of providing reasonable service to new customers without negatively impacting service to existing customers.
- The system operates in such a way as it does not impose or present hazards to customers or employees.
- Operates and provides service to a customer that is as good as or better than service provided by other utilities taking into account the unique operating characteristics of providing service north of 60.

- That Yukon Electrical's own Construction Standards, Metering Standards, Safety Standards and operating procedures are adhered to as these have been developed as tools to assist in the operation of the power system.

- Customer concerns are minimized and addressed.

(b) It is difficult to list the distribution projects in the order of necessity and priority based on the four major categories of the distribution Improvement projects listed on page 9-1 and 9-2 of Yukon Electrical's application. At any given time a project in one of the four categories can become a priority depending on the circumstances. In addition, a project may have aspects in one or more of the four categories within its scope. Please refer to the business cases in YEC-YECL-25(a) Attachment 1 which identify the reason for the upgrade and the priority of the project.

(c) YEC-YECL-27(c) Attachment 1 is the tool generally used to bring forward operational concerns. These are prioritized and the ones that are most likely to proceed during the period are included in the forecast.

(d) Yukon Electrical understands that virtually all outages may in some way be attributed to system deficiencies. However, Yukon Electrical does use the outage data to identify trends that it uses as one tool for system improvement planning. Deficiencies are defined as inadequacies or incompleteness. The bar graph attached YEC-YECL-27(d) Attachment 1 list some of the more frequent causes of power line outages. Specific action or activities in each of the noted categories has the potential to reduce the number of outages due to that cause. ie Lighting arrestors could bring down lighting caused outages or minimize equipment damages. Enhanced brushing has the potential to reduce outages caused by trees falling on energized power lines. Bird protectors or cones have the potential to reduce outage on some equipment.

(e) Please refer to YEC-YECL-27(c) Attachment 1. Evaluations of the identified projects are then reviewed by Engineering Management and if required additional work and research are undertaken and the project is then included in the capital forecast process.

(f) Prior to 2006, Yukon Electrical used a main frame system that is no longer accessible for tracking customer concerns regarding power quality issues. Since that time a different data base for recording customer concerns regarding power quality is being utilized. In 2006, Yukon Electrical has tracked 13 power quality inquires; in 2007 Yukon Electrical tracked 27 power quality inquires.

(g) Please refer to the business cases provided to see the list of options considered for projects. Yukon Electrical's Supervising Engineer is responsible to review all aspects of the capital budget related to Distribution Improvements. Alternatives are reviewed to determine the optimal solution prior to a final decision on the scope of the project. Options are considered prior to moving forward toward the solution to avoid rework. Cost of options will be evaluated if options are equally effective in dealing with the issue. Considerations when choosing between options can include, but are not limited to: line routing, future growth, access, operability of the system, protection coordination, space in generator buildings, health safety & environment, code or regulatory changes.

(h) Please refer to YEC-YECL-25(a) Attachment 1 for a summary of projects greater than 100,000.

(i) The problems caused by the reduced Right of Way widths (3 or 5m) included more trees falling onto the lines, limited access for men and equipment, brush fires, and visibility for trouble shooting. Since Yukon Electrical has adopted the new brushing standard, tree related outages have been reduced by approximately 50 .

(j) Yukon Electrical's current brushing standards rely upon numerous other rules and regulations from the overhead power and communication industry in North America.

Yukon Electrical attempts to combine the relevant regulations and standards as well as experiences in specific regions of the country with its own practices. For example, the width of a power line right of way might be different in an area that has deep top soil providing root stability or where wind conditions are less severe or where the vegetation simply does not grow tall enough.

Other considerations might be the location of the line. For example, a power line in the back yard of a home where people continually access the area may require

a different vegetation management approach than one in a rural area where public access is less.

A number of regulatory bodies speak to how vegetation is to be managed when in the vicinity of over head power lines and communication facilities. Given the potential risks and consequences of inadvertent contact, tree removal when in the vicinity of lines is required.

Some of the regulatory agencies or bodies that speak to vegetation control are:

CANADIAN STANDARDS ASSOCIATION, over head systems, page 13, 4.1.7.1.

ALBERTA ELECTRICAL UTILITY CODE, which are standards pulled together by approximately 22 organizations working either in the industry or related industries.

OCCUPATIONAL HEALTH AND SAFETY REGULATIONS.

YUKON ELECTRICAL PROTECTION ACT.

The standard used by Yukon Electrical for vegetation management is also used by Northlands Utilities and ATCO Electric.

# DISTRIBUTION SYSTEM PROBLEM FORM

| Originator | Date | Division |
|---|---|---|
| | | |

| ☐ Property No. | ☐ Town | ☐ Co. Rural | ☐ REA |
|---|---|---|---|
| | | | |

| Service Area Name | No. | Short Description |
|---|---|---|
| | | |

| ☐ System Performance (1) | ☐ Life Extension (2) | ☐ System Replacement (3) | ☐ External Forces (4) | ☐ Special Projects (5) |
|---|---|---|---|---|

WHAT IS THE DEFICIENCY PROBLEM?

- Clearly describe what the problem is.
- List the problem or specific hazard to be corrected.

SUPPORTING DATA DOCUMENTATION

| ☐ Number outages past two years | ☐ Attach a copy of outage reports by , date and cause |
|---|---|
| ☐ Number customer complaints? | ☐ Attach list complaints by name, location, date & reason |

| Voltage charts attached? | ☐ Yes ☐ No | Load readings attached? | ☐ Yes ☐ No | Test results attached? | ☐ Yes ☐ No |
|---|---|---|---|---|---|
| Maps, photos, sketches attached? | ☐ Yes ☐ No | | | | |

Suggested solution to resolve the problem and time constraints.

**DISTRIBUTION PRIORITIES**

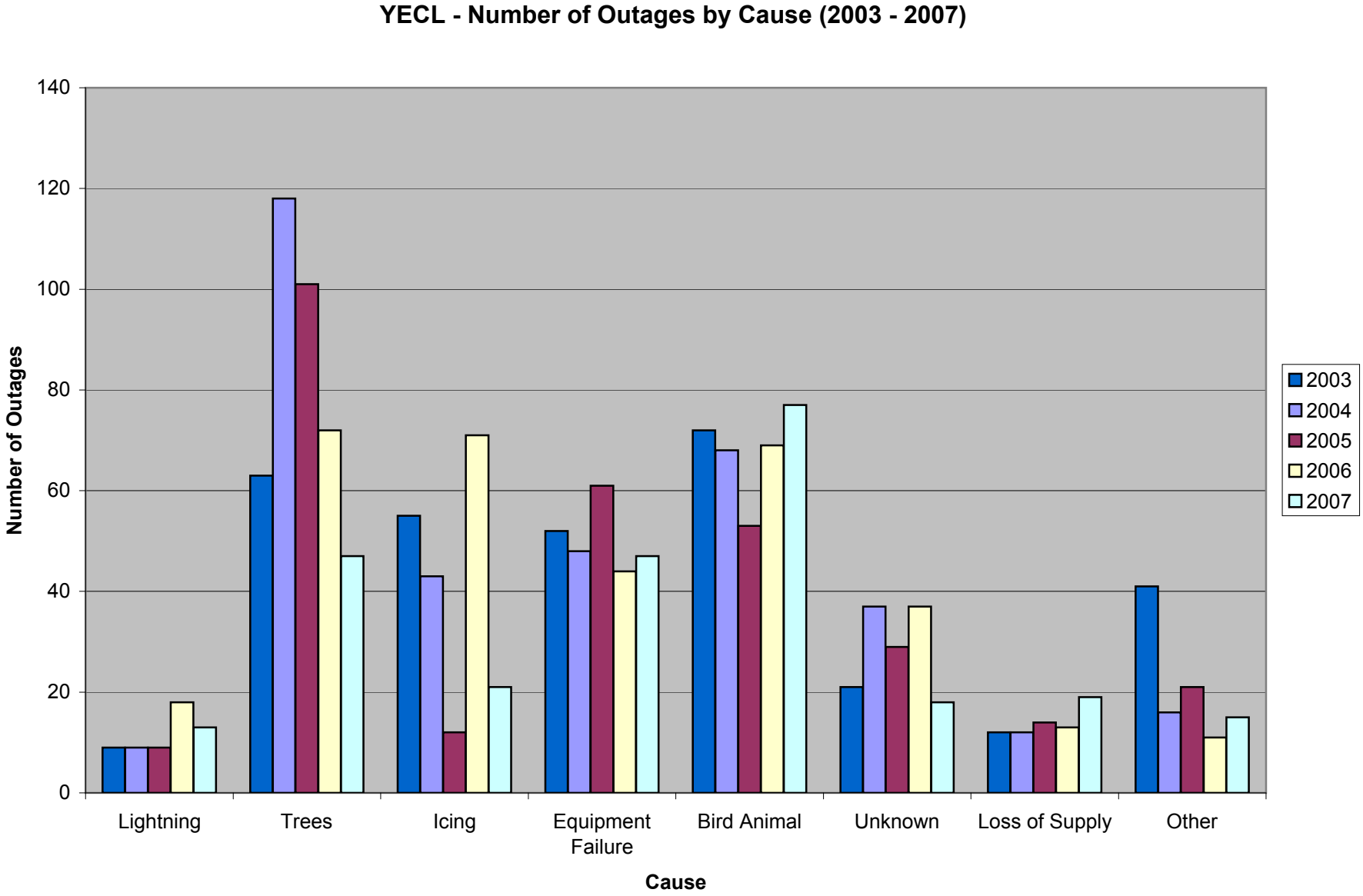
**Type A are required to**:
- ☐ Eliminate hazards
- ☐ Add new customers
- ☐ Move lines for roads
- ☐ Improve voltage
- ☐ Comply with Legislation

**Type B are to:**
- ☐ Reduce adverse effects
- ☐ Help APL to obtain unallocated areas

**Type C are to:**
- ☐ Increase operating efficiency
- ☐ Function according to standardized operating practices
- ☐ Benefit from long term cost savings
- ☐ Enhance public relations

| | Signature | Date |
|---|---|---|
| **Senior Serviceman** | | |
| **Maintenance Superintendent** | | |

| | | |
|---|---|---|
| **O M Manager** | | |


YECL - Number of Outages by Cause (2003 - 2007)
Number of Outages
140
120
100
80
60
40
20
0
Lightning
Trees
Icing
Equipment Failure
Bird Animal
Unknown
Loss of Supply
Other
Cause
2003
2004
2005
2006
2007

**YEC-YECL-28**

**Reference:** Conversion of Overhead Systems

**Requests:**

(a) With reference to Reference 9-12 - 4th Avenue Klondike Inn to Ogilvie St., please provide more information regarding how new overhead systems will not meet current electrical codes. Specify which electrical codes are violated and the provisions violated.

(b) The City is a partner is covering the costs to build underground rather than overhead. Please provide more information regarding cost sharing between the City of Whitehorse and YECL for this project.

i. Is this cost sharing undertaken pursuant to YECL utility investment policy? If the company's investment policy was not followed please explain how YECL derived its investment.

ii. By component please confirm which component of the company's investment policy with regard to maximum utility investment was used to determine YECL's investment.

iii. Please provide the total customer contribution, the company investment, the total cost of the project and the estimated demand.

(c) With reference to page 9-8 Yukon Electrical First Avenue Conversion, please provide a detailed rationale for conversion. Was any cost benefit analysis undertaken to support the prudency of conversion of a portion of the overhead system to underground locations?

(d) Was this distribution improvement undertaken as a system performance project a life extension project, a system replacement project or a forced project? Provide justification and rationale.

(e) Was this a type A or type B distribution improvement? Provide rationale.

(f) With reference to U G Rebuild Justice Centre to Whitehorse Star, please provide more information regarding how new overhead systems will not meet current electrical codes. Specify which electrical codes are violated and the provisions violated.

**Response:**

(a) In the case of this particular project, there were no specific electrical code violations. Yukon Electrical used this reference in a generic sense in that it may be one of many reasons why a project may need to be undertaken. For this particular project, relocating the displaced overhead line would violate The City Servicing Standards Manual's guidelines in that the new power line would be on top of existing water and sanitary lines. New lines need to be a minimum of 3 meters away. There was no other choice but to go underground.

(b) i) Please refer to YEC-YECL-25(a) Attachment 1 for the business case associated with this project. This project is a system improvement project that is being undertaken to replace an aged and obsolete portion of the distribution system and as such there are is no cost sharing customer contributions. Given the work is being done at the same time as City of Whitehorse work, Yukon Electrical is able to avoid civil costs that would otherwise be incurred.

ii) Please refer to YEC-YECL-28(b)(i).

iii) The total cost to Yukon Electrical for this distribution project was 650,582 and there was no customer contribution. Note that this is **not** a new extension project but rather a distribution improvement project, and as such there is no estimated demand associated with this project.

(c) Please refer to the business case found in YEC-YECL-25(a) Attachment 1

(d) Please refer to the business case found in YEC-YECL-25(a) Attachment 1

(e) Please refer to the business case found in YEC-YECL-25(a) Attachment 1

(f) For the Justice Center to Whitehorse Star Rebuild, the current electrical code could not be met by replacing the overhead system. The specific areas of concern were as follows:

- A minimum clearance of 3m horizontal or 3m vertical is the latest clearance requirement for overhead power lines. This is outlined in Alberta Electrical Utility Code.

- There is also a requirement for transformers to be 6m from any door, window or vents as per Canadian Electrical Code 26-242.

**YEC-YECL-29**

**Reference: Problem Areas**

**Requests:**

(a) With reference to Grey Mountain Top Cable, how often do failures occur to this system? Typically, how long are such failures?

(b) With reference to Carcross Km 129-131.5 Hwy 2 (south of Annie Lake Rd); please provide more information outlining how this line has been a problem area in the past. What problems have occurred? How often have such problems occurred? What has been the cost of such past problems? How does this cost compare to the cost of moving the line?

(c) Has a cost benefit analysis of been undertaken? If so, please provide summary or any report produced.

**Response:**

(a) With respect to Grey Mountain, historically outages have occurred once or twice per year and have been as long as 24 hrs or more. Generally the outages were caused by heavy snow loading, icing conditions or severe winds. Restoration was dependant on safe access to the area for men and equipment to make the repairs. The customers at this site are of significant importance to the emergency services for the City of Whitehorse and the Yukon Territory. No outages have been recorded to this location due to the above mentioned conditions since the rebuild took place.

It is important to note that these services were rebuilt for a number of reasons including age, obsolescence, access issues, and safety concerns.

(b) Please refer to the business case in YEC-YEC-25(a) Attachment 1. In all capital projects an element of professional judgement and operational experience and expertise is incorporated. Rebuilding and relocating this line from cross county to road side reduces outages and outage duration as well as decreased ongoing

brushing costs. The cost of rebuilding next to the existing line compared to rebuilding next to the road is similar in design, brushing, and digging conditions.

(c) Please refer to the business case in YEC-YEC-25(a) Attachment 1. The cost of rebuilding next to the existing line compared to rebuilding next to the road is similar in design, brushing, and digging conditions. Construction is safer as men are not working in the vicinity of an energized line and outages are reduced to the communities of Carcross & Tagish.

**YEC-YECL-30**

**Reference:** Pole Replacements

**Requests:**

(a) Does YECL have a pole inspection policy or program? If so, please provide.

(b) How often are pole inspections undertaken and by whom? Please provide any inspection reports or record of pole inspections undertaken over the past 10 years.

(c) Are pole replacements capitalized or expensed? Provide rationale.

(d) At what age do poles need to be replaced? How many poles being replaced are currently at this age or older?

(e) Does YECL have in place a plan for pole replacements on an ongoing basis? Please provide.

(f) Please describe pole replacement operations undertaken since the 1996 1997 GRA. Provide the dollar value of pole replacements undertaken from 1996 to 2005.

**Response:**

(a) Yes. Please refer to YEC-YECL-30(a) Attachment 1

(b) This program is new for Yukon Electrical, beginning in 2008. The expected cycle of the program is 9 years.

(c) Pole replacements are capitalized as it is in accordance with Generally Accepted Accounting Principles.

(d) Wooden poles 25 years and older are generally considered for the program. This is when the 9 year testing cycle commences. Age is only one factor that is considered when replacing pole. Please refer to the details provided in the program (YEC-YECL-30(a) Attachment 1).

(e) Please refer to section 9 page 9-18, and 9-25 which outlines the miscellaneous pole changes for the test years. The pole test program being undertaken in 2008 will add further value to Yukon Electrical's pole replacement program.

(f) Yukon Electrical has not tracked the number of poles or costs specifically associated with pole replacements throughout its service territory.

# DISTRIBUTION SYSTEM

# POLE PLANT

# MAINTENANCE PROGRAM

| | | |
|---|---|---|
| **Prepared by:** | Doug. Koppel<br>Doug Koppel | **Date:** 2004.12.09 |
| **Eng. Approval:** | Blair Howell<br>Blair Howell | **Date:** Dec 8, 2004. |
| **Maint. Supt. Approval:** | Al Nagel<br>Al Nagel | **Date:** DEC 08, 04 |
| **O&M MGR Approval:** | Howard Werden<br>Howard Werden | **Date:** Dec 8, 2004 |

**REVISED DATE:** December 2004
**REVISION DATE:** January 2008

**This program remains the property of ATCO Electric**

ATCO Electric

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*Appendix H:* *Pole Stubbing Diagrams*
*Appendix I:* *Drill pattern for internal treatment*
*Appendix J:* *MSDS Sheets*
*Appendix K:* *Release Indemnity Forms*
*Appendix L:* *Miscellaneous Pole Replacement*
*Appendix M:* *Danger Pole Replacement*
*Appendix N:* *Pole Change Field Check Form*
*Appendix O:* *Pole Condition Codes*

| ATCO Electric | Company Division:<br>Distribution, Isolated Generation, Fleet, Forestry | |
|---|---|---|
| | **STANDARD Maintenance Management** | |
| **Primary Process:** | **Pole Plant** | Number: |
| **Revision Date:** | | |
| **Document Owner:** | Distribution Maintenance Supt. | |

# Part I – Program Outline

## 1.0 Purpose

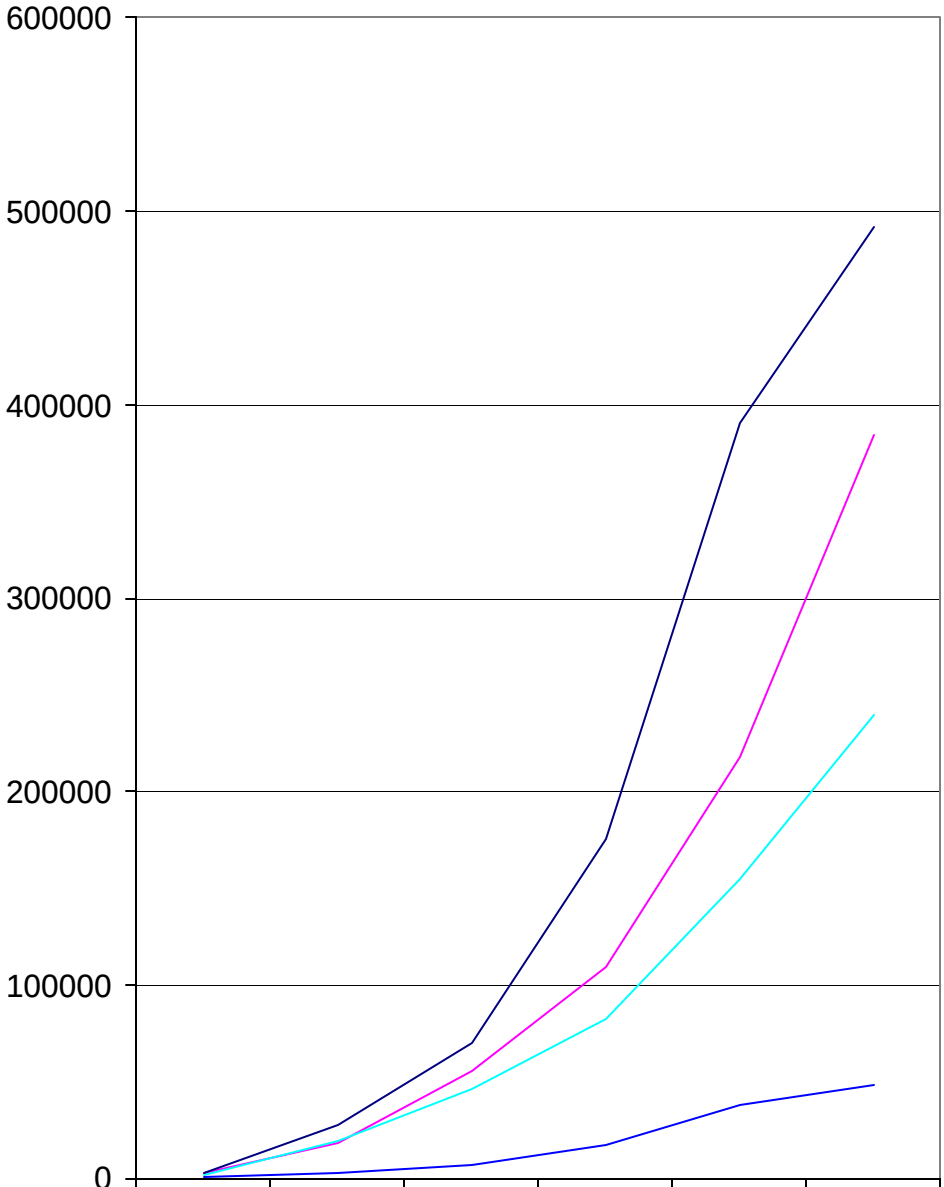
To provide a safe and economical pole management program that extends the life cycle of the distribution system.

## 2.0 General

The Pole Plant Maintenance Program provides procedures for inspecting and maintaining all wood poles owned by ATCO Electric or R.E.A.L. It is divided into two parts – a program outline that describes the program structure and administration, and a technical detail section to assist inspectors in assessing the condition and strength of all poles in service, including those that may be required to support additional loads.

Industry knowledge about wood pole preservation provided the context for developing the ATCO Electric Pole Plant Maintenance Program, recognizing the limitations of available resources.

**Distribution Asset Base**
**(assets are in constant $)**
**(1949/1959/1969 line lengths are estimates)**




| | 1949 | 1959 | 1969 | 1979 | 1989 | 1999 |
|---|---|---|---|---|---|---|
| Poles And Fixtures: ($ x 000) | 2569 | 18363 | 55444 | 108876 | 218178 | 384374 |
| Overhead Conductor: ($ x 000) | 1949 | 18682 | 45655 | 82523 | 154745 | 239862 |
| Line Length: (km) | 300 | 2618 | 6766 | 16990 | 37880 | 47727 |
| System Pole Estimate: | 3090 | 26965 | 69690 | 174997 | 390164 | 491588 |

## 3.0 Program Objectives

1. To administer the program uniformly company-wide.
2. To ensure results and data are standardized.
3. To determine the safest, most economical plan to test and treat poles.
4. To properly plan for and budget for upcoming work.
5. To provide REAs with a sound and credible program to look after their assets.
6. To implement a timely preventive maintenance program to extend the maximum useful life of poles.
7. To ensure the first time and subsequent testing procedure is well defined.
8. To ensure treating procedures for all poles are well defined.
9. To ensure all poles are maintained in safe condition and will not create any undue hazards to the public and company operating and construction staff.

## 4.0 Schedule

A nine-year schedule is to be developed by each district or O&M Supervisor to ensure systematic inspection and treatment of all poles. Depending on the critical importance of the line, the schedule may be adjusted to test and/or treat poles on a more frequent basis to increase reliability.

1. Divide each district into nine areas (one per year), roughly based on rural boundaries. Try to keep approximately the same number of poles in each area. For numbered lines, it is recommended to complete the entire line as one project. Work from one switching device to another to avoid overlapping outages for pole changes.

2. Establish and publish the pole plant maintenance schedule based on previous test and treat cycles and line patrol findings. Rotation can be adjusted as necessary.

3. Each year, use the pole plant maintenance schedule to prepare maps indicating the lines to be tested, treated and recorded according to specific property numbers and/or line ownership (e.g., R.E.A.L poles, oilfield poles, ‘5L’ distribution line poles, etc.)

4. For the second cycle of the program, use the first cycle schedule with alterations where necessary.

## 5.0 Three-Step Program

The program consists of three key steps.

### 5.1 Patrol

Patrol is necessary only if the targeted block is in its first cycle and no previous records exist, or existing records are inaccurate. If the targeted block is in its second cycle, refer to first cycle records.

Before proceeding, contact R.E.A.L offices through the region CSS to obtain approval to proceed in their areas.

### 5.2 Test And Treat

All poles owned by ATCO Electric or R.E.A.L should be tested and treated, according to schedule requirements. Customer-owned poles are excluded.

Pole species and treatment varies by region and service area, according to the year of construction and available supplies (see Appendix A: Pole Identification). In some areas, distribution poles have been retreated and may have been retreated more than once. Records of this are available.

In general, bandages should be applied to:

- All poles considered suitable during the course of the test and treat program described in detail in Part II, section 4.0;
- All poles that have been partially excavated or reset;
- Butt-treated poles where the ground level has been raised above the commercially treated area and
- Full Length Pressure Treated (F.L.P.T.) poles, which no longer have sufficient preservative to prevent decay.

A reasonable estimate of the remaining service life of F.L.P.T. poles can be attained by analyzing core samples to determine the amount of preservative remaining. In the case of butt treated poles, most of which are over 40 years old, a field examination is adequate.

### 5.2.1 Pole Plant Test and Treat Priority

Based on industry knowledge, the following priority has been established. Detail on each species' acceptance of the original treatment is also provided.

1. **Previously Untreated Poles.**

2. **Butt Treated Poles**

   Various species accepted the original butt treatment to a greater degree than others did. Following are the species and original treatments in order of priority.

   ***Fir and Larch***
   Locating fir poles in your area will likely be a problem. Once located, a permanent record should be kept for future reference.

   Due to density, these species have a very thin shell of originally treated wood. A first time ground line bandage should be installed after poles have been in service 25 years.

   See section 4.1 for detailed test and treat requirements. If Hollow Heart is found, and the pole has adequate shell strength, the poles should be given an internal treatment. Use the Wood Pole Strength Table (Appendix B) to determine the remaining strength if poles have pole top decay and to determine if the pole requires replacement. Fir and Larch should be re-inspected in **Nine (9)** years and given an internal treatment at that time, if justified.

   ***Pine***
   Pine poles generally accepted the original treatment well. A first time ground line bandage should be installed after the poles have been in service 25 years.

   See section 4.1 for detailed test and treat requirements. Pine poles should be tested for Hollow Heart. If strength is adequate, an internal treatment should be administered. If above ground decay has advanced to an unsafe condition, the pole should be replaced. These poles should be re-examined in **Nine (9)** years and re-treated, if justified.

   ***Butt Treated Western Red Cedar***
   Decay in these poles will be greatest at ground line and usually external. If the decay is not too far advanced, a ground line bandage should be installed as cedar readily accepts re-treatment**.** If decay has advanced beyond recommended limits, the pole should be replaced.

See section 4.1 for detailed test and treat requirements. If internal decay is discovered and the pole has adequate strength, an internal treatment should be administered. These poles should be re-examined in **Nine (9)** years.

**3. Full Length Pressure Treated (F.L.P.T.) Poles**

In general, full-length pressure treated poles should provide a service life of 25 years before preservative retention levels drop below toximetric threshold and decay sets in. When poles are relocated, or have their ground line changed, they should be retreated. Random sampling for assays should be carried out by persons who are properly trained in sampling and handling methods. Reports should indicate what subsequent work is required or when further tests should be carried out.

The following program should be adhered to for testing and treating of full-length pressure treated wood poles:

| Species | 1st Test & Treatment | 2nd & Subsequent Tests |
|---|---|---|
| Fir & Larch | 25 Years | Nine Year Plan |
| Pine | 25 Years | Nine Year Plan |
| Cedar | 25 Years | Nine Year Plan |

### 5.2.2 Test and Treat Program Outline

To simplify test and treat, procedures have been based on pole age (in 10-year blocks):

- Pre 1960 butt treated poles: test, record and treat internally
- 1960-1969 F.L.P.T. poles: test, record, internally treat and apply a bandage if not previously bandaged
- 1970-1979 F.L.P.T. poles: randomly test (10 per cent), treat internally, visually inspect, sound test and record the remainder, and apply external bandage to all unless previously bandaged
- 1980-1989 F.L.P.T. poles: randomly test (10 per cent), treat internally, visually inspect, sound test and record the remainder.
- 1990-1999 F.L.P.T. poles: visually inspect, sound test and record
- 2000 –2009 F.L.P.T. poles: visually inspect, sound test and record

Test and treat technical details are provided in Part II of this manual.

## 6.0 Record Keeping

To aid contract inspectors in identifying line ownership, a color-coded map with legend must be prepared prior to the start-up meeting.

- Pole inspectors are to record all poles using the Pole Inspection Report Form (see Appendix C). All inspection data, treatment and recommended actions must be recorded.
- A Construction Inspection Report must also be completed by the drive-up patrol for all pole changes (see Appendix D).
- Inspectors are required to send all completed Pole Inspection Report forms to the ATCO Electric Maintenance Supervisor, both electronically and on hard copy. ATCO Electric will be the sole owner of all records.
- The Pole Inspection Report form will be used to administer the test and treat contract payment.
- The Pole Inspection Report form will define the scope of the pole change and stubbing requirements for the following year. The information can also be used for manpower planning and to define material, equipment and outage requirements.

### 6.1 Invoices

To assist in assigning expenses to the appropriate budget (Operations & Maintenance or Capital), contractor invoices will provide a breakdown of test and treat activities based on pole age. (See Part II, section 3.0 for details).

This distinction is necessary because testing does not increase the life expectancy of poles, and is therefore deemed a maintenance cost. However, treating poles does add life expectancy to the pole plant system and is therefore deemed a capital expense.

## 6.2 T&T INVOICE VERIFICATION PROCESS

6.2.1 Match “miles” indicated on master map with “miles” documented on hardcopy or electronic record.
6.2.2 Verify that number of poles per master map “mile” approximate to the numbers indicated in the records [sequence number].
6.2.3 Verify that poles sequence numbers on urban master maps match sequence numbers in the records.
6.2.4 Verify ownership indicated in record as REA or AE matches color coding on master map.
6.2.5 Match tasks indicated on invoice with tasks indicated in appropriate Pole Admin. Electronic version “Action Count Report”.
6.2.6 Review all information documented per pole for accuracy on a random selection basis [5% / 6% of each plant number] i.e. land location, treatment, etc.
6.2.7 As per 6, check calculation that original circumference – decay deduction =present circumference.
6.2.8 Verify [as per item 6. above] that required circumference is accurate as per wind load chart Appendix B, Table 111 in program.
6.2.9 Remember * O&M tasks are indicated as such on upper left side of invoices, Capital tasks are indicated as such on lower left side of invoices .

# 7.0 Quality Control

## 7.1 Quality Control Audit

A quality control audit is to be completed to make sure contractors hired to carry out test and treat within the distribution system are doing quality work and are completing all requirements, as described in Part II, section 4.0. The audit involves:

- Completing a random (one per cent to two per cent) sampling of the test population to check that proper drilling, plugging and tagging has occurred on poles that are to remain in service.
- Completing a random (one per cent to two per cent) sampling of the population to check that proper drilling, plugging and tagging for internal treatment has occurred.
- Completing a random (one per cent to two per cent) sampling of the population to check that pole bandages were properly applied.

The Test and Treat Audit Form is provided in Appendix E.

## 7.2 Safety

ATCO Electric Supervisor or designee will complete a weekly work site visit and complete the ATCO Electric Job Observation form "Review of Worksite Safe Work Performance" (refer to the AE Intranet, Health & Safety Forms and Reports) and return to appropriate O&M Superintendent.

Alternately on a biweekly basis the Supervisor or designee will complete a Work Activity Audit on Test and Treat Crews and formally document all findings on the appropriate form (Appendix F).

### 7.2.1 ATV/OHV

All contract personnel are to be formally trained in operations and hazards associated with ATV operation and training certificate or letter verifying individuals trained to be provide and filed with ATCO Electric Pre-qualified Supervisor.

When operating an all terrain vehicle or snow vehicle as defined in the off-highway vehicle act, the worker shall wear protective headgear that has been approved by one of the following standard setting organizations for use as protective headwear in motor vehicle applications:

(a) Canadian Standards Assoc. (CSA CAN3-D230-M85)
(b) American National Standards Institute (ANSI)
(c) Snell Memorial Foundation
(d) British Standards Institution

### 7.2.2 Safety Glasses

Approved safety glasses are to be worn by Test and Treat crew personnel while performing all tasks associated with testing and treating of poles.

### 7.2.3 First Aid

Field locations have specified hazards deemed High Risk Hazards and will require the following for each truck in the field:

- One #2 First Aid Kit
- Three Blankets (1 woven, 2 thermal)
- Each crew member is the holder of a standard First Aid Certificate

### 7.2.4 Restricted Sites

All test and treat personnel will be familiar with the procedures (as per ATCO Electric Safe Practices Manual) of working in or around H2S sites.

### 7.2.5 Clothing

Test and treat crews will have available and wear F.R.C clothing when directed by ATCO Electric.

### 7.2.6 Underground Service Risers

No excavations will be attempted by test and treat crew personnel at poles with under ground services attached unless they are Qualified Utility Journeymen. (See 2.3 Excavation for details)

### 7.2.7 WHIMIS/TDG

All lead testers shall have a valid WHIMIS certificate. A valid TDG certificate is required if the crews are handling or shipping any hazardous material.

### 7.2.8 Salvaged Poles

When salvaging reusable or NCV poles from the system refer to the Materials Management and EH&S Policies regarding reuse, disposal or donation of poles.

## 8.0 Field Co-ordinator Responsibilities

- Reviews and assists Project Manager with overall schedule, production estimates and material requirements
- Reviews schedules and working maps with Maintenance supervisor in applicable Region
- Contacts applicable Senior Serviceman and reviews schedule and arranges a start up meeting in each District
- Attends start up meeting with contract crew and applicable O&M Superintendent and assists with competency verification check on new crews
- Arranges for material pickup or delivery with Region Stock keepers and return of any residual material remaining
- Reviews program technical details with Contract Supervisor on an ongoing basis
- Completes weekly status report detailing production and contractor complement
- Identifies future scheduling and completion requirements with contract and O&M Superintendent

- Reports safety and quality discrepancies to contractor supervisor as soon as possible and has authority to "shut down" the crew
- Assists contractor crews with any extra ordinary details regarding specific Districts in their daily tailboards
- Ensures that government legislated and ATCO Electric Safe Work Environmental Practices Procedures are understood and adhered to by contractor.
- Advises the O&M Superintendent of any incidents, personal, vehicle, environmental or customer related
- Follows up on any further requests regarding incident reports
- Ensures contract supervisor is following reporting in requirements of the TDSOP
- Provides emergency call numbers for contact crews
- Ensures contract crews are completing accurate and concise inspection reports and master maps as required by the program details
- Monitors safety of contract workers by completing a documented weekly Supervisor Work site Visit
- Alternately monitors accuracy of work and safety of random crews by completing a biweekly work activity check as per Appendix E Test and Treat Audit Form
- Completes a quality control audit on work completed as per 7.1 of Pole Plant Program
- Reviews program technical details to ensure personnel familiarity on an ongoing basis
- Assists O&M Superintendent with interpretation of records and invoices when required
- Completes biweekly L.T.E invoices for O&M Superintendent
- Carries out other duties as required

## 9.0 Budgeting

| | |
|---|---|
| INTERNAL TEST & RECORD | Rod/Boracol – contact O&M for current rates<br>Rod/Boracol + Record – contact O&M for current rates |

| Test & Treat | O&M Exp. | Cap. Exp. |
|---|---|---|
| Pole Patrol | v | |
| Record only | v | |
| Test & Record | v | |
| Inspect, Re-treat & Record | | v |
| Re-treat & Record | | v |
| Internal Treat & Record | | v |
| Field Check for replacement work order prep | | v |
| Prep Replacement work order | | v |

# POLE PLANT MAINTENANCE PROGRAM
# Part II – Test and Treat Technical Detail

## 1.0 General

### 1.1 Qualifications

**LEAD INSPECTOR** shall be well trained to recognize decay and other defects, calculate wood pole strength from the tables in the appendices determine the pole species, prepare the field report and organize the work. They shall hold a valid driver's license and be well versed in dealing with property owners.

**ASSISTANT INSPECTOR** shall train under a Lead Inspector until he becomes competent in all aspects of decay and other defect interpretation, wood pole strength determination, pole species identification and other duties the Lead Inspector must be qualified in to perform independently. This period of training will usually be approximately 5000 poles under direct supervision.

**LABORER** must be physically fit to undertake the rigorous work of excavation and back filling. Will have knowledgeable in product application and job quality. Shall be able to recognize the obvious rejects and exercise caution where called for, such as on poles with underground services.

**CONTRACTOR** to have a current and recognized Safety Program. ATCO Electric and contractor personnel to obtain permission prior to entering private property.

**TESTING** includes visual inspection, sound testing, excavation and drilling to determine if the pole has sufficient strength to support the load it carries. Poles requiring testing include:

- In-service poles scheduled for test and treat.
- Poles which are to bear additional loads.
- Poles in doubtful condition.

**TREATMENT** means the application of a preservative to prevent decay.

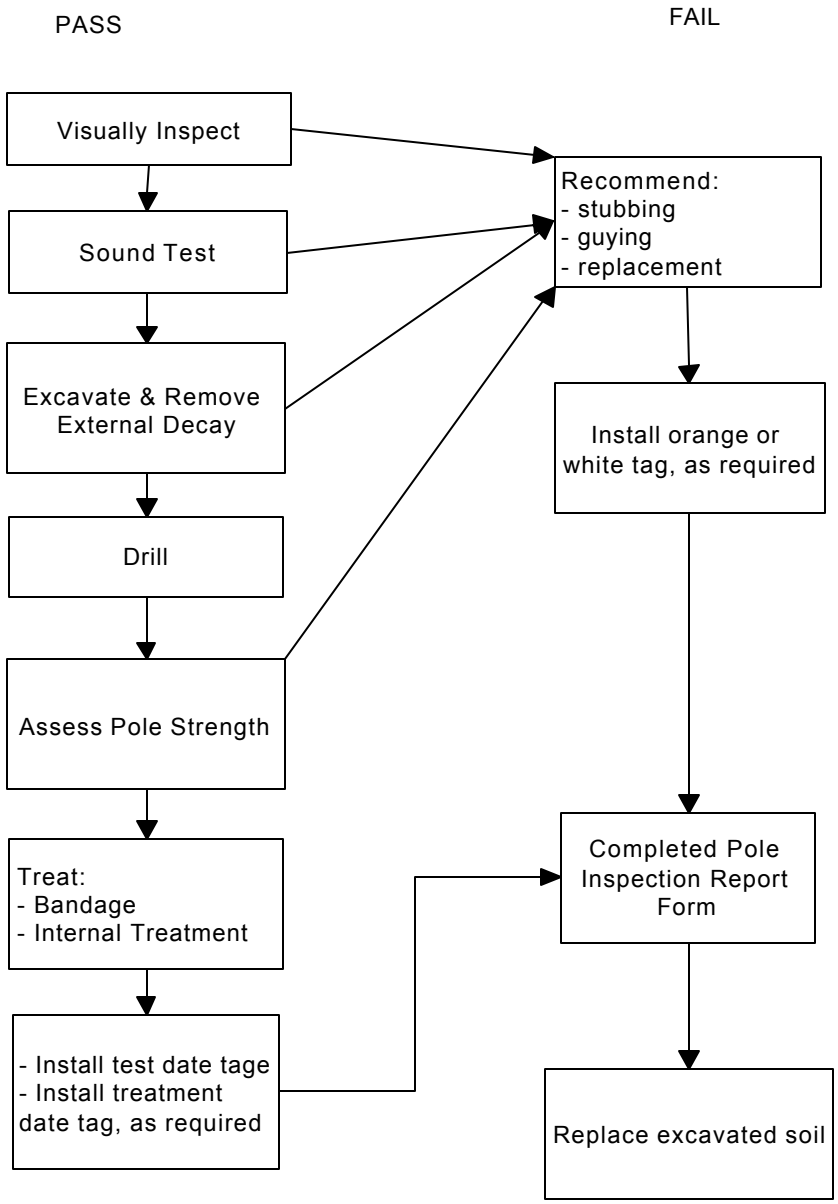
Pole testing, treating, stubbing and replacement should be done only by trained and competent personnel.

## 2.0 Process

Each step in the test and treat process is to be conducted consecutively, in the order indicated on the flow chart on the following page. Not all steps may be required – specific requirements based on the age of the poles is provided in section 4.0.

If the pole fails any test during the process, further testing is to be aborted and recommendations made for further action.

**TEST AND TREAT PROCESS FLOW CHART**



## 2.1 Visual Inspection

A thorough above ground inspection is done first to detect defects such as split tops, through checks, lightning damage, shrinkage or discoloration at the top of poles. Defects should be reported on the Pole Inspection Report form so that further investigation can be made by a lineman. Broken poles, including poles with cracks or cross breaks, should be immediately condemned for replacement.

Sawdust in checks or on the ground at base of pole is indicative of the presence of carpenter ants or bees in the upper part of pole. If present, continue with sound testing and drilling to determine the extent of the damage.

## 2.2 Sound Testing

Sound testing is used to detect decay inside the pole. Use a hammer to strike the pole around the sides from the ground line to about eight feet above the ground line. The minimum number of sounding marks per pole required is as follows: Four sounding marks in the first foot of poles starting at ground line (one in each quadrant of the pole). Twelve sounding marks in the remaining height of the pole should be evenly distributed in all four quadrants of the pole, unless a pocket is detected at a particular sounding mark then additional sounding will be required. The hammer blow will usually detect rot immediately below the surface by breaking the thin outer shell of sound wood. Remove this as external decay.

## 2.3 Excavation/External Decay Removal

**** No excavations to be under taken on poles with underground cables attached***

***** No excavations required around poles encased in cement or pavement. The test holes in this case will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm-400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.***

Excavate the base of the pole to expose decay below the ground line. Remove the soil around the pole to a minimum of six inches.

Decayed wood on the surface can best be detected by inserting a knife blade about 1/8 inch below the surface and prying a splinter loose. If the splinter pulls along the grain from the wood, the wood is sound. If the wood is broken without forming a splinter, the wood should be considered decayed.

***Probing*** **-** Probing is used to detect decay in checks and exposed pockets. It is done with a piece of steel wire 6 inches long and about 1/8 inch diameter (the reinforcing wire from scrap ACSR is ideal). Jabbing sharpened bars into the surface of a pole is prohibited as this may damage fungus resistant wood and allow decay to start in less resistant areas. The surface of the pole should be probed concentrating on areas near and in deep checks. If the wood is felt to yield under pressure, decay should be suspected.
All external decay, including decay in enclosed pockets and checks, must be removed before taking circumference measurements. If decayed wood is included in these measurements, the strength of the pole will be over-estimated. Also, decayed wood on the surface or in pockets may deprive sound wood of treatment. Suitable tools for removing decay include, scrapers, wire brush, hatchet, and wood chisel.

Take care not to remove sound wood as this will weaken the pole. After removing the decay, form a taper to about 6 inches above the ground line to provide a smooth surface.

## 2.4 Drilling – Hollow Heart Effective Shell Thickness

To detect Hollow Heart, the pole should be drilled at least three times at a minimum depth of 6 inches below ground, angling the bit at 45° and drilling toward the center at the N, SW and SE quadrants. The drill is to be 12.5 mm (1/2"). Depth of bore should be 200-250 mm minimum depending on circumference of pole.

**** No excavations to be under taken on poles with underground cables attached***

***** No excavations required around poles encased in cement or pavement. The test holes in this case will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm-400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.***

While drilling, note any change in the rate of the penetration of the drill – the sudden collapse of wood under the drill indicates decay. Powdery borings also indicate decayed wood.

After completing three drillings, measure the length of sound wood in each hole using the Shell Thickness Indicator or another acceptable method. The radial thickness of sound wood in the shell is calculated by multiplying these measurements by 2/3. To find the "Effective Shell Thickness," disregard the largest thickness and take the average of the two smaller thickness.

**For example:**

The lengths of sound wood in each boring have been measured at 7-1/2 inches, 6 inches and 3-3/4 inches.

Thickness of the shell at each boring:

Boring 1: 7 ½" X 2/3 = 5 inches
Boring 2: 6" X 2/3 = 4 inches
Boring 3: 3 ¾ X 2/3 = 2 ½ inches

Disregard the largest reading. Take the average of the two smaller readings:

Average: (4" +2 ½" )/2 = 3 ¼ inches
Refer to Appendix B, Wood Pole Strength Table H-11-4, for Hollow Heart Deductions of Pole Strength. Deductions for shell thickness are provided in ½ inch increments. Find the nearest measurement BELOW the average reading of 3 ¼ inches (3 inches). Deduct the corresponding allowance from the minimum measured circumference to determine the Hollow Heart effective shell thickness.

Poles with an effective shell thickness of less than two inches are to be condemned. If the pole is to be maintained in service, all drilled holes must be plugged with tight treated dowels. If this plugging is not done, decay organisms will have easy access to wood, which may be less decay resistant. A supply of appropriately sized treated dowels, four inches long, is required for plugging the holes.

## 2.5 Pole Strength Assessment

After external decay has been removed and drilling completed, measurements to assess strength are made as follows:

- **Minimum Measured Circumference**

  On poles where there has been no loss of wood, a thin (1/4 inch wide) flexible metal tape should be drawn tightly round the pole at the ground line; this measurement will be the "minimum measured circumference."

  On poles that have been cleared of rot near the ground line, the measurement should be made over the trimmed portion. A series of measurements down the trimmed

portion may be required to determine the smallest measurement. This smallest measurement will be the "minimum measured circumference."

- **Exposed Pockets**

  The width and depth of all exposed pockets should be measured. The length of the pockets along the pole axis is not significant.
  - Measure the width of the pocket at its widest point. If the pocket widens below the surface of the pole, estimate this width.
  - Measure the depth of pocket (the distance across the growth rings toward the center of the pole) by tightly drawing the measuring tape from the surface opening of the pocket to the sound wood inside the pole.

  After each exposed pocket has been measured, deduct pocket allowances from the minimum measured circumference (i.e. pocket or pockets).

- **Effective Circumference & Required Circumference**

  The Effective Circumference of a pole is a measure of its actual strength. It is found by deducting allowances for exposed pockets and Hollow Heart from the minimum measured circumference.

  The Required Circumference is a measure of pole strength necessary to support its conductors and other attachments. Appendix B: Wood Pole Strength Table H-11-4 gives the basis for calculating these requirements.

  When a line is to be inspected, note the factors common to each pole. For example, the line might be constructed on 40-foot poles in a heavy loading area with three-phase 3/0 conductors at 250-foot spans.

  The required circumference for most poles is calculated as follows:

| | |
|---|---|
| **Starting Circumference** | **24.5"** |
| **Load Factors:** | |
| Heavy Load Area | + 3.0" |
| Three-Phase Primary | + 4.0" |
| **Required Circumference** | **31.5"** |

For additional loading, add the allowance to the basic 31.5". For example, adding two secondary conductors will add 2" to the required circumference (1" each), for a total of 33.5".

If the Effective Circumference is equal to or greater than the Required Circumference (that is, the pole is strong enough to support its load), recommend treatment, depending on pole age.

- **Assessing Above Ground Strength**

The procedures outlined above are usually adequate for assessing the strength of a pole. However, there may be circumstances when it becomes necessary to check the strength of the above ground portion of the pole. These circumstances include:

(a) When a line is to be loaded with three phasing or larger conductors, or when heavy banks of transformers are to be installed.

(b) When there has been no ground line deterioration, but sapwood has rotted on the above ground surface of the pole.

(c) When poles appear to have extreme taper, rot or obvious damage such as bird holes.

Assess the required strength halfway up by multiplying the ground line circumference by 0.8. The required strength at the top of the pole can be assessed by multiplying the ground line circumference by 0.6.

If there are decay pockets in these areas, use the Wood Pole Strength Table (Appendix B) to make the necessary deductions.

## 2.6 Treatment

If the pole has sufficient strength, proceed with treatment as per the requirements in section 4.0. Further information on specific treatments is available in Appendix F.

### 2.6.1 External Treatment (Bandage)

External treatment involves the application of a preservative bandage below the ground line to prevent ingress of fungus and insects for eight to 10 years.

**Bandage Requirements:**

1. The bandage shall be 60 cm wide, such that a layer of preservative 50-cm wide is applied to the pole.
2. Active ingredients may include copper, copper naphthanate and borax.
3. Copper naphthanate based greases require a grease thickness of 6.35 mm.

**Bandage Application:**

1. To prepare the pole, excavate to a depth of 22 inches below ground line, remove all external decay and any decay in exposed pockets. If the pole is set in a lawn or pasture, continue the excavation to a depth of 24 inches (2 feet) so that when work is completed, the top of the bandage will be at ground level.

   (If the surrounding area is pavement or concrete or have live underground service cables, apply an internal treatment instead of a bandage.)

2. Measure the circumference of the pole 2 inches above the ground line. Cut the bandage at a separation point that allows for this length plus 2” to 6” for overlap.

3. Gently pry any ground wires away from the pole so that the bandage can be placed directly against the exposed wood. Remove the containment strips from the bandage.

4. Lower the bandage into the excavation and place around the pole, smoothing against the pole surface and using the overlap to draw the bandage tight at the top. Do not apply excessive pressure that might displace the preservative. (It may be helpful to have a coworker assist in this part of the operation.)

5. Staple the top edge of the bandage to the pole, overlapping the ends. Use a hand tacker rather than a hammer as a hammer blow might cause preservative to be splashed.

6. Backfill the excavation, being careful to protect the bandage from large rocks by placing the face of a spade against it.

7. When the application is complete, the top of the bandage should be about 2 inches above ground level except in lawns and pasture, where the top of the bandage should be level with the ground.

8. Attach a product identification tag to the pole at eye level on the roadside face to show the pole group year for future reference [e.g. 1970's] and contractor identification.

*(See Appendix G for diagrams.)*

### 2.6.2 Internal Treatment

Apply to all poles with Hollow Heart resulting from decay or insect infestation. This treatment is effective for eight to ten years.

**Treatment requirements:**

Internal treatment consists of a boron rod or fumigant applied as described below. Active ingredients may include copper, copper naphthanate, anhydrous disodium octaborate, disodium octaborate, tetrahydrate and anhydrous sodium.

**Treatment application:**

**Internal Treatment Application:**

Application efficacy is dependent on initial treatment load rates and the preservative's ability to lock in to the wood cell structure.
Internal pole treatment with a copper/boron, water soluble diffusable co-biocide is a proven system to effectively control and prevent the internal infestation of wooden utility poles by various forms of fungal spores and insects. Using this method, an initial load rate is 6kg./cuM of BAE equivalent copper/boron complex will be adequate to establish an 8-10 year efficacy term.

**Installation instructions:**

Follow the label instruction and insert 1-10 mmX120mm copper/boron rod in each of the three previously drilled inspection holes located 150mm below ground line. Tightly plug with an oversized treated plastic plug. The plug must be removable to permit Q.C. inspection and also to re-access the hole to do subsequent re-treatment without drilling extra holes. If the poles circumference (see chart #1 below) dictates the necessity for more than 3 rods, an additional treatment zone will be developed at the ground line zone.

Drill a second trio of holes starting at ground line using compass points South (S), NE, and NW, to alternate with the holes drilled below. Prior to drilling these holes determine if one rod per hole is sufficient or whether an additional rod per hole will be required to achieve the toxic loading desired. This decision will determine the proper hole drill depth, for either one or two rods per hole, in this second tier of holes.

This drill pattern and hole location will allow the migration of the active ingredients within the pole to dome up to the upper threshold and down to the lower levels (450mm) below ground line. this application procedure is in compliance with label instructions, manufacturers labeling and ATCO Electric Appendix 1.

| **Pole Circumference** | **Treatment** |
|---|---|
| Up to and including 34” | - 3 rods, one per hole |
| 35” to 39” | - 6 rods, one per hole |
| 40” and greater | - 9 rods, two per hole (second tier) |

See Appendix I for the recommended drilling pattern. Drill to be 12.5 mm (1/2")

### 2.6.2.1 Internal Flood

Depending on the results of the test at each applicable pole, a field decision will be made by the tester to internal flood the pole to destroy or inhibit active fungus or insects at or above the ground line area. A minimum of 0.5 liters of liquid Boron (10% in-solution) will be injected into each pole to accomplish this, as follows. Start at the 150mm above ground line level and continue up the pole at 150mm intervals, in a spiral fashion until beyond the infestation area. Under normal conditions a maximum of 3 holes or 450mm above ground line will be sufficient. These holes will be drilled with a 19 mm bit to a depth of 250-300 mm and bore cleaned of all cuttings, filled, then plugged with an oversized treated, removable plug. To ensure each pole receives the required amount of liquid treatment, ensure product is injected slowly and that no air pockets are created to give the false impression that the bore is filled.

### 2.6.3 Other Recommendations

While treatment is to be completed by the pole inspector, decisions on type of stub, guying, or replacement will usually rest with the supervisor.

- **Stubbing**
  Poles considered ideal candidates for stubbing should meet the requirement that the pole shell and heart are in good condition with no shell, heart, or butt rot present, starting from 300mm above ground and proceeding up the poles and from 300mm below ground and down, to provide a solid surface for the stub to align itself to.

  Poles whose effective circumference (measured over the taper) within the 600mm area, is less than the required circumference, but whose original circumference (measured over good wood just above the trimmed part of the pole) is equal to or greater than the required circumference, recommended reinforcing the ground line with a stub. (see Appendix H for diagram)

  ***Stubbing may not be economically justified in all areas.***

- **Guying**
  Where poles are inadequate because of side load due to unsupported services, guying should be recommended. With guying, treatment or stubbing may be adequate to maintain the poles in service.

- **Stubbing vs. Replacement**
  On occasions when decay or insect damage is not discovered in time but the above ground line portion of the pole is sound, stubbing of the pole may be advisable especially when replacement entails considerable transfer work. A stubbed pole must be given a supplementary treatment to kill the nesting insects or prevent the decay from progressing in the above ground section. Metal stub size and proper-banding criteria would be approved by Engineering Standards.

- **Replacement**
  Only poles that cannot be maintained by treatment, stubbing or guying should be recommended for replacement. These include broken poles, poles that have both internal and external decay at the ground line area and poles that have Hollow Heart with effective shell thickness less than two inches. Poles in this condition have deteriorated where they have become unsafe and are not economical to maintain.

## 2.7 Tag Installation

### 2.7.1 Inspected and Treated Poles

- **Inspected Only** – Attach a dated test tag at eye level on the roadside face of the pole.

- **Inspected and Treated** – The dated test tag and pole group year tag is to be attached to the pole at eye level on the roadside face of the pole. If internal treatment was applied, the dated product tag will be installed at eye level on the roadside face of the pole.

- **Stubbed Poles** – The dated test tag is to be attached on the side of the stub facing the road. The date tag should be
located immediately below the upper band. If steel stubs are installed, the date tag is to be located immediately above the stub face of the pole on the roadside.

### 2.7.2 Poles Requiring Additional Attention

Inspected poles requiring additional attention or replacement must be marked with an acceptable **ORANGE** plastic tag stapled to the pole. The tag is to be a minimum of 3 inches square and 1/16 inch thick (minimum) made of solid plastic, and should be place not less than 5 and not more than 7 feet above the ground line.

Emergency poles as defined previously, will also be tagged with a white replacement tag and poles will be changed in the same year as the test.

If any pole poses an immediate hazard (danger pole), the exact location and type of structure must be identified and the pole tagged with a **WHITE** replacement tag minimum of 3 inches square and 1/16 inch thick (minimum) made of solid plastic. The O&M Superintendent is to be notified immediately. When evaluations are completed after normal working hours or on weekends, contact After Hours Assistance (1-800-667-1261) to advise the Region Supervisor On-call or the Edmonton Emergency Centre (780-423-4211).

## 2.8 Pole Inspection Report Form

The Pole Inspection Report form is the primary record of all test and treat activities and the basis for administering payment to contractors.

Specific instructions on completing each section of the form is provided in Appendix C. It is important that the abbreviations and codes provided there be used consistently for ease of budgeting.

- All inspection data, treatment and recommendations are to be included on the Pole Inspection Report form.
- All Pole Inspection Report form numbers are to correspond to numbers indicating the location (miles) on the master map.
- One clean master map to be provided with numbered miles corresponding to the Inspection Report page numbers.
    - One master map for a combination of REA/AE/OF poles in a block.
    - One master map for each town
    - One master map for each '5L' distribution line in block

  Inspection routes and numbering to be in an organized and easy to follow sequence.
- All Pole Inspection Report forms are to indicate line ownership so that plant numbers can be charged with the appropriate capital charges. (To aid contract inspectors in identifying line ownership, a color-coded map with legend will be provided at the start-up meeting.)
- Inspectors are to indicate on a new, clean map all pole replacement locations noted on the Pole Inspection Report form.
- All Pole Inspection Report forms are to be sent both electronically and on hard copy to the ATCO Electric region maintenance supervisor. ATCO Electric will be the sole owner of all records.

## 3.0 Invoicing

Contractor invoices must indicate the number of poles tested, recorded and/or treated according to each pole age block, and assign the cost to the correct budget, as per the following:

| Pole Age Block | Activity | Budget |
|---|---|---|
| 1950s | • Test and record | O&M |
| | • Retreat | Capital |
| 1960s | • Test and record | O&M |
| | • Retreat | Capital |
| 1970s | • Test, record and retreat (10 per cent) | Capital |
| | • Retreat & record (90 per cent) | Capital |
| 1980s | • Test & record (10 per cent) | O&M |
| | • Record (90 per cent) | O&M |
| 1990s | • Record | O&M |

Summary sheet indicating number of poles in each age group and tasks completed to accompany each invoice by Plant Number.

- One for REA
- One for Company Rural Poles
- One for Oilfield Poles
- One for Towns
- One for each '5L' distribution line

## 3.1 Task Codes

A –Test, bandage, record
T –Bandage and record (treat)
I –Test and record (inspect)
V –Visual, sound, and record
B –Install boron rod
L –Internal treat (liquid)

## 4.0 Test and Treat Requirements, by Age Block

Pole identification information is provided in Appendix A.

Before starting excavation on any pole, check that it should be tested. The following categories of poles **DO NOT** require testing:

- **Full Length Pressure Treated Poles (F.L.P.T), depending on age**
  These may only be required to be recorded. See sections 4.2 to 4.6 for details.

- **Broken Poles**
  These poles should be immediately condemned for stubbing or replacement.

- **Severely Decayed Poles**
  Poles so obviously decayed at the ground line or pole top that the minimum required circumference would not be met are usually condemned for stubbing or replacing.

The procedures outlined below are based on the age of the poles, grouped in 10-year blocks. Procedures for stub and burned poles are also provided, in section 4.7.

**Refer to section 2.0 for details on testing, treatment application and tag installation.**

## 4.1 Pre 1960 Butt-Treated Poles

1. Visually inspect, sound test, excavate, drill and assess the strength of each pole according to the instructions provided in sections 2.0 to 2.5. If the pole fails any test, stop testing and go to number 3.
2. If the pole passes all tests:
   - Install a test date tag and remove any previous test date tags.
   - Treat internally for Hollow Heart and/or insects using the approved treatment.
   - Install a treatment date tag.
3. Determine further action required (i.e., stubbing,* guying, replacement) and tag the pole accordingly.
4. Record inspection data, treatment and recommended action (if any) on the Pole Inspection Report form.
5. Replace the excavated soil.

***NOTE: Stubbing may not be economically justified in all areas.***

***NOTE: Do not excavate around poles with underground services attached unless supervised by a qualified utility employee.***

***** NOTE: No excavations required around poles encased in cement or pavement. The test holes in this case will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm-400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.***

## 4.2 1960 – 1969 F.L.P.T. Poles

*Note: If any pre-1960 F.L.P.T. poles are found in the test block, test and treat them the same as 1960 – 1969 poles.*

1. Visually inspect, sound test, excavate, drill and assess the strength of each pole according to the instructions provided in sections 2.0 to 2.5. If the pole fails any test, stop testing and go to number 3.
2. If the pole passes all tests:
   - Install a test date tag and remove any previous test date tags.
   - Treat internally for hollow heart and/or insects using the approved treatment.
   - Apply an approved bandage, if not previously bandaged.
   - Install a treatment date tag.
3. Determine further action required (i.e., stubbing,* guying, replacement) and tag the pole accordingly.
4. Record inspection data, treatment and recommended action (if any) on the Pole Inspection Report form.
5. Install a 1960s date tag to simplify age identification in the next cycle.
6. Replace the excavated soil.

****NOTE: Stubbing may not be economically justified in all areas.***

****NOTE: Do not excavate around poles with underground services attached unless supervised by a qualified utility employee.***

***** NOTE: No excavations required around poles encased in cement or pavement. The test holes in this case will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm-400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.***

## 4.3 1970 – 1979 F.L.P.T. Poles

1. On 10 per cent of 1970s poles (one pole every kilometer):
   a. Conduct full testing (visual inspection, sound test, excavation, drill and strength assessment). If the pole fails any test, test the rest of the 1970s poles in that kilometer.
   b. Treat internally for Hollow Heart and/or insects, using the approved treatment.
   c. Install test and treatment date tags.
2. On all 1970s poles:
   a. Conduct visual inspection and sound tests.
   b. Apply an approved bandage and treatment date tag unless previously bandaged.
   c. Record inspection data, treatment and other recommended actions on the Pole Inspection Report form.
   d. Install a 1970s date tag to simplify age identification in the next cycle.
   e. Replace the excavated soil.

***NOTE: Do not excavate around poles with underground services attached unless supervised by a qualified utility employee.***

***NOTE: No excavations required around poles encased in cement or pavement. The test holes in this case will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm-400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.***

## 4.4 1980 - 1989 F.L.P.T. Poles

1. On 10 per cent of 1980s poles (one pole every kilometer):
   a. Conduct full testing (visual inspection, sound test, excavation, drill and strength assessment). If a pole fails any test, test the rest of the 1980s poles in that kilometer.
   b. Treat internally for Hollow Heart and/or insects, using the approved treatment.
   c. Install test and treatment date tags.
   d. Replace the excavated soil.
2. On all 1980s poles:
   a. Conduct visual inspection and sound tests.
   b. Record inspection data, treatment and other recommended actions on the Pole Inspection Report form.

***NOTE: Do not excavate around poles with underground services attached unless supervised by a qualified utility employee.***

***** NOTE: No excavations required around poles encased in cement or pavement. The test holes in this case will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm-400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.***

## 4.5 1990-1999 F.L.P.T. Poles

1. Conduct visual inspection and sound tests on all poles, and install test date tags. No treatment is required unless data indicates (i.e., evidence of insects).
2. Record inspection and treatment data on the Pole Inspection Report Form.

## 4.6 2000 - 2009 F.L.P.T. Poles

1. Conduct visual inspection and sound tests on all poles, and install test date tags. No treatment is required unless data indicates (i.e., evidence of insects).
2. Record inspection and treatment data on the Pole Inspection Report Form.

## 4.7 Other Poles

### 4.7.1 Stub Poles

1. Conduct visual inspection and sound test.
2. Inspect the tightness of the metal bands:
   a. If the bands are loose and there is indication of shell rot, the pole and stub should be replaced.
   b. If the bands are tight, drill near the metal banding area.
      - If the pole passes the drill test, treat for Hollow Heart and/or insects, install test and treatment date tags and record all inspection and treatment data on the Pole Inspection Report form.
      - If the pole fails the drill test, this is an indication of sub-surface rot. Recommend replacement of the pole and stub on the Pole Inspection Report form.

### 4.7.2 Burned Poles

For poles that have been scarred by prairie or forest fire but still have adequate strength to remain in service, install a bandage (if burned at ground line) and apply an internal treatment to deter infestation of insects and ingress of fungus at ground line.

# POLE PLANT MAINTENANCE PROGRAM
# Part III Pole Replacement and Stubbing

## 1.0 Miscellaneous Pole Replacement

Any rotten (shell/hollow heart) undersized (pole circumference) fire/machine damaged or clearance deficient pole to a maximum of two poles per Plant Number identified by field staff. These are to be replaced under the blanket project assigned to each Region. Appropriate form (Appendix L) must be completed and sent to Maintenance Supervisor for approval prior to work being undertaken.

## 2.0 Emergency Pole

Defined as a pole, not meeting specifications defined in Appendix B, but determined by formal test to be of sufficient critical condition to have to be changed in the same year as the formal test. Maximum of two poles per Plant Number can be changed using the emergency/danger project number set up for each Region. A field check form and map will need to be completed to activate the change. Three or more poles will require the set up of a separate project number per plant.

## 3.0 Danger Pole

Defined as a pole, identified by formal test, and found to be in such critical condition as to warrant immediate attention by either temporarily guying, bracing, or replacement within 24 hours. Forward completed form Appendix M to Maintenance Supervisor when job is complete. Use Regional emergency/danger pole project number to track the change.

## 4.0 Pole Replacement/Stubbing

All necessary documentation must be prepared in advance (i.e., inspection report, maps etc.). Complete, in-depth documents and maps will provide the main information for the tendering package.

4.1 Obtain approval from REA's to proceed with work.
(Lightning pole go to Task 87360)

4.2 Obtain appropriate Project number from Maintenance Clerk.

4.3 Pole replacement tags will be marked with sequential numbers that match those on the staking list to avoid conjestion on busy non-urban maps.

- Follow the selected route and document replacements. Keep in mind re-spanning requirements, neutral lowering, re-conductoring if feasible; structure height increases or rerouting. The documentation should also include the

physical conditions of the site (e.g., swamps, crops and farm field operations) and replacement timing.

4.4 Arrange manpower to complete a formal field check, using design criteria summary produced by the Tech. Services Group to aid the field checker in determining pole selection to match conditions found in the field. Document all replacements on maps and pertinent information on the Pole Change Field Check Form (Appendix N). The field check should also determine the most economical and feasible route to aid the replacement crews. Field check can be done by a Journeyman Lineman or Survey.

4.5 Completed field check is returned to Maintenance Supervisor to ensure field check notes, Tool Kit jacket, and requisition are complete. Package is then forwarded to Tech Services to review, estimate, and approve. Maintenance Supervisor to negotiate necessary due dates with Project Leads and document electronically in Asset Sheets.

4.6 When Project package is returned from Engineering, forward to Maintenance Superintendent for approval.

4.7 When Project package is approved, Maintenance Clerk documents the release date and forward to Maint. Supv. to release to the Project Lead for construction scheduling.

4.8 Construction Supv. then assigns Construction Lead and contracts for work either internally or externally by Cost plus, Unit, or Tendering.

4.9 Construction Lead and/or assigned crew design a work plan to carry out the project. When project is complete, the crew foreman completes a commissioning report and sends to the Construction Supv.

4.10 Construction Lead/Supervisor completes a quality check and documents findings as per Appendix D; Construction Inspection Report.

4.11 Five percent of replaced poles are to be cut up and photographed for quality control, to provide program justification and to aid research and development.

4.12 Disposal of all poles changed will follow the Materials management Process for NCV material disposal. A Release and Indemnity Agreement will be completed and filed for selling or donating all treated wood products deemed NCV.

4.13 Construction Lead reconciles WO as per WO Process and returns to Tech Services.

4.14 Project Lead informs Maintenance Supervisor of all applicable dates.

4.15 Transformers on poles being changed during replacement will be re-installed where they are not overloaded. Replace the ones that have oversized breakers or are in a location where we expect they have seen a lot of overload. Small parallel transformers shall be replacement with a single unit. In any case the replaced equipment shall be charged to the blanket transformer equipment work order.

It is important to handle the transformers gently when removing and reinstalling them at the same location.

**YEC-YECL-31**

**Reference:** Danger Tree Removal in ROW

**Requests:**

(a) With reference to page 9-7, is the new standard clearance implemented pursuant to a generally accepted policy or standard? If so, please provide.

(b) Where else has the new standard 6.1 meter clearance distance been implemented?

**Response:**

(a) Yes, the standard clearances are a part of our standard. Please refer to YUB-YECL-11 (a) Attachment 1 , YUB-YECL-11 (a) Attachment 2 and YUB-YECL-11 (a) Attachment 3

(b) Yukon Electrical's current brushing standards are the result of numerous other rules and regulations from the overhead power and communication industry in North America.

Yukon Electrical attempts to combine the regulations and standards with our practices and experiences in specific regions of the country, for example the width of a power line right of way might be different in an area that has deep top soil providing root stability or where wind conditions are less sever or where the vegetation simply does not grow tall enough.

Other considerations might be the location of the line, for example a power line in the back yard of a home where people continually access the area may be securitized more than one in a rural area.

A number of regulatory bodies speak to how vegetation is to be managed when in the vicinity of over head power lines and communication facilities. Given the

potential risks and consequences of inadvertent contact, tree removal when in the vicinity of lines is required.

Some of the regulatory agencies or bodies that speak to vegetation control are:

CANADIAN STANDARDS ASSOCIATION, over head systems, page 13, 4.1.7.1.

ALBERTA ELECTRICAL UTILITY CODE, which are standards pulled together by approximately 22 organizations working either in the industry or related industries.

OCCUPATIONAL HEALTH AND SAFETY REGULATIONS.

YUKON ELECTRICAL PROTECTION ACT

The standard used by Yukon Electrical for vegetation management is also used by Northland Utilities and ATCO Electric.

## YEC-YECL-32

**Reference:** Street and Sentinel Lights

**Requests:**

(a) With reference to page 9-3, please provide description of consultation process undertaken with local communities with regard to streetlight work.

(b) Please provide policy or standards employed with regard to determining whether streetlights require replacement.

(c) Please provide a copy of any report, analysis or study undertaken to determine streetlight replacement requirements.

(d) Who performs streetlight audits? How often are they performed?

(e) Is there an inspection policy? If so, please provide. Who carries out inspections and how often are they undertaken?

(f) With reference to page 9-9, please provide copy of the Rural Urban Transportation Association of Canada guidelines.

(g) Please provide a brief summary of how lighting levels do not meet the above-noted guidelines.

(h) Was the requirement and cost to replace First Avenue Streetlights in the City of Whitehorse factored into any cost benefit analysis undertaken by YECL to determine whether switching from overhead to underground was a prudent decision?

**Response:**

(a) The City of Whitehorse, YTG, First Nation Governments, and developers are consulted with as required. Specifically in regard to new street lighting requests, they are received from the authorities who ultimately will be paying for the lighting such as a municipality. On a broader basis, Yukon Electrical employees are involved in the community organizations such as Chamber of Commerce and participate in a number of workshops, planning meetings, and Charrettes where

development is the primary topic. It is from some of these interactions that Yukon Electrical receives information or is made aware of specific projects that are being planned or undertaken. In some situations Yukon Electrical initiates the dialog with customers and in other circumstances the developer or their consultant contacts Yukon Electrical. Most developers incorporate the cost of electrical service into their preliminary business plan before securing financing for a project and therefore Yukon Electrical is involved in the early stages of a potential project and is able to gather important data as a result.

(b) When a section of direct buried street light wire has failed it is replaced with cable in conduit in order to provide mechanical protection for the cable. The davits are replaced when they are structurally suspect due to severe rusting or damage. For long sections of roads where multiple cable failures and multiple damaged davits have been identified, Yukon Electrical will replace the existing system with new facilities in order to ensure that the lighting standards meet TAC, which is the guideline for new lights and determines how lighting should be provided based on roadway type to maximize safety and security. YEC-YECL-32(b) Attachment 1 is the ATCO Electric Distribution Street Light System Maintenance Program. This document is used as a guideline by Yukon Electrical.

(c) Please refer below to the answer provided in YEC-YECL-32(d) and (e) some of which also pertains to street light replacement planning.

Yukon Electrical does not specifically track its reliability statistics on a line or feeder basis but rather it tracks reliability on the system as a whole. Yukon Electrical's operations group meets weekly with engineering to discuss the past week's system performance. Of priority at these weekly meetings are all unplanned distribution outages or events which cause supply disruptions to customers. Events are recorded and trends are identified, ie: reoccurring failures of specific feeders, transformers or services. Trends are then investigated by researching the causes. Supporting information may be available by reviewing service interruption reports. Depending on the cause of the outages a determination is made to either immediately make corrections to the equipment or if the asset repairs can be put into the capital business planning cycle. Annual patrols flag the key areas of concern.

On a regular basis, Yukon Electrical completes assessments on its system. This is recorded in: monthly substation reports annual line patrols, ground rod report forms, electrical equipment reports, hydro inspection reports, diesel plant

inspection reports, safety audit reports, environmental audit reports, fleet inspection reports, and the list goes on. All of these types of reports assist Yukon Electrical in determining the condition of its power system and equipment and provides information necessary to assist with Capital and O&M planning requirements. This information is too voluminous to provide as it would take up several file cabinets. Third party assessments have only been completed on specific components of the distributions system such as a Dam Safety Audit on the Fish Lake water way or the Fish Lake turbines inspections. Yukon Electrical from time to time consults with other groups to assist with its capital planning and business planning needs.

(d) At a minimum, Yukon Electrical annually inspects its street light plant. These patrols are done by Yukon Electrical Servicemen and Field Service Representatives. During the winter, the asset is also patrolled for light outages.

(e) For Yukon Electrical's inspection policy please refer to YEC-YECL-32 Attachment 1 and (d) above.

(f) Yukon Electrical cannot share this document without permission from the Government of Canada. It is available to whoever wishes to purchase one. Please email publications tac-atc.ca, and ask for 2005 Guide for the design of Roadway Lighting.

(g) Lighting levels do not meet the guidelines when the lights can cause a roadway or an area to be under lit or over lit. Also the uniformity may be such that it leaves black or unlit areas between lights which are not considered safe for drivers. (Uniformity is the difference of light levels directly under the light compared to midway between lights). Different lighting levels are required for different road classes. The guidelines provide information on lighting and lighting design that maximizes safety and security of roadways. It is for these reasons that Yukon Electrical along with many municipalities and other utilities have adopted TAC.

(h) The business case in YEC-YECL-25(a) Attachment 1 for the Yukon Electrical First Avenue Conversion refers to synergies to do the street lights while the city was installing water and sewer systems. Cost savings on trenching and asphalting were realized while doing this work at this time.

# DISTRIBUTION

# STREET LIGHT SYSTEM

# MAINTENANCE

# PROGRAM

| | | |
|---|---|---|
| **Prepared by:** | Doug Koppel<br>Doug Koppel | **Date:** 2004.12.09 |
| **Eng. Approval:** | Blair Howell<br>Blair Howell | **Date:** Jan. 18, 2005 |
| **Maint. Supt. Approval:** | Al Nagel<br>Al Nagel | **Date:** JAN 26 2005 |
| **O&M MGR Approval:** | Howard Werden<br>Howard Werden | **Date:** June 10, 2005 |

**REVISION DATE: January 2007**

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ATCO Electric

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APPENDIX A STANDARD STEEL STREET LIGHT PAINT LIST
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APPENDIX C STREET LIGHT REPAIR FORM
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APPENDIX E STEEL POLE PAINTING DETAILS
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APPENDIX I GRADE ADJUSTMENTS

| ATCO Electric | Company Division:<br>Distribution, Fleet, Forestry | |
|---|---|---|
| | STANDARD Maintenance Management | |
| Primary Process: | **Street Light Maintenance Program** | Number: 1100 |
| Revision Date: | | |
| Document Owner: | Distribution Maintenance Supt. | |

## 1.0 Purpose

To provide an efficient standardized Street Light Maintenance Program that will enhance the efficient operation of the ATCO Electric Distribution System and maintain company ownership of the street lighting system.

## 2.0 Scope

- To maximize street light usage at lowest cost without jeopardizing service or safety.
- To develop and implement the best practices for maintaining in service and spare Distribution Lighting Equipment.
- To develop and implement new street light maintenance standards.
- To efficiently evaluate existing equipment condition.
- To implement CMMS (MAXIMO) as the centralized database for all installed street lighting equipment.
- Develop and assign responsibilities for the Street Light Maintenance Program.
- Standardize inspections, maintenance procedures and reporting.
- Link to system operations/engineering to consistently monitor system/equipment performance.
- Implementation of process for tracking lighting equipment, locations, operations, etc.
- To satisfy core service demands of new franchise agreements.
- To provide the region staff with the data to fulfill the specified sections of the franchise agreement.

## 3.0 Strategy

### 3.1 Implement Reliability Centered Maintenance (RCM) Concepts by using the best value based tools.

- Root Cause Failure Analysis (RCFA), Reliability Centered Maintenance.
- Preventative Maintenance (PM) Total Quality Maintenance (TQM).

### 3.2 Define data management requirements

- Set standards for maintenance management data (what data is required, hierarchy of data, connectivity of data).
- Format software requirements, work order generation, ability to track location and history of street light equipment.
- Determine where data information and upkeep resides most efficiently.

# 4.0 History

## 4.1 *Standards*

Throughout ATCO Electric's existence there have been many and varied types of Street Lighting Facilities installed throughout our franchise areas. They range from incandesent to mercury vapor and now to low and high-pressure sodium lamps. Luminaires have been supplied through a number of different manufacturers and come in all shapes and sizes. The same applies to street light brackets. Standards range from a few meters in length and up and maybe painted, powder coated, galvanized or corten. Styles range from single to double davit and decorative as well as heavy wall pipe that we've inherited throughout history. Street light bases include poured in place concrete, pre-cast concrete and steel bases. Lighting systems may be fed overhead or underground either on wood or steel structures. Supply voltages may be 120V or 240V depending on the engineering criteria of the day. Steel davits may also be joint use, set up on a supporting secondary pedestal. Both wood and steel lighting structures may support festoon lighting (Christmas lights) circuits and attachments, either individually controlled by photocell or group controlled by eye and relay including cascading relay systems.

## 4.2 *Corrosion and Stresses*

Deterioration and weakening of steel street light poles can be greatly accelerated by a number of factors encountered in their (pole) environment.

- Design distance from roadways and base setting depths affects corrosion levels
- Corrosion of anchor bolts (double nutting will provide more thread bonding strength)
- Stray ground current caused by close proximity to cathodic protection or unbalanced three phase lines causes metal perforation in steel bases and partially buried street light poles
- Corrosion occurring inside the steel poles if there is poor or no drainage of water or condensation build-up internally. (proper setting depth)
- Surfaces facing the sun see more corrosion due to the wet heating/cooling cycle
- Wind loading from attachments such as flower pots and banners (see 15.2 – attachment restrictions)
- Leaning steel light poles cause more stress at ground line especially if they lean in the direction of the sweep
- Plow winds –winds of varying speeds
- Rusting on two opposite sides –especially if one corroded side faces the prevailing wind
- Welding process itself causes metal fatigue due to metal crystallization just above the weld area

## 5.0 Present Standards

ATCO Electric's present day standard is to install HPS lighting on powder coated 9m davits in residential areas and HPS lighting on galvanized 12m davits along main hi-ways and arterial roads. The preferred lighting system is to have all lights individually controlled by photoelectric cell except where festoon lighting is associated with the street lighting circuit. The present day base for steel davit is a prefab screw in steel base. Luminaires mounted on wood structures use a forty-one inch by two-inch aluminum pipe style bracket.

Floodlights still incorporate the use of either 400 or 1000-watt MV lamps with external ballasts.

## 6.0 Street Light Inventory

ATCO Electric throughout its system currently owns approximately 39,000 lights. Of this the total population a portion is on the non-investment rate and the remainder lights are on the company investment rate.

**6.1 During the planning stage check if the facility is on the investment or non-investment rate. When it is determined that the pole in question is on the non-invested rate, have the District Manger or CSR contact the appropriate Franchise authority to communicate the findings and financial responsibilities.**

**Investment rate** - these lights are on the investment rate 61B. These are defined as being installed, owned and maintained by ATCO Electric.

- Co. owns and operates the lights
- Co. makes investment in new lights (as per our current approved investment levels in T&C Schedule B)
- Co. does all maintenance on lights (paint davits, repair cables, replace conductor, change heads & bulbs, etc.)
- At end-of-life, Co. will replace the lights, like-for-like using the current material standards (i.e. replace poured-in-place bases with screw-in bases, etc.) Replacements are treated as a reinvestment in facilities and the customer is not charged for like-for-like replacement
- If the design changes and new lights are required, the added lights are treated as new installs and we invest in them as per approved levels
- Rate change at the end-of-life, the old system is salvaged and a new system is installed. The Co. can then invest in the new system (up to the levels allowed in our approved T&C's)

**Non-investment rate** - these lights are on the non-investment rate 61D and E. These are defined as owned by ATCO Electric. ATCO Electric performs only maintenance and the customer is responsible for the cost of replacement.

- Co. owns and operates the lights
- Customer pays total installation costs (NO Company investment)
- Co. does all maintenance on the lights (paint davits, repair cables, change heads & bulbs, etc.)
- At end-of-life, Customer is responsible for the cost to replace the pole (wood or steel) conductor replacement, luminary if it requires upgrade with the pole change and any equipment installed solely to support the lighting system.

- Effectively all capital costs are paid by the Customer. Therefore, monthly charges are less than they are for the "investment-rate"
- Rate change before the end-of-life, the Co. can make a pro-rated investment in the existing lights. The investment would be reduced to reflect the age of the lights (i.e. if the lights are half way through their expected life, our investment would also be reduced by half). This is the option that had been formalized in our new franchise agreements. Once converted to the "investment rate" the monthly charges increase and the Co. becomes responsible for the end-of-life replacement costs.

## 7.0 Definitions

***Construct*** – means and includes establish, construct, re-construct, upgrade or extend any part of the existing Distribution System or proposed Distribution System.

***Core Services*** – means all those services set forth in Schedule "A" of the new franchise template.

***Distribution System*** – means any facilities owned by the company used to provide Distribution Access Service within the boundaries of the Municipality and shall include Street and Decorative Lighting including poles, fixtures, Luminaires, conductors, cables, bases and pedestals.

***Extra Services*** – means those services set forth in Schedule "B" of the new franchise agreement template that are requested by the Municipality on behalf of the Consumer and provided by the company.

***Maintain*** – means to keep in good repair or overhaul any part of the Distribution System including Street Lighting.

***Operate*** – means to interrupt or restore any part of the Distribution System in a safe and reliable manner.

## 8.0 Worker Qualification

**8.1** Lights-out patrols may be carried out by any ATCO employee with the proper training in using the applicable form and orientation with applicable sections of the Safety Standards Manual. Work may also be carried out by a contract employee with similar training and orientation.

Normally street light trouble shooting and maintenance can be undertaken by a single Utility Worker qualified to repair the street lighting system. This individual should have a good comprehension of the lighting system and trouble shooting techniques. Being familiar with and reviewing on an ongoing basis the ATCO Electric Street Light Maintenance Training and Development Manual (Module II) will greatly enhance the troubleshooters abilities and increase their productivity.

The Utility Worker performing this type of maintenance must be trained and qualified to perform the work safely.

**8.2** For street light painting tasks the individual performing the task must demonstrate to the company a comprehensive understanding of correct product application, recognition of hazards and public safety protection as well as aerial bucket operating and rescue technique. When overhead circuits are attached to steel poles, painting within limits of approach of live circuits can be done by a non-utility worker, only when supervised directly by a qualified utility worker or the circuit must be isolated and grounded before proceeding.

**8.3** The testing of steel poles requires an individual well vested in the recognition of hazards and public safety protection. The individual must have a good knowledge of metals, the operation and interpretation of the results using the ultra sound tool and the interpretation of the magnetic particle results as well as a full understanding of ATCO Electric pole failure criteria.

In all cases a detailed work plan and hazard identification document must be completed. Individuals working alone must include in their plans, details to include check in procedures at regular intervals.

All personnel must be familiar with limits of approach measurements.

## 9.0 Tools Required

Aerial equipment must meet CSA standards and be mechanically/electrically sound and equipped with holding valves. Tools and equipment used in the maintenance of lifting systems must be in good condition and rated for the work to be undertaken.

Full fall arrest harnesses must be in good and workable condition and worn by personnel with proper and rated attachment points on the equipment being used.
D-Meter; (for measuring steel thickness -calibrated), welders hammer.

## 10.0 Safety Management

Comply with all AE HS&E Standards and any legislated regulations.

Hard hats, safety glasses, safety boots, and FRCs (where applicable) must be worn at all time. Aerial devices must be equipped with fire extinguishers, first aid kits, fall arrest and rescue harnesses and kits.

A supply of traffic cones and work signs must be available on site at all time.

Limits of approach for workers must be maintained at all time as per the Safety Standards Manual.

The Supervisor is required to complete an ATCO Electric Job Observation form, “Review of Worksite Safe Work Performance”. Please reference to the AE Intranet, Health & Safety Forms and Reports.

## 11.0 Data Base

To efficiently track street light inventories for light audit purposes, maintenance, details, billing and history, as well as new franchise agreement reporting details to municipalities, it is recommended that the entire lighting plant be numbered as per details of the ATCO Electric Distribution System Asset Data Process. This will enable ATCO Electric to centrally track all information and generate projects efficiently with clear location identities.

## 12.0 Inspections

See System Inspection Program for detail and specifications.

- An Annual Inspection of the lighting system is required in conjunction with the Distribution System Inspection
- A Maintenance Physical Inspection is required on a 5 year rotation

## 13.0 Operational Inspection

### 13.1 Lights-out Patrols

On a monthly basis, during the eight winter months (Sept 15$^{th}$ to May 15$^{th}$) the company will conduct a "Lights Out" street light patrol to identify lights that are not working. This will include all urban and highway lighting with the exception of rural and remote communities that have no ATCO personnel residing nearby. These locations will reply on normal customer reporting channels and maintenance performed in the most expedient manner. For a non-numbered structure, identify lights-out location by address and physically marking the site. Formal lights-out patrols will not be conducted during the summer months but will be identified through normal customer reporting channels and maintained as per criteria outlined below.

## 14.0 Repairs

### 14.1 Lights-out Repairs

The company will replace a burnt out light identified in its formal patrol or those reported by external customers within 10 working days of light out notification. (See Franchise agreement for penalty clause, exception in remote areas).

Standard HPS lamps normally cycle on and off when they start to reach end of the life (16-24000 hours). If the lamp is not replaced, the ballast starter can have its life reduced or it may be destroyed if neglected too long, resulting in unnecessary replacement of the starter. (Some new bulbs do not cycle but stay off at end of life.)

An additional factor to consider is that the starter normally tries to restart the lamp every few seconds until the arc is established. Trying to start a failed lamp will destroy the starter and possibly the ballast if the starter is built into it. While the destruction time varies from a few days to a few weeks, it is possible to damage a ballast just enough so that it starts the replacement bulb too harshly, burning it out in only a few weeks or months.

The company will also use best practical efforts to replace burnt out street lights at critical locations or a complete string of lights are out a soon as possible. The location of the critical street lights will be agreed to by municipality and ATCO Electric to complete trouble shooting tasks, refer to Module II ATCO Electric Street Light Maintenance Manual to aid in completing tasks successfully and safely.

Completed repairs are to be documented and input into the Maximo database using the appropriate form or electronic process.

At this time it is also beneficial to make an evaluation as to the condition of the neutral and hot leads coming up the davit or in the wood pole street light bracket and if justified, replace at this time. Bulbs being replaced shall also be dated by marking off existing data criteria stenciled on bulbs.

### 14.2 Underground Breaks

As a minimum the company will provide a temporary overhead repair within ten working days to an identified or reported lights-out due to failed underground cable. Underground breaks identified during the summer months of April 15th to September 15th will be repaired by October 1st of the current summer construction period. A permanent repair will be made by Oct 1rst of the next year if the outage is identified during the winter months between Sept 15th and April 15th. An assessment needs to be made as to type of conductor existing, its overall condition, terrain etc. as to whether the break in the cable is found and repaired or if a new run of cable should be installed to increase the life and efficiency of the system. (see Appendix F for Repair Criteria)

### 14.3 Davit Painting

Evaluation documented in the Street Light Inspection Report indicating the need for painting davit will also dictate the degree of work required to effectively extend the life of the davit.

a. Corten - Pitted/rusted through or integrity of weld is questionable, replace the davit with new powder cost or galvanized davit depending on the area requirement, 9m for residential, 12m for main artery and hi-ways. Corten Davits can be refurbished if they meet metal thickness standards, by sand blasting and finishing with powder coat painting. They cannot be galvanized.

b. Powder Coat - Pitted/rusted/peeling condition, replace the davit with new powder coat or galvanized depending on the area they are located. Powder coated Davits can be refurbished if they still meet metal thickness standards, by sand blasting and refinishing with powder coat painting or galvanizing. For small touch up jobs on scratches, chips, a matching spray paint can be applied.

c. Galvanized - Pitted/rusting condition, replace the davit with new galvanized. Poles can be refurbished by powder coating over galvanizing.

d. Davit Cleaning - To remove salt and eye visible oil films after the davit has been sanded wire bushed or high-pressure blasted, spray on enzyme paint cleaner. Wait five minutes and rinse off. Beading water on the metal shows the need for a second application.

e. Painted - If body and weld integrity remain the decision to repaint will be based on condition. If paint is worn through and badly faded so as to show primer underneath, then a primer needs to be applied to the first ten feet (approximately) of the cleaned davit and a topcoat of oil based paint or urethane applied. If body has rust areas on it, apply a rust converter/primer to all areas affected and then apply the topcoat (ATCO brown, green, and gray). See attached standards. Painted Davits can be refurbished, if they still meet metal thickness standards, by cleaning and repainting or by sand blasting and galvanizing.

f. Decorative Lighting - if body and weld integrity remain, the decision to repaint will be based on condition. Because of the complexity and design features of the different types of steel poles it may be more efficient to remove alternating poles and have them sand blasted and repainted at a local facility that can do this type of work. Then replace and remove remaining poles.

Street Lights identified for painting will be completed in the following year's construction season. Street lights that are identified as requiring immediate work or mutually agreed to be painted by ATCO Electric and municipality will be re-painted in current construction season.

When replacing davits the current fusing, connector, mounting, grounding and meggaring standards as well as clearances found in the construction standards manual will apply.

Manufacturer’s criteria for focusing, installation and hookup located in or on product shall be carefully followed.

### 14.4 Davit Washing

In areas of high road salt/dirt contamination a program of steel pole pressure washing should be carried out on a yearly basis during late spring and early summer. The benefit to implementing this task is to extend the life of the pole and paint finish by preventing the onset of early steel corrosion.

Locations to consider are high traffic arterial roads in urban centers, highways and intersections in rural areas.

The method used to clean steel poles will be by pressure wash and scrub bristle brush using a solution of environmentally friendly detergent. Rinse off with clean water from ground level to approximately 15 feet.

Other considerations prior to implementing this task are: poles counts and budgeting, use of pre-qualified contractors and the appropriate business licenses for urban centers, as well as any local municipal environment concerns.

### 14.5 Grading Adjustment

Lights identified as below grade will be raised using the corporate specified base extension available through Materials Management.

At time of identification, note the spacing for the bolt pattern and the height of extension required to bring the davit to grade level.

### 14.6 Refurbishing

Light standards that have been damaged by traffic or other external sources are to be removed and returned to asset recovery in Nisku. Here a decision is made to repair or refurbish the standard using the technology developed by local contractor (IRIS). The process may include a mag-particular test to check weld integrity and a metal thickness test to see if the standard wall thickness is still within tolerance limits of manufacturer.

### 14.7 Street Light Pole and Base Testing

Steel light poles shall be tested for wall thickness and weld integrity on a five year schedule initially. The schedule may be modified to complete testing on a 5 year rotation for highways and high traffic areas and 10 year rotation for residential as results of the first cycle of testing may dictate.

The cycle will consist of two levels:

a. Year One Cycle:
Complete a documented Physical Street Light Inspection on all steel light poles using the Street Light Inspection Form (Appendix H).

A visual examination is completed from bottom to top to note blistering, corrosion and other defects such as holes and dents. Also at this time, it is necessary to complete a thorough visual inspection on any lights sitting on break-away bases.

Old style solid aluminum break-aways need to be accessed through the inspection cover to visually inspect the anchor bolts and condition of the aluminum base for signs of corrosion and cracks. On newer types of break-away bases, the inspector needs to remove the metal shroud, check its condition to ensure it can still deter public access to energized conductors, visually check the break-away couplers and anchor bolts for mechanical integrity, then replace or reattach the protective shroud. Document any findings on the physical inspection report.

A Sound test using a welder's hammer will be performed on all lights concentrating on the areas of worst corrosion and most importantly at the

base just above the weld. This test will identify weak spots in the metal or possibly determine that the pole has failed. It will also identify suspect poles requiring Ultra Sound or magnetic particle testing in year one. Testing at the base is most critical as this is the location where wind load stress is the highest. The criteria used to determine a failed pole are if there is more than 10% metal loss in an area, there are holes through the pole greater in diameter than 50mm, there are three or more creased corners to an octagonal pole or more than 1/3 of the surface on a round pole is dented.

Physical Maintenance inspection maps will be color coded by the Physical inspection to ease in the sorting process as follows:

Blue – indicate to replace a standard
Green – indicate to raise or extend the base
Yellow – indicate to paint a standard
Red – wash a standard

All maintenance items identified by the Inspector will be completed by service point staff in year one with the exception of those identified to be performed by the Inspector and those capital items identified for year II.

A dry magnetic particle test will be performed on those poles identified by the physical inspection on the weld portion attaching the base to the davit. This will reveal any failures/cracks to the original weld and determine future action requirements.

An ultra sound test will be completed on those steel light poles identified by the physical inspection to determine wall thickness under areas of heaviest corrosion. The surface is prepared by brushing and scraping the areas necessary to obtain this minimum thickness reading. Do not test over paint.

Steel bases identified as requiring an ultra sound test will be excavated to the needed depth where possible to attach the test probes in areas of corrosion. An alternative to the ultra sound test on steel bases is to complete a magnet strictive sensor test on below ground steel as per 2.0 Corrosion Detection Methods found in the Ground Test Program.

Minimum wall thickness on steel light poles shall meet or exceed 0.115 inches. Minimum wall thickness on steel bases shall meet or exceed a reduction of 10% metal loss except in the corners, beyond the anchor bolts, away from the shaft, at the outside top edge where it can be up to 20%metal loss on the top surface.

If any pole poses and immediate hazard (danger pole) the exact location and type of structure must be identified using its asset structure number as reference. The O&M superintendent is to be notified immediately. When evaluations are completed after normal working hours or on weekends, contact after Hours Assistance (1-800-667-1261) top advise the region Supervisor on call or the Edmonton Emergency Centre (780-423-4211)

Danger pole is defined as a steel pole, identified by formal test, and found to be in such critical condition as to warrant immediate attention by temporally guying, bracing, removal, or replacement within 24 hours. Forward completed form Danger Pole replacement to maintenance Supervisor when job is complete. Use Regional Danger pole project number to track the change.

Steel light poles deemed to be failures because of excessive dents or creases and noted on the Level II inspection from, can be repaired on site. This can be accomplished by using an approved two piece collar for the appropriate height needed and welding the seams and the base and top of the collar directly to the Davit, then primed and painted. Steel light poles should have no discernible bend between top and bottom sections (outside the dent area) for aesthetic purposes.

In summary, tasks identified and to be completed in year one of the program cycle will include magnetic and ultra sound testing where necessary, emergency pole replacements, as well as the physical maintenance inspection.

b. Year Two Cycle:
Tasks identified and to be completed in year two of the program cycle will include steel light pole and base replacement, grading adjustment, davit painting, steel light pole repairs and davit washing.

All tasks shall be performed by a contractor pre-qualified through the ATCO Electric Process.

## 14.8 Quality Control

The Region will provide Quality Control Inspections for the year one cycle tasks prior to year two tasks being undertaken.

A random 10% population will be inspected to ensure items identified by the original inspector are consistent and accurate.

The primary focus will be on those steel poles identified as requiring painting in year two, but can also verify the accuracy of the need to have completed the ultra sound test on the random sample.

If the quality control audit indicates accuracy of the original inspectors decisions, then work as identified can proceed to project preparation and ultimately, completion.

## 14.9 Report to Municipality

The new franchise agreement with municipalities has a clause within that requires a “report card” on street light maintenance upon request by the municipality. The report required may include standards painted each year, temporary o/h service replaced; number of lights fixed and time frame between reported and fixed so as to avoid monthly penalty as well as u/g cable replacement undertaken.

## 15.0 Replacement

### 15.1 Davit Base Replacement

Using documented details of steel light pole and base condition found in the annual Inspection the five year Physical street light inspection report and the test/repair criteria as per 14.7, a decision can be made to replace, repair, or repaint deteriorated light poles and bases.

A decision at this time needs to be made to replace the base. The new 12m galvanized davit will not fit the bolt pattern of most of the poured in place or pre-cast concrete bases. Condition of base is critical at this time as well.

Davits deemed to be able to be refurbished will be sent upon consultation with investment recovery supervisor to Nisku for refurbishing and reuse.

### 15.2 Attachment Restrictions

Municipalities will approach AE for approvals to attach banners, signs or flower pots to existing steel light poles. Wind loading now becomes a primary concern for the integrity of the davits. Steel street light poles can not be drilled, welded, or otherwise weakened during this process. To determine acceptable sign, banner, and/or flower pot sizes and weights, the Regional engineer shall be contacted to match conditions with pole sizes and locations.

The municipality then becomes responsible for the installation, maintenance, and liability of any of the attachments.

### 15.3 Group Lamp Replacement

Scope: To increase the value of the Street Light System using a planned maintenance technique, by completing the group replacement of the street lighting system.

Group Replacement is implemented to replace unplanned failures, improve reliability, reduce customer complaints and decrease the overall lighting system maintenance costs.

Mid -life HPS bulbs (Life Cycle 30,000 hours)

Studies have indicated Group Replacement should be completed at 70 to 80 % of life for maximum efficiency.

Average life 30,000 hours x 80% of life = 24,000 hours/4745 hours per year = 5.0 years or 5 year group replacement program

The estimated cost of a 5 year group replacement program would be the total # of lights, 39,000 lights/5 year rotation = number per year x /light = annual capital cost.

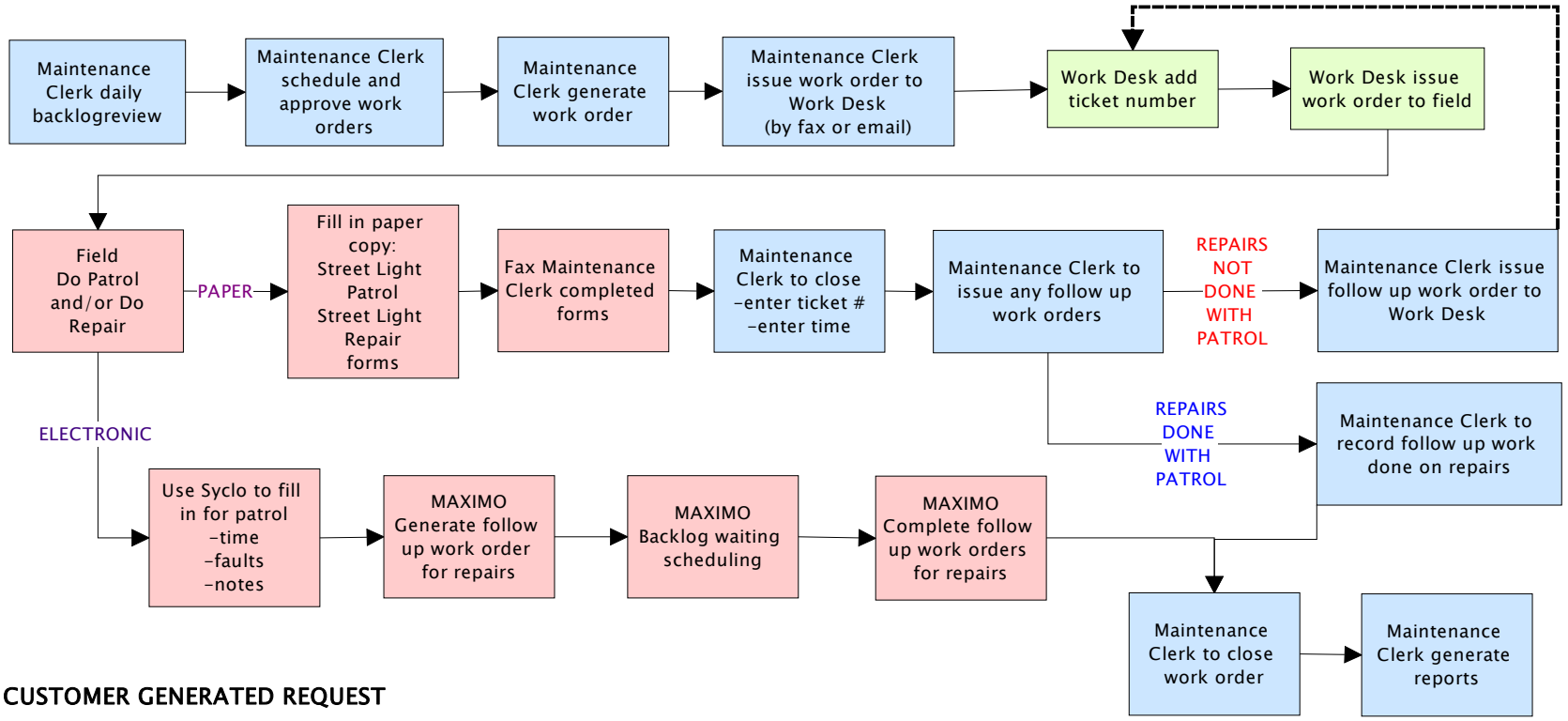
There would also be a small number that would fail premature and would require unplanned replacement.
# of lights x 3% premature failures = # of bulbs x  per light to repair =  annual O&M cost for repair

The Total Annual cost for this program is:  the annual Group Replacement + the unplanned repair cost = total cost

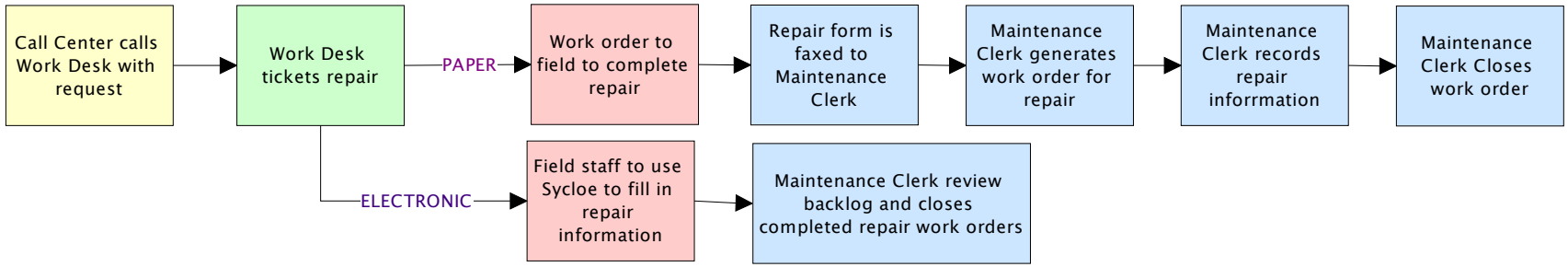
A 5 year cycle of group bulb replacement shall be initiated under three Regional Projects to record & document the group bulb replacement program.

To evaluate new products, test plots may be implemented at specified locations.  i.e. Dual Arc bulb performance

## 16 Maximo Work Order Implementation Flow Chart




### CUSTOMER GENERATED REQUEST



## 17 Funding

Funds will be identified in the Distribution Maintenance capital budget to accommodate the replacement of temporary o/h service with underground cable. The average cost for LTE & material is $20/meter.

Allocation example:

- If the cable is spliced/repaired charges are directed to the appropriate Service Point O&M account.
- If the span of cable is replaced charges are allocated to the Distribution Maintenance capital budget.

The cost of painting metal standards is a capital expenditure.

The cost to replace a metal standard with base costs is approximately $2000/location. (capital)

Lights-out patrols based on a group sampling of service points indicates approximately 15 hour per month for 8 months as defined in the New Franchise Agreement and funded by the Service Point O&M account

Street light steel pole washing will be charged to Service Point O&M account

One Project Number per Region will be generated to complete the Level II inspections as per the five year schedule. (Dist. Maint. O&M)

Appropriate number of D-series projects will be generated to collect capital costs for work required as required as per each Plant number affected.

When replacing non-invested stand-alone street lighting poles, whether they are wood or steel, use the following process:

- Complete all of the work on the capital project assigned
- Determine what lights the municipality is responsible for total replacement cost
- Calculate the average cost of replacement
- District to invoice the municipality for these costs
- Tech. Services to credit the capital project with the funds from the municipality

## 18 Storage

All steel standards shall be stored horizontal on raised soft surfaced bunks to avoid ground contact, corrosion, and damage to paint, powder coat and galvanizing from sharp or hard objects.

Luminaires and lamps are to be stored indoors in proper bin locations with easy access.

## 19 Recycling

All damaged/failed Luminaires and lamps shall be returned to the local warehouse and placed in the proper storage bins made available for recycling. Recycling is to be in accordance with procedures outlined in the Waste Minimization Program 9-1 of the EH&S Management System.

Recycle containers will be shipped through normal channels to Nisku Investment Recovery (contact supervisor).
Concrete bases will be disposed of through field warehousing directions.

Steel poles will either be recycled or disposed of through the Investment Recovery Supervisor.

## YEC-YECL-33

**Reference:** Generation Projects Undertaken from 1996 to 2005

**Requests:**

(a) For projects greater than 100,000 and in a manner consistent with 1996 97 GRA question YUB-YEC YECL-1-35, please complete a table that details (1) project name and total expense capitalized, (2) project description, (3) rationale justification, and (4) cost benefit for all distribution projects between January 1, 1996 and 2007. On an annual basis, please ensure that table provides the sum of all projects not included in this analysis that reconciles to the total distribution capitalized for a given year.

(b) For 1996 and 1997 please explain any discrepancies regard forecast projects and actual results.

**Response:**

(a) Please refer to YEC-YECL-25(a) Attachment 1.

(b) Please refer to response to YEC-YECL-25(b).

**YEC-YECL-34**

**Reference:** Fish Lake Generator Rebuild

**Requests:**

(a) With reference to page 9-16, Third party inspections recommended that this unit needs to be cleaned and that an electrical arcing noise be addressed.

i. Who performed the third party inspections? When? Were these mandatory inspections or were such inspections undertaken voluntarily by YECL?

ii. Were such inspections undertaken pursuant to a regular inspection program or other assessment process? If so, please describe.

iii. Please provide complete recommendations and reports issued by third party inspectors.

iv. Were such third party inspections carried out on Fish Lake specifically or were they undertaken for all generation plants? If other third party inspections were undertaken please provide other recommendations or reports issued.

**Response:**

i. The third party inspections were performed by Geatano Grubisa Lorne Bowes in 2007. Yukon Electrical sanctioned these inspections based on noted operating information.

ii. Daily visual audible and temperature inspections are done at Fish Lake. These inspections noted changes in the equipment; concerns were brought forward for follow up and as a result a more detailed assessment was undertaken.

iii. For reports please refer to attachments YUB-YECL-5 attachment 2, YUB-YECL-5 attachment 3.

iv. The attached reports were undertaken specifically for the Fish Lake Hydro System. No other third party inspections were done on these Hydro units.

## YEC-YECL-35

**Reference:** Haines Junction Diesel Plant Upgrade

**Requests:**

(a) With reference to page 9-16, were any studies or assessments undertaken by YECL or third parties prior to determining the need for this project? If so, please provide a copy of study or report justifying project.

(b) If project was undertaken pursuant to third party inspection please provide any recommendations provided.

(c) Were other options available or considered? Please provide brief description and summary regarding why such options were not considered optimal. Please provide all internally generated documents discussing options.

**Response:**

(a) No third party assessments were done or required as this project is consistent with and works toward stronger environmental stewardship and meeting of current codes similar to other generating locations owned and operated by Yukon Electrical.

(b) N A.

(c) Please refer to the business case in YEC-YECL-25(a) Attachment 1.

**YEC-YECL-36**

**Reference:** Fish Lake Weir in Ditch 3 or Gate

**Requests:**

(a) Please provide YECL's 2007 Dam Safety Review.

(b) Were third parties contracted to review this project and provide options and recommendations? If so provide recommendations and report or study provided to YECL.

(c) Were other options considered? If not, why not? If so, why was this considered the optimal option? Please provide all internally generated documents discussing options.

**Response:**

(a) Please refer to YUB-YECL-9(b) Attachment 1.

(b) Two third party consultants assisted Yukon Electrical in developing the plan to upgrade the weir in Ditch 3 on the Fish Lake Hydro system. It has also been reviewed and approved by the technical authority of the Yukon Water Board.

(c) The option selected was most effective to manage the situation. No other options were recommended. The Dam Safety Review is based on the Fish Lake Dam Control Structure being fully opened once the reservoir reached the FSL of 30.0 m (112.39m elevation). It was understood that this discharge may exceed the capacity of Ditch 3, but it was assumed that the safety of the dam would take precedence over that of the downstream structures. (See 5.2 of Dam Safety Review dated November 28, 2008) Based on the assumption that maximum discharge from Fish Lake combined with unrestricted inflow from Bonus Creek would jeopardize the structural integrity of Ditch 3, options to divert some of the water flow prior to it entering Ditch 3 were reviewed. The only apparent location to divert the flow without crossing First Nation Land and requiring major earth work is the existing lease for the diversion to Franklin Lake. For these reasons, Ditch 3 Diversion was considered to be the optimal option.

## YEC-YECL-37

**Reference:** Fish Lake Unit 2 New Wheel, Shaft and Bearing Pedestal

**Requests:**

(a) Please provide more information regarding the third party inspections and recommendations provided.

i. Who performed third party inspections? Were these mandatory inspections or were such inspections undertaken voluntarily by YECL?

ii. Were such inspections undertaken pursuant to a regular inspection program or other assessment process? If so, please describe.

iii. Please provide complete recommendations or report issued by third party inspectors.

iv. Were such third party inspections carried out on Fish Lake specifically or were they undertaken for all generation plants? If other third party inspections were undertaken please provide other recommendations or reports issued.

**Response:**

(a) i. Grubisa Millwright Services Ltd. out of Edmonton did the inspections. The inspections were conducted at the request of Yukon Electrical.

ii. Yes. Please refer to YEC-YECL-34.

iii. Please refer to YUB-YECL-5 Attachment 2 and 3.

iv. Third party inspections were undertaken only on the Fish Lake Hydro generators.

**YEC-YECL-38**

**Reference:** Carcross New 1.5 MW Power Plant

**Requests:**

(a) Please provide copies of all documents including any documents setting out YECL's franchise rights which deal in any way with the issue of why YECL believes diesel backup at Carcross is YECL's responsibility.

(b) Please provide basis for statement at page 9-23 that this project is per Yukon Energy's Resource Plan ? Provide quotes of any relevant portions of Yukon Energy's Resource Plan. Identify and summarize any and all YECL discussions with YEC leading to YECL's proposal of this project in this GRA.

(c) Prior to determining the need for a diesel unit at Carcross what assessment or analysis of the justification, need for and alternatives to the proposed project was undertaken?

(d) Please provide any analysis undertaken by third parties or YECL to justify the need for this unit at this time. Please provide all internally generated documents including reports done for or by senior management to justify this project.

(e) Were other contingency options considered and assessed? If so, please provide any analysis or study undertaken and rationale underlying selection of a new Carcross unit as the preferred option. If not, why not?

(f) Were other interested parties consulted with regard to the need or justification for a new unit at Carcross for contingency purposes? If so, please provide a summary of other views obtained. If not, why not?

**Response:**

(a) Yukon Electrical relies on the Public Utilities Act and Regulations there under for its rights and obligations to serve Carcross.

(b) Please refer to response to YUB-YECL-49(a) below:

It is Yukon Electrical's understanding that the YUB provided recommendations to the Justice Minister regarding the 20 Year Resource Plan put forward by Yukon Energy (YEC). The report of the YUB was submitted to the Minister January 15, 2007.

In YEC's 2007 annual report in the President's message it states Yukon Energy's primary focus this year was to proceed with some of the major initiatives laid out in our 20- year resource plan. The plan addresses our major electrical generation and transmission needs from 2006 until 2025 and was **approved last year by the Yukon Utilities Board (YUB).**

In the report filed with the minister by the YUB on page 11 of 55 and page 12 of 55 it stated

> *"YEC's criterion respecting communities to the WAF or MD grids, which states that any location with a load large enough to justify a diesel of about 1MW or more should be considered as a preferred location for new diesel units, is a criterion for deciding where to locate new units rather than a planning criterion to decide if new units are needed or not. Therefore, the Board has no concerns with YEC adopting this criterion."*

Although Yukon Electrical works closely with YEC on operational aspects of the power system, Yukon Electrical does not believe it has any obligation to seek advice from YEC on how Yukon Electrical chooses to provide reliable and safe service to its customers in Carcross or elsewhere.

(c) Carcross Tagish is the only community of Yukon Electrical that meets the above mentioned criterion and Yukon Electrical believes that adding the generator will enhance reliability for customers on the Carcross and Tagish grids.

Below is the information showing the peak demand on the Carcross Tagish system since 2003:

Carcross Substation

| | |
|---|---|
| 2003 | 748 KW |
| 2004 | 835 KW |
| 2005 | 864 KW |
| 2006 | 921 KW |

2007 864 KW
2008 1025 KW

Loads have increased such that they are expected to peak consistently over 1MW on a go forward basis.

The criteria relied upon by Yukon Electrical, including a need to enhance reliability and reduce outages, have already been vetted through past public processes and provide a valid basis for undertaking system improvement projects. However, Yukon Electrical did look at the outage statistics for the area. The option of installing a substation at Jake's Corner to give the area a second feed was also evaluated at a high level. The cost was higher than the backup generator option providing very little benefit due to the fact that the line to Carcross and the line to Teslin are one in the same for the first 20 km.

(d) Yukon Electrical did not engage a third party in its review of this project. Please refer to business case attached in YEC-YECL-25(a) Attachment 1. In addition please refer to (c) above.

(e) Please refer to (c) and (d) above

(f) Yukon Electrical did have discussions with customers in the Carcross and Tagish area. Concerns were expressed over duration of outages, reliability and emergency response. Meetings were held with community members, associations and politicians. One of the options considered to address these concerns was the addition of a standby diesel plant. Yukon Electrical also believes that its rate application is another way to engage interested parties in discussions regarding this option.

**YEC-YECL-39**

**Reference:** Return on Equity

**Requests:**

(a) Please provide a copy of the engagement letter and terms of reference between YECL and Foster Associates, Inc. for the preparation of the cost of capital evidence in this proceeding.

(b) Please provide the ROE allowed by the BCUC for benchmark low risk utilities for the past 10 years and provide appropriate references.

(c) Please provide the actual regulated ROE by year for YECL for that same period.

(d) Please confirm that YECL is protected from fuel price risk for diesel generation by Rider F. If not, why not.

(e) Please explain why, in Ms. McShane's view, it is reasonable to use one average long-term Canada bond yield for the two test years as the basis for the proposed ROE instead of using different ROEs for each test year.

(f) Please provide the data relied on by Ms. McShane to support the statements that the quarterly consensus forecasts for U.S. 10-year Treasury bond yields can be used to approximate the forecast for the 10-year Government of Canada bond yield, as the available consensus forecasts show that the Canadian and U.S. rates are expected to track closely, with the 10-year Canada bond slightly higher (10 basis points) than the 10-year Treasury by 2010 (pages 10 and 11 of the Foster Associates Inc evidence).

(g) Please provide the actual long-term Canada bond yield at June 30, 2008 and the average long-term Canada bond yield for the first six months of 2008.

(h) Please indicate the generic return on equity that would be calculated using the Alberta EUB method if:

i. The actual June 30, 2008 long-term Canada bond yield were used as the basis for the return on equity calculation for 2008.

ii. The average long-term Canada bond yield for the first six months of 2008 was used as the basis for the return on equity calculation for 2008.

(i) Please provide a copy of schedule 1.1 for YECL under each of the following assumptions as to rate of return on common equity: 9 , 8.5 , 8 and 7.5 .

**Response:**

(a) Please refer to YEC-YECL-39(a) Attachment 1 for a copy of the Requisition Enhancement form and YEC-YECL-39(a) Attachment 2 for a copy of a Blanket Purchase Order for Foster Associates Inc.

(b) The BCUC has identified Terasen Gas Inc. as the benchmark utility. The requested returns are shown on Schedule 5, page 2 of 3.

(c) The actual YECL regulated return is as follows:

| Year | Actual |
|---|---|
| 1998 | 9.65 |
| 1999 | 9.75 |
| 2000 | 10.09 |
| 2001 | 10.67 |
| 2002 | 10.98 |
| 2003 | 10.55 |
| 2004 | 10.20 |
| 2005 | 9.04 |
| 2006 | 10.69 |
| 2007 | 10.70 |

(d) Confirmed.

(e) There is no compelling theoretical rationale for setting two separate ROEs for the test period. Setting a single ROE for the test period, rather than separate ROEs for each of the two test years, recognizes that the cost of equity is a longer-term concept that, at any point in time, is a single value, incorporating both current and forecast interest rates (among other factors).

(f) A copy of the May 1, 2008 Blue Chip *Financial Forecasts* is attached as YEC-YECL-39(f) Attachment 1 - Blue Chip. As stated at page 10 of the Foster Associates Inc. evidence, commencing at line 277, due to the absence of a consensus 2009 forecast for the 10-year Canada yield, the 2009 forecast was based on the quarterly consensus forecasts for the U.S. 10-year Treasury bond. The Blue Chip *Financial Forecasts* (May 1, 2008) anticipated 10-year Treasury bond yields of:

| | |
|---|---|
| **1st Quarter 2009** | 4.0 |
| **2nd Quarter 2009** | 4.1 |
| **3rd Quarter 2009** | 4.3 |

With a further 0.1 increase in the 4th quarter, the 4th quarter 10-year yield would be 4.4 for an annual average of 4.2 .

The 10-year Canada bond yield was estimated to be approximately the same as the forecast 10-year U.S yields, given that, as noted at lines 283-285, the available consensus forecasts show that the Canadian and U.S. rates are expected to track closely with the 10-year Canada bond slightly higher (10 basis points) than the 10-year Treasury by 2010 as per the April 2008 Consensus Economics Consensus Forecasts. The relevant pages of the forecast are attached as YEC-YECL-39(f) Attachment 2 - Consensus Economics April 2008 extract.

(g) The long-term Canada bond yield was 4.08 on June 30, 2008, equivalent to the average for the first six months of the year.

(h) As the yield is the same, the resulting ROE would be 8.40 in both cases.

(i) This information is not being provided as any number of combinations have been or could have been requested and the information is readily available through the spreadsheets provided in the application.

ATCO Electric

# REQUISITION ENHANCEMENT FORM

**Requisition No. :** 56800

**NOTE: If other than standard purchasing quotation and Supplier/Contractor selection guidelines (G93) are to be considered the originator must complete the following c/w appropriate approvals and attach to the submitted requisition.**

| CATEGORY | CATEGORY DEFINITION |
|---|---|
| **RUSH ORDER** | No other Supplier / Contractor is able to supply this product / Service. |
| RATIONALE: | |
| | |
| | |

| | |
|---|---|
| **SINGLE SOURCE** | Preferred Supplier / Contractor for this order, no other considerations acceptable this time. |
| RATIONALE : Foster and associates was used as the expert witness for NUY & NWT 2008-10 GRA. YECL will use to be consistent and because they are already familiar with North of Sixty issues. | |

| | |
|---|---|
| **SOLE SOURCE** | Product or service only available from this supplier. |
| RATIONALE: | |
| | |
| | |

| | |
|---|---|
| **DESIGNATED CO. STANDARD** | Company has standardized on a specific product / service or line of equipment. |
| RATIONALE: | |
| | |
| | |

| | |
|---|---|
| **OEM** | Original Equipment Manufacturer |
| RATIONALE: | |
| **OTHER** RATIONALE: | |

| | | |
|---|---|---|
| **ORIGINATOR SIGNATURE:** | PRINT NAME: | **DATE:** (MM/ DD/ YYYY) |
| | Rob Pitzel | 02/25/2008 |
| **ADDITIONAL SIGNATURE:** (AS REQUIRED) | PRINT NAME: | **DATE:** (MM/ DD/ YYYY) |
| | Jerome Babyn | 02/25/2008 |
| **ADDITIONAL SIGNATURE:** (AS REQUIRED) | PRINT NAME: | **DATE:** (MM/ DD/ YYYY) |
| | | |

# BLANKET PURCHASE ORDER

**The Yukon Electrical Company Limited**
An *ATCO* Company

**ORDER NUMBER** **YECL17662**

PAGE 1 OF 2

| | | | |
|---|---|---|---|
| TO (SUPPLIER) | FOSTER ASSOCIATES INC<br>350N 4550 MONTGOMERY AVE<br>BETHESDA, MO 20814<br>UNITED STATES Fax: (301) 664- 7810 | ORDER DATE<br>PAYMENT TERMS<br>FREIGHT TERMS<br>TRADE TERMS<br>SHIP VIA | 07-MAR-2008<br>NET 30<br>Y10867 |
| SHIP TO | THE YUKON ELECTRICAL COMPANY LIMITED<br>AS PER RELEASE<br>CANADA | BILL TO (PURCHASER) | THE YUKON ELECTRICAL COMPANY LIMITED<br>ACCOUNTS PAYABLE<br>100 1100 1ST AVENUE<br>WHITEHORSE, YT Y1A 3T4<br>CANADA<br>PHONE 867-633-7007 FAX 867-668-6692 |

PROVIDE GENERAL RATE APPLICATION FOR YUKON ELECTRIC KATHY MCSHANE WILL BE THE PRINCIPAL PROVIDING THIS WORK AND WILL BE ASSISSTED BY SCOTT MILLER AND KAREN MORGAN

RATES:
K.MCSHANE $225 US PER HOUR PLUS OUT OF POCKET EXPENSES
K.MORGAN $165 US PER HOUR PLUS OUT OF POCKET EXPENSES
S.MILLER $165 US PER HOUR PLUS OUT OF POCKET EXPENSES

FOSTERS ASSOCIATES INC TO PROVIDE AN EXEMPTION FOR THE CANADA REVENUE AGENCY (CRA) WITHHOLDING TAX %15 REQUIREMENT FOR A FOREIGN CONTRACTOR/CONSULTANT RENDERING SERVICE IN CANADA. APPLICATION FOR THE WAIVER SHOULD BE COMPLETED 30 DAYS PRIOR TO INVOICING FOR THE SERVICES.

IF THE EXEMPTION IS NOT RECEIVED, YUKON ELECTRIC WILL DEDUCT 15% WITHHOLDING TAX FROM THE INVOICE. THE AMOUNT WILL BE REMITTED TO THE CRA AND A TAX SLIP ISSUED AT THE END OF THE YEAR.

INVOICE SHOULD INDICATE WHETHER THE WORK BEING BILLED WAS COMPLETED IN CANADA OR THE US.

ALL INVOICES PERTAINING TO THIS ORDER MUST CONTAIN THIS OURCHASE ORDER NUMBER
ALL PRICES AND AMOUNTS ON THIS ORDER ARE EXPRESSED IN US Dollars
EFFECTIVE FROM 01-FEB-2008 TO 31-JAN-2009 ESTIMATED AGREEMENT AMOUNT $105,000.00

| LINE | ITEM | DESCRIPTION | QUANTITY | UNIT | UNIT PRICE | AMOUNT |
|---|---|---|---|---|---|---|
| 1 | | MISCELLANEOUS DOLLARS FOR REGULATORY SERVICES | | | | |

| BUYER CONTACT | PHONE |
|---|---|
| HALSTEAD, ARLYN<br>Arlyn.Halstead@atcoelectric.com | 780-420-7281 |

The Yukon Electrical Company Limited
An *ATCO* Company

# BLANKET PURCHASE ORDER

**ORDER NUMBER** **YECL17662**



TO (SUPPLIER)
FOSTER ASSOCIATES INC
350N 4550 MONTGOMERY AVE
BETHESDA, MO 20814
UNITED STATES Fax: (301) 664- 7810

ORDER DATE 07-MAR-2008
PAYMENT TERMS NET 30
FREIGHT TERMS
TRADE TERMS
SHIP VIA

SHIP TO
THE YUKON ELECTRICAL COMPANY LIMITED
AS PER RELEASE
CANADA

BILL TO (PURCHASER)
THE YUKON ELECTRICAL COMPANY LIMITED
ACCOUNTS PAYABLE
100 1100 1ST AVENUE
WHITEHORSE, YT Y1A 3T4
CANADA
PHONE 867-633-7007 FAX 867-668-6692

Standard Purchase Order
Terms & Conditions

P01 ACCEPTANCE
Any work, shipment or acknowledgment by Supplier in response to this purchase order shall constitute complete acceptance by Supplier of entire purchase order including all terms and conditions contained or referenced herein and no contrary terms and conditions shall apply.

P02 ALTERATION AND CANCELLATION
Purchaser reserves the right to change any and all quantities and descriptions for items on this purchase order at Purchaser's absolute discretion. Purchaser shall confirm such change in writing to Supplier. Provided Supplier is in compliance with all terms, conditions and specifications of purchase order at time of change, Supplier shall be entitled to fair and reasonable compensation from Purchaser for material previously received by Purchaser, out-of-pocket costs to Supplier for work-in-progress prior to change, and expenses incurred by Supplier to meet such change.

P03 PRICES
Unless otherwise specified herein prices shown shall be fixed and inclusive of any other charges including but not limited to deposits, packaging and handling.

P04 SHIPMENT AND DELIVERY
Time is of the essence and Supplier shall cause goods or services to be provided to Purchaser upon the specified delivery date. Unless otherwise specified herein, Supplier shall select appropriate mode of shipment, the carrier, and the payment arrangement for shipping charges. Any bills from Supplier to Purchaser for agreed and prepaid carrier charges exceeding fifty Canadian dollars ($50) or its equivalent shall be supported by copy of the carrier billing.

P05 TITLE AND OWNERSHIP
Supplier represents and warrants to be the absolute owner of materials specified herein with good and marketable title thereto free and clear of any lien, charge, encumbrance or right of others whatsoever and is exclusively entitled to possess and sell same. Unless otherwise specified herein, title and risk for goods hereunder shall pass to Purchaser only upon acceptance by Purchaser at the FOB point specified herein. Any design, drawing, sample, pattern, tool or material supplied by, loaned by, or paid for by Purchaser in relation to this purchase order shall remain or become property of Purchaser.

P06 CONFIDENTIALITY
All documents, designs, drawings, specifications, samples and the like furnished by Purchaser to Supplier shall be treated as confidential by Supplier, used by Supplier only in relation to this purchase order and disclosed to Supplier's employees and subcontractors only after appropriate written acknowledgment of confidentiality is obtained from such parties.

P07 USE OF PURCHASER'S NAME
Supplier shall not use Purchaser's name in any form of promotion or advertising without Purchaser's prior written consent.

P08 BILLING AND PAYMENT
Invoices shall specify this purchase order number and provide a breakdown to at least the item level. The time for payment specified herein shall commence upon receipt of suitable invoice or satisfactory receipt of the specified goods and services, whichever shall be the later. Purchaser reserves the right to deduct monies due, or accruing due, from Supplier to Purchaser at time of payment.

P09 GUARANTEE
Supplier warrants all goods and services supplied hereunder to meet requirements of the law, generally accepted industry standards, and any specification provided by Purchaser. Unless otherwise specified herein, Supplier shall repair or replace without charge to Purchaser, any defective or failed goods or workmanship detected within twelve (12) months of first use by Purchaser, provided Purchaser has cared for and used such goods in a reasonable manner. Such repair or replacement shall be without prejudice to any of Purchaser's other rights or remedies.

P10 INDEMNIFICATION
In accepting this purchase order Supplier shall indemnify and save harmless Purchaser from all loss, costs, damages and claims to the extent they are attributable to the performance or purported performance by Supplier in response to this purchase order including without limitation those with respect to patent infringement, injury and death.

P11 INSURANCE
Supplier and Supplier's subcontractors or agents hereunder shall have insurance adequate to cover obligations incurred under this purchase order or to any minimum amount specified herein and to the satisfaction of the Purchaser. At Purchaser's request, Supplier shall provide independent documentary proof of such coverage.

P12 ASSIGNMENT
Supplier shall not assign any obligation or benefit arising from this purchase order without Purchaser's prior written consent.

P13 GOVERNING LAW
This purchase order shall be governed by the laws of the province or territory named as the office of Purchaser in the purchase order and any disputes arising shall be subject to the exclusive jurisdiction of those courts.

BUYER CONTACT
HALSTEAD, ARLYN
Arlyn.Halstead@atcoelectric.com

PHONE
780-420-7281

**Aspen Publishers**

# Blue Chip Financial Forecasts

**Top Analysts' Forecasts of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them**

**Vol. 27, No. 5, May 1, 2008**

**Wolters Kluwer**
**Law & Business**

**BLUE CHIP FINANCIAL FORECASTS**

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# Is The Fed Preparing To Pause?

**Domestic Commentary** Despite some speculation that the Federal Open Market Committee might leave interest rates unchanged when it meets April 29th-30th, financial markets and an overwhelming majority of our panelists foresee a 25 basis point reduction in the target federal funds rate to 2.00%. That would mark the seventh cut in the last eight months and bring to 325 basis points the total reduction in the fed funds target since last September. However, some analysts suspect the statement issued after the meeting will signal a desire on the part of the FOMC to hold interest rates steady for a time as it assesses the impact of the federal tax rebate checks that will begin to go out within weeks, as well as its own previous moves to lower interest rates and pump liquidity into dysfunctional credit markets. A pause in the easing cycle also would likely serve to support the value of the U.S. dollar, knock commodity prices down and buttress the Fed's inflation-fighting credibility. However, it is thought unlikely that the statement would completely rule out additional rate reductions given the still relatively sober outlook for economic growth in the medium term among analysts at the Fed and in the private sector. The Fed tried that gambit in October by noting that weak growth and inflation were of equal concern to policymakers, but had to reverse course within weeks when credit markets went into a tailspin.

Specifically, the results of our April 21st-22nd survey show 86% of our panelists predicting the target federal funds rate will be reduced by a quarter of a percentage point at the late-April meeting. A couple of panelists forecast no change in the Fed's overnight rate at the meeting while seven predicted a 50 basis point cut. A slim majority (51%) say the target fed funds rate will remain at 2.00% following the FOMC's June 24th-25th meeting. Last month, 44% said the funds rate would be at 2.0% following the June meeting. About 42% believe the target fed funds rate will stand at 1.75% after the late-June meeting, one panelist foresees a 1.50% funds rate and two foresee 1.25% or lower target. Overall, the consensus predicts the target fed funds rate will average 1.9% in Q3 and Q4 of this year, 0.1 of a point higher than estimated a month ago. The funds rate will average 2.0% in Q1 2009, 2.2% in Q2 2009 and 2.5% in Q3 of next year, says the consensus, unchanged from last month's forecast.

Reacting to a variety of catalysts, the Treasury market has gotten absolutely crushed over the past several weeks as safe-haven demand dried up. Yields hit their cyclical lows during the week ended March 21st when the Fed engineered the shotgun wedding of Bear Stearns to J.P. Morgan Chase, announced a lending facility for non-bank brokers, broadened the list of collateral it would accept for loans and cut the target funds rate by 75 basis points to 2.25%. These moves eased concern about systemic risk and a deep, prolonged downturn in the economy, thus reducing demand for risk-free Treasuries. More recently, earnings reports from the financial sector apparently have been insufficiently grim enough to worry investors, prompting a considerable tightening of credit spreads and higher stock prices. The ability of financial firms to raise fresh capital in order to shore up balance sheets, even if it is at the expense of diluting existing shareholder equity, also has helped reduce concern among investors. Though hardly robust, better-than-feared news over the past month on retail sales, industrial production and unemployment claims, also seem to have inspired confidence, further decreasing demand for Treasuries in favor of riskier assets. Lastly, Treasuries have suffered as speculation increased that the Fed might cut interest rates little if any more. As a result, yields at the front end of the Treasury curve have shot to their highest level and the curve is at its flattest since late January/early February. Two-year Treasury yields have soared a bit more than 100 basis points above their March 17th lows, the five-year note yield is up 90 basis points and the 10-year yield some 45 basis points higher.

At the same time, we also have witnessed renewed turmoil in the interbank lending market which suggests things may not be as nearly rosy in the banking and broader financial system as investors have come to assume of late. The three-month LIBOR has spike to 2.91%, some 37 basis points higher than on March 18th. That has pushed the 3-month LIBOR/OIS spread (an indirect measure of funds available in the money market) to 89 basis points, a new high for 2008 and close to the high reached last December. Granted, some of this results from an investigation by British authorities into whether banks were inaccurately reporting their funding costs. However, some of the rise likely reflects continued unease among banks about counterparty risk and the hoarding of funds. The jump in LIBOR served to produce a sharp blowout in swap spreads and problems in the Eurodollar futures market that contributed to the upward pressure on Treasury yields. Whatever the cause, the rise in LIBOR is troubling since interest payments on over $600 billion of investment grade debt, about $30 billion of high yield floating corporate debt and $900 billion in subprime mortgages are tied to this rate.

Besides the signals from the interbank lending market, there remain other reasons to suspect increased optimism on the part of investors could be misplaced and that even if it pauses in the near-term the Fed may ultimately decide to cut interest rates further. Real GDP likely grew at a rate of less than 1.0% for a second straight quarter in Q1 2008 and the consensus now assumes an outright contraction in the economy growth during Q2. Although the consensus assumes improved growth of 1.6% in the second half of this year and growth of about 2.25% in the first half of 2009, several analysts worry that collateral damage to the American economy resulting from the housing and financial crisis will instead broaden and continue to grow.

Consumer confidence dropped to a 26-year low in March, according to the University of Michigan and the rise in gasoline prices to a record $3.50 per gallon in late-April likely sent it even lower. Indeed, the average price of gasoline this summer may come close to being a dollar higher than last year, completely offsetting the boost to discretionary consumer spending that was expected to result from the tax rebate program. Reduced hiring and slower wage growth also is likely to weigh on consumer spending. Nonfarm payrolls have contracted at an average monthly rate of 77,000 since the start of this year and even bigger declines may lie ahead. Increased economic uncertainty has also taken its toll on capital spending plans and investment in business structures may swoon following robust growth in 2007. Reduced domestic demand produced a sharp build-up of business inventories during Q1. Although that will add to Q1 rate of real GDP growth, a paring of inventory levels in Q2 is likely to be a major drag on growth. Moreover, there is yet to be seen signs of a bottom in the housing market. Starts and new home sales fell sharply in March and persistently high inventories of unsold homes, coupled with steadily rising delinquency and foreclosure rates continue to exert downward pressure on prices. Recent, sharp increases in loan-loss provisions by banks further suggests more write downs lie ahead on all manner of consumer, corporate and housing debt.

**Consensus Forecast** The consensus says the FOMC will cut interest rates by 25 basis points on April 30th, but the percentage of those expecting additional rates cuts fell over the past month. Partly as a result, a majority of our analysts think the value of the dollar will bottom in Q2 *(see page 2 for U.S. consensus forecasts).*

**Special Questions** A bit more than 34% of our panelists agree with Martin Feldstein that the FOMC should not cut its target federal funds rate below 2.0%. Almost 62% of the panelists think the Treasury market is overvalued. Yet, 72% of the panelists say the U.S. is in, or will enter, a recession this year *(see page 14 for details).*

# Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

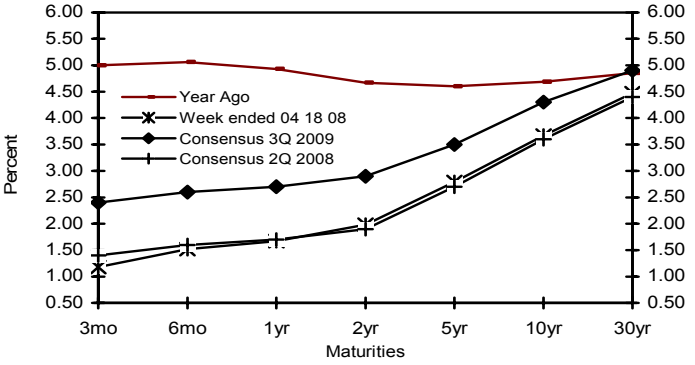
| | History | | | | | | | | Consensus Forecasts-Quarterly Avg. | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Average For Week End | | | | Average For Month | | | Latest Q | 2Q | 3Q | 4Q | 1Q | 2Q | 3Q |
| Interest Rates | Apr.18 | Apr.11 | Apr.4 | Mar.28 | Mar. | Feb. | Jan. | 1Q 2008 | 2008 | 2008 | 2008 | 2009 | 2009 | 2009 |
| Federal Funds Rate | 2.34 | 2.23 | 2.23 | 2.18 | 2.61 | 2.98 | 3.94 | 3.18 | **2.0** | **1.9** | **1.9** | **2.0** | **2.2** | **2.5** |
| Prime Rate | 5.25 | 5.25 | 5.25 | 5.25 | 5.66 | 6.00 | 6.98 | 6.21 | **5.0** | **4.9** | **4.9** | **5.0** | **5.3** | **5.6** |
| LIBOR, 3-mo. | 2.79 | 2.71 | 2.70 | 2.68 | 2.78 | 3.09 | 3.92 | 3.26 | **2.5** | **2.3** | **2.3** | **2.4** | **2.7** | **2.9** |
| Commercial Paper, 1-mo. | 2.11 | 2.10 | 2.08 | 2.14 | 2.36 | 2.90 | 3.61 | 2.96 | **2.2** | **2.1** | **2.2** | **2.3** | **2.6** | **2.9** |
| Treasury bill, 3-mo. | 1.18 | 1.33 | 1.39 | 1.29 | 1.28 | 2.17 | 2.82 | 2.09 | **1.4** | **1.4** | **1.5** | **1.7** | **2.0** | **2.4** |
| Treasury bill, 6-mo. | 1.52 | 1.52 | 1.54 | 1.53 | 1.54 | 2.10 | 2.84 | 2.16 | **1.6** | **1.6** | **1.7** | **1.9** | **2.3** | **2.6** |
| Treasury bill, 1 yr. | 1.67 | 1.63 | 1.63 | 1.60 | 1.54 | 2.05 | 2.71 | 2.10 | **1.7** | **1.8** | **1.9** | **2.1** | **2.4** | **2.7** |
| Treasury note, 2 yr. | 1.98 | 1.84 | 1.81 | 1.75 | 1.62 | 1.97 | 2.48 | 2.02 | **1.9** | **2.0** | **2.1** | **2.3** | **2.6** | **2.9** |
| Treasury note, 5 yr. | 2.79 | 2.66 | 2.64 | 2.58 | 2.48 | 2.78 | 2.98 | 2.75 | **2.7** | **2.8** | **2.9** | **3.1** | **3.3** | **3.5** |
| Treasury note, 10 yr. | 3.67 | 3.54 | 3.55 | 3.52 | 3.51 | 3.74 | 3.74 | 3.66 | **3.6** | **3.7** | **3.8** | **4.0** | **4.1** | **4.3** |
| Treasury note, 30 yr. | 4.47 | 4.34 | 4.36 | 4.33 | 4.39 | 4.52 | 4.33 | 4.41 | **4.4** | **4.4** | **4.5** | **4.6** | **4.7** | **4.9** |
| Corporate Aaa bond | 5.60 | 5.47 | 5.53 | 5.51 | 5.51 | 5.53 | 5.33 | 5.46 | **5.5** | **5.5** | **5.6** | **5.6** | **5.7** | **5.9** |
| Corporate Baa bond | 7.03 | 6.91 | 6.96 | 6.93 | 6.89 | 6.82 | 6.54 | 6.75 | **6.8** | **6.8** | **6.8** | **6.9** | **7.0** | **7.1** |
| State & Local bonds | 4.62 | 4.61 | 4.90 | 4.96 | 4.93 | 4.64 | 4.27 | 4.61 | **4.6** | **4.5** | **4.6** | **4.6** | **4.7** | **4.8** |
| Home mortgage rate | 5.88 | 5.88 | 5.88 | 5.85 | 5.97 | 5.92 | 5.76 | 5.88 | **5.8** | **5.8** | **5.9** | **6.0** | **6.1** | **6.2** |

| | History | | | | | | | | Consensus Forecasts-Quarterly Avg. | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2Q | 3Q | 4Q | 1Q | 2Q | 3Q | 4Q | *1Q** | 2Q | 3Q | 4Q | 1Q | 2Q | 3Q |
| Key Assumptions | 2006 | 2006 | 2006 | 2007 | 2007 | 2007 | 2007 | *2008* | 2008 | 2008 | 2008 | 2009 | 2009 | 2009 |
| Major Currency Index | 82.2 | 81.7 | 81.6 | 81.9 | 79.3 | 77.0 | 73.3 | 72.0 | **70.1** | **70.4** | **70.7** | **71.3** | **72.1** | **72.8** |
| Real GDP | 2.4 | 1.1 | 2.1 | 0.6 | 3.8 | 4.9 | 0.6 | *0.2* | **-0.3** | **1.6** | **1.6** | **1.9** | **2.5** | **2.7** |
| GDP Price Index | 3.5 | 2.4 | 1.7 | 4.2 | 2.6 | 1.0 | 2.4 | *2.9* | **2.3** | **2.4** | **2.3** | **2.4** | **2.2** | **2.2** |
| Consumer Price Index | 3.9 | 3.8 | -1.6 | 3.8 | 4.6 | 2.7 | 5.1 | 4.2 | **3.0** | **2.7** | **2.1** | **2.4** | **2.2** | **2.3** |

Individual panel members' forecasts are on pages 4 through 9. Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Definitions reported here are same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis. Historical data for the U.S. Federal Reserve Board's Major Currency Index is from FRSR H.10 and G.5. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS). ***Figures for 1Q 2008 Real GDP and GDP Chained Price Index are consensus forecasts based on a special question asked of the panelists (see page 14).***

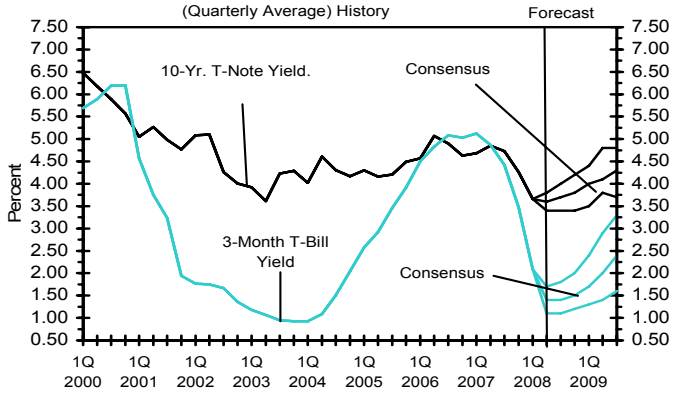
## U.S. Treasury Yield Curve

Week ended April 18, 2008 and Year Ago vs.
2Q 2008 and 3Q 2009 Consensus forecasts



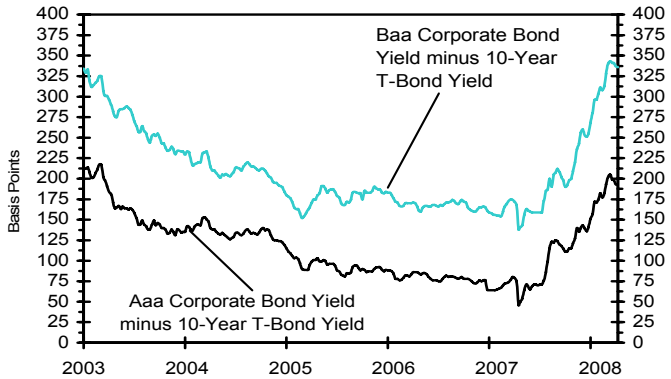

## U.S. 3-Mo. T-Bills 10-Yr. T-Note Yield

(Quarterly Average) History



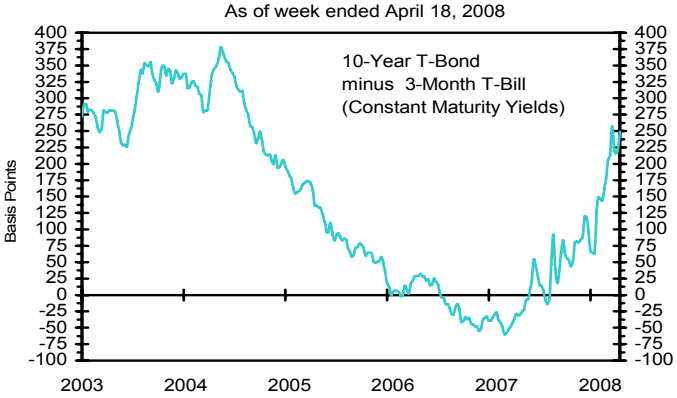

## Corporate Bond Spreads

As of week ended April 18, 2008




## U.S. Treasury Yield Curve

As of week ended April 18, 2008



**----------3-Month Interest Rates[1]----------**

| | History | | | Consensus Forecasts Months From Now: | | |
|---|---|---|---|---|---|---|
| | Latest: | Month Ago: | Year Ago: | 3 | 6 | 12 |
| U.S. | 3.09 | 2.63 | 5.38 | **2.03** | **1.74** | **1.66** |
| Japan | 1.02 | 0.90 | 0.66 | **0.88** | **0.84** | **0.95** |
| U.K. | 5.85 | 5.85 | 5.66 | **5.40** | **5.06** | **4.88** |
| Switzerland | 2.82 | 2.86 | 2.34 | **2.82** | **2.90** | **2.87** |
| Canada | 3.43 | 3.65 | 4.34 | **2.93** | **2.87** | **2.90** |
| Australia | 7.82 | 7.78 | 6.45 | **8.23** | **8.12** | **7.42** |
| Eurozone | 4.80 | 4.66 | 4.00 | **4.43** | **4.01** | **3.93** |

**----------10-Yr. Government Bond Yields[1]------**

| | History | | | Consensus Forecasts Months From Now: | | |
|---|---|---|---|---|---|---|
| | Latest: | Month Ago: | Year Ago: | 3 | 6 | 12 |
| U.S. | 3.75 | 3.52 | 4.63 | **3.36** | **3.54** | **3.91** |
| Germany | 4.14 | 3.76 | 4.17 | **4.00** | **3.94** | **3.91** |
| Japan | 1.41 | 1.26 | 1.68 | **1.48** | **1.63** | **1.69** |
| U.K. | 4.74 | 4.30 | 5.05 | **4.53** | **4.45** | **4.53** |
| France | 4.37 | 3.96 | 4.22 | **4.10** | **4.00** | **3.98** |
| Italy | 4.60 | 4.31 | 4.40 | **4.33** | **4.20** | **4.18** |
| Switzerland | 3.22 | 2.76 | 2.76 | **2.98** | **3.00** | **3.02** |
| Canada | 3.70 | 3.50 | 4.15 | **3.37** | **3.53** | **4.03** |
| Australia | 6.22 | 5.97 | 5.88 | **6.22** | **6.22** | **6.07** |
| Spain | 4.42 | 4.12 | 4.21 | **4.15** | **4.05** | **4.03** |
| Eurozone | 4.43 | 4.11 | 4.25 | **3.97** | **4.00** | **4.03** |

**----------Foreign Exchange Rates[1]----------**

| | History | | | Consensus Forecasts Months From Now: | | |
|---|---|---|---|---|---|---|
| | Latest: | Month Ago: | Year Ago: | 3 | 6 | 12 |
| U.S. | 70.716 | 71.022 | 79.24 | **70.7** | **71.7** | **73.7** |
| Japan | 104.56 | 100.77 | 118.52 | **99.5** | **99.1** | **101.3** |
| U.K. | 1.9965 | 1.9852 | 2.0028 | **1.97** | **1.94** | **1.88** |
| Switzerland | 1.0253 | 1.0230 | 1.2031 | **0.98** | **0.98** | **1.02** |
| Canada | 1.0084 | 1.0203 | 1.1228 | **1.02** | **1.02** | **1.04** |
| Australia | 0.9294 | 0.9062 | 0.8284 | **0.95** | **0.94** | **0.90** |
| Euro | 1.5742 | 1.5394 | 1.3622 | **1.60** | **1.58** | **1.52** |

| | Consensus 3-Month Rates vs. U.S. Rate | | | Consensus 10-Year Gov't Yields vs. U.S. Yield | |
|---|---|---|---|---|---|
| | Now | In 12 Mo. | | Now | In 12 Mo. |
| Japan | -1.73 | **-0.71** | Germany | 0.39 | **0.00** |
| U.K. | 3.22 | **3.21** | Japan | -2.34 | **-2.23** |
| Switzerland | 0.23 | **1.20** | U.K. | 0.99 | **0.61** |
| Canada | 1.02 | **1.24** | France | 0.62 | **0.06** |
| Australia | 5.15 | **5.75** | Italy | 0.85 | **0.26** |
| Eurozone | 2.03 | **2.26** | Switzerland | -0.53 | **-0.90** |
| | | | Canada | -0.05 | **0.12** |
| | | | Australia | 2.47 | **2.15** |
| | | | Spain | 0.67 | **0.11** |
| | | | Eurozone | 0.68 | **0.12** |

*Forecasts of individual panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Three month currency interest rates. Government bonds are yields to maturity. Foreign exchange rate forecasts for U.K., Australia and the Euro are currencies per U.S. dollar. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's Major Currency Index.*

**International Commentary** Confronted by the fastest inflation in 16 years, the European Central Bank (ECB) left its repo rate at 4.0% on April 10th. Analysts worry that high energy costs, tightening credit conditions and the Euro's almost 20% surge versus the U.S. dollar over the past year poses downside risks to growth. Many continue to cut their forecasts of real GDP growth this year and next in the currency zone. To date, however, PMI data for the manufacturing and services sectors indicate that though slowing, growth remains relatively healthy. That's particularly true in the north. In Ireland and southern parts of the Eurozone, however (Spain, Portugal and Italy), the outlook is much grimmer due to bursting bubbles in the housing market. Keeping the ECB from preemptively easing, consumer price inflation rose to 3.6% in March and could jump to 4.0% this summer as food and energy prices continue to rise. The consensus, nonetheless, predicts faltering economic growth and easing inflation will eventually prompt the ECB to cut rates before the year is up.

The Bank of England (BoE) voted 6-3 to cut its base rate by 25 basis points to 5.00% on April 10th, the third reduction since December (one member voted for a bigger cut, while two others voted to leave rates unchanged). Deteriorating credit conditions were highlighted has the primary motivation for the move. Although policymakers acknowledged that inflation may rise a bit more in coming months, they remained confident it would fall back in the medium term. Consumer spending remains tepid and the credit crunch hitting the housing, services and financial sectors has grown worse. Rising mortgage payments, tightening credit and higher inflation are expected to crimp consumer spending while business investment pulls back due to heightened economic uncertainty. Large budget deficits will make it difficult for the government to provide meaningful fiscal stimulus. Real GDP growth this year may be the slowest since 1992. The y/y change in consumer price inflation remains above the BoE's target of 2.0% and may hit 3.0% this summer. Nonetheless, the consensus sees at least two more rate cuts this year.

The Bank of Canada (BoC) reduced its overnight target rate by 50 basis points to 3.0% on April 22nd. That marked the second half-point reduction in as many months and brings the total amount of easing since December to 150 basis points. In announcing its latest cut, the BoC signaled that further easing would likely be required in the medium term, but the easing bias appeared less forceful than in the immediate past. The BoC currently expects real GDP to grow only 1.4% this year, the smallest increase since 1992. Domestic demand remains buoyant but export growth is slowing due to the loonie's strength and weakening imports from America, Canada's largest trading partner. Inflation remains quite tame, with the overall consumer price index up just 1.4% in March on a y/y basis and core inflation up only 1.3%.

Inflation in Australia jumped to a two-year high in Q1, driving the value of its currency versus the U.S. dollar to its highest level since 1984 on speculation the Reserve Bank of Australia will have to maintain a tight policy for longer than expected . The RBA last tightened in March, raising its overnight target rate to 7.25%. The housing sector is beginning to slump and consumer confidence is at its lowest level since 1993. However, extremely low unemployment and fast rising wages threaten to keep inflation high.

The Bank of Japan (BoJ) left interest rates unchanged on April 9th as the bank cut its assessment of the economy amid rising concern about a possible recession. The unemployment rate is up and consumer spending is weakening. That leaves Japan dependent upon exports for sustaining the expansion at a time when its largest trading partner the U.S. may have entered a recession Those worries were reflected in the latest Tankan report that showed confidence among Japan's largest manufacturers has slipped to a 4-year low. Large companies said they plan to cut capital spending by 1.6% in this fiscal year, the worst projection since Japan's economy emerged from recession in 2002 *(see 10 and 11 for individual panel members' forecasts).*

# Second Quarter 2008

## Interest Rate Forecasts

## Key Assumptions

| Blue Chip Financial Forecasts Panel Members | Percent Per Annum -- Average For Quarter | | | | | | | | | | | | | | | Avg. For Qtr. | (Q-Q Change) (SAAR) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Short-Term | | | | | | | Intermediate-Term | | | | Long-Term | | | | | | | |
| | 1 Federal Funds Rate | 2 Prime Bank Rate | 3 LIBOR Rate 3-Mo. | 4 Com. Paper 1-Mo. | 5 Treas. Bills 3-Mo. | 6 Treas. Bills 6-Mo. | 7 Treas. Bills 1-Yr. | 8 Treas. Notes 2-Yr. | 9 Treas. Notes 5-Yr. | 10 Treas. Notes 10-Yr. | 11 Treas. Bond 30-Yr. | 12 Aaa Corp. Bond | 13 Baa Corp. Bond | 14 State & Local Bonds | 15 Home Mtg. Rate | A. Fed's Major Currency Index | B. Real GDP | C. GDP Price Index | D. Cons. Price Index |
| Wayne Hummer Investments | 2.3 H | 5.3 H | 3.0 H | 2.8 H | 1.4 | 1.7 | 1.8 | 2.2 | 3.0 | 3.8 | 4.5 | 5.5 | 6.5 | 4.5 | 5.9 | 70.5 | 1.0 | 3.0 | 4.0 |
| ING Investment Mgt. | 2.3 H | 5.3 H | 2.5 | 2.3 | 1.7 | 1.7 | 1.9 | 1.9 | 2.9 | 3.8 | 4.4 | 5.5 | 6.8 | 4.3 | 6.0 | 70.0 | 0.0 | 2.2 | 2.7 |
| RidgeWorth Capital Management | 2.2 | 5.2 | 2.4 | 2.1 | 1.4 | 1.6 | 1.5 | 1.9 | 2.4 | 3.4 | 3.7 | 4.9 | 6.2 | 3.5 L | 5.4 L | 70.0 | -0.5 | 2.3 | 2.5 |
| Goldman Sachs & Co. | 2.1 | 5.3 H | 2.6 | na | 1.4 | na | na | 1.7 | 2.6 | 3.6 | 4.3 | 5.2 | na | na | 5.6 | na | -1.0 | 3.6 | 4.4 |
| Swiss Re | 2.1 | 5.1 | 2.9 | 2.5 | 1.4 | 1.5 | 1.4 | 1.8 | 2.7 | 3.6 | 4.5 | 5.5 | 7.0 | na | 6.0 | na | -0.3 | 3.2 | 3.2 |
| Wells Capital Management | 2.1 | 5.3 | 2.6 | 2.0 | 1.1 | 1.2 | 1.4 | 1.7 | 2.4 | 3.7 | 4.1 | 5.3 | 6.7 | 4.8 | 6.0 | 70.0 | 0.1 | 2.6 | 2.8 |
| Nat'l Assn. of Realtors | 2.1 | 5.1 | 2.8 | 2.5 | 1.4 | 1.7 | 2.0 | 1.8 | 2.7 | 3.6 | 4.4 | 5.7 | 7.0 | 4.9 | 5.8 | na | 0.3 | 2.2 | 2.8 |
| Naroff Economic Advisors | 2.1 | 5.1 | 2.8 | 2.4 | 1.5 | 1.8 | 1.8 | 1.9 | 2.7 | 3.7 | 4.5 | 5.5 | 6.8 | 4.8 | 5.9 | 67.7 L | -0.3 | 3.1 | 4.3 |
| PNC Financial Services Corp. | 2.1 | 5.1 | 2.6 | 2.3 | 1.5 | 1.6 | 1.8 | 1.9 | 2.9 | 3.7 | 4.5 | 5.7 | 7.1 | 4.7 | 5.9 | 69.0 | -1.5 | 2.0 | 2.6 |
| Bear Stearns & Co. | 2.1 | 5.1 | 2.6 | 2.1 | 1.7 | 1.8 | 2.0 | 2.1 | 2.8 | 3.8 | 4.6 | 5.8 | 7.1 | 4.7 | 6.0 | 68.1 | -1.0 | 2.8 | 3.0 |
| Mesirow Financial | 2.1 | 5.1 | 2.5 | 2.2 | 1.8 | 1.6 | 1.5 | 1.7 | 3.0 | 3.7 | 4.4 | 5.6 | na | na | 5.9 | 70.1 | 0.5 | 1.8 | 1.8 |
| Thredgold Economic Assoc. | 2.1 | 5.1 | 2.5 | 2.4 | 1.7 | 1.9 | 2.0 | 2.0 | 2.8 | 3.7 | 4.4 | 5.5 | 6.7 | 4.6 | 5.8 | 70.6 | -0.6 | 2.5 | 2.9 |
| Bank of America | 2.1 | 5.1 | 2.4 | na | 1.4 | 1.7 | 1.9 | 1.7 | 2.6 | 3.5 | 4.5 | 5.4 | 6.9 | na | 5.8 | na | -0.1 | 2.3 | 2.3 |
| Woodworth Holdings | 2.1 | 5.1 | 2.3 | 2.4 | 1.6 | 1.8 | 1.9 | 2.0 | 3.0 | 4.0 H | 4.8 H | 5.9 H | 7.3 H | 4.7 | 6.2 H | 70.0 | -0.8 | 2.8 | 5.5 H |
| Georgia State University | 2.1 | 5.1 | na | na | 1.4 | 1.5 | 1.6 | 2.0 | 2.8 | 3.8 | 4.5 | 5.6 | 7.0 | na | 5.8 | na | -1.0 | 0.2 L | 1.9 |
| Barclays Capital | 2.1 | 5.1 | 2.6 | 2.4 | 1.5 | 1.6 | 1.7 | 1.8 | 2.6 | 3.6 | 4.4 | 5.5 | 6.9 | 4.7 | 5.9 | na | 1.0 | 2.5 | 2.7 |
| National City Corporation | 2.1 | 5.1 | 2.7 | 2.0 | 1.4 | 1.7 | 1.9 | 2.2 | 2.9 | 3.7 | 4.5 | 5.6 | 7.0 | 4.7 | 5.9 | 70.4 | 1.2 | 0.3 | 2.7 |
| State House Policy Office | 2.1 | 5.1 | 3.0 H | 2.3 | 1.4 | 1.6 | 1.6 | 1.9 | 2.9 | 3.6 | 4.4 | 5.5 | 6.9 | 4.8 | 5.8 | 70.8 | -1.9 | 2.2 | 2.3 |
| ClearView Economics | 2.1 | 5.1 | 2.8 | 2.0 | 1.1 | 1.4 | 1.7 | 1.9 | 2.8 | 3.6 | 4.4 | 5.5 | 6.9 | 4.6 | 5.8 | 69.0 | 1.7 | 3.2 | 3.0 |
| Nomura Securities, Inc. | 2.1 | 5.1 | 2.8 | 2.0 | 1.3 | 1.5 | 1.6 | 2.2 | 3.0 | 3.8 | 4.6 | 5.6 | 7.1 | na | 6.1 | 70.0 | -0.3 | 3.5 | 3.7 |
| Chmura Economics & Analytics | 2.1 | 5.1 | 2.6 | 2.2 | 1.3 | 1.5 | 1.7 | 2.0 | 2.7 | 3.6 | 4.4 | 5.5 | na | na | 5.9 | 73.0 H | -0.3 | 2.5 | 2.8 |
| The Northern Trust Company | 2.1 | 5.1 | 2.5 | na | 1.2 | na | 1.7 | 1.9 | 2.7 | 3.5 | 4.3 | 5.5 | 5.8 L | 4.6 | na | na | -0.7 | 2.1 | 2.4 |
| RBS Greenwich Capital Econ. | 2.1 | 5.1 | 2.7 | 2.1 | 1.4 | 1.5 | 1.5 | 2.0 | 2.8 | 3.7 | 4.4 | 5.6 | 6.9 | 4.6 | 5.9 | 69.7 | 0.2 | 2.5 | 3.1 |
| Economist Intelligence Unit | 2.1 | 5.1 | 2.5 | na | 1.3 | 1.5 | 1.6 | 1.7 | 2.5 | 3.6 | 4.3 | na | na | na | 5.8 | na | 1.2 | na | 2.8 |
| Fannie Mae | 2.1 | 5.1 | na | na | 1.2 | na | 2.4 | na | na | 3.8 | 4.2 | 5.6 | na | na | 6.0 | na | 0.6 | 2.0 | 3.3 |
| Comerica Bank | 2.1 | 5.1 | 2.7 | 2.2 | 1.4 | 1.6 | 1.7 | 2.1 | 2.8 | 3.7 | 4.4 | 5.5 | 6.8 | 4.3 | 5.7 | 70.0 | -2.0 L | 1.8 | 2.1 |
| Lehman Brothers | 2.1 | 5.1 | 2.7 | 1.8 | 1.4 | 1.7 | 1.7 | 2.0 | 2.8 | 3.6 | 4.5 | 5.7 | 7.0 | 5.1 H | 5.9 | na | -1.0 | 1.7 | 2.5 |
| Moody's Economy.com | 2.1 | 5.1 | 2.2 | 2.3 | 2.4 H | 2.7 H | 2.7 H | 2.9 H | 3.3 H | 3.7 | 4.3 | 5.5 | 6.8 | na | 5.9 | na | -0.7 | 1.9 | 2.3 |
| Moody's Analytics | 2.0 | 5.0 | 2.6 | 2.6 | 1.3 | 1.7 | 1.8 | 2.0 | 2.9 | 3.6 | 4.4 | 5.5 | 7.0 | 4.5 | 6.0 | 70.0 | 0.4 | 2.5 | 3.0 |
| Argus Research | 2.0 | 5.0 | 3.0 H | 2.5 | 1.3 | 1.4 | 1.6 | 1.8 | 2.5 | 3.6 | 4.5 | 5.6 | 7.0 | 4.6 | 6.0 | 70.6 | 1.8 | 3.2 | 3.4 |
| Cycledata Corp. | 2.0 | 5.0 | 2.5 | 2.4 | 1.5 | 1.7 | 1.8 | 2.0 | 2.7 | 3.5 | 4.2 | 5.2 | 6.4 | 4.2 | 5.5 | 71.0 | -0.5 | 2.4 | 3.4 |
| Kellner Economic Advisers | 2.0 | 5.0 | 2.5 | 2.6 | 1.3 | 1.6 | 1.8 | 1.9 | 2.5 | 3.5 | 4.3 | 5.5 | 7.0 | 5.0 | 6.0 | 70.0 | -1.5 | 2.8 | 3.9 |
| Wachovia | 2.0 | 5.0 | 2.4 | 2.4 | 1.7 | 1.8 | 1.9 | 2.2 | 3.0 | 3.8 | 4.2 | 5.3 | 6.5 | 4.8 | 5.4 | 70.4 | -0.7 | 3.3 | 4.3 |
| UBS Warburg | 2.0 | na | 2.5 | na | 1.4 | na | na | na | 1.6 L | 2.5 L | 3.5 L | 4.4 L | na | na | na | na | -1.5 | 1.9 | 1.6 L |
| Merrill Lynch Economics | 2.0 | na | 2.5 | na | 1.3 | na | na | 1.6 | 2.5 | 3.6 | 4.4 | na | na | na | na | na | -2.0 | 1.6 | 1.9 |
| DePrince & Assoc. | 2.0 | 5.0 | 2.6 | 2.0 | 1.2 | 1.4 | 1.6 | 1.8 | 2.7 | 3.5 | 4.4 | 5.4 | 6.8 | 4.6 | 5.8 | 70.3 | 0.8 | 2.7 | 3.2 |
| Standard & Poor's Corp. | 1.9 | 4.9 | 2.7 | 2.3 | 1.4 | 1.5 | 1.6 | 1.7 | 2.5 | 3.5 | na | 5.6 | 7.0 | 4.4 | 5.7 | 68.2 | -0.9 | 0.2 L | 1.9 |
| Stone Harbor Investment Partners | 1.9 | 4.9 | 2.0 | 1.9 | 1.2 | 1.6 | 1.8 | 2.1 | 2.9 | 3.6 | 4.3 | 5.1 | 6.2 | na | 5.5 | 71.0 | -0.6 | 3.7 H | 2.9 |
| BMO Capital Markets | 1.9 | 4.9 | 2.6 | 2.3 | 1.4 | 1.7 | 1.9 | 2.0 | 3.0 | 3.5 | 4.3 | 5.5 | 6.9 | 4.6 | 5.8 | 70.0 | -0.7 | 2.2 | 2.5 |
| J.W. Coons Advisors LLC | 1.9 | 4.9 | 2.5 | 1.8 | 1.2 | 1.5 | 1.6 | 2.0 | 2.8 | 3.7 | 4.5 | 5.6 | 7.0 | na | 5.8 | 70.7 | -0.6 | 2.8 | 3.7 |
| JPMorgan Privare Client Services | 1.9 | 4.9 | 2.5 | 1.8 | 1.2 | 1.5 | 1.6 | 2.0 | 2.8 | 3.7 | 4.5 | 5.6 | 7.0 | na | 5.8 | 70.7 | -0.6 | 2.8 | 3.7 |
| Action Economics | 1.8 | 4.8 | 2.7 | 2.1 | 1.4 | 1.4 | 1.6 | 2.0 | 2.9 | 3.7 | 4.5 | 5.6 | 6.8 | 4.7 | 6.0 | 70.2 | -0.5 | 1.7 | 4.2 |
| Loomis, Sayles & Company | 1.8 | 4.8 | 2.0 | 1.6 L | 0.9 L | 1.1 L | 1.3 L | 1.7 | 2.7 | 3.6 | 4.4 | 5.5 | 6.9 | 4.6 | 5.8 | 70.6 | 2.5 H | 1.8 | 2.1 |
| J.P. Morgan Chase | 1.8 | na | 2.2 | na | 0.9 L | na | na | 1.5 L | 2.7 | 3.8 | 4.7 | na | na | na | na | na | -1.0 | 2.1 | 3.4 |
| Scotiabank | 1.3 L | 4.3 L | 1.8 L | na | 1.0 | 1.4 | na | 1.8 | 2.6 | 3.4 | 4.3 | 5.3 | 6.3 | 4.3 | 5.8 | 70.0 | -0.5 | 2.0 | 2.5 |
| **May Consensus** | **2.0** | **5.0** | **2.5** | **2.2** | **1.4** | **1.6** | **1.7** | **1.9** | **2.7** | **3.6** | **4.4** | **5.5** | **6.8** | **4.6** | **5.8** | **70.1** | **-0.3** | **2.3** | **3.0** |
| Top 10 Avg. | 2.1 | 5.2 | 2.8 | 2.5 | 1.7 | 1.8 | 2.1 | 2.2 | 3.0 | 3.8 | 4.6 | 5.7 | 7.1 | 4.8 | 6.0 | 71.0 | 1.2 | 3.3 | 4.2 |
| Bottom 10 Avg. | 1.8 | 4.8 | 2.2 | 1.9 | 1.1 | 1.4 | 1.5 | 1.7 | 2.4 | 3.4 | 4.1 | 5.1 | 6.4 | 4.3 | 5.6 | 69.2 | -1.4 | 1.3 | 2.0 |
| April Consensus | 2.0 | 5.0 | 2.4 | 2.2 | 1.3 | 1.5 | 1.6 | 1.7 | 2.5 | 3.5 | 4.3 | 5.4 | 6.7 | 4.6 | 5.8 | 70.8 | 0.0 | 2.5 | 2.9 |
| Number of Forecasts Changed From A Month Ago: | | | | | | | | | | | | | | | | | | | |
| Down | 9 | 9 | 6 | 11 | 17 | 11 | 8 | 6 | 6 | 6 | 11 | 9 | 5 | 13 | 11 | 16 | 22 | 17 | 12 |
| Same | 20 | 16 | 7 | 6 | 9 | 7 | 6 | 4 | 4 | 9 | 10 | 9 | 7 | 7 | 11 | 7 | 16 | 17 | 14 |
| Up | 16 | 17 | 30 | 17 | 19 | 21 | 26 | 33 | 34 | 30 | 23 | 23 | 24 | 9 | 18 | 7 | 7 | 10 | 19 |
| Diffusion Index | 58 | 60 | 78 | 59 | 52 | 63 | 73 | 81 | 82 | 77 | 64 | 67 | 76 | 43 | 59 | 35 | 33 | 42 | 58 |

# Third Quarter 2008

## Interest Rate Forecasts

## Key Assumptions

| Blue Chip Financial Forecasts Panel Members | Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate | 2 Prime Bank Rate | 3 LIBOR Rate 3-Mo. | 4 Com. Paper 1-Mo. | 5 Treas. Bills 3-Mo. | 6 Treas. Bills 6-Mo. | 7 Treas. Bills 1-Yr. | Intermediate-Term: 8 Treas. Notes 2-Yr. | 9 Treas. Notes 5-Yr. | 10 Treas. Notes 10-Yr. | 11 Treas. Bond 30-Yr. | Long-Term: 12 Aaa Corp. Bond | 13 Baa Corp. Bond | 14 State & Local Bonds | 15 Home Mtg. Rate | Avg. For Qtr.: A. Fed's Major Currency Index | (Q-Q Change) (SAAR): B. Real GDP | C. GDP Price Index | D. Cons. Price Index |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Wayne Hummer Investments | 2.3 H | 5.3 H | 2.9 | 2.8 H | 1.5 | 1.8 | 1.9 | 2.3 | 3.1 | 3.9 | 4.6 | 5.6 | 6.6 | 4.6 | 6.0 | 70.7 | 2.4 | 2.4 | 2.5 |
| ING Investment Mgt. | 2.3 H | 5.3 H | 2.4 | 2.3 | 1.8 | 1.8 | 2.0 | 2.0 | 3.0 | 3.9 | 4.5 | 5.5 | 6.7 | 4.3 | 6.0 | 70.0 | 1.0 | 2.3 | 2.6 |
| Argus Research | 2.0 | 5.0 | 3.0 H | 2.7 | 1.2 | 1.3 | 1.6 | 1.8 | 2.7 | 3.8 | 4.6 | 5.6 | 7.0 | 4.6 | 6.1 | 71.6 | 3.3 | 3.1 | 3.7 |
| State House Policy Office | 2.0 | 5.0 | 2.8 | 2.2 | 1.4 | 1.5 | 1.7 | 1.9 | 2.7 | 3.4 | 4.1 | 4.9 | 6.5 | 4.4 | 5.5 | 70.5 | 2.1 | 1.9 | 3.0 |
| ClearView Economics | 2.0 | 5.0 | 2.7 | 1.9 | 1.0 | 1.4 | 1.6 | 1.8 | 2.7 | 3.5 | 4.3 | 5.5 | 6.9 | 4.6 | 5.8 | 68.0 | 2.8 | 2.4 | 2.5 |
| National City Corporation | 2.0 | 5.0 | 2.7 | 2.1 | 1.6 | 1.9 | 2.1 | 2.4 | 3.2 | 4.0 | 4.7 | 5.8 | 7.1 | 4.8 | 6.1 | 69.4 | 3.9 | 3.1 | 2.1 |
| Swiss Re | 2.0 | 5.0 | 2.6 | 2.6 | 1.6 | 1.7 | 1.6 | 2.0 | 2.9 | 3.5 | 4.4 | 5.5 | 7.0 | na | 5.9 | na | 0.7 | 2.9 | 2.9 |
| Barclays Capital | 2.0 | 5.0 | 2.5 | 2.3 | 1.8 | 1.7 | 1.9 | 1.6 | 2.7 | 3.9 | 4.6 | 5.7 | 7.0 | 4.8 | 6.0 | na | 3.5 | 2.6 | 4.4 H |
| Nat'l Assn. of Realtors | 2.0 | 5.0 | 2.5 | 2.5 | 1.7 | 2.0 | 2.3 | 2.3 | 2.9 | 3.7 | 4.5 | 5.8 | 7.1 | 5.0 | 5.8 | na | 2.2 | 1.8 | 2.0 |
| Nomura Securities, Inc. | 2.0 | 5.0 | 2.5 | 2.1 | 1.6 | 1.5 | 1.6 | 2.5 | 3.2 | 4.0 | 4.7 | 5.7 | 7.3 | na | 6.1 | 72.0 | 4.1 | 3.1 | 2.7 |
| Goldman Sachs & Co. | 2.0 | 5.0 | 2.5 | na | 1.6 | na | na | 1.9 | 2.9 | 3.7 | 4.3 | 5.2 | na | na | 5.6 | na | 1.0 | 3.1 | 2.9 |
| Naroff Economic Advisors | 2.0 | 5.0 | 2.5 | 2.2 | 2.0 | 2.1 | 2.2 | 2.3 | 2.9 | 4.0 | 4.6 | 5.7 | 6.9 | 4.9 | 6.0 | 65.0 L | 0.1 | 2.9 | 4.2 |
| Chmura Economics & Analytics | 2.0 | 5.0 | 2.4 | 2.1 | 1.5 | 1.6 | 1.8 | 2.1 | 2.8 | 3.7 | 4.4 | 5.5 | na | na | 5.9 | 72.8 | 0.5 | 1.4 L | 2.7 |
| Thredgold Economic Assoc. | 2.0 | 5.0 | 2.3 | 2.3 | 1.6 | 1.8 | 1.9 | 2.0 | 2.8 | 3.7 | 4.4 | 5.5 | 6.7 | 4.6 | 5.8 | 71.0 | 1.5 | 2.4 | 2.7 |
| Cycledata Corp. | 2.0 | 5.0 | 2.3 | 2.2 | 1.5 | 1.7 | 1.9 | 2.1 | 2.8 | 3.7 | 4.4 | 5.4 | 6.6 | 4.2 | 5.5 | 72.0 | 1.0 | 2.3 | 3.2 |
| RidgeWorth Capital Management | 2.0 | 5.0 | 2.3 | 2.0 | 1.4 | 1.6 | 1.6 | 1.9 | 2.4 | 3.4 | 3.6 L | 4.8 | 6.0 | 3.4 L | 5.2 L | 71.0 | -0.5 | 1.9 | 2.1 |
| Wachovia | 2.0 | 5.0 | 2.3 | 2.3 | 1.8 | 1.9 | 2.0 | 2.4 | 3.1 | 3.9 | 4.3 | 5.4 | 6.5 | 4.7 | 5.4 | 71.3 | 2.4 | 3.7 H | 3.1 |
| Mesirow Financial | 2.0 | 5.0 | 2.2 | 2.2 | 2.0 | 1.7 | 1.7 | 1.9 | 3.1 | 3.8 | 4.4 | 5.9 | na | na | 5.9 | 70.3 | 1.7 | 2.6 | 2.7 |
| Woodworth Holdings | 2.0 | 5.0 | 2.2 | 2.2 | 1.9 | 2.0 | 2.1 | 2.2 | 3.2 | 4.2 | 5.0 H | 5.7 | 6.9 | 4.5 | 5.8 | 79.0 H | 3.1 | 2.3 | 3.0 |
| The Northern Trust Company | 2.0 | 5.0 | 2.1 | na | 1.3 | na | 1.7 | 1.9 | 2.8 | 3.4 | 4.2 | 5.3 | 5.5 L | 4.5 | na | na | 0.3 | 1.6 | 1.9 |
| Moody's Economy.com | 2.0 | 5.0 | 2.1 | 2.1 | 2.2 H | 2.4 H | 2.5 H | 2.8 H | 3.6 H | 4.3 H | 4.7 | 6.0 | 7.3 | na | 6.3 H | na | 3.3 | 2.4 | 1.5 L |
| Georgia State University | 2.0 | 5.0 | na | na | 1.3 | 1.4 | 1.6 | 2.0 | 2.9 | 3.7 | 4.4 | 5.6 | 6.9 | na | 5.6 | na | 0.9 | 2.8 | 3.0 |
| PNC Financial Services Corp. | 1.8 | 4.8 | 2.4 | 2.0 | 1.5 | 1.6 | 1.8 | 2.0 | 3.0 | 3.8 | 4.6 | 5.8 | 7.3 | 4.6 | 6.0 | 68.0 | 0.7 | 1.6 | 1.5 |
| Kellner Economic Advisers | 1.8 | 4.8 | 2.4 | 2.5 | 1.4 | 1.7 | 2.0 | 2.2 | 2.7 | 3.6 | 4.4 | 5.6 | 7.1 | 5.1 H | 6.1 | 70.0 | -0.9 | 2.9 | 3.8 |
| Bear Stearns & Co. | 1.8 | 4.8 | 2.2 | 1.8 | 1.4 | 1.4 | 1.8 | 2.2 | 3.0 | 4.1 | 4.9 | 6.2 H | 7.5 H | 4.9 | 6.3 H | 67.3 | -0.5 | 2.9 | 2.9 |
| Standard & Poor's Corp. | 1.8 | 4.8 | 2.9 | 2.5 | 1.5 | 1.6 | 1.7 | 1.9 | 2.7 | 3.8 | na | 5.8 | 7.1 | 4.5 | 5.8 | 67.8 | 2.5 | 2.9 | 3.0 |
| JPMorgan Privare Client Services | 1.8 | 4.8 | 2.7 | 2.4 | 0.9 L | 1.5 | 1.6 | 2.0 | 2.7 | 3.5 | 4.3 | 4.8 L | 6.9 | 4.4 | 5.6 | 71.0 | 1.0 | 2.4 | 2.7 |
| Wells Capital Management | 1.8 | 4.8 | 2.6 | 2.0 | 1.1 | 1.1 L | 1.4 L | 1.8 | 2.4 | 3.9 | 4.2 | 5.3 | 6.8 | 4.8 | 6.2 | 69.4 | 1.8 | 2.3 | 2.4 |
| Action Economics | 1.8 | 4.8 | 2.6 | 2.0 | 1.5 | 1.6 | 1.8 | 2.2 | 2.9 | 3.8 | 4.4 | 5.3 | 6.4 | 4.6 | 5.9 | 70.0 | 2.0 | 2.6 | 3.5 |
| Lehman Brothers | 1.8 | 4.8 | 2.4 | 1.5 L | 1.6 | 1.7 | 1.6 | 2.0 | 2.8 | 3.6 | 4.3 | 5.5 | 6.8 | 4.8 | 5.9 | na | 1.5 | 3.0 | 3.8 |
| RBS Greenwich Capital Econ. | 1.8 | 4.8 | 2.4 | 1.8 | 1.4 | 1.4 | 1.5 | 2.0 | 2.9 | 3.9 | 4.5 | 5.6 | 6.9 | 4.4 | 6.0 | 70.0 | 1.9 | 2.1 | 3.1 |
| BMO Capital Markets | 1.8 | 4.8 | 2.2 | 2.1 | 1.3 | 1.7 | 1.8 | 1.9 | 2.8 | 3.3 | 4.1 | 5.4 | 6.8 | 4.5 | 5.7 | 70.5 | 2.4 | 1.9 | 1.9 |
| DePrince & Associates | 1.8 | 4.8 | 2.2 | 2.0 | 1.3 | 1.5 | 1.5 | 2.0 | 2.8 | 3.6 | 4.4 | 5.4 | 6.6 | 4.5 | 5.7 | 70.3 | 1.5 | 2.6 | 2.8 |
| Loomis, Sayles & Company | 1.8 | 4.8 | 2.1 | 1.8 | 1.2 | 1.3 | 1.6 | 1.8 | 2.8 | 3.7 | 4.5 | 5.5 | 6.8 | 4.6 | 5.6 | 70.2 | 4.3 H | 2.7 | 3.0 |
| Comerica Bank | 1.8 | 4.8 | 2.0 | 1.8 | 1.5 | 1.7 | 1.8 | 2.1 | 2.9 | 3.8 | 4.3 | 5.2 | 6.5 | 4.1 | 5.6 | 69.5 | -1.0 | 1.4 L | 1.5 L |
| Stone Harbor Investment Partners | 1.8 | 4.8 | 1.9 | 1.7 | 1.2 | 1.6 | 1.8 | 2.3 | 3.0 | 3.6 | 4.3 | 4.9 | 5.9 | na | 5.4 | 73.0 | 2.2 | 2.2 | 3.1 |
| Fannie Mae | 1.8 | 4.8 | na | na | 1.1 | na | 2.4 | na | na | 4.0 | 4.4 | 5.8 | na | na | 6.0 | na | 1.6 | 2.7 | 2.7 |
| Merrill Lynch Economics | 1.8 | na | 2.1 | na | 1.0 | na | na | 1.4 L | 2.3 | 3.4 | 4.2 | na | na | na | na | na | 0.4 | 2.2 | 2.7 |
| J.P. Morgan Chase | 1.8 | na | 2.0 | na | 0.9 L | na | na | na | 1.8 L | 3.0 L | 4.1 | 4.9 | na | na | na | na | 3.0 | 2.2 | 2.2 |
| UBS Warburg | 1.6 | na | 2.4 | na | 1.4 | na | na | 1.6 | 2.6 | 3.6 | 4.5 | na | na | na | na | na | 1.5 | 1.8 | 3.1 |
| Moody's Analytics | 1.6 | 4.6 | 2.2 | 2.1 | 1.5 | 1.8 | 2.0 | 2.1 | 3.0 | 3.8 | 4.5 | 5.6 | 7.1 | 4.5 | 6.0 | 70.1 | 2.5 | 2.1 | 2.1 |
| Economist Intelligence Unit | 1.6 | 4.6 | 2.2 | na | 1.4 | 1.7 | 1.8 | 1.8 | 2.6 | 3.6 | 4.3 | na | na | na | 5.8 | na | -1.8 L | na | 2.0 |
| Bank of America | 1.6 | 4.6 | 1.9 | na | 1.2 | 1.5 | 1.7 | 1.7 | 2.7 | 3.6 | 4.4 | 5.5 | 7.0 | na | 5.9 | na | 0.9 | 2.1 | 2.2 |
| J.W. Coons Advisors LLC | 1.5 | 4.5 | 2.3 | 1.5 L | 1.2 | 1.5 | 1.7 | 2.1 | 2.9 | 3.7 | 4.5 | 5.5 | 6.9 | na | 5.7 | 70.3 | 1.0 | 3.1 | 3.6 |
| Scotiabank | 1.0 L | 4.0 L | 1.5 L | na | 1.2 | 1.6 | na | 2.0 | 2.8 | 3.6 | 4.5 | 5.5 | 6.5 | 4.5 | 6.0 | 69.0 | 1.6 | 2.0 | 2.0 |
| **May Consensus** | **1.9** | **4.9** | **2.3** | **2.1** | **1.4** | **1.6** | **1.8** | **2.0** | **2.8** | **3.7** | **4.4** | **5.5** | **6.8** | **4.5** | **5.8** | **70.4** | **1.6** | **2.4** | **2.7** |
| Top 10 Avg. | 2.1 | 5.1 | 2.7 | 2.5 | 1.8 | 1.9 | 2.2 | 2.4 | 3.1 | 4.0 | 4.7 | 5.8 | 7.2 | 4.8 | 6.1 | 72.5 | 3.4 | 3.1 | 3.6 |
| Bottom 10 Avg. | 1.6 | 4.6 | 2.0 | 1.8 | 1.1 | 1.4 | 1.5 | 1.7 | 2.5 | 3.4 | 4.1 | 5.1 | 6.3 | 4.2 | 5.5 | 68.3 | -0.3 | 1.7 | 1.9 |
| April Consensus | 1.8 | 4.9 | 2.2 | 2.1 | 1.4 | 1.6 | 1.7 | 1.8 | 2.6 | 3.6 | 4.3 | 5.4 | 6.6 | 4.5 | 5.8 | 70.9 | 1.6 | 2.3 | 2.6 |
| Number of Forecasts Changed From A Month Ago: | | | | | | | | | | | | | | | | | | | |
| Down | 7 | 7 | 5 | 11 | 16 | 12 | 9 | 7 | 6 | 7 | 11 | 10 | 5 | 11 | 12 | 16 | 19 | 5 | 5 |
| Same | 24 | 22 | 8 | 10 | 10 | 8 | 6 | 8 | 8 | 9 | 11 | 8 | 5 | 7 | 8 | 8 | 14 | 25 | 21 |
| Up | 14 | 13 | 30 | 13 | 19 | 19 | 25 | 28 | 30 | 29 | 22 | 23 | 26 | 12 | 20 | 7 | 12 | 14 | 19 |
| Diffusion Index | 58 | 57 | 79 | 53 | 53 | 59 | 70 | 74 | 77 | 74 | 63 | 66 | 79 | 52 | 60 | 35 | 42 | 60 | 66 |

# Fourth Quarter 2008

## Interest Rate Forecasts

## Key Assumptions

| Blue Chip Financial Forecasts Panel Members | Percent Per Annum -- Average For Quarter | | | | | | | | | | | | | | | Avg. For | (Q-Q Change) (SAAR) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Short-Term | | | | | | | Intermediate-Term | | | | Long-Term | | | | Qtr. | | | |
| | 1 Federal Funds Rate | 2 Prime Bank Rate | 3 LIBOR Rate 3-Mo. | 4 Com. Paper 1-Mo. | 5 Treas. Bills 3-Mo. | 6 Treas. Bills 6-Mo. | 7 Treas. Bills 1-Yr. | 8 Treas. Notes 2-Yr. | 9 Treas. Notes 5-Yr. | 10 Treas. Notes 10-Yr. | 11 Treas. Bond 30-Yr. | 12 Aaa Corp. Bond | 13 Baa Corp. Bond | 14 State & Local Bonds | 15 Home Mtg. Rate | A. Fed's Major Currency Index | B. Real GDP | C. GDP Price Index | D. Cons. Price Index |
| Wayne Hummer Investments | 2.5 H | 5.5 H | 2.9 | 2.7 H | 1.7 | 2.0 | 2.1 | 2.4 | 3.2 | 4.0 | 4.7 | 5.7 | 6.7 | 4.7 | 6.1 | 71.1 | 2.7 | 2.3 | 2.3 |
| ING Investment Mgt. | 2.5 H | 5.5 H | 2.6 | 2.5 | 2.1 | 2.1 | 2.3 | 2.3 | 3.2 | 4.0 | 4.7 | 5.5 | 6.6 | 4.4 | 6.0 | 70.0 | 2.0 | 2.3 | 2.5 |
| Moody's Economy.com | 2.4 | 5.4 | 2.5 | 2.4 | 2.5 H | 2.6 H | 2.7 H | 3.1 H | 4.0 H | 4.8 H | 5.2 | 6.4 | 7.7 | na | 6.7 | na | 4.3 H | 1.9 | 2.4 |
| Nat'l Assn. of Realtors | 2.3 | 5.3 | 2.6 | 2.6 | 1.9 | 2.3 | 2.5 | 2.6 | 3.0 | 3.8 | 4.6 | 5.9 | 7.2 | 5.1 | 5.9 | na | 2.0 | 1.7 | 1.7 |
| Naroff Economic Advisors | 2.3 | 5.3 | 2.5 | 2.5 | 2.3 | 2.4 | 2.5 | 2.7 | 3.2 | 4.2 | 4.8 | 5.7 | 6.9 | 5.0 | 6.2 | 66.0 L | 1.9 | 2.6 | 1.8 |
| Action Economics | 2.0 | 5.0 | 2.6 | 2.0 | 1.7 | 1.8 | 2.1 | 2.4 | 3.2 | 3.9 | 4.4 | 5.3 | 6.3 | 4.4 | 5.8 | 69.5 | 1.5 | 2.6 | 2.9 |
| Argus Research | 2.0 | 5.0 | 3.0 H | 2.7 H | 1.3 | 1.4 | 1.7 | 1.8 | 2.8 | 3.9 | 4.6 | 5.7 | 7.0 | 4.7 | 6.1 | 72.2 | 3.1 | 3.1 H | 3.7 |
| ClearView Economics | 2.0 | 5.0 | 2.7 | 1.9 | 1.0 | 1.4 | 1.6 | 1.8 | 2.7 | 3.5 | 4.3 | 5.5 | 6.9 | 4.6 | 5.8 | 68.0 | 3.2 | 2.7 | 3.0 |
| National City Corporation | 2.0 | 5.0 | 2.7 | 2.2 | 1.7 | 2.0 | 2.2 | 2.4 | 3.3 | 4.1 | 4.8 | 5.8 | 7.0 | 4.8 | 6.2 | 70.8 | 3.0 | 2.5 | 1.4 |
| State House Policy Office | 2.0 | 5.0 | 2.5 | 2.1 | 1.3 | 1.5 | 1.6 | 1.7 | 2.5 | 3.0 L | 3.6 | 4.7 | 6.3 | 3.8 | 5.3 | 71.3 | 2.7 | 2.3 | 2.3 |
| Barclays Capital | 2.0 | 5.0 | 2.5 | 2.2 | 2.0 | 2.0 | 2.3 | 2.0 | 3.1 | 4.3 | 4.9 | 5.9 | 7.1 | 5.0 | 6.3 | na | 2.5 | 2.3 | 3.0 |
| Swiss Re | 2.0 | 5.0 | 2.4 | 2.6 | 1.8 | 1.8 | 1.8 | 2.1 | 3.0 | 3.5 | 4.4 | 5.5 | 7.1 | na | 5.9 | na | -0.2 | 2.4 | 2.4 |
| Chmura Economics & Analytics | 2.0 | 5.0 | 2.4 | 2.1 | 1.6 | 1.7 | 1.9 | 2.2 | 2.8 | 3.7 | 4.4 | 5.5 | na | na | 5.9 | 73.1 | 1.4 | 2.4 | 2.0 |
| Goldman Sachs & Co. | 2.0 | 5.0 | 2.4 | na | 1.7 | na | na | 2.0 | 3.1 | 3.9 | 4.3 | 5.2 | na | na | 5.6 | na | 1.5 | 1.4 L | 2.0 |
| Nomura Securities, Inc. | 2.0 | 5.0 | 2.4 | 2.1 | 1.7 | 1.7 | 1.6 | 2.7 | 3.4 | 4.1 | 4.8 | 5.8 | 7.3 | na | 6.1 | 72.5 | 1.5 | 2.5 | 2.7 |
| Wachovia | 2.0 | 5.0 | 2.3 | 2.3 | 2.0 | 2.1 | 2.2 | 2.5 | 3.2 | 4.1 | 4.4 | 5.4 | 6.5 | 4.6 | 5.4 | 73.1 | 0.4 | 2.6 | 2.4 |
| Thredgold Economic Assoc. | 2.0 | 5.0 | 2.3 | 2.3 | 1.6 | 1.8 | 1.9 | 2.0 | 2.8 | 3.7 | 4.4 | 5.5 | 6.7 | 4.6 | 5.7 | 71.3 | 1.5 | 2.4 | 2.5 |
| Cycledata Corp. | 2.0 | 5.0 | 2.3 | 2.2 | 1.6 | 1.8 | 1.9 | 2.1 | 2.8 | 3.7 | 4.5 | 5.5 | 6.7 | 4.1 | 5.5 | 73.0 | 0.5 | 2.2 | 3.0 |
| RidgeWorth Capital Management | 2.0 | 5.0 | 2.3 | 2.0 | 1.4 | 1.6 | 1.6 | 1.9 | 2.3 | 3.4 | 3.5 L | 4.6 L | 5.7 | 3.3 L | 5.2 L | 73.0 | 2.5 | 1.8 | 2.0 |
| Woodworth Holdings | 2.0 | 5.0 | 2.2 | 2.2 | 1.7 | 1.9 | 2.0 | 2.0 | 3.0 | 4.0 | 4.8 | 5.8 | 7.2 | 4.6 | 6.1 | 71.0 | 0.0 | 2.5 | 4.1 H |
| The Northern Trust Company | 2.0 | 5.0 | 2.1 | na | 1.5 | na | 1.8 | 1.8 | 2.7 | 3.6 | 4.4 | 5.5 | 5.4 L | 4.8 | na | na | 0.1 | 1.4 L | 1.7 |
| Mesirow Financial | 2.0 | 5.0 | 2.1 | 2.2 | 2.0 | 1.9 | 1.9 | 1.9 | 3.2 | 4.0 | 4.5 | 6.1 | na | na | 5.8 | 70.8 | 3.1 | 2.6 | 2.9 |
| Georgia State University | 2.0 | 5.0 | na | na | 1.3 | 1.4 | 1.7 | 2.2 | 3.0 | 3.8 | 4.5 | 5.7 | 7.0 | na | 5.7 | na | 1.3 | 2.5 | -2.0 |
| PNC Financial Services Corp. | 1.8 | 4.8 | 2.3 | 2.0 | 1.5 | 1.6 | 1.8 | 2.0 | 3.0 | 3.8 | 4.6 | 5.8 | 7.4 | 4.6 | 6.0 | 70.0 | 2.4 | 1.8 | 2.0 |
| Kellner Economic Advisers | 1.8 | 4.8 | 2.3 | 2.4 | 1.5 | 1.8 | 2.1 | 2.3 | 2.9 | 3.7 | 4.5 | 5.7 | 7.2 | 5.1 | 6.2 | 72.0 | -0.5 | 2.9 | 3.9 |
| Bear Stearns & Co. | 1.8 | 4.8 | 2.1 | 1.8 | 1.4 | 1.4 | 1.8 | 2.2 | 3.1 | 4.5 | 5.3 H | 6.5 H | 7.8 H | 5.2 H | 6.7 H | 66.9 | 1.0 | 3.0 | 3.0 |
| Standard & Poor's Corp. | 1.8 | 4.8 | 2.9 | 2.5 | 1.6 | 1.6 | 1.7 | 1.9 | 2.8 | 3.9 | na | 5.8 | 7.2 | 4.5 | 5.9 | 67.4 | 1.3 | 2.1 | 1.2 |
| Wells Capital Management | 1.8 | 4.8 | 2.8 | 2.2 | 1.3 | 1.1 L | 1.3 L | 2.0 | 2.6 | 4.1 | 4.5 | 5.6 | 7.1 | 4.9 | 6.3 | 69.6 | 2.0 | 2.3 | 2.3 |
| JPMorgan Privare Client Services | 1.8 | 4.8 | 2.7 | 2.4 | 0.9 L | 1.5 | 1.7 | 2.0 | 2.7 | 3.5 | 4.3 | 4.8 | 7.0 | 4.4 | 5.6 | 71.1 | 1.5 | 2.3 | 2.4 |
| DePrince & Associates | 1.8 | 4.8 | 2.4 | 2.2 | 1.5 | 1.7 | 1.8 | 2.2 | 2.9 | 3.6 | 4.4 | 5.4 | 6.5 | 4.4 | 5.7 | 70.6 | 2.2 | 2.3 | 2.6 |
| RBS Greenwich Capital Econ. | 1.8 | 4.8 | 2.3 | 1.8 | 1.5 | 1.5 | 1.6 | 2.2 | 3.0 | 4.1 | 4.7 | 5.7 | 6.8 | 4.5 | 6.1 | 71.0 | 1.6 | 2.1 | 2.6 |
| BMO Capital Markets | 1.8 | 4.8 | 2.1 | 2.1 | 1.3 | 1.7 | 1.9 | 2.0 | 2.9 | 3.4 | 4.3 | 5.6 | 7.1 | 4.6 | 5.9 | 71.0 | 1.7 | 2.0 | 1.8 |
| Loomis, Sayles & Company | 1.8 | 4.8 | 2.1 | 1.9 | 1.4 | 1.5 | 1.8 | 2.0 | 3.0 | 4.0 | 4.6 | 5.7 | 6.9 | 4.8 | 5.9 | 70.1 | 0.8 | 2.7 | 2.3 |
| Comerica Bank | 1.8 | 4.8 | 2.0 | 1.8 | 1.5 | 1.7 | 1.8 | 2.1 | 2.9 | 3.8 | 4.2 | 5.0 | 6.0 | 4.0 | 5.5 | 69.5 | 2.0 | 1.5 | 1.6 |
| Stone Harbor Investment Partners | 1.8 | 4.8 | 1.9 | 1.8 | 1.3 | 1.7 | 1.9 | 2.4 | 3.0 | 3.5 | 4.1 | 4.6 | 5.5 | na | 5.3 | 75.0 H | 2.6 | 2.3 | 2.9 |
| Fannie Mae | 1.8 | 4.8 | na | na | 1.3 | na | 2.6 | na | na | 4.1 | 4.5 | 5.8 | na | na | 6.0 | na | 1.7 | 2.7 | 2.4 |
| J.P. Morgan Chase | 1.8 | na | 2.0 | na | 1.1 | na | na | 1.9 | 3.1 | 4.1 | 4.9 | na | na | na | na | na | 1.5 | 2.4 | 2.2 |
| Lehman Brothers | 1.7 | 4.7 | 2.1 | 1.5 L | 1.5 | 1.4 | 1.4 | 1.9 | 2.8 | 3.6 | 4.1 | 5.4 | 6.7 | 4.6 | 5.9 | na | 1.0 | 2.0 | -0.6 |
| Economist Intelligence Unit | 1.6 | 4.6 | 2.3 | na | 1.4 | 1.7 | 1.8 | 1.8 | 2.7 | 3.7 | 4.3 | na | na | na | 5.8 | na | -1.5 L | na | 1.6 |
| J.W. Coons Advisors LLC | 1.5 | 4.5 | 2.5 | 1.7 | 1.3 | 1.6 | 1.9 | 2.4 | 3.2 | 3.8 | 4.6 | 5.7 | 7.0 | na | 5.8 | 71.3 | 1.7 | 2.9 | 2.9 |
| Moody's Analytics | 1.5 | 4.5 | 2.0 | 2.0 | 1.6 | 1.9 | 2.0 | 2.2 | 3.0 | 3.9 | 4.4 | 5.5 | 7.0 | 4.4 | 6.0 | 70.5 | 2.2 | 2.0 | 2.4 |
| Bank of America | 1.5 | 4.5 | 1.7 | na | 1.3 | 1.6 | 1.8 | 1.8 | 2.8 | 3.7 | 4.4 | 5.6 | 7.1 | na | 6.0 | na | 1.5 | 2.1 | 2.4 |
| UBS Warburg | 1.5 | na | 2.3 | na | 1.5 | na | na | 1.8 | 2.8 | 3.8 | 4.6 | na | na | na | na | na | 2.8 | 1.8 | -2.5 L |
| Merrill Lynch Economics | 1.3 | na | 2.0 | na | 1.0 | na | na | 1.1 L | 2.0 L | 3.3 | 4.1 | na | na | na | na | na | -0.5 | 2.4 | 1.9 |
| Scotiabank | 1.0 L | 4.0 L | 1.5 L | na | 1.6 | 1.9 | na | 2.4 | 3.1 | 3.9 | 4.7 | 5.7 | 6.7 | 4.7 | 6.2 | 68.0 | 1.4 | 2.0 | 2.0 |
| **May Consensus** | **1.9** | **4.9** | **2.3** | **2.2** | **1.5** | **1.7** | **1.9** | **2.1** | **2.9** | **3.8** | **4.5** | **5.6** | **6.8** | **4.6** | **5.9** | **70.7** | **1.6** | **2.3** | **2.1** |
| Top 10 Avg. | 2.2 | 5.2 | 2.8 | 2.5 | 2.0 | 2.1 | 2.3 | 2.5 | 3.3 | 4.2 | 4.9 | 6.0 | 7.3 | 4.9 | 6.3 | 72.7 | 3.0 | 2.8 | 3.2 |
| Bottom 10 Avg. | 1.5 | 4.6 | 1.9 | 1.8 | 1.2 | 1.4 | 1.6 | 1.7 | 2.6 | 3.4 | 4.1 | 5.0 | 6.1 | 4.2 | 5.5 | 68.5 | 0.0 | 1.7 | 0.6 |
| April Consensus | 1.8 | 4.9 | 2.2 | 2.1 | 1.5 | 1.7 | 1.8 | 1.9 | 2.7 | 3.7 | 4.4 | 5.5 | 6.7 | 4.6 | 5.8 | 71.2 | 1.7 | 2.2 | 2.2 |
| Number of Forecasts Changed From A Month Ago: | | | | | | | | | | | | | | | | | | | |
| Down | 6 | 6 | 7 | 8 | 10 | 8 | 7 | 8 | 5 | 6 | 7 | 11 | 8 | 11 | 11 | 16 | 19 | 3 | 12 |
| Same | 27 | 24 | 11 | 12 | 15 | 13 | 10 | 10 | 10 | 15 | 18 | 8 | 5 | 6 | 11 | 7 | 18 | 26 | 23 |
| Up | 12 | 12 | 25 | 14 | 20 | 18 | 23 | 26 | 29 | 24 | 19 | 22 | 23 | 13 | 18 | 7 | 8 | 15 | 10 |
| Diffusion Index | 57 | 57 | 71 | 59 | 61 | 63 | 70 | 70 | 77 | 70 | 64 | 63 | 71 | 53 | 59 | 35 | 38 | 64 | 48 |

# First Quarter 2009

## Interest Rate Forecasts

## Key Assumptions

| Blue Chip Financial Forecasts Panel Members | Percent Per Annum -- Average For Quarter | | | | | | | | | | | | | | | Avg. For | (Q-Q Change) (SAAR) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Short-Term | | | | | | | Intermediate-Term | | | | Long-Term | | | | Qtr. | | | |
| | 1 Federal Funds Rate | 2 Prime Bank Rate | 3 LIBOR Rate 3-Mo. | 4 Com. Paper 1-Mo. | 5 Treas. Bills 3-Mo. | 6 Treas. Bills 6-Mo. | 7 Treas. Bills 1-Yr. | 8 Treas. Notes 2-Yr. | 9 Treas. Notes 5-Yr. | 10 Treas. Notes 10-Yr. | 11 Treas. Bond 30-Yr. | 12 Aaa Corp. Bond | 13 Baa Corp. Bond | 14 State & Local Bonds | 15 Home Mtg. Rate | A. Fed's Major Currency Index | B. Real GDP | C. GDP Price Index | D. Cons. Price Index |
| Moody's Economy.com | 3.5 H | 6.5 H | 3.6 H | 3.2 H | 3.2 H | 3.3 H | 3.5 H | 3.7 H | 4.4 H | 5.1 H | 5.5 H | 6.7 H | 8.0 H | na | 6.9 H | na | 2.8 | 2.2 | 2.0 |
| ING Investment Mgt. | 3.0 | 6.0 | 3.1 | 3.0 | 2.7 | 2.7 | 2.9 | 2.9 | 3.5 | 4.2 | 4.8 | 5.5 | 6.5 | 4.4 | 6.2 | 72.0 | 2.5 | 2.4 | 2.5 |
| Naroff Economic Advisors | 2.8 | 5.8 | 3.0 | 2.9 | 2.8 | 3.0 | 3.1 | 3.3 | 3.7 | 4.4 | 5.0 | 5.9 | 7.0 | 5.1 | 6.3 | 70.0 | 3.6 H | 2.5 | 2.4 |
| Wayne Hummer Investments | 2.7 | 5.7 | 3.0 | 2.8 | 2.0 | 2.2 | 2.3 | 2.6 | 3.4 | 4.2 | 4.9 | 5.9 | 6.8 | 4.8 | 6.2 | 71.4 | 3.0 | 2.2 | 2.2 |
| Nat'l Assn. of Realtors | 2.5 | 5.5 | 2.7 | 2.7 | 2.2 | 2.4 | 2.7 | 2.7 | 3.1 | 3.8 | 4.6 | 5.9 | 7.2 | 5.1 | 5.9 | na | 2.8 | 1.5 L | 1.7 |
| National City Corporation | 2.4 | 5.4 | 3.0 | 2.5 | 2.1 | 2.4 | 2.6 | 2.8 | 3.6 | 4.4 | 4.9 | 6.0 | 7.1 | 4.8 | 6.3 | 72.2 | 1.6 | 2.7 | 2.2 |
| Argus Research | 2.3 | 5.3 | 3.0 | 2.8 | 1.4 | 1.5 | 1.7 | 1.9 | 2.8 | 3.9 | 4.6 | 5.8 | 7.1 | 4.7 | 6.2 | 73.3 | 2.0 | 3.1 H | 3.4 |
| State House Policy Office | 2.3 | 5.3 | 2.7 | 2.4 | 1.7 | 1.8 | 1.9 | 2.0 | 2.6 | 3.2 | 3.7 L | 4.6 | 6.2 | 3.6 L | 5.3 L | 71.6 | 2.0 | 2.0 | 2.1 |
| Action Economics | 2.3 | 5.3 | 2.6 | 2.3 | 2.0 | 2.2 | 2.4 | 2.7 | 3.4 | 4.0 | 4.5 | 5.2 | 6.3 | 4.3 | 5.8 | 69.0 | 2.8 | 3.0 | 2.6 |
| Swiss Re | 2.3 | 5.3 | 2.5 | 2.8 | 2.0 | 2.0 | 2.0 | 2.3 | 3.1 | 3.6 | 4.5 | 5.6 | 7.1 | na | 6.0 | na | 2.8 | 1.7 | 1.7 |
| RidgeWorth Capital Management | 2.3 | 5.3 | 2.5 | 2.2 | 1.9 | 2.1 | 2.0 | 2.4 | 2.8 | 3.8 | 3.9 | 5.0 | 6.0 | 3.7 | 5.5 | 74.0 | 3.0 | 2.0 | 2.0 |
| Wachovia | 2.3 | 5.3 | 2.4 | 2.4 | 2.3 | 2.4 | 2.5 | 2.7 | 3.3 | 4.1 | 4.5 | 5.5 | 6.5 | 4.5 | 5.6 | 75.0 H | 2.3 | 2.4 | 2.6 |
| ClearView Economics | 2.2 | 5.2 | 3.1 | 2.1 | 1.3 | 1.7 | 2.0 | 2.3 | 3.0 | 3.8 | 4.5 | 5.7 | 7.0 | 4.6 | 6.0 | 68.0 | 3.3 | 2.2 | 2.5 |
| Barclays Capital | 2.0 | 5.0 | 2.5 | 2.2 | 2.2 | 2.3 | 2.6 | 2.6 | 3.5 | 4.4 | 5.1 | 6.1 | 7.2 | 5.0 | 6.3 | na | 2.5 | 2.4 | 2.6 |
| Chmura Economics & Analytics | 2.0 | 5.0 | 2.4 | 2.1 | 1.7 | 1.8 | 1.9 | 2.3 | 2.9 | 3.8 | 4.4 | 5.5 | na | na | 5.9 | 73.8 | 2.1 | 2.8 | 1.6 |
| Thredgold Economic Assoc. | 2.0 | 5.0 | 2.3 | 2.3 | 1.6 | 1.8 | 1.9 | 2.1 | 2.9 | 3.8 | 4.5 | 5.5 | 6.7 | 4.6 | 5.7 | 71.6 | 1.5 | 2.4 | 2.5 |
| Cycledata Corp. | 2.0 | 5.0 | 2.3 | 2.2 | 1.7 | 1.9 | 1.9 | 2.1 | 2.8 | 3.7 | 4.5 | 5.5 | 6.7 | 4.1 | 5.5 | 74.0 | 0.8 | 2.2 | 3.0 |
| Kellner Economic Advisers | 2.0 | 5.0 | 2.3 | 2.5 | 1.7 | 1.9 | 2.3 | 2.5 | 3.1 | 3.8 | 4.7 | 5.8 | 7.3 | 5.2 | 6.3 | 74.0 | 0.0 | 3.0 | 3.8 |
| Goldman Sachs & Co. | 2.0 | 5.0 | 2.3 | na | 1.8 | na | na | 1.8 | 2.9 | 3.8 | 4.2 | 5.0 | na | na | 5.5 | na | 0.0 | 2.6 | 2.0 |
| Nomura Securities, Inc. | 2.0 | 5.0 | 2.2 | 2.1 | 1.8 | 1.7 | 1.7 | 2.9 | 3.6 | 4.2 | 4.9 | 5.8 | 7.4 | na | 6.1 | 73.0 | 2.4 | 2.2 | 2.5 |
| Woodworth Holdings | 2.0 | 5.0 | 2.2 | 2.2 | 1.8 | 1.9 | 2.0 | 2.1 | 3.1 | 4.1 | 4.9 | 5.8 | 7.1 | 4.5 | 6.0 | 73.0 | 1.8 | 2.4 | 3.6 |
| Stone Harbor Investment Partners | 2.0 | 5.0 | 2.1 | 2.0 | 1.6 | 1.9 | 2.2 | 2.6 | 3.1 | 3.6 | 4.1 | 4.5 L | 5.4 L | na | 5.3 | 72.0 | 2.8 | 2.1 | 2.0 |
| Mesirow Financial | 2.0 | 5.0 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.0 | 3.2 | 4.2 | 4.6 | 6.0 | na | na | 5.7 | 71.0 | 1.6 | 2.7 | 2.6 |
| Georgia State University | 2.0 | 5.0 | na | na | 1.5 | 1.5 | 1.8 | 2.3 | 3.1 | 4.0 | 4.7 | 5.8 | 6.9 | na | 5.8 | na | 1.5 | 2.3 | 1.5 |
| PNC Financial Services Corp. | 1.8 | 4.8 | 2.3 | 2.0 | 1.5 | 1.6 | 1.8 | 2.0 | 3.0 | 3.8 | 4.6 | 5.8 | 7.4 | 4.6 | 6.0 | 72.0 | 2.0 | 2.8 | 2.2 |
| Loomis, Sayles & Company | 1.8 | 4.8 | 2.3 | 2.1 | 1.7 | 1.8 | 2.0 | 2.3 | 3.3 | 4.3 | 4.8 | 5.9 | 7.0 | 4.7 | 6.0 | 70.1 | 2.9 | 2.8 | 2.3 |
| Bear Stearns & Co. | 1.8 | 4.8 | 2.1 | 1.8 | 1.5 | 1.5 | 1.9 | 2.3 | 3.2 | 4.6 | 5.5 | 6.6 | 7.8 | 5.4 H | 6.8 | 66.5 | 1.4 | 3.0 | 3.1 |
| Comerica Bank | 1.8 | 4.8 | 2.0 | 1.8 | 1.5 | 1.7 | 1.9 | 2.2 | 2.9 | 3.8 | 4.3 | 5.1 | 6.0 | 4.0 | 5.5 | 69.8 | 2.5 | 1.8 | 1.9 |
| Wells Capital Management | 1.8 | 4.8 | 2.8 | 2.3 | 1.4 | 1.0 L | 1.3 L | 2.2 | 2.6 | 4.2 | 4.7 | 5.8 | 7.2 | 4.9 | 6.3 | 70.0 | 2.5 | 2.5 | 2.4 |
| Standard & Poor's Corp. | 1.8 | 4.8 | 2.8 | 2.5 | 1.6 | 1.7 | 1.8 | 1.9 | 2.8 | 3.9 | na | 5.8 | 7.1 | 4.5 | 5.9 | 66.5 L | 0.5 | 2.2 | 2.1 |
| JPMorgan Privare Client Services | 1.8 | 4.8 | 2.8 | 2.5 | 1.0 L | 1.6 | 1.8 | 2.1 | 2.8 | 3.6 | 4.4 | 4.9 | 7.1 | 4.5 | 5.7 | 71.4 | 1.7 | 2.3 | 2.4 |
| J.W. Coons Advisors LLC | 1.8 | 4.8 | 2.7 | 1.8 | 1.6 | 1.9 | 2.2 | 2.6 | 3.4 | 4.0 | 4.7 | 5.8 | 7.0 | na | 5.9 | 72.6 | 1.2 | 2.6 | 2.4 |
| DePrince & Assoc. | 1.8 | 4.8 | 2.5 | 2.3 | 1.6 | 1.8 | 2.1 | 2.4 | 3.0 | 3.7 | 4.4 | 5.5 | 6.4 | 4.4 | 5.7 | 71.1 | 2.5 | 2.4 | 2.7 |
| RBS Greenwich Capital Econ. | 1.8 | 4.8 | 2.5 | 1.8 | 1.6 | 1.7 | 1.9 | 2.4 | 3.2 | 4.4 | 4.9 | 5.8 | 6.9 | 4.7 | 6.3 | 72.0 | 2.1 | 3.1 | 2.6 |
| BMO Capital Markets | 1.8 | 4.8 | 2.1 | 2.0 | 1.3 | 1.9 | 2.1 | 2.3 | 3.2 | 3.7 | 4.5 | 5.8 | 7.3 | 4.8 | 6.0 | 71.5 | 2.0 | 1.8 | 2.4 |
| Fannie Mae | 1.8 | 4.8 | na | na | 1.5 | na | 2.8 | na | na | 4.1 | 4.5 | 5.8 | na | na | 6.0 | na | 1.7 | 2.7 | 2.4 |
| J.P. Morgan Chase | 1.8 | na | 2.2 | na | 1.2 | na | na | 2.0 | 3.2 | 4.2 | 4.9 | na | na | na | na | na | 2.5 | 2.5 | 2.3 |
| Moody's Analytics | 1.7 | 4.7 | 2.2 | 2.1 | 1.8 | 2.1 | 2.1 | 2.2 | 3.1 | 3.9 | 4.3 | 5.3 | 6.9 | 4.3 | 5.9 | 71.1 | 1.8 | 2.0 | 2.3 |
| Economist Intelligence Unit | 1.6 | 4.6 | 2.6 | na | 1.7 | 1.8 | 2.0 | 2.0 | 3.0 | 3.7 | 4.4 | na | na | na | 5.9 | na | 0.2 | na | 2.0 |
| Bank of America | 1.5 | 4.5 | 1.6 | na | 1.4 | 1.7 | 1.9 | 1.9 | 2.9 | 3.8 | 4.5 | 5.7 | 7.2 | na | 6.1 | na | 2.2 | 2.3 | 2.6 |
| UBS Warburg | 1.5 | na | 2.3 | na | 1.5 | na | na | 2.0 | 2.9 | 4.0 | 4.8 | na | na | na | na | na | 3.2 | 1.8 | 5.2 H |
| Lehman Brothers | 1.3 | 4.3 | 1.8 | 1.2 L | 1.3 | 1.3 | 1.4 | 1.8 | 2.7 | 3.5 | 3.9 | 5.3 | 6.6 | 4.5 | 5.8 | na | -1.0 L | 2.3 | 1.2 L |
| Scotiabank | 1.0 L | 4.0 L | 1.5 L | na | 2.0 | 2.3 | na | 2.7 | 3.5 | 4.2 | 5.1 | 6.1 | 7.1 | 5.1 | 6.6 | 68.0 | 1.6 | 2.0 | 2.0 |
| Merrill Lynch Economics | 1.0 L | na | 1.7 | na | 1.0 | na | na | 1.0 L | 1.9 L | 3.2 L | 3.9 | na | na | na | na | na | -0.2 | 1.8 | 1.4 |
| **May Consensus** | **2.0** | **5.0** | **2.4** | **2.3** | **1.7** | **1.9** | **2.1** | **2.3** | **3.1** | **4.0** | **4.6** | **5.6** | **6.9** | **4.6** | **6.0** | **71.3** | **1.9** | **2.4** | **2.4** |
| Top 10 Avg. | 2.6 | 5.6 | 3.0 | 2.8 | 2.4 | 2.5 | 2.7 | 2.9 | 3.6 | 4.4 | 5.1 | 6.1 | 7.4 | 5.0 | 6.4 | 73.5 | 3.0 | 2.9 | 3.3 |
| Bottom 10 Avg. | 1.5 | 4.6 | 1.9 | 1.9 | 1.3 | 1.5 | 1.7 | 1.8 | 2.6 | 3.5 | 4.1 | 5.0 | 6.2 | 4.2 | 5.5 | 68.9 | 0.4 | 1.8 | 1.7 |
| April Consensus | 2.0 | 5.0 | 2.3 | 2.3 | 1.7 | 1.9 | 2.0 | 2.2 | 2.9 | 3.8 | 4.5 | 5.6 | 6.7 | 4.6 | 5.9 | 71.9 | 1.9 | 2.4 | 2.4 |
| Number of Forecasts Changed From A Month Ago: | | | | | | | | | | | | | | | | | | | |
| Down | 10 | 10 | 8 | 10 | 12 | 11 | 10 | 12 | 10 | 9 | 9 | 12 | 4 | 11 | 12 | 17 | 15 | 9 | 10 |
| Same | 23 | 20 | 15 | 11 | 14 | 10 | 10 | 9 | 10 | 10 | 15 | 9 | 10 | 8 | 10 | 8 | 19 | 23 | 22 |
| Up | 11 | 11 | 19 | 13 | 18 | 18 | 19 | 22 | 23 | 25 | 19 | 19 | 22 | 10 | 18 | 6 | 10 | 11 | 12 |
| Diffusion Index | 51 | 51 | 63 | 54 | 57 | 59 | 62 | 62 | 65 | 68 | 62 | 59 | 75 | 48 | 58 | 32 | 44 | 52 | 52 |

# Second Quarter 2009

## Interest Rate Forecasts

## Key Assumptions

| Blue Chip Financial Forecasts Panel Members | 1 Federal Funds Rate | 2 Prime Bank Rate | 3 LIBOR Rate 3-Mo. | 4 Com. Paper 1-Mo. | 5 Treas. Bills 3-Mo. | 6 Treas. Bills 6-Mo. | 7 Treas. Bills 1-Yr. | 8 Treas. Notes 2-Yr. | 9 Treas. Notes 5-Yr. | 10 Treas. Notes 10-Yr. | 11 Treas. Bond 30-Yr. | 12 Aaa Corp. Bond | 13 Baa Corp. Bond | 14 State & Local Bonds | 15 Home Mtg. Rate | A. Fed's Major Currency Index | B. Real GDP | C. GDP Price Index | D. Cons. Price Index |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Percent Per Annum -- Average For Quarter | | | | | | | | | | | | | | | Avg. For Qtr. | (Q-Q Change) (SAAR) | | |
| | Short-Term | | | | | | | Intermediate-Term | | | | Long-Term | | | | | | | |
| Moody's Economy.com | 4.2 H | 7.2 H | 4.3 H | 3.8 H | 3.9 H | 3.9 H | 4.1 H | 4.2 H | 4.7 H | 5.3 H | 5.7 H | 6.8 H | 8.2 H | na | 7.1 H | na | 3.8 | 2.1 | 1.7 |
| ING Investment Mgt. | 3.5 | 6.5 | 3.6 | 3.5 | 3.3 | 3.3 | 3.5 | 3.5 | 3.9 | 4.3 | 4.9 | 5.6 | 6.5 | 4.5 | 6.4 | 74.0 | 3.0 | 2.5 | 2.4 |
| National City Corporation | 3.4 | 6.4 | 3.9 | 3.5 | 3.1 | 3.3 | 3.4 | 3.5 | 4.1 | 4.7 | 5.1 | 6.2 | 7.4 | 5.0 | 6.7 | 72.7 | 3.0 | 1.6 | 0.1 |
| Naroff Economic Advisors | 3.3 | 6.3 | 3.4 | 3.5 | 3.4 | 3.5 | 3.7 | 3.9 | 4.2 | 4.7 | 5.2 | 6.0 | 7.0 | 5.1 | 6.4 | 76.0 | 4.5 H | 2.4 | 2.4 |
| Stone Harbor Investment Partners | 3.0 | 6.0 | 3.1 | 3.0 | 2.7 | 2.9 | 3.2 | 3.4 | 3.7 | 4.1 | 4.6 | 4.9 | 5.8 L | na | 5.7 | 69.0 | 3.1 | 2.6 | 1.8 |
| Wayne Hummer Investments | 2.9 | 5.9 | 3.2 | 3.2 | 2.3 | 2.4 | 2.5 | 2.9 | 3.7 | 4.5 | 5.2 | 6.2 | 6.9 | 4.9 | 6.6 | 72.0 | 3.1 | 2.3 | 2.3 |
| Nat'l Assn. of Realtors | 2.8 | 5.8 | 3.0 | 3.0 | 2.5 | 2.7 | 3.0 | 3.0 | 3.2 | 3.9 | 4.7 | 5.9 | 7.1 | 5.2 | 6.0 | na | 2.6 | 1.5 | 1.7 |
| Swiss Re | 2.8 | 5.8 | 2.9 | 3.2 | 2.5 | 2.6 | 2.6 | 2.9 | 3.5 | 4.0 | 4.7 | 5.8 | 7.3 | na | 6.2 | na | 3.5 | 1.5 | 1.7 |
| ClearView Economics | 2.7 | 5.7 | 3.7 | 2.6 | 1.7 | 2.3 | 2.7 | 2.9 | 3.5 | 4.2 | 4.8 | 5.9 | 7.3 | 4.8 | 6.3 | 69.0 | 3.3 | 2.5 | 3.0 |
| Loomis, Sayles & Company | 2.5 | 5.5 | 2.9 | 2.7 | 2.4 | 2.5 | 2.7 | 2.5 | 3.5 | 4.3 | 4.8 | 5.8 | 6.8 | 4.8 | 6.0 | 70.0 | 3.0 | 2.2 | 2.2 |
| State House Policy Office | 2.5 | 5.5 | 2.9 | 2.6 | 2.1 | 2.2 | 2.3 | 2.3 | 2.8 | 3.4 | 3.8 | 4.6 L | 6.3 | 3.5 L | 5.5 | 71.8 | 3.0 | 2.0 | 2.0 |
| Action Economics | 2.5 | 5.5 | 2.8 | 2.5 | 2.3 | 2.5 | 2.7 | 2.9 | 3.6 | 4.2 | 4.6 | 5.2 | 6.3 | 4.3 | 5.8 | 68.5 | 2.8 | 2.6 | 2.6 |
| RidgeWorth Capital Management | 2.5 | 5.5 | 2.8 | 2.5 | 2.1 | 2.3 | 2.3 | 2.6 | 3.0 | 3.9 | 4.0 | 5.1 | 6.1 | 3.8 | 5.7 | 75.0 | 3.5 | 2.0 | 2.0 |
| Wachovia | 2.5 | 5.5 | 2.7 | 2.6 | 2.5 | 2.6 | 2.7 | 2.8 | 3.4 | 4.3 | 4.6 | 5.6 | 6.6 | 4.6 | 5.8 | 78.3 H | 2.2 | 2.3 | 2.3 |
| Barclays Capital | 2.4 | 5.4 | 2.9 | 2.6 | 2.6 | 2.7 | 3.0 | 2.8 | 3.6 | 4.4 | 5.2 | 6.1 | 7.2 | 5.0 | 6.2 | na | 3.0 | 2.5 | 1.1 |
| Thredgold Economic Assoc. | 2.3 | 5.3 | 2.6 | 2.6 | 1.9 | 2.1 | 2.2 | 2.4 | 3.3 | 4.2 | 4.9 | 5.9 | 7.0 | 4.5 | 6.1 | 72.0 | 1.5 | 2.4 | 2.5 |
| Kellner Economic Advisers | 2.3 | 5.3 | 2.4 | 2.6 | 1.9 | 2.2 | 2.5 | 2.6 | 3.3 | 3.9 | 4.8 | 5.9 | 7.4 | 5.3 | 6.4 | 75.0 | 0.0 L | 3.0 | 3.9 |
| Argus Research | 2.3 | 5.3 | 3.0 | 2.8 | 1.4 | 1.5 | 1.7 | 1.9 | 2.8 | 3.9 | 4.6 | 5.9 | 7.2 | 4.7 | 6.2 | 74.0 | 2.5 | 3.1 H | 4.6 H |
| Comerica Bank | 2.2 | 5.2 | 2.5 | 2.2 | 2.0 | 2.2 | 2.3 | 2.6 | 3.2 | 4.0 | 4.5 | 5.3 | 6.2 | 4.2 | 5.7 | 70.3 | 3.0 | 1.9 | 2.0 |
| Moody's Analytics | 2.1 | 5.1 | 2.5 | 2.5 | 2.2 | 2.4 | 2.4 | 2.5 | 3.4 | 4.3 | 4.6 | 5.5 | 7.0 | 4.6 | 6.2 | 71.8 | 2.9 | 2.1 | 3.1 |
| BMO Capital Markets | 2.1 | 5.1 | 2.5 | 2.4 | 1.7 | 2.3 | 2.5 | 2.7 | 3.4 | 3.8 | 4.6 | 5.9 | 7.4 | 4.9 | 6.1 | 72.0 | 2.5 | 2.2 | 2.6 |
| J.W. Coons Advisors LLC | 2.0 | 5.0 | 3.0 | 2.1 | 1.9 | 2.2 | 2.5 | 2.9 | 3.6 | 4.1 | 4.8 | 5.9 | 7.1 | na | 6.0 | 74.2 | 2.2 | 2.5 | 2.3 |
| JPMorgan Privare Client Services | 2.0 | 5.0 | 2.9 | 2.6 | 1.1 | 1.7 | 1.9 | 2.2 | 2.9 | 3.7 | 4.5 | 5.0 | 7.2 | 4.6 | 5.8 | 71.2 | 2.0 | 2.2 | 2.3 |
| Economist Intelligence Unit | 2.0 | 5.0 | 2.6 | na | 1.8 | 2.1 | 2.3 | 2.3 | 3.2 | 3.9 | 4.5 | na | na | na | 5.9 | na | 2.6 | na | 2.0 |
| PNC Financial Services Corp. | 2.0 | 5.0 | 2.5 | 2.2 | 1.7 | 1.8 | 2.0 | 2.2 | 3.2 | 4.0 | 4.8 | 6.0 | 7.6 | 4.8 | 6.2 | 73.0 | 2.5 | 2.0 | 2.4 |
| Chmura Economics & Analytics | 2.0 | 5.0 | 2.4 | 2.1 | 1.8 | 1.9 | 2.0 | 2.4 | 3.0 | 3.8 | 4.4 | 5.5 | na | na | 5.9 | 73.9 | 2.5 | 3.0 | 1.5 |
| Cycledata Corp. | 2.0 | 5.0 | 2.3 | 2.2 | 1.7 | 1.9 | 1.9 | 2.1 | 2.8 | 3.7 | 4.5 | 5.5 | 6.7 | 4.1 | 5.5 | 74.0 | 1.0 | 2.2 | 2.9 |
| Goldman Sachs & Co. | 2.0 | 5.0 | 2.2 | na | 1.8 | na | na | 1.8 | 2.9 | 3.7 | 4.1 | 4.8 | na | na | 5.4 L | na | 1.0 | 2.1 | 1.9 |
| Woodworth Holdings | 2.0 | 5.0 | 2.2 | 2.2 | 1.8 | 2.0 | 2.1 | 2.1 | 3.1 | 4.1 | 4.9 | 5.7 | 7.0 | 4.5 | 5.9 | 76.0 | 2.5 | 2.4 | 3.2 |
| Nomura Securities, Inc. | 2.0 | 5.0 | 2.2 | 2.1 | 1.8 | 1.7 | 1.7 | 3.1 | 3.7 | 4.4 | 5.0 | 5.8 | 7.4 | na | 6.2 | 75.0 | 2.6 | 2.3 | 2.2 |
| Mesirow Financial | 2.0 | 5.0 | 2.1 | 2.1 | 2.1 | 2.2 | 2.2 | 2.3 | 3.3 | 4.2 | 4.7 | 6.0 | na | na | 5.9 | 71.5 | 1.7 | 2.0 | 2.2 |
| Georgia State University | 2.0 | 5.0 | na | na | 1.7 | 1.8 | 2.0 | 2.5 | 3.2 | 4.1 | 4.8 | 5.9 | 7.0 | na | 5.9 | na | 2.3 | 0.8 L | 0.8 |
| RBS Greenwich Capital Econ. | 1.9 | 4.9 | 2.7 | 2.0 | 2.0 | 2.2 | 2.5 | 3.1 | 3.7 | 4.7 | 5.2 | 5.9 | 6.9 | 4.9 | 6.6 | 73.5 | 2.3 | 2.7 | 2.8 |
| Fannie Mae | 1.9 | 4.9 | na | na | 1.9 | na | 3.0 | na | na | 4.2 | 4.6 | 5.9 | na | na | 6.1 | na | 2.4 | 2.3 | 2.3 |
| Wells Capital Management | 1.9 | 4.9 | 2.9 | 2.4 | 1.6 | 0.9 L | 1.1 L | 2.4 | 2.4 | 4.2 | 4.8 | 5.9 | 7.3 | 5.1 | 6.2 | 70.5 | 2.8 | 2.6 | 2.6 |
| Standard & Poor's Corp. | 1.9 | 4.9 | 3.0 | 2.7 | 1.8 | 1.9 | 2.0 | 2.2 | 3.0 | 4.2 | na | 5.9 | 7.2 | 4.6 | 6.1 | 65.3 L | 3.3 | 1.2 | 0.0 L |
| Bear Stearns & Co. | 1.8 | 4.8 | 2.2 | 1.8 | 1.7 | 1.8 | 2.1 | 2.3 | 3.3 | 4.7 | 5.6 | 6.6 | 7.8 | 5.5 H | 6.9 | 66.0 | 2.0 | 3.0 | 3.2 |
| DePrince & Assoc. | 1.8 | 4.8 | 2.7 | 2.3 | 1.7 | 2.0 | 2.3 | 2.6 | 3.1 | 3.8 | 4.4 | 5.5 | 6.5 | 4.4 | 5.8 | 71.6 | 2.8 | 2.4 | 2.7 |
| Bank of America | 1.5 | 4.5 | 1.7 | na | 1.5 | 1.8 | 2.0 | 2.1 | 3.0 | 3.9 | 4.6 | 5.8 | 7.3 | na | 6.2 | na | 2.6 | 2.2 | 2.2 |
| UBS Warburg | 1.5 | na | 2.2 | na | 1.5 | na | na | 2.2 | 3.1 | 4.1 | 4.9 | na | na | na | na | na | 3.2 | 1.9 | 2.7 |
| Lehman Brothers | 1.3 | 4.3 | 1.5 | 1.2 L | 1.3 | 1.3 | 1.4 | 1.8 | 2.7 | 3.5 | 3.8 | 5.3 | 6.6 | 4.5 | 5.7 | na | 1.1 | 1.2 | 2.4 |
| Scotiabank | 1.0 L | 4.0 L | 1.4 | na | 2.3 | 2.6 | na | 3.0 | 3.7 | 4.4 | 5.2 | 6.2 | 7.2 | 5.2 | 6.7 | 69.0 | 2.0 | 2.0 | 2.0 |
| Merrill Lynch Economics | 1.0 L | na | 1.3 L | na | 1.1 L | na | na | 1.0 L | 1.6 L | 2.8 L | 3.4 L | na | na | na | na | na | 1.5 | 1.3 | 0.9 |
| **May Consensus** | **2.2** | **5.3** | **2.7** | **2.6** | **2.0** | **2.3** | **2.4** | **2.6** | **3.3** | **4.1** | **4.7** | **5.7** | **7.0** | **4.7** | **6.1** | **72.1** | **2.5** | **2.2** | **2.2** |
| Top 10 Avg. | 3.1 | 6.1 | 3.4 | 3.2 | 2.9 | 3.0 | 3.2 | 3.4 | 3.9 | 4.6 | 5.2 | 6.2 | 7.5 | 5.1 | 6.6 | 75.2 | 3.4 | 2.8 | 3.2 |
| Bottom 10 Avg. | 1.5 | 4.7 | 1.9 | 2.0 | 1.4 | 1.6 | 1.8 | 1.9 | 2.7 | 3.6 | 4.1 | 5.1 | 6.3 | 4.2 | 5.6 | 68.9 | 1.4 | 1.5 | 1.1 |
| April Consensus | 2.2 | 5.3 | 2.6 | 2.5 | 2.0 | 2.3 | 2.4 | 2.5 | 3.2 | 4.0 | 4.7 | 5.7 | 6.8 | 4.6 | 6.0 | 72.5 | 2.4 | 2.2 | 2.3 |
| Number of Forecasts Changed From A Month Ago: | | | | | | | | | | | | | | | | | | | |
| Down | 13 | 13 | 9 | 11 | 14 | 13 | 13 | 10 | 8 | 11 | 10 | 15 | 5 | 9 | 14 | 17 | 10 | 8 | 11 |
| Same | 20 | 18 | 16 | 12 | 17 | 10 | 9 | 14 | 13 | 12 | 16 | 9 | 8 | 8 | 9 | 8 | 16 | 23 | 23 |
| Up | 10 | 10 | 16 | 11 | 12 | 16 | 17 | 18 | 21 | 20 | 16 | 16 | 22 | 11 | 17 | 6 | 17 | 11 | 9 |
| Diffusion Index | 47 | 46 | 59 | 50 | 48 | 54 | 55 | 60 | 65 | 60 | 57 | 51 | 74 | 54 | 54 | 32 | 58 | 54 | 48 |

# Third Quarter 2009

## Interest Rate Forecasts

## Key Assumptions

| Blue Chip Financial Forecasts Panel Members | Percent Per Annum -- Average For Quarter | | | | | | | | | | | | | | | Avg. For | (Q-Q Change) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Short-Term | | | | | | | Intermediate-Term | | | | Long-Term | | | | Qtr. | (SAAR) | | |
| | 1 Federal Funds Rate | 2 Prime Bank Rate | 3 LIBOR Rate 3-Mo. | 4 Com. Paper 1-Mo. | 5 Treas. Bills 3-Mo. | 6 Treas. Bills 6-Mo. | 7 Treas. Bills 1-Yr. | 8 Treas. Notes 2-Yr. | 9 Treas. Notes 5-Yr. | 10 Treas. Notes 10-Yr. | 11 Treas. Bond 30-Yr. | 12 Aaa Corp. Bond | 13 Baa Corp. Bond | 14 State & Local Bonds | 15 Home Mtg. Rate | A. Fed's Major Currency Index | B. Real GDP | C. GDP Price Index | D. Cons. Price Index |
| Moody's Economy.com | 4.6 H | 7.6 H | 4.7 H | 4.2 H | 4.3 H | 4.3 H | 4.5 H | 4.6 H | 5.0 H | 5.5 H | 5.9 H | 7.0 H | 8.4 H | na | 7.2 H | na | 3.6 H | -0.1 L | 2.0 |
| National City Corporation | 4.0 | 7.0 | 4.5 | 4.1 | 3.6 | 3.9 | 4.0 | 4.0 | 4.5 | 5.0 | 5.2 | 6.4 | 7.5 | 5.1 | 6.9 | 73.3 | 2.8 | 2.4 | 2.3 |
| Naroff Economic Advisors | 3.8 | 6.8 | 3.9 | 3.9 | 3.9 | 4.1 | 4.2 | 4.4 | 4.7 | 5.0 | 5.5 | 6.2 | 7.0 | 5.2 | 6.6 | 80.0 | 3.2 | 2.4 | 2.3 |
| Stone Harbor Investment Partners | 3.5 | 6.5 | 3.6 | 3.5 | 3.2 | 3.4 | 3.5 | 3.7 | 4.0 | 4.4 | 4.9 | 5.2 | 6.1 L | na | 6.0 | 66.0 | 3.5 | 2.2 | 2.0 |
| ING Investment Mgt. | 3.5 | 6.5 | 3.6 | 3.5 | 3.3 | 3.3 | 3.5 | 3.5 | 4.0 | 4.4 | 5.0 | 5.7 | 6.5 | 4.5 | 6.5 | 75.0 | 3.0 | 2.5 | 2.4 |
| Swiss Re | 3.3 | 6.3 | 3.5 | 3.6 | 3.0 | 3.1 | 3.1 | 3.4 | 3.9 | 4.3 | 5.0 | 6.0 | 7.5 | na | 6.3 | na | 3.2 | 2.3 | 2.5 |
| Wayne Hummer Investments | 3.2 | 6.2 | 3.5 | 3.2 | 2.6 | 2.7 | 2.8 | 3.2 | 3.9 | 4.7 | 5.4 | 6.4 | 7.2 | 5.0 | 6.7 | 72.3 | 3.3 | 2.2 | 2.2 |
| ClearView Economics | 3.0 | 6.0 | 4.0 | 2.9 | 2.1 | 2.6 | 2.9 | 3.2 | 3.7 | 4.3 | 4.9 | 6.0 | 7.4 | 4.9 | 6.5 | 69.5 | 3.4 | 2.2 | 2.5 |
| RidgeWorth Capital Management | 3.0 | 6.0 | 3.3 | 3.0 | 2.7 | 2.9 | 2.9 | 3.2 | 3.6 | 4.4 | 4.5 | 5.6 | 6.6 | 4.3 | 6.2 | 76.0 | 3.5 | 2.0 | 2.0 |
| Nat'l Assn. of Realtors | 3.0 | 6.0 | 3.2 | 3.2 | 2.7 | 2.9 | 3.1 | 3.2 | 3.3 | 3.9 | 4.7 | 5.9 | 7.1 | 5.2 | 6.0 | na | 2.8 | 1.5 | 1.8 |
| RBS Greenwich Capital Econ. | 2.9 | 5.9 | 3.6 | 2.9 | 3.0 | 2.4 | 2.6 | 3.9 | 4.3 | 4.9 | 5.4 | 6.0 | 6.9 | 5.0 | 6.7 | 75.0 | 3.0 | 2.2 | 3.0 |
| Loomis, Sayles & Company | 2.8 | 5.8 | 3.3 | 3.2 | 2.9 | 3.0 | 3.0 | 3.0 | 3.8 | 4.4 | 4.8 | 5.5 | 6.4 | 4.3 | 6.0 | 71.6 | 2.9 | 2.1 | 2.2 |
| Action Economics | 2.8 | 5.8 | 3.1 | 2.8 | 2.6 | 2.8 | 3.0 | 3.2 | 3.8 | 4.3 | 4.6 | 5.3 | 6.2 | 4.3 | 5.8 | 68.0 | 2.9 | 2.4 | 2.5 |
| State House Policy Office | 2.8 | 5.8 | 3.0 | 2.9 | 2.5 | 2.6 | 2.6 | 2.7 | 3.1 | 3.5 | 3.9 | 5.0 L | 6.6 | 3.7 L | 5.6 L | 72.0 | 3.2 | 2.1 | 1.9 |
| Barclays Capital | 2.8 | 5.8 | 3.0 | 2.8 | 2.7 | 2.9 | 3.1 | 2.8 | 3.6 | 4.4 | 5.2 | 6.1 | 7.1 | 4.9 | 6.2 | na | 3.0 | 2.4 | 3.3 |
| Comerica Bank | 2.7 | 5.7 | 3.0 | 2.8 | 2.5 | 2.8 | 2.9 | 3.2 | 3.7 | 4.5 | 4.9 | 5.7 | 6.6 | 4.6 | 6.2 | 70.9 | 3.5 | 2.0 | 2.1 |
| PNC Financial Services Corp. | 2.7 | 5.7 | 3.2 | 2.8 | 2.5 | 2.6 | 2.8 | 3.0 | 3.7 | 4.5 | 5.3 | 6.5 | 8.0 | 5.1 | 6.5 | 73.0 | 2.5 | 1.8 | 2.4 |
| Moody's Analytics | 2.7 | 5.7 | 3.1 | 3.0 | 2.8 | 3.0 | 2.9 | 2.9 | 3.7 | 4.5 | 4.8 | 5.6 | 7.1 | 4.7 | 6.3 | 72.4 | 2.5 | 2.4 | 2.9 |
| Mesirow Financial | 2.6 | 5.6 | 2.7 | 2.8 | 2.7 | 2.8 | 2.9 | 2.0 | 3.9 | 4.9 | 5.2 | 6.0 | na | na | 6.5 | 71.9 | 2.8 | 1.7 | 1.8 |
| Thredgold Economic Assoc. | 2.5 | 5.5 | 2.8 | 2.8 | 2.1 | 2.3 | 2.4 | 2.6 | 3.4 | 4.3 | 5.1 | 6.0 | 7.1 | 4.5 | 6.2 | 72.3 | 1.5 | 2.4 | 2.5 |
| BMO Capital Markets | 2.5 | 5.5 | 2.8 | 2.7 | 2.1 | 2.7 | 2.9 | 3.1 | 3.7 | 4.0 | 4.8 | 6.0 | 7.4 | 4.9 | 6.3 | 72.5 | 2.8 | 2.3 | 1.8 |
| Wachovia | 2.5 | 5.5 | 2.7 | 2.7 | 2.6 | 2.7 | 2.8 | 3.0 | 3.5 | 4.3 | 4.7 | 5.7 | 6.7 | 4.7 | 5.9 | 81.0 H | 2.3 | 2.2 | 2.2 |
| Kellner Economic Advisers | 2.5 | 5.5 | 2.6 | 2.8 | 2.2 | 2.4 | 2.7 | 2.7 | 3.5 | 4.0 | 4.9 | 6.0 | 7.5 | 5.5 | 6.5 | 75.0 | 0.4 L | 3.1 H | 4.0 H |
| Fannie Mae | 2.5 | 5.5 | na | na | 2.4 | na | 3.1 | na | na | 4.3 | 4.7 | 5.9 | na | na | 6.1 | na | 2.7 | 2.0 | 2.3 |
| Georgia State University | 2.4 | 5.4 | na | na | 2.3 | 2.4 | 2.5 | 2.7 | 3.5 | 4.3 | 5.0 | 6.0 | 7.0 | na | 6.1 | na | 2.5 | 2.0 | 2.4 |
| Standard & Poor's Corp. | 2.4 | 5.4 | 3.4 | 3.2 | 2.3 | 2.4 | 2.5 | 2.7 | 3.5 | 4.5 | na | 6.1 | 7.4 | 4.9 | 6.4 | 65.7 L | 3.6 H | 2.3 | 2.2 |
| Chmura Economics & Analytics | 2.3 | 5.3 | 2.7 | 2.4 | 2.2 | 2.3 | 2.4 | 2.5 | 3.0 | 3.8 | 4.6 | 5.5 | na | na | 5.9 | 74.7 | 2.7 | 3.0 | 1.6 |
| Wells Capital Management | 2.3 | 5.3 | 3.3 | 2.7 | 1.9 | 1.1 L | 1.2 L | 2.8 | 2.6 | 4.6 | 5.1 | 6.2 | 7.6 | 5.5 H | 6.5 | 70.9 | 3.0 | 2.6 | 2.4 |
| J.W. Coons Advisors LLC | 2.3 | 5.3 | 3.3 | 2.3 | 2.1 | 2.4 | 2.7 | 3.1 | 3.8 | 4.3 | 4.9 | 6.0 | 7.2 | na | 6.1 | 75.1 | 2.8 | 2.3 | 2.4 |
| Argus Research | 2.3 | 5.3 | 3.0 | 2.9 | 1.5 | 1.6 | 1.8 | 1.9 | 2.8 | 3.9 | 4.7 | 5.9 | 7.2 | 4.7 | 6.2 | 75.0 | 2.3 | 3.1 | 3.9 |
| Economist Intelligence Unit | 2.3 | 5.3 | 2.8 | na | 2.0 | 2.3 | 2.5 | 2.5 | 3.4 | 4.1 | 4.7 | na | na | na | 5.9 | na | 1.9 | na | 2.4 |
| Cycledata Corp. | 2.2 | 5.2 | 2.5 | 2.4 | 1.9 | 2.0 | 2.1 | 2.2 | 3.0 | 3.9 | 4.7 | 5.7 | 6.9 | 4.3 | 5.6 | 74.0 | 1.0 | 2.2 | 2.9 |
| JPMorgan Privare Client Services | 2.0 | 5.0 | 3.1 | 2.8 | 1.3 | 1.9 | 2.1 | 2.4 | 3.1 | 3.9 | 4.7 | 5.2 | 7.4 | 4.8 | 6.0 | 71.3 | 2.3 | 2.1 | 2.3 |
| Goldman Sachs & Co. | 2.0 | 5.0 | 2.3 | na | 1.9 | na | na | 2.2 | 3.3 | 3.9 | 4.3 | 5.0 | na | na | 5.6 | na | 2.5 | 1.3 | 1.7 |
| Woodworth Holdings | 2.0 | 5.0 | 2.2 | 2.2 | 1.9 | 2.0 | 2.1 | 2.2 | 3.2 | 4.2 | 5.0 | 5.7 | 6.9 | 4.5 | 5.8 | 79.0 | 3.1 | 2.3 | 3.0 |
| Nomura Securities, Inc. | 2.0 | 5.0 | 2.2 | 2.1 | 1.8 | 1.8 | 1.7 | 3.3 | 3.9 | 4.5 | 5.1 | 5.9 | 7.5 | na | 6.3 | 76.0 | 2.9 | 2.8 | 2.0 |
| Bank of America | 2.0 | 5.0 | 2.2 | na | 2.1 | 2.4 | 2.6 | 2.3 | 3.1 | 4.0 | 4.8 | 5.9 | 7.4 | na | 6.3 | na | 3.1 | 2.2 | 2.1 |
| Bear Stearns & Co. | 1.9 | 4.9 | 2.4 | 1.9 | 2.0 | 2.2 | 2.4 | 2.6 | 3.5 | 4.9 | 5.7 | 6.7 | 7.9 | 5.5 | 7.0 | 66.8 | 2.1 | 3.1 | 3.2 |
| DePrince & Associates | 1.8 | 4.8 | 2.5 | 2.3 | 1.7 | 2.0 | 2.5 | 2.7 | 3.2 | 3.8 | 4.4 | 5.5 | 6.5 | 4.5 | 5.8 | 72.0 | 3.0 | 2.3 | 2.7 |
| UBS Warburg | 1.5 | na | 2.2 | na | 1.6 | na | na | 2.4 | 3.3 | 4.3 | 5.0 | na | na | na | na | na | 3.1 | 1.8 | 0.9 |
| Scotiabank | 1.3 | 4.3 L | 1.7 | na | 2.4 | 2.7 | na | 3.1 | 3.8 | 4.5 | 5.3 | 6.3 | 7.3 | 5.3 | 6.8 | 70.0 | 2.4 | 2.0 | 2.0 |
| Lehman Brothers | 1.3 | 4.3 L | 1.4 | 1.2 L | 1.3 | 1.3 | 1.4 | 1.8 | 2.7 | 3.5 | 3.8 | 5.3 | 6.6 | 4.5 | 5.7 | na | 1.7 | 1.5 | 2.4 |
| Merrill Lynch Economics | 1.0 L | na | 1.3 L | na | 1.1 L | na | na | 1.1 L | 1.7 L | 2.8 L | 3.4 L | na | na | na | na | na | 2.5 | 1.0 | 0.4 L |
| **May Consensus** | **2.5** | **5.6** | **2.9** | **2.9** | **2.4** | **2.6** | **2.7** | **2.9** | **3.5** | **4.3** | **4.9** | **5.9** | **7.1** | **4.8** | **6.2** | **72.8** | **2.7** | **2.2** | **2.3** |
| Top 10 Avg. | 3.5 | 6.5 | 3.8 | 3.6 | 3.3 | 3.4 | 3.5 | 3.7 | 4.2 | 4.8 | 5.4 | 6.4 | 7.7 | 5.2 | 6.7 | 76.7 | 3.4 | 2.7 | 3.1 |
| Bottom 10 Avg. | 1.7 | 4.8 | 2.0 | 2.2 | 1.6 | 1.8 | 1.9 | 2.0 | 2.8 | 3.7 | 4.3 | 5.3 | 6.5 | 4.3 | 5.7 | 69.1 | 1.8 | 1.5 | 1.6 |
| April Consensus | 2.5 | 5.6 | 2.9 | 2.8 | 2.4 | 2.6 | 2.7 | 2.9 | 3.4 | 4.2 | 4.8 | 5.8 | 6.9 | 4.7 | 6.2 | 73.5 | 2.7 | 2.2 | 2.3 |
| Number of Forecasts Changed From A Month Ago: | | | | | | | | | | | | | | | | | | | |
| Down | 11 | 11 | 7 | 10 | 11 | 13 | 13 | 10 | 10 | 7 | 8 | 12 | 6 | 9 | 13 | 17 | 10 | 7 | 9 |
| Same | 21 | 20 | 17 | 10 | 17 | 9 | 10 | 14 | 11 | 15 | 17 | 9 | 9 | 9 | 11 | 9 | 19 | 21 | 25 |
| Up | 10 | 9 | 16 | 13 | 14 | 16 | 15 | 17 | 20 | 20 | 16 | 18 | 20 | 11 | 15 | 4 | 12 | 12 | 7 |
| Diffusion Index | 49 | 48 | 61 | 55 | 54 | 54 | 53 | 59 | 62 | 65 | 60 | 58 | 70 | 53 | 53 | 28 | 52 | 56 | 48 |

# International Interest Rate And Foreign Exchange Rate Forecasts

## United States

| Blue Chip Forecasters | 3 Mo. Dollar Rate | | | 10 Yr. Gov't Bond Yield | | | Fed's Major Currency Index | | |
|---|---|---|---|---|---|---|---|---|---|
| | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. |
| Scotiabank | 1.80 | 1.50 | 1.50 | 3.40 | 3.60 | 4.20 | 72.0 | 71.0 | 71.0 |
| Deutsche Bank AG | na | na | na | na | na | na | na | na | na |
| WestLB | 2.00 | 2.00 | 2.25 | 3.40 | 3.70 | 4.10 | 71.0 | 73.0 | 75.0 |
| ING Financial Markets | 1.90 | 1.35 | 1.30 | 3.00 | 3.20 | 3.70 | 70.6 | 72.6 | 77.1 |
| Mizuho Research Institute | 2.40 | 2.10 | 1.60 | 3.65 | 3.65 | 3.65 | 69.3 | 70.2 | 71.5 |
| **May Consensus** | **2.03** | **1.74** | **1.66** | **3.36** | **3.54** | **3.91** | **70.7** | **71.7** | **73.7** |
| High | 2.40 | 2.10 | 2.25 | 3.65 | 3.70 | 4.20 | 72.0 | 73.0 | 77.1 |
| Low | 1.80 | 1.35 | 1.30 | 3.00 | 3.20 | 3.65 | 69.3 | 70.2 | 71.0 |
| Last Months Avg. | 1.98 | 1.86 | 1.81 | 3.30 | 3.45 | 3.71 | 70.6 | 71.6 | 72.7 |

## Japan

| Blue Chip Forecasters | 3 Mo. Yen Rate | | | 10 Yr. Gov't Bond Yield | | | Yen USD | | |
|---|---|---|---|---|---|---|---|---|---|
| | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. |
| Scotiabank | 0.85 | 0.90 | 1.10 | 1.40 | 1.70 | 2.00 | 96.0 | 95.0 | 93.0 |
| Deutsche Bank AG | na | na | na | na | na | na | na | na | na |
| WestLB | 0.90 | 0.75 | 1.00 | 1.80 | 2.00 | 1.95 | 107.0 | 109.0 | 112.0 |
| ING Financial Markets | 0.90 | 0.90 | 0.90 | 1.30 | 1.45 | 1.50 | 95.0 | 92.5 | 98.0 |
| Mizuho Research Institute | 0.85 | 0.80 | 0.80 | 1.40 | 1.35 | 1.30 | 100.0 | 100.0 | 102.0 |
| **May Consensus** | **0.88** | **0.84** | **0.95** | **1.48** | **1.63** | **1.69** | **99.5** | **99.1** | **101.3** |
| High | 0.90 | 0.90 | 1.10 | 1.80 | 2.00 | 2.00 | 107.0 | 109.0 | 112.0 |
| Low | 0.85 | 0.75 | 0.80 | 1.30 | 1.35 | 1.30 | 95.0 | 92.5 | 93.0 |
| Last Months Avg. | 0.85 | 0.85 | 0.99 | 1.50 | 1.64 | 1.69 | 99.5 | 99.9 | 100.8 |

## United Kingdom

| Blue Chip Forecasters | 3 Mo. Sterling Rate | | | 10 Yr. Gilt Yields | | | USD Pound Sterling | | |
|---|---|---|---|---|---|---|---|---|---|
| | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. |
| Scotiabank | 5.50 | 5.30 | 5.00 | 4.60 | 4.50 | 4.40 | 1.98 | 2.00 | 1.97 |
| Deutsche Bank AG | na | na | na | na | na | na | na | na | na |
| WestLB | 5.60 | 5.20 | 5.20 | 4.60 | 4.70 | 4.90 | 1.97 | 1.97 | 1.94 |
| ING Financial Markets | 5.40 | 4.90 | 4.50 | 4.50 | 4.20 | 4.30 | 1.95 | 1.85 | 1.73 |
| Mizuho Research Institute | 5.10 | 4.85 | 4.80 | 4.40 | 4.40 | 4.50 | na | na | na |
| **May Consensus** | **5.40** | **5.06** | **4.88** | **4.53** | **4.45** | **4.53** | **1.97** | **1.94** | **1.88** |
| High | 5.60 | 5.30 | 5.20 | 4.60 | 4.70 | 4.90 | 1.98 | 2.00 | 1.97 |
| Low | 5.10 | 4.85 | 4.50 | 4.40 | 4.20 | 4.30 | 1.95 | 1.85 | 1.73 |
| Last Months Avg. | 5.40 | 5.03 | 4.90 | 4.39 | 4.41 | 4.53 | 1.99 | 1.96 | 1.94 |

## Switzerland

| Blue Chip Forecasters | 3 Mo. Franc Rate | | | 10 Yr. Gov't Bond Yield | | | CHF USD | | |
|---|---|---|---|---|---|---|---|---|---|
| | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. |
| Scotiabank | 2.80 | 2.80 | 2.80 | 3.00 | 2.90 | 2.70 | 0.97 | 0.96 | 0.99 |
| Deutsche Bank AG | na | na | na | na | na | na | na | na | na |
| WestLB | 2.75 | 2.80 | 2.80 | 2.90 | 2.90 | 3.10 | 1.00 | 1.00 | 1.05 |
| ING Financial Markets | 2.90 | 3.10 | 3.00 | 3.05 | 3.20 | 3.25 | 0.96 | 0.98 | 1.03 |
| Mizuho Research Institute | na | na | na | na | na | na | na | na | na |
| **May Consensus** | **2.82** | **2.90** | **2.87** | **2.98** | **3.00** | **3.02** | **0.98** | **0.98** | **1.02** |
| High | 2.90 | 3.10 | 3.00 | 3.05 | 3.20 | 3.25 | 1.00 | 1.00 | 1.05 |
| Low | 2.75 | 2.80 | 2.80 | 2.90 | 2.90 | 2.70 | 0.96 | 0.96 | 0.99 |
| Last Months Avg. | 2.82 | 3.00 | 2.97 | 3.08 | 3.20 | 3.45 | 1.01 | 1.03 | 1.04 |

## Canada

| Blue Chip Forecasters | 3 Mo. Dollar Rate | | | 10 Yr. Gov't Bond Yield | | | CAD USD | | |
|---|---|---|---|---|---|---|---|---|---|
| | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. |
| Scotiabank | 3.00 | 3.00 | 3.00 | 3.30 | 3.50 | 4.10 | 0.99 | 0.97 | 0.96 |
| Deutsche Bank AG | na | na | na | na | na | na | na | na | na |
| WestLB | 3.00 | 3.00 | 3.00 | 3.40 | 3.60 | 4.20 | 1.02 | 1.02 | 1.05 |
| ING Financial Markets | 2.80 | 2.60 | 2.70 | 3.40 | 3.50 | 3.80 | 1.05 | 1.08 | 1.12 |
| Mizuho Research Institute | na | na | na | na | na | na | na | na | na |
| **May Consensus** | **2.93** | **2.87** | **2.90** | **3.37** | **3.53** | **4.03** | **1.02** | **1.02** | **1.04** |
| High | 3.00 | 3.00 | 3.00 | 3.40 | 3.60 | 4.20 | 1.05 | 1.08 | 1.12 |
| Low | 2.80 | 2.60 | 2.70 | 3.30 | 3.50 | 3.80 | 0.99 | 0.97 | 0.96 |
| Last Months Avg. | 3.23 | 3.10 | 3.03 | 3.58 | 3.80 | 4.17 | 1.02 | 1.03 | 1.03 |

# International Interest Rate And Foreign Exchange Rate Forecasts

## Australia

| | 3 Mo. Dollar Rate | | | 10 Yr. Gov't Bond Yield | | | USD AUD | | |
|---|---|---|---|---|---|---|---|---|---|
| **Blue Chip Forecasters** | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. |
| Scotiabank | 7.75 | 7.75 | 7.25 | 6.30 | 6.30 | 6.00 | 0.96 | 0.97 | 0.96 |
| Deutsche Bank AG | na | na | na | na | na | na | na | na | na |
| WestLB | 8.00 | 8.00 | 7.60 | 6.45 | 6.60 | 6.80 | 0.95 | 0.95 | 0.90 |
| ING Financial Markets | 8.95 | 8.60 | 7.40 | 5.90 | 5.75 | 5.40 | 0.94 | 0.91 | 0.85 |
| Mizuho Research Institute | na | na | na | na | na | na | na | na | na |
| **May Consensus** | **8.23** | **8.12** | **7.42** | **6.22** | **6.22** | **6.07** | **0.95** | **0.94** | **0.90** |
| High | 8.95 | 8.60 | 7.60 | 6.45 | 6.60 | 6.80 | 0.96 | 0.97 | 0.96 |
| Low | 7.75 | 7.75 | 7.25 | 5.90 | 5.75 | 5.40 | 0.94 | 0.91 | 0.85 |
| Last Months Avg. | 7.77 | 7.75 | 7.45 | 6.30 | 6.27 | 6.20 | 0.92 | 0.90 | 0.89 |

## Eurozone

| | 3 Mo. Euro Rate | | | 10 Yr. Euro Bond Yield | | | USD EUR | | |
|---|---|---|---|---|---|---|---|---|---|
| **Blue Chip Forecasters** | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. |
| Scotiabank | 4.50 | 4.30 | 4.20 | 4.10 | 4.10 | 4.00 | 1.60 | 1.61 | 1.56 |
| Deutsche Bank AG | na | na | na | na | na | na | na | na | na |
| WestLB | 4.50 | 4.30 | 4.20 | 4.10 | 4.20 | 4.30 | 1.60 | 1.60 | 1.55 |
| ING Financial Markets | 4.50 | 3.80 | 3.70 | 3.70 | 3.70 | 3.80 | 1.60 | 1.55 | 1.45 |
| Mizuho Research Institute | 4.20 | 3.65 | 3.60 | na | na | na | 1.58 | 1.55 | 1.52 |
| **May Consensus** | **4.43** | **4.01** | **3.93** | **3.97** | **4.00** | **4.03** | **1.60** | **1.58** | **1.52** |
| High | 4.50 | 4.30 | 4.20 | 4.10 | 4.20 | 4.30 | 1.60 | 1.61 | 1.56 |
| Low | 4.20 | 3.65 | 3.60 | 3.70 | 3.70 | 3.80 | 1.58 | 1.55 | 1.45 |
| Last Months Avg. | 4.20 | 3.96 | 3.78 | 3.83 | 3.87 | 3.97 | 1.52 | 1.51 | 1.48 |

## 10 Yr. Gov't Bond Yields

| | Germany | | | France | | | Italy | | | Spain | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Blue Chip Forecasters** | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. | In 3 Mo. | In 6 Mo. | In 12 Mo. |
| Scotiabank | 4.10 | 4.10 | 4.00 | 4.30 | 4.20 | 4.10 | 4.50 | 4.40 | 4.30 | 4.30 | 4.20 | 4.10 |
| West LB | 4.25 | 4.15 | 4.05 | 4.25 | 4.15 | 4.05 | 4.45 | 4.35 | 4.25 | 4.35 | 4.25 | 4.15 |
| ING Financial Markets | 3.70 | 3.70 | 3.80 | 3.80 | 3.80 | 3.90 | 3.90 | 3.90 | 4.00 | 3.80 | 3.80 | 3.90 |
| Mizuho Research Institute | 3.95 | 3.80 | 3.80 | 4.05 | 3.85 | 3.85 | 4.45 | 4.15 | 4.15 | 4.15 | 3.95 | 3.95 |
| **May Consensus** | **4.00** | **3.94** | **3.91** | **4.10** | **4.00** | **3.98** | **4.33** | **4.20** | **4.18** | **4.15** | **4.05** | **4.03** |
| High | 4.25 | 4.15 | 4.05 | 4.30 | 4.20 | 4.10 | 4.50 | 4.40 | 4.30 | 4.35 | 4.25 | 4.15 |
| Low | 3.70 | 3.70 | 3.80 | 3.80 | 3.80 | 3.85 | 3.90 | 3.90 | 4.00 | 3.80 | 3.80 | 3.90 |
| Last Months Avg. | 3.79 | 3.80 | 3.89 | 3.90 | 3.86 | 3.95 | 4.15 | 4.08 | 4.16 | 3.94 | 3.90 | 3.99 |

## Consensus Forecasts 10-year Bond Yields vs U.S. Yield

| | Current | In 3 Mo. | In 6 Mo. | In 12 Mo. |
|---|---|---|---|---|
| Japan | -2.34 | -1.89 | -1.91 | -2.23 |
| United Kingdom | 0.99 | 1.16 | 0.91 | 0.61 |
| Switzerland | -0.53 | -0.38 | -0.54 | -0.90 |
| Canada | -0.05 | 0.00 | 0.00 | 0.12 |
| Australia | 2.47 | 2.85 | 2.68 | 2.15 |
| Germany | 0.39 | 0.64 | 0.40 | 0.00 |
| France | 0.62 | 0.74 | 0.46 | 0.06 |
| Italy | 0.85 | 0.96 | 0.66 | 0.26 |
| Spain | 0.67 | 0.79 | 0.51 | 0.11 |
| Eurozone | 0.68 | 0.60 | 0.46 | 0.12 |

## Consensus Forecasts 3 Mo. Interest Rates vs U.S. Rate

| | Current | In 3 Mo. | In 6 Mo. | In 12 Mo. |
|---|---|---|---|---|
| Japan | -1.73 | -1.15 | -2.58 | -0.71 |
| United Kingdom | 3.22 | 3.38 | 3.33 | 3.21 |
| Switzerland | 0.23 | 0.79 | 1.16 | 1.20 |
| Canada | 1.02 | 0.91 | 1.13 | 1.24 |
| Australia | 5.15 | 6.21 | 6.38 | 5.75 |
| Eurozone | 2.03 | 2.40 | 2.28 | 2.26 |

# Viewpoints:

**A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others**

**No Help Wanted**

The economy's problems are intensifying. Payrolls have fallen by nearly a quarter-million since the start of the year, and the losses go well beyond jobs in housing and autos. Employment is falling from retailing and transportation to Wall Street and even professional services. Unemployment is up sharply, rising from 4.4% at its low a year ago to 5.1% this March.

Consumers, nearing panic, are driving the downturn. With employment down, stock and house prices off sharply, and gasoline prices on the rise, consumers are pulling back. Vehicle sales came in at 15.3 million units annualized in the first quarter, compared with 16.1 million units last year, and closer to 17 million units during the first half of this decade. Other retailers, from home improvement centers to high-end department stores, are also seeing weaker sales.

The economy probably began contracting in December—this won't be known precisely until all historical data revisions are done—and it is not expected to stabilize until June. This will make for a seven-month recession, some five months shorter than the average length of the 10 recessions since World War II. This downturn is also expected to be mild. Unemployment is projected to peak at close to 6% early in 2009, up 1.5 percentage points from its low. This compares with an unemployment rise of 2.5 percentage points in a typical recession.

The unprecedented housing downturn, and more specifically the collapse in house prices, is at the center of the recession. According to the national Case-Shiller Home Price Indices, prices fell 10% from their peak in the spring 2006 selling season through the end of last year. Judging by the recent pace of decline, they are now probably down as much as 15%. In California and Florida, prices have fallen closer to 25% from their peak, back to where they were in 2004.

The sharp price declines, following a wave of homebuyers who put little of their own money into their purchases, mean that an estimated 9 million homeowners are underwater. That is, they owe more on their mortgages than their houses are worth. Add in rising job losses and the result is a surge in mortgage defaults. First mortgage loan defaults—the first step in the foreclosure process—are running at a stunning annual pace of 2 million. The housing market is now trapped in a self-reinforcing negative cycle in which price declines ignite foreclosures, which in turn push prices lower as foreclosed homes flood the market.

The surge in foreclosures and resulting mortgage losses have undermined the financial system. The private residential mortgage securities market has completely shut down, and the resulting panic weighs on every corner of the fixed-income market. Bond issuance is down and credit spreads have widened. Credit has become harder to get, and the cost of capital has risen. Households and businesses are the casualties.

The 15% decline in house prices translates into a loss in housing wealth of approximately $3 trillion. When combined with the collapse in mortgage equity withdrawal—homeowners can no longer borrow freely against their houses—consumers have no choice but to rein in their spending. Every $1 decline in housing wealth eventually reduces consumer spending by an estimated 7 cents. This trend will thus reduce consumer spending by 2% this year and cut GDP growth by nearly 1.5 percentage points.

With all that is going wrong, it may be hard to understand how this recession could be short and mild. There are reasons for optimism, however. The global economy continues to perform well. Growth is slowing in Europe, Canada and Japan, but emerging economies continue to shrug off the U.S. downturn. Combined with a low and falling U.S. dollar, chances are strong that a narrowing trade deficit will add about a percentage point to growth this year.

Corporate balance sheets outside of financials and housing-related industries are strong. The interest coverage ratio for nonfinancial corporations—the share of cash flow needed to service corporate debt—is as low as it has been since the 1960s. With so much financial wherewithal, businesses can avoid significant cuts in investment and hiring. In fact, although investment is soft, it is not falling, and the decline in payroll employment is modest for this stage of a recession. By this point in the 2001 cycle, payrolls were falling 150,000 to 200,000 per month.

The reason employment is not falling faster is that firms had been disciplined in their earlier hiring. Before previous recessions, businesses hired ahead of their need. Then when sales turned soft, they came under pressure to shed workers aggressively. This time, payrolls were relatively lean to begin with. There will still be layoffs, but they should be modest. Firms also did a good job of managing their inventories. The ratio of inventories to sales is a bit elevated, but only a bit, and although firms are likely to draw down inventories more, the resulting drag on growth should be smaller.

The most important reason for optimism is that policymakers are fully engaged in stemming the recession. The Federal Reserve has slashed interest rates and is expected to cut its funds rate target again in a few weeks to 2%. The central bank is also using new tools to provide liquidity to various parts of the credit market. If the Federal Reserve follows through on its commitments, it will trade some $400 billion of Treasury bonds on its $900 billion balance sheet for assets ranging from agency mortgage-backed securities to investment grade corporate bonds.

Congress and the Bush administration are also working hard to stimulate growth and stem the housing crisis. A full $100 billion in tax rebate checks will be distributed to consumers from May to July. If households respond as they did to a similar tax rebate in 2001, two-thirds of the money will be spent by year's end. The Federal Housing Administration, Fannie Mae, Freddie Mac, and the Federal Home Loan Bank have also been empowered to provide more mortgage credit. Although this still won't fill the void left by the collapse of the private mortgage securities market, it will help.

Policymakers are also expected to pass a mortgage write-down plan by this summer. The plan would allow homeowners facing foreclosure to significantly cut their mortgage balances, giving them lower monthly mortgage payments. Foreclosures will rise to a record high this year, but this plan would keep them from rising even higher and help cushion the fall in house prices.

Real GDP is forecast to decline during the first half of 2008, but turn positive during the second half. For all of 2008, real GDP is expected to grow by 1.5%. Growth is expected to accelerate in 2009 near 3%.

The risks to this outlook remain decidedly to the downside. Not only is there a significant risk of a more severe recession, but the subsequent recovery may well be less buoyant than we expect. How this plays out will depend on whether the financial system stabilizes soon. And that will depend on whether house-price declines begin to abate, which in turn depends on policymakers. Policymakers must come through with a plan that succeeds in keeping a large number of underwater homeowners in their homes, or the remainder of this decade will be very difficult.

*Mark Zandi, Moody's Economy.com, West Chester, PA*

**After the Repricing**

The recent equity and credit market rally can be justified by three factors. First, the data are consistent with a recession, but not at this point with the deep slump feared by some market participants. Second, the tax rebates will start early next month, and this should give a lift to spending. Third, there have been some large- *(continued on next page)*

# Viewpoints

**A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others**

large-scale equity infusions into financial institutions. As we noted in scale equity infusions into financial institutions. As we noted in our *Leveraged Losses* paper back in late February, this is indeed a key pre-requisite for resolving the financial crisis

But it would be a mistake to treat the recent moves as the start of a "standard" recovery. In the near term, the main risk is that energy prices remain on a tear and the money markets are under considerable stress. This is not only visible in elevated LIBOR spreads, but also in the commercial paper market where the spread between 30-day AA and A2/P2 rated nonfinancial paper closed at 97 basis points on Friday, which is actually higher than the Monday after the Bear/JPM deal. We don't know how the contrast between equity/credit vs. money markets will resolve itself this time, but it has been a dangerous one to ignore over the past 9 months.

More fundamentally, the economy will only get a temporary boost from the fiscal stimulus. A true recovery is unlikely until house prices have stabilized, which in our forecast does not happen until the second half of 2009. Until then, consumer spending and business investment will be constrained by the housing collapse and the associated credit crunch. In addition, there are a few sectors that have been strong so far but are likely to look much weaker in late 2008 and 2009. Nonresidential private construction has added ½ percentage point to real GDP growth in 2007, but it will likely subtract around ¼ point in 2008 and 2009. Another issue is the deterioration in state and local tax revenues. While the lags between revenues and spending at the state and local level are long, this should eventually lead to a substantial slowdown in spending, probably in 2009.

Given all this, the front end of the US yield curve has become a lot more attractive. The very short end is now approximately fair, as the market has moved to our forecast for a 25-basis-point cut on April 30. Risks around this forecast are evenly distributed in my view -- some chance that the renewed money market turmoil persuades the committee to do 50bp, but also some risk that they stand pat following the two dissents last time and continued headline inflation worries among some committee members.

But beyond the next few meetings, the market looks quite attractive as it now discounts 75-100bp of tightening in 2009. The FOMC is unlikely to tighten policy until they can be reasonably confident that the unemployment rate has peaked and house prices have bottomed, conditions that in our forecast aren't met until late 2009. Consistent with this, I thought it was notable that the March 18 FOMC omitted the phrase suggesting a "rapid reversal" of monetary easing that had appeared in the January 30 minutes. While our baseline forecast remains a 2% funds rate until the end of 2009, there is a decent chance of further rate cuts in late 2008 or early 2009 if the economy weakens anew after the fiscal stimulus has gone through the system. Therefore, long positions in the 1-2 year sector look quite attractive to me, although the chaos in the money markets admittedly makes the implementation of this view trickier than usual.

*Jan Hatzius, Goldman, Sachs & Co., New York, NY*

**Modest Fed Ease In April But Still Weak Fundamentals**

Some easing in market strains, along with growing arguments that monetary policy is sufficiently accommodative, has led market participants to expect little in the way of further Fed rate cuts. While we expect that the FOMC will ease only 25 basis points at its upcoming meeting, we caution that economic fundamentals remain weak, and still look for a 1.5% funds rate target later this year. Tight credit conditions, mounting job losses, soaring energy costs, and falling home values provide an unfavorable backdrop for consumer spending, as recent reports have indicated. Importantly, few signs of housing recovery have yet emerged, and inventory accumulation in Q1 may point to weaker production ahead.

We now expect a 25 basis point ease at the upcoming April 29-30 Fed meeting, but continue to see moderate further easing ahead. Economic conditions remain weak, with below-1% GDP growth likely in the first half of 2008. Aided by accommodative monetary policy and the recently enacted fiscal stimulus package, we do anticipate gradual economic improvement in 2H 2008.

The Fed call has changed for two primary reasons. First, the recent sharp gains in headline inflation, led by sustained energy, food and other commodity price pressures and related in part to lower U.S. interest rates and the weak dollar, are increasingly worrisome to the FOMC. Multiple dissents in March make clear that this issue has already played an important part in Fed deliberations. Secondly, the Fed funds futures market is currently pricing in a 25 basis point cut in the funds rate on April 30th. Unless market and/or economic conditions deteriorate sharply in the coming days, the FOMC is not likely to ease more than Fed funds futures anticipate.

Some recent releases for March confirmed the Fed's Beige Book summary that economic activity has continued to weaken. Ongoing declines in housing were highlighted by the March drop in single-family and multi-family housing starts. Total starts fell a greater-than-expected 11.9% to 947,000 units, and declined at an 34.5% annualized pace in 1Q 2008, suggesting a continued significant housing drag on GDP growth. Building permits, a proxy for future building activity also fell 5.8%. After falling 0.4% in February, retail sales advanced 0.2% in March. However, excluding gasoline store sales, retail sales were flat. The key control group, which is retail sales excluding the automotive, building materials and gasoline categories, advanced at a 0.9% annualized pace in Q1, the smallest quarterly increase since 2002. While industrial production advanced 0.3% in March, it was flat in Q1 and manufacturing output fell for a second straight quarter.

Producer prices soared 1.1% in March as higher energy and food prices drove up the index. Core producer prices posted a moderate 0.2% advance. Core intermediate goods prices jumped 1.1% in March and are up 5.5% over the past year, an additional source of concern. Boosted by a 1.9% increase in energy costs, the consumer price index advanced 0.3% in March. Stripping out the volatile food and energy components, the core CPI increased 0.2% for a second consecutive month. On a year-over-year basis, the core index is up 2.4%. While believe that a slowing economy will ease price pressures in the months ahead, persistent headline inflation remains worrisome.

Despite less favorable trade trade data in February, we now estimate just above 1% GDP growth last quarter. However, domestic demand likely declined in Q1, and we expect it to remain flat this quarter. Somewhat larger (and undesired) inventory accumulation added an estimated one percent to Q1 GDP growth, and likely points to weaker production this quarter. We estimate a slight GDP decline in 2Q 2008, and a soft rebound in the second half of the year. The unemployment rate will continue to drift higher for the balance of the year and into 2009.

*Peter E. Kretzmer, Mickey Levy and Gary Bigg, Bank of America, New York, NY*

# Special Questions:

**1.** Please provide your forecasts of the seasonally-adjusted annualized percent change in the following variables during Q1 2008?

| | Q1 2008 SAAR | |
|---|---|---|
| | Real GDP | Chained GDP Price Index |
| **Consensus** | **0.2%** | **2.9%** |
| Top 10 Average | 0.9% | 3.8% |
| Bottom 10 Average | -0.6% | 2.3% |

**2. A.** The FOMC's target federal funds rate was cut to 2.25% on March 18th. What will be the FOMC's target for the federal funds rate following the April 29th/30th meeting?

| Number of Panelists Predicting: | | Target Fed Funds Rate After April 29th/30th Meeting | |
|---|---|---|---|
| 2.25% | 2 | **Consensus** | **1.97%** |
| 2.00% | 34 | Top 10 Average | 2.05% |
| 1.75% | 7 | Bottom 10 Average | 1.83% |

**…B**. What will be the FOMC's target for the federal funds rate following its June 24th/25th meeting?

| Number of Panelists Predicting: | | Target Fed Funds Rate After June 24th/25th Meeting | |
|---|---|---|---|
| 2.25% | 2 | **Consensus** | **1.86%** |
| 2.00% | 20 | Top 10 Average | 2.05% |
| 1.75% | 18 | Bottom 10 Average | 1.63% |
| 1.50% | 1 | | |
| 1.25% or less | 2 | | |

**3.** Martin Feldstein recently argued in a *Wall Street Journal* piece that the FOMC should stop cutting interest rates. Do you think the Fed SHOULD cut its target federal funds rate to below 2.0%?

| (Percentage of those responding) | |
|---|---|
| Yes | No |
| 34.1% | 65.9% |

**4.** Given your outlook for economic growth, inflation and Fed policy, do you think the Treasury market is currently overvalued, fairly valued or undervalued?

| (Percentage of those responding) | | |
|---|---|---|
| Overvalued | Fairly Valued | Undervalued |
| 61.9% | 26.2% | 11.9% |

**5.** Through March, the Consumer Price Index excluding food and energy prices (core CPI) was up 2.4% on a y/y basis. What will be the year-over-year percent change in the "core" CPI as of June and December of this year?

| | Year-over-year percent change in core CPI as of: | |
|---|---|---|
| | June 2008 | December 2008 |
| **Consensus** | **2.4%** | **2.3%** |
| Top 10 Average | 2.6% | 2.6% |
| Bottom 10 Average | 2.3% | 2.0% |

**6.** The unemployment rate stood at 5.1% in March. What will be the unemployment rate in June and December of this year?

| | Unemployment Rate in: | |
|---|---|---|
| | June 2008 | December 2008 |
| **Consensus** | **5.3%** | **5.6%** |
| Top 10 Average | 5.5% | 6.0% |
| Bottom 10 Average | 5.2% | 5.3% |

**7.** Do you believe the U.S. economy is in, or will enter, a recession in 2008?

| (Percentage of those responding) | |
|---|---|
| Yes | No |
| 72.1% | 27.9% |

# Databank:

## 2008

| Monthly Indicator | Jan | Feb | Mar | Apr | May | Jun | Jly | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Retail and Food Service Sales (a) | 0.4 | -0.4 | 0.2 | | | | | | | | | |
| Auto & Light Truck Sales (b) | 15.3 | 15.3 | 15.1 | | | | | | | | | |
| Personal Income (a, current $) | 0.3 | 0.5 | | | | | | | | | | |
| Personal Consumption (a, current $) | 0.4 | 0.1 | | | | | | | | | | |
| Consumer Credit (e) | 4.9 | 2.4 | | | | | | | | | | |
| Consumer Sentiment (U. of Mich.) | 78.4 | 70.8 | 69.0 | | | | | | | | | |
| Household Employment (c) | 37 | -255 | -24 | | | | | | | | | |
| Non-farm Payroll Employment (c) | -76 | -76 | -80 | | | | | | | | | |
| Unemployment Rate (%) | 4.9 | 4.8 | 5.1 | | | | | | | | | |
| Average Hourly Earnings ('82$) | 8.26 | 8.29 | | | | | | | | | | |
| Average Hourly Earnings (current $) | 17.75 | 17.81 | 17.86 | | | | | | | | | |
| Non-Farm Workweek (hrs.) | 33.7 | 33.7 | 33.8 | | | | | | | | | |
| Industrial Production (d) | 2.6 | 1.2 | 1.5 | | | | | | | | | |
| Capacity Utilization (%) | 81.0 | 80.3 | 80.5 | | | | | | | | | |
| ISM Manufacturing Index (g) | 50.7 | 48.3 | 48.6 | | | | | | | | | |
| ISM Non-Manufacturing Index (g) | 44.6 | 49.3 | 49.6 | | | | | | | | | |
| Housing Starts (b) | 1.083 | 1.075 | .947 | | | | | | | | | |
| Housing Permits (b) | 1.061 | .984 | .927 | | | | | | | | | |
| New Home Sales (1-family, c) | 607 | 575 | 526 | | | | | | | | | |
| Construction Expenditures (a) | -1.0 | -0.3 | | | | | | | | | | |
| Consumer Price Index (nsa., d) | 4.3 | 4.0 | 4.0 | | | | | | | | | |
| CPI ex. Food and Energy (nsa., d) | 2.5 | 2.3 | 2.4 | | | | | | | | | |
| Producer Price Index (n.s.a., d) | 7.4 | 6.4 | 6.9 | | | | | | | | | |
| Durable Goods Orders (a) | -4.4 | -0.9 | -0.3 | | | | | | | | | |
| Leading Economic Indicators (g) | -0.4 | -0.5 | | | | | | | | | | |
| Balance of Trade & Services (f) | -59.0 | -62.3 | | | | | | | | | | |
| Federal Funds Rate (%) | 3.94 | 2.98 | 2.60 | | | | | | | | | |
| 3-Mo. Treasury Bill Rate (%) | 2.75 | 2.12 | 1.34 | | | | | | | | | |
| 10-Year Treasury Note Yield (%) | 3.74 | 3.74 | 3.51 | | | | | | | | | |

## 2007

| Monthly Indicator | Jan | Feb | Mar | Apr | May | Jun | Jly | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Retail and Food Service Sales (a) | 0.0 | 0.6 | 1.0 | -0.3 | 1.6 | -0.8 | 0.6 | 0.1 | 0.8 | 0.0 | 0.8 | -0.7 |
| Auto & Light Truck Sales (b) | 16.6 | 16.5 | 16.2 | 16.2 | 16.3 | 15.6 | 15.2 | 16.2 | 16.2 | 16.0 | 16.1 | 16.2 |
| Personal Income (a, current $) | 1.1 | 0.7 | 0.8 | -0.3 | 0.4 | 0.4 | 0.6 | 0.5 | 0.4 | 0.2 | 0.3 | 0.4 |
| Personal Consumption (a, current $) | 0.4 | 0.3 | 0.2 | 0.6 | 0.5 | 0.2 | 0.4 | 0.4 | 0.5 | 0.3 | 1.0 | 0.2 |
| Consumer Credit (e) | 4.2 | 2.8 | 6.4 | 2.3 | 7.5 | 5.1 | 6.4 | 10.1 | 2.6 | 2.7 | 8.0 | 1.0 |
| Consumer Sentiment (U. of Mich.) | 96.9 | 91.3 | 88.4 | 87.1 | 88.3 | 85.3 | 90.4 | 83.4 | 83.4 | 80.9 | 76.1 | 75.5 |
| Household Employment (c) | -34 | -27 | 257 | -432 | 200 | 174 | -42 | -292 | 507 | -244 | 631 | -436 |
| Non-Farm Payroll Employment (c) | 126 | 25 | 177 | 46 | 162 | 107 | 57 | 74 | 81 | 140 | 60 | 41 |
| Unemployment Rate (%) | 4.6 | 4.5 | 4.4 | 4.5 | 4.5 | 4.6 | 4.7 | 4.7 | 4.7 | 4.8 | 4.7 | 5.0 |
| Average Hourly Earnings ('82$) | 8.35 | 8.35 | 8.33 | 8.33 | 8.31 | 8.32 | 8.33 | 8.35 | 8.35 | 8.34 | 8.27 | 8.27 |
| Average Hourly Earnings (current $) | 17.12 | 17.17 | 17.24 | 17.29 | 17.34 | 17.41 | 17.47 | 17.51 | 17.57 | 17.59 | 17.64 | 17.70 |
| Non-farm Workweek (hrs.) | 33.8 | 33.7 | 33.9 | 33.8 | 33.8 | 33.9 | 33.8 | 33.8 | 33.8 | 33.8 | 33.8 | 33.8 |
| Industrial Production (d) | 0.9 | 1.7 | 1.3 | 1.5 | 1.6 | 1.4 | 1.7 | 1.6 | 2.3 | 1.9 | 2.6 | 2.0 |
| Capacity Utilization (%) | 80.5 | 80.9 | 80.7 | 81.0 | 80.9 | 81.0 | 81.4 | 81.2 | 81.3 | 80.8 | 81.1 | 81.0 |
| ISM Manufacturing Index (g) | 49.3 | 51.5 | 50.7 | 52.8 | 52.8 | 53.4 | 52.3 | 51.2 | 50.5 | 50.4 | 50.0 | 48.4 |
| ISM Non-Manufacturing Index (g) | 57.9 | 54.9 | 53.0 | 56.0 | 58.4 | 59.7 | 55.9 | 56.3 | 55.7 | 55.5 | 54.8 | 54.4 |
| Housing Starts (b) | 1.403 | 1.487 | 1.491 | 1.485 | 1.440 | 1.468 | 1.371 | 1.347 | 1.182 | 1.274 | 1.178 | 1.000 |
| Housing Permits (b) | 1.566 | 1.541 | 1.569 | 1.457 | 1.520 | 1.413 | 1.389 | 1.322 | 1.261 | 1.170 | 1.162 | 1.080 |
| New Home Sales (1-family, c) | 890 | 840 | 830 | 907 | 861 | 797 | 796 | 701 | 693 | 725 | 631 | 610 |
| Construction Expenditures (a) | -0.6 | 0.2 | 0.1 | 0.2 | 0.5 | -0.1 | -0.8 | 0.4 | 0.3 | -0.9 | -0.3 | -1.7 |
| Consumer Price Index (s.a., d) | 2.1 | 2.4 | 2.8 | 2.6 | 2.7 | 2.7 | 2.4 | 2.0 | 2.8 | 3.5 | 4.3 | 4.1 |
| CPI ex. Food and Energy (s.a., d) | 2.7 | 2.7 | 2.5 | 2.3 | 2.2 | 2.2 | 2.2 | 2.1 | 2.1 | 2.2 | 2.3 | 2.4 |
| Producer Price Index (n.s.a., d) | 0.1 | 2.4 | 3.1 | 3.2 | 3.9 | 3.3 | 4.2 | 2.3 | 4.4 | 6.1 | 7.3 | 6.3 |
| Durable Goods Orders (a) | -6.1 | 0.5 | 5.1 | 1.1 | -2.4 | 1.8 | 5.9 | -5.3 | -1.4 | -0.5 | 0.5 | 4.4 |
| Leading Economic Indicators (g) | -0.3 | -0.6 | 0.6 | -0.2 | 0.2 | -0.1 | 0.7 | -0.9 | 0.2 | -0.5 | -0.5 | -0.1 |
| Balance of Trade & Services (f) | -57.4 | -58.2 | -63.0 | -59.2 | -60.3 | -60.0- | -59.0 | -56.7 | -57.0 | -57.6 | -62.4 | -57.9 |
| Federal Funds Rate (%) | 5.25 | 5.26 | 5.26 | 5.25 | 5.25 | 5.25 | 5.26 | 5.79 | 4.94 | 4.76 | 4.49 | 4.24 |
| 3-Mo. Treasury Bill Rate (%) | 4.98 | 5.03 | 4.94 | 4.87 | 4.73 | 4.61 | 4.82 | 4.20 | 3.89 | 3.90 | 3.27 | 3.00 |
| 10-Year Treasury Note Yield (%) | 4.75 | 4.72 | 4.56 | 4.69 | 4.75 | 5.10 | 5.00 | 4.67 | 4.52 | 4.53 | 4.15 | 4.10 |

**(a) month-over-month % change; (b) millions, saar; (c) thousands, saar; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.**

## Calendar Of Upcoming Economic Data Releases

| Monday | Tuesday | Wednesday | Thursday | Friday |
|---|---|---|---|---|
| **28**<br>Texas Manufacturing Outlook Survey (Apr)<br>Housing Vacancies (Q1) | **29**<br>**FOMC Meeting**<br>S&P/Case-Shiller Home Price Index (Feb)<br>Consumer Confidence (Conference Board, Apr)<br>Weekly Store Sales<br>ABC Consumer Comfort Index | **30**<br>**FOMC Meeting**<br>ADP Employment Report (Apr)<br>GDP (Q1)<br>Employment Cost Index (Q1)<br>Chicago PMI (Apr)<br>Agricultural Prices (Apr)<br>EIU Crude Oil Stocks<br>Mortgage Applications | **May 1**<br>ISM Manufacturing (Apr)<br>Auto and Light Truck Sales (Apr)<br>Challenger Layoffs (Apr)<br>Personal Income & Consumption (Mar)<br>Construction Expenditures (Mar)<br>Weekly Jobless Claims<br>Weekly Money Supply | **2**<br>Employment Report (Apr)<br>Factory Orders (Mar) |
| **5**<br>ISM Non-Manufacturing (Apr) | **6**<br>Semiannual ISM forecast<br>ABC Consumer Comfort Index<br>Weekly Store Sales | **7**<br>Pending Home Sales (Mar)<br>Consumer Credit (Mar)<br>Productivity and Costs (Q1)<br>EIA Crude Oil Stocks<br>Mortgage Applications | **8**<br>Chain Store Sales (Apr)<br>Wholesale Trade (Mar)<br>Weekly Jobless Claims<br>Weekly Money Supply | **9**<br>Trade Balance (Mar) |
| **12**<br>Treasury Budget (Apr) | **13**<br>Retail Sales (Apr)<br>Trade Price Indices (Apr)<br>Weekly Store Sales<br>ABC Consumer Comfort Index | **14**<br>Consumer Price Index (Apr)<br>EIA Crude Oil Stocks<br>Mortgage Applications | **15**<br>Industrial Production (Apr)<br>NAHB Housing Market Index (May)<br>Empire State Index (May)<br>Philadelphia Fed Survey (May)<br>Treasury International Capital Flows (Mar)<br>Weekly Jobless Claims<br>Weekly Money Supply | **16**<br>Housing Starts (Apr)<br>Consumer Sentiment (May, Preliminary, University of Michigan) |
| **19**<br>Leading Economic Indicators (Apr) | **20**<br>Producer Price Index (Apr)<br>ABC Consumer Comfort Index<br>Weekly Store Sales | **21**<br>FOMC Minutes (Apr 29-30 meeting)<br>Mortgage Applications<br>EIA Crude Oil Stocks | **22**<br>OFHEO Home Price Index (Q1)<br>Weekly Jobless Claims<br>Weekly Money Supply | **23**<br>Existing Home Sales (Apr) |
| **26**<br>**Memorial Day Holiday**<br>**All Markets Closed** | **27**<br>S&P/Case-Shiller Home Price Index (Mar and Q1))<br>Consumer Confidence (Conference Board, May)<br>New Home Sales (Apr)<br>Richmond Fed Manufacturing Survey (May)<br>Texas Manufacturing Survey (May)<br>Weekly Store Sales | **28**<br>Durable Goods Orders (Apr)<br>EIU Crude Oil Stocks<br>Mortgage Applications | **29**<br>GDP (Preliminary, Q1)<br>Corporate Profits (Preliminary, Q1)<br>Kansas City Manufacturing Survey (May)<br>Help Wanted Index (Apr)<br>Weekly Jobless Claims<br>Weekly Money Supply | **30**<br>Personal Income and Consumption (Apr)<br>Chicago PMI (May)<br>Consumer Sentiment (May, Final, University of Michigan)<br>Agricultural Prices Employment Report (May) |
| **June 2**<br>ISM Manufacturing (May)<br>Construction Expenditures (Apr)<br>Online Help Wanted (May) | **6**<br>Auto and Light Truck Sales (May)<br>Factory Orders (May)<br>ABC Consumer Comfort Index<br>Weekly Store Sales | **7**<br>ISM Non-Manufacturing (May)<br>ADP Employment Report (May)<br>Challenger Layoffs (May)<br>Productivity and Costs (Revised, Q1)<br>EIA Crude Oil Stocks<br>Mortgage Applications | **8**<br>Chain Store Sales (May)<br>Flow of Funds (Q1)<br>Weekly Jobless Claims<br>Weekly Money Supply | **9**<br>Employment Report (May)<br>Wholesale Trade (Apr)<br>Consumer Credit (Apr) |

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# CONSENSUS FORECASTS

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**Survey Date**
**April 14, 2008**

Every month, Consensus Economics surveys over 240 prominent financial and economic forecasters for their estimates of a range of variables including future growth, inflation, interest rates and exchange rates. More than 20 countries are covered and the reference data, together with analysis and polls on topical issues, is rushed to subscribers by express mail and e-mail.

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## Survey Highlights

- Forecasts for **consumer price inflation** in many of the countries surveyed have been raised as the global phenomenon of surging food and energy prices intensifies.

- In the **US**, further evidence that the economy is in recession has led to forecasts for a number of key variables being downgraded. Consequently, our panel attaches a high likelihood of a rate cut at the next FOMC meeting (see below):

**Likelihood of a Federal Reserve Interest Rate Change**
Our panel's estimated average probability of a change in the **Fed Funds rate (currently 2.25%) at or before the next FOMC meeting (April 29-30)** was:

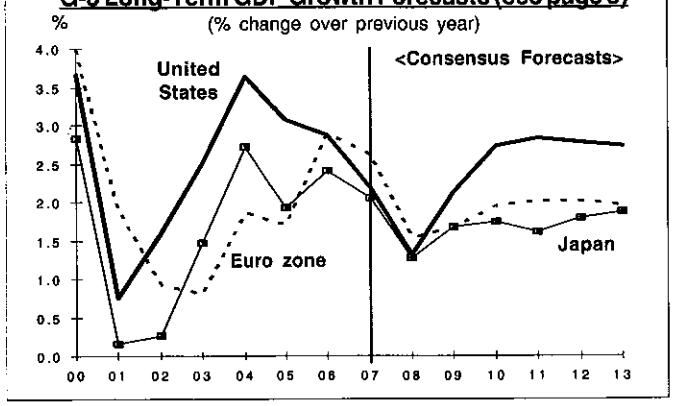
| INCREASE | | NO CHANGE | | DECREASE | | |
|---|---|---|---|---|---|---|
| 0.6 | + | 16.2 | + | 83.3 | = | 100 % |

**Most likely rate change mentioned: -0.25 %**

- The outlook for **Italy** and **Spain** has worsened, with GDP growth forecasts for both being cut. In Italy, the economy is expected to stagnate in 2008, while in Spain, retrenchment in the construction sector is seen driving the slowdown.

- This month's special survey is a repeat of our regular compilation of **Long-Term Forecasts** (pages 3, 28, and 29), with consensus expectations for the next 5-10 years.

**G-3 Long-Term GDP Growth Forecasts (see page 3)**




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In addition to their regular forecasts, country panellists were asked to provide longer-term forecasts covering the period until 2018 for growth in real GDP, consumer spending, investment and industrial production, along with consumer price inflation, current account balances and long-term bond yields. All definitions correspond to those used in the individual country pages.

## United States

| * % change over previous year | Historical | | | | Consensus Forecasts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018[1] |
| **Gross Domestic Product*** | 3.6 | 3.1 | 2.9 | 2.2 | 1.3 | 2.1 | 2.7 | 2.8 | 2.8 | 2.7 | 2.7 |
| **Personal Consumption*** | 3.6 | 3.2 | 3.1 | 2.9 | 1.3 | 1.7 | 2.5 | 2.7 | 2.7 | 2.6 | 2.5 |
| **Business Investment*** | 5.8 | 7.1 | 6.6 | 4.7 | 2.2 | 1.1 | 4.3 | 4.7 | 4.3 | 3.7 | 3.8 |
| **Industrial Production*** | 2.5 | 3.3 | 2.2 | 1.7 | 0.7 | 2.2 | 2.9 | 2.9 | 2.7 | 2.5 | 2.6 |
| **Consumer Prices*** | 2.7 | 3.4 | 3.2 | 2.9 | 3.6 | 2.3 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| **Current Account Balance (US$bn)** | -640 | -755 | -811 | -739 | -688 | -619 | -631 | -620 | -625 | -616 | -590 |
| **10 Year Treasury Bond Yield, %[2]** | 4.2 | 4.4 | 4.7 | 4.2 | 3.6 [3] | 4.1 [4] | 4.9 | 5.1 | 5.1 | 5.1 | 5.1 |

[1]*Signifies average for period* [2]*End period* [3]*End July, 2008* [4]*End April, 2009*

Financial market turmoil and the onset of a possible recession in the US have impacted on near-term GDP growth expectations for all G-7 and Western European countries. Moreover, growth projections going further out have also eased somewhat compared with our survey of long-term trends conducted in October 2007. In the **United States**, the ongoing housing retrenchment – coupled with the deepening credit crunch, faltering job market and inflationary pressures – is battering consumer spending, forecasts for which suggest that expenditure might not immediately bounce back to previous strong rates of expansion. Indeed, while the US downturn itself is expected to be shallow, the recovery may take longer to gather momentum, and GDP forecasts over the next 5-10 years point to growth below 3% (considered the US trend rate). The decade-long era of strong activity and benign inflation – fuelled by the technology revolution which lifted GDP and productivity growth rates – appears to have ended, and the US economy is now grappling with rising inflation and heavily indebted equity markets and households. The **United Kingdom** faces similar challenges given that it, too, is reliant on an influential financial sector and overextended property market. Other countries are somewhat less exposed to US volatility. However, globalisation (which at one time helped to keep import costs down) has contributed to resurgent commodity prices. Our panels' short-term inflation forecasts suggest a jump for most countries surveyed (**Canada** being a notable exception). Indeed, central banks are worried that stronger inflation could become more entrenched. In particular, the **ECB** has remained cautious about cutting interest rates in the face of above-target inflation and has to-date refrained from doing so. The **Bank of England**, wary of rising inflation expectations, has cut rates only gradually. The **Bank of Japan**, meanwhile, is unlikely to loosen monetary policy given that rates remain at such low levels. Moreover, inflation expectations are unlikely to break 1.5% over the next 10 years.

*(tables continued on pages 28-29)*

## Japan

| * % change over previous year | Historical | | | | Consensus Forecasts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018[1] |
| **Gross Domestic Product*** | 2.7 | 1.9 | 2.4 | 2.0 | 1.3 | 1.7 | 1.7 | 1.6 | 1.8 | 1.9 | 1.6 |
| **Private Consumption*** | 1.6 | 1.3 | 2.0 | 1.5 | 1.0 | 1.5 | 1.7 | 1.6 | 2.0 | 1.8 | 1.7 |
| **Business Investment*** | 5.4 | 9.2 | 4.3 | 2.1 | 2.0 | 2.8 | 3.1 | 2.2 | 3.1 | 2.5 | 2.0 |
| **Industrial Production*** | 5.2 | 1.5 | 4.5 | 2.9 | 1.1 | 2.4 | 1.9 | 1.1 | 2.4 | 2.0 | 1.7 |
| **Consumer Prices*** | 0.0 | -0.3 | 0.2 | 0.0 | 0.7 | 0.5 | 1.2 | 1.1 | 1.2 | 1.0 | 1.5 |
| **Current Account Balance (¥tn)** | 18.6 | 18.3 | 19.8 | 25.0 | 24.1 | 25.1 | 28.8 | 29.1 | 29.1 | 28.6 | 26.3 |
| **10 Year Treasury Bond Yield, %[2]** | 1.4 | 1.5 | 1.7 | 1.5 | 1.4 [3] | 1.6 [4] | 2.3 | 2.5 | 2.6 | 2.7 | 2.9 |

## Germany

| * % change over previous year | Historical | | | | Consensus Forecasts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018[1] |
| **Gross Domestic Product*** | 1.1 | 0.8 | 2.9 | 2.5 | 1.7 | 1.6 | 1.8 | 1.8 | 1.6 | 1.6 | 1.5 |
| **Private Consumption*** | 0.2 | -0.1 | 1.0 | -0.4 | 0.9 | 1.5 | 1.4 | 1.3 | 1.2 | 1.2 | 1.2 |
| **Machinery & Eqpt Investment*** | 4.6 | 6.0 | 8.3 | 8.2 | 4.0 | 3.3 | 3.5 | 3.0 | 3.1 | 3.0 | 2.9 |
| **Industrial Production*** | 2.5 | 2.8 | 6.0 | 5.8 | 3.7 | 2.6 | 2.3 | 2.2 | 1.9 | 2.3 | 2.2 |
| **Consumer Prices*** | 1.7 | 1.5 | 1.6 | 2.3 | 2.5 | 1.9 | 1.8 | 1.7 | 1.7 | 1.6 | 1.7 |
| **Current Account Balance (Euro bn)** | 103 | 117 | 141 | 184 | 168 | 165 | 141 | 137 | 131 | 108 | 109 |
| **10 Year Treasury Bond Yield, %[2]** | 3.7 | 3.3 | 4.0 | 4.3 | 3.9 [3] | 4.1 [4] | 4.5 | 4.4 | 4.4 | 4.4 | 4.4 |

[1]*Signifies average for period* [2]*End period* [3]*End July, 2008* [4]*End April, 2009*

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*continued from page 3*

## France

| * % change over previous year | Historical | | | | Consensus Forecasts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018[1] |
| Gross Domestic Product* | 2.3 | 1.7 | 2.2 | 1.9 | 1.5 | 1.7 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 |
| Household Consumption* | 2.5 | 2.2 | 2.3 | 2.1 | 1.9 | 2.0 | 2.3 | 2.3 | 2.2 | 2.2 | 2.2 |
| Business Investment* | 3.6 | 2.7 | 4.6 | 5.1 | 2.7 | 2.6 | 3.8 | 3.5 | 3.4 | 3.4 | 3.4 |
| Industrial Production* | 2.3 | 0.4 | 1.3 | 1.8 | 1.4 | 1.5 | 2.7 | 2.2 | 2.1 | 2.1 | 2.0 |
| Consumer Prices* | 2.1 | 1.8 | 1.6 | 1.5 | 2.5 | 1.8 | 1.8 | 1.8 | 1.9 | 1.8 | 1.8 |
| Current Account Balance (Euro bn | 8.5 | -15.7 | -22.5 | -24.4 | -30.8 | -32.6 | -24.8 | -23.7 | -20.4 | -15.0 | -12.5 |
| 10 Year Treasury Bond Yield, %[2] | 3.7 | 3.3 | 4.0 | 4.4 | 4.0 [3] | 4.2 [4] | 4.4 | 4.5 | 4.5 | 4.5 | 4.5 |

## United Kingdom

| * % change over previous year | Historical | | | | Consensus Forecasts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018[1] |
| Gross Domestic Product* | 3.3 | 1.8 | 2.9 | 3.0 | 1.6 | 1.7 | 2.0 | 2.2 | 2.3 | 2.4 | 2.4 |
| Household Consumption* | 3.5 | 1.5 | 1.9 | 3.0 | 1.5 | 1.4 | 1.7 | 2.0 | 2.1 | 2.2 | 2.3 |
| Gross Fixed Investment* | 5.9 | 1.5 | 7.6 | 6.2 | 2.1 | 1.5 | 1.7 | 1.9 | 2.6 | 2.9 | 3.2 |
| Manufacturing Production* | 2.0 | -1.2 | 1.5 | 0.6 | 0.2 | 0.7 | 0.4 | 0.9 | 1.1 | 1.2 | 1.1 |
| Retail Prices (underlying rate)* | 2.2 | 2.3 | 2.9 | 3.2 | 3.4 | 2.5 | 2.7 | 2.7 | 2.6 | 2.6 | 2.7 |
| Consumer Prices* | 1.3 | 2.1 | 2.3 | 2.3 | 2.6 | 2.0 | 2.2 | 2.2 | 2.1 | 2.1 | 2.1 |
| Current Account Balance (£ bn) | -19.3 | -31.0 | -50.7 | -57.8 | -58.9 | -52.8 | -51.8 | -51.2 | -51.9 | -53.7 | -60.7 |
| 10 Year Treasury Bond Yield, %[2] | 4.5 | 4.1 | 4.7 | 4.6 | 4.4 [3] | 4.5 [4] | 4.9 | 5.1 | 5.1 | 5.0 | 5.0 |

## Italy

| * % change over previous year | Historical | | | | Consensus Forecasts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018[1] |
| Gross Domestic Product* | 1.0 | 0.2 | 1.9 | 1.6 | 0.6 | 1.1 | 1.5 | 1.4 | 1.4 | 1.4 | 1.4 |
| Household Consumption* | 0.7 | 0.6 | 1.5 | 1.6 | 0.8 | 1.1 | 1.4 | 1.4 | 1.5 | 1.4 | 1.4 |
| Gross Fixed Investment* | 1.3 | -0.2 | 2.4 | 1.8 | 0.9 | 1.2 | 1.7 | 1.7 | 1.5 | 1.4 | 1.4 |
| Industrial Production* | -0.3 | -0.8 | 2.6 | -0.2 | -0.1 | 0.9 | 1.2 | 1.2 | 1.1 | 1.0 | 1.0 |
| Consumer Prices* | 2.2 | 2.0 | 2.1 | 1.8 | 2.9 | 2.1 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 |
| Current Account Balance (Euro bn) | -13.1 | -23.4 | -38.2 | -36.5 | -37.6 | -36.2 | -32.5 | -26.5 | -25.2 | -24.3 | -22.3 |
| 10 Year Treasury Bond Yield, %[2] | 3.8 | 3.5 | 4.2 | 4.6 | 4.1 [3] | 4.2 [4] | 4.6 | 4.7 | 4.8 | 4.7 | 4.7 |

## Canada

| * % change over previous year | Historical | | | | Consensus Forecasts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018[1] |
| Gross Domestic Product* | 3.1 | 3.1 | 2.8 | 2.7 | 1.4 | 2.3 | 2.7 | 2.6 | 2.6 | 2.3 | 2.3 |
| Personal Expenditure* | 3.4 | 3.8 | 4.2 | 4.7 | 4.4 | 3.0 | 2.7 | 2.6 | 2.4 | 2.3 | 2.2 |
| Machinery & Eqpt Investment* | 9.3 | 10.8 | 7.4 | 5.1 | 8.3 | 5.7 | 4.5 | 4.0 | 4.0 | 3.8 | 3.3 |
| Industrial Production* | 1.9 | 1.6 | -0.2 | 0.3 | -2.1 | 1.5 | 2.3 | 2.3 | 2.4 | 2.3 | 2.3 |
| Consumer Prices* | 1.8 | 2.2 | 2.0 | 2.2 | 1.7 | 2.0 | 2.0 | 2.1 | 2.1 | 2.0 | 2.0 |
| Current Account Balance (C$ bn) | 29.1 | 27.9 | 23.6 | 14.2 | -7.9 | -7.8 | -9.2 | -6.1 | -6.1 | -5.4 | -9.7 |
| 10 Year Treasury Bond Yield, %[2] | 4.3 | 4.0 | 4.1 | 4.0 | 3.6 [3] | 3.9 [4] | 5.0 | 5.2 | 5.2 | 5.1 | 5.1 |

## Euro zone

| * % change over previous year | Historical | | | | Consensus Forecasts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018[1] |
| Gross Domestic Product* | 1.9 | 1.7 | 2.9 | 2.6 | 1.5 | 1.7 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| Private Consumption* | 1.5 | 1.6 | 1.8 | 1.5 | 1.3 | 1.6 | 1.8 | 1.8 | 1.9 | 1.9 | 1.8 |
| Gross Fixed Investment* | 2.0 | 3.1 | 5.3 | 4.2 | 2.4 | 2.2 | 2.7 | 3.0 | 2.9 | 2.8 | 2.8 |
| Industrial Production* | 2.1 | 1.4 | 4.0 | 3.4 | 2.0 | 1.9 | 2.2 | 2.3 | 2.1 | 2.0 | 1.9 |
| Consumer Prices* | 2.1 | 2.2 | 2.2 | 2.1 | 2.9 | 2.1 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| Current Account Balance (Euro bn) | 59.8 | 7.1 | -13.7 | 14.9 | -2.7 | -2.1 | -2.8 | -2.8 | -1.5 | -5.0 | -5.0 |

*[1]Signifies average for period [2]End period [3]End July, 2008 [4]End April, 2009*



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**YEC-YECL-40**

**Reference:** Capital Structure

**Requests:**

(a) Please provide a copy of schedule 1.1 for YECL under each of the following assumptions as to equity ratio in the capital structure: 40 , 41 , 42 and 43 .

(b) Please provide a copy of schedule 1.1 for YECL assuming a capital structure of 52.5 common equity and a return on equity of 8.75 .

(c) Please confirm that YECL has operated at a capital structure of approximately 40 to 43 equity for each year from 2003 through 2007.

(d) Please discuss, and provide any relevant evidence, if YECL has had difficulty accessing capital markets with a capital structure of 40-43 equity. If so, please provide a detailed summary of those difficulties and the debt cost impacts on YECL from 2003 to 2007.

(e) Please confirm that obtaining a capital structure of 46.86 by mid-year for the 2009 test year requires additional mid-year equity of 3.181 million in 2008 and 4.305 million in 2009 (if not, please provide the correct equity amounts in each year). Please confirm that the largest increase in mid-year equity for the period 2003 through 2007 was 0.652 million in 2005 (per Schedule 8.1 provided in the package dated July 4 2008).

(f) Please elaborate on the need and justification for these large increases in equity in the test years. Please explain in detail why such large equity increases were not required between 2004 and 2007.

(g) Please provide a copy of the source of Table 5 (page 27) of the Foster Associates Inc. evidence.

(h) Please explain in detail how the business risk score of 4 , the notional business risk score attributed to YECL was determined (page 27 of the Foster Associates Inc. evidence).

(i) Please provide the impact on customers resulting from the increase in YECL's equity component.

**Response:**

(a) This information is not being provided as any number of combinations have been or could have been requested and the information is readily available through the spreadsheets provided in the application.

(b) This information is not being provided as any number of combinations have been or could have been requested and the information is readily available through the spreadsheets provided in the application.

(c) Confirmed.

(d) Yukon Electrical does not access capital markets directly as all debt financing required by Yukon Electrical is completed by CU Inc. Equity financing when required would be completed by CU Inc.'s parent company, Canadian Utilities Limited. Both CU Inc. and Canadian Utilities Limited. have, to this point, been able to access capital markets directly when required and YECL therefore benefits from the financial strength of both CU Inc. and Canadian Utilities Limited.

(e) Confirmed.

(f) The need for the large increases in equity is explained in detail in Ms. McShane's testimony in Section 8, Attachment 1 of the Application.

These increases in equity would have been required between 2004 and 2007 for the reasons stated in Ms. McShane's testimony. However, to seek this increase Yukon Electrical would have been required to file a General Rate Application. Given the costs to customers for such an application combined with the fact that YECL could continue to operate under existing rates, management decided to continue operations with the existing structure and defer seeking an increase in the equity thickness until such time as a GRA was required.

(g) The requested document is attached as YEC-YECL-40(g) Attachment 1.

(h) The assignment of a 4 was discussed at page 25, lines 659-662 and was based on the conclusion that, on balance, as a very small utility operating in a service territory with an undiversified economic base tied to a single industry and facing significant geographic physical operating challenges, Yukon Electrical is exposed to a higher degree of business risk than the typical electricity distribution utility in Canada, is of higher than average business risk within the spectrum of Canadian utilities and is of approximately equal risk to the A rated U.S. utilities. The average business profile score that was assigned to Canadian utilities was 3. A score of 4 reflects the average score that was assigned to A rated U.S. utilities, which is lower than the average score of 5 that was assigned to the universe of U.S. electric utilities. The guidelines referenced by Ms. McShane on page 27 were last published in the S&P report attached in response to part (g) above.

(i) The impact is an increase in the Revenue Requirement of approximately 173,000 per year (approximately 0.4 rate increase on existing rates) for 2008 and an additional 113,000 in 2009 going from a 40 to 47.5 equity ratio.

STANDARD &POOR'S RATINGSDIRECT

**RESEARCH**

### Key Credit Factors:

# Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers

**Publication date:** 14-Sep-2006
**Primary Credit Analyst:** Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com
**Secondary Credit Analyst:** Richard W Cortright, Jr., New York (1) 212-438-7665; richard_cortright@standardandpoors.com

The methodology that Standard & Poor's Ratings Services uses to rate vertically integrated electric, gas, and combination investor-owned utilities in the U.S. is based on the same precepts that we have used for many years, though the emphasis has changed as the utility industry has evolved. The fundamental methodology encompasses two basic components--business risk and financial risk--and their relationship. Where a utility presents a strong business risk profile, the financial profile can be less robust for any given rating. Likewise, where a utility's business risk profile is weaker, its financial performance must be stronger for any given rating. For combination utilities, the gas operations may have a stabilizing influence on credit quality, but since the electric business is typically significantly larger, it is the major credit driver. (For details on Standard & Poor's analytical approach to gas utilities, see "Key Credit Factors For Natural Gas Distributors" published Feb. 28, 2006.)

Often, an integrated utility is a part of a larger holding company structure that also owns other businesses, frequently unregulated electricity generation. This fact does not alter how we analyze the utility, but it may affect the ultimate rating outcome due to any credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

## Five Factors Determine The Business Profile

Five basic characteristics define a vertically integrated utility's business profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Standard & Poor's is most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations. While considerable attention has focused in recent years on companies in states that deregulated in the late 1990s and the early part of this decade and the related credit consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

On Standard & Poor's business profile scale (where '1' is excellent and '10' is vulnerable), vertically integrated utilities generally have satisfactory business profiles of '5' or '6'. (See tables 1 and 2 in the Appendix below for business profile benchmarks plus a list of utilities we rate and their business profile scores.) We view a company that owns regulated generation, transmission, and distribution operations, as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management.

**Regulation**

Regulation is a critical aspect that underlies integrated utilities' creditworthiness. Decisions by state public service commissions can profoundly affect financial performance. Standard & Poor's assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program and incurs substantial deferrals of fuel costs.

Standard & Poor's evaluation encompasses the administrative, judicial, and legislative processes involved in state and federal regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case-by-case with regard to the potential effect on credit quality. As frequently postulated in prior years, our evaluation of regulation focuses on the willingness and ability of regulation to provide cash flow and earnings quality adequate to meet investment needs, earnings stability through timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity. Regulators' authorization of high rates of return is of little value unless returns are realistic and achievable. Allowing high returns based on noncash items does not benefit bondholders. A regulatory jurisdiction that permits incentives whereby utilities are allowed to earn a return based on their ability to sustain rates at competitive levels is viewed favorably. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Also important is the ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses or with fixed-fuel mechanisms, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. Standard & Poor's notes that fuel-adjustment mechanisms have become more common in the industry, but not all are created equal. While some jurisdictions permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions, such as Washington State, impose a deadband in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. In Arizona, Arizona Public Service Co. has a 90/10 sharing mechanism between the company and ratepayers, respectively, for all costs passed through the power supply adjuster. The mechanism is triggered based on a date (once a year in February 2006) and not on a threshold level of deferrals. The annual adjustment is also subject to a lifetime cap of 4 mils per kilowatt-hour, which has led to power deferrals.

In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes significant cash flow drain and reduces the utility's need to issue debt during construction.

Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery. Also supportive of credit quality is the ability of the utility, commission staff,

consumer advocates, and other major interveners to reach a comprehensive settlement before construction of new base load capacity. Certain states, such as Indiana, Texas, Kansas, and Minnesota, have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with environmental compliance equipment without having to file a formal rate case. Creditworthiness can also be enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing storm damage, as in Florida. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, it has shown a willingness to work with utilities to help them recover at least some of these costs on a timely basis and to start replenishing storm reserves. Finally, the greater the percentage of a utility's rates that are recovered through fixed charges rather than volume-based charges, the greater the support for credit quality.

For utilities that own a natural gas business, automatic and timely pass-through of commodity costs provides the strongest level of credit support. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels.

Due to the extreme volatility and high gas prices over the past few heating seasons, more regulators have revised gas adjustment clauses to provide monthly gas adjustments rather than awaiting the end of the heating season to begin reimbursement. This expedited treatment helps the utility to reduce any regulatory lag to recover costs and streamlines working capital needs, which in turn should allow the firm to modestly temper rising gas bills to their customers.

Both regulators and natural gas companies are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and companies are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting the company's bottom line and still allow utilities to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Key success factors include:

- Alternative ratemaking/flexibility,
- Attention to credit quality,
- Timely and consistent rate treatment,
- Support for fuel cost recovery,
- Support for a reasonable cash return on investment, and
- Support for rapid return on investment.

**Markets**

Assessing market dynamics begins with an economic and demographic evaluation of the service area in which a utility operates. Strength of long-term demand for energy is examined from a macroeconomic perspective, which enables Standard & Poor's to measure the affordability of rates and the staying power of demand. Distribution by classification according to total number of customers, revenues, and margins is closely scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed with some caution because the utility may be exposed to cyclical volatility and face competitive alternatives. A large residential component, on the other hand, produces a more stable and predictable revenue stream. The utility's largest customers are identified to determine their stability and importance to the bottom line because the loss of one large customer could adversely affect the utility's financial position. Moreover, large customers may turn to self-generation, potentially leading to less financial protection for the utility.

Standard & Poor's also analyzes any long-term consumption trends and the reasons behind them. Factors addressed include the market's size and growth rate, the franchise's strength, historical and projected growth rates, income levels and trends in population, employment, and per capita income. A utility with a

healthy economy and customer base, as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment, will be better able to support its operations.

For the gas business, Standard & Poor's also examines customer saturation. Firms that operate in service areas with low growth potential still can expand at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to companies operating in low population growth service areas.

Despite the review of market characteristics, they are clearly a secondary consideration to regulation. In Nevada, for years the country's fastest growing state, Nevada Power Co. and Sierra Pacific Power Co. struggled to recover capital expenditures on a timely basis, and were accordingly rated as low investment-grade credits. In Florida, which has competed with Nevada for years in its pace of growth, the Florida Public Service Commission established polices of quick recovery of capital investments and, on a stand-alone basis, the state's utilities' credit metrics have remained strong.

Critical success factors include:

- A healthy and growing economy,
- Growth in population and number of customers,
- An attractive business environment, and
- An above-average residential base.

**Operations**

Standard & Poor's focuses on cost, reliability, safety, and quality of service when assessing a utility's operations. Management is always under pressure to optimize the use of resources, and if it is not cost-effective in meeting service standards and reliability, regulatory or competitive pressures are likely to increase. Consequently, Standard & Poor's emphasizes areas that require heightened and ongoing management attention, in the absence of which political, regulatory, or competitive problems are likely to arise.

The status of utility plant investment is reviewed with regard to generating station availability, efficiency, and utilization, as well as for compliance with existing and potential environmental and other regulatory standards. The record of plant outages, system losses, equivalent availability, load factors, heat rates, and capacity factors are examined. Important considerations include the projected capital improvements and plant additions necessary to provide high-quality, reliable service. The general condition of the assets and how well such assets are maintained are also important considerations.

Emphasis is placed on reserve margins, fuel mix, fuel contract terms, purchased-power arrangements, and system operators. Moreover, the quality and concentration of capacity is just as important as the size of reserves. Standard & Poor's recognizes that reserve requirements differ among companies, depending upon individual operating and load characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to switch generating sources to take advantage of cheaper fuels is viewed favorably. Dependence on any single fuel, or asset concentration in one or two large generating stations, can cause significant swings in a company's financial performance. Similarly, utilities that rely on nuclear generation receive an elevated degree of attention due to the scale, technical complexity, and politically sensitive nature of nuclear facilities. Indeed, the sound operation of nuclear units can define a utility's operational risk profile and its ability to achieve projected financial results. Standard & Poor's seeks to distinguish between those operators that have exhibited sound and stable operational performance, and the likelihood that it will continue, and those whose nuclear operations are vulnerable to problems that may impair financial results.

But having a large concentration of capacity based on fossil fuels also imposes certain risks. Coal-fired capacity is burdened with increased environmental costs related to reducing sulfur dioxide, nitrogen oxide,

mercury, and eventually carbon dioxide emissions. Gas-fired capacity presents its own challenges, particularly the extreme volatility and significant increase in gas prices over the past few years. Buying power may be a more appropriate option for a utility than new plant construction because the utility avoids construction costs and the financial risks posed by regulatory lag when seeking recovery of costs. Purchasing power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Despite these benefits, such a strategy does commit the utility to a fixed obligation, which Standard & Poor's captures analytically through certain adjustments to financial statements. We calculate the net present value of future annual capacity payments (discounted at the company's cost of debt) over the life of the contract. Standard & Poor's then applies a risk factor against this value and adds the result to the utility's balance sheet. The risk factor is largely a function of the strength of the regulatory recovery mechanisms established to address procurement costs.

Other operational characteristics that will support an above-average evaluation for vertically integrated companies are assets that are in good physical condition and are well maintained. In addition, capital expenditures for necessary system improvements must be at manageable levels, yet sufficient to provide for constant renewal and refurbishment of the system. Operating performance, reliability statistics (such as outage duration and frequency), and efficiency measures are expected to meet industry and regional averages. Having interconnections that provide access to low-cost and diverse power supply sources is viewed favorably, as is limited environmental exposure.

For a gas company, drawing from a single interstate pipeline or relying on a particular gas basin exposes it to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects the utility from such disruptions. Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. Gas distributors benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Outdated systems requiring extensive maintenance and capital expenditures lower profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, operational efficiencies can be obtained through the use of new technology.

Critical success factors include:

- Well-maintained assets,
- Solid plant performance,
- Fuel diversity,
- Adequate generating reserves, and
- Compliance with environmental standards.

**Competitiveness**

For vertically integrated utilities, competitive factors include percentage of firm wholesale revenues that are most vulnerable to competition, industrial load, and revenue concentrations, particularly in energy intensive industries; exposure of key customers to alternative suppliers; commercial concentrations; rates charged to various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Electricity competes with other fuels--particularly natural gas--for certain segments of the market like space heating, water heating, and cooking. Thus, high electricity prices, which can be attributed to inefficient operations, are cause for concern if customers have access to alternative energy sources. Self-generation has been a risk, as large commercial and industrial customers may take advantage of cogeneration technologies to reduce their reliance on, and in some cases to disconnect from the system. In the future, technology could pose a greater threat. Bypass risk, too, may grow if distributed generation, microgeneration, and self-generation prove more economically attractive for smaller customers.

Due to their proximity to interstate gas pipelines, some large customers can directly tie into a transmission

line and completely bypass gas distributors' services. Although such pipelines provide key sources of gas supply for these companies, it is important to recognize this bypass risk. Ideally located gas companies have adequate transmission access but have industrial customers far from interstate pipelines.

Critical success factors include:

- Low cost structure,
- Limited bypass risk, and
- Management's commitment to lowering costs.

**Management**

Evaluating management is of paramount importance to Standard & Poor's analysis because management decisions affect all areas of a company's operations and financial health. Although regulation, the economy, and other outside factors certainly influence results, the quality of management ultimately determines a company's success. Standard & Poor's private meetings with senior management significantly augment the public record in the effort to appraise management. Meetings are very useful for the candid interpretation of recent developments and, importantly, to provide executives with a forum for the presentation of goals, objectives, and strategies.

Management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple--and often incompatible--priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

Standard & Poor's also focuses on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

In addition, a company's accounting and financing practices are critical to Standard & Poor's analysis. For example, proactive management will likely adopt accounting practices that are more appropriate in a competitive environment such as higher depreciation rates for electric generation equipment. Large, growing cost deferrals or regulatory assets are viewed more negatively. Management can enhance its financial condition by taking any number of discretionary actions, such as selling common equity, reducing the common dividend payout, and deleveraging. A utility's management will also be evaluated on cost-cutting ability and creativity in entering into strategic alliances that improve efficiency.

Strong corporate governance, reflected in active, independent board of directors that participate in determining and monitoring corporate controls, help to support management's credibility and corporate financial disclosure. If it is evident that a company's board is passive and does not exercise proper oversight, it weakens the checks and balances of the organization and may detract from credit quality. Included in Standard & Poor's review of corporate governance is the proportion of independent directors on the board, the breadth and depth of the directors' experience, the proportion of independent directors on the board's audit committee, and directors' compensation.

Some vertically integrated utilities have felt compelled to invest outside their traditional businesses to increase earnings, especially as stock prices have underperformed market indices. Participation in higher-risk, unregulated activities such as merchant generation, exploration and development, gathering and processing, or marketing and trading can significantly detract from the consolidated entity's credit profile. In this regard, credit ratings are not based on the regulated business only, but on the qualitative and quantitative fundamentals of the consolidated entity. Standard & Poor's considers the ratings of the regulated businesses as being less vulnerable to the negative credit influence of other affiliates and holding company activities, as relevant, where very strong structural and/or regulatory insulation exists, which tends to be more the exception than the rule.

Critical success factors include:

- Commitment to credit quality,
- Credibility,
- Strong corporate governance, and
- Conservative financial policies, especially regarding nonregulated activities, if relevant.

## Effect On Ratings

In summary, Standard & Poor's examines the key business risk drivers for vertically integrated utilities--regulation, markets, operations, competitiveness, and management--in conjunction with financial measures when assigning credit ratings. The credit quality of most vertically integrated utilities is solidly investment grade. This is a primarily a function of the existence of regulation. As discussed above, the factors that further differentiate ratings among this sector include their markets, operational track record, competitive posture, and management's risk appetite. Vertically integrated utilities generally have satisfactory business risk profile scores, with only a few having strong or weak business positions.

## Appendix

**Table 1**

**Industry Benchmarks**

| Business Profile | AA | | A | | BBB | | BB | |
|---|---|---|---|---|---|---|---|---|
| **Adjusted FFO interest coverage (x)** | | | | | | | | |
| 1 | 3.0 | 2.5 | 2.5 | 1.5 | 1.5 | 1.0 | < 1.0 | < 1.0 |
| 2 | 4.0 | 3.0 | 3.0 | 2.0 | 2.0 | 1.0 | < 1.0 | < 1.0 |
| 3 | 4.5 | 3.5 | 3.5 | 2.5 | 2.5 | 1.5 | 1.5 | 1.0 |
| 4 | 5.0 | 4.2 | 4.2 | 3.5 | 3.5 | 2.5 | 2.5 | 1.5 |
| 5 | 5.5 | 4.5 | 4.5 | 3.8 | 3.8 | 2.8 | 2.8 | 1.8 |
| 6 | 6.0 | 5.2 | 5.2 | 4.2 | 4.2 | 3.0 | 3.0 | 2.0 |
| 7 | 8.0 | 6.5 | 6.5 | 4.5 | 4.5 | 3.2 | 3.2 | 2.2 |
| 8 | 10.0 | 7.5 | 7.5 | 5.5 | 5.5 | 3.5 | 3.5 | 2.5 |
| 9 | N/A | N/A | 10.0 | 7.0 | 7.0 | 4.0 | 4.0 | 2.8 |
| 10 | N/A | N/A | 11.0 | 8.0 | 8.0 | 5.0 | 5.0 | 3.0 |
| **Adjusted FFO/average total debt (%)** | | | | | | | | |
| 1 | 20.0 | 15.0 | 15.0 | 10.0 | 10.0 | 5.0 | < 5.0 | < 5.0 |
| 2 | 25.0 | 20.0 | 20.0 | 12.0 | 12.0 | 8.0 | < 8.0 | < 8.0 |
| 3 | 30.0 | 25.0 | 25.0 | 15.0 | 15.0 | 10.0 | 10.0 | 5.0 |
| 4 | 35.0 | 28.0 | 28.0 | 20.0 | 20.0 | 12.0 | 12.0 | 8.0 |
| 5 | 40.0 | 30.0 | 30.0 | 22.0 | 22.0 | 15.0 | 15.0 | 10.0 |
| 6 | 45.0 | 35.0 | 35.0 | 28.0 | 28.0 | 18.0 | 18.0 | 12.0 |
| 7 | 55.0 | 45.0 | 45.0 | 30.0 | 30.0 | 20.0 | 20.0 | 15.0 |
| 8 | 70.0 | 55.0 | 55.0 | 40.0 | 40.0 | 25.0 | 25.0 | 15.0 |
| 9 | N/A | N/A | 65.0 | 45.0 | 45.0 | 30.0 | 30.0 | 20.0 |
| 10 | N/A | N/A | 70.0 | 55.0 | 55.0 | 40.0 | 40.0 | 25.0 |
| **Adjusted total debt/total capital (%)** | | | | | | | | |
| 1 | 48.0 | 55.0 | 55.0 | 60.0 | 60.0 | 70.0 | > 70.0 | > 70.0 |
| 2 | 45.0 | 52.0 | 52.0 | 58.0 | 58.0 | 68.0 | > 68.0 | > 68.0 |
| 3 | 42.0 | 50.0 | 50.0 | 55.0 | 55.0 | 65.0 | 65.0 | 70.0 |
| 4 | 38.0 | 45.0 | 45.0 | 52.0 | 52.0 | 62.0 | 62.0 | 68.0 |
| 5 | 35.0 | 42.0 | 42.0 | 50.0 | 50.0 | 60.0 | 60.0 | 65.0 |
| 6 | 32.0 | 40.0 | 40.0 | 48.0 | 48.0 | 58.0 | 58.0 | 62.0 |
| 7 | 30.0 | 38.0 | 38.0 | 45.0 | 45.0 | 55.0 | 55.0 | 60.0 |
| 8 | 25.0 | 35.0 | 35.0 | 42.0 | 42.0 | 52.0 | 52.0 | 58.0 |
| 9 | N/A | N/A | 32.0 | 40.0 | 40.0 | 50.0 | 50.0 | 55.0 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 10 | N/A | N/A | 25.0 | 35.0 | 35.0 | 48.0 | 48.0 | 52.0 |

Note: Business profile scores are characterized from '1' (excellent) to '10' (weak). FFO--Funds from operations. N/A--Not applicable.

**Table 2**

**Vertically Integrated Utilities**

| Company | Corporate credit rating | Business profile score |
|---|---|---|
| Aquila Inc. | B/CW-Pos/B-2 | 6 |
| AGL Resources Inc. | A-/Negative/A-2 | 4 |
| Alabama Power Co. | A/Stable/A-1 | 4 |
| ALLETE Inc. | BBB+/Stable/A-2 | 5 |
| Ameren Corp. | BBB+/CW-Neg/A-2 | 6 |
| Appalachian Power Co. | BBB/Stable/-- | 5 |
| Arizona Public Service Co. | BBB-/Stable/A-3 | 6 |
| Atmos Energy Corp. | BBB/Stable/A-2 | 4 |
| Black Hills Power Inc. | BBB-/Negative/-- | 6 |
| Central Illinois Light Co. | BBB+/CW-Neg/-- | 7 |
| Central Vermont Public Service Corp. | BB+/Stable/-- | 6 |
| CILCORP Inc. | BBB+/CW-Neg/-- | 7 |
| Cincinnati Gas & Electric Co. | BBB/Positive/A-2 | 6 |
| Cleco Power LLC | BBB/Negative/-- | 6 |
| Cleveland Electric Illuminating Co. | BBB/Stable/-- | 6 |
| Consolidated Natural Gas Co. | BBB/Stable/A-2 | 6 |
| Consumers Energy Co. | BB/Stable/-- | 6 |
| Dayton Power & Light Co. | BB+/Positive/-- | 5 |
| Detroit Edison Co. | BBB/Stable/A-2 | 6 |
| Duke Power Co. LLC | BBB/Positive/A-2 | 4 |
| El Paso Electric Co. | BBB/Stable/-- | 6 |
| Empire District Electric Co. | BBB-/Stable/A-3 | 6 |
| Energy East Corp. | BBB+/Negative/A-2 | 3 |
| Enogex Inc. | BBB+/Stable/-- | 7 |
| Entergy Arkansas Inc. | BBB/Negative/-- | 5 |
| Entergy Gulf States Inc. | BBB/Negative/-- | 6 |
| Entergy Louisiana LLC | BBB/Negative/-- | 5 |
| Entergy Mississippi Inc. | BBB/Negative/-- | 6 |
| Entergy New Orleans Inc. | D/--/-- | 8 |
| Equitable Resources Inc. | A-/CW-Neg/A-2 | 8 |
| Florida Power & Light Co. | A/CW-Neg/A-1 | 4 |
| Georgia Power Co. | A/Stable/A-1 | 4 |
| Green Mountain Power Corp. | BBB/CW-Pos/-- | 5 |
| Gulf Power Co. | A/Stable/-- | 4 |
| Hawaiian Electric Co. Inc. | BBB+/Negative/A-2 | 5 |
| IDACORP Inc. | BBB+/Negative/A-2 | 5 |
| Idaho Power Co. | BBB+/Negative/A-2 | 5 |
| Indiana Michigan Power Co. | BBB/Stable/-- | 6 |
| Indianapolis Power & Light Co. | BB+/Positive/-- | 4 |
| Interstate Power & Light Co. | BBB+/Stable/A-2 | 5 |
| IPALCO Enterprises Inc. | BB+/Positive/-- | 4 |
| Kansas City Power & Light Co. | BBB/Stable/A-2 | 6 |
| Kansas Gas & Electric Co. | BB+/Positive/-- | 6 |
| Kentucky Power Co. | BBB/Stable/-- | 5 |
| Kentucky Utilities Co. | BBB+/Stable/A-2 | 5 |
| Louisville Gas & Electric Co. | BBB+/Stable/-- | 5 |

| | | |
|---|---|---|
| Madison Gas & Electric Co. | AA-/Stable/A-1+ | 4 |
| Michigan Consolidated Gas Co. | BBB/Stable/A-2 | 4 |
| MidAmerican Energy Co. | A-/Stable/A-1 | 5 |
| Mississippi Power Co. | A/Stable/A-1 | 4 |
| Monongahela Power Co. | BB+/Positive/-- | 5 |
| Montana-Dakota Utilities Co. | BBB+/Stable/-- | 6 |
| National Fuel Gas Co. | BBB+/Stable/A-2 | 7 |
| Nevada Power Co. | B+/Positive/-- | 6 |
| New York State Electric & Gas Corp. | BBB+/Negative/A-2 | 3 |
| NiSource | BBB/Stable/-- | 4 |
| Northern Indiana Public Service Co. | BBB/Stable/-- | 5 |
| Northern States Power Co. | BBB/Stable/A-2 | 5 |
| Northern States Power Wisconsin | BBB+/Stable/-- | 4 |
| Ohio Edison Co. | BBB/Stable/A-2 | 6 |
| Oklahoma Gas & Electric Co. | BBB+/Stable/A-2 | 5 |
| Pacific Gas & Electric Co. | BBB/Stable/A-2 | 5 |
| PacifiCorp | A-/Stable/A-1 | 5 |
| Pennsylvania Power Co. | BBB/Stable/-- | 6 |
| Pinnacle West Capital Corp. | BBB-/Stable/A-3 | 6 |
| PNM Resources Inc. | BBB/Negative/A-3 | 6 |
| Portland General Electric Co. | BBB+/Negative/A-2 | 5 |
| Progress Energy Carolinas Inc. | BBB/PositiveA-2 | 5 |
| Progress Energy Florida Inc. | BBB/Positive/A-2 | 4 |
| PSI Energy Inc. | BBB/Positive/A-2 | 4 |
| Public Service Co. of Colorado | BBB/Stable/A-2 | 4 |
| Public Service Co. of New Hampshire | BBB/Stable/-- | 5 |
| Public Service Co. of New Mexico | BBB/Negative/A-3 | 6 |
| Public Service Co. of Oklahoma | BBB/Stable/-- | 5 |
| Puget Energy Inc. | BBB-/Stable/-- | 4 |
| Puget Sound Energy Inc. | BBB-/Stable/A-3 | 4 |
| Questar Market Resources Inc. | BBB+/Stable/--- | 8 |
| Rochester Gas & Electric Corp. | BBB+/Negative/-- | 3 |
| San Diego Gas & Electric Co. | A/Stable/A-1 | 5 |
| Savannah Electric & Power Co. | A/Stable/-- | 4 |
| SCANA Corp. | A-/Stable/-- | 4 |
| Sierra Pacific Power Co. | B+/Positive/-- | 6 |
| Sierra Pacific Resources | B+/Positive/B-2 | 6 |
| South Carolina Electric & Gas Co. | A-/Stable/A-2 | 4 |
| Southern California Edison Co. | BBB+/Stable/A-2 | 6 |
| Southern Co. | A/Stable/A-1 | 4 |
| Southern Indiana Gas & Electric Co. | A-/Stable/-- | 4 |
| Southwestern Electric Power Co. | BBB/Stable/-- | 5 |
| Southwestern Public Service Co. | BBB/Stable/A-2 | 5 |
| System Energy Resources Inc. | BBB-/Negative/-- | 7 |
| Tampa Electric Co. | BBB-/Stable/A-3 | 4 |
| Toledo Edison Co. | BBB/Stable/-- | 6 |
| Tucson Electric Power Co. | BB/Stable/B-2 | 6 |
| TXU U.S. Holdings Co. | BBB-/Negative/-- | 8 |
| Union Electric Co. | BBB+/CW-Neg/A-2 | 5 |
| Union Light Heat & Power Co. | BBB/Positive/-- | 5 |
| Vectren Utility Holdings Inc. | A-/Stable/A-2 | 3 |
| Virginia Electric & Power Co. | BBB/Stable/A-2 | 5 |

| | | |
|---|---|---|
| Westar Energy Inc. | BB+/Positive/-- | 5 |
| Wisconsin Electric Power Co. | A-/Negative/A-2 | 4 |
| Wisconsin Energy Corp. | BBB+/Negative/A-2 | 5 |
| Wisconsin Power & Light Co. | A-/Stable/A-2 | 4 |
| Wisconsin Public Service Corp. | A+/CW-Neg/A-1 | 4 |
| Xcel Energy Inc. | BBB/Stable/A-2 | 5 |

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**YEC-YECL-41**

**Reference: Cost of Debt**

**Requests:**

(a) Please provide the basis for the 200 basis point spread over the 4.55 forecast long-term Canada Bond yield used to estimate the cost of debt in the test years.

(b) Please provide the actual spread over long-term Canada bond yields for each actual debt issuance from 2000 through 2007.

(c) Please explain why the effective cost rates (per Schedule 8.3) for the forecast 2008 and 2009 debt issuances are substantially higher than the effective cost rates for the 2004 through 2006 debt issuances.

(d) Please provide a copy of Schedule 8.3 assuming:

i. The spread over the long-term Canada bond yield for debt issuances in 2008 and 2009 is the average spread for the actual debt issuances from 2002 through 2006.

ii. The long-term Canada bond yield for 2008 used is the actual average yield for the first six months of 2008.

**Response:**

(a) The 200 basis point spread is based on:

(i) Yukon Electrical's affiliated company, ATCO Gas, filed a 2008-2009 GRA using a 200 basis point spread. In that proceeding, ATCO Gas in response to IR, UCA-AG-67(b) Supplemental (filed March 12, 2008) stated:

*"(b) At the time of preparation of the rate application, it was the general consensus of our financial advisors that the financial markets were very volatile due to the sub prime credit crisis and that credit spreads were anticipated to go much higher than current levels being seen in the market at that time. While the ultimate impact of the sub prime crisis could not be known with certainty, the consensus of the financial advisors was that it would be significant and in the range of 200 basis points. The impact of the sub prime crisis continues to have a significant impact on the markets today and is expected to have a significant impact going forward. It is a common belief in the financial community that the impact on credit spreads has not yet peaked. The increase in credit spreads is evident in the response to CAL-AG 24(a) where the average historical spread for CU Inc.'s 30 year bonds was approximately 90 basis points as seen in June, 2007, and has jumped to approximately 130 basis points towards the end of 2007. Further, as of March 10, 2008 CU Inc.'s 30 year debenture spread is 154 basis points over long Canada bonds. This confirms the trend of increasing spreads and higher volatility that the financial advisors were predicting and because of the opinion that the crisis is not yet over, it is reasonable to assume a 200 basis point spread over the average long Canada bond rate for ATCO Gas' forecasted debenture rates."*

(ii) As well, it is important to note that the CU Inc. 30 year spread continues to increase. This is evidenced by the July 21, 2008 RBC Capital markets

publication which indicates the 30 year CU Inc. spread is now 165 basis points.

(b) The actual spreads over long Canada bond yield for each actual debt issuance from 2000 to 2007 were based on the then existing market conditions and are as follows:

| Series | Issue Date | Company Rate | Long Canada Bond Yield | Spread |
|---|---|---|---|---|
| L | 06-02-2000 | 7.00 | 5.71 | 1.29 |
| N | 11-22-2002 | 6.16 | 5.67 | 0.49 |
| O | 01-23-2004 | 5.42 | 5.11 | 0.30 |
| P | 11-18-2004 | 5.11 | 5.11 | -- |
| Q | 11-21-2005 | 5.18 | 4.38 | 0.80 |
| R | 22-10-2006 | 5.02 | 4.26 | 0.76 |

(c) The effective cost rate in the test period is driven by the forecast for long Canada bond yield of 4.55 and a 200 basis point spread for corporate bonds. The increase in this rate compared to the rate for 2004-2006 issues is primarily due to the increase in the spread that is now required as outlined in (a) above.

(d) (i) The average spread as per (b) above for the period 2002-2006 is 0.47 . As such, the debt issues using this spread would be 5.07 comprising 4.55 long term Canada Bond Yield, a 0.47 spread and 0.05 issue costs. Please refer to YEC-YECL-41(d) Attachment 1 which uses the 5.07 debt rate for 2008 and 2009.

(ii) The average yield for the six months to June 2008 was 4.1 . Given a 200 basis point spread and 0.05 issue costs, Schedule 8.3 attached (YEC-YECL-41(d) Attachment 2) has used a 6.15 debt rate for the 2008 and 2009 issues.

**Yukon Electrical Limited**
**2008 - 2009 General Rate Application**
**Schedule of Debt Capital Employed and Embedded Cost**
**Updated for new rates for test period**

**( 000's)**

| Line No. | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **2008 Test Period** | | | | | | **Net Capital Employed** | | | | | |
| 2 | | | | | | Principal | | Per 100 of | | Principal | | Average |
| 3 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | Outstanding | Carrying | Embedded |
| 4 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | **31-Dec-08** | **Cost** | **Cost Rate** |
| 5 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 6 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 7 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 8 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 9 | | L | 06-02-2000 | 7.00 | 2008 | 0 | 0 | | 7.05 | 0 | 0 | |
| 10 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 11 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 12 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 13 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 14 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 15 | | T | 11-20-2008 | 6.10 | 2038 | 2,150 | 2,150 | 100.00 | 6.15 | 2,150 | 132 | |
| 16 | Total | | | | | 25,350 | | | | 25,350 | 1,763 | 6.96 |
| 17 | Prior Year | | | | | | | | | 23,800 | 1,673 | 7.03 |
| 18 | Total | | | | | | | | | 49,150 | 3,436 | |
| 19 | Mid Year | | | | | | | | | 24,575 | 1,718 | 6.99 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20 | **2009 Test Period** | | | | | | **Net Capital Employed** | | | | | |
| 21 | | | | | | Principal | | Per 100 of | | Principal | | Average |
| 22 | | | Issue | Coupon | Maturity | Amount | Total | Principal | Effective | Outstanding | Carrying | Embedded |
| 23 | **Description** | **Series** | **Date** | **Rate** | **Date** | **Offered** | **Amount** | **Amount** | **Cost Rate** | **31-Dec-09** | **Cost** | **Cost Rate** |
| 24 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 25 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 26 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 27 | | L | 06-02-2000 | 7.00 | 2008 | 0 | 0 | | 7.05 | 0 | 0 | |
| 28 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 29 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 30 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 31 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 32 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 33 | | T | 11-20-2008 | 6.10 | 2038 | 2,150 | 2,150 | 100.00 | 6.15 | 2,150 | 132 | |
| 34 | | U | 11-20-2009 | 6.10 | 2039 | 5,200 | 5,200 | 100.00 | 6.15 | 5,200 | 320 | |
| 35 | Total | | | | | 28,550 | | | | 28,550 | 1,876 | 6.57 |
| 36 | Prior Year | | | | | | | | | 25,350 | 1,763 | 6.96 |
| 37 | Total | | | | | | | | | 53,900 | 3,640 | |
| 38 | Mid Year | | | | | | | | | 26,950 | 1,820 | 6.75 |

**Schedule 8.3**

**Yukon Electrical Limited**
**2008 - 2009 General Rate Application**
**Schedule of Debt Capital Employed and Embedded Cost**
**Updated for new rates for test period**

**( 000's)**

| Line No. | 2008 Test Period | | | | | | Net Capital Employed | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Description | Series | Issue Date | Coupon Rate | Maturity Date | Principal Amount Offered | Total Amount | Per 100 of Principal Amount | Effective Cost Rate | Principal Outstanding 31-Dec-08 | Carrying Cost | Average Embedded Cost Rate |
| 1 | | C | 11-30-1989 | 10.28 | 2009 | 2,000 | 2,000 | 100.00 | 10.33 | 2,000 | 207 | |
| 2 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 3 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 4 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 5 | | L | 06-02-2000 | 7.00 | 2008 | 0 | 0 | | 7.05 | 0 | 0 | |
| 6 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 7 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 8 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 9 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 10 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 11 | | T | 11-20-2008 | 5.02 | 2038 | 2,150 | 2,150 | 100.00 | 5.07 | 2,150 | 109 | |
| 12 | Total | | | | | 25,350 | | | | 25,350 | 1,740 | 6.86 |
| 13 | Prior Year | | | | | | | | | 23,800 | 1,673 | 7.03 |
| 14 | Total | | | | | | | | | 49,150 | 3,413 | |
| 15 | Mid Year | | | | | | | | | 24,575 | 1,706 | 6.94 |

| Line No. | 2009 Test Period | | | | | | Net Capital Employed | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Description | Series | Issue Date | Coupon Rate | Maturity Date | Principal Amount Offered | Total Amount | Per 100 of Principal Amount | Effective Cost Rate | Principal Outstanding 31-Dec-09 | Carrying Cost | Average Embedded Cost Rate |
| 16 | | D | 11-28-1990 | 11.85 | 2020 | 1,500 | 1,500 | 100.00 | 11.91 | 1,500 | 179 | |
| 17 | | E | 05-08-1992 | 9.46 | 2023 | 2,500 | 2,500 | 100.00 | 9.51 | 2,500 | 238 | |
| 18 | | K | 08-13-1999 | 6.80 | 2019 | 4,500 | 4,500 | 100.00 | 6.85 | 4,500 | 308 | |
| 19 | | L | 06-02-2000 | 7.00 | 2008 | 0 | 0 | | 7.05 | 0 | 0 | |
| 20 | | N | 11-22-2002 | 6.16 | 2017 | 3,900 | 3,900 | 100.00 | 6.21 | 3,900 | 242 | |
| 21 | | O | 01-23-2004 | 5.42 | 2019 | 1,000 | 1,000 | 100.00 | 5.47 | 1,000 | 55 | |
| 22 | | P | 11-18-2004 | 5.11 | 2014 | 500 | 500 | 100.00 | 5.16 | 500 | 26 | |
| 23 | | Q | 11-21-2005 | 5.18 | 2035 | 4,300 | 4,300 | 100.00 | 5.23 | 4,300 | 225 | |
| 24 | | R | 11-20-2006 | 5.02 | 2036 | 3,000 | 3,000 | 100.00 | 5.07 | 3,000 | 152 | |
| 25 | | T | 11-20-2008 | 5.02 | 2038 | 2,150 | 2,150 | 100.00 | 5.07 | 2,150 | 109 | |
| 26 | | U | 11-20-2009 | 5.02 | 2039 | 5,200 | 5,200 | 100.00 | 5.07 | 5,200 | 264 | |
| 27 | Total | | | | | 28,550 | | | | 28,550 | 1,797 | 6.29 |
| 28 | Prior Year | | | | | | | | | 25,350 | 1,740 | 6.86 |
| 29 | Total | | | | | | | | | 53,900 | 3,537 | |
| 30 | Mid Year | | | | | | | | | 26,950 | 1,768 | 6.56 |

**Schedule 8.3**

**YEC-YECL-42**

**Reference:** Accounting Policy

**Requests:**

(a) Describe any changes in YECL's accounting policies since the time of YECL's last General Rate Application and indicate the impact of each change on the revenue requirement.

**Response:**

(a) Please refer to CW-YECL-5 below:

In accordance with Board Order 2008-5, information dating prior to 2003 was not required to test the revenue requirement. However, given that changes occurring since 1997 impact the test period, to the extent the changes are still applicable, the requested information is as follows:

Changes in Accounting Practice:

2000 Effective January 1, 2000 the Corporation prospectively adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for employee future benefits. This accounting change had the effect of decreasing earnings by 35,000.

2001 Effective January 1, 2001, the Corporation retroactively adopted the Canadian Institute of Chartered Accountants recommendations to disclose its unrecorded future income taxes. Under these recommendations, income taxes are accounted for using the liability method where by future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted tax rates and substantively enacted tax rates.

Previously, the Corporation determined its unrecorded future income taxes using the normalized deferred method.

2004 Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. The impairment loss may be deferred by the Corporation if there is reasonable assurance that the loss will be included in future rate to customers. The adoption of this recommendation had no effect on earnings for the year ended December 31, 2004.

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for asset retirement obligations. The CICA recommendations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. An asset retirement obligation is recorded as a liability, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

The Corporation has determined that it has tangible long lived assets where there is a legal liability regarding asset retirement. For these tangible long lived assets, asset retirement obligations have not been recorded as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time.

2005 Effective January 1, 2005, the Corporation prospectively adopted the CICA guideline pertaining to the consolidation of variable interest entities. The guideline requires the Corporation to identify variable interest entities in which it has an interest, determine whether it is the primary beneficiary of such entities and, if so, to consolidate them. This change had no effect on the financial statements.

Effective January 1, 2005, the Corporation prospectively adopted the CICA guideline pertaining to lease arrangements. The guideline requires the Corporation to identify arrangements that do not take the legal form of a lease but convey a right to use a tangible asset in return for a payment or series of payments and, if so, to account for them as leases. This change had no effect on the financial statements.

2006 Effective January 1, 2006, the Corporation retroactively adopted the CICA Emergency Issues Abstract regarding conditional asset retirement obligations. This Abstract requires an entity to record a liability for an asset retirement obligation even if the obligation is conditional upon the occurrence of a future event that may or may not be within the control of the entity. This change had no effect on the financial statements.

2007 Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity and other financial liabilities are measured at their carrying value. This change in accounting had no effect on the financial statements for the year ended December 31, 2007.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and

effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the financial statements for the year ended December 31, 2007.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owners, and includes earnings of the Corporation, unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the financial statements.

Changes in Regulatory Practices:

The following components were added to working capital, Schedule as compared to the same calculation in the 1996-1997 GRA.

- Return - Long Term Debt
- Return - 50 of Common Equity
- Net Depreciation

These changes are appropriate and are consistent with the calculation approved by the Alberta Utilities Commission for ATCO Electric.

As stated on Page 8-2 of the Application, other post employment benefits are now accounted for on the cash basis.

**YEC-YECL-43**

**Reference:** Pre-Tax Interest Coverage

**Requests:**

(a) Provide YECL's pre-tax interest coverage for the past five years and the projections for 2008 and 2009 based upon the application.

**Response:**

(a) Please refer to YEC-YECL-43 Attachment 1.

**Yukon Electrical Company Limited**
**Pre-Tax Interest Coverage**

**2003**

| | Mid Yr Balance | Ratio | Cost | Before Tax | |
|---|---|---|---|---|---|
| Long Term Debt | 19,600 | 55.88 | 7.51 | 4.20 | (a) |
| Common Stock Equity | 15,032 | 42.86 | 11.02 | 4.72 | (b) |
| No Cost Capital | 443 | 1.26 | 0.00 | 0.00 | |
| | 35,075 | 100.00 | | 8.92 | (c) |
| Interest Coverage Ratio | | | | 2.12 | (a) (c) |
| Fixed Charge Coverage Ratio | | | | 2.12 | (a) (c) |

**2004**

| | Mid Yr Balance | Ratio | Cost | Before Tax | |
|---|---|---|---|---|---|
| Long Term Debt | 20,100 | 56.23 | 7.37 | 4.15 | (a) |
| Common Stock Equity | 15,253 | 42.67 | 10.81 | 4.61 | (b) |
| No Cost Capital | 392 | 1.10 | 0.00 | 0.00 | |
| | 35,745 | 100.00 | | 8.76 | (c) |
| Interest Coverage Ratio | | | | 2.11 | (a) (c) |
| Fixed Charge Coverage Ratio | | | | 2.11 | (a) (c) |

**2005**

| | Mid Yr Balance | Ratio | Cost | Before Tax | |
|---|---|---|---|---|---|
| Long Term Debt | 21,000 | 56.28 | 7.54 | 4.25 | (a) |
| Common Stock Equity | 15,905 | 42.63 | 8.99 | 3.83 | (b) |
| No Cost Capital | 406 | 1.09 | 0.00 | 0.00 | |
| | 37,311 | 100.00 | | 8.08 | (c) |
| Interest Coverage Ratio | | | | 1.90 | (a) (c) |
| Fixed Charge Coverage Ratio | | | | 1.90 | (a) (c) |

**2006**

| | Mid Yr Balance | Ratio | Cost | Before Tax | |
|---|---|---|---|---|---|
| Long Term Debt | 22,475 | 57.18 | 7.14 | 4.09 | (a) |
| Common Stock Equity | 16,280 | 41.42 | 10.66 | 4.42 | (b) |
| No Cost Capital | 549 | 1.40 | 0.00 | 0.00 | |
| | 39,304 | 100.00 | | 8.50 | (c) |
| Interest Coverage Ratio | | | | 2.08 | (a) (c) |
| Fixed Charge Coverage Ratio | | | | 2.08 | (a) (c) |

**2007**

| | Mid Yr Balance | Ratio | Cost | Before Tax | |
|---|---|---|---|---|---|
| Long Term Debt | 23,800 | 57.60 | 7.03 | 4.05 | (a) |
| Common Stock Equity | 16,890 | 40.87 | 10.37 | 4.24 | (b) |
| No Cost Capital | 632 | 1.53 | 0.00 | 0.00 | |
| | 41,322 | 100.00 | | 8.29 | (c) |
| Interest Coverage Ratio | | | | 2.05 | (a) (c) |
| Fixed Charge Coverage Ratio | | | | 2.05 | (a) (c) |

**2008**

| | Mid Yr Balance | Ratio | Cost | Before Tax | |
|---|---|---|---|---|---|
| Long Term Debt | 24,575 | 54.23 | 7.01 | 3.80 | (a) |
| Common Stock Equity | 20,071 | 44.29 | 9.25 | 4.10 | (b) |
| No Cost Capital | 669 | 1.48 | 0.00 | 0.00 | |
| | 45,315 | 100.00 | | 7.90 | (c) |
| Interest Coverage Ratio | | | | 2.08 | (a) (c) |
| Fixed Charge Coverage Ratio | | | | 2.08 | (a) (c) |

| | 2009 | | | | |
|---|---|---|---|---|---|
| | Mid Yr Balance | Ratio | Cost | Before Tax | |
| Long Term Debt | 26,950 | 51.81 | 6.83 | 3.54 | (a) |
| Common Stock Equity | 24,376 | 46.86 | 9.25 | 4.33 | (b) |
| No Cost Capital | 695 | 1.34 | 0.00 | 0.00 | |
| | 52,021 | 100.00 | | 7.87 | (c) |
| Interest Coverage Ratio | | | | 2.22 | (a) (c) |
| Fixed Charge Coverage Ratio | | | | 2.22 | (a) (c) |

## YEC-YECL-44

**Reference:** Fixed Charges

**Requests:**

(a) Provide YECL's fixed charge coverage ratios for the past five years and the projections for 2008 and 2009 based upon the application.

**Response:**

(a) Please refer to YEC-YECL-43 Attachment 1.

## YEC-YECL-45

**Reference:** Rate Case

**Requests:**

(a) Provide a detailed breakdown by major component of the forecast regulatory hearing costs for 2008 and 2009 (page 8-5).

(b) What was the difference between the forecast and actual hearing costs for the 1996 1997 GRA? Explain the variances.

(c) As part of the 1996 1997 GRA, did YECL have a rate case reserve as a component of rate base and revenue requirement?

(d) If yes, please provide a continuity schedule of what has been expensed and what has been incurred for each of the years 1996 through to what is forecast for 2008 and 2009. For greater clarity please update the Regulatory Cost component of 1996 1997 GRA CITY-YEC YECL-1-19.

(e) For each of the years 1996 through to December 31, 2007, please provide a detailed schedule that shows regulatory expenses incurred that exceed the allowed rate and the net expense charged against the deferred regulatory account.

(f) Please confirm your accounting of regulatory disbursements is consistent with the proposal detailed in 1996 1997 GRA UCG-YEC YECl-1-7. If not, please explain why.

(g) Please provide copies of all correspondence with the Board with respect to regulatory costs between 1996 and December 31, 2007.

(h) Please explain and justify the treatment of any deferred credits taken into income since 1996 from the rate case reserve by YEC, e.g. see Schedule 8.8 for 2008.

**Response:**

(a) The table below outlines the forecast.

| | | |
|---|---|---|
| **Yukon Utilities Board:** | Hearing costs | 250,000 |
| **Yukon Electrical:** | | |
| Internal | GRA prep and hearing costs | 30,000 |
| AEL | Phase 2 | 105,000 |
| External - Gannet Flemming | Depreciation consultant | 60,000 |
| External - Foster & Ass. | Cost of Capital consultant | 105,000 |
| Bennett Jones | | 130,000 |
| **Intervenors:** | | |
| YEC | | 30,000 |
| Utilities Consumers Group | | 10,000 |
| City of Whitehorse | | 20,000 |
| Yukon Conservation Society | | 5,000 |
| Leading Edge | | 5,000 |
| **TOTAL** | | 750,000 |

(b) This proceeding was a joint proceeding.

| | |
|---|---|
| The forecast costs for this joint proceeding were | 600,000 |
| The actual costs for this proceeding were: | 533,000 |
| Reduction from forecast: | 67,000 |

The main reason for these joint costs being lower than forecast is a result of the 1996 97 proceeding being a negotiated settlement.

(c) At the time of the 1996 97 proceeding Yukon Electrical did have a rate case reserve. In 2005, however, this treatment changed to be consistent with the treatment followed by YEC and supported in Board Order 2005-17. In this application Yukon Electrical, is seeking to re-establish the reserve account treatment for its rate case costs as outlined on page 8-5 of the Application.

(d) In accordance with Board Order 2008-5, information prior to 2005 is not required to test the revenue requirement. Given that the rate case costs were not being treated as a reserve account through to the test period, as outlined in (c) above, a continuity schedule prior to 2005 is not required to test the revenue requirement in the test period. Please refer to Schedule 8.8 of the Application for the continuity schedule from 2005.

(e) In accordance with Board Order 2008-5, information prior to 2005 is not required to test the revenue requirement. Given that the rate case costs was not a reserve account in 2005 (see (c) above), there was not a balance in this account at 2005. As such, information prior to 2005 does not impact the revenue requirement in the test period and is not being provided.

(f) As outlined in (c) above, Yukon Electrical's treatment of these costs is consistent with Yukon Energy's approved treatment followed in its 2005 GRA.

(g) In accordance with Board Order 2008-5, information prior to 2005 is not required to test the revenue requirement. Given that the rate case costs was not a reserve account in 2005 (refer to (c) above) there was not a balance in this account at 2005. As such, information prior to 2005 does not impact the revenue requirement in the test period and is not being provided. There has been no correspondence with the Board with respect to regulatory costs subsequent to 2005.

(h) To be consistent with the treatment followed by YEC in its 2005 06 GRA and supported by Board Order 2005-17, Yukon Electrical adjusted its treatment of rate case costs in 2005 such that it was no longer accorded deferral account treatment for the period 1998-2007.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



## YEC-YECL-46

**Reference:** General Plant and Equipment

**Requests:**

(a) Provide details of items for which capital expenditures were made planned for 2006-2009 under the category of general property and equipment (e.g., list in detail the anticipated purchases of Office Computer Equipment).

(b) Provide policies and procedures followed for approval of capital expenditures.

**Response:**

(a) Please refer to Schedule 9 for a break down of costs in GP&E. To be helpful, Tools, instruments & equipment relates to the aforementioned for service and line staff and technicians as well as safety equipment. Office furniture and equipment is as the title describes. Office Computer equipment relates to small specialized pieces of software or hardware that are not provided by ATCO I-Tek. Communications equipment mainly relates to a Northwestel telephone protection upgrade. Transportation equipment mainly relates to line and service vehicles, a digger and a forklift. Land and buildings mainly relates to small upgrades at company houses, heating and fuel storage work at the downtown Whitehorse office as well as Service Complex and a new bunkhouse in Old Crow.

(b) Capital expenditures are provided for in the annual capital forecast which is prepared by the Yukon Electrical management team and ultimately approved by the Company's Board.

Yukon Electrical has a comprehensive capitalization policy that it adheres to based on the requirements that pertain to the company as determined from time to time. Although the document is of significant size to be helpful attached is an excerpt from the policy. Please refer to YEC-YECL-46(b) Attachment 1.

| ATCO ELECTRIC LIMITED ACCOUNTING POLICY MANUAL | *Planning and Control of Capital Commitments and Expenditures* | |
|---|---|---|
| | **Date:** 06-01-27 | **Number:** D.1.a.1 |
| **PREPARED BY:** D.R. MacIver | **APPROVED BY:** | Dennis DeChamplain |
| | **UPDATED:** | January 27, 2006 |

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## APPENDIX

CEAR Form
Levels of Authorization

| ATCO ELECTRIC LIMITED ACCOUNTING POLICY MANUAL | *Planning and Control of Capital Commitments and Expenditures* |
|---|---|
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| | **UPDATED:** January 27, 2006 |

## A. – POLICY

### A.1 – Objectives of the Capital Expenditure Program

Through the planning and control of capital expenditure programs, management exercises a basic and important function, the allocation of the Company's managerial and financial resources.

Accordingly, the Company has established a uniform policy for the planning and control of capital expenditures to ensure major capital expenditure programs receive objective corporate evaluation within the framework of the Company's long-range goals.

### A.2 – Scope

The term "capital expenditure" will be used in this document to refer both to the cash outlays on capital items of a appropriation or plan plus any future "capital commitments" of expenditures implied by the approval of a given appropriation or plan. The object is to avoid piecemeal approvals of capital projects and ensure that all capital expenditures resulting from an appropriation or plan are considered when the appropriation is initially approved. For the purposes of this policy, capital expenditures are defined as in policy D.1.a:

*An expenditure is capital in nature if it involves: constructing or purchasing a new asset or upgrading, rehabilitating or replacing an existing asset.*

*a. Constructing or purchasing a new asset*
- *i. Outright purchase of fixed assets, such as land, a building, a vehicle, machinery, standby equipment, office furniture, etc.*
- *ii. The entire cost of constructing new additions to physical assets such as transmission lines, distribution facilities, substations, etc.*
- *iii. All start up and commissioning costs*

*b. Upgrade existing assets*
- *i. An enlargement of existing structures or facilities*
- *ii. To increase the capacity of an existing asset*
- *iii. A substantial improvement in the facility affecting quality of output or reduces operating costs*

*c. Rehabilitate existing assets*
- *i. As a general guideline, to determine if a cost falls into this category, one must consider if the expenditures were planned to be incurred at the time of purchasing the asset.*

1. *If these expenditures were planned at time of purchase to occur in the future, they will be expensed to O&M when they are incurred.*
2. *When extraordinary, material unplanned items are incurred in the future, they will be considered capital*

ii. *To insure achievement of life of an asset*
iii. *To extend the life of an asset beyond its normal service life*

d. *Replace existing assets*
   i. *The substitution of new for existing facilities that are worn out, irreparably damaged, or have been become inadequate in service.*
   ii. *The substitution having substantially no greater capacity than the facility for which it is substituted.*

### A.3 – Administrative Responsibility

The Vice President & Controller is responsible for the development of this policy.

The President is responsible for assuring the implementation of procedures that will fully support both this policy and the general principles of sound planning, analysis and control of the Company's capital expenditures programs.

## B - PROCEDURES

### B.1 – Annual Capital Expenditure Business Plan

Annually, at dates to be established by the Vice President & Controller, each department shall submit an Annual Business Plan incorporating a Capital Expenditures forecast updating its current year capital expenditure requirements and detailing new capital commitments for the next three ensuing years. As a minimum, detail should include, for each carry over and new appropriation (including blanket appropriations), appropriation title, timing of expenditures and supporting business cases.

The first year of the business plan will only include those appropriations that have a high probability of proceeding. The projected expenditures for each appropriation shall be the most probable expected amount. It is recognized that future years of a business plan, because of the time period involved, may include more speculative appropriations.

Capital Expenditures incorporated in the business plan will ultimately require approval by the Board of Directors. It must be emphasized that this approval does not constitute authorization to expend funds on any appropriation. This authorization can be secured only through the proper approval of a Capital Expenditure Appropriation Request (CEAR) as outlined in section E.2.d. Authorization to expend funds must be obtained prior to the commencement of any appropriation. This does not preclude the necessary internal allocation of funds to outline and define proposed appropriations. CEAR authorization may be deferred in cases where it is necessary to purchase specialized equipment such as transformers and breakers to meet an in-service date. Written guarantees must be in place with the customer **whose credit quality has been approved by the Chief Financial Officer.** Also, regulatory approvals in progress may result in the delay of the formal application of the CEAR.

## B.2 – Approval of Capital Expenditures

### B.2.a - Delegation of Approval Authority

Authority to approve the expenditure of funds for capital commitment proposals as outlined in Appendix 2, ATCO Electric Capital Expenditure Authorities. Appropriations that extend beyond one year only require approval for the total appropriation in the year expenditures begin unless overruns occur in excess of the defined limits.

### B.2.b - Approval Amount

The approval amount for a specific capital expenditure proposal shall represent gross-capital expenditures required for the proposal, and shall not have netted against it any prepaid expenses, grants or incentives, disposals, trade-ins, financing plans, customer advances or salvage value.

### B.2.c - Submission of Capital Commitment Proposals

All capital commitment proposals and overrun requests shall be submitted for approval in Capital Expenditure Appropriation Request (CEAR) format.

### B.2.d - Evaluation of Capital Commitment Proposals

The evaluation of any capital commitment proposal will be based upon a thorough consideration of its technical and business integrity, its economic and intangible benefits, risk characteristics, and its relationship to the strategic plans of the departments and to the long-range objectives of the Company.

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## B.3 - Appropriation Development Costs

Project development costs incurred prior to the actual commencement of an appropriation will form part of the CEAR approved amount if the project proceeds. If it is decided a project does not proceed, a determination will be made as to whether the costs are written off to O&M or may be capitalized as part of ES&G. Costs are eligible to be included in ES&G if the study findings are applicable to future capital appropriations.

All development costs are segregated in projects in an unapproved appropriation. Financial Reporting will review this appropriation periodically and take the actions noted in the above paragraph once it has been determined if an individual project will proceed.

## B.4 – Capital Expenditure Reporting

A Capital Expenditure Status Report (CESR) on all planned appropriations and all appropriations approved since the Business Plan will be prepared on a monthly basis. For information on report contents and layout refer to section D.

## B.5 – CEAR Post Completion Review

Upon completion of an appropriation (which is generally considered the in-service date/energization date or the end of the calendar year for a blanket CEAR), a Post Completion Review (PCR) shall be prepared within three months. This applies to all CEARs (except cancelled CEARs with no expeditures). The objective of this analysis is to determine the reason for deviations in appropriation expenditures. This will enable the Company to justify any overspending or underspending, improve cost planning and learn from any problems that may have arisen.

It is company policy that no expenditures are incurred without prior management approval. However, it is recognized that in some circumstances, expenditures on an approved appropriation may exceed the approved amount before a revised CEAR can be obtained. In such a situation a PCR will be prepared explaining the reasons for the overrun and the fact that prior approval could not be obtained.

If the appropriation incurred a cost overrun and a revised CEAR was prepared, the analysis would involved comparing actuals against the revised CEAR. Any variance between the original CEAR and the revised CEAR should have been explained on the revised CEAR.

The post completion analysis shall be reviewed and approved by the Originator of the CEAR, generally the Vice President of the department responsible for the CEAR and the President. A copy of this analysis will be made available as required to Internal Audit as part of the ongoing audit of capital expenditures and the original filed with the CEAR in the permanent records found in the Controllers Department.

## C - DEFINITIONS

### C.1 - Approval Amount

The approval amount for a specific capital expenditure proposal determines the ultimate organization level of approval required for authorization to commit funds. The approval amount is in general, the gross amount of anticipated expenditure requirements. Cost of retirement excluding salvage, are to be included in the CEAR amounts. The salvage value can be reflected in a separate line on the CEAR form.

Specific exceptions to this general rule are as follows:

### C.1.a - Leases

For appropriations which propose the lease of land, buildings, equipment and any other capital asset, the approval amount shall be determined as follows:

#### C.1.a.1 - Type A Leases

If assets proposed for lease can also be acquired by purchase, and/or are normally available for purchase, then the approval amount shall include the actual or estimated purchase price; and

#### C.1.a.2 - Type B Lease

If the assets cannot be, or normally are not, acquired by purchase, the approval amount shall include the total of all lease payments for such assets over the life of the appropriation.

Prior regulatory approval is required for all capitalized leases.

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| | **UPDATED:** January 27, 2006 |

## C.1.b - Disposals

### C.1.b.1 - Cost of Retirement

Dismantling, selling or other related disposal expenses.

### C.1.b.2 - Salvage Value

Sales or salvage proceeds. Cost of retirement as outlined in C.1.b.1 is not factored in salvage value.

### C.1.b.3 - Disposal Without Replacement

For appropriations which the sole purpose is to dispose of, or retire a capital asset without replacement, a Disposition CEAR is required. The approval amount of the CEAR will be the greater of the net book value (NBV) of the asset being disposed or the salvage value. Any cost of retirement will be included in the CEAR value. The amount of the salvage value can be identified on the CEAR in the salvage area.

Example (disposal without replacement) A transformer is no longer needed for operations and is to be sold. It has a net book value of $350,000, but can be sold for $300,000. Estimated cost of retirement is $75,000. The amount of the CEAR will be the net book value, which is greater than the salvage value, plus the cost of retirement.

| | |
|---|---|
| Greater of NBV or Salvage Value | $350,000 |
| Cost of Retirement | $ 75,000 |
| CEAR Approved Amount | $425,000 |
| Grants and Contributions | 0 |
| Salvage Value | ($300,000) |
| Net Cost to Company | $125,000 |

### C.1.b.4 - Disposal With Replacement

For appropriations that involve the replacement of a capital asset which will then be disposed or retired, the approval amount of the CEAR will include the replacement asset and the cost of retirement. The amount of the salvage value of the asset can be identified on the CEAR in the salvage area.

Example (disposal with replacement) The same transformer (example above) is to be replaced by a larger one costing $900,000. Installation expenses for the new transformer are $125,000. Estimated cost of retirement for the old transformer are $75,000. The appropriation approval amount is then:

| | |
|---|---|
| New Transformer Purchase Price | $900,000 |
| Related Expenses: Installation | $125,000 |
| Cost of Retirement | $75,000 |
| CEAR Approved Amount | $1,100,000 |
| Grants and Contributions | 0 |
| Salvage Value | ($300,000) |
| Net Cost to Company | $800,000 |

## C.2 - Blanket CEAR

In certain circumstances expenditures of the same category may be combined and approved as one appropriation. Examples include distribution systems, transmission line improvements and general property expenditures where individually the amounts are relatively small but collectively are significant. A blanket CEAR shall not include individual projects in excess of $500,000.

Blanket CEARs expire at the end of the calendar year for which the CEAR was approved. Projects not commenced shall be included on the CEAR for the next calendar year. Should a blanket CEAR for a year be insufficient to complete all projects already commenced, a revised CEAR must be submitted for that year in accordance with section C.8.

## C.3 - Capital Assets

Capital assets are defined to include land, building, poles, towers, conductors, machinery and equipment, furniture and fixtures, automotive equipment, tooling, software development, etc. In general, a capital asset is any unit of property which can be physically identified and normally expected to have a useful life in excess of one year. The value of a capital asset shall include any non-recurring, related appropriation costs that are normally capitalized.

### C.4 - Capital Commitment

The aggregate of capital expenditures required to fulfill a given capital expenditure proposal, regardless of the timing of actual expenditures, constitutes the amount of capital commitment. Because this amount is also the approval amount, it represents the level of commitment of capital that is implied by the approval of a given proposal, or a group of proposals. The capital commitment represented by the Business Plan is, therefore, the total capital expenditure requirements of all proposals included in that plan, including allowance for funds used during construction.

### C.5 - Cancelled Appropriation

For cancelled appropriations where a CEAR has been raised and there are expenditures, the variance to approved amount will be explained in a PCR. The costs of a cancelled appropriation will not be capitalized unless the cost can be clearly shown to provide a benefit to another capital appropriation.

For cancelled appropriations where a CEAR has been raised and there are no expenditures, the only actions required are to indicate CANCELLED on the CEAR, distribute to the appropriation signatories and file it in the permanent records.

### C.6 - Expired CEAR

Authority to spend money expires on a Capital Appropriation that has not commenced by the end of the calendar year for which commencement was approved.

Where the Capital Appropriation has commenced, the authority to spend money continues until the appropriation is completed. When the completion of the appropriation is delayed beyond one year this shall be reflected in the next operating plan. No additional approval is required.

### C.7 - Original CEAR

The first approved CEAR for an appropriation. Where an appropriation runs over several years and there are cost revisions the amount of the original CEAR will be disclosed on any subsequent CEARs.

### C.8 - Overrun/Underruns

Overruns are the amount by which the final indicated costs of the facilities authorized to be acquired by capital expenditures, and required to completely satisfy the original, undiminished intent of the appropriation, exceed the level of capital expenditures currently authorized. By this definition, appropriations that cannot be completed within their authorized capital expenditure limits without a curtailment or alteration of their originally stated intent are said to be in overrun status. Where projected expenditures are expected to exceed 10% of the approved amount of a CEAR, a Revised CEAR must be raised immediately and before any over expenditure can occur.

There is no action required for cost underruns. The reflection on these facts will be reported in the Capital Expenditure Status Report (CESR) and the PCR and is sufficient notification to management.

### C.9 - Emergency CEAR

In the event of an extreme situation requiring immediate action to be carried out in the best interests of the Company, the President or his designate is authorized to approve the necessary expenditure. This is then followed as soon as possible with a regular CEAR.

### C10 - Appropriation

A basic principle of the policies for planning and control of capital expenditures is that proposals shall be developed, reviewed and controlled on an appropriation basis. An appropriation shall be a complete, self-contained program intended to accomplish a specific objective. Its completion or effectiveness shall not depend upon, or require, the approval of any other appropriations, or any additional expenditure for items other than those included in the appropriation. Too narrow an appropriation scope may foster "piece meal" planning and disguise the true financial impact of a total program.

The scope of an appropriation, however, shall not be so broad that it represents a consolidation of multiple capital expenditure actions that could be taken independently. Certain expenditures of the same category can be combined and approved as one appropriation (i.e. Blanket CEAR).

### C.11 - Planned Appropriation

A capital expenditure proposal which was specifically included in, and approved as part of, the Business Plan Expenditures.

| ATCO ELECTRIC LIMITED ACCOUNTING POLICY MANUAL | *Planning and Control of Capital Commitments and Expenditures* |
|---|---|
| | **Date:** 06-01-27 **Number:** D.1.a.1 |
| **PREPARED BY:** D.R. MacIver | **APPROVED BY:** Dennis DeChamplain |
| | **UPDATED:** January 27, 2006 |

## D - CAPITAL EXPENDITURE REPORTING

The CESR summarizes by function (e.g.: Transmission, Distribution etc.) the capital expenditures included in the most recent Business Plan and compares forecasted expenditures for the period with actual costs incurred.

Commitments, which can be incurred prior to the actual expenditures, should not be included in actuals.

### D.1 - Total CEAR Program

Total CEAR Program is the sum of the capital expenditures by function.

### D.2 - Purchases of Property, Plant and Equipment

The term Purchases of Property, Plant and Equipment is used to describe the Total CEAR Program less depreciation capitalized.

### D.3 - CEAR Requirement Approved by Board of Directors

The CEAR Requirement Approved by Board of Directors is the Purchases of Property, Plant and Equipment plus depreciation capitalized and expenditures approved for future years less expenditures approved in prior years.

### D.4 - Appropriation Final Forecast

Appropriation Final Forecast is comprised of total expenditures over the life of the appropriation including prior year's expenditures, current year forecasted expenditures and forecasted costs to complete the appropriation in future years.

### D.5 - Total Approved CEAR

Total approved CEAR expenditures for the appropriation

### D.6 - Total Appropriation Over/Under CEAR

This indicates the difference between the Appropriation Final Forecast and Total Approved CEAR.

| ATCO ELECTRIC LIMITED ACCOUNTING POLICY MANUAL | *Planning and Control of Capital Commitments and Expenditures* |
|---|---|
| | **Date:** 06-01-27 **Number:** D.1.a.1 |
| **PREPARED BY:** D.R. MacIver | **APPROVED BY:** Dennis DeChamplain |
| | **UPDATED:** January 27, 2006 |

# E - CAPITAL EXPENDITURE APPROPRIATION REQUEST (CEAR)

## E.1 - Authorization

The granting of authority to commit funds for capital appropriations is the second part of a two-step process. The first is the approval in principle of the Annual Business Plan that includes the capital program.

Subsequent to business plan approval all appropriations require authorization prior to commitment of funds. This is achieved with the approval of a "Capital Expenditure Appropriation Request" (CEAR). For an example of a CEAR see Appendix 1.

If overruns above approved amounts exceed allowable tolerance levels, a Revised CEAR would also have to be authorized. A chart outlining the levels of authorization is shown in Appendix 2, ATCO Electric Capital Expenditure Authorities .

## E.2 - CEAR Completion Guide

To assist in the completion of the CEAR, the following sections are explained below.

### E.2.a – Appropriation Start Up

The date when the first contract is signed or when funds are expended other than internal funds used to prepare and define the appropriation.

### E.2.b - Description of Proposal

This section shall include a brief summary of the proposed appropriation and the rationale for it. The description of the appropriation shall include any other significant factors such as customer contributions, service contracts, etc. which will assist management in their approval decision. Reference should be made to any site visits that have been conducted and the findings from those visits. Further information may be necessary and this shall be attached to the CEAR form. An example of further information required would be a listing of major items included in a "blanket" CEAR or an analysis of total appropriation costs. Explanations for any increases over planned amounts and previously approved CEAR's shall be set out in this section.

If the appropriation extends over a period greater than one year this section should also contain details of projected expenditures by year, for the CEAR, original CEAR (if applicable), current Business Plan and most recently submitted GTA.

### E.2.c - Appropriation Investment

The appropriation investment is the amount that the appropriation should cost following reasonable assumptions as to pricing, construction time, etc. This should be the amount that is included in the Business Plan for planned appropriations. If not, any deviations from the planned amount shall be explained.

### E.2.d - Approvals

A single owner will be assigned to each CEAR. The CEAR owner is responsible for reviewing the CEAR on an ongoing basis and obtaining CEAR approval.

Prior to a CEAR being approved at the department level, it shall be sent to Regulation and Business Plans who will ensure that it has been correctly completed. Regulation and Business Plans will then arrange for any required Company and ATCO approvals. Refer to Appendix 2, ATCO Electric Capital Expenditure Authorities. When fully approved, Regulation and Business Plans will retain the original copy and copies will be sent to those on the distribution list.

Where signatures of approval are not required or when Board of Director approval is not required, the appropriate box shall be completed with the words “Not Required”.

| ATCO ELECTRIC LIMITED ACCOUNTING POLICY MANUAL | *Planning and Control of Capital Commitments and Expenditures* |
|---|---|
| | **Date:** 06-01-27 **Number:** D.1.a.1 |
| **PREPARED BY:** D.R. MacIver | **APPROVED BY:** Dennis DeChamplain |
| | **UPDATED:** January 27, 2006 |

## Appendix 1, Capital Expenditure Authorization Request (CEAR) form

ATCO Electric

### CAPITAL EXPENDITURE APPROPRIATION REQUEST

Page __ of __

| COMPANY **ATCO Electric** | APPRN. NO. | DATE SUBMITTED |
|---|---|---|
| APPRN. TITLE | APPRN START UP Date of Commitment and/or Expenditure of Funds | |

| Is this Apprn. included in the current Business Plan? ☐ Yes ☐ No | For this CEAR will current year expenditures exceed the BP? ☐ Yes ☐ No | For this CEAR will total expenditures (i.e. sum of all years) exceed the BP total expenditures? ☐ Yes ☐ No | Original CEAR ☐ Revised CEAR ☐ |
|---|---|---|---|

1. DESCRIPTION OF PROPOSAL (Include a brief summary of appropriations, including breakdown of major items, together with rationale for expenditures and projected expenditures analyzed by year. Attach additional sheet if necessary.)

1. This appropriation is required to .....
2. For additional information see the attached .....
3. The in service date is.....
4. A site visit.....

| APPRN. Cash Flow: | This Request | Original Request | 2006 Business Plan | 2005/2006 GTA |
|---|---|---|---|---|
| 2006 Total | | | | |

| 2. APPROPRIATION INVESTMENT | | 3. APPROVAL | | |
|---|---|---|---|---|
| | AMOUNT $000 | RECOMMENDED FOR APPROVAL | SIGNATURE | DATE |
| ORIGINAL APPROVED CEAR AMOUNT (Complete only if original CEAR approved in prior year) | | CHECKED BY ATCO Electric CONTROLLERS | ▶ | |
| TOTAL APPRN. CURRENT BUSINESS PLAN | | ORIGINATOR(S) ▶<br>▶<br>VICE PRESIDENT ▶ | | |
| PRIOR CEAR REQUEST (If original CEAR leave blank) | | PRESIDENT | ▶ | |
| CHANGE FROM PRIOR REQUEST (If original request include total amount) | | MANAGING DIRECTOR | ▶ | |
| TOTAL APPRN. APPROVAL AMOUNT | | CFO ▶<br>CU PRESIDENT & CEO ▶ | | |
| LESS GRANTS AND CONTRIBUTIONS | | ATCO Electric BOARD OF DIRECTORS | ▶ | |
| LESS SALVAGE | | CU BOARD OF DIRECTORS | ▶ | |
| NET COST TO COMPANY | | ATCO BOARD OF DIRECTORS | ▶ | |

| ATCO ELECTRIC LIMITED ACCOUNTING POLICY MANUAL | *Planning and Control of Capital Commitments and Expenditures* |
|---|---|
| | **Date:** 06-01-27 **Number:** D.1.a.1 |
| **PREPARED BY:** D.R. MacIver | **APPROVED BY:** Dennis DeChamplain |
| | **UPDATED:** January 27, 2006 |

**Appendix 2,**

**ATCO Electric Capital Expenditure Authorities**

| Approval Level (Sequential) | Capital Expenditures in Business Plan | Capital Expenditures not in Business Plan | Acquisitions and Disposal of Businesses | Disposals of Capital Assets | Increase to Approved Expenditure |
|---|---|---|---|---|---|
| President | Up to $5M | Up to $3M | 0 | Up to $0.5M | Up to $3M |
| Managing Director | $5M - $10M | $3M - $5M | 0 | $0.5M - $1M | $3M - $5M |
| CFO & CEO | $10M - $20M | $5M - $10M | Up to $5M | $1M - $5M | $5M - $10M |
| Utilities Board | $20M - $30M | $10M - $30M | $5M - $20M | $5M - $20M | Over $10M treat as new capital expenditures |
| CU Board | Over $30M | Over $30M | Over $20M | Over $20M | |
| ATCO Board | Over $50M | Over $50M | Over $50M | Over $50M | |

## YEC-YECL-47

**Reference:** Reliability

**Requests:**

(a) Identify which capital projects are improving reliability and provide an explanation for how they improve reliability.

(b) Describe (for each project in a that is improving reliability) the reliability criteria used and how it would be violated if the project were not undertaken.

**Response:**

(a) All capital work that is either replacing like for like, upgrading or adding to the system will inherently improve reliability, since it will be newer equipment and built to an improved standard. Certain projects have been justified primarily on reliability, while others have been justified by other drivers like safety. Yukon Electrical conducted a review of its forecast improvement projects for 2008 and 2009 and determined that all projects improved reliability in some way or another. The explanations provided in Yukon Electrical's Application, Section 9, provide information on why a project is to be undertaken and outlines reliability benefits on a project by project basis.

(b) The reliably criteria for the projects referred to in (a) above can be found in Section 9 of Yukon Electrical's GRA. Yukon Electrical has developed its system improvement forecast identifying projects that are necessary to maintain the safety and reliability of the power system. The power system cannot be run to failure but rather must be maintained and upgraded on a timely basis. Yukon Electrical uses its professional expertise, the experience of qualified trades people, industry standards and data it gathers regarding its facilities and operations to determine which projects must be undertaken to benefit customers and fulfill Yukon Electrical's obligation to serve. If these projects are not undertaken, Yukon Electrical believes that safety and reliability will be impacted negatively. The response to YEC-YECL-23 has numerous other factors taken into consideration when preparing System Improvement plans.

## YEC-YECL-48

**Reference:** Deferred Costs

**Requests:**

(a) Please provide a continuity schedule for each category of deferred cost for YECL for the years 1996 to 2009 showing additions and amortizations.

**Response:**

(a) In accordance with Board order 2008-5 information dating back to 1996 is not required to test the revenue requirement in the test period.

Please refer to YEC-YECL-48 Attachment 1 for a continuity schedule going back to 2003.

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Continuity Schedule of Deferred Charges Credits**
**( 000s)**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 |
|---|---|---|---|---|---|---|---|
| 1 | **Total Deferred Charges Credits Summary** | | | | | | |
| 2 | | | | | | | |
| 3 | **Write-off Summary** | | | | | | |
| 4 | Rate Case Costs | | (75) | (75) | 428 | - | - |
| 5 | Diesel Plant Major Overhaul Costs | | - | - | - | - | (108) |
| 6 | Fish Lake License Renewal Costs | | - | - | - | - | (79) |
| 7 | **Total Write-off** | S.1.1 L.14 | (75) | (75) | 428 | - | (187) |
| 8 | | | | | | | |
| 9 | **Deferred Credits Mid-Year Balance Summary** | | | | | | |
| 10 | Rate Case Reserve | | (316) | (391) | (214) | - | 15 |
| 11 | Diesel Plant Major Overhaul Costs | | - | - | - | - | 215 |
| 12 | Fish Lake Licence Reserve | | - | - | - | | 79 |
| 13 | **Total Deferred Credits Mid-Year Balance** | S.8.5 L.12 | (316) | (391) | (214) | - | 309 |
| 14 | | | | | | | |
| 15 | Rate Case Costs | | | | | | |
| 16 | Balance at beginning of year | | (278) | (353) | (428) | - | - |
| 17 | Add: Rate Case Costs | | | | | - | 30 |
| 18 | Less: Rate Case Write-off | | (75) | (75) | 428 | - | - |
| 19 | Balance at end of year | | (353) | (428) | - | - | 30 |
| 20 | | | | | | | |
| 21 | Mid-Year balance | (L.16 L.19) 2 | (316) | (391) | (214) | - | 15 |
| 22 | | | | | | | |
| 23 | Diesel Plant Major Overhaul Costs | | | | | | |
| 24 | Balance at beginning of year | | - | - | - | - | - |
| 25 | Add: Watson Lake plant overhaul costs | | - | - | - | - | 538 |
| 26 | Less; Watson Lake plant overhaul Write-off | | - | - | - | - | (108) |
| 27 | Balance at end of year | | - | - | - | - | 430 |
| 28 | | | | | | | |
| 29 | Mid-Year balance | (L.24 L.27) 2 | - | - | - | - | 215 |
| 30 | | | | | | | |
| 31 | | | | | | | |
| 32 | Fish Lake License Renewal Costs | | | | | | |
| 33 | Balance at beginning of year | | - | - | - | - | - |
| 34 | Add: Fish Lake Costs | | - | - | - | - | 237 |
| 35 | Less: Fish Lake Write-off | | - | - | - | - | (79) |
| 36 | Balance at end of year | | - | - | - | - | 158 |
| 37 | | | | | | | |
| 38 | Mid-Year balance | (L.33 L.36) 2 | - | - | - | - | 79 |
| 39 | | | | | | | |

**YEC-YECL-49**

**Reference:** RFID

**Requests:**

(a) Please provide a continuity schedule for the account for 1996-2009 with an explanation of all claims made against the account including why they qualify as a charge against the account.

(b) Provide a schedule showing the historical losses and damages incurred since 1996 that would support any charges for replenishing RFID reserves in 2008 and 2009.

**Response:**

(a&b) Please see YEC-YECL-49(a) Attachment 1.

# The Yukon Electrical Company Limited
# Reserve for Injuries and Damages
# Continuity Schedule 1996 to 2007

| | 000's | 000's |
|---|---|---|
| **January 1, 1996 Beginning Balance** | | **(30)** |
| 1996 Write-off | | **(75)** |
| Old Crow engine failure | **12** | |
| **1996 Costs** | | **12** |
| **December 31, 1996 Ending Balance** | | **(93)** |
| | | |
| **January 1, 1997 Beginning Balance** | | **(93)** |
| 1997 Write-off | | **(75)** |
| Unit 432 1995 Arctic Cat credit | **(6)** | |
| **1997 Costs** | | **(6)** |
| **December 31, 1997 Ending Balance** | | **(174)** |
| | | |
| **January 1, 1998 Beginning Balance** | | **(174)** |
| 1998 Write-off | | **(75)** |
| Selkirk First Nation--Power Outage Damage | **20** | |
| **1998 Costs** | | **20** |
| **December 31, 1998 Ending Balance** | | **(229)** |
| | | |
| **January 1, 1999 Beginning Balance** | | **(229)** |
| 1999 Write-off | | **(75)** |
| J00124 Burwash fire damages June 1999 | **68** | |
| J00132 Halloween wind storm | **89** | |
| J00133 Haines Jct Halloween wind storm | **66** | |
| J00127 Pelly Diesel Unit 3 failure September 1999 | **32** | |
| **1999 Costs** | | **255** |
| **December 31, 1999 Ending Balance** | | **(49)** |
| | | |
| **January 1, 2000 Beginning Balance** | | **(49)** |
| 2000 Write-off | | **(75)** |
| **2000 Costs** | | **0** |
| **December 31, 2000 Ending Balance** | | **(124)** |
| | | |
| **January 1, 2001 Beginning Balance** | | **(124)** |
| 2001 Write-off | | **(75)** |
| Pelly Crossing Unit 2 failure | **79** | |
| Destruction Bay Unit 1 failure | **26** | |
| **2001 Costs** | | **105** |
| **December 31, 2001 Ending Balance** | | **(94)** |
| | | |
| **January 1, 2002 Beginning Balance** | | **(94)** |
| 2002 Write-off | | **(75)** |
| Beaver Creek Unit 2 March 2002 engine failure | **29** | |
| **2002 Costs** | | **29** |
| **December 31, 2002 Ending Balance** | | **(140)** |

# The Yukon Electrical Company Limited
# Reserve for Injuries and Damages
# Continuity Schedule 1996 to 2007

| | 000's | 000's |
|---|---|---|
| **January 1, 2003 Beginning Balance** | | **(140)** |
| 2003 Write-off | | **(75)** |
| Watson Lake pole damage June 11, 2003 | **7** | |
| Watson Lake Unit 6 March 21, 2003--bearing seizure | **52** | |
| Service Complex flood May 19, 2003--water tank failure | **25** | |
| D. Bay Unit 2 September 2003--generator bearing failure | **29** | |
| **2003 Costs** | | **113** |
| **December 31, 2003 Ending Balance** | | **(102)** |
| | | |
| **January 1, 2004 Beginning Balance** | | **(102)** |
| 2004 Write-off | | **(75)** |
| Pelly Unit 3 Jun 15, 2004--turbo failure(internal explosion)--valve | **28** | |
| Pelly Unit 2 Sept. 30, 2004--cracked cylinder block | **82** | |
| wind storm damages September 2004 | **45** | |
| wind storm damages October 2004 | **95** | |
| rain snow ice storm damages November 2004 | **85** | |
| **2004 Costs** | | **335** |
| **December 31, 2004 Ending Balance** | | **158** |
| | | |
| **January 1, 2005 Beginning Balance** | | **158** |
| 2005 Write-off | | **(75)** |
| Pelly Unit 2 Sept. 30, 2004--cracked cylinder block(core credit) | **(5)** | |
| **2005 Costs** | | **(5)** |
| **December 31, 2005 Ending Balance** | | **78** |
| | | |
| **January 1, 2006 Beginning Balance** | | **78** |
| 2006 Write-off | | **(75)** |
| Watson Lake Unit 5 Dec 05--unit failure | **26** | |
| Watson Lake Units 1 & 6--2006 premature cylinder failure | **25** | |
| **2006 Costs** | | **51** |
| **December 31, 2006 Ending Balance** | | **54** |
| | | |
| **January 1, 2007 Beginning Balance** | | **54** |
| 2007 Write-off | | **(75)** |
| Watson Lake Unit 4 Aug 07--unit failure | **22** | |
| Pelly Unit 3 Aug 07--unit failure | **51** | |
| **2007 Costs** | | **73** |
| **December 31, 2007 Ending Balance** | | **52** |

**YEC-YECL-50**

**Reference:** YECL Income Tax Computation

**Requests:**

(a) Please provide a detailed Income Tax computation for 1997 to 2009 including a reconciliation of earnings to taxable income in the format of T2S (1).

(b) Please provide a continuity schedule of capital cost allowance in similar format to T2S (8).

**Response:**

(a) In accordance with Board Order 2008-05 information prior to 2003 is not required to test the revenue requirement. As such Yukon Electrical will not be providing information prior to 2003. For the 2003-2009 information please refer to YEC-YECL-50(a) Attachment 1.

(b) In accordance with Board Order 2008-05 information prior to 2003 is not required to test the revenue requirement. However given that Undepreciated Capital Cost impacts the revenue requirement in the test period Yukon Electrical has provided the information requested (please refer to YEC-YECL-50(b) Attachment 1).

Schedule 10.1

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Income Tax Expense**
**( 000s)**

| Line No. | Description | Cross Ref. | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test Period 2008 | Test Period 2009 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Utility earnings before tax | | 3,040 | 2,918 | 2,795 | 2,845 | 2,703 | 2,298 | 3,260 |
| 2 | **Add:** | | | | | | | | |
| 3 | Depreciation | S.1.1 L.12 | 3,355 | 3,481 | 3,727 | 3,901 | 4,171 | 4,365 | 4,837 |
| 4 | Amortization of contributions | S.1.1 L.13 | (847) | (901) | (962) | (1,008) | (1,092) | (963) | (1,028) |
| 5 | Non-allowable expenses | | 14 | 20 | 18 | 18 | 18 | 18 | 18 |
| 6 | Plant Maintenance write-off | S.8.8 L.26 | | | | - | 108 | 123 | 123 |
| 7 | Rate case write-off (Note 1) | S.8.8 L.18 | 75 | 75 | - | - | - | 375 | 375 |
| 8 | Injuries & Damages write-off | S.8.4 L27 | 75 | 75 | 75 | 75 | 75 | 86 | 86 |
| 9 | Fish Lake Water License write-off | S.8.8 L.35 | - | - | - | - | 79 | 154 | 154 |
| 10 | Charges to deferred pension & OPEB | S.8.4 L.13 L.20 | 113 | 155 | 126 | 132 | 623 | 639 | 689 |
| 11 | Sub-total | | 2,785 | 2,905 | 2,984 | 3,118 | 3,982 | 4,797 | 5,253 |
| 12 | | | | | | | | | |
| 13 | **Deduct:** | | | | | | | | |
| 14 | CCA | | 1,801 | 1,933 | 2,056 | 2,259 | 2,518 | 3,528 | 3,960 |
| 15 | Plant Maintenance Reserve Charges | S.8.8 L.25 | - | - | - | - | 538 | 60 | - |
| 16 | Rate Case Expenditure | S.8.8 L.17 | - | - | - | - | 30 | 720 | - |
| 17 | Injuries & Damages Costs | S.8.4 L28 | 113 | 335 | (5) | 51 | 73 | 60 | 60 |
| 18 | Fish Lake Water License Costs | S.8.8 L.34 | - | - | - | - | 237 | 150 | - |
| 19 | Pension & OPEB payments | S.8.4 L.14 L.21 | 37 | 35 | 38 | 39 | 576 | 639 | 689 |
| 20 | Inventory Pool Costs Capitalized | | | | | - | - | 358 | 376 |
| 21 | Cumulative Eligible Captial | | 16 | 16 | 12 | 12 | 11 | 10 | 9 |
| | Donated Land | | 18 | - | - | | | | |
| 22 | ES&G | | 217 | 311 | 306 | 348 | 334 | 350 | 350 |
| 23 | Sub-total | | 2,202 | 2,630 | 2,407 | 2,709 | 4,317 | 5,875 | 5,444 |
| 24 | | | | | | | | | |
| 25 | Taxable income | | 3,623 | 3,193 | 3,372 | 3,254 | 2,368 | 1,220 | 3,070 |
| 26 | Tax rate | | 38.00 | 36.00 | 36.00 | 36.00 | 36.00 | 34.50 | 34.00 |
| 27 | Income tax | | 1,377 | 1,149 | 1,214 | 1,171 | 852 | 421 | 1,044 |
| 28 | Surtax | | 41 | 36 | 38 | 36 | 27 | - | - |
| 29 | Prior & current years' book to filing (over) under provision | | (60) | 55 | 76 | (174) | (24) | - | - |
| 30 | Total current provision | S.1.1 L.16 | 1,357 | 1,240 | 1,328 | 1,034 | 855 | 421 | 1,044 |
| 31 | | | | | | | | | |

# YUKON ELECTRICAL COMPANY LIMITED
# ACTUAL CAPITAL COST ALLOWANCE
# CONTINIUTY SCHEDULE

| | Class 1<br>4 | Class 2<br>6 | Class 3<br>5 | Class 17<br>8 | Class 8<br>20 | Class 9<br>25 | Class 10<br>30 | Class 12<br>100 | Class 45<br>45 | Class 47<br>8 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **1996** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 1996** | 19,099,373 | 7,254,458 | 376,631 | 0 | 304,479 | 183 | 568,711 | | | | 27,603,835 |
| **Capital Additions** | 2,896,484 | 0 | 0 | 0 | 126,643 | 0 | 325,942 | | | | 3,349,069 |
| **Undepreciated Capital Cost Before 1997 Claim** | 21,995,857 | 7,254,458 | 376,631 | 0 | 431,122 | 183 | 894,653 | | | | 30,952,904 |
| Less: 1996 Claim: On Balance Forward | 763,755 | 435,267 | 18,832 | 0 | 60,896 | 46 | 170,613 | | | | 1,449,409 |
| On Net Additions | 58,037 | 0 | 0 | 0 | 12,664 | 0 | 48,891 | | | | 119,592 |
| **Total 1996 Capital Cost Allowance Claim** | 821,792 | 435,267 | 18,832 | 0 | 73,560 | 46 | 219,504 | | | | 1,569,001 |
| **Undepreciated Capital Cost December 31, 1997** | 21,174,065 | 6,819,191 | 357,799 | 0 | 357,562 | 137 | 675,149 | | | | 29,383,903 |
| **1997** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 1996** | 21,174,065 | 6,819,191 | 357,799 | 0 | 357,562 | 137 | 675,149 | | | | 29,383,903 |
| **Capital Additions** | 1,924,618 | 0 | 0 | 0 | 79,912 | 0 | 219,516 | | | | 2,224,046 |
| **Undepreciated Capital Cost Before 1997 Claim** | 23,098,683 | 6,819,191 | 357,799 | 0 | 437,474 | 137 | 894,665 | | | | 31,607,949 |
| Less: 1997 Claim: On Balance Forward | 846,179 | 409,151 | 17,890 | 0 | 71,512 | 34 | 202,545 | | | | 1,547,311 |
| On Net Additions | 38,225 | 0 | 0 | 0 | 7,991 | 0 | 32,927 | | | | 79,143 |
| **Total 1997 Capital Cost Allowance Claim** | 884,404 | 409,151 | 17,890 | 0 | 79,503 | 34 | 235,472 | | | | 1,626,454 |
| **Undepreciated Capital Cost December 31, 1997** | 22,214,279 | 6,410,040 | 339,909 | 0 | 357,971 | 103 | 659,193 | | | | 29,981,495 |
| **1998** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 1997** | 22,214,279 | 6,410,040 | 339,909 | 0 | 289,194 | 103 | 665,327 | | | | 29,918,852 |
| **Capital Additions** | 3,506,344 | 0 | (63,606) | 0 | 93,340 | 0 | (123,050) | | | | 3,413,028 |
| **Undepreciated Capital Cost Before 1998 Claim** | 25,720,623 | 6,410,040 | 276,303 | 0 | 382,534 | 103 | 542,277 | | | | 33,331,880 |
| Less: 1998 Claim: On Balance Forward | 888,571 | 384,602 | 13,815 | 0 | 57,839 | 26 | 199,598 | | | | 1,544,451 |
| On Net Additions | 70,127 | 0 | 0 | 0 | 9,334 | 0 | (18,457) | | | | 61,004 |
| **Total 1998 Capital Cost Allowance Claim** | 958,698 | 384,602 | 13,815 | 0 | 67,173 | 26 | 181,141 | | | | 1,605,455 |
| **Undepreciated Capital Cost December 31, 1998** | 24,761,925 | 6,025,438 | 262,488 | 0 | 315,361 | 77 | 361,136 | | | | 31,726,425 |
| **1999** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 1998** | 24,761,925 | 6,025,438 | 262,488 | 0 | 315,361 | 77 | 361,136 | | | | 31,726,425 |
| **Capital Additions** | 2,559,612 | 0 | (90,213) | 0 | 307,773 | 0 | 166,444 | | | | 2,943,616 |
| **Undepreciated Capital Cost Before 1999 Claim** | 27,321,537 | 6,025,438 | 172,275 | 0 | 623,134 | 77 | 527,580 | | | | 34,670,041 |
| Less: 1999 Claim: On Balance Forward | 990,477 | 361,526 | 8,614 | 0 | 63,072 | 19 | 101,768 | | | | 1,525,476 |
| On Net Additions | 56,182 | 0 | 0 | 0 | 30,777 | 0 | 28,253 | | | | 115,212 |
| **Total 1999 Capital Cost Allowance Claim** | 1,046,659 | 361,526 | 8,614 | 0 | 93,849 | 19 | 130,021 | | | | 1,640,688 |
| **Undepreciated Capital Cost December 31, 1999** | 26,274,878 | 5,663,912 | 163,661 | 0 | 529,285 | 58 | 397,559 | | | | 33,029,353 |
| **2000** | | | | | | | | | | | |

# YUKON ELECTRICAL COMPANY LIMITED
# ACTUAL CAPITAL COST ALLOWANCE
# CONTINIUTY SCHEDULE

| | Class 1<br>4 | Class 2<br>6 | Class 3<br>5 | Class 17<br>8 | Class 8<br>20 | Class 9<br>25 | Class 10<br>30 | Class 12<br>100 | Class 45<br>45 | Class 47<br>8 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Undepreciated Capital Cost December 31, 1999** | 26,274,878 | 5,663,912 | 163,661 | 0 | 529,285 | 58 | 397,559 | | | | 33,029,353 |
| **Capital Additions** | 2,303,723 | 0 | (101,106) | 0 | 73,978 | 0 | 14,161 | | | | 2,290,756 |
| **Undepreciated Capital Cost Before 2000 Claim** | 28,578,601 | 5,663,912 | 62,555 | 0 | 603,263 | 58 | 411,720 | | | | 35,320,109 |
| Less: 2000 Claim: On Balance Forward | 1,048,689 | 339,835 | 3,128 | 0 | 105,857 | 15 | 119,268 | | | | 1,616,792 |
| On Net Additions | 48,381 | 0 | 0 | 0 | 7,398 | 0 | 2,124 | | | | 57,903 |
| **Total 2000 Capital Cost Allowance Claim** | 1,097,070 | 339,835 | 3,128 | 0 | 113,255 | 15 | 121,392 | | | | 1,674,695 |
| **Undepreciated Capital Cost December 31, 2000** | 27,481,531 | 5,324,077 | 59,427 | 0 | 490,008 | 43 | 290,328 | | | | 33,645,414 |
| **2001** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 2000** | 27,481,531 | 5,324,077 | 59,427 | 0 | 490,008 | 43 | 290,328 | | | | 33,645,414 |
| **Capital Additions** | 3,182,845 | 0 | 0 | 0 | 29,936 | 0 | 344,295 | | | | 3,557,076 |
| **Undepreciated Capital Cost Before 2001 Claim** | 30,664,376 | 5,324,077 | 59,427 | 0 | 519,944 | 43 | 634,623 | | | | 37,202,490 |
| Less: 2001 Claim: On Balance Forward | 1,099,290 | 319,445 | 2,971 | 0 | 98,002 | 11 | 87,098 | | | | 1,606,817 |
| On Net Additions | 63,628 | 0 | 0 | 0 | 2,994 | 0 | 51,644 | | | | 118,266 |
| **Total 2001 Capital Cost Allowance Claim** | 1,162,918 | 319,445 | 2,971 | 0 | 100,996 | 11 | 138,742 | | | | 1,725,083 |
| **Undepreciated Capital Cost December 31, 2001** | 29,501,458 | 5,004,632 | 56,456 | 0 | 418,948 | 32 | 495,881 | | | | 35,477,407 |
| **2002** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 2001** | 29,501,458 | 5,004,632 | 56,456 | 0 | 418,949 | 32 | 495,880 | | | | 35,477,407 |
| **Capital Additions** | 2,048,870 | 0 | 0 | 48,667 | 103,663 | 0 | 174,804 | | | | 2,376,004 |
| **Undepreciated Capital Cost Before 2002 Claim** | 31,550,328 | 5,004,632 | 56,456 | 48,667 | 522,612 | 32 | 670,684 | | | | 37,853,411 |
| Less: 2002 Claim: On Balance Forward | 1,180,212 | 300,278 | 2,823 | 0 | 83,790 | 8 | 148,764 | | | | 1,715,875 |
| On Net Additions | 40,824 | 0 | 0 | 1,947 | 10,366 | 0 | 26,221 | | | | 79,358 |
| **Total 2002 Capital Cost Allowance Claim** | 1,221,036 | 300,278 | 2,823 | 1,947 | 94,156 | 8 | 174,985 | | | | 1,795,233 |
| **Undepreciated Capital Cost December 31, 2002** | 30,329,292 | 4,704,354 | 53,633 | 46,720 | 428,456 | 24 | 495,699 | | | | 36,058,178 |
| **2003** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 2002** | 30,329,292 | 4,704,354 | 53,633 | 46,720 | 428,456 | 24 | 495,699 | | | | 36,058,178 |
| **Capital Additions** | 1,990,680 | 0 | 0 | 414,282 | 26,090 | 0 | 36,701 | | | | 2,467,753 |
| **Undepreciated Capital Cost Before 2003 Claim** | 32,319,972 | 4,704,354 | 53,633 | 461,002 | 454,546 | 24 | 532,400 | | | | 38,525,931 |
| Less: 2003 Claim: On Balance Forward | 1,213,172 | 282,261 | 2,682 | 3,738 | 85,691 | 6 | 148,710 | | | | 1,736,260 |
| On Net Additions | 39,814 | 0 | 0 | 16,571 | 2,609 | 0 | 5,505 | | | | 64,499 |
| **Total 2003 Capital Cost Allowance Claim** | 1,252,986 | 282,261 | 2,682 | 20,309 | 88,300 | 6 | 154,215 | | | | 1,800,759 |
| **Undepreciated Capital Cost December 31, 2003** | 31,066,986 | 4,422,093 | 50,951 | 440,693 | 366,246 | 18 | 378,185 | | | | 36,725,172 |
| **2004** | | | | | | | | | | | |

# YUKON ELECTRICAL COMPANY LIMITED
# ACTUAL CAPITAL COST ALLOWANCE
# CONTINIUTY SCHEDULE

| | Class 1<br>4 | Class 2<br>6 | Class 3<br>5 | Class 17<br>8 | Class 8<br>20 | Class 9<br>25 | Class 10<br>30 | Class 12<br>100 | Class 45<br>45 | Class 47<br>8 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Undepreciated Capital Cost December 31, 2003** | 31,066,987 | 4,422,093 | 50,951 | 440,693 | 366,246 | 18 | 378,185 | 0 | | | 36,725,173 |
| **Capital Additions** | 2,347,913 | 0 | 0 | 939,189 | 110,099 | 0 | 1,622 | 235,498 | | | 3,634,320 |
| **Undepreciated Capital Cost Before 2004 Claim** | 33,414,900 | 4,422,093 | 50,951 | 1,379,882 | 476,345 | 18 | 379,807 | 235,498 | | | 40,359,493 |
| Less: 2004 Claim: On Balance Forward | 1,242,679 | 265,326 | 2,548 | 35,255 | 73,249 | 5 | 113,456 | 0 | | | 1,732,518 |
| On Net Additions | 46,958 | 0 | 0 | 37,568 | 11,010 | 0 | 243 | 117,749 | | | 213,528 |
| **Total 2004 Capital Cost Allowance Claim** | 1,289,637 | 265,326 | 2,548 | 72,823 | 84,259 | 5 | 113,699 | 117,749 | | | 1,946,046 |
| **Undepreciated Capital Cost December 31, 2004** | 32,125,263 | 4,156,767 | 48,403 | 1,307,059 | 392,086 | 13 | 266,108 | 117,749 | | | 38,413,447 |
| **2005** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 2004** | 32,125,262 | 4,156,767 | 48,403 | 1,307,059 | 392,086 | 13 | 266,108 | 117,749 | 0 | 0 | 38,413,447 |
| **Capital Additions** | (251,315) | 0 | 0 | 937,081 | 76,372 | 0 | 159,789 | 0 | 5,116 | 3,578,925 | 4,505,968 |
| **Undepreciated Capital Cost Before 2005 Claim** | 31,873,947 | 4,156,767 | 48,403 | 2,244,140 | 468,458 | 13 | 425,897 | 117,749 | 5,116 | 3,578,925 | 42,919,415 |
| Less: 2005 Claim: On Balance Forward | 1,285,010 | 249,406 | 2,420 | 104,565 | 78,417 | 3 | 79,832 | 117,749 | 0 | 0 | 1,917,402 |
| On Net Additions | (10,053) | 0 | 0 | 37,483 | 7,637 | 0 | 23,968 | 0 | 1,151 | 143,157 | 203,343 |
| **Total 2005 Capital Cost Allowance Claim** | 1,274,957 | 249,406 | 2,420 | 142,048 | 86,054 | 3 | 103,800 | 117,749 | 1,151 | 143,157 | 2,120,745 |
| **Undepreciated Capital Cost December 31, 2005** | 30,598,990 | 3,907,361 | 45,983 | 2,102,092 | 382,404 | 10 | 322,097 | 0 | 3,965 | 3,435,768 | 40,798,670 |
| **2006** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 2005** | 30,598,989 | 3,907,361 | 45,983 | 2,102,092 | 382,404 | 10 | 322,095 | 0 | 3,965 | 3,435,768 | 40,798,667 |
| **Capital Additions** | 0 | 0 | 0 | 419,898 | 103,252 | 0 | 94,928 | 0 | 2,796 | 3,447,706 | 4,068,580 |
| **Undepreciated Capital Cost Before 2006 Claim** | 30,598,989 | 3,907,361 | 45,983 | 2,521,990 | 485,656 | 10 | 417,023 | 0 | 6,761 | 6,883,474 | 44,867,247 |
| Less: 2006 Claim: On Balance Forward | 1,223,960 | 234,442 | 2,299 | 168,167 | 76,481 | 3 | 96,629 | 0 | 1,784 | 274,861 | 2,078,626 |
| On Net Additions | 0 | 0 | 0 | 16,796 | 10,325 | 0 | 14,239 | 0 | 629 | 137,908 | 179,897 |
| **Total 2006 Capital Cost Allowance Claim** | 1,223,960 | 234,442 | 2,299 | 184,963 | 86,806 | 3 | 110,868 | 0 | 2,413 | 412,769 | 2,258,523 |
| **Undepreciated Capital Cost December 31, 2006** | 29,375,029 | 3,672,919 | 43,684 | 2,337,027 | 398,850 | 7 | 306,155 | 0 | 4,348 | 6,470,705 | 42,608,724 |
| **2007** | | | | | | | | | | | |
| **Undepreciated Capital Cost December 31, 2006** | 29,375,029 | 3,672,919 | 43,684 | 2,337,027 | 398,850 | 7 | 306,155 | 0 | 4,348 | 6,470,705 | 42,608,724 |
| **Capital Additions** | 179,311 | 0 | 0 | 344,241 | 136,353 | 0 | 500,355 | 0 | 300 | 3,278,557 | 4,439,117 |
| **Undepreciated Capital Cost Before 2007 Claim** | 29,554,340 | 3,672,919 | 43,684 | 2,681,268 | 535,203 | 7 | 806,510 | 0 | 4,648 | 9,749,262 | 47,047,841 |
| Less: 2007 Claim: On Balance Forward | 1,175,001 | 220,375 | 2,184 | 186,962 | 79,770 | 2 | 91,847 | 0 | 1,957 | 517,656 | 2,275,754 |
| On Net Additions | 7,172 | 0 | 0 | 13,770 | 13,635 | 0 | 75,053 | 0 | 68 | 131,142 | 240,840 |
| **Total 2007 Capital Cost Allowance Claim** | 1,182,173 | 220,375 | 2,184 | 200,732 | 93,405 | 2 | 166,900 | 0 | 2,025 | 648,798 | 2,516,594 |
| **Undepreciated Capital Cost December 31, 2007** | 28,372,167 | 3,452,544 | 41,500 | 2,480,536 | 441,798 | 5 | 639,610 | 0 | 2,623 | 9,100,464 | 44,531,247 |

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## YEC-YECL-51

**Reference:** Deferred Study Costs

**Requests:**

(a) In a manner consistent with information provided in 1996 1997 GRA CITY-YEC YECL1-19 please provide a listing of the various deferred study cost Total Expenditures, Amortization Rate and Method (including commencement date), Accumulated Amortization and Unamortized balance for the actual years 2006 and 2007 as well as the test years 2008 and 2009. December 31, 2006 and December 31, 2007.

(b) For all deferred study cost projects please complete a table that details (1) project name and total expense capitalized, (2) project description, (3) rationale justification and (4) cost benefit.

(c) Please provide a summary to any changes or expected changes to terms and conditions of licences for any facilities re-licenced. Please provide an assessment of the financial implications of any of these changes on ratepayers.

**Response:**

(a-c) There are no deferred study costs.

## YEC-YECL-52

**Reference:** Inventory

**Requests:**

(a) For each year starting in 1996 and including forecast 2008 and 2009, please provide a breakdown of YECL's fuel, distribution, transmission and generation inventory as of December 31. Please ensure the analysis breaks down distribution, transmission and generation inventory in their respective major categories.

(b) Please provide variance analysis for increases or decreases including annual turnover analysis for distribution inventory.

**Response:**

(a) The last approved test period was 1996 1997. Information provided in response to information requests is in accordance with Board Order 2008-05, which confirmed that Yukon Electrical is not required to provide information prior to 2003 to test the revenue requirement.

| | ( 000's) | | | | | |
|---|---|---|---|---|---|---|
| | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test 2008 | Test 2009 |
| **Distribution** | 890 | 1,054 | 1,381 | 1,272 | 1,334 | 1,400 |
| **Fuel** | 399 | 421 | 404 | 577 | 606 | 636 |
| **Transmission** | 0 | 0 | 0 | 0 | 0 | 0 |
| **Generation** | 0 | 0 | 0 | 0 | 0 | 0 |
| **TOTAL** | 1,289 | 1,474 | 1,784 | 1,849 | 1,940 | 2,036 |

(b) In regard to the distribution inventory the increase between 2005 and 2006 is mainly attributed to price increases of various line materials. These price increases were driven by robust economies in North America as well as by natural disasters and higher commodity prices that had an impact on supply and cost of materials. Yukon Electrical experienced significant increases in the cost of underground cable, copper wire, and transformers.

The increase in fuel inventory between 2006 and 2007 is as a result of price increases.

The inventory turnover is not available for the years 2003 -2005. For the years 2006 to 2007 it was 1.12 and 1.02 respectively.

## YEC-YECL-53

**Reference:** Retirements, Disposals and Adjustments

**Requests:**

(a) For each year starting in 1996 and including 2008 and 2009 forecast please provide a breakdown of YECL's retirements, disposals and adjustments.

**Response:**

(a) Please refer to YEC-YECL-53(a) Attachment 1. Information provided in response to information requests is in accordance with Board Order 2008-05, which confirmed that Yukon Electrical is not required to provide information prior to 2003 to test the revenue requirement.

**Yukon Electical**
**Retirements and Disposals**
**($000's)**

| | Actual 2003 | Actual 2004 | Actual 2005 | Actual 2006 | Actual 2007 | Test 2008 | Test 2009 |
|---|---|---|---|---|---|---|---|
| **General Property** | | | | | | | |
| Tool & Work Equipment | 59 | 54 | 61 | 59 | 61 | 59 | 59 |
| Office Furniture & Equipment | 40 | 51 | 45 | 43 | 41 | 44 | 44 |
| Vehicles | - | - | - | - | 288 | 57 | 57 |
| Other Under 20,000 | - | - | - | - | - | 1 | 1 |
| | 99 | 105 | 106 | 102 | 390 | 161 | 161 |
| **Distribution** | | | | | | | |
| Poles and Fixtures | 106 | 16 | 73 | 66 | 11 | 54 | 54 |
| Overhead conductor | 60 | 4 | 3 | 1 | 0 | 14 | 14 |
| Underground conduit | 1 | 2 | - | 1 | - | - | - |
| Meters | 140 | 106 | 101 | 49 | 15 | 82 | 896 |
| Street Lights | 15 | 11 | 5 | 5 | 4 | 8 | 8 |
| Transformers | 50 | 3 | 15 | 18 | 3 | 18 | 18 |
| | 372 | 142 | 197 | 140 | 33 | 176 | 990 |
| **Generation** | | | | | | | |
| Hydro Generators | - | - | - | - | 3 | - | - |
| Diesel Generation Equipment | 10 | 91 | - | - | - | 14 | 14 |
| | 10 | 91 | - | - | 3 | 14 | 14 |
| **TOTAL** | 481 | 339 | 303 | 242 | 426 | 351 | 1,165 |

## YEC-YECL-54

**Reference:** AFUDC

**Requests:**

(a) For each year starting in 1996 and including forecast 2008 2009, please provide a breakdown of the projects, and associated Allowance for Funds Used during Construction, contributing to the income and addition to YEC's rate base.

**Response:**

(a) In accordance with Board Order 2008-5, information prior to 2003 for Schedule 9.1 was not required to test the revenue requirement in the test period. This information is provided below from 2005:

| Project | AFU 2005 | AFU 2006 ( 000) | AFU 2007 |
|---|---|---|---|
| Distribution New Extensions | 5 | 10 | 16 |
| Distribution Improvements | 24 | 20 | 21 |
| Street Lights and Sentinel Lights | 1 | 2 | 2 |
| Distribution Meters and Equipment | 1 | 2 | 1 |
| Transportation | - | 2 | 2 |
| New CIS Billing System | - | - | 17 |
| GP&E - Corporate | 8 | - | - |
| Buildings - Corporate | - | - | - |
| Small Generating Plant | 16 | 17 | 18 |
| Total | 54 | 54 | 77 |

AFUDC prior to 2005 is not available by project however the amounts are not considered significant and in total are as follows:

| Year | Amount ( 000's) |
|---|---|
| 1996 | 17 |
| 1997 | 20 |
| 1998 | 8 |
| 1999 | 7 |
| 2000 | 47 |
| 2001 | 42 |
| 2002 | 23 |
| 2003 | 44 |
| 2004 | 51 |

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## YEC-YECL-55

**Reference:** Distribution and Transmission Construction (Technical) Standards

**Requests:**

(a) Has YECL developed distribution and transmission construction (technical) standards? If yes, please describe how these standards are documented and utilized on an ongoing basis.

(b) Please provide the amount spent each year since 2003 on external as well as internal resources on the development and maintenance of Distribution and Transmission Construction Standards. Please confirm whether these expenses have been capitalized or expensed.

**Response:**

(a) Yes, YECL has developed and maintains a Distribution Construction Standards Manual. Each print is designed and approved by a Professional Engineer holding a permit number; the print is assigned a specific identification number and index in a manual. In the design stages of a project these prints are referred to and incorporated as appropriate. YECL does not maintain a transmission standards manual however has access to detailed construction standards through its parent company.

(b) Over the years these standards have been collaboratively developed and updated with our parent company. Suggested changes or adjustments to the standards are vetted though ATCO Electric's standards group and implemented if appropriate. Updates and changes are generally one of's with minimal financial impacts to the overall cost of the manual. Time specifically spent on this process is capitalized; the funds spent are not tracked in detail but rather would be part of the pre-set labor allocations of those involved in this activity. If a significant amount of work was required in regard to the standards a project number would be established for tracking of costs and allocated to the appropriate capital and O&M accounts.

**YUB-YECL-1**

**Reference:** Overview, Application, page 1-2 Background

**Issue Sub-Issue:** Performance Metrics

**Quote**: Although Yukon Electrical has not been before the Yukon Utilities Board with a General Rate Application since the test years 1996-1997, Yukon Electrical has continued to provide safe reliable and cost effective service to our customers. However there have been significant cost pressures in recent years that require Yukon Electrical to come forward to the Board to ensure that it is possible to continue to deliver the same

**Preamble**: The Board wishes further information regarding reliability measures.

**Request:**

(a) Please provide a table showing reliability performance measures on a calendar year basis with respect YECL's service area. The table should include such indices as:

the System Average Interruption Duration Index (SAIDI),

the System Average Interruption Frequency Index (SAIFI),

the Customer Average Interruption Duration Index (CAIDI), for the period 2002 to 2007,

Annual averages must be derived from raw data, not by averaging monthly averages.

(b) Please identify any formalized evaluation process that YECL has in place in order to identify worst-performing circuits in its service area. For the period 2003 through 2007, please identify the top 5 of the worst performing circuits on YECL's system and identify reasons for the poor performance.

(c) Please provide a table that shows YECL's performance in respect of the Canadian Electricity Association's (CEA) All Injury Illness Frequency Rate (AIIFR) performance index for the period 2003 through 2007.

(d) Please provide a table that illustrates YECL's performance in relation to the Canadian Electricity Association's (CEA) Motor Vehicle Accident Frequency Rate (MVAR) performance index for the period 2003 through 2007.

(e) In regard to call answer performance measures, please indicate if YECL has such a metric. If YECL has such a performance measure, please provide the metrics, the minimum performance standards that YECL has dictated for itself, and performance measure results for the last 5 years. If not, please explain why YECL does not monitor such metrics.

(f) Please provide an Excel spreadsheet containing data regarding YECL's annual operational and financial results for the period 2003 through 2007. Please use the attached Excel spreadsheet YUB-YECL-1 Operational Financial Reporting attachment.xls as a template.

(g) Please provide a comparison of actual 1996-97 results versus the latest Board Decision relating to those years.

**Response:**

(a) Please refer to the following table;

| | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** |
|---|---|---|---|---|---|---|
| SAIDI | 5.15 | 2.57 | 7.41 | 3.11 | 8.99 | 4.54 |
| SAIFI | 4.85 | 3.23 | 5.78 | 4.11 | 6.76 | 4.69 |
| CAIDI | 1.06 | 0.79 | 1.28 | 0.76 | 1.33 | 0.97 |

(b) Yukon Electrical does not specifically track its reliability statistics on a line or feeder basis but rather it tracks reliability on the system as a whole. Yukon Electrical's operations group meets weekly with engineering to discuss the past weeks system performance. Of priority at these weekly meetings are all unplanned distribution outages or events which cause supply disruptions to customers. Events are recorded and trends are identified, i.e: reoccurring failures of specific feeders, transformers or services. Trends are then investigated by researching the causes. Supporting information may be available by reviewing service interruption reports. Depending on the cause of the outages a determination is made to either immediately make corrections to the equipment or if the asset repairs can be put into the capital business planning cycle.

Yukon Electrical has approximately 65 feeders in its service area. For four feeders, or approximately 5 of the total number of feeders, based on a general assessment and operating experience Yukon Electrical has concluded that the worst performing feeders currently are in the Southern Lakes region. Yukon Electrical has recognized this and has included projects in its capital plan to address deficiencies.

(c) **Disabling Injury Statistics:**

| | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| Accidents | 0 | 0 | 0 | 0 | 1 |
| Days Lost | 0 | 0 | 0 | 0 | 1 |

| | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| YECL | 0 | 0 | 0 | 0 | 0.07 |
| CEA | | | | | |

-Disabling Injury frequency is calculated in the following manner: $\frac{\text{Number of Disabling injuries x 200,000}}{\text{Exposure hours (hours worked)}}$

Yukon Electrical is not a member of CEA and as such is not able to provide this data. Yukon Electrical's parent is a member of CEA and Yukon Electrical does compare its statistics to CEA internally however cannot disclose this information publicly. Yukon Electrical can confirm that its injury statistics are better than the CEA average.

(d) **Vehicle Incident Statistics:**

| | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| Vehicle Incidents | 3 | 2 | 5 | 7 | 10 |
| CEA | | | | | |

Please refer to YUB-YECL-1(c).

(e) Yes. Yukon Electrical tracks the performance of its after hours call center. However Yukon Electrical has only been with its current after hours call center provider since January of 2007. Prior to 2007 Yukon electrical used a small local service provider that did not have the technology to provide statistics. As a feature with our after hours trouble call service provider, call performance measurement is offered. Statistics are compiled monthly. Primarily the number of calls answered and the number of seconds the caller waits on the line before the call is answered is tracked. Yukon Electrical is still in the process of

assessing which factors are most beneficial to monitor and ultimately benchmark. At the present time Yukon Electrical reviews the reports that are provided and addresses any concerns brought forward by customers. Please refer to YUB-YECL-1(e) Attachment 1 as a sample of data available from the call center.

(f) Yukon Electrical has provided fully detailed schedules relating to its annual operational and financial results. Given the size of Yukon Electrical, Yukon Electrical does not believe a detailed filing that is in place for those major electric utilities in Alberta should be required. To do so would require increased resources on the part of Yukon Electrical.

As well, it should be noted that Yukon Electrical does not have an approved forecast for the years requested so all variance analysis would be to the prior year in accordance with EUB Directive 014. As such this information has been provided in the various schedules throughout the application.

(g) Yukon Electrical believes, that in accordance with Board Order 2008-5, it is not required to provide information dating back to 1996-1997 to test the revenue requirement in the test period. In order to be helpful Yukon Electrical will provide the information requested as follows:

| | | 1996 97 GRA | Actual |
|---|---|---|---|
| **1996** | Revenue Requirement | 29,360 | 29,798 |
| | Net Rate Base | 30,895 | 29,778 |
| | Return on Equity | 11.25 | 13.03 |
| **1997** | Revenue Requirement | 30,829 | 31,244 |
| | Net Rate Base | 32,123 | 31,346 |
| | Rate on Equity | 11.25 | 11.60 |

| MONTHLY RESULTS-2007 | CALLS OFFERED | CALLS ANSWERED | AVERAGE ANSWER DELAY IN SECONDS |
|---|---|---|---|
| | | | |
| JANUARY | 177 | 147 | 19 |
| FEBRUARY | 246 | 199 | 21 |
| MARCH | 970 | 563 | 51 |
| APRIL | 380 | 209 | 26 |
| MAY | 487 | 240 | 88 |
| JUNE | 496 | 351 | 37 |
| JULY | 724 | 464 | 63 |
| AUGUST | 500 | 381 | 35 |
| SEPTEMBER | 329 | 266 | 26 |
| OCTOBER | 205 | 132 | 38 |
| NOVEMBER | 222 | 169 | 21 |
| DECEMBER | 214 | 170 | 32 |
| **TOTAL** | **4950** | **3291** | **AVERAGE 38** |

| MONTHLY RESULTS-2008 | CALLS OFFERED | CALLS ANSWERED | AVERAGE ANSWER DELAY IN SECONDS |
|---|---|---|---|
| | | | |
| JANUARY | 369 | 282 | 41 |
| FEBRUARY | 237 | 210 | 12 |
| MARCH | 249 | 220 | 13 |
| APRIL | 193 | 165 | 22 |
| MAY | 782 | 540 | 50 |
| JUNE | 23 | 19 | 8 |
| JULY | | | |
| AUGUST | | | |
| SEPTEMBER | | | |
| OCTOBER | | | |
| NOVEMBER | | | |
| DECEMBER | | | |
| **TOTAL** | **1853** | **1436** | **AVERAGE 24** |

**YUB-YECL-2**

**Reference:** Overview; Application, page 1-5

**Issue Sub-Issue:** Deferral Accounts

**Quote**: The above noted ongoing and new deferral accounts meet the typical criteria for the establishment of a deferral account and are required as the costs related to these deferral accounts are:

1) Not under the control of the company and are not reasonably forecastable; or

2) An error in forecasting could produce a loss or gain of a substantial magnitude.

**Request:**

(a) Please define what YECL would describe as being a loss or gain of a substantial magnitude.

(b) Please provide an update to the forecast in respect of the connection of Pelly Crossing to the WAF grid effective November 1, 2008.

**Response:**

(a) A loss or gain of substantial magnitude is a loss that would have a material impact on the company's earnings. What is material is a matter of judgement and would be determined on a case by case basis. This position is consistent with the criteria used for Yukon Electrical's parent company ATCO Electric.

(b) The scope of this project has changed since the original filing of Yukon Electrical's General Rate Application (GRA). On July 18 2008, YEC's consultant suggested that 2nd 138kv to 25kv transmission line proposed for the community of Pelly Crossing is being reviewed. An alternate interim interface point and configuration has been proposed by YEC. Essentially the change requires that, from the interface tie between YEC and Yukon Electrical, there will be an OSS (Oil Sectionalizing Switch) to sectionalize from and synchronize to the grid when

required. Yukon Electrical will then step the voltage down to the current community distribution voltage of 2400V. A short distribution line will be built to reach the community's existing distribution system. Construction of the tie is tentatively scheduled for the 3rd week of August 2008, completion by September 15 2008. Yukon Electrical's design is complete, material is on hand, a final field check has been completed and we are in the process of securing a line route (July 28, 2008).

It is expected that if the transmission or distribution line required to extend the power system from the Minto Mine to Pelly is in place by October 1, 2008 that Yukon Electrical will meet the November 1, 2008 proposed connection to the grid date.

**YUB-YECL-3**

**Reference:** Overview; Attachment 1

**Issue Sub-Issue:** Manpower requirements

**Request:**

(a) Please explain and provide details regarding the changes that have necessitated the need for an additional Field Service Representative for 2009.

(b) Please provide YECL's vacancy rates for the period 2003 through 2007.

**Response:**

(a) The continued shortage of qualified utility employees (journeyman lineman) has forced Yukon Electrical and other utilities to pursue other methods of completing required work. With the additional Field Service Representative (FSR) for 2009, we are able to off-load some of the non-journeyman work from the qualified linemen. The Field Service Representative is a utility employee that is able to work on energized equipment and apparatus below 750 volts between conductors. This allows Yukon Electrical to assign low voltage work to a Field Service Representative and use the qualified journeyman linemen to complete the essential high voltage work. Additional value is obtained from this position, as the FSR can assist during after hours emergency call-out, where two men must be dispatched due to the nature of the work or location. This position provides another option to support power restoration.

A Field Service Representative can be trained and take on non-critical, low hazard, tasks to the operations group in 6 to 12 months. For a journeyman lineman it takes a minimum of 4 years of training before they become fully qualified.

The addition of an FSR is one component of a multiple solution approach being implemented by Yukon Electrical to meet increased workloads, reduce long term costs, and address attraction and retention issues.

(b) Vacancy rates are calculated based on an approved complement for FTEs. As such vacancy rates are not applicable for this period given that there were no Board approved FTEs.

**YUB-YECL-4**

**Reference:** Forecast Process; Application, page 2-2

**Issue Sub-Issue:** Derivation of the Forecast

**Quote**: The forecast process involves the review of historic sales data by customer class and takes into account the most recent information available at the time the forecast is prepared.

The normalization calculations are provided in Attachments 1 to 28.

**Preamble**: The Board wishes to understand fully the normalization calculations

**Request:**

(a) Please provide the spreadsheets that underpin the Normalized UPC (kWh) numbers illustrated in Attachments 1, 3, 5, 7, 9, 11, 13, 15, 17, 19, 21, 23, and 25; Please ensure that all spreadsheets are complete with formulae and linkages that clearly show all the calculations in order to arrive at the numbers in the above referenced Attachments.

(b) Please provide the spreadsheets that underpin the Normalized UPC (kWh) numbers illustrated in Attachments 2, 4, 6, 8, 10, 12, 14, 16, 18, 20, 22, 24, and 26; Please ensure that all spreadsheets are complete with formulae and linkages that clearly show all the calculations in order to arrive at the numbers in the above referenced Attachments.

**Response:**

(a&b) Please refer to YUB-YECL-04 Attachments 1-30 in Excel format. These spreadsheets contain all the formulae and linkages necessary to show the calculations used to arrive at the Normalized UPC (kWh).

| Whitehorse Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-94 | 10,620 | 7,258 | 1,463 | 1,085 | 1,469 | |
| Feb-94 | 9,272 | 7,257 | 1,278 | 1,125 | 1,120 | |
| Mar-94 | 10,014 | 7,256 | 1,380 | 654 | 1,448 | |
| Apr-94 | 7,688 | 7,230 | 1,063 | 431 | 1,097 | |
| May-94 | 6,149 | 7,239 | 849 | 321 | 850 | |
| Jun-94 | 5,512 | 7,236 | 762 | 166 | 758 | |
| Jul-94 | 4,898 | 7,233 | 677 | 84 | 693 | |
| Aug-94 | 4,436 | 7,270 | 610 | 70 | 663 | |
| Sep-94 | 5,130 | 7,311 | 702 | 335 | 693 | |
| Oct-94 | 6,302 | 7,359 | 856 | 507 | 881 | |
| Nov-94 | 7,649 | 7,418 | 1,031 | 936 | 967 | |
| Dec-94 | 9,284 | 7,428 | 1,250 | 1,029 | 1,204 | |
| Jan-95 | 10,985 | 7,438 | 1,477 | 1,020 | 1,520 | |
| Feb-95 | 8,416 | 7,429 | 1,133 | 840 | 1,137 | |
| Mar-95 | 9,223 | 7,424 | 1,242 | 880 | 1,182 | |
| Apr-95 | 7,544 | 7,431 | 1,015 | 440 | 1,043 | |
| May-95 | 6,487 | 7,410 | 875 | 251 | 916 | |
| Jun-95 | 5,503 | 7,423 | 741 | 139 | 753 | |
| Jul-95 | 4,891 | 7,425 | 659 | 97 | 668 | |
| Aug-95 | 4,677 | 7,458 | 627 | 198 | 606 | |
| Sep-95 | 5,450 | 7,520 | 725 | 227 | 778 | |
| Oct-95 | 6,041 | 7,601 | 795 | 525 | 809 | |
| Nov-95 | 7,662 | 7,616 | 1,006 | 894 | 965 | |
| Dec-95 | 9,633 | 7,631 | 1,262 | 1,049 | 1,205 | |
| Jan-96 | 11,311 | 7,653 | 1,478 | 1,556 | 1,216 | |
| Feb-96 | 12,054 | 7,626 | 1,581 | 836 | 1,587 | |
| Mar-96 | 9,322 | 7,634 | 1,221 | 806 | 1,203 | |
| Apr-96 | 7,854 | 7,631 | 1,029 | 526 | 1,008 | |
| May-96 | 6,699 | 7,634 | 877 | 357 | 858 | |
| Jun-96 | 5,843 | 7,693 | 760 | 194 | 740 | |
| Jul-96 | 5,207 | 7,690 | 677 | 125 | 670 | |
| Aug-96 | 4,973 | 7,736 | 643 | 227 | 606 | |
| Sep-96 | 5,732 | 7,734 | 741 | 363 | 717 | |
| Oct-96 | 6,674 | 7,795 | 856 | 680 | 782 | |
| Nov-96 | 8,574 | 7,853 | 1,092 | 975 | 1,005 | |
| Dec-96 | 9,599 | 7,854 | 1,222 | 1,156 | 1,104 | |
| Jan-97 | 12,873 | 7,871 | 1,635 | 1,186 | 1,584 | 1439.89 |
| Feb-97 | 9,406 | 7,861 | 1,197 | 657 | 1,305 | 1343.11 |
| Mar-97 | 8,363 | 7,870 | 1,063 | 855 | 1,016 | 1133.74 |
| Apr-97 | 7,870 | 7,882 | 998 | 484 | 1,001 | 1017.71 |
| May-97 | 6,574 | 7,874 | 835 | 331 | 830 | 868.11 |
| Jun-97 | 5,894 | 7,893 | 747 | 149 | 753 | 748.54 |
| Jul-97 | 5,083 | 7,907 | 643 | 93 | 654 | 663.88 |
| Aug-97 | 4,852 | 7,913 | 613 | 130 | 631 | 614.46 |
| Sep-97 | 5,378 | 7,924 | 679 | 282 | 700 | 731.59 |
| Oct-97 | 6,348 | 7,925 | 801 | 641 | 749 | 780.17 |
| Nov-97 | 7,552 | 7,978 | 947 | 694 | 1,020 | 996.75 |
| Dec-97 | 7,629 | 7,981 | 956 | 762 | 1,061 | 1123.26 |
| Jan-98 | 10,691 | 8,001 | 1,336 | 1,166 | 1,296 | 1365.40 |
| Feb-98 | 8,562 | 7,976 | 1,074 | 719 | 1,146 | 1346.24 |
| Mar-98 | 8,195 | 7,960 | 1,030 | 757 | 1,039 | 1086.21 |
| Apr-98 | 7,202 | 7,963 | 904 | 459 | 922 | 977.21 |
| May-98 | 6,273 | 7,950 | 789 | 271 | 819 | 835.56 |
| Jun-98 | 5,570 | 7,982 | 698 | 120 | 720 | 737.70 |
| Jul-98 | 5,006 | 7,963 | 629 | 112 | 629 | 651.01 |
| Aug-98 | 4,825 | 7,973 | 605 | 189 | 590 | 608.90 |
| Sep-98 | 5,654 | 7,992 | 707 | 328 | 703 | 706.64 |
| Oct-98 | 6,270 | 8,020 | 782 | 558 | 777 | 769.58 |
| Nov-98 | 7,456 | 8,068 | 924 | 792 | 941 | 988.77 |
| Dec-98 | 7,847 | 8,072 | 972 | 1,052 | 913 | 1025.91 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1994** | 11,922 | 11,842 | - |
| **1995** | 11,558 | 11,582 | - |
| **1996** | 12,177 | 11,496 | - |
| **1997** | 11,113 | 11,305 | 11,461 |
| **1998** | 10,450 | 10,496 | 11,099 |
| **1999** | 10,713 | 10,686 | 10,829 |
| **2000** | 10,292 | 10,366 | 10,516 |
| **2001** | 10,207 | 10,270 | 10,441 |
| **2002** | 10,247 | 10,377 | 10,338 |
| **2003** | 10,325 | 10,367 | 10,338 |
| **2004** | 10,307 | 10,517 | 10,421 |
| **2005** | 10,313 | 10,585 | 10,490 |
| **2006** | 10,733 | 10,515 | 10,539 |
| **2007** | 10,551 | 10,472 | 10,524 |

| Whitehorse Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-99 | 11,228 | 8,106 | 1,385 | 1,183 | 1,335 | 1405.18 |
| Feb-99 | 9,463 | 8,113 | 1,166 | 976 | 1,093 | 1181.51 |
| Mar-99 | 8,434 | 8,088 | 1,043 | 734 | 1,065 | 1040.38 |
| Apr-99 | 7,645 | 8,081 | 946 | 509 | 935 | 952.79 |
| May-99 | 6,488 | 7,976 | 813 | 392 | 774 | 807.68 |
| Jun-99 | 6,065 | 8,019 | 756 | 154 | 759 | 744.14 |
| Jul-99 | 5,179 | 7,996 | 648 | 109 | 650 | 644.29 |
| Aug-99 | 4,895 | 8,001 | 612 | 146 | 621 | 614.02 |
| Sep-99 | 5,641 | 8,074 | 699 | 311 | 704 | 702.21 |
| Oct-99 | 6,196 | 8,097 | 765 | 500 | 794 | 773.38 |
| Nov-99 | 7,205 | 8,156 | 883 | 793 | 900 | 953.85 |
| Dec-99 | 8,127 | 8,160 | 996 | 844 | 1,055 | 1009.57 |
| Jan-00 | 10,362 | 8,178 | 1,267 | 1,083 | 1,274 | 1301.86 |
| Feb-00 | 8,484 | 8,178 | 1,037 | 735 | 1,101 | 1113.53 |
| Mar-00 | 7,522 | 8,175 | 920 | 659 | 985 | 1030.07 |
| Apr-00 | 6,961 | 8,133 | 856 | 516 | 841 | 899.28 |
| May-00 | 6,899 | 8,131 | 848 | 382 | 815 | 802.55 |
| Jun-00 | 5,955 | 8,123 | 733 | 173 | 726 | 735.10 |
| Jul-00 | 5,338 | 8,119 | 657 | 142 | 641 | 639.80 |
| Aug-00 | 5,051 | 8,131 | 621 | 220 | 588 | 599.66 |
| Sep-00 | 6,012 | 8,176 | 735 | 354 | 716 | 707.41 |
| Oct-00 | 6,465 | 8,200 | 788 | 539 | 795 | 788.49 |
| Nov-00 | 7,281 | 8,220 | 886 | 691 | 961 | 934.12 |
| Dec-00 | 7,761 | 8,237 | 942 | 978 | 925 | 964.13 |
| Jan-01 | 9,773 | 8,234 | 1,187 | 723 | 1,399 | 1336.02 |
| Feb-01 | 7,744 | 8,239 | 940 | 864 | 930 | 1041.51 |
| Mar-01 | 8,161 | 8,249 | 989 | 765 | 994 | 1015.03 |
| Apr-01 | 7,151 | 8,226 | 869 | 507 | 859 | 878.44 |
| May-01 | 6,719 | 8,218 | 818 | 390 | 779 | 789.36 |
| Jun-01 | 6,287 | 8,219 | 765 | 167 | 760 | 748.41 |
| Jul-01 | 5,412 | 8,220 | 658 | 140 | 643 | 644.42 |
| Aug-01 | 4,936 | 8,231 | 600 | 140 | 612 | 607.21 |
| Sep-01 | 5,443 | 8,222 | 662 | 309 | 668 | 695.84 |
| Oct-01 | 6,241 | 8,259 | 756 | 573 | 742 | 776.82 |
| Nov-01 | 7,520 | 8,302 | 906 | 818 | 908 | 923.13 |
| Dec-01 | 8,798 | 8,318 | 1,058 | 1,095 | 974 | 984.55 |
| Jan-02 | 10,192 | 8,326 | 1,224 | 936 | 1,315 | 1329.21 |
| Feb-02 | 8,444 | 8,323 | 1,015 | 825 | 1,028 | 1019.68 |
| Mar-02 | 8,314 | 8,318 | 999 | 921 | 916 | 965.14 |
| Apr-02 | 8,230 | 8,299 | 992 | 653 | 898 | 866.25 |
| May-02 | 6,639 | 8,299 | 800 | 362 | 778 | 790.61 |
| Jun-02 | 5,869 | 8,286 | 708 | 176 | 699 | 728.32 |
| Jul-02 | 5,350 | 8,309 | 644 | 131 | 633 | 638.90 |
| Aug-02 | 5,406 | 8,326 | 649 | 183 | 637 | 612.66 |
| Sep-02 | 5,682 | 8,335 | 682 | 314 | 685 | 689.58 |
| Oct-02 | 6,363 | 8,377 | 760 | 444 | 820 | 785.44 |
| Nov-02 | 7,363 | 8,419 | 875 | 583 | 1,011 | 959.94 |
| Dec-02 | 7,580 | 8,426 | 900 | 845 | 958 | 952.22 |
| Jan-03 | 10,157 | 8,437 | 1,204 | 989 | 1,264 | 1325.90 |
| Feb-03 | 8,415 | 8,446 | 996 | 757 | 1,048 | 1001.95 |
| Mar-03 | 8,335 | 8,446 | 987 | 835 | 952 | 954.16 |
| Apr-03 | 7,546 | 8,440 | 894 | 514 | 880 | 879.22 |
| May-03 | 6,685 | 8,443 | 792 | 364 | 768 | 775.16 |
| Jun-03 | 6,345 | 8,452 | 751 | 193 | 732 | 730.36 |
| Jul-03 | 5,572 | 8,458 | 659 | 84 | 675 | 650.26 |
| Aug-03 | 5,234 | 8,468 | 618 | 181 | 608 | 619.08 |
| Sep-03 | 6,027 | 8,482 | 711 | 359 | 688 | 680.40 |
| Oct-03 | 6,201 | 8,516 | 728 | 467 | 775 | 779.05 |
| Nov-03 | 7,795 | 8,549 | 912 | 875 | 882 | 933.88 |
| Dec-03 | 9,211 | 8,573 | 1,074 | 912 | 1,095 | 1008.84 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Whitehorse Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-04 | 10,725 | 8,596 | 1,248 | 1,255 | 1,157 | 1245.39 |
| Feb-04 | 9,387 | 8,584 | 1,094 | 695 | 1,180 | 1085.15 |
| Mar-04 | 7,948 | 8,590 | 925 | 756 | 935 | 934.48 |
| Apr-04 | 8,168 | 8,596 | 950 | 467 | 963 | 913.83 |
| May-04 | 6,477 | 8,603 | 753 | 273 | 781 | 775.92 |
| Jun-04 | 6,128 | 8,601 | 712 | 84 | 755 | 728.73 |
| Jul-04 | 5,774 | 8,638 | 668 | 74 | 690 | 666.01 |
| Aug-04 | 5,257 | 8,644 | 608 | 102 | 642 | 629.12 |
| Sep-04 | 5,819 | 8,679 | 670 | 368 | 643 | 672.13 |
| Oct-04 | 6,636 | 8,701 | 763 | 541 | 768 | 787.65 |
| Nov-04 | 7,864 | 8,747 | 899 | 720 | 958 | 950.25 |
| Dec-04 | 8,897 | 8,757 | 1,016 | 900 | 1,043 | 1031.91 |
| Jan-05 | 11,218 | 8,772 | 1,279 | 1,165 | 1,239 | 1220.23 |
| Feb-05 | 9,715 | 8,766 | 1,108 | 795 | 1,138 | 1121.95 |
| Mar-05 | 8,112 | 8,783 | 924 | 614 | 1,015 | 967.42 |
| Apr-05 | 7,969 | 8,785 | 907 | 453 | 928 | 923.54 |
| May-05 | 6,478 | 8,801 | 736 | 257 | 774 | 774.49 |
| Jun-05 | 6,221 | 8,809 | 706 | 154 | 709 | 732.02 |
| Jul-05 | 5,836 | 8,826 | 661 | 133 | 650 | 671.49 |
| Aug-05 | 5,518 | 8,864 | 623 | 151 | 629 | 626.27 |
| Sep-05 | 6,605 | 8,888 | 743 | 299 | 755 | 695.49 |
| Oct-05 | 6,562 | 8,930 | 735 | 535 | 744 | 762.32 |
| Nov-05 | 8,293 | 8,986 | 923 | 774 | 950 | 930.09 |
| Dec-05 | 8,741 | 9,023 | 969 | 794 | 1,056 | 1064.58 |
| Jan-06 | 10,810 | 9,021 | 1,198 | 1,096 | 1,198 | 1198.11 |
| Feb-06 | 9,451 | 9,041 | 1,045 | 821 | 1,060 | 1126.00 |
| Mar-06 | 9,712 | 9,041 | 1,074 | 906 | 999 | 982.96 |
| Apr-06 | 8,272 | 8,843 | 935 | 519 | 919 | 936.44 |
| May-06 | 7,273 | 9,057 | 803 | 347 | 789 | 781.44 |
| Jun-06 | 6,585 | 9,049 | 728 | 173 | 720 | 728.07 |
| Jul-06 | 6,392 | 9,060 | 705 | 118 | 702 | 680.63 |
| Aug-06 | 5,771 | 9,069 | 636 | 202 | 614 | 628.36 |
| Sep-06 | 6,709 | 9,095 | 738 | 296 | 751 | 716.54 |
| Oct-06 | 7,281 | 9,136 | 797 | 521 | 814 | 775.06 |
| Nov-06 | 8,643 | 9,192 | 940 | 1,162 | 747 | 885.07 |
| Dec-06 | 10,405 | 9,193 | 1,132 | 824 | 1,202 | 1100.27 |
| Jan-07 | 11,483 | 9,206 | 1,247 | 912 | 1,352 | 1262.91 |
| Feb-07 | 9,696 | 9,215 | 1,052 | 999 | 966 | 1054.74 |
| Mar-07 | 10,533 | 9,235 | 1,141 | 954 | 1,038 | 1017.23 |
| Apr-07 | 9,110 | 9,235 | 986 | 512 | 974 | 939.91 |
| May-07 | 6,803 | 9,240 | 736 | 322 | 737 | 766.51 |
| Jun-07 | 6,655 | 9,232 | 721 | 141 | 731 | 720.09 |
| Jul-07 | 6,511 | 9,254 | 704 | 102 | 709 | 687.01 |
| Aug-07 | 5,550 | 9,275 | 598 | 154 | 603 | 615.12 |
| Sep-07 | 6,404 | 9,283 | 690 | 308 | 696 | 734.20 |
| Oct-07 | 7,061 | 9,343 | 756 | 544 | 759 | 772.15 |
| Nov-07 | 8,659 | 9,372 | 924 | 725 | 980 | 892.45 |
| Dec-07 | 9,369 | 9,405 | 996 | 1,070 | 927 | 1061.45 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**WHITEHORSE RESIDENTIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.86433212 |
| R Square | 0.74707001 |
| Adjusted R Square | 0.74554633 |
| Standard Error | 112.772517 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 6235562.056 | 6235562.06 | 490.308088 | 2.00774E-51 |
| Residual | 166 | 2111128.342 | 12717.6406 | | |
| Total | 167 | 8346690.399 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 585.389349 | 16.59380952 | 35.2775744 | 4.8854E-79 | 552.6272333 | 618.151465 | 552.627233 | 618.151465 |
| MHDD | 0.56836559 | 0.025668072 | 22.1429015 | 2.0077E-51 | 0.517687637 | 0.61904355 | 0.51768764 | 0.61904355 |

| Carmacks Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-94 | 244 | 169 | 1,443 | 1,085 | 1,449 | |
| Feb-94 | 189 | 171 | 1,105 | 1,125 | 941 | |
| Mar-94 | 185 | 171 | 1,083 | 654 | 1,155 | |
| Apr-94 | 155 | 172 | 901 | 431 | 936 | |
| May-94 | 124 | 173 | 714 | 321 | 716 | |
| Jun-94 | 104 | 170 | 611 | 166 | 607 | |
| Jul-94 | 108 | 167 | 646 | 84 | 663 | |
| Aug-94 | 101 | 169 | 599 | 70 | 653 | |
| Sep-94 | 132 | 175 | 757 | 335 | 748 | |
| Oct-94 | 126 | 181 | 698 | 507 | 724 | |
| Nov-94 | 163 | 180 | 905 | 936 | 837 | |
| Dec-94 | 189 | 193 | 977 | 1,029 | 929 | |
| Jan-95 | 258 | 189 | 1,365 | 1,020 | 1,409 | |
| Feb-95 | 175 | 187 | 936 | 840 | 940 | |
| Mar-95 | 180 | 188 | 960 | 880 | 897 | |
| Apr-95 | 167 | 189 | 885 | 440 | 915 | |
| May-95 | 122 | 187 | 650 | 251 | 693 | |
| Jun-95 | 97 | 189 | 515 | 139 | 527 | |
| Jul-95 | 112 | 189 | 592 | 97 | 601 | |
| Aug-95 | 106 | 185 | 571 | 198 | 549 | |
| Sep-95 | 133 | 193 | 687 | 227 | 743 | |
| Oct-95 | 124 | 173 | 715 | 525 | 729 | |
| Nov-95 | 156 | 172 | 906 | 894 | 864 | |
| Dec-95 | 205 | 175 | 1,173 | 1,049 | 1,113 | |
| Jan-96 | 259 | 175 | 1,477 | 1,556 | 1,204 | |
| Feb-96 | 228 | 171 | 1,333 | 836 | 1,340 | |
| Mar-96 | 159 | 171 | 927 | 806 | 908 | |
| Apr-96 | 136 | 170 | 798 | 526 | 776 | |
| May-96 | 117 | 169 | 693 | 357 | 672 | |
| Jun-96 | 117 | 167 | 702 | 194 | 682 | |
| Jul-96 | 96 | 167 | 577 | 125 | 570 | |
| Aug-96 | 110 | 169 | 651 | 227 | 612 | |
| Sep-96 | 114 | 174 | 658 | 363 | 632 | |
| Oct-96 | 143 | 179 | 797 | 680 | 719 | |
| Nov-96 | 203 | 177 | 1,149 | 975 | 1,059 | |
| Dec-96 | 169 | 177 | 956 | 1,156 | 832 | |
| Jan-97 | 286 | 174 | 1,644 | 1,186 | 1,591 | 1401.17 |
| Feb-97 | 205 | 173 | 1,182 | 657 | 1,296 | 1191.95 |
| Mar-97 | 145 | 166 | 874 | 855 | 826 | 876.96 |
| Apr-97 | 143 | 170 | 840 | 484 | 843 | 844.79 |
| May-97 | 143 | 168 | 849 | 331 | 844 | 736.24 |
| Jun-97 | 102 | 169 | 604 | 149 | 610 | 606.31 |
| Jul-97 | 103 | 167 | 618 | 93 | 629 | 599.96 |
| Aug-97 | 111 | 165 | 670 | 130 | 689 | 616.68 |
| Sep-97 | 111 | 168 | 663 | 282 | 685 | 686.70 |
| Oct-97 | 134 | 171 | 783 | 641 | 729 | 725.93 |
| Nov-97 | 162 | 170 | 953 | 694 | 1,029 | 983.84 |
| Dec-97 | 157 | 172 | 914 | 762 | 1,024 | 989.60 |
| Jan-98 | 234 | 174 | 1,347 | 1,166 | 1,306 | 1366.64 |
| Feb-98 | 161 | 176 | 915 | 719 | 991 | 1208.83 |
| Mar-98 | 149 | 175 | 851 | 757 | 861 | 865.13 |
| Apr-98 | 138 | 175 | 789 | 459 | 807 | 809.00 |
| May-98 | 139 | 175 | 794 | 271 | 825 | 780.35 |
| Jun-98 | 94 | 172 | 547 | 120 | 571 | 620.83 |
| Jul-98 | 103 | 170 | 607 | 112 | 608 | 602.18 |
| Aug-98 | 122 | 173 | 705 | 189 | 689 | 663.32 |
| Sep-98 | 117 | 175 | 668 | 328 | 663 | 660.10 |
| Oct-98 | 158 | 177 | 892 | 558 | 887 | 778.44 |
| Nov-98 | 152 | 179 | 848 | 792 | 866 | 984.55 |
| Dec-98 | 177 | 180 | 981 | 1,052 | 919 | 925.18 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1994** | 10,440 | 10,357 | - |
| **1995** | 9,954 | 9,979 | - |
| **1996** | 10,717 | 10,005 | - |
| **1997** | 10,595 | 10,796 | 10,260 |
| **1998** | 9,944 | 9,993 | 10,265 |
| **1999** | 10,301 | 10,273 | 10,354 |
| **2000** | 10,373 | 10,450 | 10,238 |
| **2001** | 9,634 | 9,700 | 10,141 |
| **2002** | 10,153 | 10,290 | 10,146 |
| **2003** | 10,103 | 10,147 | 10,045 |
| **2004** | 9,799 | 10,019 | 10,152 |
| **2005** | 10,208 | 10,492 | 10,219 |
| **2006** | 10,599 | 10,371 | 10,294 |
| **2007** | 10,731 | 10,648 | 10,504 |

| Carmacks Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-99 | 258 | 180 | 1,435 | 1,183 | 1,383 | 1426.45 |
| Feb-99 | 179 | 180 | 997 | 976 | 921 | 1069.08 |
| Mar-99 | 155 | 177 | 878 | 734 | 902 | 863.06 |
| Apr-99 | 169 | 181 | 933 | 509 | 922 | 857.52 |
| May-99 | 134 | 182 | 735 | 392 | 694 | 787.71 |
| Jun-99 | 105 | 177 | 593 | 154 | 596 | 592.17 |
| Jul-99 | 127 | 178 | 714 | 109 | 717 | 651.15 |
| Aug-99 | 102 | 178 | 571 | 146 | 580 | 652.83 |
| Sep-99 | 136 | 185 | 734 | 311 | 739 | 695.62 |
| Oct-99 | 156 | 184 | 849 | 500 | 878 | 831.43 |
| Nov-99 | 164 | 179 | 919 | 793 | 937 | 943.85 |
| Dec-99 | 170 | 180 | 944 | 844 | 1,005 | 982.93 |
| Jan-00 | 252 | 181 | 1,393 | 1,083 | 1,401 | 1363.09 |
| Feb-00 | 166 | 183 | 908 | 735 | 974 | 961.90 |
| Mar-00 | 152 | 183 | 833 | 659 | 901 | 888.19 |
| Apr-00 | 151 | 184 | 818 | 516 | 803 | 843.92 |
| May-00 | 148 | 183 | 808 | 382 | 773 | 763.95 |
| Jun-00 | 135 | 186 | 726 | 173 | 718 | 628.28 |
| Jul-00 | 111 | 180 | 616 | 142 | 598 | 640.69 |
| Aug-00 | 115 | 184 | 625 | 220 | 591 | 620.04 |
| Sep-00 | 157 | 184 | 855 | 354 | 835 | 745.41 |
| Oct-00 | 151 | 187 | 809 | 539 | 815 | 860.13 |
| Nov-00 | 170 | 192 | 887 | 691 | 965 | 922.45 |
| Dec-00 | 209 | 191 | 1,095 | 978 | 1,077 | 1000.36 |
| Jan-01 | 186 | 191 | 976 | 723 | 1,197 | 1326.94 |
| Feb-01 | 179 | 192 | 930 | 864 | 920 | 938.32 |
| Mar-01 | 207 | 192 | 1,078 | 765 | 1,083 | 962.08 |
| Apr-01 | 149 | 192 | 775 | 507 | 765 | 829.69 |
| May-01 | 133 | 192 | 690 | 390 | 650 | 705.63 |
| Jun-01 | 135 | 193 | 698 | 167 | 693 | 668.97 |
| Jul-01 | 109 | 192 | 567 | 140 | 551 | 621.69 |
| Aug-01 | 109 | 193 | 566 | 140 | 580 | 583.59 |
| Sep-01 | 145 | 195 | 744 | 309 | 750 | 774.57 |
| Oct-01 | 139 | 192 | 726 | 573 | 712 | 801.85 |
| Nov-01 | 198 | 198 | 999 | 818 | 1,001 | 967.62 |
| Dec-01 | 174 | 197 | 885 | 1,095 | 798 | 959.86 |
| Jan-02 | 235 | 193 | 1,219 | 936 | 1,313 | 1303.78 |
| Feb-02 | 226 | 194 | 1,166 | 825 | 1,180 | 1024.77 |
| Mar-02 | 182 | 193 | 942 | 921 | 855 | 946.31 |
| Apr-02 | 163 | 191 | 853 | 653 | 756 | 774.32 |
| May-02 | 157 | 194 | 812 | 362 | 789 | 737.11 |
| Jun-02 | 107 | 194 | 552 | 176 | 543 | 651.17 |
| Jul-02 | 115 | 198 | 580 | 131 | 569 | 572.52 |
| Aug-02 | 137 | 193 | 712 | 183 | 700 | 623.41 |
| Sep-02 | 124 | 194 | 638 | 314 | 641 | 742.12 |
| Oct-02 | 174 | 194 | 896 | 444 | 959 | 828.65 |
| Nov-02 | 154 | 197 | 783 | 583 | 926 | 964.06 |
| Dec-02 | 198 | 198 | 999 | 845 | 1,060 | 978.13 |
| Jan-03 | 208 | 195 | 1,067 | 989 | 1,130 | 1213.57 |
| Feb-03 | 185 | 196 | 944 | 757 | 998 | 1032.78 |
| Mar-03 | 174 | 196 | 886 | 835 | 850 | 929.35 |
| Apr-03 | 176 | 196 | 897 | 514 | 882 | 800.70 |
| May-03 | 146 | 195 | 751 | 364 | 727 | 721.88 |
| Jun-03 | 107 | 193 | 556 | 193 | 536 | 590.39 |
| Jul-03 | 131 | 193 | 679 | 84 | 695 | 604.90 |
| Aug-03 | 117 | 197 | 595 | 181 | 584 | 621.20 |
| Sep-03 | 139 | 194 | 715 | 359 | 691 | 694.28 |
| Oct-03 | 168 | 198 | 850 | 467 | 899 | 856.69 |
| Nov-03 | 182 | 197 | 924 | 875 | 893 | 940.00 |
| Dec-03 | 242 | 195 | 1,240 | 912 | 1,261 | 1039.49 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Carmacks Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-04 | 239 | 194 | 1,229 | 1,255 | 1,135 | 1192.81 |
| Feb-04 | 185 | 196 | 943 | 695 | 1,033 | 1070.34 |
| Mar-04 | 178 | 192 | 928 | 756 | 939 | 881.26 |
| Apr-04 | 182 | 192 | 949 | 467 | 963 | 866.65 |
| May-04 | 121 | 189 | 639 | 273 | 668 | 727.96 |
| Jun-04 | 107 | 193 | 552 | 84 | 597 | 558.52 |
| Jul-04 | 126 | 192 | 656 | 74 | 678 | 647.47 |
| Aug-04 | 96 | 192 | 501 | 102 | 537 | 606.96 |
| Sep-04 | 152 | 193 | 788 | 368 | 760 | 697.48 |
| Oct-04 | 157 | 195 | 803 | 541 | 809 | 888.95 |
| Nov-04 | 167 | 194 | 861 | 720 | 922 | 913.49 |
| Dec-04 | 183 | 193 | 950 | 900 | 979 | 1099.73 |
| Jan-05 | 285 | 193 | 1,479 | 1,165 | 1,438 | 1234.30 |
| Feb-05 | 202 | 195 | 1,034 | 795 | 1,065 | 1032.05 |
| Mar-05 | 165 | 196 | 842 | 614 | 937 | 908.72 |
| Apr-05 | 186 | 195 | 955 | 453 | 977 | 940.34 |
| May-05 | 127 | 191 | 666 | 257 | 705 | 700.05 |
| Jun-05 | 134 | 196 | 684 | 154 | 687 | 606.77 |
| Jul-05 | 107 | 195 | 550 | 133 | 538 | 637.25 |
| Aug-05 | 114 | 193 | 593 | 151 | 599 | 573.56 |
| Sep-05 | 151 | 198 | 761 | 299 | 773 | 741.35 |
| Oct-05 | 153 | 197 | 775 | 535 | 784 | 830.71 |
| Nov-05 | 191 | 201 | 950 | 774 | 978 | 931.02 |
| Dec-05 | 187 | 203 | 919 | 794 | 1,010 | 1083.10 |
| Jan-06 | 283 | 202 | 1,402 | 1,096 | 1,402 | 1324.83 |
| Feb-06 | 198 | 202 | 980 | 821 | 996 | 1031.20 |
| Mar-06 | 250 | 198 | 1,263 | 906 | 1,184 | 1020.00 |
| Apr-06 | 160 | 199 | 805 | 519 | 787 | 908.90 |
| May-06 | 137 | 199 | 689 | 347 | 674 | 682.52 |
| Jun-06 | 135 | 193 | 698 | 173 | 689 | 657.97 |
| Jul-06 | 126 | 196 | 641 | 118 | 637 | 617.88 |
| Aug-06 | 102 | 199 | 515 | 202 | 491 | 542.66 |
| Sep-06 | 150 | 202 | 742 | 296 | 757 | 763.16 |
| Oct-06 | 151 | 202 | 750 | 521 | 767 | 786.67 |
| Nov-06 | 206 | 205 | 1,006 | 1,162 | 805 | 901.65 |
| Dec-06 | 226 | 204 | 1,108 | 824 | 1,181 | 1056.53 |
| Jan-07 | 317 | 204 | 1,554 | 912 | 1,663 | 1500.85 |
| Feb-07 | 217 | 206 | 1,055 | 999 | 965 | 1008.58 |
| Mar-07 | 249 | 204 | 1,221 | 954 | 1,114 | 1078.46 |
| Apr-07 | 171 | 199 | 858 | 512 | 845 | 869.64 |
| May-07 | 131 | 200 | 657 | 322 | 657 | 678.80 |
| Jun-07 | 144 | 198 | 728 | 141 | 740 | 705.48 |
| Jul-07 | 119 | 201 | 590 | 102 | 596 | 590.53 |
| Aug-07 | 130 | 201 | 648 | 154 | 652 | 581.07 |
| Sep-07 | 134 | 204 | 655 | 308 | 662 | 730.38 |
| Oct-07 | 159 | 208 | 763 | 544 | 766 | 772.53 |
| Nov-07 | 222 | 205 | 1,083 | 725 | 1,141 | 974.86 |
| Dec-07 | 189 | 206 | 919 | 1,070 | 846 | 1012.48 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**CARMACKS RESIDENTIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.8679877 |
| R Square | 0.75340265 |
| Adjusted R Square | 0.75191712 |
| Standard Error | 115.889076 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 6811328.373 | 6811328.37 | 507.162129 | 2.43733E-52 |
| Residual | 166 | 2229426.144 | 13430.278 | | |
| Total | 167 | 9040754.517 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 527.466406 | 17.05239277 | 30.9321052 | 8.3091E-71 | 493.798883 | 561.13393 | 493.798883 | 561.13393 |
| MHDD | 0.59402659 | 0.02637743 | 22.5202604 | 2.4373E-52 | 0.541948108 | 0.64610507 | 0.54194811 | 0.64610507 |

| Carcross Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-94 | 130 | 165 | 790 | 1,085 | 793 | |
| Feb-94 | 120 | 164 | 730 | 1,125 | 644 | |
| Mar-94 | 135 | 165 | 818 | 654 | 855 | |
| Apr-94 | 112 | 167 | 673 | 431 | 692 | |
| May-94 | 79 | 167 | 473 | 321 | 474 | |
| Jun-94 | 78 | 166 | 471 | 166 | 469 | |
| Jul-94 | 79 | 167 | 475 | 84 | 483 | |
| Aug-94 | 65 | 166 | 394 | 70 | 422 | |
| Sep-94 | 71 | 164 | 430 | 335 | 425 | |
| Oct-94 | 92 | 164 | 560 | 507 | 573 | |
| Nov-94 | 86 | 170 | 508 | 936 | 473 | |
| Dec-94 | 128 | 170 | 752 | 1,029 | 727 | |
| Jan-95 | 169 | 169 | 1,001 | 1,020 | 1,025 | |
| Feb-95 | 135 | 167 | 807 | 840 | 809 | |
| Mar-95 | 127 | 169 | 750 | 880 | 717 | |
| Apr-95 | 108 | 168 | 642 | 440 | 657 | |
| May-95 | 103 | 168 | 614 | 251 | 636 | |
| Jun-95 | 82 | 172 | 476 | 139 | 482 | |
| Jul-95 | 82 | 172 | 478 | 97 | 483 | |
| Aug-95 | 70 | 171 | 409 | 198 | 398 | |
| Sep-95 | 79 | 172 | 458 | 227 | 487 | |
| Oct-95 | 90 | 171 | 526 | 525 | 534 | |
| Nov-95 | 94 | 174 | 541 | 894 | 519 | |
| Dec-95 | 112 | 177 | 635 | 1,049 | 604 | |
| Jan-96 | 168 | 176 | 957 | 1,556 | 813 | |
| Feb-96 | 191 | 176 | 1,084 | 836 | 1,088 | |
| Mar-96 | 152 | 178 | 853 | 806 | 843 | |
| Apr-96 | 118 | 174 | 677 | 526 | 666 | |
| May-96 | 115 | 174 | 660 | 357 | 649 | |
| Jun-96 | 96 | 174 | 549 | 194 | 538 | |
| Jul-96 | 83 | 175 | 473 | 125 | 469 | |
| Aug-96 | 79 | 177 | 444 | 227 | 424 | |
| Sep-96 | 96 | 175 | 549 | 363 | 535 | |
| Oct-96 | 92 | 172 | 534 | 680 | 494 | |
| Nov-96 | 115 | 174 | 659 | 975 | 612 | |
| Dec-96 | 130 | 175 | 741 | 1,156 | 676 | |
| Jan-97 | 182 | 174 | 1,044 | 1,186 | 1,016 | 951.21 |
| Feb-97 | 139 | 173 | 801 | 657 | 861 | 919.27 |
| Mar-97 | 120 | 173 | 696 | 855 | 671 | 743.57 |
| Apr-97 | 122 | 175 | 694 | 484 | 696 | 673.06 |
| May-97 | 99 | 176 | 564 | 331 | 561 | 615.41 |
| Jun-97 | 99 | 178 | 554 | 149 | 557 | 525.88 |
| Jul-97 | 86 | 181 | 473 | 93 | 479 | 476.90 |
| Aug-97 | 78 | 181 | 429 | 130 | 438 | 420.26 |
| Sep-97 | 84 | 185 | 454 | 282 | 465 | 495.94 |
| Oct-97 | 88 | 186 | 472 | 641 | 444 | 490.27 |
| Nov-97 | 123 | 183 | 669 | 694 | 709 | 613.35 |
| Dec-97 | 117 | 186 | 627 | 762 | 685 | 654.76 |
| Jan-98 | 148 | 186 | 795 | 1,166 | 774 | 867.52 |
| Feb-98 | 146 | 186 | 785 | 719 | 825 | 924.44 |
| Mar-98 | 129 | 184 | 698 | 757 | 704 | 739.31 |
| Apr-98 | 114 | 187 | 607 | 459 | 617 | 659.59 |
| May-98 | 108 | 186 | 583 | 271 | 599 | 603.14 |
| Jun-98 | 90 | 190 | 473 | 120 | 485 | 526.91 |
| Jul-98 | 82 | 192 | 428 | 112 | 428 | 458.84 |
| Aug-98 | 84 | 193 | 437 | 189 | 428 | 430.23 |
| Sep-98 | 89 | 194 | 460 | 328 | 457 | 486.00 |
| Oct-98 | 97 | 195 | 499 | 558 | 497 | 477.96 |
| Nov-98 | 110 | 193 | 571 | 792 | 581 | 634.00 |
| Dec-98 | 115 | 197 | 585 | 1,052 | 553 | 637.73 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1994** | 7,074 | 7,031 | - |
| **1995** | 7,336 | 7,350 | - |
| **1996** | 8,180 | 7,808 | - |
| **1997** | 7,477 | 7,582 | 7,580 |
| **1998** | 6,922 | 6,947 | 7,446 |
| **1999** | 7,170 | 7,155 | 7,228 |
| **2000** | 6,360 | 6,401 | 6,834 |
| **2001** | 6,264 | 6,299 | 6,618 |
| **2002** | 6,695 | 6,766 | 6,488 |
| **2003** | 6,671 | 6,694 | 6,586 |
| **2004** | 6,675 | 6,789 | 6,750 |
| **2005** | 6,862 | 7,010 | 6,831 |
| **2006** | 7,334 | 7,215 | 7,005 |
| **2007** | 7,031 | 6,988 | 7,071 |

| Carcross Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-99 | 165 | 197 | 838 | 1,183 | 811 | 866.73 |
| Feb-99 | 144 | 198 | 728 | 976 | 688 | 791.00 |
| Mar-99 | 136 | 196 | 693 | 734 | 705 | 693.22 |
| Apr-99 | 118 | 195 | 607 | 509 | 601 | 637.95 |
| May-99 | 119 | 196 | 609 | 392 | 588 | 582.81 |
| Jun-99 | 100 | 199 | 501 | 154 | 503 | 515.04 |
| Jul-99 | 98 | 200 | 489 | 109 | 490 | 465.89 |
| Aug-99 | 82 | 200 | 412 | 146 | 417 | 427.96 |
| Sep-99 | 88 | 202 | 435 | 311 | 437 | 453.29 |
| Oct-99 | 111 | 205 | 541 | 500 | 556 | 498.75 |
| Nov-99 | 107 | 204 | 527 | 793 | 536 | 608.63 |
| Dec-99 | 162 | 205 | 791 | 844 | 823 | 686.69 |
| Jan-00 | 115 | 206 | 558 | 1,083 | 562 | 715.45 |
| Feb-00 | 140 | 202 | 695 | 735 | 730 | 747.55 |
| Mar-00 | 117 | 202 | 577 | 659 | 612 | 673.79 |
| Apr-00 | 120 | 204 | 588 | 516 | 580 | 599.13 |
| May-00 | 106 | 201 | 526 | 382 | 507 | 564.77 |
| Jun-00 | 99 | 203 | 488 | 173 | 484 | 490.65 |
| Jul-00 | 91 | 204 | 448 | 142 | 439 | 452.40 |
| Aug-00 | 79 | 202 | 391 | 220 | 373 | 406.14 |
| Sep-00 | 101 | 202 | 500 | 354 | 489 | 461.36 |
| Oct-00 | 93 | 204 | 455 | 539 | 458 | 503.69 |
| Nov-00 | 102 | 203 | 503 | 691 | 544 | 553.49 |
| Dec-00 | 128 | 203 | 631 | 978 | 621 | 665.61 |
| Jan-01 | 129 | 203 | 636 | 723 | 751 | 708.07 |
| Feb-01 | 113 | 203 | 556 | 864 | 551 | 656.25 |
| Mar-01 | 137 | 203 | 674 | 765 | 677 | 664.81 |
| Apr-01 | 106 | 200 | 532 | 507 | 526 | 568.94 |
| May-01 | 102 | 199 | 511 | 390 | 490 | 528.43 |
| Jun-01 | 101 | 200 | 506 | 167 | 503 | 496.69 |
| Jul-01 | 82 | 198 | 412 | 140 | 404 | 444.19 |
| Aug-01 | 86 | 201 | 428 | 140 | 435 | 408.38 |
| Sep-01 | 82 | 199 | 410 | 309 | 413 | 446.59 |
| Oct-01 | 90 | 201 | 448 | 573 | 441 | 484.99 |
| Nov-01 | 109 | 201 | 540 | 818 | 541 | 540.36 |
| Dec-01 | 124 | 202 | 612 | 1,095 | 566 | 670.24 |
| Jan-02 | 165 | 202 | 818 | 936 | 867 | 726.75 |
| Feb-02 | 127 | 200 | 636 | 825 | 643 | 641.34 |
| Mar-02 | 133 | 207 | 642 | 921 | 597 | 628.63 |
| Apr-02 | 135 | 208 | 651 | 653 | 600 | 568.73 |
| May-02 | 118 | 208 | 568 | 362 | 556 | 517.86 |
| Jun-02 | 96 | 207 | 462 | 176 | 457 | 481.56 |
| Jul-02 | 89 | 206 | 434 | 131 | 428 | 423.53 |
| Aug-02 | 95 | 213 | 446 | 183 | 439 | 415.66 |
| Sep-02 | 95 | 214 | 446 | 314 | 447 | 450.01 |
| Oct-02 | 101 | 214 | 474 | 444 | 506 | 468.44 |
| Nov-02 | 123 | 217 | 567 | 583 | 641 | 575.38 |
| Dec-02 | 118 | 214 | 552 | 845 | 584 | 590.55 |
| Jan-03 | 159 | 213 | 744 | 989 | 777 | 798.57 |
| Feb-03 | 133 | 213 | 625 | 757 | 653 | 615.72 |
| Mar-03 | 129 | 212 | 609 | 835 | 590 | 621.33 |
| Apr-03 | 130 | 213 | 612 | 514 | 604 | 576.99 |
| May-03 | 120 | 214 | 560 | 364 | 547 | 531.19 |
| Jun-03 | 104 | 215 | 482 | 193 | 472 | 477.40 |
| Jul-03 | 103 | 217 | 473 | 84 | 481 | 437.67 |
| Aug-03 | 91 | 216 | 422 | 181 | 416 | 430.03 |
| Sep-03 | 98 | 214 | 460 | 359 | 448 | 436.02 |
| Oct-03 | 91 | 208 | 437 | 467 | 463 | 470.05 |
| Nov-03 | 124 | 213 | 584 | 875 | 568 | 583.39 |
| Dec-03 | 140 | 212 | 662 | 912 | 674 | 607.91 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Carcross Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-04 | 170 | 214 | 795 | 1,255 | 746 | 796.65 |
| Feb-04 | 153 | 214 | 716 | 695 | 764 | 686.63 |
| Mar-04 | 127 | 214 | 593 | 756 | 598 | 595.13 |
| Apr-04 | 128 | 217 | 590 | 467 | 597 | 600.50 |
| May-04 | 125 | 220 | 569 | 273 | 585 | 562.74 |
| Jun-04 | 98 | 223 | 439 | 84 | 462 | 463.83 |
| Jul-04 | 109 | 224 | 486 | 74 | 498 | 469.04 |
| Aug-04 | 88 | 222 | 395 | 102 | 414 | 423.01 |
| Sep-04 | 89 | 225 | 394 | 368 | 379 | 424.79 |
| Oct-04 | 108 | 221 | 488 | 541 | 491 | 486.95 |
| Nov-04 | 127 | 223 | 571 | 720 | 603 | 603.88 |
| Dec-04 | 142 | 223 | 638 | 900 | 653 | 636.67 |
| Jan-05 | 192 | 223 | 860 | 1,165 | 838 | 787.05 |
| Feb-05 | 169 | 222 | 760 | 795 | 777 | 731.17 |
| Mar-05 | 143 | 223 | 642 | 614 | 692 | 626.90 |
| Apr-05 | 137 | 227 | 604 | 453 | 615 | 605.57 |
| May-05 | 114 | 226 | 506 | 257 | 527 | 552.91 |
| Jun-05 | 99 | 229 | 433 | 154 | 434 | 456.09 |
| Jul-05 | 103 | 228 | 451 | 133 | 445 | 474.64 |
| Aug-05 | 90 | 227 | 398 | 151 | 402 | 410.54 |
| Sep-05 | 107 | 228 | 470 | 299 | 476 | 434.30 |
| Oct-05 | 120 | 228 | 524 | 535 | 529 | 494.49 |
| Nov-05 | 125 | 225 | 558 | 774 | 573 | 581.09 |
| Dec-05 | 150 | 229 | 655 | 794 | 703 | 676.34 |
| Jan-06 | 188 | 223 | 842 | 1,096 | 841 | 808.48 |
| Feb-06 | 164 | 223 | 737 | 821 | 745 | 761.80 |
| Mar-06 | 145 | 223 | 649 | 906 | 608 | 632.88 |
| Apr-06 | 153 | 222 | 691 | 519 | 682 | 631.49 |
| May-06 | 116 | 224 | 518 | 347 | 510 | 540.59 |
| Jun-06 | 136 | 231 | 591 | 173 | 587 | 494.42 |
| Jul-06 | 103 | 232 | 443 | 118 | 441 | 461.14 |
| Aug-06 | 109 | 235 | 462 | 202 | 450 | 421.83 |
| Sep-06 | 114 | 237 | 480 | 296 | 488 | 447.71 |
| Oct-06 | 118 | 238 | 497 | 521 | 506 | 508.71 |
| Nov-06 | 144 | 235 | 612 | 1,162 | 507 | 560.75 |
| Dec-06 | 188 | 232 | 811 | 824 | 850 | 735.00 |
| Jan-07 | 191 | 230 | 831 | 912 | 887 | 855.76 |
| Feb-07 | 186 | 230 | 810 | 999 | 763 | 761.76 |
| Mar-07 | 181 | 228 | 792 | 954 | 736 | 678.71 |
| Apr-07 | 168 | 229 | 732 | 512 | 725 | 674.24 |
| May-07 | 128 | 231 | 555 | 322 | 555 | 530.73 |
| Jun-07 | 124 | 234 | 529 | 141 | 534 | 518.38 |
| Jul-07 | 108 | 236 | 459 | 102 | 462 | 449.11 |
| Aug-07 | 109 | 235 | 465 | 154 | 467 | 439.68 |
| Sep-07 | 107 | 238 | 451 | 308 | 455 | 472.77 |
| Oct-07 | 119 | 238 | 499 | 544 | 501 | 512.11 |
| Nov-07 | 54 | 237 | 229 | 725 | 259 | 446.34 |
| Dec-07 | 160 | 236 | 680 | 1,070 | 642 | 731.33 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**CARCROSS RESIDENTIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.74068913 |
| R Square | 0.54862039 |
| Adjusted R Square | 0.54590124 |
| Standard Error | 95.9687139 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1858221.381 | 1858221.38 | 201.76141 | 1.7639E-30 |
| Residual | 166 | 1528859.01 | 9209.99404 | | |
| Total | 167 | 3387080.391 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 412.835263 | 14.12122916 | 29.2350799 | 2.2912E-67 | 384.9549047 | 440.71562 | 384.954905 | 440.71562 |
| MHDD | 0.31026923 | 0.02184337 | 14.2042743 | 1.7639E-30 | 0.2671426 | 0.35339585 | 0.2671426 | 0.35339585 |

| Haines Junction Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-94 | 261 | 275 | 948 | 1,085 | 951 | |
| Feb-94 | 206 | 276 | 747 | 1,125 | 661 | |
| Mar-94 | 238 | 277 | 860 | 654 | 897 | |
| Apr-94 | 211 | 276 | 764 | 431 | 783 | |
| May-94 | 172 | 277 | 620 | 321 | 620 | |
| Jun-94 | 167 | 281 | 595 | 166 | 592 | |
| Jul-94 | 159 | 282 | 565 | 84 | 574 | |
| Aug-94 | 147 | 279 | 527 | 70 | 555 | |
| Sep-94 | 175 | 278 | 630 | 335 | 626 | |
| Oct-94 | 182 | 283 | 642 | 507 | 655 | |
| Nov-94 | 192 | 280 | 686 | 936 | 651 | |
| Dec-94 | 252 | 278 | 905 | 1,029 | 879 | |
| Jan-95 | 285 | 275 | 1,035 | 1,020 | 1,059 | |
| Feb-95 | 226 | 277 | 814 | 840 | 817 | |
| Mar-95 | 237 | 275 | 860 | 880 | 827 | |
| Apr-95 | 184 | 273 | 675 | 440 | 691 | |
| May-95 | 199 | 276 | 720 | 251 | 742 | |
| Jun-95 | 172 | 280 | 614 | 139 | 620 | |
| Jul-95 | 170 | 284 | 598 | 97 | 603 | |
| Aug-95 | 153 | 280 | 547 | 198 | 535 | |
| Sep-95 | 182 | 280 | 650 | 227 | 680 | |
| Oct-95 | 182 | 281 | 647 | 525 | 655 | |
| Nov-95 | 200 | 289 | 691 | 894 | 668 | |
| Dec-95 | 246 | 290 | 847 | 1,049 | 816 | |
| Jan-96 | 301 | 289 | 1,042 | 1,556 | 897 | |
| Feb-96 | 295 | 292 | 1,012 | 836 | 1,015 | |
| Mar-96 | 228 | 290 | 786 | 806 | 776 | |
| Apr-96 | 215 | 293 | 734 | 526 | 723 | |
| May-96 | 189 | 294 | 644 | 357 | 633 | |
| Jun-96 | 182 | 301 | 606 | 194 | 595 | |
| Jul-96 | 167 | 303 | 553 | 125 | 549 | |
| Aug-96 | 174 | 304 | 572 | 227 | 551 | |
| Sep-96 | 184 | 304 | 605 | 363 | 592 | |
| Oct-96 | 193 | 307 | 627 | 680 | 587 | |
| Nov-96 | 242 | 305 | 795 | 975 | 747 | |
| Dec-96 | 272 | 309 | 881 | 1,156 | 816 | |
| Jan-97 | 356 | 309 | 1,151 | 1,186 | 1,122 | 1026.26 |
| Feb-97 | 250 | 308 | 813 | 657 | 873 | 901.58 |
| Mar-97 | 223 | 309 | 721 | 855 | 696 | 766.26 |
| Apr-97 | 223 | 310 | 721 | 484 | 723 | 712.08 |
| May-97 | 203 | 308 | 659 | 331 | 657 | 677.41 |
| Jun-97 | 195 | 314 | 621 | 149 | 624 | 613.45 |
| Jul-97 | 181 | 317 | 571 | 93 | 577 | 576.14 |
| Aug-97 | 174 | 316 | 549 | 130 | 559 | 548.55 |
| Sep-97 | 190 | 317 | 599 | 282 | 610 | 627.20 |
| Oct-97 | 192 | 321 | 598 | 641 | 569 | 603.56 |
| Nov-97 | 239 | 315 | 758 | 694 | 798 | 737.90 |
| Dec-97 | 238 | 320 | 743 | 762 | 801 | 810.84 |
| Jan-98 | 316 | 321 | 984 | 1,166 | 962 | 993.89 |
| Feb-98 | 242 | 319 | 757 | 719 | 798 | 895.21 |
| Mar-98 | 235 | 319 | 737 | 757 | 742 | 737.92 |
| Apr-98 | 214 | 320 | 667 | 459 | 677 | 707.48 |
| May-98 | 205 | 320 | 641 | 271 | 657 | 649.09 |
| Jun-98 | 184 | 322 | 571 | 120 | 583 | 601.06 |
| Jul-98 | 191 | 325 | 589 | 112 | 589 | 571.72 |
| Aug-98 | 163 | 322 | 505 | 189 | 497 | 535.78 |
| Sep-98 | 192 | 321 | 599 | 328 | 597 | 599.61 |
| Oct-98 | 210 | 318 | 659 | 558 | 657 | 604.16 |
| Nov-98 | 218 | 317 | 689 | 792 | 698 | 747.85 |
| Dec-98 | 224 | 317 | 706 | 1,052 | 673 | 763.34 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1994** | 8,489 | 8,445 | - |
| **1995** | 8,699 | 8,712 | - |
| **1996** | 8,856 | 8,481 | - |
| **1997** | 8,504 | 8,610 | 8,601 |
| **1998** | 8,105 | 8,130 | 8,407 |
| **1999** | 8,425 | 8,410 | 8,383 |
| **2000** | 8,142 | 8,183 | 8,241 |
| **2001** | 8,233 | 8,268 | 8,287 |
| **2002** | 8,229 | 8,301 | 8,251 |
| **2003** | 7,738 | 7,761 | 8,110 |
| **2004** | 7,632 | 7,747 | 7,936 |
| **2005** | 7,738 | 7,888 | 7,798 |
| **2006** | 7,862 | 7,742 | 7,792 |
| **2007** | 8,133 | 8,089 | 7,906 |

| Haines Junction Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-99 | 325 | 318 | 1,022 | 1,183 | 995 | 1026.40 |
| Feb-99 | 266 | 318 | 837 | 976 | 797 | 822.28 |
| Mar-99 | 242 | 319 | 759 | 734 | 771 | 736.40 |
| Apr-99 | 234 | 319 | 734 | 509 | 728 | 709.32 |
| May-99 | 192 | 317 | 605 | 392 | 584 | 632.50 |
| Jun-99 | 195 | 317 | 616 | 154 | 618 | 608.49 |
| Jul-99 | 189 | 321 | 589 | 109 | 591 | 585.66 |
| Aug-99 | 175 | 325 | 539 | 146 | 544 | 533.31 |
| Sep-99 | 192 | 326 | 589 | 311 | 592 | 599.59 |
| Oct-99 | 211 | 324 | 651 | 500 | 666 | 630.76 |
| Nov-99 | 230 | 323 | 712 | 793 | 721 | 739.24 |
| Dec-99 | 248 | 322 | 771 | 844 | 804 | 759.29 |
| Jan-00 | 297 | 323 | 919 | 1,083 | 923 | 959.97 |
| Feb-00 | 248 | 323 | 768 | 735 | 803 | 798.98 |
| Mar-00 | 224 | 322 | 696 | 659 | 732 | 748.40 |
| Apr-00 | 209 | 320 | 654 | 516 | 645 | 683.60 |
| May-00 | 208 | 321 | 647 | 382 | 629 | 623.12 |
| Jun-00 | 202 | 318 | 634 | 173 | 630 | 610.27 |
| Jul-00 | 189 | 320 | 589 | 142 | 580 | 586.59 |
| Aug-00 | 183 | 324 | 566 | 220 | 547 | 529.33 |
| Sep-00 | 201 | 321 | 625 | 354 | 614 | 600.89 |
| Oct-00 | 208 | 322 | 645 | 539 | 649 | 657.27 |
| Nov-00 | 227 | 327 | 695 | 691 | 736 | 718.36 |
| Dec-00 | 231 | 327 | 705 | 978 | 695 | 724.00 |
| Jan-01 | 310 | 327 | 948 | 723 | 1,064 | 994.10 |
| Feb-01 | 241 | 326 | 741 | 864 | 735 | 778.25 |
| Mar-01 | 223 | 324 | 687 | 765 | 690 | 731.03 |
| Apr-01 | 207 | 327 | 632 | 507 | 626 | 666.71 |
| May-01 | 217 | 325 | 668 | 390 | 646 | 619.53 |
| Jun-01 | 212 | 326 | 650 | 167 | 648 | 631.79 |
| Jul-01 | 185 | 326 | 568 | 140 | 559 | 576.60 |
| Aug-01 | 184 | 323 | 570 | 140 | 577 | 556.15 |
| Sep-01 | 186 | 327 | 569 | 309 | 573 | 592.85 |
| Oct-01 | 208 | 328 | 633 | 573 | 625 | 646.83 |
| Nov-01 | 237 | 330 | 719 | 818 | 721 | 725.91 |
| Dec-01 | 278 | 328 | 848 | 1,095 | 802 | 767.09 |
| Jan-02 | 317 | 328 | 966 | 936 | 1,016 | 1000.99 |
| Feb-02 | 247 | 329 | 752 | 825 | 759 | 765.86 |
| Mar-02 | 243 | 330 | 737 | 921 | 692 | 704.48 |
| Apr-02 | 255 | 331 | 772 | 653 | 720 | 664.05 |
| May-02 | 208 | 331 | 629 | 362 | 617 | 630.63 |
| Jun-02 | 201 | 335 | 600 | 176 | 595 | 624.14 |
| Jul-02 | 191 | 337 | 567 | 131 | 561 | 566.91 |
| Aug-02 | 190 | 336 | 566 | 183 | 560 | 561.52 |
| Sep-02 | 203 | 338 | 600 | 314 | 601 | 596.10 |
| Oct-02 | 216 | 339 | 639 | 444 | 672 | 648.54 |
| Nov-02 | 264 | 340 | 776 | 583 | 851 | 769.16 |
| Dec-02 | 214 | 342 | 625 | 845 | 657 | 718.15 |
| Jan-03 | 320 | 346 | 925 | 989 | 958 | 1012.66 |
| Feb-03 | 247 | 349 | 708 | 757 | 737 | 743.84 |
| Mar-03 | 231 | 349 | 661 | 835 | 642 | 674.59 |
| Apr-03 | 223 | 344 | 649 | 514 | 642 | 662.80 |
| May-03 | 207 | 347 | 596 | 364 | 583 | 615.35 |
| Jun-03 | 203 | 346 | 586 | 193 | 575 | 606.03 |
| Jul-03 | 188 | 345 | 545 | 84 | 554 | 558.24 |
| Aug-03 | 178 | 346 | 515 | 181 | 509 | 548.67 |
| Sep-03 | 197 | 348 | 565 | 359 | 553 | 575.58 |
| Oct-03 | 191 | 350 | 547 | 467 | 573 | 623.15 |
| Nov-03 | 235 | 352 | 668 | 875 | 652 | 741.30 |
| Dec-03 | 274 | 354 | 773 | 912 | 784 | 747.63 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Haines Junction Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-04 | 310 | 355 | 873 | 1,255 | 823 | 932.29 |
| Feb-04 | 272 | 354 | 767 | 695 | 815 | 770.31 |
| Mar-04 | 226 | 356 | 635 | 756 | 641 | 658.22 |
| Apr-04 | 236 | 351 | 672 | 467 | 679 | 680.41 |
| May-04 | 192 | 349 | 551 | 273 | 566 | 588.61 |
| Jun-04 | 177 | 350 | 506 | 84 | 530 | 566.68 |
| Jul-04 | 203 | 349 | 582 | 74 | 594 | 569.74 |
| Aug-04 | 170 | 347 | 490 | 102 | 508 | 525.70 |
| Sep-04 | 197 | 343 | 574 | 368 | 559 | 570.94 |
| Oct-04 | 194 | 342 | 567 | 541 | 570 | 604.77 |
| Nov-04 | 226 | 348 | 650 | 720 | 682 | 728.24 |
| Dec-04 | 266 | 348 | 765 | 900 | 780 | 740.25 |
| Jan-05 | 303 | 350 | 866 | 1,165 | 844 | 875.05 |
| Feb-05 | 280 | 350 | 799 | 795 | 815 | 788.99 |
| Mar-05 | 217 | 350 | 620 | 614 | 670 | 650.91 |
| Apr-05 | 240 | 350 | 687 | 453 | 698 | 672.86 |
| May-05 | 197 | 346 | 568 | 257 | 589 | 579.29 |
| Jun-05 | 184 | 347 | 531 | 154 | 533 | 545.93 |
| Jul-05 | 192 | 342 | 562 | 133 | 555 | 567.73 |
| Aug-05 | 170 | 343 | 495 | 151 | 499 | 505.28 |
| Sep-05 | 222 | 344 | 646 | 299 | 653 | 588.01 |
| Oct-05 | 195 | 340 | 573 | 535 | 578 | 573.45 |
| Nov-05 | 236 | 344 | 687 | 774 | 702 | 678.62 |
| Dec-05 | 241 | 342 | 705 | 794 | 753 | 772.33 |
| Jan-06 | 300 | 342 | 877 | 1,096 | 876 | 847.80 |
| Feb-06 | 270 | 343 | 787 | 821 | 795 | 808.51 |
| Mar-06 | 253 | 343 | 738 | 906 | 696 | 668.99 |
| Apr-06 | 218 | 343 | 635 | 519 | 625 | 667.42 |
| May-06 | 214 | 345 | 620 | 347 | 613 | 589.25 |
| Jun-06 | 196 | 347 | 565 | 173 | 561 | 541.08 |
| Jul-06 | 208 | 347 | 599 | 118 | 597 | 582.13 |
| Aug-06 | 185 | 349 | 531 | 202 | 518 | 508.35 |
| Sep-06 | 204 | 351 | 581 | 296 | 588 | 599.85 |
| Oct-06 | 179 | 348 | 514 | 521 | 523 | 556.85 |
| Nov-06 | 265 | 350 | 757 | 1,162 | 651 | 678.42 |
| Dec-06 | 231 | 350 | 659 | 824 | 698 | 743.55 |
| Jan-07 | 381 | 350 | 1,088 | 912 | 1,145 | 955.23 |
| Feb-07 | 277 | 350 | 792 | 999 | 745 | 785.10 |
| Mar-07 | 278 | 350 | 795 | 954 | 739 | 701.68 |
| Apr-07 | 249 | 349 | 713 | 512 | 706 | 676.46 |
| May-07 | 192 | 354 | 541 | 322 | 541 | 580.90 |
| Jun-07 | 221 | 352 | 629 | 141 | 635 | 576.16 |
| Jul-07 | 168 | 351 | 479 | 102 | 482 | 544.76 |
| Aug-07 | 174 | 353 | 493 | 154 | 496 | 504.19 |
| Sep-07 | 217 | 355 | 611 | 308 | 615 | 618.55 |
| Oct-07 | 196 | 353 | 554 | 544 | 556 | 552.19 |
| Nov-07 | 246 | 356 | 690 | 725 | 721 | 691.37 |
| Dec-07 | 263 | 353 | 746 | 1,070 | 708 | 719.43 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**HAINES JUNCTION RESIDENTIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.81794091 |
| R Square | 0.66902733 |
| Adjusted R Square | 0.66703352 |
| Standard Error | 74.9169487 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1883302.063 | 1883302.06 | 335.551992 | 1.0471E-41 |
| Residual | 166 | 931683.1679 | 5612.5492 | | |
| Total | 167 | 2814985.231 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 511.286091 | 11.02358632 | 46.3811029 | 6.0823E-97 | 489.5215885 | 533.050594 | 489.521588 | 533.050594 |
| MHDD | 0.31235608 | 0.017051793 | 18.3180783 | 1.0471E-41 | 0.278689743 | 0.34602242 | 0.27868974 | 0.34602242 |

| Teslin Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-94 | 196 | 215 | 912 | 1,085 | 915 | |
| Feb-94 | 134 | 204 | 659 | 1,125 | 584 | |
| Mar-94 | 137 | 216 | 635 | 654 | 668 | |
| Apr-94 | 124 | 213 | 584 | 431 | 600 | |
| May-94 | 93 | 215 | 431 | 321 | 431 | |
| Jun-94 | 92 | 217 | 423 | 166 | 421 | |
| Jul-94 | 101 | 217 | 464 | 84 | 472 | |
| Aug-94 | 93 | 216 | 430 | 70 | 455 | |
| Sep-94 | 110 | 212 | 517 | 335 | 513 | |
| Oct-94 | 92 | 216 | 426 | 507 | 437 | |
| Nov-94 | 118 | 219 | 537 | 936 | 507 | |
| Dec-94 | 150 | 218 | 688 | 1,029 | 667 | |
| Jan-95 | 187 | 218 | 856 | 1,020 | 877 | |
| Feb-95 | 133 | 217 | 612 | 840 | 614 | |
| Mar-95 | 150 | 218 | 686 | 880 | 658 | |
| Apr-95 | 112 | 215 | 521 | 440 | 535 | |
| May-95 | 90 | 210 | 430 | 251 | 449 | |
| Jun-95 | 85 | 211 | 402 | 139 | 407 | |
| Jul-95 | 104 | 211 | 493 | 97 | 497 | |
| Aug-95 | 93 | 216 | 428 | 198 | 419 | |
| Sep-95 | 107 | 222 | 483 | 227 | 508 | |
| Oct-95 | 105 | 216 | 486 | 525 | 492 | |
| Nov-95 | 136 | 217 | 629 | 894 | 609 | |
| Dec-95 | 144 | 217 | 664 | 1,049 | 637 | |
| Jan-96 | 174 | 217 | 802 | 1,556 | 678 | |
| Feb-96 | 184 | 218 | 844 | 836 | 847 | |
| Mar-96 | 129 | 216 | 596 | 806 | 587 | |
| Apr-96 | 117 | 218 | 538 | 526 | 528 | |
| May-96 | 110 | 219 | 501 | 357 | 492 | |
| Jun-96 | 112 | 217 | 518 | 194 | 509 | |
| Jul-96 | 98 | 216 | 453 | 125 | 450 | |
| Aug-96 | 116 | 216 | 538 | 227 | 520 | |
| Sep-96 | 100 | 219 | 457 | 363 | 445 | |
| Oct-96 | 107 | 222 | 482 | 680 | 447 | |
| Nov-96 | 152 | 222 | 686 | 975 | 645 | |
| Dec-96 | 158 | 221 | 717 | 1,156 | 661 | |
| Jan-97 | 222 | 222 | 1,002 | 1,186 | 978 | 843.99 |
| Feb-97 | 146 | 223 | 653 | 657 | 704 | 721.56 |
| Mar-97 | 126 | 226 | 556 | 855 | 535 | 593.13 |
| Apr-97 | 128 | 226 | 566 | 484 | 567 | 543.14 |
| May-97 | 123 | 224 | 547 | 331 | 545 | 495.21 |
| Jun-97 | 101 | 219 | 462 | 149 | 465 | 460.26 |
| Jul-97 | 92 | 221 | 417 | 93 | 422 | 456.31 |
| Aug-97 | 116 | 225 | 516 | 130 | 525 | 487.81 |
| Sep-97 | 93 | 222 | 418 | 282 | 428 | 460.57 |
| Oct-97 | 125 | 221 | 564 | 641 | 540 | 493.06 |
| Nov-97 | 120 | 224 | 538 | 694 | 572 | 608.98 |
| Dec-97 | 137 | 225 | 609 | 762 | 659 | 652.08 |
| Jan-98 | 183 | 225 | 815 | 1,166 | 796 | 817.06 |
| Feb-98 | 130 | 223 | 583 | 719 | 618 | 722.97 |
| Mar-98 | 122 | 225 | 544 | 757 | 549 | 556.79 |
| Apr-98 | 131 | 226 | 579 | 459 | 587 | 560.53 |
| May-98 | 101 | 227 | 446 | 271 | 461 | 499.07 |
| Jun-98 | 93 | 227 | 411 | 120 | 421 | 464.95 |
| Jul-98 | 114 | 228 | 499 | 112 | 499 | 457.13 |
| Aug-98 | 102 | 229 | 443 | 189 | 436 | 493.65 |
| Sep-98 | 103 | 224 | 458 | 328 | 456 | 443.15 |
| Oct-98 | 124 | 229 | 540 | 558 | 538 | 508.23 |
| Nov-98 | 127 | 229 | 554 | 792 | 562 | 593.23 |
| Dec-98 | 143 | 229 | 624 | 1,052 | 596 | 638.63 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1994** | 6,706 | 6,668 | - |
| **1995** | 6,690 | 6,701 | - |
| **1996** | 7,131 | 6,809 | - |
| **1997** | 6,847 | 6,938 | 6,816 |
| **1998** | 6,497 | 6,519 | 6,755 |
| **1999** | 6,621 | 6,608 | 6,688 |
| **2000** | 6,457 | 6,492 | 6,540 |
| **2001** | 6,427 | 6,457 | 6,519 |
| **2002** | 6,401 | 6,462 | 6,470 |
| **2003** | 6,270 | 6,290 | 6,403 |
| **2004** | 6,428 | 6,527 | 6,427 |
| **2005** | 6,524 | 6,652 | 6,490 |
| **2006** | 6,797 | 6,694 | 6,624 |
| **2007** | 7,011 | 6,974 | 6,773 |

| Teslin Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-99 | 192 | 229 | 837 | 1,183 | 813 | 862.19 |
| Feb-99 | 140 | 232 | 604 | 976 | 569 | 630.37 |
| Mar-99 | 152 | 230 | 659 | 734 | 670 | 584.36 |
| Apr-99 | 133 | 227 | 587 | 509 | 581 | 578.46 |
| May-99 | 103 | 226 | 458 | 392 | 439 | 481.54 |
| Jun-99 | 114 | 224 | 510 | 154 | 512 | 465.84 |
| Jul-99 | 113 | 223 | 509 | 109 | 510 | 477.03 |
| Aug-99 | 93 | 227 | 411 | 146 | 416 | 458.77 |
| Sep-99 | 106 | 229 | 463 | 311 | 466 | 449.91 |
| Oct-99 | 121 | 232 | 524 | 500 | 537 | 538.18 |
| Nov-99 | 119 | 233 | 512 | 793 | 520 | 551.39 |
| Dec-99 | 127 | 232 | 548 | 844 | 576 | 610.37 |
| Jan-00 | 194 | 232 | 837 | 1,083 | 840 | 816.39 |
| Feb-00 | 132 | 233 | 564 | 735 | 595 | 593.83 |
| Mar-00 | 114 | 232 | 492 | 659 | 523 | 580.39 |
| Apr-00 | 127 | 232 | 545 | 516 | 538 | 568.81 |
| May-00 | 111 | 234 | 474 | 382 | 458 | 452.59 |
| Jun-00 | 121 | 235 | 514 | 173 | 510 | 481.05 |
| Jul-00 | 97 | 232 | 419 | 142 | 411 | 473.34 |
| Aug-00 | 99 | 233 | 423 | 220 | 407 | 419.65 |
| Sep-00 | 125 | 228 | 547 | 354 | 537 | 486.37 |
| Oct-00 | 113 | 233 | 487 | 539 | 490 | 521.62 |
| Nov-00 | 138 | 234 | 590 | 691 | 625 | 569.07 |
| Dec-00 | 132 | 234 | 566 | 978 | 557 | 576.58 |
| Jan-01 | 149 | 234 | 638 | 723 | 738 | 797.07 |
| Feb-01 | 133 | 233 | 570 | 864 | 566 | 576.47 |
| Mar-01 | 147 | 233 | 629 | 765 | 631 | 607.94 |
| Apr-01 | 124 | 230 | 537 | 507 | 532 | 550.72 |
| May-01 | 110 | 231 | 475 | 390 | 457 | 451.46 |
| Jun-01 | 120 | 232 | 515 | 167 | 513 | 511.73 |
| Jul-01 | 105 | 232 | 453 | 140 | 445 | 455.35 |
| Aug-01 | 99 | 234 | 424 | 140 | 430 | 417.50 |
| Sep-01 | 114 | 232 | 490 | 309 | 493 | 498.73 |
| Oct-01 | 110 | 232 | 473 | 573 | 467 | 498.05 |
| Nov-01 | 137 | 236 | 581 | 818 | 583 | 575.95 |
| Dec-01 | 150 | 234 | 640 | 1,095 | 601 | 578.01 |
| Jan-02 | 148 | 231 | 639 | 936 | 682 | 753.54 |
| Feb-02 | 168 | 233 | 720 | 825 | 726 | 628.82 |
| Mar-02 | 124 | 231 | 538 | 921 | 498 | 550.73 |
| Apr-02 | 125 | 233 | 539 | 653 | 494 | 521.71 |
| May-02 | 137 | 235 | 584 | 362 | 573 | 496.22 |
| Jun-02 | 98 | 233 | 420 | 176 | 416 | 479.76 |
| Jul-02 | 98 | 230 | 428 | 131 | 423 | 426.26 |
| Aug-02 | 112 | 230 | 486 | 183 | 480 | 438.97 |
| Sep-02 | 96 | 230 | 416 | 314 | 417 | 482.66 |
| Oct-02 | 125 | 234 | 533 | 444 | 561 | 506.15 |
| Nov-02 | 123 | 232 | 529 | 583 | 593 | 600.47 |
| Dec-02 | 132 | 232 | 570 | 845 | 598 | 585.19 |
| Jan-03 | 168 | 233 | 721 | 989 | 750 | 723.42 |
| Feb-03 | 127 | 232 | 547 | 757 | 571 | 620.95 |
| Mar-03 | 125 | 235 | 531 | 835 | 515 | 548.10 |
| Apr-03 | 102 | 236 | 434 | 514 | 427 | 484.74 |
| May-03 | 133 | 236 | 565 | 364 | 554 | 528.17 |
| Jun-03 | 99 | 232 | 427 | 193 | 418 | 449.01 |
| Jul-03 | 113 | 236 | 480 | 84 | 487 | 451.76 |
| Aug-03 | 101 | 237 | 428 | 181 | 423 | 444.12 |
| Sep-03 | 109 | 235 | 464 | 359 | 453 | 454.52 |
| Oct-03 | 120 | 233 | 516 | 467 | 538 | 522.25 |
| Nov-03 | 126 | 236 | 536 | 875 | 522 | 565.86 |
| Dec-03 | 148 | 238 | 623 | 912 | 632 | 610.19 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Teslin Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-04 | 195 | 234 | 832 | 1,255 | 789 | 740.37 |
| Feb-04 | 150 | 233 | 643 | 695 | 684 | 660.38 |
| Mar-04 | 103 | 234 | 440 | 756 | 445 | 485.86 |
| Apr-04 | 135 | 234 | 575 | 467 | 581 | 500.91 |
| May-04 | 102 | 235 | 432 | 273 | 446 | 524.44 |
| Jun-04 | 106 | 236 | 450 | 84 | 470 | 434.71 |
| Jul-04 | 121 | 236 | 511 | 74 | 521 | 476.90 |
| Aug-04 | 96 | 238 | 405 | 102 | 421 | 441.38 |
| Sep-04 | 124 | 234 | 531 | 368 | 518 | 463.00 |
| Oct-04 | 119 | 237 | 503 | 541 | 506 | 535.20 |
| Nov-04 | 124 | 235 | 529 | 720 | 557 | 557.24 |
| Dec-04 | 134 | 233 | 576 | 900 | 589 | 606.18 |
| Jan-05 | 216 | 233 | 925 | 1,165 | 907 | 815.10 |
| Feb-05 | 144 | 235 | 615 | 795 | 629 | 627.92 |
| Mar-05 | 125 | 234 | 535 | 614 | 578 | 512.38 |
| Apr-05 | 128 | 235 | 545 | 453 | 555 | 521.11 |
| May-05 | 113 | 235 | 480 | 257 | 498 | 499.25 |
| Jun-05 | 98 | 235 | 416 | 154 | 418 | 435.32 |
| Jul-05 | 110 | 236 | 466 | 133 | 461 | 489.70 |
| Aug-05 | 102 | 236 | 430 | 151 | 433 | 425.90 |
| Sep-05 | 123 | 236 | 522 | 299 | 528 | 499.85 |
| Oct-05 | 109 | 238 | 459 | 535 | 463 | 502.40 |
| Nov-05 | 131 | 237 | 553 | 774 | 566 | 548.01 |
| Dec-05 | 137 | 237 | 577 | 794 | 618 | 612.97 |
| Jan-06 | 193 | 236 | 816 | 1,096 | 816 | 837.00 |
| Feb-06 | 142 | 236 | 600 | 821 | 607 | 639.80 |
| Mar-06 | 175 | 237 | 739 | 906 | 703 | 575.14 |
| Apr-06 | 122 | 239 | 511 | 519 | 503 | 546.46 |
| May-06 | 119 | 237 | 502 | 347 | 495 | 479.73 |
| Jun-06 | 125 | 238 | 523 | 173 | 520 | 469.24 |
| Jul-06 | 106 | 241 | 442 | 118 | 440 | 473.93 |
| Aug-06 | 101 | 242 | 419 | 202 | 409 | 421.17 |
| Sep-06 | 131 | 242 | 540 | 296 | 547 | 531.06 |
| Oct-06 | 113 | 236 | 477 | 521 | 485 | 484.70 |
| Nov-06 | 132 | 242 | 546 | 1,162 | 455 | 525.78 |
| Dec-06 | 163 | 239 | 682 | 824 | 715 | 640.47 |
| Jan-07 | 196 | 238 | 822 | 912 | 871 | 864.49 |
| Feb-07 | 142 | 240 | 591 | 999 | 550 | 595.16 |
| Mar-07 | 175 | 237 | 737 | 954 | 688 | 656.30 |
| Apr-07 | 127 | 239 | 530 | 512 | 524 | 527.33 |
| May-07 | 150 | 243 | 617 | 322 | 617 | 536.74 |
| Jun-07 | 127 | 244 | 522 | 141 | 527 | 488.01 |
| Jul-07 | 108 | 244 | 444 | 102 | 446 | 449.11 |
| Aug-07 | 115 | 246 | 465 | 154 | 468 | 436.51 |
| Sep-07 | 124 | 247 | 500 | 308 | 504 | 526.09 |
| Oct-07 | 136 | 247 | 550 | 544 | 551 | 499.81 |
| Nov-07 | 161 | 249 | 645 | 725 | 672 | 564.03 |
| Dec-07 | 146 | 248 | 589 | 1,070 | 556 | 629.65 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**TESLIN RESIDENTIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.78984568 |
| R Square | 0.62385619 |
| Adjusted R Square | 0.62159027 |
| Standard Error | 71.2568958 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1397952.639 | 1397952.64 | 275.320571 | 4.43118E-37 |
| Residual | 166 | 842872.502 | 5077.54519 | | |
| Total | 167 | 2240825.141 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 404.278455 | 10.48503115 | 38.557678 | 9.3954E-85 | 383.5772531 | 424.979658 | 383.577253 | 424.979658 |
| MHDD | 0.26911395 | 0.016218731 | 16.5927867 | 4.4312E-37 | 0.23709237 | 0.30113552 | 0.23709237 | 0.30113552 |

| Ross River Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-94 | 125 | 145 | 863 | 1,085 | 867 | |
| Feb-94 | 136 | 143 | 952 | 1,125 | 837 | |
| Mar-94 | 120 | 143 | 837 | 654 | 886 | |
| Apr-94 | 98 | 136 | 721 | 431 | 746 | |
| May-94 | 85 | 135 | 629 | 321 | 629 | |
| Jun-94 | 78 | 136 | 574 | 166 | 571 | |
| Jul-94 | 61 | 137 | 447 | 84 | 459 | |
| Aug-94 | 71 | 137 | 517 | 70 | 555 | |
| Sep-94 | 62 | 132 | 473 | 335 | 467 | |
| Oct-94 | 89 | 136 | 657 | 507 | 675 | |
| Nov-94 | 95 | 139 | 682 | 936 | 635 | |
| Dec-94 | 115 | 140 | 818 | 1,029 | 785 | |
| Jan-95 | 161 | 140 | 1,152 | 1,020 | 1,183 | |
| Feb-95 | 98 | 141 | 693 | 840 | 696 | |
| Mar-95 | 91 | 148 | 613 | 880 | 569 | |
| Apr-95 | 100 | 151 | 659 | 440 | 680 | |
| May-95 | 79 | 150 | 525 | 251 | 555 | |
| Jun-95 | 79 | 150 | 529 | 139 | 538 | |
| Jul-95 | 70 | 150 | 465 | 97 | 472 | |
| Aug-95 | 67 | 146 | 459 | 198 | 444 | |
| Sep-95 | 80 | 149 | 538 | 227 | 577 | |
| Oct-95 | 85 | 151 | 561 | 525 | 571 | |
| Nov-95 | 111 | 155 | 717 | 894 | 687 | |
| Dec-95 | 135 | 154 | 874 | 1,049 | 832 | |
| Jan-96 | 175 | 154 | 1,136 | 1,556 | 946 | |
| Feb-96 | 145 | 152 | 953 | 836 | 958 | |
| Mar-96 | 112 | 144 | 777 | 806 | 763 | |
| Apr-96 | 114 | 145 | 787 | 526 | 772 | |
| May-96 | 88 | 148 | 591 | 357 | 577 | |
| Jun-96 | 81 | 149 | 546 | 194 | 532 | |
| Jul-96 | 80 | 148 | 538 | 125 | 533 | |
| Aug-96 | 71 | 153 | 461 | 227 | 434 | |
| Sep-96 | 92 | 154 | 600 | 363 | 583 | |
| Oct-96 | 97 | 156 | 620 | 680 | 567 | |
| Nov-96 | 116 | 159 | 729 | 975 | 666 | |
| Dec-96 | 143 | 161 | 891 | 1,156 | 804 | |
| Jan-97 | 207 | 164 | 1,260 | 1,186 | 1,222 | 1116.89 |
| Feb-97 | 142 | 164 | 867 | 657 | 946 | 866.48 |
| Mar-97 | 124 | 162 | 765 | 855 | 731 | 687.86 |
| Apr-97 | 115 | 165 | 695 | 484 | 697 | 716.19 |
| May-97 | 89 | 166 | 538 | 331 | 535 | 555.57 |
| Jun-97 | 83 | 165 | 505 | 149 | 509 | 526.34 |
| Jul-97 | 84 | 166 | 507 | 93 | 515 | 506.73 |
| Aug-97 | 74 | 165 | 446 | 130 | 460 | 445.92 |
| Sep-97 | 90 | 162 | 558 | 282 | 573 | 577.63 |
| Oct-97 | 107 | 168 | 639 | 641 | 601 | 579.59 |
| Nov-97 | 115 | 169 | 683 | 694 | 736 | 696.36 |
| Dec-97 | 108 | 167 | 646 | 762 | 723 | 786.58 |
| Jan-98 | 178 | 168 | 1,059 | 1,166 | 1,029 | 1065.81 |
| Feb-98 | 130 | 162 | 803 | 719 | 856 | 919.83 |
| Mar-98 | 129 | 165 | 783 | 757 | 790 | 761.54 |
| Apr-98 | 103 | 162 | 636 | 459 | 648 | 705.62 |
| May-98 | 85 | 162 | 528 | 271 | 549 | 553.61 |
| Jun-98 | 82 | 164 | 502 | 120 | 519 | 520.02 |
| Jul-98 | 91 | 164 | 553 | 112 | 554 | 534.06 |
| Aug-98 | 74 | 163 | 451 | 189 | 440 | 444.58 |
| Sep-98 | 94 | 167 | 560 | 328 | 557 | 570.88 |
| Oct-98 | 99 | 174 | 567 | 558 | 564 | 577.18 |
| Nov-98 | 103 | 174 | 592 | 792 | 605 | 668.94 |
| Dec-98 | 146 | 174 | 841 | 1,052 | 798 | 775.17 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1994** | 8,171 | 8,113 | - |
| **1995** | 7,786 | 7,804 | - |
| **1996** | 8,630 | 8,134 | - |
| **1997** | 8,109 | 8,249 | 8,062 |
| **1998** | 7,875 | 7,909 | 8,097 |
| **1999** | 7,780 | 7,760 | 7,973 |
| **2000** | 8,011 | 8,065 | 7,911 |
| **2001** | 7,520 | 7,566 | 7,797 |
| **2002** | 7,193 | 7,288 | 7,640 |
| **2003** | 6,856 | 6,886 | 7,247 |
| **2004** | 7,154 | 7,307 | 7,160 |
| **2005** | 7,453 | 7,650 | 7,281 |
| **2006** | 7,725 | 7,566 | 7,508 |
| **2007** | 7,504 | 7,446 | 7,554 |

| Ross River Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-99 | 165 | 173 | 956 | 1,183 | 920 | 1057.19 |
| Feb-99 | 140 | 175 | 799 | 976 | 745 | 849.08 |
| Mar-99 | 124 | 176 | 707 | 734 | 723 | 748.11 |
| Apr-99 | 121 | 172 | 703 | 509 | 695 | 680.07 |
| May-99 | 98 | 170 | 576 | 392 | 547 | 543.64 |
| Jun-99 | 81 | 160 | 505 | 154 | 507 | 511.69 |
| Jul-99 | 97 | 166 | 582 | 109 | 583 | 550.73 |
| Aug-99 | 79 | 167 | 472 | 146 | 479 | 459.28 |
| Sep-99 | 80 | 169 | 471 | 311 | 474 | 534.75 |
| Oct-99 | 109 | 171 | 640 | 500 | 661 | 608.65 |
| Nov-99 | 112 | 173 | 647 | 793 | 659 | 666.79 |
| Dec-99 | 125 | 173 | 724 | 844 | 766 | 762.53 |
| Jan-00 | 165 | 171 | 963 | 1,083 | 968 | 972.34 |
| Feb-00 | 132 | 170 | 778 | 735 | 824 | 808.56 |
| Mar-00 | 115 | 170 | 679 | 659 | 726 | 746.47 |
| Apr-00 | 131 | 166 | 788 | 516 | 777 | 706.70 |
| May-00 | 87 | 169 | 515 | 382 | 490 | 528.83 |
| Jun-00 | 105 | 161 | 650 | 173 | 644 | 556.67 |
| Jul-00 | 75 | 160 | 467 | 142 | 454 | 530.42 |
| Aug-00 | 76 | 161 | 475 | 220 | 451 | 456.49 |
| Sep-00 | 101 | 161 | 628 | 354 | 614 | 548.23 |
| Oct-00 | 99 | 165 | 600 | 539 | 605 | 609.85 |
| Nov-00 | 102 | 166 | 616 | 691 | 670 | 644.64 |
| Dec-00 | 144 | 169 | 854 | 978 | 842 | 802.13 |
| Jan-01 | 138 | 168 | 824 | 723 | 978 | 955.16 |
| Feb-01 | 115 | 169 | 680 | 864 | 673 | 747.64 |
| Mar-01 | 141 | 166 | 847 | 765 | 850 | 766.50 |
| Apr-01 | 97 | 164 | 594 | 507 | 587 | 686.35 |
| May-01 | 93 | 160 | 580 | 390 | 552 | 529.77 |
| Jun-01 | 90 | 160 | 560 | 167 | 557 | 569.30 |
| Jul-01 | 75 | 161 | 468 | 140 | 456 | 497.99 |
| Aug-01 | 70 | 162 | 431 | 140 | 440 | 456.69 |
| Sep-01 | 84 | 165 | 511 | 309 | 515 | 534.40 |
| Oct-01 | 91 | 162 | 561 | 573 | 551 | 605.49 |
| Nov-01 | 123 | 168 | 735 | 818 | 737 | 688.54 |
| Dec-01 | 122 | 167 | 730 | 1,095 | 670 | 759.25 |
| Jan-02 | 135 | 164 | 823 | 936 | 889 | 944.80 |
| Feb-02 | 143 | 167 | 854 | 825 | 863 | 786.85 |
| Mar-02 | 109 | 166 | 657 | 921 | 596 | 724.03 |
| Apr-02 | 112 | 168 | 665 | 653 | 598 | 653.83 |
| May-02 | 103 | 168 | 615 | 362 | 599 | 546.97 |
| Jun-02 | 74 | 166 | 448 | 176 | 441 | 547.33 |
| Jul-02 | 73 | 170 | 428 | 131 | 420 | 443.59 |
| Aug-02 | 86 | 167 | 512 | 183 | 503 | 464.95 |
| Sep-02 | 73 | 177 | 415 | 314 | 417 | 515.34 |
| Oct-02 | 85 | 173 | 494 | 444 | 537 | 564.34 |
| Nov-02 | 118 | 178 | 663 | 583 | 762 | 722.75 |
| Dec-02 | 111 | 178 | 622 | 845 | 664 | 725.06 |
| Jan-03 | 150 | 177 | 845 | 989 | 889 | 918.50 |
| Feb-03 | 127 | 177 | 718 | 757 | 755 | 763.90 |
| Mar-03 | 110 | 175 | 630 | 835 | 605 | 683.53 |
| Apr-03 | 96 | 175 | 550 | 514 | 539 | 574.66 |
| May-03 | 97 | 173 | 561 | 364 | 544 | 564.75 |
| Jun-03 | 74 | 172 | 431 | 193 | 417 | 471.57 |
| Jul-03 | 79 | 173 | 457 | 84 | 468 | 448.18 |
| Aug-03 | 67 | 173 | 387 | 181 | 379 | 440.96 |
| Sep-03 | 69 | 172 | 403 | 359 | 386 | 439.55 |
| Oct-03 | 82 | 173 | 473 | 467 | 508 | 532.06 |
| Nov-03 | 115 | 170 | 675 | 875 | 654 | 717.41 |
| Dec-03 | 125 | 172 | 727 | 912 | 742 | 691.81 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Ross River Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-04 | 152 | 172 | 884 | 1,255 | 818 | 865.16 |
| Feb-04 | 129 | 168 | 769 | 695 | 832 | 816.94 |
| Mar-04 | 109 | 171 | 640 | 756 | 648 | 615.96 |
| Apr-04 | 118 | 172 | 685 | 467 | 695 | 610.47 |
| May-04 | 84 | 169 | 499 | 273 | 520 | 553.98 |
| Jun-04 | 77 | 169 | 453 | 84 | 485 | 447.51 |
| Jul-04 | 81 | 167 | 487 | 74 | 503 | 463.61 |
| Aug-04 | 70 | 169 | 415 | 102 | 440 | 440.81 |
| Sep-04 | 91 | 169 | 539 | 368 | 519 | 440.76 |
| Oct-04 | 86 | 171 | 500 | 541 | 504 | 516.38 |
| Nov-04 | 98 | 172 | 568 | 720 | 610 | 675.27 |
| Dec-04 | 124 | 173 | 715 | 900 | 735 | 713.46 |
| Jan-05 | 171 | 171 | 999 | 1,165 | 970 | 892.41 |
| Feb-05 | 141 | 170 | 829 | 795 | 851 | 812.80 |
| Mar-05 | 108 | 171 | 633 | 614 | 699 | 650.34 |
| Apr-05 | 117 | 170 | 688 | 453 | 703 | 645.50 |
| May-05 | 87 | 170 | 513 | 257 | 541 | 534.58 |
| Jun-05 | 75 | 172 | 435 | 154 | 437 | 446.33 |
| Jul-05 | 84 | 172 | 489 | 133 | 481 | 483.88 |
| Aug-05 | 79 | 172 | 457 | 151 | 462 | 426.87 |
| Sep-05 | 99 | 170 | 584 | 299 | 592 | 499.26 |
| Oct-05 | 85 | 171 | 496 | 535 | 503 | 504.73 |
| Nov-05 | 101 | 171 | 593 | 774 | 613 | 625.69 |
| Dec-05 | 122 | 166 | 736 | 794 | 800 | 758.66 |
| Jan-06 | 159 | 166 | 961 | 1,096 | 960 | 916.16 |
| Feb-06 | 133 | 166 | 801 | 821 | 811 | 831.45 |
| Mar-06 | 119 | 170 | 697 | 906 | 643 | 663.03 |
| Apr-06 | 123 | 168 | 730 | 519 | 717 | 704.82 |
| May-06 | 93 | 167 | 557 | 347 | 547 | 535.63 |
| Jun-06 | 90 | 169 | 533 | 173 | 527 | 483.11 |
| Jul-06 | 73 | 171 | 426 | 118 | 423 | 468.95 |
| Aug-06 | 67 | 170 | 394 | 202 | 377 | 426.30 |
| Sep-06 | 90 | 172 | 522 | 296 | 532 | 547.87 |
| Oct-06 | 90 | 171 | 525 | 521 | 537 | 514.42 |
| Nov-06 | 116 | 168 | 689 | 1,162 | 548 | 590.47 |
| Dec-06 | 149 | 167 | 892 | 824 | 942 | 825.52 |
| Jan-07 | 130 | 167 | 779 | 912 | 854 | 928.29 |
| Feb-07 | 119 | 166 | 714 | 999 | 652 | 771.22 |
| Mar-07 | 159 | 165 | 963 | 954 | 888 | 743.21 |
| Apr-07 | 114 | 167 | 682 | 512 | 673 | 697.59 |
| May-07 | 85 | 168 | 505 | 322 | 505 | 530.89 |
| Jun-07 | 86 | 164 | 527 | 141 | 535 | 499.85 |
| Jul-07 | 71 | 168 | 422 | 102 | 426 | 443.31 |
| Aug-07 | 79 | 168 | 469 | 154 | 472 | 437.03 |
| Sep-07 | 75 | 168 | 445 | 308 | 450 | 524.93 |
| Oct-07 | 95 | 168 | 563 | 544 | 566 | 534.96 |
| Nov-07 | 122 | 166 | 733 | 725 | 773 | 644.88 |
| Dec-07 | 117 | 166 | 703 | 1,070 | 652 | 798.05 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**ROSS RIVER RESIDENTIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.84597515 |
| R Square | 0.71567396 |
| Adjusted R Square | 0.71396115 |
| Standard Error | 88.8706756 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 3300073.562 | 3300073.56 | 417.836772 | 3.38559E-47 |
| Residual | 166 | 1311067.499 | 7897.99698 | | |
| Total | 167 | 4611141.061 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 413.852072 | 13.07679477 | 31.6478219 | 3.2221E-72 | 388.0338014 | 439.670343 | 388.033801 | 439.670343 |
| MHDD | 0.41347741 | 0.020227791 | 20.441056 | 3.3856E-47 | 0.373540515 | 0.45341431 | 0.37354051 | 0.45341431 |

| Tagish Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-94 | 147 | 243 | 603 | 1,085 | 605 | |
| Feb-94 | 119 | 238 | 498 | 1,125 | 438 | |
| Mar-94 | 114 | 239 | 475 | 654 | 501 | |
| Apr-94 | 75 | 239 | 315 | 431 | 327 | |
| May-94 | 69 | 240 | 288 | 321 | 288 | |
| Jun-94 | 56 | 241 | 232 | 166 | 231 | |
| Jul-94 | 63 | 241 | 261 | 84 | 268 | |
| Aug-94 | 61 | 243 | 250 | 70 | 270 | |
| Sep-94 | 69 | 242 | 284 | 335 | 280 | |
| Oct-94 | 74 | 245 | 301 | 507 | 311 | |
| Nov-94 | 109 | 244 | 446 | 936 | 421 | |
| Dec-94 | 120 | 244 | 493 | 1,029 | 475 | |
| Jan-95 | 156 | 243 | 643 | 1,020 | 659 | |
| Feb-95 | 111 | 244 | 457 | 840 | 458 | |
| Mar-95 | 149 | 243 | 612 | 880 | 589 | |
| Apr-95 | 80 | 242 | 331 | 440 | 342 | |
| May-95 | 73 | 251 | 290 | 251 | 305 | |
| Jun-95 | 77 | 252 | 307 | 139 | 312 | |
| Jul-95 | 70 | 252 | 277 | 97 | 280 | |
| Aug-95 | 64 | 252 | 255 | 198 | 247 | |
| Sep-95 | 80 | 250 | 321 | 227 | 341 | |
| Oct-95 | 82 | 251 | 327 | 525 | 333 | |
| Nov-95 | 108 | 254 | 426 | 894 | 411 | |
| Dec-95 | 143 | 254 | 562 | 1,049 | 540 | |
| Jan-96 | 140 | 255 | 549 | 1,556 | 448 | |
| Feb-96 | 166 | 253 | 656 | 836 | 659 | |
| Mar-96 | 100 | 253 | 394 | 806 | 387 | |
| Apr-96 | 87 | 253 | 345 | 526 | 337 | |
| May-96 | 84 | 256 | 327 | 357 | 320 | |
| Jun-96 | 69 | 260 | 266 | 194 | 259 | |
| Jul-96 | 77 | 262 | 293 | 125 | 291 | |
| Aug-96 | 82 | 262 | 312 | 227 | 298 | |
| Sep-96 | 80 | 259 | 310 | 363 | 301 | |
| Oct-96 | 95 | 259 | 365 | 680 | 337 | |
| Nov-96 | 103 | 256 | 404 | 975 | 371 | |
| Dec-96 | 135 | 257 | 525 | 1,156 | 479 | |
| Jan-97 | 154 | 256 | 603 | 1,186 | 583 | 563.59 |
| Feb-97 | 97 | 254 | 382 | 657 | 424 | 513.68 |
| Mar-97 | 95 | 257 | 368 | 855 | 351 | 442.04 |
| Apr-97 | 87 | 260 | 335 | 484 | 336 | 338.36 |
| May-97 | 80 | 262 | 306 | 331 | 304 | 309.80 |
| Jun-97 | 68 | 260 | 261 | 149 | 264 | 277.94 |
| Jul-97 | 71 | 262 | 272 | 93 | 276 | 282.29 |
| Aug-97 | 77 | 265 | 292 | 130 | 299 | 281.02 |
| Sep-97 | 73 | 266 | 275 | 282 | 283 | 308.27 |
| Oct-97 | 93 | 266 | 350 | 641 | 331 | 333.42 |
| Nov-97 | 86 | 264 | 324 | 694 | 352 | 377.93 |
| Dec-97 | 94 | 262 | 358 | 762 | 399 | 472.85 |
| Jan-98 | 150 | 264 | 569 | 1,166 | 553 | 528.33 |
| Feb-98 | 103 | 264 | 391 | 719 | 419 | 500.40 |
| Mar-98 | 95 | 264 | 360 | 757 | 363 | 366.87 |
| Apr-98 | 88 | 264 | 335 | 459 | 342 | 338.26 |
| May-98 | 78 | 265 | 295 | 271 | 307 | 310.19 |
| Jun-98 | 73 | 270 | 270 | 120 | 278 | 266.83 |
| Jul-98 | 83 | 270 | 307 | 112 | 307 | 291.24 |
| Aug-98 | 78 | 275 | 284 | 189 | 278 | 291.50 |
| Sep-98 | 83 | 277 | 300 | 328 | 299 | 294.16 |
| Oct-98 | 93 | 274 | 341 | 558 | 339 | 335.54 |
| Nov-98 | 95 | 272 | 349 | 792 | 355 | 359.46 |
| Dec-98 | 103 | 273 | 378 | 1,052 | 355 | 411.01 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1994** | 4,446 | 4,416 | - |
| **1995** | 4,808 | 4,817 | - |
| **1996** | 4,746 | 4,486 | - |
| **1997** | 4,127 | 4,201 | 4,501 |
| **1998** | 4,177 | 4,195 | 4,294 |
| **1999** | 4,127 | 4,117 | 4,171 |
| **2000** | 3,765 | 3,793 | 4,035 |
| **2001** | 3,641 | 3,665 | 3,858 |
| **2002** | 3,741 | 3,791 | 3,749 |
| **2003** | 3,698 | 3,714 | 3,723 |
| **2004** | 3,917 | 3,998 | 3,834 |
| **2005** | 4,059 | 4,163 | 3,958 |
| **2006** | 4,591 | 4,508 | 4,223 |
| **2007** | 4,790 | 4,759 | 4,477 |

| Tagish Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-99 | 147 | 274 | 537 | 1,183 | 518 | 551.54 |
| Feb-99 | 116 | 274 | 424 | 976 | 396 | 412.67 |
| Mar-99 | 102 | 273 | 375 | 734 | 383 | 365.78 |
| Apr-99 | 102 | 273 | 373 | 509 | 368 | 348.87 |
| May-99 | 81 | 277 | 292 | 392 | 277 | 296.01 |
| Jun-99 | 76 | 282 | 271 | 154 | 272 | 271.35 |
| Jul-99 | 88 | 286 | 306 | 109 | 307 | 296.66 |
| Aug-99 | 79 | 282 | 281 | 146 | 284 | 287.14 |
| Sep-99 | 84 | 285 | 295 | 311 | 297 | 292.81 |
| Oct-99 | 82 | 285 | 288 | 500 | 299 | 322.73 |
| Nov-99 | 88 | 282 | 313 | 793 | 319 | 342.16 |
| Dec-99 | 105 | 280 | 374 | 844 | 396 | 383.22 |
| Jan-00 | 127 | 279 | 454 | 1,083 | 456 | 509.22 |
| Feb-00 | 94 | 279 | 337 | 735 | 362 | 391.98 |
| Mar-00 | 91 | 279 | 325 | 659 | 350 | 365.50 |
| Apr-00 | 87 | 283 | 308 | 516 | 303 | 337.60 |
| May-00 | 85 | 286 | 299 | 382 | 286 | 289.80 |
| Jun-00 | 76 | 289 | 263 | 173 | 260 | 270.16 |
| Jul-00 | 80 | 289 | 276 | 142 | 269 | 294.49 |
| Aug-00 | 86 | 288 | 300 | 220 | 287 | 283.34 |
| Sep-00 | 78 | 285 | 275 | 354 | 267 | 287.56 |
| Oct-00 | 77 | 287 | 270 | 539 | 272 | 303.19 |
| Nov-00 | 82 | 283 | 291 | 691 | 320 | 331.40 |
| Dec-00 | 103 | 280 | 368 | 978 | 361 | 370.74 |
| Jan-01 | 97 | 281 | 344 | 723 | 425 | 466.32 |
| Feb-01 | 102 | 283 | 359 | 864 | 356 | 371.04 |
| Mar-01 | 86 | 285 | 303 | 765 | 305 | 346.07 |
| Apr-01 | 81 | 285 | 284 | 507 | 281 | 317.19 |
| May-01 | 78 | 286 | 273 | 390 | 258 | 273.75 |
| Jun-01 | 70 | 289 | 241 | 167 | 240 | 257.35 |
| Jul-01 | 75 | 292 | 257 | 140 | 251 | 275.72 |
| Aug-01 | 81 | 289 | 279 | 140 | 283 | 285.04 |
| Sep-01 | 77 | 295 | 262 | 309 | 264 | 276.06 |
| Oct-01 | 81 | 294 | 275 | 573 | 270 | 280.03 |
| Nov-01 | 94 | 291 | 324 | 818 | 325 | 321.38 |
| Dec-01 | 127 | 289 | 439 | 1,095 | 407 | 388.28 |
| Jan-02 | 122 | 290 | 420 | 936 | 454 | 445.12 |
| Feb-02 | 102 | 290 | 352 | 825 | 357 | 358.21 |
| Mar-02 | 93 | 290 | 321 | 921 | 289 | 314.62 |
| Apr-02 | 92 | 291 | 315 | 653 | 279 | 287.43 |
| May-02 | 83 | 293 | 283 | 362 | 275 | 273.00 |
| Jun-02 | 74 | 296 | 248 | 176 | 245 | 248.22 |
| Jul-02 | 81 | 296 | 272 | 131 | 268 | 262.75 |
| Aug-02 | 86 | 297 | 291 | 183 | 286 | 285.60 |
| Sep-02 | 75 | 296 | 253 | 314 | 254 | 261.91 |
| Oct-02 | 88 | 295 | 299 | 444 | 322 | 287.93 |
| Nov-02 | 92 | 291 | 317 | 583 | 369 | 338.11 |
| Dec-02 | 108 | 293 | 369 | 845 | 391 | 386.58 |
| Jan-03 | 128 | 293 | 438 | 989 | 461 | 446.74 |
| Feb-03 | 103 | 293 | 353 | 757 | 372 | 361.78 |
| Mar-03 | 98 | 291 | 336 | 835 | 323 | 305.68 |
| Apr-03 | 92 | 292 | 314 | 514 | 308 | 289.36 |
| May-03 | 83 | 296 | 282 | 364 | 273 | 268.63 |
| Jun-03 | 76 | 298 | 256 | 193 | 249 | 244.36 |
| Jul-03 | 87 | 301 | 288 | 84 | 294 | 270.94 |
| Aug-03 | 81 | 298 | 270 | 181 | 266 | 278.67 |
| Sep-03 | 83 | 301 | 277 | 359 | 269 | 262.49 |
| Oct-03 | 74 | 304 | 244 | 467 | 262 | 284.51 |
| Nov-03 | 80 | 305 | 263 | 875 | 252 | 315.54 |
| Dec-03 | 116 | 308 | 377 | 912 | 385 | 394.40 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Tagish Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-04 | 131 | 307 | 426 | 1,255 | 392 | 435.73 |
| Feb-04 | 116 | 306 | 378 | 695 | 411 | 380.17 |
| Mar-04 | 104 | 305 | 340 | 756 | 344 | 318.73 |
| Apr-04 | 109 | 303 | 360 | 467 | 365 | 317.52 |
| May-04 | 87 | 309 | 281 | 273 | 292 | 279.88 |
| Jun-04 | 78 | 311 | 250 | 84 | 267 | 253.34 |
| Jul-04 | 90 | 309 | 291 | 74 | 299 | 287.12 |
| Aug-04 | 80 | 311 | 257 | 102 | 270 | 274.19 |
| Sep-04 | 99 | 311 | 317 | 368 | 307 | 276.69 |
| Oct-04 | 96 | 314 | 305 | 541 | 307 | 296.95 |
| Nov-04 | 105 | 312 | 336 | 720 | 359 | 326.65 |
| Dec-04 | 118 | 314 | 375 | 900 | 386 | 387.19 |
| Jan-05 | 166 | 312 | 532 | 1,165 | 517 | 456.74 |
| Feb-05 | 134 | 312 | 428 | 795 | 439 | 407.59 |
| Mar-05 | 102 | 313 | 325 | 614 | 359 | 342.21 |
| Apr-05 | 98 | 310 | 316 | 453 | 324 | 332.50 |
| May-05 | 85 | 312 | 272 | 257 | 286 | 283.59 |
| Jun-05 | 79 | 314 | 252 | 154 | 254 | 256.24 |
| Jul-05 | 90 | 314 | 286 | 133 | 282 | 291.69 |
| Aug-05 | 95 | 317 | 300 | 151 | 303 | 279.76 |
| Sep-05 | 88 | 319 | 276 | 299 | 281 | 285.39 |
| Oct-05 | 100 | 320 | 312 | 535 | 316 | 294.76 |
| Nov-05 | 110 | 317 | 346 | 774 | 357 | 322.46 |
| Dec-05 | 131 | 317 | 412 | 794 | 445 | 405.31 |
| Jan-06 | 175 | 318 | 550 | 1,096 | 550 | 486.25 |
| Feb-06 | 138 | 317 | 436 | 821 | 442 | 430.66 |
| Mar-06 | 143 | 316 | 454 | 906 | 425 | 376.21 |
| Apr-06 | 120 | 315 | 381 | 519 | 374 | 354.49 |
| May-06 | 104 | 319 | 327 | 347 | 322 | 300.00 |
| Jun-06 | 85 | 323 | 262 | 173 | 259 | 259.89 |
| Jul-06 | 104 | 325 | 320 | 118 | 319 | 300.02 |
| Aug-06 | 90 | 325 | 277 | 202 | 268 | 280.26 |
| Sep-06 | 99 | 322 | 308 | 296 | 313 | 300.25 |
| Oct-06 | 105 | 322 | 326 | 521 | 332 | 318.17 |
| Nov-06 | 136 | 321 | 425 | 1,162 | 351 | 355.35 |
| Dec-06 | 167 | 318 | 526 | 824 | 553 | 461.32 |
| Jan-07 | 190 | 318 | 596 | 912 | 636 | 567.67 |
| Feb-07 | 174 | 317 | 549 | 999 | 516 | 465.86 |
| Mar-07 | 143 | 315 | 455 | 954 | 416 | 400.19 |
| Apr-07 | 113 | 316 | 358 | 512 | 353 | 350.37 |
| May-07 | 106 | 318 | 332 | 322 | 332 | 313.37 |
| Jun-07 | 97 | 325 | 297 | 141 | 302 | 271.50 |
| Jul-07 | 93 | 325 | 286 | 102 | 288 | 296.11 |
| Aug-07 | 97 | 326 | 298 | 154 | 299 | 290.03 |
| Sep-07 | 98 | 328 | 297 | 308 | 300 | 297.93 |
| Oct-07 | 113 | 331 | 341 | 544 | 342 | 329.99 |
| Nov-07 | 154 | 328 | 471 | 725 | 492 | 399.94 |
| Dec-07 | 167 | 327 | 510 | 1,070 | 483 | 493.71 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**TAGISH RESIDENTIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.80161532 |
| R Square | 0.64258711 |
| Adjusted R Square | 0.64043403 |
| Standard Error | 55.3125283 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 913096.9995 | 913096.999 | 298.44884 | 6.29458E-39 |
| Residual | 166 | 507872.9799 | 3059.47578 | | |
| Total | 167 | 1420969.979 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 229.28296 | 8.13891169 | 28.1712062 | 3.8618E-65 | 213.2138365 | 245.352083 | 213.213836 | 245.352083 |
| MHDD | 0.21749458 | 0.012589645 | 17.2756719 | 6.2946E-39 | 0.192638115 | 0.24235104 | 0.19263812 | 0.24235104 |

| Marsh Lake Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-94 | 358 | 354 | 1,011 | 1,085 | 1,016 | |
| Feb-94 | 294 | 350 | 839 | 1,125 | 718 | |
| Mar-94 | 271 | 353 | 767 | 654 | 819 | |
| Apr-94 | 203 | 353 | 576 | 431 | 602 | |
| May-94 | 175 | 351 | 499 | 321 | 500 | |
| Jun-94 | 146 | 353 | 413 | 166 | 409 | |
| Jul-94 | 142 | 357 | 398 | 84 | 410 | |
| Aug-94 | 150 | 359 | 418 | 70 | 458 | |
| Sep-94 | 169 | 360 | 469 | 335 | 463 | |
| Oct-94 | 194 | 361 | 537 | 507 | 556 | |
| Nov-94 | 273 | 360 | 758 | 936 | 708 | |
| Dec-94 | 343 | 360 | 952 | 1,029 | 917 | |
| Jan-95 | 300 | 357 | 839 | 1,020 | 872 | |
| Feb-95 | 262 | 357 | 734 | 840 | 737 | |
| Mar-95 | 297 | 357 | 833 | 880 | 786 | |
| Apr-95 | 206 | 359 | 575 | 440 | 596 | |
| May-95 | 185 | 364 | 508 | 251 | 540 | |
| Jun-95 | 149 | 364 | 409 | 139 | 417 | |
| Jul-95 | 161 | 368 | 436 | 97 | 443 | |
| Aug-95 | 167 | 367 | 456 | 198 | 440 | |
| Sep-95 | 177 | 370 | 478 | 227 | 518 | |
| Oct-95 | 201 | 373 | 538 | 525 | 549 | |
| Nov-95 | 278 | 374 | 743 | 894 | 712 | |
| Dec-95 | 369 | 373 | 989 | 1,049 | 945 | |
| Jan-96 | 304 | 373 | 815 | 1,556 | 614 | |
| Feb-96 | 455 | 372 | 1,224 | 836 | 1,229 | |
| Mar-96 | 259 | 373 | 694 | 806 | 680 | |
| Apr-96 | 224 | 372 | 602 | 526 | 586 | |
| May-96 | 192 | 376 | 510 | 357 | 495 | |
| Jun-96 | 157 | 376 | 418 | 194 | 403 | |
| Jul-96 | 174 | 376 | 462 | 125 | 457 | |
| Aug-96 | 171 | 376 | 454 | 227 | 426 | |
| Sep-96 | 187 | 376 | 497 | 363 | 479 | |
| Oct-96 | 248 | 373 | 666 | 680 | 609 | |
| Nov-96 | 313 | 374 | 837 | 975 | 771 | |
| Dec-96 | 374 | 377 | 992 | 1,156 | 901 | |
| Jan-97 | 446 | 376 | 1,187 | 1,186 | 1,148 | 878.06 |
| Feb-97 | 263 | 377 | 697 | 657 | 781 | 915.55 |
| Mar-97 | 252 | 377 | 669 | 855 | 633 | 699.62 |
| Apr-97 | 249 | 376 | 662 | 484 | 665 | 615.64 |
| May-97 | 187 | 374 | 500 | 331 | 496 | 510.44 |
| Jun-97 | 160 | 379 | 422 | 149 | 426 | 415.47 |
| Jul-97 | 187 | 379 | 494 | 93 | 502 | 467.52 |
| Aug-97 | 152 | 376 | 404 | 130 | 418 | 427.91 |
| Sep-97 | 180 | 379 | 475 | 282 | 491 | 495.97 |
| Oct-97 | 247 | 378 | 653 | 641 | 613 | 590.55 |
| Nov-97 | 242 | 379 | 639 | 694 | 695 | 725.74 |
| Dec-97 | 301 | 381 | 791 | 762 | 872 | 906.20 |
| Jan-98 | 352 | 381 | 923 | 1,166 | 892 | 884.67 |
| Feb-98 | 274 | 381 | 720 | 719 | 776 | 928.41 |
| Mar-98 | 241 | 380 | 633 | 757 | 641 | 651.20 |
| Apr-98 | 224 | 380 | 589 | 459 | 603 | 617.83 |
| May-98 | 188 | 380 | 494 | 271 | 516 | 502.62 |
| Jun-98 | 167 | 380 | 439 | 120 | 456 | 428.46 |
| Jul-98 | 185 | 380 | 487 | 112 | 488 | 482.33 |
| Aug-98 | 179 | 383 | 467 | 189 | 455 | 432.79 |
| Sep-98 | 212 | 383 | 554 | 328 | 551 | 506.89 |
| Oct-98 | 216 | 386 | 561 | 558 | 557 | 593.22 |
| Nov-98 | 251 | 383 | 656 | 792 | 669 | 711.44 |
| Dec-98 | 341 | 385 | 887 | 1,052 | 841 | 871.47 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1994** | 7,637 | 7,576 | - |
| **1995** | 7,538 | 7,556 | - |
| **1996** | 8,173 | 7,650 | - |
| **1997** | 7,592 | 7,740 | 7,649 |
| **1998** | 7,409 | 7,444 | 7,611 |
| **1999** | 7,314 | 7,293 | 7,493 |
| **2000** | 7,004 | 7,061 | 7,266 |
| **2001** | 7,054 | 7,103 | 7,152 |
| **2002** | 6,943 | 7,043 | 7,069 |
| **2003** | 6,953 | 6,986 | 7,044 |
| **2004** | 7,138 | 7,300 | 7,110 |
| **2005** | 7,197 | 7,406 | 7,230 |
| **2006** | 7,843 | 7,675 | 7,460 |
| **2007** | 7,878 | 7,816 | 7,632 |

| Marsh Lake Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-99 | 347 | 383 | 907 | 1,183 | 869 | 969.53 |
| Feb-99 | 310 | 382 | 812 | 976 | 756 | 770.65 |
| Mar-99 | 253 | 383 | 661 | 734 | 678 | 650.69 |
| Apr-99 | 238 | 386 | 615 | 509 | 607 | 624.78 |
| May-99 | 198 | 386 | 514 | 392 | 484 | 498.78 |
| Jun-99 | 183 | 387 | 473 | 154 | 475 | 452.65 |
| Jul-99 | 179 | 387 | 461 | 109 | 463 | 484.37 |
| Aug-99 | 165 | 386 | 429 | 146 | 436 | 436.17 |
| Sep-99 | 197 | 385 | 511 | 311 | 515 | 519.00 |
| Oct-99 | 199 | 384 | 517 | 500 | 539 | 569.87 |
| Nov-99 | 226 | 383 | 589 | 793 | 602 | 655.32 |
| Dec-99 | 316 | 384 | 824 | 844 | 869 | 860.71 |
| Jan-00 | 322 | 388 | 829 | 1,083 | 834 | 864.88 |
| Feb-00 | 258 | 387 | 666 | 735 | 714 | 748.65 |
| Mar-00 | 223 | 386 | 578 | 659 | 629 | 649.21 |
| Apr-00 | 219 | 385 | 569 | 516 | 558 | 589.16 |
| May-00 | 203 | 387 | 525 | 382 | 499 | 499.80 |
| Jun-00 | 168 | 391 | 430 | 173 | 424 | 451.90 |
| Jul-00 | 176 | 389 | 452 | 142 | 439 | 463.15 |
| Aug-00 | 191 | 387 | 494 | 220 | 468 | 453.07 |
| Sep-00 | 194 | 386 | 502 | 354 | 487 | 517.55 |
| Oct-00 | 225 | 388 | 581 | 539 | 585 | 560.61 |
| Nov-00 | 228 | 386 | 591 | 691 | 648 | 639.83 |
| Dec-00 | 306 | 388 | 788 | 978 | 775 | 828.36 |
| Jan-01 | 275 | 385 | 715 | 723 | 877 | 859.96 |
| Feb-01 | 260 | 385 | 674 | 864 | 667 | 712.51 |
| Mar-01 | 235 | 385 | 609 | 765 | 613 | 639.85 |
| Apr-01 | 217 | 387 | 561 | 507 | 553 | 572.65 |
| May-01 | 213 | 384 | 554 | 390 | 525 | 502.69 |
| Jun-01 | 173 | 389 | 445 | 167 | 441 | 446.79 |
| Jul-01 | 188 | 391 | 481 | 140 | 469 | 456.85 |
| Aug-01 | 170 | 387 | 438 | 140 | 448 | 450.70 |
| Sep-01 | 178 | 393 | 453 | 309 | 457 | 486.33 |
| Oct-01 | 225 | 394 | 572 | 573 | 562 | 562.08 |
| Nov-01 | 256 | 398 | 643 | 818 | 645 | 631.76 |
| Dec-01 | 361 | 396 | 911 | 1,095 | 846 | 830.13 |
| Jan-02 | 321 | 398 | 806 | 936 | 876 | 862.24 |
| Feb-02 | 256 | 397 | 645 | 825 | 655 | 678.80 |
| Mar-02 | 247 | 393 | 628 | 921 | 563 | 601.59 |
| Apr-02 | 259 | 393 | 659 | 653 | 587 | 566.18 |
| May-02 | 200 | 395 | 506 | 362 | 489 | 504.33 |
| Jun-02 | 177 | 398 | 445 | 176 | 438 | 434.39 |
| Jul-02 | 178 | 400 | 446 | 131 | 438 | 448.46 |
| Aug-02 | 187 | 402 | 465 | 183 | 456 | 457.41 |
| Sep-02 | 186 | 402 | 463 | 314 | 466 | 469.90 |
| Oct-02 | 223 | 398 | 560 | 444 | 606 | 584.18 |
| Nov-02 | 229 | 397 | 576 | 583 | 681 | 657.88 |
| Dec-02 | 296 | 397 | 745 | 845 | 789 | 803.52 |
| Jan-03 | 307 | 397 | 773 | 989 | 819 | 857.25 |
| Feb-03 | 243 | 397 | 611 | 757 | 651 | 657.63 |
| Mar-03 | 237 | 395 | 601 | 835 | 574 | 583.55 |
| Apr-03 | 239 | 397 | 602 | 514 | 591 | 577.31 |
| May-03 | 184 | 400 | 460 | 364 | 442 | 485.17 |
| Jun-03 | 180 | 400 | 450 | 193 | 435 | 438.27 |
| Jul-03 | 187 | 401 | 466 | 84 | 479 | 461.70 |
| Aug-03 | 183 | 402 | 456 | 181 | 448 | 450.54 |
| Sep-03 | 211 | 404 | 522 | 359 | 505 | 475.86 |
| Oct-03 | 197 | 401 | 492 | 467 | 529 | 565.28 |
| Nov-03 | 278 | 399 | 697 | 875 | 675 | 666.64 |
| Dec-03 | 327 | 397 | 823 | 912 | 838 | 824.69 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Marsh Lake Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-04 | 320 | 396 | 807 | 1,255 | 738 | 810.79 |
| Feb-04 | 258 | 393 | 657 | 695 | 724 | 676.53 |
| Mar-04 | 244 | 394 | 618 | 756 | 626 | 587.93 |
| Apr-04 | 247 | 396 | 624 | 467 | 634 | 604.04 |
| May-04 | 191 | 397 | 482 | 273 | 504 | 478.26 |
| Jun-04 | 198 | 400 | 494 | 84 | 527 | 467.01 |
| Jul-04 | 183 | 401 | 457 | 74 | 474 | 463.33 |
| Aug-04 | 186 | 403 | 461 | 102 | 487 | 463.61 |
| Sep-04 | 212 | 404 | 524 | 368 | 503 | 491.19 |
| Oct-04 | 219 | 403 | 544 | 541 | 548 | 560.70 |
| Nov-04 | 257 | 404 | 635 | 720 | 680 | 678.40 |
| Dec-04 | 336 | 403 | 835 | 900 | 855 | 827.73 |
| Jan-05 | 350 | 403 | 869 | 1,165 | 839 | 798.54 |
| Feb-05 | 304 | 403 | 755 | 795 | 778 | 717.63 |
| Mar-05 | 244 | 403 | 605 | 614 | 675 | 625.03 |
| Apr-05 | 212 | 405 | 524 | 453 | 540 | 588.16 |
| May-05 | 212 | 407 | 521 | 257 | 550 | 498.72 |
| Jun-05 | 185 | 410 | 452 | 154 | 454 | 472.24 |
| Jul-05 | 194 | 409 | 473 | 133 | 464 | 472.20 |
| Aug-05 | 196 | 411 | 477 | 151 | 482 | 472.19 |
| Sep-05 | 211 | 411 | 513 | 299 | 522 | 510.06 |
| Oct-05 | 220 | 412 | 534 | 535 | 540 | 538.91 |
| Nov-05 | 286 | 409 | 699 | 774 | 721 | 691.66 |
| Dec-05 | 316 | 408 | 774 | 794 | 841 | 845.01 |
| Jan-06 | 346 | 408 | 849 | 1,096 | 848 | 808.24 |
| Feb-06 | 324 | 407 | 796 | 821 | 807 | 769.78 |
| Mar-06 | 308 | 407 | 758 | 906 | 700 | 666.86 |
| Apr-06 | 237 | 408 | 582 | 519 | 569 | 580.65 |
| May-06 | 224 | 409 | 549 | 347 | 538 | 530.85 |
| Jun-06 | 189 | 410 | 462 | 173 | 456 | 478.98 |
| Jul-06 | 193 | 415 | 466 | 118 | 463 | 467.13 |
| Aug-06 | 212 | 417 | 508 | 202 | 491 | 486.49 |
| Sep-06 | 219 | 415 | 527 | 296 | 537 | 520.94 |
| Oct-06 | 243 | 417 | 582 | 521 | 595 | 561.09 |
| Nov-06 | 366 | 416 | 880 | 1,162 | 732 | 710.74 |
| Dec-06 | 366 | 414 | 885 | 824 | 939 | 878.45 |
| Jan-07 | 371 | 414 | 895 | 912 | 975 | 887.36 |
| Feb-07 | 361 | 413 | 875 | 999 | 808 | 798.00 |
| Mar-07 | 297 | 414 | 718 | 954 | 640 | 671.45 |
| Apr-07 | 245 | 416 | 589 | 512 | 579 | 562.43 |
| May-07 | 207 | 417 | 496 | 322 | 496 | 528.24 |
| Jun-07 | 198 | 418 | 474 | 141 | 482 | 463.97 |
| Jul-07 | 201 | 419 | 480 | 102 | 485 | 470.84 |
| Aug-07 | 214 | 418 | 513 | 154 | 516 | 496.24 |
| Sep-07 | 208 | 419 | 497 | 308 | 502 | 520.60 |
| Oct-07 | 269 | 418 | 644 | 544 | 647 | 594.13 |
| Nov-07 | 328 | 412 | 796 | 725 | 838 | 763.58 |
| Dec-07 | 371 | 412 | 900 | 1,070 | 847 | 875.53 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**MARSH LAKE RESIDENTIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.89809713 |
| R Square | 0.80657845 |
| Adjusted R Square | 0.80541326 |
| Standard Error | 72.8549545 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 3674244.197 | 3674244.2 | 692.229071 | 4.14185E-61 |
| Residual | 166 | 881102.1705 | 5307.8444 | | |
| Total | 167 | 4555346.368 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 376.92952 | 10.72017606 | 35.1607584 | 7.9425E-79 | 355.764058 | 398.094983 | 355.764058 | 398.094983 |
| MHDD | 0.43628872 | 0.016582464 | 26.3102465 | 4.1419E-61 | 0.403549004 | 0.46902844 | 0.403549 | 0.46902844 |

| Deep Creek Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-98 | 30 | 33 | 906 | 1,166 | 879 | |
| Feb-98 | 21 | 33 | 639 | 719 | 688 | |
| Mar-98 | 25 | 33 | 764 | 757 | 770 | |
| Apr-98 | 18 | 33 | 560 | 459 | 571 | |
| May-98 | 13 | 32 | 412 | 271 | 432 | |
| Jun-98 | 11 | 33 | 348 | 120 | 363 | |
| Jul-98 | 13 | 33 | 401 | 112 | 401 | |
| Aug-98 | 16 | 34 | 457 | 189 | 447 | |
| Sep-98 | 14 | 34 | 402 | 328 | 399 | |
| Oct-98 | 20 | 33 | 605 | 558 | 602 | |
| Nov-98 | 23 | 34 | 677 | 792 | 688 | |
| Dec-98 | 25 | 34 | 732 | 1,052 | 692 | |
| Jan-99 | 22 | 23 | 943 | 1,183 | 910 | |
| Feb-99 | 18 | 23 | 798 | 976 | 749 | |
| Mar-99 | 12 | 23 | 523 | 734 | 539 | |
| Apr-99 | 10 | 23 | 443 | 509 | 436 | |
| May-99 | 9 | 23 | 380 | 392 | 353 | |
| Jun-99 | 7 | 22 | 309 | 154 | 311 | |
| Jul-99 | 7 | 22 | 321 | 109 | 323 | |
| Aug-99 | 6 | 22 | 273 | 146 | 279 | |
| Sep-99 | 8 | 22 | 371 | 311 | 374 | |
| Oct-99 | 8 | 22 | 353 | 500 | 372 | |
| Nov-99 | 10 | 23 | 450 | 793 | 461 | |
| Dec-99 | 11 | 23 | 478 | 844 | 517 | |
| Jan-00 | 19 | 24 | 806 | 1,083 | 810 | 866.49 |
| Feb-00 | 12 | 24 | 504 | 735 | 546 | 661.03 |
| Mar-00 | 10 | 24 | 420 | 659 | 463 | 590.71 |
| Apr-00 | 11 | 24 | 464 | 516 | 454 | 486.87 |
| May-00 | 8 | 23 | 329 | 382 | 307 | 364.07 |
| Jun-00 | 7 | 24 | 275 | 173 | 270 | 314.36 |
| Jul-00 | 8 | 24 | 325 | 142 | 314 | 345.82 |
| Aug-00 | 7 | 23 | 294 | 220 | 272 | 332.69 |
| Sep-00 | 8 | 22 | 354 | 354 | 341 | 371.12 |
| Oct-00 | 8 | 22 | 381 | 539 | 385 | 452.93 |
| Nov-00 | 10 | 23 | 429 | 691 | 479 | 542.90 |
| Dec-00 | 16 | 23 | 702 | 978 | 690 | 633.00 |
| Jan-01 | 9 | 23 | 394 | 723 | 535 | 751.71 |
| Feb-01 | 12 | 23 | 532 | 864 | 526 | 607.03 |
| Mar-01 | 10 | 23 | 446 | 765 | 450 | 483.79 |
| Apr-01 | 10 | 23 | 444 | 507 | 437 | 442.20 |
| May-01 | 7 | 23 | 310 | 390 | 284 | 314.77 |
| Jun-01 | 7 | 23 | 298 | 167 | 295 | 291.66 |
| Jul-01 | 6 | 24 | 251 | 140 | 241 | 292.28 |
| Aug-01 | 5 | 24 | 206 | 140 | 215 | 255.34 |
| Sep-01 | 8 | 24 | 326 | 309 | 330 | 348.36 |
| Oct-01 | 7 | 24 | 288 | 573 | 279 | 345.27 |
| Nov-01 | 10 | 24 | 428 | 818 | 430 | 456.69 |
| Dec-01 | 15 | 24 | 610 | 1,095 | 554 | 587.07 |
| Jan-02 | 16 | 24 | 649 | 936 | 709 | 684.94 |
| Feb-02 | 11 | 24 | 479 | 825 | 487 | 519.75 |
| Mar-02 | 10 | 24 | 421 | 921 | 365 | 425.89 |
| Apr-02 | 8 | 24 | 337 | 653 | 274 | 388.44 |
| May-02 | 7 | 24 | 293 | 362 | 278 | 289.74 |
| Jun-02 | 5 | 24 | 218 | 176 | 211 | 258.58 |
| Jul-02 | 6 | 24 | 243 | 131 | 236 | 263.50 |
| Aug-02 | 7 | 24 | 281 | 183 | 273 | 253.19 |
| Sep-02 | 6 | 24 | 238 | 314 | 240 | 303.86 |
| Oct-02 | 8 | 25 | 308 | 444 | 348 | 337.48 |
| Nov-02 | 10 | 24 | 410 | 583 | 501 | 469.86 |
| Dec-02 | 12 | 25 | 475 | 845 | 514 | 586.10 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1998** | 6,902 | 6,933 | - |
| **1999** | 5,641 | 5,623 | - |
| **2000** | 5,281 | 5,330 | 5,962 |
| **2001** | 4,533 | 4,576 | 5,176 |
| **2002** | 4,351 | 4,438 | 4,781 |
| **2003** | 5,452 | 5,480 | 4,831 |
| **2004** | 6,284 | 6,425 | 5,447 |
| **2005** | 5,269 | 5,450 | 5,785 |
| **2006** | 5,423 | 5,278 | 5,718 |
| **2007** | 5,580 | 5,526 | 5,418 |

| Deep Creek Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-03 | 12 | 25 | 480 | 989 | 521 | 588.39 |
| Feb-03 | 16 | 25 | 621 | 757 | 655 | 556.06 |
| Mar-03 | 11 | 25 | 448 | 835 | 425 | 413.18 |
| Apr-03 | 9 | 25 | 371 | 514 | 361 | 357.53 |
| May-03 | 9 | 25 | 343 | 364 | 327 | 296.51 |
| Jun-03 | 7 | 24 | 288 | 193 | 275 | 260.40 |
| Jul-03 | 8 | 24 | 351 | 84 | 362 | 279.58 |
| Aug-03 | 8 | 24 | 322 | 181 | 314 | 267.42 |
| Sep-03 | 11 | 22 | 502 | 359 | 488 | 352.78 |
| Oct-03 | 8 | 24 | 343 | 467 | 374 | 333.85 |
| Nov-03 | 12 | 23 | 534 | 875 | 514 | 481.77 |
| Dec-03 | 20 | 24 | 849 | 912 | 863 | 643.63 |
| Jan-04 | 24 | 24 | 987 | 1,255 | 927 | 719.00 |
| Feb-04 | 20 | 24 | 834 | 695 | 891 | 677.98 |
| Mar-04 | 15 | 24 | 625 | 756 | 632 | 473.95 |
| Apr-04 | 13 | 24 | 545 | 467 | 553 | 396.19 |
| May-04 | 9 | 24 | 388 | 273 | 407 | 337.36 |
| Jun-04 | 8 | 24 | 338 | 84 | 367 | 284.56 |
| Jul-04 | 8 | 24 | 342 | 74 | 357 | 318.30 |
| Aug-04 | 8 | 25 | 333 | 102 | 356 | 314.54 |
| Sep-04 | 10 | 26 | 391 | 368 | 373 | 367.00 |
| Oct-04 | 12 | 26 | 463 | 541 | 466 | 396.29 |
| Nov-04 | 16 | 26 | 607 | 720 | 646 | 553.84 |
| Dec-04 | 11 | 26 | 430 | 900 | 449 | 608.46 |
| Jan-05 | 22 | 28 | 799 | 1,165 | 773 | 740.17 |
| Feb-05 | 17 | 28 | 616 | 795 | 636 | 727.61 |
| Mar-05 | 15 | 31 | 488 | 614 | 549 | 535.39 |
| Apr-05 | 14 | 32 | 432 | 453 | 446 | 453.34 |
| May-05 | 10 | 32 | 303 | 257 | 328 | 353.84 |
| Jun-05 | 13 | 32 | 415 | 154 | 417 | 353.18 |
| Jul-05 | 11 | 32 | 333 | 133 | 325 | 347.91 |
| Aug-05 | 13 | 31 | 403 | 151 | 408 | 359.48 |
| Sep-05 | 11 | 32 | 351 | 299 | 358 | 406.32 |
| Oct-05 | 12 | 32 | 368 | 535 | 374 | 404.94 |
| Nov-05 | 12 | 33 | 377 | 774 | 396 | 518.78 |
| Dec-05 | 13 | 33 | 382 | 794 | 440 | 583.86 |
| Jan-06 | 16 | 33 | 486 | 1,096 | 486 | 728.56 |
| Feb-06 | 23 | 33 | 684 | 821 | 694 | 740.62 |
| Mar-06 | 16 | 33 | 472 | 906 | 422 | 534.39 |
| Apr-06 | 14 | 33 | 422 | 519 | 411 | 469.89 |
| May-06 | 14 | 34 | 423 | 347 | 413 | 382.60 |
| Jun-06 | 13 | 31 | 420 | 173 | 415 | 399.76 |
| Jul-06 | 12 | 33 | 362 | 118 | 360 | 347.25 |
| Aug-06 | 11 | 35 | 315 | 202 | 300 | 354.72 |
| Sep-06 | 14 | 36 | 380 | 296 | 390 | 373.65 |
| Oct-06 | 12 | 35 | 339 | 521 | 350 | 396.97 |
| Nov-06 | 16 | 35 | 461 | 1,162 | 332 | 457.84 |
| Dec-06 | 23 | 35 | 658 | 824 | 705 | 531.27 |
| Jan-07 | 28 | 35 | 813 | 912 | 882 | 713.69 |
| Feb-07 | 22 | 35 | 625 | 999 | 567 | 632.52 |
| Mar-07 | 21 | 35 | 601 | 954 | 532 | 501.21 |
| Apr-07 | 21 | 34 | 603 | 512 | 594 | 483.62 |
| May-07 | 11 | 35 | 321 | 322 | 321 | 353.97 |
| Jun-07 | 13 | 36 | 348 | 141 | 355 | 395.70 |
| Jul-07 | 13 | 36 | 351 | 102 | 355 | 346.53 |
| Aug-07 | 11 | 36 | 318 | 154 | 321 | 342.99 |
| Sep-07 | 13 | 35 | 373 | 308 | 377 | 374.96 |
| Oct-07 | 11 | 35 | 327 | 544 | 329 | 351.15 |
| Nov-07 | 19 | 37 | 511 | 725 | 548 | 425.24 |
| Dec-07 | 14 | 37 | 391 | 1,070 | 344 | 496.48 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**DEEP CREEK RESIDENTIAL SUMMARY OUTPUT**

Data: 1998:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.7489567 |
| R Square | 0.56093614 |
| Adjusted R Square | 0.55721526 |
| Standard Error | 109.888898 |
| Observations | 120 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1820435.801 | 1820435.8 | 150.753614 | 7.88801E-23 |
| Residual | 118 | 1424917.244 | 12075.5699 | | |
| Total | 119 | 3245353.045 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 249.963852 | 19.54806457 | 12.7871407 | 5.0268E-24 | 211.2533631 | 288.674342 | 211.253363 | 288.674342 |
| MHDD | 0.37962809 | 0.030918931 | 12.2781763 | 7.888E-23 | 0.318400191 | 0.44085599 | 0.31840019 | 0.44085599 |

| Takhini River Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-98 | 19 | 27 | 711 | 1,166 | 683 | |
| Feb-98 | 15 | 27 | 554 | 719 | 604 | |
| Mar-98 | 14 | 27 | 501 | 757 | 508 | |
| Apr-98 | 12 | 27 | 455 | 459 | 467 | |
| May-98 | 10 | 27 | 389 | 271 | 409 | |
| Jun-98 | 10 | 27 | 352 | 120 | 368 | |
| Jul-98 | 8 | 27 | 294 | 112 | 294 | |
| Aug-98 | 8 | 27 | 293 | 189 | 282 | |
| Sep-98 | 9 | 27 | 331 | 328 | 328 | |
| Oct-98 | 12 | 28 | 431 | 558 | 428 | |
| Nov-98 | 13 | 28 | 464 | 792 | 476 | |
| Dec-98 | 17 | 29 | 572 | 1,052 | 531 | |
| Jan-99 | 24 | 29 | 817 | 1,183 | 783 | |
| Feb-99 | 18 | 29 | 628 | 976 | 577 | |
| Mar-99 | 15 | 29 | 531 | 734 | 547 | |
| Apr-99 | 13 | 29 | 462 | 509 | 454 | |
| May-99 | 11 | 30 | 370 | 392 | 343 | |
| Jun-99 | 10 | 30 | 343 | 154 | 345 | |
| Jul-99 | 9 | 30 | 306 | 109 | 307 | |
| Aug-99 | 9 | 30 | 298 | 146 | 304 | |
| Sep-99 | 11 | 29 | 373 | 311 | 377 | |
| Oct-99 | 11 | 30 | 354 | 500 | 374 | |
| Nov-99 | 13 | 30 | 434 | 793 | 445 | |
| Dec-99 | 15 | 30 | 516 | 844 | 557 | |
| Jan-00 | 18 | 30 | 611 | 1,083 | 616 | 693.84 |
| Feb-00 | 19 | 29 | 670 | 735 | 714 | 631.94 |
| Mar-00 | 14 | 30 | 475 | 659 | 520 | 524.92 |
| Apr-00 | 11 | 29 | 369 | 516 | 359 | 426.54 |
| May-00 | 12 | 30 | 384 | 382 | 361 | 370.75 |
| Jun-00 | 11 | 30 | 382 | 173 | 377 | 363.05 |
| Jul-00 | 10 | 30 | 323 | 142 | 311 | 304.11 |
| Aug-00 | 9 | 29 | 301 | 220 | 278 | 288.04 |
| Sep-00 | 11 | 29 | 372 | 354 | 358 | 354.30 |
| Oct-00 | 13 | 29 | 433 | 539 | 437 | 413.17 |
| Nov-00 | 14 | 29 | 485 | 691 | 536 | 485.75 |
| Dec-00 | 13 | 31 | 432 | 978 | 420 | 502.51 |
| Jan-01 | 21 | 29 | 738 | 723 | 884 | 760.90 |
| Feb-01 | 14 | 29 | 484 | 864 | 477 | 589.57 |
| Mar-01 | 15 | 29 | 519 | 765 | 522 | 529.70 |
| Apr-01 | 13 | 29 | 462 | 507 | 456 | 422.83 |
| May-01 | 14 | 29 | 474 | 390 | 448 | 383.64 |
| Jun-01 | 11 | 30 | 356 | 167 | 353 | 358.26 |
| Jul-01 | 10 | 30 | 348 | 140 | 337 | 318.51 |
| Aug-01 | 9 | 29 | 305 | 140 | 314 | 298.73 |
| Sep-01 | 10 | 30 | 345 | 309 | 349 | 361.22 |
| Oct-01 | 15 | 30 | 484 | 573 | 475 | 428.81 |
| Nov-01 | 17 | 30 | 557 | 818 | 559 | 513.66 |
| Dec-01 | 21 | 30 | 691 | 1,095 | 633 | 536.56 |
| Jan-02 | 26 | 29 | 907 | 936 | 970 | 823.20 |
| Feb-02 | 19 | 29 | 640 | 825 | 649 | 613.65 |
| Mar-02 | 17 | 29 | 574 | 921 | 516 | 519.49 |
| Apr-02 | 16 | 29 | 536 | 653 | 471 | 428.66 |
| May-02 | 13 | 29 | 441 | 362 | 426 | 411.42 |
| Jun-02 | 11 | 30 | 354 | 176 | 347 | 358.98 |
| Jul-02 | 11 | 31 | 344 | 131 | 337 | 328.39 |
| Aug-02 | 10 | 31 | 328 | 183 | 320 | 303.95 |
| Sep-02 | 10 | 31 | 319 | 314 | 322 | 342.88 |
| Oct-02 | 15 | 30 | 491 | 444 | 533 | 481.73 |
| Nov-02 | 15 | 29 | 519 | 583 | 613 | 569.53 |
| Dec-02 | 18 | 31 | 567 | 845 | 607 | 553.20 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1998** | 5,345 | 5,376 | - |
| **1999** | 5,431 | 5,412 | - |
| **2000** | 5,237 | 5,288 | 5,359 |
| **2001** | 5,763 | 5,807 | 5,502 |
| **2002** | 6,020 | 6,111 | 5,735 |
| **2003** | 6,118 | 6,147 | 6,022 |
| **2004** | 6,264 | 6,409 | 6,222 |
| **2005** | 6,651 | 6,839 | 6,465 |
| **2006** | 5,801 | 5,650 | 6,299 |
| **2007** | 6,485 | 6,430 | 6,306 |

| Takhini River Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Whitehorse) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-03 | 26 | 31 | 826 | 989 | 867 | 907.13 |
| Feb-03 | 21 | 31 | 663 | 757 | 699 | 608.44 |
| Mar-03 | 18 | 31 | 575 | 835 | 552 | 529.85 |
| Apr-03 | 14 | 30 | 483 | 514 | 473 | 466.63 |
| May-03 | 13 | 30 | 450 | 364 | 433 | 435.69 |
| Jun-03 | 12 | 31 | 401 | 193 | 388 | 362.81 |
| Jul-03 | 12 | 31 | 391 | 84 | 402 | 358.59 |
| Aug-03 | 13 | 31 | 425 | 181 | 417 | 350.39 |
| Sep-03 | 9 | 31 | 297 | 359 | 282 | 317.39 |
| Oct-03 | 11 | 31 | 343 | 467 | 376 | 461.22 |
| Nov-03 | 18 | 31 | 588 | 875 | 567 | 579.79 |
| Dec-03 | 21 | 31 | 677 | 912 | 691 | 643.58 |
| Jan-04 | 23 | 31 | 744 | 1,255 | 682 | 839.57 |
| Feb-04 | 23 | 31 | 750 | 695 | 810 | 719.41 |
| Mar-04 | 16 | 31 | 504 | 756 | 511 | 526.22 |
| Apr-04 | 17 | 31 | 541 | 467 | 550 | 498.09 |
| May-04 | 12 | 31 | 399 | 273 | 419 | 426.02 |
| Jun-04 | 12 | 31 | 373 | 84 | 402 | 379.15 |
| Jul-04 | 12 | 31 | 378 | 74 | 393 | 377.26 |
| Aug-04 | 10 | 30 | 340 | 102 | 363 | 366.93 |
| Sep-04 | 13 | 30 | 431 | 368 | 412 | 338.46 |
| Oct-04 | 13 | 31 | 428 | 541 | 431 | 446.71 |
| Nov-04 | 16 | 30 | 545 | 720 | 585 | 588.45 |
| Dec-04 | 27 | 32 | 831 | 900 | 850 | 715.97 |
| Jan-05 | 32 | 32 | 987 | 1,165 | 959 | 836.09 |
| Feb-05 | 30 | 32 | 946 | 795 | 967 | 825.21 |
| Mar-05 | 24 | 33 | 733 | 614 | 796 | 619.37 |
| Apr-05 | 20 | 32 | 635 | 453 | 649 | 557.34 |
| May-05 | 13 | 32 | 411 | 257 | 437 | 429.66 |
| Jun-05 | 13 | 31 | 407 | 154 | 409 | 399.68 |
| Jul-05 | 11 | 31 | 344 | 133 | 336 | 376.98 |
| Aug-05 | 9 | 31 | 293 | 151 | 297 | 359.34 |
| Sep-05 | 12 | 30 | 394 | 299 | 402 | 365.41 |
| Oct-05 | 12 | 30 | 400 | 535 | 406 | 404.48 |
| Nov-05 | 18 | 32 | 572 | 774 | 591 | 581.03 |
| Dec-05 | 17 | 32 | 530 | 794 | 590 | 710.48 |
| Jan-06 | 22 | 32 | 681 | 1,096 | 680 | 773.78 |
| Feb-06 | 21 | 33 | 640 | 821 | 650 | 808.99 |
| Mar-06 | 20 | 33 | 610 | 906 | 558 | 621.48 |
| Apr-06 | 15 | 33 | 448 | 519 | 437 | 545.21 |
| May-06 | 15 | 33 | 453 | 347 | 444 | 433.01 |
| Jun-06 | 12 | 32 | 385 | 173 | 380 | 396.88 |
| Jul-06 | 10 | 32 | 328 | 118 | 326 | 351.61 |
| Aug-06 | 9 | 32 | 280 | 202 | 264 | 308.34 |
| Sep-06 | 12 | 33 | 362 | 296 | 371 | 395.32 |
| Oct-06 | 11 | 33 | 329 | 521 | 340 | 392.58 |
| Nov-06 | 17 | 33 | 514 | 1,162 | 381 | 518.88 |
| Dec-06 | 25 | 33 | 771 | 824 | 820 | 753.34 |
| Jan-07 | 24 | 32 | 763 | 912 | 835 | 824.95 |
| Feb-07 | 23 | 33 | 689 | 999 | 630 | 748.91 |
| Mar-07 | 25 | 32 | 773 | 954 | 702 | 685.24 |
| Apr-07 | 22 | 32 | 689 | 512 | 680 | 588.54 |
| May-07 | 15 | 32 | 459 | 322 | 459 | 446.45 |
| Jun-07 | 14 | 32 | 424 | 141 | 432 | 406.71 |
| Jul-07 | 12 | 32 | 383 | 102 | 387 | 349.44 |
| Aug-07 | 10 | 32 | 302 | 154 | 305 | 288.71 |
| Sep-07 | 11 | 31 | 353 | 308 | 357 | 376.96 |
| Oct-07 | 14 | 31 | 447 | 544 | 450 | 398.72 |
| Nov-07 | 16 | 31 | 532 | 725 | 570 | 513.81 |
| Dec-07 | 21 | 31 | 671 | 1,070 | 623 | 677.89 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**TAKHINI RIVER RESIDENTIAL SUMMARY OUTPUT**

Data: 1998:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.80607439 |
| R Square | 0.64975593 |
| Adjusted R Square | 0.64678776 |
| Standard Error | 94.3540325 |
| Observations | 120 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1948867.873 | 1948867.87 | 218.907915 | 1.18755E-28 |
| Residual | 118 | 1050516.646 | 8902.68344 | | |
| Total | 119 | 2999384.519 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 279.481134 | 16.78457747 | 16.6510676 | 9.239E-33 | 246.2431019 | 312.719167 | 246.243102 | 312.719167 |
| MHDD | 0.3927913 | 0.026547958 | 14.795537 | 1.1875E-28 | 0.340219113 | 0.44536348 | 0.34021911 | 0.44536348 |

| Lower Post BC Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-96 | 68 | 69 | 985 | 1,605 | 890 | |
| Feb-96 | 52 | 67 | 769 | 947 | 776 | |
| Mar-96 | 54 | 68 | 801 | 874 | 802 | |
| Apr-96 | 47 | 68 | 696 | 548 | 694 | |
| May-96 | 39 | 67 | 581 | 366 | 570 | |
| Jun-96 | 34 | 67 | 512 | 164 | 504 | |
| Jul-96 | 37 | 67 | 550 | 103 | 546 | |
| Aug-96 | 34 | 68 | 503 | 185 | 494 | |
| Sep-96 | 40 | 69 | 576 | 355 | 564 | |
| Oct-96 | 39 | 73 | 538 | 662 | 507 | |
| Nov-96 | 56 | 72 | 783 | 1,121 | 729 | |
| Dec-96 | 58 | 72 | 812 | 1,361 | 745 | |
| Jan-97 | 77 | 74 | 1,036 | 1,407 | 1,002 | |
| Feb-97 | 54 | 72 | 754 | 885 | 779 | |
| Mar-97 | 49 | 72 | 683 | 944 | 662 | |
| Apr-97 | 51 | 71 | 725 | 528 | 729 | |
| May-97 | 40 | 70 | 566 | 312 | 572 | |
| Jun-97 | 39 | 71 | 545 | 143 | 543 | |
| Jul-97 | 40 | 70 | 573 | 84 | 574 | |
| Aug-97 | 35 | 70 | 495 | 110 | 510 | |
| Sep-97 | 42 | 72 | 588 | 271 | 602 | |
| Oct-97 | 42 | 74 | 568 | 660 | 538 | |
| Nov-97 | 54 | 74 | 736 | 936 | 739 | |
| Dec-97 | 53 | 73 | 723 | 984 | 773 | |
| Jan-98 | 75 | 71 | 1,059 | 1,410 | 1,024 | 972.13 |
| Feb-98 | 57 | 72 | 791 | 942 | 799 | 784.86 |
| Mar-98 | 54 | 73 | 740 | 843 | 750 | 737.90 |
| Apr-98 | 48 | 73 | 661 | 500 | 674 | 698.96 |
| May-98 | 40 | 73 | 554 | 211 | 590 | 577.14 |
| Jun-98 | 37 | 73 | 504 | 89 | 519 | 522.05 |
| Jul-98 | 34 | 73 | 460 | 66 | 468 | 529.28 |
| Aug-98 | 35 | 73 | 481 | 157 | 481 | 494.77 |
| Sep-98 | 42 | 74 | 570 | 321 | 568 | 578.20 |
| Oct-98 | 45 | 75 | 600 | 561 | 601 | 548.70 |
| Nov-98 | 60 | 76 | 790 | 958 | 787 | 751.68 |
| Dec-98 | 60 | 76 | 788 | 1,253 | 755 | 757.96 |
| Jan-99 | 70 | 75 | 934 | 1,350 | 918 | 981.47 |
| Feb-99 | 58 | 75 | 773 | 1,066 | 743 | 773.89 |
| Mar-99 | 54 | 76 | 711 | 871 | 713 | 708.28 |
| Apr-99 | 52 | 76 | 678 | 506 | 689 | 697.32 |
| May-99 | 45 | 76 | 598 | 372 | 585 | 582.36 |
| Jun-99 | 41 | 76 | 540 | 140 | 539 | 533.65 |
| Jul-99 | 36 | 75 | 479 | 99 | 476 | 505.95 |
| Aug-99 | 37 | 75 | 499 | 128 | 508 | 499.39 |
| Sep-99 | 42 | 73 | 580 | 293 | 587 | 585.67 |
| Oct-99 | 43 | 74 | 577 | 520 | 591 | 576.61 |
| Nov-99 | 55 | 77 | 710 | 940 | 712 | 745.99 |
| Dec-99 | 53 | 76 | 698 | 1,013 | 740 | 756.05 |
| Jan-00 | 70 | 76 | 921 | 1,345 | 906 | 949.50 |
| Feb-00 | 63 | 75 | 844 | 956 | 848 | 796.65 |
| Mar-00 | 50 | 73 | 688 | 750 | 727 | 730.02 |
| Apr-00 | 49 | 73 | 664 | 591 | 649 | 670.68 |
| May-00 | 48 | 75 | 638 | 374 | 625 | 600.06 |
| Jun-00 | 38 | 73 | 526 | 158 | 520 | 525.77 |
| Jul-00 | 42 | 77 | 543 | 84 | 544 | 495.89 |
| Aug-00 | 37 | 72 | 520 | 217 | 502 | 496.80 |
| Sep-00 | 40 | 73 | 545 | 315 | 546 | 566.94 |
| Oct-00 | 47 | 76 | 617 | 576 | 613 | 601.38 |
| Nov-00 | 52 | 76 | 681 | 858 | 708 | 735.58 |
| Dec-00 | 57 | 76 | 757 | 1,223 | 733 | 742.70 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1996** | 8,106 | 7,820 | - |
| **1997** | 7,991 | 8,024 | - |
| **1998** | 7,999 | 8,017 | 7,954 |
| **1999** | 7,778 | 7,799 | 7,947 |
| **2000** | 7,944 | 7,920 | 7,912 |
| **2001** | 7,661 | 7,668 | 7,796 |
| **2002** | 7,721 | 7,679 | 7,756 |
| **2003** | 7,530 | 7,566 | 7,638 |
| **2004** | 7,758 | 7,877 | 7,707 |
| **2005** | 7,364 | 7,551 | 7,665 |
| **2006** | 8,682 | 8,632 | 8,020 |
| **2007** | 9,151 | 9,132 | 8,438 |

| Lower Post BC Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-01 | 73 | 75 | 975 | 1,043 | 1,053 | 959.10 |
| Feb-01 | 51 | 74 | 692 | 1,031 | 673 | 754.48 |
| Mar-01 | 51 | 75 | 683 | 845 | 693 | 710.91 |
| Apr-01 | 49 | 75 | 658 | 536 | 659 | 665.69 |
| May-01 | 43 | 75 | 578 | 367 | 567 | 592.36 |
| Jun-01 | 39 | 72 | 536 | 156 | 530 | 529.39 |
| Jul-01 | 35 | 69 | 506 | 120 | 496 | 505.42 |
| Aug-01 | 33 | 67 | 496 | 121 | 507 | 505.64 |
| Sep-01 | 38 | 71 | 537 | 300 | 542 | 558.20 |
| Oct-01 | 42 | 70 | 598 | 577 | 593 | 598.98 |
| Nov-01 | 48 | 71 | 671 | 975 | 662 | 693.96 |
| Dec-01 | 51 | 70 | 732 | 1,275 | 692 | 721.50 |
| Jan-02 | 63 | 70 | 904 | 1,246 | 920 | 959.85 |
| Feb-02 | 51 | 70 | 725 | 970 | 724 | 748.23 |
| Mar-02 | 51 | 70 | 724 | 991 | 689 | 702.96 |
| Apr-02 | 53 | 70 | 759 | 695 | 712 | 673.34 |
| May-02 | 42 | 71 | 593 | 366 | 582 | 591.21 |
| Jun-02 | 38 | 71 | 540 | 148 | 537 | 528.79 |
| Jul-02 | 33 | 71 | 468 | 122 | 458 | 499.58 |
| Aug-02 | 39 | 72 | 543 | 182 | 535 | 514.79 |
| Sep-02 | 37 | 70 | 532 | 331 | 527 | 538.22 |
| Oct-02 | 42 | 73 | 576 | 515 | 591 | 599.16 |
| Nov-02 | 50 | 74 | 670 | 822 | 709 | 692.95 |
| Dec-02 | 50 | 73 | 686 | 1,118 | 695 | 706.58 |
| Jan-03 | 65 | 74 | 884 | 1,178 | 921 | 964.64 |
| Feb-03 | 49 | 74 | 664 | 965 | 665 | 687.42 |
| Mar-03 | 49 | 74 | 665 | 900 | 658 | 679.96 |
| Apr-03 | 54 | 74 | 730 | 554 | 726 | 698.92 |
| May-03 | 47 | 73 | 648 | 342 | 644 | 597.76 |
| Jun-03 | 34 | 72 | 475 | 180 | 462 | 509.41 |
| Jul-03 | 34 | 69 | 489 | 57 | 499 | 484.48 |
| Aug-03 | 34 | 68 | 497 | 163 | 495 | 512.49 |
| Sep-03 | 38 | 72 | 534 | 330 | 529 | 532.73 |
| Oct-03 | 38 | 71 | 536 | 526 | 547 | 577.36 |
| Nov-03 | 48 | 70 | 684 | 964 | 678 | 683.06 |
| Dec-03 | 50 | 69 | 725 | 1,096 | 741 | 709.33 |
| Jan-04 | 58 | 69 | 847 | 1,366 | 826 | 888.83 |
| Feb-04 | 56 | 69 | 806 | 881 | 833 | 740.84 |
| Mar-04 | 49 | 69 | 709 | 810 | 730 | 692.31 |
| Apr-04 | 46 | 68 | 671 | 497 | 685 | 707.42 |
| May-04 | 35 | 68 | 507 | 292 | 519 | 581.71 |
| Jun-04 | 39 | 69 | 562 | 74 | 581 | 526.43 |
| Jul-04 | 35 | 69 | 514 | 36 | 531 | 496.05 |
| Aug-04 | 32 | 67 | 480 | 146 | 483 | 504.49 |
| Sep-04 | 34 | 66 | 510 | 371 | 494 | 516.50 |
| Oct-04 | 38 | 67 | 567 | 565 | 566 | 568.41 |
| Nov-04 | 52 | 66 | 783 | 876 | 805 | 730.64 |
| Dec-04 | 55 | 68 | 802 | 1,071 | 825 | 753.79 |
| Jan-05 | 69 | 68 | 1,013 | 1,330 | 1,003 | 916.46 |
| Feb-05 | 41 | 68 | 610 | 942 | 618 | 705.56 |
| Mar-05 | 42 | 67 | 633 | 727 | 679 | 688.95 |
| Apr-05 | 41 | 67 | 619 | 465 | 642 | 684.26 |
| May-05 | 39 | 67 | 581 | 257 | 604 | 589.08 |
| Jun-05 | 30 | 67 | 445 | 127 | 448 | 496.75 |
| Jul-05 | 33 | 66 | 494 | 137 | 479 | 502.96 |
| Aug-05 | 29 | 65 | 449 | 162 | 447 | 475.11 |
| Sep-05 | 33 | 64 | 509 | 297 | 515 | 512.55 |
| Oct-05 | 41 | 66 | 621 | 500 | 641 | 584.84 |
| Nov-05 | 43 | 67 | 648 | 758 | 706 | 729.68 |
| Dec-05 | 49 | 66 | 743 | 1,061 | 769 | 778.58 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Lower Post BC Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-06 | 61 | 65 | 943 | 1,185 | 978 | 935.42 |
| Feb-06 | 59 | 65 | 910 | 1,017 | 895 | 782.25 |
| Mar-06 | 54 | 65 | 827 | 961 | 801 | 736.50 |
| Apr-06 | 46 | 65 | 715 | 528 | 719 | 681.98 |
| May-06 | 38 | 65 | 584 | 371 | 571 | 564.67 |
| Jun-06 | 38 | 61 | 617 | 137 | 617 | 548.36 |
| Jul-06 | 34 | 62 | 548 | 79 | 552 | 520.55 |
| Aug-06 | 35 | 63 | 557 | 172 | 552 | 494.22 |
| Sep-06 | 36 | 64 | 563 | 292 | 570 | 526.27 |
| Oct-06 | 44 | 65 | 675 | 543 | 682 | 629.57 |
| Nov-06 | 54 | 64 | 837 | 1,196 | 760 | 756.94 |
| Dec-06 | 58 | 64 | 906 | 1,050 | 936 | 843.48 |
| Jan-07 | 70 | 63 | 1,105 | 1,102 | 1,166 | 1048.66 |
| Feb-07 | 56 | 62 | 909 | 1,017 | 894 | 802.56 |
| Mar-07 | 57 | 62 | 920 | 1,002 | 881 | 786.96 |
| Apr-07 | 59 | 62 | 950 | 543 | 949 | 770.11 |
| May-07 | 40 | 59 | 681 | 332 | 681 | 618.60 |
| Jun-07 | 32 | 59 | 544 | 123 | 549 | 537.57 |
| Jul-07 | 37 | 62 | 589 | 89 | 589 | 539.91 |
| Aug-07 | 32 | 60 | 534 | 143 | 538 | 512.48 |
| Sep-07 | 34 | 59 | 571 | 315 | 572 | 552.35 |
| Oct-07 | 47 | 68 | 691 | 553 | 694 | 672.20 |
| Nov-07 | 55 | 69 | 797 | 957 | 794 | 753.50 |
| Dec-07 | 59 | 69 | 858 | 1,255 | 825 | 843.38 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**LOWER POST RESIDENTIAL SUMMARY OUTPUT**

Data: 1996:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.86834728 |
| R Square | 0.754027 |
| Adjusted R Square | 0.75229479 |
| Standard Error | 72.850001 |
| Observations | 144 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 2310185.873 | 2310185.87 | 435.299131 | 4.34878E-45 |
| Residual | 142 | 753611.4152 | 5307.12264 | | |
| Total | 143 | 3063797.288 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 474.671718 | 10.9370022 | 43.4005323 | 7.7206E-84 | 453.0513321 | 496.292104 | 453.051332 | 496.292104 |
| MHDD | 0.30910974 | 0.014815585 | 20.8638235 | 4.3488E-45 | 0.279822133 | 0.33839735 | 0.27982213 | 0.33839735 |

| Upper Liard Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-96 | 72 | 75 | 956 | 1,605 | 867 | |
| Feb-96 | 57 | 74 | 771 | 947 | 777 | |
| Mar-96 | 57 | 74 | 770 | 874 | 771 | |
| Apr-96 | 47 | 73 | 650 | 548 | 648 | |
| May-96 | 40 | 74 | 547 | 366 | 537 | |
| Jun-96 | 47 | 72 | 650 | 164 | 642 | |
| Jul-96 | 24 | 72 | 336 | 103 | 332 | |
| Aug-96 | 33 | 72 | 458 | 185 | 450 | |
| Sep-96 | 36 | 71 | 500 | 355 | 489 | |
| Oct-96 | 39 | 72 | 539 | 662 | 510 | |
| Nov-96 | 54 | 72 | 748 | 1,121 | 697 | |
| Dec-96 | 53 | 71 | 750 | 1,361 | 687 | |
| Jan-97 | 71 | 72 | 985 | 1,407 | 953 | |
| Feb-97 | 53 | 72 | 735 | 885 | 759 | |
| Mar-97 | 43 | 71 | 600 | 944 | 580 | |
| Apr-97 | 42 | 71 | 591 | 528 | 595 | |
| May-97 | 37 | 71 | 527 | 312 | 532 | |
| Jun-97 | 34 | 71 | 485 | 143 | 484 | |
| Jul-97 | 32 | 71 | 452 | 84 | 453 | |
| Aug-97 | 32 | 70 | 460 | 110 | 474 | |
| Sep-97 | 35 | 71 | 498 | 271 | 511 | |
| Oct-97 | 40 | 70 | 572 | 660 | 544 | |
| Nov-97 | 47 | 71 | 664 | 936 | 667 | |
| Dec-97 | 42 | 70 | 597 | 984 | 644 | |
| Jan-98 | 70 | 70 | 998 | 1,410 | 965 | 928.22 |
| Feb-98 | 46 | 70 | 653 | 942 | 661 | 732.12 |
| Mar-98 | 39 | 70 | 552 | 843 | 562 | 637.65 |
| Apr-98 | 40 | 71 | 564 | 500 | 576 | 606.10 |
| May-98 | 37 | 71 | 517 | 211 | 552 | 540.31 |
| Jun-98 | 32 | 71 | 449 | 89 | 463 | 529.36 |
| Jul-98 | 32 | 70 | 459 | 66 | 466 | 417.01 |
| Aug-98 | 35 | 71 | 494 | 157 | 494 | 472.70 |
| Sep-98 | 37 | 73 | 506 | 321 | 505 | 501.43 |
| Oct-98 | 40 | 72 | 555 | 561 | 555 | 536.58 |
| Nov-98 | 51 | 74 | 687 | 958 | 684 | 682.78 |
| Dec-98 | 51 | 73 | 695 | 1,253 | 664 | 665.04 |
| Jan-99 | 67 | 74 | 908 | 1,350 | 893 | 936.86 |
| Feb-99 | 50 | 73 | 683 | 1,066 | 655 | 691.34 |
| Mar-99 | 46 | 75 | 609 | 871 | 610 | 584.05 |
| Apr-99 | 47 | 75 | 622 | 506 | 632 | 600.78 |
| May-99 | 38 | 76 | 502 | 372 | 490 | 524.62 |
| Jun-99 | 35 | 74 | 477 | 140 | 476 | 474.14 |
| Jul-99 | 34 | 73 | 467 | 99 | 464 | 461.23 |
| Aug-99 | 35 | 74 | 480 | 128 | 488 | 485.38 |
| Sep-99 | 35 | 73 | 482 | 293 | 489 | 501.48 |
| Oct-99 | 37 | 74 | 494 | 520 | 506 | 535.20 |
| Nov-99 | 55 | 74 | 740 | 940 | 742 | 697.67 |
| Dec-99 | 35 | 74 | 473 | 1,013 | 512 | 606.53 |
| Jan-00 | 65 | 74 | 873 | 1,345 | 859 | 905.74 |
| Feb-00 | 52 | 74 | 701 | 956 | 705 | 673.40 |
| Mar-00 | 40 | 73 | 555 | 750 | 591 | 587.86 |
| Apr-00 | 44 | 73 | 606 | 591 | 592 | 599.73 |
| May-00 | 40 | 73 | 547 | 374 | 534 | 525.30 |
| Jun-00 | 35 | 73 | 475 | 158 | 469 | 469.32 |
| Jul-00 | 33 | 72 | 465 | 84 | 466 | 465.58 |
| Aug-00 | 36 | 74 | 485 | 217 | 467 | 483.23 |
| Sep-00 | 40 | 74 | 534 | 315 | 535 | 509.46 |
| Oct-00 | 40 | 74 | 538 | 576 | 535 | 532.00 |
| Nov-00 | 44 | 74 | 592 | 858 | 617 | 681.01 |
| Dec-00 | 50 | 74 | 674 | 1,223 | 652 | 609.13 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1996** | 7,675 | 7,406 | - |
| **1997** | 7,165 | 7,196 | - |
| **1998** | 7,128 | 7,145 | 7,249 |
| **1999** | 6,936 | 6,956 | 7,099 |
| **2000** | 7,046 | 7,024 | 7,042 |
| **2001** | 6,620 | 6,627 | 6,869 |
| **2002** | 6,701 | 6,661 | 6,770 |
| **2003** | 7,191 | 7,225 | 6,837 |
| **2004** | 7,222 | 7,334 | 7,073 |
| **2005** | 7,359 | 7,535 | 7,365 |
| **2006** | 7,927 | 7,879 | 7,583 |
| **2007** | 7,608 | 7,590 | 7,668 |

| Upper Liard Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-01 | 57 | 74 | 771 | 1,043 | 845 | 865.66 |
| Feb-01 | 43 | 74 | 587 | 1,031 | 569 | 642.78 |
| Mar-01 | 45 | 73 | 620 | 845 | 629 | 610.21 |
| Apr-01 | 36 | 73 | 487 | 536 | 489 | 570.72 |
| May-01 | 37 | 74 | 499 | 367 | 488 | 504.05 |
| Jun-01 | 36 | 74 | 482 | 156 | 476 | 473.81 |
| Jul-01 | 32 | 74 | 434 | 120 | 425 | 451.78 |
| Aug-01 | 34 | 74 | 453 | 121 | 463 | 473.00 |
| Sep-01 | 33 | 72 | 452 | 300 | 456 | 493.31 |
| Oct-01 | 35 | 70 | 507 | 577 | 502 | 514.47 |
| Nov-01 | 45 | 71 | 636 | 975 | 628 | 662.34 |
| Dec-01 | 49 | 71 | 694 | 1,275 | 657 | 606.76 |
| Jan-02 | 53 | 71 | 745 | 1,246 | 760 | 821.49 |
| Feb-02 | 51 | 71 | 715 | 970 | 714 | 662.61 |
| Mar-02 | 37 | 71 | 525 | 991 | 491 | 570.64 |
| Apr-02 | 41 | 70 | 580 | 695 | 536 | 538.53 |
| May-02 | 39 | 71 | 554 | 366 | 544 | 522.09 |
| Jun-02 | 30 | 72 | 418 | 148 | 414 | 453.24 |
| Jul-02 | 32 | 70 | 451 | 122 | 441 | 444.18 |
| Aug-02 | 33 | 71 | 463 | 182 | 455 | 462.08 |
| Sep-02 | 33 | 72 | 453 | 331 | 448 | 479.73 |
| Oct-02 | 39 | 71 | 556 | 515 | 570 | 535.60 |
| Nov-02 | 47 | 71 | 655 | 822 | 692 | 645.59 |
| Dec-02 | 43 | 74 | 587 | 1,118 | 595 | 634.61 |
| Jan-03 | 60 | 74 | 814 | 1,178 | 849 | 817.95 |
| Feb-03 | 47 | 72 | 653 | 965 | 654 | 645.60 |
| Mar-03 | 45 | 72 | 619 | 900 | 612 | 577.55 |
| Apr-03 | 44 | 71 | 619 | 554 | 615 | 546.35 |
| May-03 | 40 | 72 | 552 | 342 | 549 | 526.80 |
| Jun-03 | 34 | 71 | 477 | 180 | 464 | 451.47 |
| Jul-03 | 34 | 71 | 477 | 57 | 487 | 451.13 |
| Aug-03 | 35 | 71 | 494 | 163 | 492 | 470.39 |
| Sep-03 | 37 | 72 | 512 | 330 | 507 | 470.65 |
| Oct-03 | 35 | 70 | 499 | 526 | 509 | 527.17 |
| Nov-03 | 53 | 72 | 741 | 964 | 736 | 685.02 |
| Dec-03 | 53 | 72 | 735 | 1,096 | 750 | 667.29 |
| Jan-04 | 72 | 70 | 1,029 | 1,366 | 1,009 | 872.54 |
| Feb-04 | 49 | 69 | 705 | 881 | 730 | 699.32 |
| Mar-04 | 44 | 69 | 635 | 810 | 655 | 586.11 |
| Apr-04 | 42 | 69 | 613 | 497 | 626 | 592.02 |
| May-04 | 35 | 69 | 505 | 292 | 516 | 536.21 |
| Jun-04 | 31 | 69 | 452 | 74 | 470 | 449.58 |
| Jul-04 | 34 | 69 | 487 | 36 | 503 | 477.10 |
| Aug-04 | 31 | 70 | 447 | 146 | 451 | 466.18 |
| Sep-04 | 36 | 68 | 523 | 371 | 507 | 487.38 |
| Oct-04 | 40 | 70 | 570 | 565 | 570 | 549.63 |
| Nov-04 | 44 | 71 | 618 | 876 | 639 | 688.72 |
| Dec-04 | 45 | 70 | 638 | 1,071 | 660 | 668.30 |
| Jan-05 | 65 | 69 | 943 | 1,330 | 933 | 930.19 |
| Feb-05 | 42 | 67 | 625 | 942 | 633 | 672.18 |
| Mar-05 | 38 | 67 | 567 | 727 | 611 | 625.96 |
| Apr-05 | 42 | 67 | 633 | 465 | 655 | 631.75 |
| May-05 | 32 | 67 | 481 | 257 | 503 | 522.53 |
| Jun-05 | 30 | 67 | 441 | 127 | 443 | 459.22 |
| Jul-05 | 30 | 64 | 466 | 137 | 452 | 480.72 |
| Aug-05 | 34 | 65 | 517 | 162 | 515 | 486.05 |
| Sep-05 | 38 | 65 | 585 | 297 | 591 | 534.96 |
| Oct-05 | 40 | 65 | 619 | 500 | 638 | 572.32 |
| Nov-05 | 45 | 65 | 693 | 758 | 747 | 707.31 |
| Dec-05 | 52 | 66 | 790 | 1,061 | 815 | 741.46 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Upper Liard Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-06 | 62 | 65 | 954 | 1,185 | 987 | 976.09 |
| Feb-06 | 54 | 66 | 819 | 1,017 | 805 | 722.35 |
| Mar-06 | 52 | 66 | 786 | 961 | 762 | 675.82 |
| Apr-06 | 46 | 65 | 715 | 528 | 719 | 666.29 |
| May-06 | 35 | 65 | 545 | 371 | 533 | 517.48 |
| Jun-06 | 32 | 63 | 515 | 137 | 515 | 476.34 |
| Jul-06 | 32 | 64 | 500 | 79 | 503 | 486.02 |
| Aug-06 | 29 | 63 | 455 | 172 | 450 | 472.07 |
| Sep-06 | 31 | 64 | 480 | 292 | 487 | 528.00 |
| Oct-06 | 38 | 62 | 614 | 543 | 620 | 609.05 |
| Nov-06 | 44 | 63 | 691 | 1,196 | 619 | 668.26 |
| Dec-06 | 54 | 63 | 853 | 1,050 | 881 | 785.10 |
| Jan-07 | 60 | 63 | 954 | 1,102 | 1,011 | 976.86 |
| Feb-07 | 47 | 64 | 732 | 1,017 | 718 | 718.34 |
| Mar-07 | 52 | 63 | 818 | 1,002 | 782 | 718.19 |
| Apr-07 | 44 | 63 | 704 | 543 | 703 | 692.12 |
| May-07 | 32 | 62 | 524 | 332 | 523 | 519.72 |
| Jun-07 | 30 | 62 | 487 | 123 | 491 | 483.06 |
| Jul-07 | 31 | 62 | 495 | 89 | 495 | 483.39 |
| Aug-07 | 27 | 62 | 438 | 143 | 442 | 469.17 |
| Sep-07 | 32 | 63 | 507 | 315 | 507 | 528.12 |
| Oct-07 | 34 | 63 | 539 | 553 | 542 | 599.70 |
| Nov-07 | 42 | 63 | 667 | 957 | 664 | 676.61 |
| Dec-07 | 48 | 65 | 745 | 1,255 | 713 | 802.97 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**UPPER LIARD RESIDENTIAL SUMMARY OUTPUT**

Data: 1996:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.85505527 |
| R Square | 0.73111952 |
| Adjusted R Square | 0.72922599 |
| Standard Error | 72.8334677 |
| Observations | 144 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 2048233.303 | 2048233.3 | 386.115688 | 2.45835E-42 |
| Residual | 142 | 753269.3907 | 5304.71402 | | |
| Total | 143 | 2801502.694 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 422.519051 | 10.93452006 | 38.640841 | 3.1262E-77 | 400.903572 | 444.13453 | 400.903572 | 444.13453 |
| MHDD | 0.2910576 | 0.014812222 | 19.6498267 | 2.4583E-42 | 0.261776637 | 0.32033856 | 0.26177664 | 0.32033856 |

| Watson Lake Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-96 | 640 | 558 | 1,147 | 1,605 | 1,041 | |
| Feb-96 | 526 | 551 | 955 | 947 | 962 | |
| Mar-96 | 442 | 557 | 794 | 874 | 795 | |
| Apr-96 | 399 | 555 | 720 | 548 | 717 | |
| May-96 | 359 | 552 | 651 | 366 | 639 | |
| Jun-96 | 311 | 554 | 562 | 164 | 552 | |
| Jul-96 | 302 | 554 | 545 | 103 | 541 | |
| Aug-96 | 317 | 545 | 581 | 185 | 572 | |
| Sep-96 | 331 | 537 | 616 | 355 | 603 | |
| Oct-96 | 373 | 542 | 688 | 662 | 654 | |
| Nov-96 | 488 | 554 | 880 | 1,121 | 820 | |
| Dec-96 | 518 | 548 | 946 | 1,361 | 873 | |
| Jan-97 | 656 | 551 | 1,191 | 1,407 | 1,153 | |
| Feb-97 | 502 | 557 | 901 | 885 | 930 | |
| Mar-97 | 400 | 551 | 726 | 944 | 702 | |
| Apr-97 | 389 | 551 | 706 | 528 | 710 | |
| May-97 | 360 | 549 | 655 | 312 | 661 | |
| Jun-97 | 311 | 549 | 567 | 143 | 565 | |
| Jul-97 | 302 | 554 | 545 | 84 | 547 | |
| Aug-97 | 305 | 549 | 556 | 110 | 572 | |
| Sep-97 | 319 | 540 | 592 | 271 | 607 | |
| Oct-97 | 372 | 554 | 672 | 660 | 639 | |
| Nov-97 | 438 | 560 | 781 | 936 | 785 | |
| Dec-97 | 469 | 565 | 831 | 984 | 886 | |
| Jan-98 | 594 | 564 | 1,054 | 1,410 | 1,015 | 1069.87 |
| Feb-98 | 433 | 564 | 768 | 942 | 777 | 889.53 |
| Mar-98 | 393 | 559 | 702 | 843 | 714 | 736.99 |
| Apr-98 | 393 | 556 | 707 | 500 | 721 | 716.25 |
| May-98 | 313 | 555 | 564 | 211 | 605 | 635.07 |
| Jun-98 | 292 | 554 | 527 | 89 | 544 | 553.46 |
| Jul-98 | 290 | 554 | 524 | 66 | 532 | 539.64 |
| Aug-98 | 295 | 549 | 538 | 157 | 538 | 560.56 |
| Sep-98 | 316 | 546 | 579 | 321 | 578 | 595.84 |
| Oct-98 | 364 | 549 | 664 | 561 | 664 | 652.33 |
| Nov-98 | 415 | 554 | 748 | 958 | 745 | 783.32 |
| Dec-98 | 482 | 553 | 871 | 1,253 | 835 | 864.67 |
| Jan-99 | 541 | 550 | 984 | 1,350 | 966 | 1044.88 |
| Feb-99 | 433 | 549 | 788 | 1,066 | 754 | 820.41 |
| Mar-99 | 406 | 546 | 744 | 871 | 746 | 720.78 |
| Apr-99 | 393 | 549 | 715 | 506 | 727 | 719.43 |
| May-99 | 348 | 552 | 631 | 372 | 616 | 627.58 |
| Jun-99 | 302 | 552 | 547 | 140 | 546 | 551.25 |
| Jul-99 | 294 | 559 | 526 | 99 | 523 | 533.83 |
| Aug-99 | 307 | 561 | 547 | 128 | 557 | 555.66 |
| Sep-99 | 349 | 559 | 625 | 293 | 633 | 605.78 |
| Oct-99 | 356 | 567 | 628 | 520 | 643 | 648.80 |
| Nov-99 | 432 | 564 | 766 | 940 | 769 | 766.18 |
| Dec-99 | 446 | 560 | 797 | 1,013 | 843 | 854.65 |
| Jan-00 | 640 | 562 | 1,139 | 1,345 | 1,122 | 1034.52 |
| Feb-00 | 501 | 561 | 894 | 956 | 898 | 809.80 |
| Mar-00 | 365 | 558 | 654 | 750 | 697 | 719.08 |
| Apr-00 | 397 | 565 | 703 | 591 | 686 | 711.33 |
| May-00 | 363 | 572 | 635 | 374 | 620 | 613.89 |
| Jun-00 | 318 | 570 | 558 | 158 | 551 | 546.70 |
| Jul-00 | 308 | 564 | 547 | 84 | 549 | 534.50 |
| Aug-00 | 328 | 558 | 589 | 217 | 568 | 554.40 |
| Sep-00 | 334 | 553 | 603 | 315 | 604 | 604.65 |
| Oct-00 | 374 | 563 | 664 | 576 | 659 | 655.64 |
| Nov-00 | 430 | 567 | 758 | 858 | 788 | 767.09 |
| Dec-00 | 552 | 568 | 971 | 1,223 | 945 | 874.17 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|---|
| **1996** | 9,084 | 8,767 | - |
| **1997** | 8,721 | 8,758 | - |
| **1998** | 8,248 | 8,268 | 8,598 |
| **1999** | 8,299 | 8,322 | 8,449 |
| **2000** | 8,714 | 8,687 | 8,426 |
| **2001** | 8,349 | 8,357 | 8,456 |
| **2002** | 8,419 | 8,372 | 8,472 |
| **2003** | 8,489 | 8,528 | 8,419 |
| **2004** | 8,581 | 8,713 | 8,538 |
| **2005** | 8,594 | 8,801 | 8,681 |
| **2006** | 8,989 | 8,933 | 8,816 |
| **2007** | 8,890 | 8,869 | 8,868 |

| Watson Lake Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-01 | 526 | 565 | 932 | 1,043 | 1,019 | 1035.66 |
| Feb-01 | 460 | 566 | 813 | 1,031 | 791 | 814.56 |
| Mar-01 | 411 | 566 | 727 | 845 | 738 | 727.11 |
| Apr-01 | 381 | 562 | 677 | 536 | 679 | 697.25 |
| May-01 | 370 | 567 | 652 | 367 | 639 | 625.23 |
| Jun-01 | 320 | 568 | 564 | 156 | 557 | 551.17 |
| Jul-01 | 304 | 565 | 538 | 120 | 527 | 533.01 |
| Aug-01 | 306 | 552 | 555 | 121 | 567 | 564.11 |
| Sep-01 | 307 | 561 | 547 | 300 | 553 | 596.32 |
| Oct-01 | 365 | 560 | 652 | 577 | 647 | 649.81 |
| Nov-01 | 448 | 565 | 793 | 975 | 783 | 779.97 |
| Dec-01 | 510 | 566 | 901 | 1,275 | 857 | 881.54 |
| Jan-02 | 544 | 563 | 967 | 1,246 | 984 | 1041.63 |
| Feb-02 | 458 | 561 | 817 | 970 | 816 | 835.09 |
| Mar-02 | 411 | 567 | 725 | 991 | 686 | 707.08 |
| Apr-02 | 418 | 564 | 741 | 695 | 689 | 684.56 |
| May-02 | 366 | 570 | 642 | 366 | 630 | 629.69 |
| Jun-02 | 310 | 570 | 544 | 148 | 540 | 549.42 |
| Jul-02 | 307 | 566 | 542 | 122 | 531 | 535.73 |
| Aug-02 | 342 | 560 | 610 | 182 | 602 | 579.14 |
| Sep-02 | 316 | 566 | 558 | 331 | 552 | 569.57 |
| Oct-02 | 387 | 567 | 682 | 515 | 698 | 668.23 |
| Nov-02 | 432 | 567 | 762 | 822 | 805 | 792.12 |
| Dec-02 | 466 | 563 | 828 | 1,118 | 838 | 879.99 |
| Jan-03 | 536 | 566 | 948 | 1,178 | 989 | 997.07 |
| Feb-03 | 434 | 564 | 770 | 965 | 771 | 792.97 |
| Mar-03 | 399 | 567 | 704 | 900 | 696 | 706.54 |
| Apr-03 | 438 | 566 | 774 | 554 | 769 | 712.27 |
| May-03 | 342 | 567 | 603 | 342 | 599 | 622.65 |
| Jun-03 | 315 | 567 | 556 | 180 | 541 | 546.12 |
| Jul-03 | 318 | 565 | 563 | 57 | 575 | 544.42 |
| Aug-03 | 314 | 572 | 549 | 163 | 547 | 571.98 |
| Sep-03 | 347 | 570 | 609 | 330 | 604 | 569.85 |
| Oct-03 | 369 | 568 | 649 | 526 | 662 | 669.14 |
| Nov-03 | 453 | 570 | 795 | 964 | 790 | 792.69 |
| Dec-03 | 550 | 568 | 968 | 1,096 | 986 | 893.51 |
| Jan-04 | 548 | 564 | 972 | 1,366 | 948 | 973.64 |
| Feb-04 | 458 | 567 | 807 | 881 | 837 | 808.17 |
| Mar-04 | 424 | 566 | 750 | 810 | 773 | 718.13 |
| Apr-04 | 426 | 571 | 746 | 497 | 761 | 739.64 |
| May-04 | 340 | 577 | 588 | 292 | 601 | 610.02 |
| Jun-04 | 346 | 572 | 605 | 74 | 627 | 569.38 |
| Jul-04 | 332 | 578 | 574 | 36 | 592 | 566.02 |
| Aug-04 | 325 | 575 | 565 | 146 | 569 | 572.69 |
| Sep-04 | 373 | 577 | 646 | 371 | 628 | 594.77 |
| Oct-04 | 369 | 567 | 650 | 565 | 650 | 670.08 |
| Nov-04 | 443 | 568 | 779 | 876 | 804 | 799.50 |
| Dec-04 | 507 | 565 | 897 | 1,071 | 923 | 915.60 |
| Jan-05 | 595 | 565 | 1,053 | 1,330 | 1,042 | 992.92 |
| Feb-05 | 455 | 563 | 807 | 942 | 816 | 808.28 |
| Mar-05 | 421 | 564 | 746 | 727 | 798 | 755.29 |
| Apr-05 | 403 | 564 | 714 | 465 | 740 | 756.74 |
| May-05 | 356 | 568 | 627 | 257 | 652 | 617.62 |
| Jun-05 | 330 | 564 | 584 | 127 | 588 | 585.20 |
| Jul-05 | 312 | 566 | 551 | 137 | 535 | 567.18 |
| Aug-05 | 319 | 565 | 565 | 162 | 563 | 559.74 |
| Sep-05 | 388 | 563 | 690 | 297 | 696 | 642.67 |
| Oct-05 | 357 | 571 | 626 | 500 | 647 | 653.08 |
| Nov-05 | 421 | 573 | 735 | 758 | 800 | 797.77 |
| Dec-05 | 513 | 573 | 895 | 1,061 | 924 | 944.23 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

| Watson Lake Residential monthly | Energy (MWh) | Cust | Calculated UPC (kWh) | (Watson Lake) MHDD | Normalized UPC (kWh) | 3-Yr Average Mthly Normal UPC (kWh) |
|---|---|---|---|---|---|---|
| Jan-06 | 524 | 571 | 918 | 1,185 | 957 | 982.36 |
| Feb-06 | 517 | 568 | 911 | 1,017 | 894 | 849.14 |
| Mar-06 | 409 | 446 | 916 | 961 | 887 | 819.15 |
| Apr-06 | 409 | 564 | 726 | 528 | 730 | 743.68 |
| May-06 | 367 | 567 | 646 | 371 | 632 | 628.73 |
| Jun-06 | 328 | 568 | 578 | 137 | 578 | 597.43 |
| Jul-06 | 335 | 570 | 587 | 79 | 591 | 572.52 |
| Aug-06 | 325 | 563 | 578 | 172 | 573 | 568.46 |
| Sep-06 | 359 | 562 | 639 | 292 | 647 | 656.70 |
| Oct-06 | 376 | 566 | 664 | 543 | 671 | 656.03 |
| Nov-06 | 476 | 564 | 843 | 1,196 | 758 | 787.14 |
| Dec-06 | 557 | 567 | 983 | 1,050 | 1,016 | 954.30 |
| Jan-07 | 550 | 566 | 972 | 1,102 | 1,039 | 1012.48 |
| Feb-07 | 547 | 567 | 965 | 1,017 | 949 | 886.36 |
| Mar-07 | 500 | 569 | 879 | 1,002 | 836 | 840.17 |
| Apr-07 | 431 | 574 | 751 | 543 | 751 | 740.26 |
| May-07 | 394 | 571 | 690 | 332 | 689 | 658.09 |
| Jun-07 | 349 | 578 | 605 | 123 | 609 | 591.65 |
| Jul-07 | 324 | 575 | 563 | 89 | 564 | 563.09 |
| Aug-07 | 336 | 582 | 577 | 143 | 582 | 572.72 |
| Sep-07 | 342 | 584 | 586 | 315 | 587 | 643.07 |
| Oct-07 | 376 | 576 | 652 | 553 | 656 | 658.10 |
| Nov-07 | 479 | 568 | 843 | 957 | 840 | 799.21 |
| Dec-07 | 462 | 574 | 805 | 1,255 | 768 | 902.43 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) | Annual 3-Yr Avg Mthly Normal UPC (kWh) |
|---|---|---|

**WATSON LAKE RESIDENTIAL SUMMARY OUTPUT**

Data: 1996:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.93323961 |
| R Square | 0.87093618 |
| Adjusted R Square | 0.87002728 |
| Standard Error | 54.4463342 |
| Observations | 144 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 2840582.712 | 2840582.71 | 958.230852 | 5.26882E-65 |
| Residual | 142 | 420945.2704 | 2964.40331 | | |
| Total | 143 | 3261527.982 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 507.415358 | 8.174051746 | 62.0763575 | 8.588E-105 | 491.2568029 | 523.573913 | 491.256803 | 523.573913 |
| MHDD | 0.34276222 | 0.011072811 | 30.9553041 | 5.2688E-65 | 0.32087337 | 0.36465108 | 0.32087337 | 0.36465108 |

| Watson Lake<br>Heating Degree Day (HDD)<br>Degree Days Below 18.0 C<br>Month | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 12-year "Normal" HDD (1996-07) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JAN | 1,605.2 | 1,406.6 | 1,409.7 | 1,350.2 | 1,344.8 | 1,043.4 | 1,246.3 | 1,177.5 | 1,365.6 | 1,330.3 | 1,185.2 | 1,102.4 | **1,297.3** |
| FEB | 947.3 | 884.8 | 942.0 | 1,066.4 | 956.0 | 1,031.0 | 970.3 | 964.7 | 881.2 | 941.8 | 1,016.7 | 1,017.3 | **968.3** |
| MAR | 874.3 | 943.9 | 843.4 | 871.4 | 750.1 | 844.9 | 991.4 | 899.5 | 809.9 | 726.9 | 960.5 | 1,001.9 | **876.5** |
| APR | 547.7 | 527.9 | 500.1 | 506.4 | 590.9 | 535.8 | 694.8 | 554.4 | 497.4 | 464.8 | 528.2 | 543.0 | **541.0** |
| MAY | 366.4 | 311.8 | 211.0 | 372.2 | 373.8 | 366.6 | 365.9 | 341.6 | 292.3 | 256.9 | 371.1 | 332.2 | **330.2** |
| JUN | 163.9 | 142.6 | 89.0 | 140.2 | 158.0 | 155.5 | 147.8 | 179.9 | 74.1 | 126.6 | 136.5 | 122.6 | **136.4** |
| JUL | 103.3 | 84.1 | 65.7 | 99.4 | 84.3 | 120.3 | 121.6 | 56.6 | 35.6 | 136.9 | 79.2 | 88.6 | **89.6** |
| AUG | 185.1 | 109.6 | 156.8 | 127.8 | 216.9 | 120.6 | 181.5 | 163.0 | 145.7 | 162.2 | 171.7 | 143.1 | **157.0** |
| SEP | 354.7 | 271.1 | 320.7 | 292.5 | 314.8 | 299.6 | 331.0 | 330.2 | 370.7 | 297.3 | 292.4 | 314.7 | **315.8** |
| OCT | 662.2 | 659.7 | 561.2 | 519.8 | 575.8 | 577.0 | 514.8 | 526.1 | 565.0 | 500.3 | 543.3 | 553.1 | **563.2** |
| NOV | 1,121.2 | 935.8 | 958.1 | 939.9 | 858.4 | 975.2 | 821.9 | 963.9 | 875.5 | 758.4 | 1,196.2 | 956.6 | **946.8** |
| DEC | 1,361.1 | 983.7 | 1,252.7 | 1,013.0 | 1,222.8 | 1,275.4 | 1,117.9 | 1,095.5 | 1,070.7 | 1,061.0 | 1,050.0 | 1,255.1 | **1,146.6** |
| **TOTAL** | **8,292.4** | **7,261.6** | **7,310.4** | **7,299.2** | **7,446.6** | **7,345.3** | **7,505.2** | **7,252.9** | **6,983.7** | **6,763.4** | **7,531.0** | **7,430.6** | **7,368.5** |

| Whitehorse<br>Heating Degree Day (HDD)<br>Degree Days Below 18.0 C<br>Month | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 20-year "Normal" HDD (1988-07) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JAN | 1,133.2 | 1,231.3 | 1,114.4 | 1,140.7 | 812.3 | 1,119.6 | 1,085.4 | 1,020.1 | 1,556.4 | 1,185.7 | 1,165.7 | 1,183.1 | 1,082.9 | 722.7 | 935.6 | 989.1 | 1,254.5 | 1,164.7 | 1,096.2 | 912.0 | **1,095.3** |
| FEB | 809.3 | 997.6 | 1,083.6 | 712.1 | 859.8 | 841.7 | 1,124.5 | 840.1 | 835.8 | 656.5 | 719.1 | 976.4 | 735.2 | 864.1 | 824.6 | 756.6 | 695.3 | 795.2 | 821.3 | 998.8 | **847.4** |
| MAR | 650.0 | 928.4 | 667.0 | 782.3 | 660.7 | 693.4 | 653.9 | 880.0 | 805.8 | 855.4 | 756.6 | 734.0 | 659.2 | 765.3 | 921.1 | 834.5 | 756.3 | 613.7 | 906.3 | 954.2 | **773.9** |
| APR | 480.0 | 443.6 | 458.4 | 461.7 | 536.3 | 417.3 | 430.8 | 439.9 | 526.0 | 484.0 | 458.6 | 508.8 | 515.6 | 506.8 | 653.3 | 514.3 | 466.6 | 453.3 | 519.1 | 511.9 | **489.3** |
| MAY | 337.1 | 275.7 | 300.8 | 300.0 | 378.3 | 244.1 | 320.9 | 250.7 | 357.3 | 331.1 | 270.6 | 391.9 | 382.0 | 390.4 | 361.6 | 363.7 | 272.5 | 256.6 | 346.9 | 322.1 | **322.7** |
| JUN | 186.3 | 163.4 | 185.7 | 159.9 | 176.8 | 132.5 | 166.2 | 139.0 | 193.6 | 148.9 | 119.5 | 153.9 | 172.5 | 167.3 | 175.6 | 192.8 | 83.7 | 154.4 | 173.1 | 140.5 | **159.3** |
| JUL | 168.1 | 72.8 | 98.1 | 144.2 | 123.8 | 96.8 | 83.7 | 96.6 | 124.9 | 92.8 | 111.6 | 108.6 | 142.1 | 139.6 | 130.9 | 84.4 | 74.2 | 132.6 | 118.4 | 102.3 | **112.3** |
| AUG | 181.6 | 99.3 | 132.9 | 199.3 | 176.2 | 158.0 | 69.6 | 198.3 | 227.3 | 130.0 | 189.2 | 145.7 | 219.9 | 139.6 | 182.8 | 180.6 | 101.7 | 150.8 | 201.6 | 154.2 | **161.9** |
| SEP | 359.6 | 283.3 | 272.0 | 289.0 | 461.1 | 279.2 | 334.9 | 226.5 | 362.6 | 282.1 | 327.8 | 311.2 | 354.2 | 309.0 | 314.4 | 359.2 | 367.5 | 299.3 | 295.7 | 308.4 | **319.9** |
| OCT | 532.3 | 569.7 | 606.8 | 623.6 | 613.1 | 478.7 | 507.0 | 524.9 | 679.9 | 641.0 | 557.9 | 499.8 | 539.2 | 573.4 | 444.3 | 466.7 | 540.5 | 534.6 | 520.5 | 543.7 | **549.9** |
| NOV | 775.8 | 905.6 | 1,114.1 | 815.9 | 677.5 | 732.2 | 935.9 | 894.4 | 975.0 | 694.0 | 792.3 | 792.5 | 691.2 | 818.0 | 582.6 | 874.6 | 719.8 | 774.1 | 1,162.2 | 724.6 | **822.6** |
| DEC | 887.2 | 769.6 | 1,103.0 | 903.7 | 1,150.6 | 825.6 | 1,028.9 | 1,048.6 | 1,155.8 | 762.0 | 1,051.8 | 844.0 | 977.8 | 1,094.6 | 845.2 | 911.6 | 899.5 | 794.4 | 824.3 | 1,069.5 | **947.4** |
| **TOTAL** | **6,500.5** | **6,740.3** | **7,136.8** | **6,532.4** | **6,626.5** | **6,019.1** | **6,741.7** | **6,559.1** | **7,800.4** | **6,263.5** | **6,520.7** | **6,649.9** | **6,471.8** | **6,490.8** | **6,372.0** | **6,528.1** | **6,232.1** | **6,123.7** | **6,985.6** | **6,742.2** | **6,601.9** |

| Whitehorse Commercial monthly | (kWh) UPC | (Whitehorse) MHDD | Normalized UPC (kWh) |
|---|---|---|---|
| Jan-94 | 6,431 | 1,085 | 6,445 |
| Feb-94 | 5,872 | 1,125 | 5,494 |
| Mar-94 | 6,357 | 654 | 6,520 |
| Apr-94 | 5,470 | 431 | 5,550 |
| May-94 | 4,869 | 321 | 4,872 |
| Jun-94 | 4,796 | 166 | 4,786 |
| Jul-94 | 4,649 | 84 | 4,688 |
| Aug-94 | 4,677 | 70 | 4,803 |
| Sep-94 | 4,644 | 335 | 4,624 |
| Oct-94 | 4,896 | 507 | 4,954 |
| Nov-94 | 5,403 | 936 | 5,249 |
| Dec-94 | 6,078 | 1,029 | 5,967 |
| Jan-95 | 6,461 | 1,020 | 6,564 |
| Feb-95 | 5,710 | 840 | 5,720 |
| Mar-95 | 6,048 | 880 | 5,904 |
| Apr-95 | 5,345 | 440 | 5,413 |
| May-95 | 4,988 | 251 | 5,086 |
| Jun-95 | 4,817 | 139 | 4,844 |
| Jul-95 | 4,726 | 97 | 4,747 |
| Aug-95 | 4,705 | 198 | 4,656 |
| Sep-95 | 4,702 | 227 | 4,830 |
| Oct-95 | 4,871 | 525 | 4,905 |
| Nov-95 | 5,531 | 894 | 5,433 |
| Dec-95 | 6,052 | 1,049 | 5,914 |
| Jan-96 | 6,774 | 1,556 | 6,145 |
| Feb-96 | 6,462 | 836 | 6,478 |
| Mar-96 | 6,062 | 806 | 6,019 |
| Apr-96 | 5,546 | 526 | 5,497 |
| May-96 | 4,953 | 357 | 4,905 |
| Jun-96 | 4,888 | 194 | 4,841 |
| Jul-96 | 4,792 | 125 | 4,775 |
| Aug-96 | 4,754 | 227 | 4,665 |
| Sep-96 | 4,820 | 363 | 4,762 |
| Oct-96 | 5,085 | 680 | 4,908 |
| Nov-96 | 5,831 | 975 | 5,624 |
| Dec-96 | 6,002 | 1,156 | 5,718 |
| Jan-97 | 7,201 | 1,186 | 7,077 |
| Feb-97 | 5,969 | 657 | 6,229 |
| Mar-97 | 5,604 | 855 | 5,493 |
| Apr-97 | 5,719 | 484 | 5,726 |
| May-97 | 4,832 | 331 | 4,821 |
| Jun-97 | 4,922 | 149 | 4,936 |
| Jul-97 | 4,886 | 93 | 4,913 |
| Aug-97 | 4,675 | 130 | 4,718 |
| Sep-97 | 4,756 | 282 | 4,807 |
| Oct-97 | 5,044 | 641 | 4,920 |
| Nov-97 | 5,430 | 694 | 5,605 |
| Dec-97 | 5,326 | 762 | 5,578 |
| Jan-98 | 6,537 | 1,166 | 6,441 |
| Feb-98 | 5,662 | 719 | 5,837 |
| Mar-98 | 5,721 | 757 | 5,745 |
| Apr-98 | 5,190 | 459 | 5,231 |
| May-98 | 4,616 | 271 | 4,687 |
| Jun-98 | 4,683 | 120 | 4,738 |
| Jul-98 | 5,044 | 112 | 5,045 |
| Aug-98 | 4,612 | 189 | 4,575 |
| Sep-98 | 4,991 | 328 | 4,980 |
| Oct-98 | 4,860 | 558 | 4,849 |
| Nov-98 | 5,372 | 792 | 5,413 |
| Dec-98 | 5,430 | 1,052 | 5,287 |

| | Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) |
|---|---|---|
| **1994** | 64,142 | 63,951 |
| **1995** | 63,958 | 64,016 |
| **1996** | 65,970 | 64,337 |
| **1997** | 64,363 | 64,824 |
| **1998** | 62,718 | 62,828 |
| **1999** | 62,814 | 62,749 |
| **2000** | 62,473 | 62,650 |
| **2001** | 62,690 | 62,841 |
| **2002** | 63,828 | 64,142 |
| **2003** | 64,208 | 64,308 |
| **2004** | 65,827 | 66,331 |
| **2005** | 65,434 | 66,085 |
| **2006** | 67,414 | 66,891 |
| **2007** | 67,763 | 67,572 |

| Whitehorse Commercial monthly | (kWh) UPC | (Whitehorse) MHDD | Normalized UPC (kWh) |
|---|---|---|---|
| Jan-99 | 6,313 | 1,183 | 6,193 |
| Feb-99 | 5,783 | 976 | 5,608 |
| Mar-99 | 5,639 | 734 | 5,693 |
| Apr-99 | 5,332 | 509 | 5,306 |
| May-99 | 4,621 | 392 | 4,527 |
| Jun-99 | 4,954 | 154 | 4,961 |
| Jul-99 | 4,695 | 109 | 4,700 |
| Aug-99 | 4,816 | 146 | 4,838 |
| Sep-99 | 4,779 | 311 | 4,791 |
| Oct-99 | 4,769 | 500 | 4,837 |
| Nov-99 | 5,703 | 793 | 5,744 |
| Dec-99 | 5,411 | 844 | 5,552 |
| Jan-00 | 6,273 | 1,083 | 6,289 |
| Feb-00 | 5,621 | 735 | 5,774 |
| Mar-00 | 5,375 | 659 | 5,532 |
| Apr-00 | 5,138 | 516 | 5,102 |
| May-00 | 4,912 | 382 | 4,832 |
| Jun-00 | 5,038 | 173 | 5,020 |
| Jul-00 | 5,242 | 142 | 5,202 |
| Aug-00 | 4,601 | 220 | 4,522 |
| Sep-00 | 4,692 | 354 | 4,645 |
| Oct-00 | 5,078 | 539 | 5,093 |
| Nov-00 | 5,167 | 691 | 5,346 |
| Dec-00 | 5,335 | 978 | 5,294 |
| Jan-01 | 6,243 | 723 | 6,751 |
| Feb-01 | 5,377 | 864 | 5,354 |
| Mar-01 | 5,579 | 765 | 5,590 |
| Apr-01 | 5,258 | 507 | 5,234 |
| May-01 | 4,877 | 390 | 4,785 |
| Jun-01 | 5,070 | 167 | 5,059 |
| Jul-01 | 4,861 | 140 | 4,824 |
| Aug-01 | 4,692 | 140 | 4,722 |
| Sep-01 | 4,703 | 309 | 4,718 |
| Oct-01 | 4,779 | 573 | 4,747 |
| Nov-01 | 5,169 | 818 | 5,175 |
| Dec-01 | 6,082 | 1,095 | 5,881 |
| Jan-02 | 6,644 | 936 | 6,861 |
| Feb-02 | 5,659 | 825 | 5,690 |
| Mar-02 | 5,661 | 921 | 5,461 |
| Apr-02 | 5,830 | 653 | 5,607 |
| May-02 | 4,995 | 362 | 4,942 |
| Jun-02 | 4,986 | 176 | 4,964 |
| Jul-02 | 4,839 | 131 | 4,814 |
| Aug-02 | 5,123 | 183 | 5,094 |
| Sep-02 | 4,700 | 314 | 4,708 |
| Oct-02 | 4,784 | 444 | 4,928 |
| Nov-02 | 5,350 | 583 | 5,677 |
| Dec-02 | 5,257 | 845 | 5,396 |
| Jan-03 | 6,128 | 989 | 6,273 |
| Feb-03 | 5,478 | 757 | 5,602 |
| Mar-03 | 5,566 | 835 | 5,483 |
| Apr-03 | 5,645 | 514 | 5,611 |
| May-03 | 4,805 | 364 | 4,749 |
| Jun-03 | 5,203 | 193 | 5,157 |
| Jul-03 | 4,881 | 84 | 4,919 |
| Aug-03 | 4,837 | 181 | 4,811 |
| Sep-03 | 4,986 | 359 | 4,933 |
| Oct-03 | 4,918 | 467 | 5,032 |
| Nov-03 | 5,720 | 875 | 5,649 |
| Dec-03 | 6,041 | 912 | 6,090 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) |
|---|---|

| Whitehorse Commercial monthly | (kWh) UPC | (Whitehorse) MHDD | Normalized UPC (kWh) |
|---|---|---|---|
| Jan-04 | 6,337 | 1,255 | 6,120 |
| Feb-04 | 5,894 | 695 | 6,102 |
| Mar-04 | 5,728 | 756 | 5,752 |
| Apr-04 | 5,684 | 467 | 5,715 |
| May-04 | 4,928 | 273 | 4,996 |
| Jun-04 | 5,266 | 84 | 5,369 |
| Jul-04 | 5,394 | 74 | 5,445 |
| Aug-04 | 5,204 | 102 | 5,286 |
| Sep-04 | 4,980 | 368 | 4,915 |
| Oct-04 | 4,913 | 541 | 4,926 |
| Nov-04 | 5,561 | 720 | 5,701 |
| Dec-04 | 5,938 | 900 | 6,003 |
| Jan-05 | 6,556 | 1,165 | 6,461 |
| Feb-05 | 5,843 | 795 | 5,914 |
| Mar-05 | 5,588 | 614 | 5,806 |
| Apr-05 | 5,459 | 453 | 5,509 |
| May-05 | 5,235 | 257 | 5,325 |
| Jun-05 | 4,929 | 154 | 4,935 |
| Jul-05 | 5,082 | 133 | 5,054 |
| Aug-05 | 5,052 | 151 | 5,067 |
| Sep-05 | 5,118 | 299 | 5,146 |
| Oct-05 | 5,031 | 535 | 5,052 |
| Nov-05 | 5,836 | 774 | 5,902 |
| Dec-05 | 5,706 | 794 | 5,915 |
| Jan-06 | 6,656 | 1,096 | 6,654 |
| Feb-06 | 5,781 | 821 | 5,817 |
| Mar-06 | 6,407 | 906 | 6,226 |
| Apr-06 | 5,968 | 519 | 5,928 |
| May-06 | 4,767 | 347 | 4,734 |
| Jun-06 | 5,294 | 173 | 5,275 |
| Jul-06 | 5,295 | 118 | 5,287 |
| Aug-06 | 5,016 | 202 | 4,962 |
| Sep-06 | 5,016 | 296 | 5,049 |
| Oct-06 | 5,304 | 521 | 5,344 |
| Nov-06 | 5,726 | 1,162 | 5,264 |
| Dec-06 | 6,182 | 824 | 6,350 |
| Jan-07 | 6,820 | 912 | 7,069 |
| Feb-07 | 6,053 | 999 | 5,847 |
| Mar-07 | 6,467 | 954 | 6,221 |
| Apr-07 | 6,024 | 512 | 5,993 |
| May-07 | 5,043 | 322 | 5,043 |
| Jun-07 | 5,136 | 141 | 5,162 |
| Jul-07 | 5,526 | 102 | 5,540 |
| Aug-07 | 4,958 | 154 | 4,969 |
| Sep-07 | 5,045 | 308 | 5,061 |
| Oct-07 | 4,997 | 544 | 5,005 |
| Nov-07 | 5,821 | 725 | 5,954 |
| Dec-07 | 5,873 | 1,070 | 5,707 |

| Annual Actual UPC (kWh) | Annual Normalized UPC (kWh) |
|---|---|

**WHITEHORSE COMMERCIAL SUMMARY OUTPUT**

Data: 1994:1 - 2007:12

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.81085088 |
| R Square | 0.65747916 |
| Adjusted R Square | 0.65541578 |
| Standard Error | 335.348684 |
| Observations | 168 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 35834082.04 | 35834082 | 318.642038 | 1.8196E-40 |
| Residual | 166 | 18668150.81 | 112458.74 | | |
| Total | 167 | 54502232.85 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* | *Lower 95.0%* | *Upper 95.0%* |
|---|---|---|---|---|---|---|---|---|
| Intercept | 4628.54159 | 49.34457725 | 93.8004103 | 1.01E-145 | 4531.117746 | 4725.96544 | 4531.11775 | 4725.96544 |
| MHDD | 1.36250504 | 0.076328475 | 17.8505473 | 1.8196E-40 | 1.211805331 | 1.51320476 | 1.21180533 | 1.51320476 |

**YUB-YECL-5**

**Reference:** Purchase Power; Application, page 3-1

**Issue Sub-Issue:** Fish Lake Hydro generation rebuilds

**Quote**: The Fish Lake hydro generation in the test period outlined in Schedule 3.2, is based on the average generation over the last 10 years at Fish Lake adjusted for estimated downtime in the test period, for required rebuilds.

**Preamble**: The Board wishes to understand the necessity of required rebuilds

**Request:**

For the period 2003 through 2007, please provide on an annual basis the generation output, type of and length of maintenance outages, and rebuilds and reasons for the rebuilds if any.

**Response:**

Please refer to YUB-YECL-05 Attachment 1, YUB-YECL-05 Attachment 2, YUB-YECL-05 Attachment 3 and YUB-YECL-05 Attachment 4. There were no rebuilds on the Fish Lake Hydro System between 2003 and 2007.

The Yukon Electrical Company Limited
Historical Water Levels at Fish Lake
Annual 1998-2007

| Date | Unit 1 kWhr | Unit 1 Average kW | Unit 2 kWhr | Unit 2 Average kW | Combined kWhr | Combined Average kW |
|---|---|---|---|---|---|---|
| 1998 | 2,870,400 | 328 | 2,692,830 | 307 | 5,563,230 | 635 |
| 1999 | 2,305,680 | 263 | 2,246,040 | 256 | 4,551,720 | 520 |
| 2000 | 4,046,400 | 461 | 2,932,200 | 334 | 6,978,600 | 794 |
| 2001 | 5,171,640 | 590 | 3,936,960 | 449 | 9,108,600 | 1,040 |
| 2002 | 4,750,200 | 542 | 3,826,080 | 437 | 8,576,280 | 979 |
| 2003 | 2,462,400 | 281 | 2,485,560 | 284 | 4,947,960 | 565 |
| 2004 | 3,138,840 | 357 | 2,660,520 | 303 | 5,799,360 | 660 |
| 2005 | 3,933,000 | 449 | 2,948,160 | 337 | 6,881,160 | 786 |
| 2006 | 4,728,480 | 540 | 3,464,640 | 396 | 8,193,120 | 935 |
| 2007 | 5,336,880 | 609 | 3,688,320 | 421 | 9,025,200 | 1,030 |
| | | | | Ten Year Average | 6,962,523 | |

| Date | January | February | March | April | May | June | July | August | September | October | November | December | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1998 | 721,790 | 560,230 | 665,200 | 667,690 | 547,590 | 372,940 | 390,080 | 363,280 | 279,510 | 255,230 | 257,710 | 481,980 | 5,563,230 |
| 1999 | 477,960 | 437,040 | 512,160 | 461,880 | 545,160 | 630,720 | 224,040 | 199,560 | 193,680 | 208,920 | 282,720 | 377,880 | 4,551,720 |
| 2000 | 507,960 | 600,360 | 345,360 | 269,520 | 499,800 | 547,800 | 595,560 | 696,840 | 803,520 | 719,040 | 665,520 | 727,320 | 6,978,600 |
| 2001 | 775,800 | 697,200 | 763,680 | 698,280 | 738,960 | 783,480 | 792,480 | 774,480 | 789,840 | 763,920 | 757,200 | 773,280 | 9,108,600 |
| 2002 | 792,480 | 731,160 | 807,240 | 782,160 | 838,080 | 734,280 | 780,600 | 772,080 | 667,920 | 628,320 | 542,520 | 499,440 | 8,576,280 |
| 2003 | 492,000 | 435,840 | 477,480 | 473,640 | 535,080 | 384,600 | 406,920 | 366,720 | 381,120 | 407,880 | 297,360 | 289,320 | 4,947,960 |
| 2004 | 295,080 | 370,560 | 588,720 | 604,680 | 665,880 | 471,120 | 508,560 | 564,960 | 502,680 | 445,440 | 356,400 | 425,280 | 5,799,360 |
| 2005 | 467,640 | 488,040 | 575,520 | 589,800 | 723,960 | 552,120 | 596,280 | 584,640 | 623,160 | 511,200 | 527,040 | 641,760 | 6,881,160 |
| 2006 | 607,800 | 575,640 | 633,720 | 599,160 | 714,000 | 746,520 | 774,000 | 784,440 | 711,000 | 651,600 | 632,400 | 762,840 | 8,193,120 |
| 2007 | 761,160 | 688,440 | 764,520 | 741,600 | 793,200 | 768,240 | 820,200 | 804,960 | 552,720 | 768,960 | 759,360 | 801,840 | 9,025,200 |

The Yukon Electrical Company Limited
Historical Water Levels at Fish Lake
Annual 1998-2007

YUB-YECL-05
Attachment 1
Annual by Unit

| Date | Unit 1 kWhr | Unit 1 Average kW | Unit 2 kWhr | Unit 2 Average kW | Combined kWhr | Combined Average kW |
|---|---|---|---|---|---|---|
| 1998 | 2,870,400 | 328 | 2,692,830 | 307 | 5,563,230 | 635 |
| 1999 | 2,305,680 | 263 | 2,246,040 | 256 | 4,551,720 | 520 |
| 2000 | 4,046,400 | 461 | 2,932,200 | 334 | 6,978,600 | 794 |
| 2001 | 5,171,640 | 590 | 3,936,960 | 449 | 9,108,600 | 1,040 |
| 2002 | 4,750,200 | 542 | 3,826,080 | 437 | 8,576,280 | 979 |
| 2003 | 2,462,400 | 281 | 2,485,560 | 284 | 4,947,960 | 565 |
| 2004 | 3,138,840 | 357 | 2,660,520 | 303 | 5,799,360 | 660 |
| 2005 | 3,933,000 | 449 | 2,948,160 | 337 | 6,881,160 | 786 |
| 2006 | 4,728,480 | 540 | 3,464,640 | 396 | 8,193,120 | 935 |
| 2007 | 5,336,880 | 609 | 3,688,320 | 421 | 9,025,200 | 1,030 |
| | | | | Ten Year Average | 6,962,523 | |

| Date | January | February | March | April | May | June | July | August | September | October | November | December | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1998 | 721,790 | 560,230 | 665,200 | 667,690 | 547,590 | 372,940 | 390,080 | 363,280 | 279,510 | 255,230 | 257,710 | 481,980 | 5,563,230 |
| 1999 | 477,960 | 437,040 | 512,160 | 461,880 | 545,160 | 630,720 | 224,040 | 199,560 | 193,680 | 208,920 | 282,720 | 377,880 | 4,551,720 |
| 2000 | 507,960 | 600,360 | 345,360 | 269,520 | 499,800 | 547,800 | 595,560 | 696,840 | 803,520 | 719,040 | 665,520 | 727,320 | 6,978,600 |
| 2001 | 775,800 | 697,200 | 763,680 | 698,280 | 738,960 | 783,480 | 792,480 | 774,480 | 789,840 | 763,920 | 757,200 | 773,280 | 9,108,600 |
| 2002 | 792,480 | 731,160 | 807,240 | 782,160 | 838,080 | 734,280 | 780,600 | 772,080 | 667,920 | 628,320 | 542,520 | 499,440 | 8,576,280 |
| 2003 | 492,000 | 435,840 | 477,480 | 473,640 | 535,080 | 384,600 | 406,920 | 366,720 | 381,120 | 407,880 | 297,360 | 289,320 | 4,947,960 |
| 2004 | 295,080 | 370,560 | 588,720 | 604,680 | 665,880 | 471,120 | 508,560 | 564,960 | 502,680 | 445,440 | 356,400 | 425,280 | 5,799,360 |
| 2005 | 467,640 | 488,040 | 575,520 | 589,800 | 723,960 | 552,120 | 596,280 | 584,640 | 623,160 | 511,200 | 527,040 | 641,760 | 6,881,160 |
| 2006 | 607,800 | 575,640 | 633,720 | 599,160 | 714,000 | 746,520 | 774,000 | 784,440 | 711,000 | 651,600 | 632,400 | 762,840 | 8,193,120 |
| 2007 | 761,160 | 688,440 | 764,520 | 741,600 | 793,200 | 768,240 | 820,200 | 804,960 | 552,720 | 768,960 | 759,360 | 801,840 | 9,025,200 |

# FISH LAKE UNIT 1 INSPECTION

Inspection period: September 15 to September 19, 2007

Inspected by: Gaetano Grubisa, Peter McCollum, YECL
Lorne Bowes, Norm Curzon, YECL

Prior to shutting down Unit 1 for the inspection on September 15, a complete set of readings was taken to determine if it could carry full load without any difficulty. The governor was controlling the deflector shaft in the wide open position and the spear valve was open wide enough to produce 400 kw. At this load, the turbine was operating quietly with no cavitation sounds within the turbine and very little vibration at the two bearings. The generator bearings showed no vibration, running smoothly, and had a loud buzzing sound coming from the left side. The generator rotor and stator was very dirty, the slip ring area was fairly clean, there was no sparking of the brushes with minor etch marks on the outboard slip ring. The exciter was also dirty and the commutator was smooth with no significant wear on the surface. There was minor brush noise indicating the commutator may need machining. All carbon brushes were in good condition.

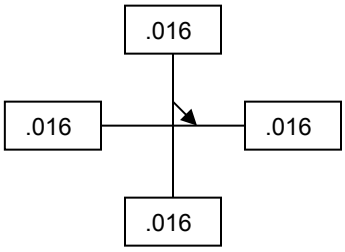
Readings recorded on September 14, 2007:

| | | Head | Spear Valve | JOURNAL BEARINGS | | | | |
|---|---|---|---|---|---|---|---|---|
| Time | Load | Press | Pressure | Turbine | Turbine | Generator | Generator | Exciter |
| 14:20 | 400 kw | 188 psi | 0 | 37 C | 29 C | 33 C | 37 C | 35 C |
| 14:35 | 500 kw | 185 psi | 0 | 37 C | 29 C | 32 C | 37 C | 35 C |
| 14:50 | 600 kw | 182 psi | 0 | 37 C | 29 C | 32 C | 37 C | 34 C |
| 15:10 | 690 kw | 179 psi | 0 | 41 C | 30 C | 33 C | 38 C | 36 C |

Pressure gauge missing.
Full load on the turbine is 700 kw.

**Turbine Outboard Bearing**

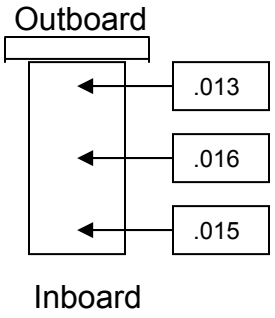
Mitchell journal bearing from Mitchell Bearings Ltd.
Order 30493




Turbine outboard bearing

oil seal (inner)

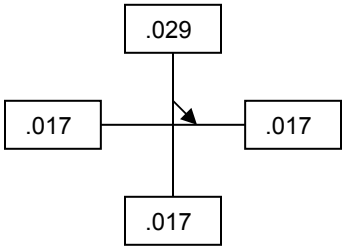
Bearing Clearances: (lead wire) .013 to .016



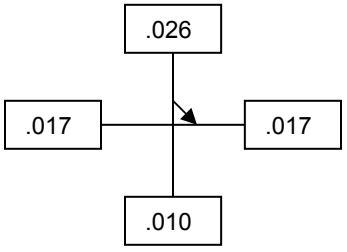

- Bearing housing has no dowel pins; corner bolts on bearing are body-fit.
- Bearing journal and thrust bearing in good condition.
- Bearing clearance is .013 to .016 .
- The turbine outboard thrust pads are installed only on the bottom half of the bearing. Eight small thrust pads are installed on the inboard side of the thrust collar to resist the thrust created by water hitting the runner wheel. All thrust pads are in good condition except the first pad on the right side. This pad has a small piece missing (1 8 x ) at the top split line. All pads were cleaned up and reinstalled. All pads are numbered P12 90R.
- Shaft journal is slightly rough and was cleaned with emery cloth.
- Thrust collar is in excellent condition.
- Oil was drained, the sump was cleaned and new Teresso 46 oil added.
- Bearing housing split line was sealed with Hylomar.

**Turbine Inboard Bearing**

Mitchell journal bearing from Mitchell Bearings Ltd.
Order 30493

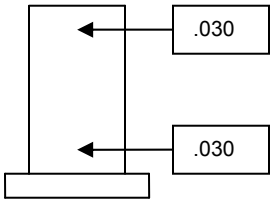



Turbine inboard bearing
oil seal (inner)




Turbine inboard bearing
oil seal (coupling side)

Bearing Clearance (lead wire) .030




Coupling end

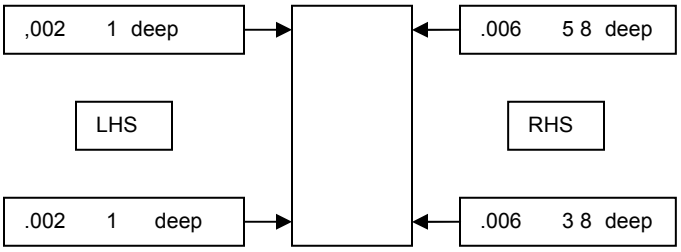
Mitchell Journal Bearing

Mitchell Bearings Ltd.
Order 30493

- Bearing has no dowel pins; corner bolts on bearing are body-fit.
- Bearing has no thrust pads.
- Bearing is in good condition.
- Vertical clearance on bearing .030 (lead wire on center pad).
- Journal bearing has 3 pads on the lower and 3 pads on the upper half. All pads are in good condition.
- Shaft journal is slightly rough and was cleaned with emery cloth.
- Oil was drained, the sump was cleaned and new Teresso 46 oil was added.
- Bearing housing split line was sealed with Hylomar.

## Generator Inboard Bearing

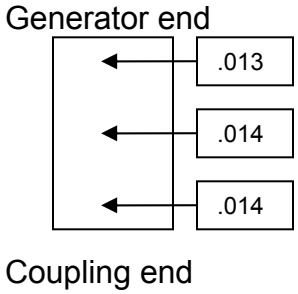
Side clearance .002 to .006




Bearing shell to housing fit
RHS 0
LHS .012

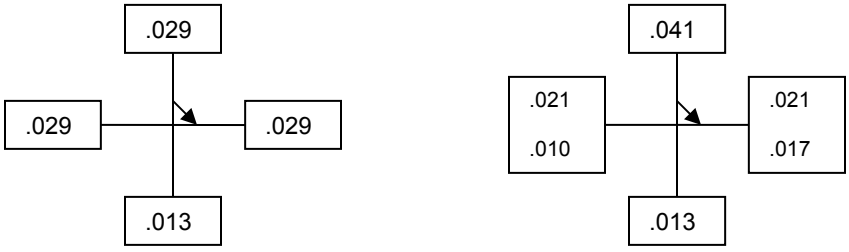
- The lower pedestal, bearing and bearing cover to be shipped to the machine shop for rebabbitting and spray welding the outside diameter of the bearing. It is .012 loose on the sides and .022 loose vertically.

Bearing Clearance .013 to .014




Bearing cap pinch .001
left .024
right .022
Three shims each .007 were reinstalled after pinch readings were taken.

Bearing cap seals

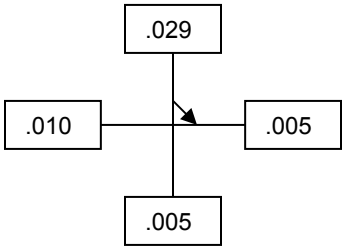



generator side coupling side

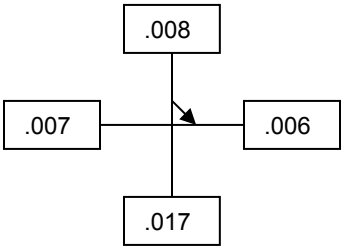
- This bearing is in fair condition.
- The babbitt is separating along the split line in places on both the upper and lower shells. The upper shell is the worst in the areas where the oil groove was repaired in 1997.
- Shaft contact is good and even on the bottom half.
- Bearing clearance is .013 to .014 .
- The bearing is loose in the housing and shows signs of fretting and loss of metal on both the upper and lower housings. It is also .012 loose at the split line on the left side. If the generator is shipped out for clean-up, this bearing and pedestal should be rebabbitted and spray-welded.
- Oil slinger rings were cleaned and fitted with new Robertson screws at the splits.
- Oil was drained, the sump was cleaned and new Terresso 46 oil was added.
- Bearing housing split line was sealed with Hylomar.
- Identification of oil slinger rings: coupling side 7
  generator side 27

**Generator outboard bearing**

As Found

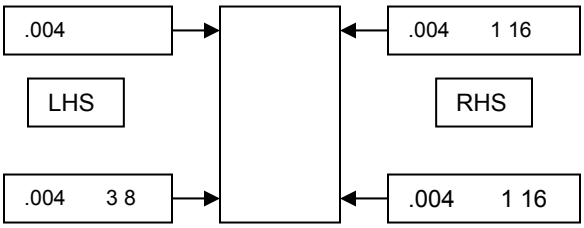



Outboard bearing oil seals

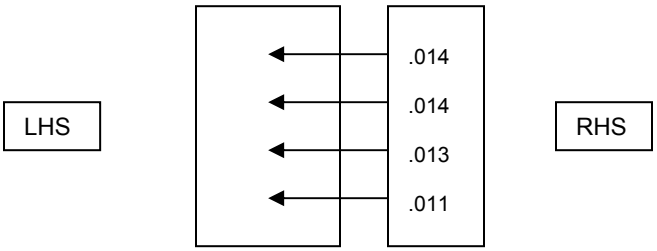



Inboard bearing oil seals

Side clearance .004




Bearing clearance .011 to .014

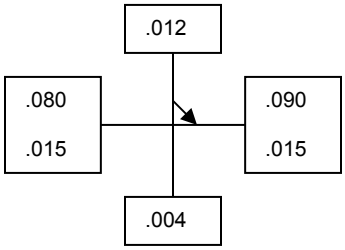



Bearing clearance (lead wire)

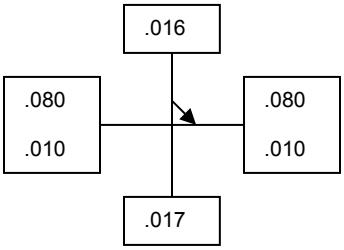
- Babbitt bearing is in good condition.
- Shaft, bearing, oil and sump were black and very dirty.
- Wear pattern is good; however, slightly to the right hand side.
- Oil slinger rings in good condition and have slightly worn into the babbitt in the upper oil slinger grooves.
- Oil was drained, the sump was cleaned and new Terresso oil was added.
- Bearing housing split line was sealed with Hylomar.
- Identification of oil slinger rings: outboard 19
  inboard 2

## Generator outboard bearing

Final




Outboard bearing cap oil seals




Inboard bearing cap oil seals

## Generator

At the start of the inspection, with 400 kw load, the generator had a loud buzzing sound coming from the upper left hand side of the generator. There was no external indication where the sound was coming from but it appears to be occurring at all loads.

During the inspection, the generator upper-end cover was removed on the outboard end and no obvious signs of looseness could be found. The generator windings are very dirty and the cooling slots in the stator are completely plugged. This generator needs to be shipped to an electrical motor repair shop for cleaning, testing and repairs.

## Generator slip rings

The slip rings are, generally, in good condition with good wearing surfaces. The outboard ring; however, it has minor scuffing and was stoned and polished during start-up on September 18, 2007. When the generator is shipped out for clean-up, the slip rings will be machined and polished.

## Exciter

The exciter windings are dirty with carbon dust, tree fluff and road dust and should be cleaned at the same time the generator is serviced. The commutator is in good condition and should be machined and undercut when the exciter is in the electrical shop.

## Main Coupling

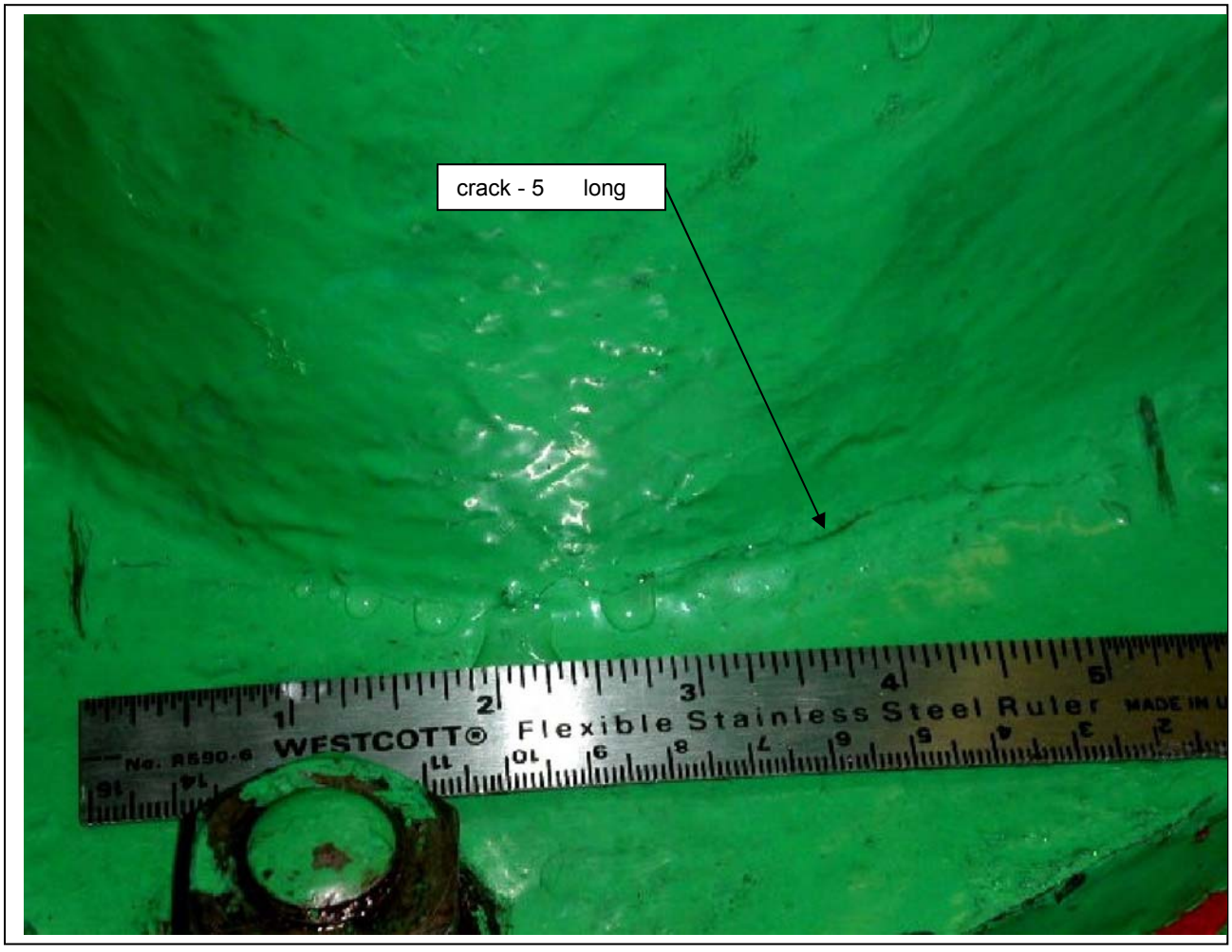
The cracks found on the turbine side coupling hub keyway remain unchanged since 1997. The generator side coupling hub is free of cracks around the keyway.

**Water wheel casing**

The water wheel casing is in good condition. When the upper half was removed for the inspection, the 1 16 thick rubber gasket was in good condition and had to be reused. Silicone sealant was used on both sides of the gasket to assure no leaks on start-up.

The repairs made by Jacobs Machine Shop of Whitehorse approximately 15 years ago on the lower water wheel casing remains in good condition. The welded cracks and the internal reinforcing plate and bolting are unchanged since the repair. Three nuts on the exterior of the housing show signs of leaking, copper gaskets and silicone was used to provide a better seal around these bolts.

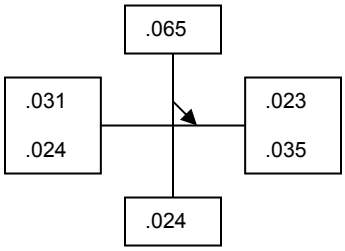
After the inspection and start-up, we noticed a crack on the right side upper casing. This crack is 5 long and is located just above the split line. This crack is leaking slightly and should be ground out and welded if additional work is scheduled on the runner wheel vane cracks.



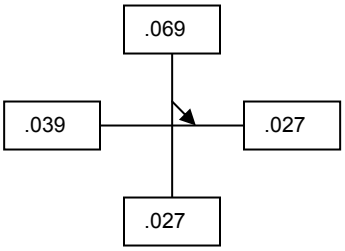

Water wheel casing, RHS

Water wheel casing cover seal clearances

Final




Outboard end




Inboard end

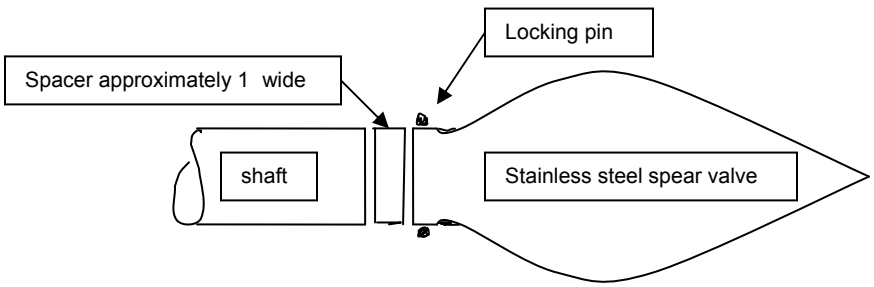
**Runner wheel**

The runner wheel is still in good condition with many cracks found in the repaired areas of the vanes. Vanes 17 and 22 have extended cracks and should be inspected annually. When the generator is shipped out to be cleaned, the casing should be removed and the cracks ground out, silver soldered and built up in the area on both sides of the vanes.

**Spear valve**

The spear valve was inspected through the inspection hole on the elbow and from the tailrace. It appears to be in good condition with no cavitation or metal loss on the spear or the spear nozzle plate. The shaft bushings show little wear and remain in good condition.

It appears some modifications were made to the end of the shaft on previous overhauls as a 1 spacer is installed prior to threading the spear valve on the shaft. There is mechanical looseness at this spacer and the spear valve can be moved vertically up and down by approximately . The locking pin through the spear valve and threaded shaft is solid and in good condition. This valve with mechanical looseness would not be centered in the nozzle plate and could have some effect on the direction of flow to the runner wheel. Some turbulence could be occurring if the water is not hitting the vanes at the proper point on the runner wheel.



Inlet Spear Valve

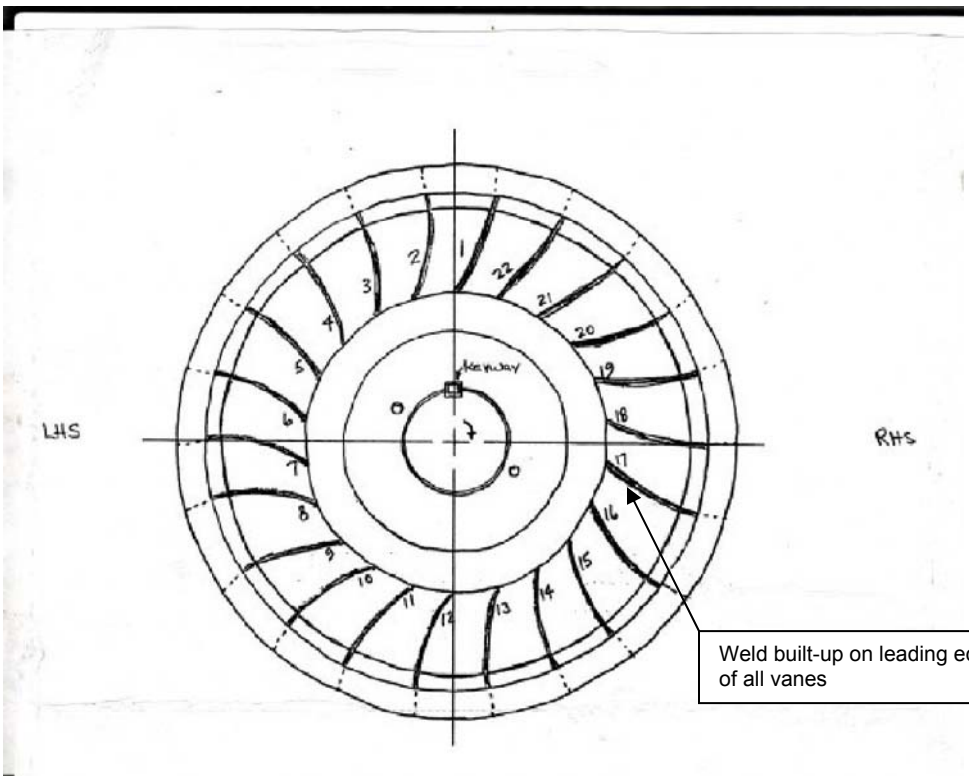
**Runner vanes - inlet leading edge**

| Vane | Vane condition |
|---|---|
| 1 | 4 - cracks, 6 cracks 1 8 long |
| 2 | 2 - cracks, 3 cracks 1 8 long |
| 3 | 5 - cracks, 4 cracks 1 8 long |
| 4 | 1 crack long, 3 cracks long |
| 5 | 2 cracks long, 2 cracks 1 8 long |
| 6 | 6 cracks long, 3 cracks 1 8 long |
| 7 | 8 cracks long |
| 8 | 3 cracks long |
| 9 | 3 cracks long |
| 10 | 3 cracks long, 5 cracks 1 8 long |
| 11 | 3 cracks long |
| 12 | 3 cracks long, 2 cracks long |
| 13 | 4 cracks long, several smaller cracks 1 8 to long |
| 14 | 2 cracks long |
| 15 | 1 crack 1 long, piece missing x , 2 cracks long |
| 16 | 1 crack 1 long, 1 crack 1 3 8 long |
| 17 | 1 crack 3 long, 1 crack 1 long |
| 18 | 1 crack long, 7 cracks long |
| 19 | 1 crack long, 5 cracks long |
| 20 | 8 cracks long |
| 21 | 1 crack 1 long, 3 cracks long |
| 22 | 1 crack 5 long, 5 cracks long |

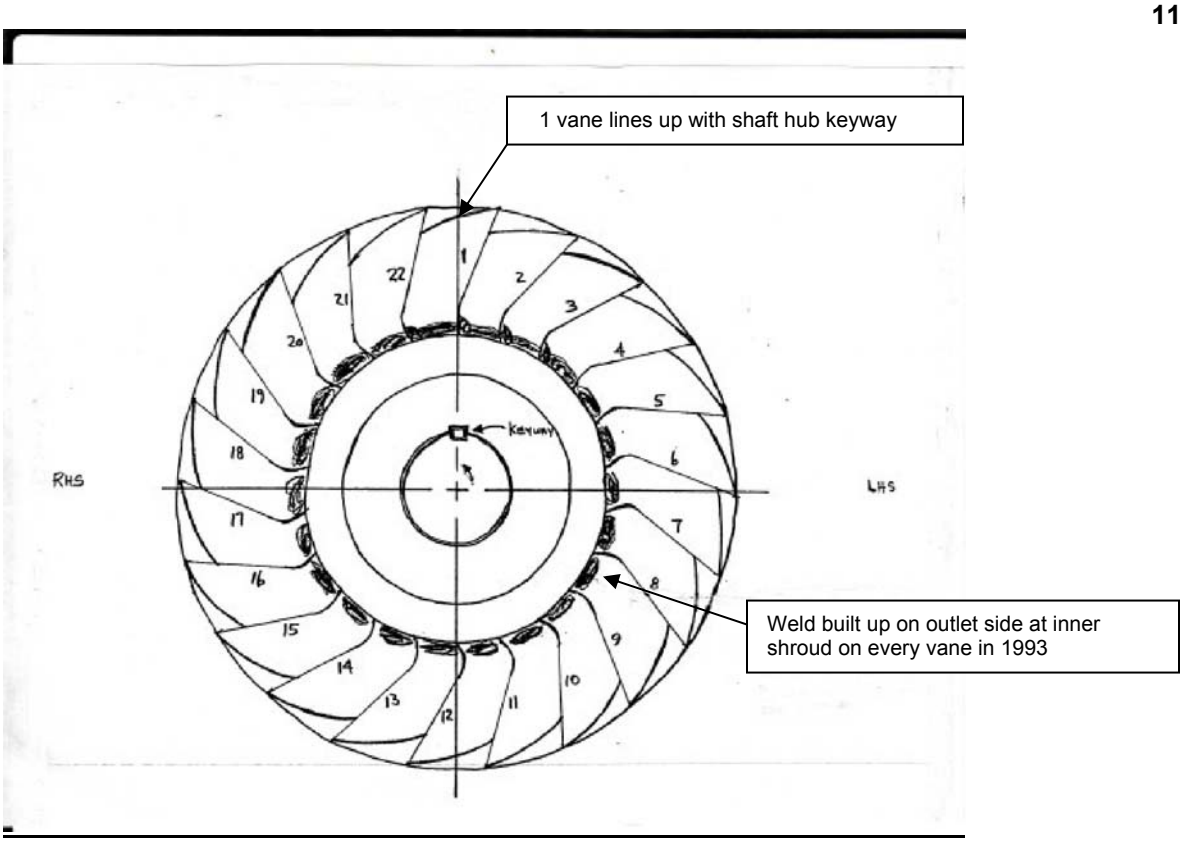
**Runner vanes - outlet trailing edge**

| Vane | Vane condition |
|---|---|
| 1 | 1 crack 1 long 6 from hub |
| 2 | |
| 3 | 1 crack long near hub |
| 4 | 3 cracks 7 from hub long |
| 5 | |
| 6 | |
| 7 | |
| 8 | 1 crack 2 long near hub |
| 9 | 1 crack long near hub |
| 10 | 1 crack long near hub |
| 11 | 1 crack long near hub |
| 12 | 1 crack 1 long near hub |
| 13 | 1 crack 1 long |
| 14 | 1 crack 1 long |
| 15 | 1 crack 2 long |
| 16 | 1 crack 1 long |

17
18
19
20 1 crack 2 long near hub
21
22




Turbine runner
Inlet vanes




Turbine runner - outlet vanes

## Fish Lake Unit 1 Start-up

09:00 rotated machine to approximately 100 rpm to stone and polish the outboard slip ring on the generator.

11:45 with the spear valve open by approximately , the unit was started and the governor automatically opened the deflector to 100 open position. Head pressure was 190 psi; pressure before spear valve was 184 psi.

12:02 on line, load was increased by opening the spear valve using the automatic controls.

Readings taken on September 18, 2007

| | Head | Spear | | Spear valve | Journal Bearings | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Time | Pressure | Pressure | Load | Open | Brg 1 | Brg 2 | Brg 3 | Brg 4 | Brg 5 |
| 12:05 | 190 psi | 184 psi | 130 kw | .250 | 21 C | 18 C | 11 C | 12 C | 17 C |
| 12:18 | 190 psi | 182 psi | 300 kw | 7 8 | 27 C | 22 C | 13 C | 14 C | 20 C |
| 12:45 | 190 psi | 182 psi | 300 kw | 7 8 | 32 C | 25 C | 17 C | 18 C | 24 C |
| 12:50 | 190 psi | 179 psi | 400 kw | 1 3 8 | 33 C | 27 C | 19 C | 21 C | 26 C |
| 13:20 | 190 psi | 176 psi | 500 kw | 2 | 38 C | 28 C | 21 C | 23 C | 28 C |
| 14:00 | 185 psi | 172 psi | 600 kw | 3 | 38 C | 28 C | 24 C | 26 C | 32 C |
| 14:40 | 185 psi | 165psi | 680-690kw | 4 7 16 | 40 C | 29 C | 27 C | 28 C | 34 C |

Bearing temperature readings taken with an infrared gun.

Turbine cavitation noise began around 400 kw and noise increased to full load. Generator noise was not evident at 130 kw but was buzzing from 400 kw to full load.

Reduced load to 400 kw and left site 15:30.

## Recommendations

- Replace the leather belt to governor drive.
- The generator and exciter urgently require cleaning and testing in an electrical repair shop
- The generator inboard bearing is loose in the bearing pedestal housing. The housing and bearing should be spray welded to bring it back to standard size., If this work is done, the bearing would have to be rebabbitted.
- The spear valve should be removed and dismantled to determine reason for mechanical looseness. A quotation for a new spear valve and nozzle plate should be obtained from Gilkes in England
- Provide high temperature alarm trips for the four journal bearings
- Provide overspeed protection to open the generator breaker and stop the governor. A small gear could be provided to be installed on the turbine shaft for the speed pickup.

Prepared by: Lorne Bowes
September 24, 2007

## Fish Lake Unit 1 Name Plate Data

### Water Wheel

Gilkes

| | | |
|---|---|---|
| Order 5163 | Year 1952 | |
| BHP 940 | FT Head 400 | RPM 720 |

Kendal, England
Gilbert Gilkes & Gordon Ltd.

### Generator

Westinghouse

| | | | |
|---|---|---|---|
| 875 | KVa | Exc Amps | 58.0 |
| 2300 | volts | Exc Amps | 125 |
| 219 | Amps | Load | 100 |
| .80 | P.F. | Hours | 24 |
| 3 | PH | C Temp Rise | 50 |

| | | | |
|---|---|---|---|
| 60 | Cycles | S.O. | 30S-989 |
| 720 | RPM | Serial | 459340 |

Canadian Westinghouse Co. Ltd.
Hamilton, Ontario

Exciter

Westinghouse DC Generator Type SK

| | |
|---|---|
| 7.5 kw | Amps 60 |
| 125 Volts | RPM 720 |
| Shunt Wound | Frame 83 |
| S.O. 30S-990 | Serial 459303 |

Canadian Westinghouse Co. Ltd.
Hamilton, Ontario

Governor

| | |
|---|---|
| Gilkes oil pressure governor | size No. 1 |
| | Governor No. 233 |

# FISH LAKE UNIT 2 INSPECTION

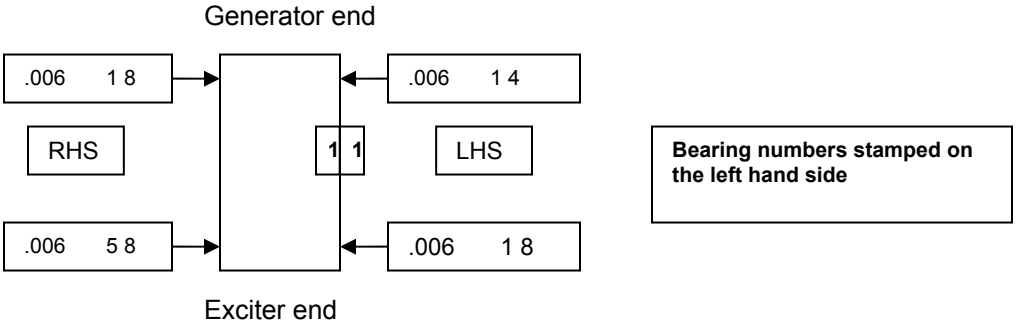
Inspection period: September 10 to September 14, 2007

Inspected by: Gaetano Grubisa, Lorne Bowes, Peter McCollum, YECL, Norm Curzon, YECL

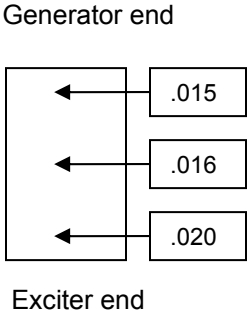
Prior to shutting down Unit 2 for the inspection on September 10, 2007, the load was increased from 375 kw to 506 kw. The governor and gates were completely open and the maximum load obtained was 506 kw. Vibrations were normal on the turbine bearing and both generator bearings. There were no strange sounds coming from the turbine or generator and the unit operated smoothly at full load. There was no head pressure gauge on the inlet pipe and the pressure gauge installed off the turbine casing was not working (later found the vibration pulsator plugged). The water flowed evenly through the discharge elbow and didn't appear to be cavitating. The vacuum gauge was not working on the discharge from the turbine even though it showed 10 of Hg. The valve was partly open indicating the vacuum was probably set correctly.

## Generator Outboard Bearing 1

Bearing side clearance .006




Bearing clearances (lead wire) .015 to .020

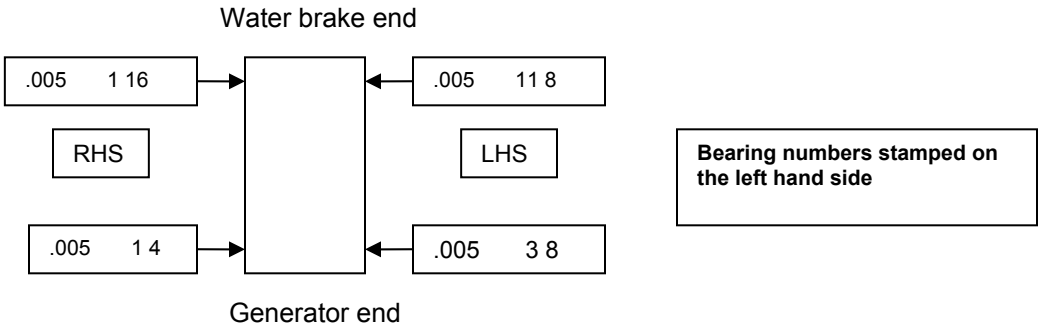


Clearances: journal bearing clearance .015 to .020
journal bearing side clearance .006

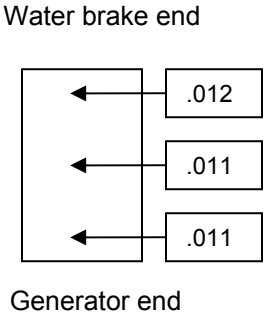
- This bearing was found in good condition. Clearance is .015 to .020 and contact to the shaft was fair with heavy contact on the exciter end. The bearing was cleaned and reinstalled as found.
- The oil slinger rings had worn a groove in the babbitt on both inboard and outboard channels of the upper bearing shell. The bearing was left as found but the oil slinger rings were filed smooth at the split lines and new Robertson screws were installed on both rings.
- Oil was drained, the sump was cleaned and new Terresso 46 oil was added.
- Bearing housing split line was sealed with Hylomar.

## Generator Inboard Bearing 2

Bearing side clearance .005




Bearing clearance (lead wire) .011 to 012




Clearances: journal bearing .011
journal bearing side clearance .005

- This babbitt bearing was found in good condition. Bearing clearances were good and the condition of the babbitt was good except in a couple of areas along the split line.
- When the lower half bearing was rolled out we noticed one small area of electrolysis on the left side and several small areas on the generator shaft. These were cleaned

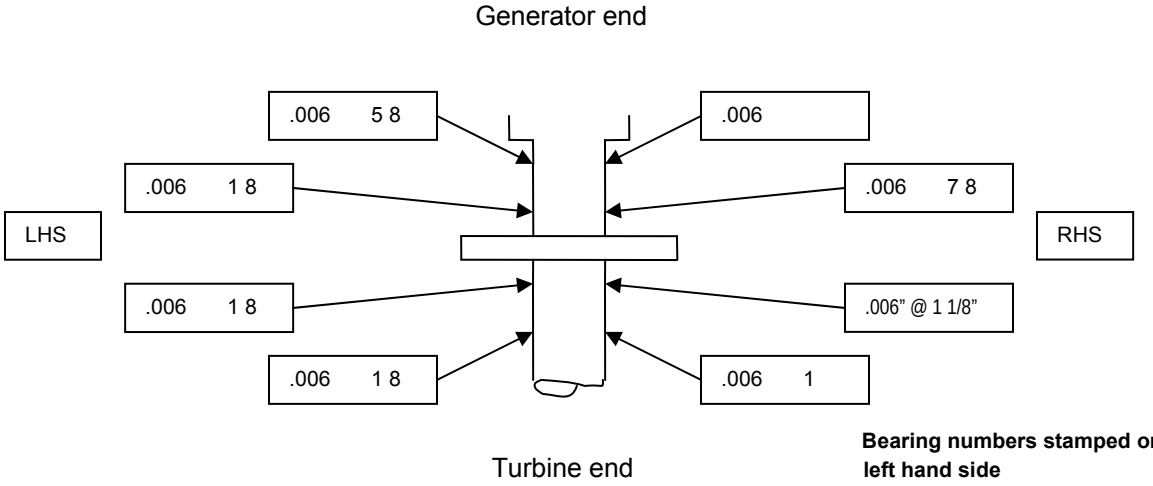
and the shaft polished with fine wet and dry emery paper. It was later discovered that the source of the electrolysis was a loose generator ground wire clamp and it had been secured to the painted generator frame. This painted area was scraped, polished and the ground clamp bolt was tightened properly.

- Both oil slinger rings were cleaned and filed smooth at the split lines and new Robertson screws installed.
- Oil was drained, the sump was cleaned and new Terresso 46 oil was added.
- Bearing housing split line was sealed with Hylomar.

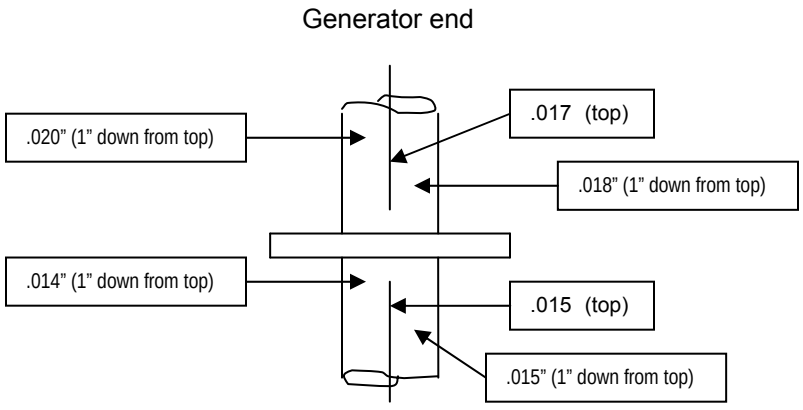
## Turbine thrust Bearing 3

Mitchell Bearings Ltd.
Bearing No. 36187
Fore and aft clearance .025
Journal clearance .010

Bearing side clearances .006




Bearing clearance (lead wire) .015 to 017

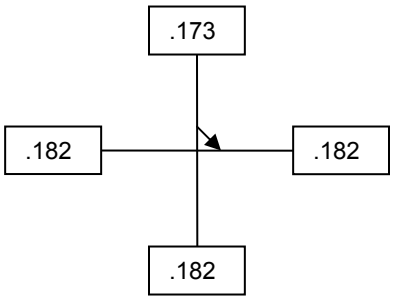


Turbine end

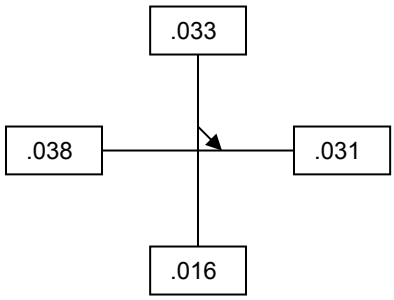
Clearances: journal bearing clearance .015 to 017
journal bearing side clearance .006
thrust bearing clearance .012

- The combination thrust journal bearing was completely removed, inspected, cleaned and reinstalled. The turbine side thrust collar is slightly grooved and the generator side collar is in good condition. The six lower pads on the turbine side are slightly scratched from the roughness of the ring.
- The lower generator side pads (4) are all in good condition. The bearing journal on the lower half is in good condition but the wear pattern is poor indicating contact on the sides at 45 degrees below split line.
- The upper half thrust journal bearing is in good condition. There is no evidence of the shaft hitting the top half so minor scraping and cleaning was only necessary. The six thrust pads on the turbine side are slightly rough while the 4 thrust pads on the generator side are in good condition.
- The turbine bearing cover and the center intermediate block had no dowel pins installed from previous overhauls. Considerable time was taken to set the upper bearing cap so the dowel pins could be installed. The left hand side dowel pin was installed without reaming the hole; however, the right hand side dowel pin hole had to reamed with a reamer before the dowel pin could be installed.
- Oil was drained, the sump was cleaned and new Terresso 46 was added.
- Bearing housing split line was sealed with Hylomar.

## Discharge Elbow and Adaptor




Clearance - runner to elbow adaptor



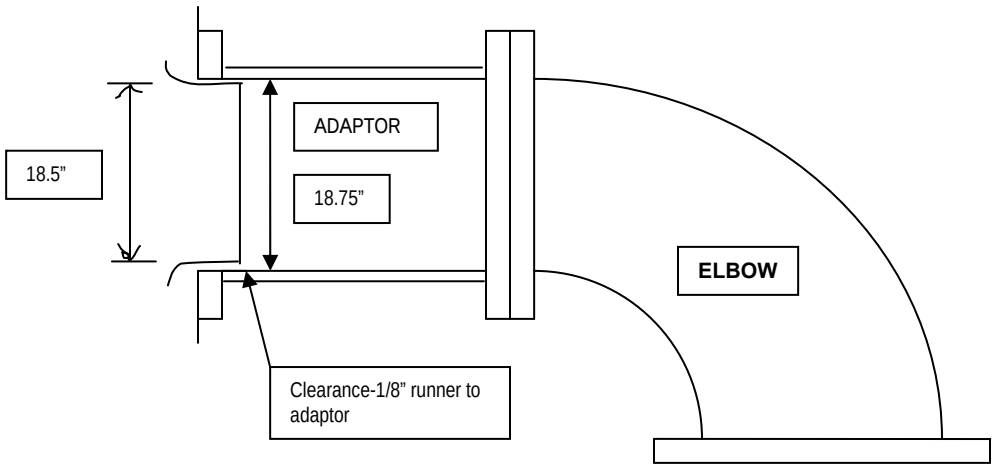

Clearance - runner to scroll cage wear rings

## Gaskets

| | As found gaskets | As left gaskets |
|---|---|---|
| Elbow to floor | 1 - rubber gasket 1 8 thick<br>1 - 1 16 garlock gasket | 1 - 1 8 rubber |
| Elbow to adaptor | 1 - 1 32 garlock gasket | 1 - 1 16 garlock gasket |

| | | |
|---|---|---|
| Runner casing to adaptor | 1 - 1 16 garlock gasket | 1 - 1 16 garlock gasket |

## Runner Wheel to Adaptor




The runner wheel wear ring, elbow adaptor and the discharge elbow are all in good condition. The runner wheel wear ring is 18 years old and shows no signs of wear. The draft tube below the discharge elbow, also, is in good condition.

## Runner Wheel Casing

The interior of the runner wheel casing is in good condition. The inlet screen was clean except for a few small branches caught in the screens. The gates are in good condition viewed through the small inspection holes in the casing.

The outboard casing wear ring is worn on the interior (next to the gates) and wear is estimated at least 3 16 to . The outboard casing wear ring as viewed from the discharge elbow is not worn and measured .033 on the right and .038 on the left side. The inboard casing wear ring could not be viewed or measured but it is assumed that it will be worn the same as the outboard wear ring.

## Runner Wheel

This runner wheel was installed new in 1989 and has erosion on the outlet vanes which has worn very thin and created holes in some vanes. Five out of the eleven vanes have holes varying from 1 8 to in diameter. Other areas where the vanes are eroded will soon have holes and pieces missing. This runner may have another year or two of operation before it should be replaced.

Runner Wheel Damage

1 vane in line with keyway




nominal thickness of vanes near inner rim is .150

Fish Lake 2

Runner Wheel

| Vane | Vane outlet thickness | Damage |
|---|---|---|
| 1 | .047 | |
| 2 | .068 | one hole in vane |
| 3 | .064 | |
| 4 | .089 | one hole in vane |
| 5 | .073 | |
| 6 | .093 | one hole in vane |
| 7 | .062 | two holes in vane |
| 8 | .075 | |
| 9 | .098 | |
| 10 | .072 | |
| 11 | .061 | one hole in vane |

## Generator and Exciter

The generator rotor and stator is still fairly clean after being rewound at the Standard Electric shop in 2000. The outboard slip ring had been damaged slightly by an excessively worn brush and this slip ring was stoned and polished before start-up.

The exciter was also last serviced in 2000 and is still fairly clean. Measurements were taken to install a new gear at the end of the shaft if the decision is made to provide overspeed protection.

## Gilkes Water Brake

The water brake was not dismantled and appears to work properly when slowing the unit down.

## Other Work Completed

- Replace 1 leather belt to upper governor drive.
- Remove 2 links off lower 3 belts driving governor gear pump.
- Clean strainer and replace cooling pipe with hydraulic hose to the governor.
- Clean strainer on supply pipe to turbine bearing housing.
- Drained oil from governor and added new Terresso 46 oil.
- Welded threadolet on penstock for installation of head pressure gauge.

## Past History

- New runner wheel and shaft installed in 1989.
- New turbine casing wear rings installed in 1989.
- Turbine bearing had some work done on it in 2000.
- Generator stator failed and was rewound in 2000.

**Start-up**

11:00 - 11:30 spin unit to synchronous speed
12:00 on line loaded to 150 kw

| | | | - - JOURNAL BEARINGS - - | | | | |
|---|---|---|---|---|---|---|---|
| Date | Time | Load | Turbine | Generator Inboard | Generator Outboard | Head Pressure | Turbine Casing Pressure |
| Sept 14 | 12:30 | 150 kw | 55 C | 52 C | 38 C | 83 psi | 81 psi |
| Sept 14 | 13:00 | 150 kw | 50 C | 53 C | 39 C | 84 psi | 81 psi |
| Sept 14 | 13:10 | 155 kw | 48 C | 55 C | 40 C | 84 psi | 81 psi |
| Sept 14 | 13:15 | Off line | | Install lower generator brushes | | | |
| Sept 14 | 17:00 | Unit put on line | | 200 kw | | | |
| Sept 15 | 11:30 | 200 kw | 45 C | 60 C | 45 C | 84 psi | 80 psi |
| Sept 17 | 15:00 | 200 kw | 45 C | 60 C | 45 C | 84 psi | 80 psi |

**Recommendations**

- Purchase and install a new vacuum gauge on the discharge elbow and adjust the vacuum to its' highest steady reading.
- Provide overspeed protection. A new gear should be installed on the exciter end c w mag pick-up and electrically connected to trip the generator breaker and slow the governor speed.
- Provide shutdown protection for high bearing temperature. Currently, RTD's are installed, alarm circuit is operational; however, the trip circuit is not connected.
- Order a new bronze runner wheel and shaft from Gilkes in England. Alternative to the bronze runner would be to supply it in stainless steel material. When the new runner is installed, the wear rings, gates, bushings, etc. would have to be checked over and new parts installed where required.
- To remove the turbine bearing 3 pedestal in the future, the center bearing pedestal has to be dowelled to the lower bearing pedestal. Currently, the dowel pins are missing between the center and lower pedestals.

Prepared by: Lorne Bowes
September 24, 2007

# Fish Lake Unit 2 Name Plate Data

Water Wheel

Gilkes

Order 5367 Year 1955
BHP 800 FT Head 200
RPM 1200

Manufactured Kendal, England

Oil Pressure Governor

No. 989
Size D
Capacity 3600 ft-lbs
Gilbert Gilkes & Gordon Ltd.
Kendal, England

Governing System (water brake)

Gilkes

Giljet Governing System
British Patents
No. 626256 and
No. 637908

Generator

Westinghouse
KVA 812 Exc Amps 42.0
Volts 2300 Exc Volts 125
Amps 203 Load 100

| | |
|---|---|
| P.F. .80 | Hours 24 |
| Phase 3 | C Temp Rise 60 |
| Cycles 60 | Serial 1S3E0088 |
| RPM 1200 | |

Canadian Westinghouse Co. Ltd.
Hamilton, Ontario

Exciter

| | |
|---|---|
| Westinghouse | Shunt Wound |
| Type SK | Frame 326 |
| Serial 3E0137 | RPM 1200 |
| KW 6.5 | |
| Volts 125 | |

Canadian Westinghouse Co. Ltd.
Hamilton, Ontario

# FISH LAKE MAINTENANCE OUTAGES

| DATE | DURATION | MAINTENANCE PERFORMED |
|---|---|---|
| **FL 2** | | |
| Apr 30 2003: | 1 day | Bearing oil, brushes, clean screens |
| Feb 11 2004: | 6 hours | |
| Oct 19 2005 | Oct 19 Oct 25 | breaker, bearing governor oil, plumbing, bus generator, brushes slip rings |
| Mar 27 2006 | 1 hr 25 min | brushes, water screens |
| Jun 12 2006 | day | cooling screens |
| Jul 28 2006 | 1 day | brushes, slip rings |
| Apr 11 2007 | 1 hr 30 min | oil sample step up xmer |
| Sept 10 2007 | 4 days | turbine and bearing inspection by Grubisa, breaker, protection |
| | | |
| **FL 1** | | |
| Aug 07 2003: | 45 min | brushes |
| Dec 23 2003: | 1 hr 8 min | brushes |
| May 07 2005 | 116 min | water cooling leak |
| Apr 27 2006 | 1 day | brushes, slip rings |
| Sept 14 2007 | 4 days | turbine and bearing inspection by Grubisa, breaker, protection |

# FISH LAKE MAINTENANCE OUTAGES

| DATE | DURATION | MAINTENANCE PERFORMED |
|---|---|---|
| **FL 2** | | |
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**YUB-YECL-6**

**Reference:** Deferral Account; Application, page 3-2

**Quote**: These rates do not include any adjustment to the rates equal to the approved run out rate for non-governmental residential service for the hydro zone.

Overall line losses are determined based on a five year historical average of 6.2 .

**Preamble**: The Board wishes further information.

**Request:**

(a) Please provide a detailed explanation and example as to what is meant by the above quote, in particular the part of the phrase that refers to run out rate".

(b) Please provide a detailed explanation and a spreadsheet analysis complete with formulae and linkages that illustrate the determination of the five-year historical average of 6.2 line loss percentage shown on page 3-2.

(c) Please provide explanation and a spreadsheet analysis complete with formulae and linkages that determines the line loss percentages for each of the five years that make up the five-year historical average referred to in the above quote.

**Response:**

(a) Yukon Electrical's Application incorporates a forecast purchased power rate of 6.84 cents per kWh for power purchased from Yukon Energy as per the currently approved Wholesale Power Rate Schedule 42. The purchased power expense also reflects a flow through of Rider J collections through to Yukon Energy. Please refer to YUB-YECL-6(a) Attachment 1 for a copy of Rate Schedule 42 that details the 6.84 cents per kWh as well as a description of the Energy Reconciliation Adjustment.

The Energy Reconciliation Adjustment (ERA) refers to the wholesale rate charged from Yukon Energy to Yukon Electrical being periodically adjusted to reconcile actual wholesale purchases to test year forecast purchases. To the extent that actual wholesale purchases fall short or exceed forecast wholesale purchases, an adjustment to the Yukon Electrical bills will be made at a rate equal to the approved run out rate for non-government residential service for the Hydro zone. This rate has been set at 10.45 cents per kWh since the 1996 1997 GRA. Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10 of the forecast wholesale purchases in any period. In 1999, it was clarified the ERA mechanism would apply only during months when diesel was on the margin for the WAF system.

It is important to note the design of Rate Schedule 42 was done at a time when Yukon Electrical and Yukon Energy were jointly preparing and simultaneously filing their phase I and phase II applications. Diesel was also on the margin due to Yukon Energy's industrial sales to the Faro mine. Neither one of these two important factors is applicable for the 2008-2009 test period.

Yukon Electrical does not know whether diesel will be on the margin for the WAF system during the test period. Yukon Electrical also does not know whether Yukon Energy will interpret the currently worded rate Schedule 42 in a way that would result in the Yukon Energy charging or crediting Yukon Electrical 10.45 cents per kWh for actual wholesale purchases that fall short or exceed forecast wholesale purchases. Yukon Electrical anticipates these matters will be addressed as part of Yukon Energy's pending phase I and phase II applications. In the meantime, Yukon Electrical is requesting the continuation of a deferral account to flow through increases or decreases to purchased power rates.

(b) Please refer to the YUB-YECL-06(a) Attachment 1. The average calculation of 6.2 is shown. Please note that there was a keying error on Schedule 3.2 Line 7 for 2005 Hydro generation.

(c) Please refer to the YUB-YECL-06(a) Attachment 1. The line losses are calculated based upon the difference between actual sales and the total power generated and purchased. The purchased power and generated power are measured at source, before distribution. The amount of sales includes an estimate of unbilled usage at month end. Since electricity cannot be stored the

difference is the 'loss' of power. Yukon Electrical does not separate out Company used power and this is included in the line loss figure.

Note that in the revised GRA schedules submitted July, 4 2008, Schedule 3.1 Line 7, for the year 2005, there was keying error. Hydro generation was input as 6,239 MWh and should have been 6,858 MWh. This error did not have any effect on the five year average line loss percentage of 6.2 used in the test years. The Attachment shows the correct figure.

# RATE SCHEDULE - 42

# WHOLESALE PRIMARY

**AVAILABLE:** To The Yukon Electrical Company Limited.

**APPLICABLE:** For wholesale primary supply to The Yukon Electrical Company Limited.

**RATE:**

Energy Charge

All Energy consumed at 6.84 per kW.h

Energy Reconciliation Adjustment

Charges to YECL will be periodically adjusted to reconcile actual wholesale purchases to test year forecast purchases. To the extent that actual wholesale purchases fall short or exceed forecast wholesale purchases, an adjustment to the YECL bills will be made at a rate equal to the approved run out rate for non-government residential service for the Hydro zone. Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10 of the forecast wholesale purchases in any period.

**ELECTRIC SERVICE REGULATIONS:** The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.

**Yukon Electrical - Purchased Power Sales**
**Line Loss Analysis (kW.h's)**

| | 2003 (ACT) | 2004 (ACT) | 2005 (ACT) | 2006 (ACT) | 2007(ACT) | |
|---|---|---|---|---|---|---|
| Actual Primary Sales | 241,596,000 | 246,480,000 | 249,741,835 | 263,650,450 | 268,186,101 | |
| Actual Secondary Sales | 13,039,000 | 15,998,000 | 18,362,880 | 21,555,375 | 23,565,970 | |
| Total Sales | 254,635,000 | 262,478,000 | 268,104,715 | 285,205,825 | 291,752,071 | |
| Energy Supply | | | | | | |
| YEC Primary (WAF&Mayo Dawson) | 229,731,000 | 235,982,000 | 237,418,690 | 251,860,613 | 254,914,047 | |
| YEC Secondary | 13,039,000 | 15,998,000 | 18,362,880 | 21,555,375 | 23,565,970 | |
| Fish Lake Hydro Generation | 4,948,000 | 5,799,000 | 6,858,360 | 8,215,920 | 9,025,200 | |
| Diesel Generation | 21,753,000 | 21,988,000 | 21,806,599 | 22,165,014 | 22,333,749 | |
| Total Energy Supply | 269,471,000 | 279,767,000 | 284,446,529 | 303,796,922 | 309,838,966 | |
| Line Losses KwH | 14,836,000 | 17,289,000 | 16,341,814 | 18,591,097 | 18,086,895 | |
| Line Losses percentage of sales | 5.8 | 6.6 | 6.1 | 6.5 | 6.2 | Average 6.2 |

**YUB-YECL-7**

**Reference:** Diesel Fuel Costs; Application, page 4-2

**Issue Sub-Issue:** Forecasting Fuel Costs

**Quote**: Diesel fuel costs are a function of forecast sales, line losses, plant efficiencies. and delivered fuel prices.

**Preamble**: The Board wishes to understand the forecasting fuel costs process.

**Request:**

(a) Please provide process documentation as to how the fuel providers are chosen and contracts are awarded.

(b) Please provide the list of vendors who have supplied fuel to YECL for the period 1998 through 2007.

(c) With respect to YECL's diesel plants, please provide by community the size, type and make of diesel plant, as well as the age vintage of the plant.

(d) Please confirm that, in regard to Schedule 4.2, the values shown in Line No. 17 through 23, are calculated by dividing the Generation (MWh) per respective plant by the Litres Consumed (000s).

(e) It appears that for the forecast test period, the heat rates associated with YECL's generation plant are flat or worsening slightly. Please provide details as to the upgrades that YECL has planned, if any, in order to improve the efficiencies of its plant and at the same time lessen the impact of the costs associated with diesel generation on its customers.

(f) Please provide an explanation as to what Hydro grid standby diesel generation is as well as an explanation for the significant increase in Hydro grid standby diesel generation that was experienced in 2007 and is illustrated in Schedule 3.2, line No. 8.

(g) In light of current fuel economics that have been developing for some time, it appears that because of higher fuel costs, heating with electricity may be more

economical. Does YECL wish to update the diesel generation forecast illustrated in Schedule 3.2? Please provide an explanation in regard to the assumptions that underlie YECL diesel generation forecast wherein diesel generation is forecast to decrease by 1.5 and 6.6 in 2008 and 2009 respectively.

(h) Does YECL envision putting in place or has YECL put in place demand-side management programs that benefit its customers? If programs have been implemented, please describe the types of programs and successes that have arisen through their implementation.

(i) Has YECL considered other sources of power or the implementation of efficiency increases in respect of its generation plant and or loss reductions in its delivery of power?

(j) With respect to increased fuel costs associated with Pelly Crossing, the information shown on page 4-3 of the Application indicates a heat rate of 3.62 kWh per liter whereas Schedule 4.2 shows a heat rate of 3.71 kWh liter; please reconcile the differences.

**Response:**

(a) Yukon Electrical initiates a tender process where fuel providers are invited to submit proposals for the delivery of diesel fuel to Yukon Electrical generating plants. The proposals are reviewed and evaluated with the criteria being price, reliability, safety, reputation, responsiveness to Yukon Electrical, and flexibility. Please refer to YUB-YECL-07 (a) Attachment 1.

(b) Air North, Great Northern Oil, Husky Petroleum, Mackenzie Petroleum, North 60 Petro, Petro-Canada, Total Trac

(c) Please refer to YUB-YECL-07(c) Attachment 1

(d) This is confirmed.

(e) Yukon Electrical believes that the heat rates overall when looking at the average over the past 3 years is very flat and are not worsening . Heat rates do vary based on which units are running (when and for how long), how old the unit is and the type of unit.

Yukon Electrical has no particular upgrades planned that are being specifically undertaken to reduce the heat rates in the diesel communities however it does monitor heat rates by plant and anomalies are investigated if and when they occur. In addition when new engines are purchased heat rates are one of many considerations used in the purchasing decision.

(f) Standby diesel were called peaking units when the Faro mine was running. These units are now only used when grid power is not available (standby mode). In 2007 Yukon Electrical made a concerted effort to run each of it's plants at least once a month for 1hour. This is to help us ensure they are operationally ready if needed. This explains the one component of the increase fuel consumption, with the balance being due to loss of supply from the grid.

(g) Yukon Electrical does not wish to update the Schedule 3.2 generation forecast. Yukon Electrical remains of the view that it's sales forecast, line losses, and generator heat rates ie: the inputs that drive the diesel generation, are reasonable. The decrease in diesel generation is primarily driven by assumptions regarding Pelly Crossing cutover to the WAF grid in 2008. Please refer to YCS-YECL-09 below:

Although the cost of fuel has been significant over the past number of months there have been other factors that have provided a price signal to customers that would actually encourage customers to use less electricity, such as the loss of 50 of the Rate Stabilization Fund. Therefore Yukon Electrical has not seen a significant number of customers converting to Electric heat from fossil fuels. In fact the energy use per customer as shown in section 2 of Yukon Electrical's application demonstrates that energy usage has remained relatively flat for many years despite ever changing market conditions.

Yukon Electrical has also seen that several customers are converting to pellet stoves for heating which has little or no impact on electric usage. The cost for conversion to change heat sources can be significant for customers and there are those who still believe that fuel costs may actually go down in the near future.

Therefore based on a number of external factors it is not expected that the average use per customer will be impacted in any significant way in the test years and Yukon Electrical believes its sales forecast is reasonable.

(h) The following is the response provided to LE-YECL-16

Yukon Electrical has taken the approach that education and providing information to consumers is the practical and cost effective focus of its efforts regarding promoting efficiency and conservation in the communities it serves. Yukon Electrical makes available a variety of printed material to assist customers in energy planning. These include:

- Managing Electricity Costs
- Make Your Home Powersmart
- Guide to Conservation

These same publications are also available on Yukon Electrical's website.

Yukon Electrical works closely with the Energy Solution Center (ESC) in a number of ways including the following:

- Providing information and data that is helpful to ESC in developing there energy programs for Yukoners.
- Yukon Electrical includes bill inserts comprised of materials that ESC wants to get out to the public.
- Yukon Electrical refers its customers to the ESC for assistance with home audits etc.

Yukon Electrical also places ads in Yukon newspapers that provide conservation tips to customers.

Yukon Electrical proposes to update its energy management publications and information on its website and continue to make the information available to its customers throughout the test period. Yukon Electrical will also continue to work

with the ESC and the Government of the Yukon with respect to their various initiatives.

In terms of the programs success customers still seek out the information and appear to be appreciative of the response from Yukon Electrical and its staff.

(i) The following is the response provided to LE-YECL-14.

Yukon Electrical has been having discussions with some of its diesel served customers on exploring micro-hydro opportunities. In fact, Yukon Electrical has a confidential Memorandum of Understanding with one customer group on a micro hydro project. Initial data collection on water flows has been completed and the project will move to the next stage of pre-feasibility. In the past Yukon Electrical has worked with customers and their consultants regarding the incorporation of wind energy into the diesel production mix.

Yukon Electrical also monitors other jurisdictions such as the Northwest Territories to ascertain if there are alternate sources of generation for diesel communities. To date Yukon Electrical is not aware of any non grid connected generation alternative that has proven financially beneficial or that meets the reliability standards that are required in the jurisdictions it has looked at.

Yukon Electrical is participating in the development of a Yukon Government Energy Strategy and has provided input to government officials into its thoughts on how the strategy may best serve Yukoners.

Yukon Electrical participates in seminars, workshops and conferences when appropriate to learn more about technologies such as wind and solar and to determine if break throughs have been made that will allow for successful conversion of diesel communities.

In addition Yukon Electrical takes advantage of any grid extension that could remove customers from diesel onto hydro such as it is doing in Pelly Crossing.

Yukon Electrical has not included any costs in its revenue requirement for research and development looking at new technologies. Yukon Electrical will, however, continue to support worthwhile initiatives being pursued by qualified groups and lend its expertise as necessary. If there are viable solutions and

alternatives being put forward, Yukon Electrical is always prepared to review the information for applicability in serving its diesel communities.

In regard to line losses Yukon Electrical does consider line losses when it is undertaking work on the system. Specifically Yukon Electrical, based on a 2003 analysis, is using 1 0 conductor as a minimum on all 3 phase lines. In addition all transformers are purchased with line losses being considered in the overall life cycle cost analysis. The losses being experienced by Yukon Electrical are in line with the losses being experienced for similar systems in the Northwest Territories and on similar portions of the ATCO Electric system.

(j) The schedule 4.2, line 21, does show Pelly Crossing with a 3.62kWh Litre heat rate consistent with page 4-3 of the application. The 3.71 kWh litre is the overall average heat rate for all plants shown on schedule 4.1 line 2.

# QUOTE F-1708

## SUMMARY OF ATTACHMENTS

| ATTACHMENT | DESCRIPTION |
|---|---|
| A | Yukon Electrical Fuel Specification for P18 fuel |
| B | Yukon Electrical Fuel Specification for P40 fuel |
| C | Yukon Electrical Fuel Specification for P50 fuel |
| D | Yukon Electrical Site Deliveries |
| E | Form of Contract |

# ATTACHMENT A

## YUKON ELECTRICAL COMPANY LIMITED

## FUEL SPECIFICATION

**Bidder's Name:**

**Technical Information Required With Bid**

**for: P18 Fuel Oil**

**PLEASE SEE ATTACHMENT 1A FOLLOWING THIS PAGE**

| Fuel Properties and Characteristics | | Permissible Fuel as Delivered to Site | Guaranteed Fuels as Delivered to Site |
|---|---|---|---|
| Aromatics (ASTM D1319) | Maximum | 35 | |
| Ash Weight (ASTM D482) | Maximum | 2 | |
| Carbon Residur on 10 Bottoms (ASTM D524) | Maximum | 1.05 | |
| Cetane Number (ASTM D613) | Maximum | 35PC 40DI | |
| Cloud Point $^{o}$C (ASTMD97) | Maximum | Not above ambient | |
| Cooper Strip Corrosion (ASSTM D130) | Maximum | No. 3 | |
| Distillation (ASTM D86, D158 or D285) | | | |
| -10 $^{o}$C | Maximum | 282 $^{o}$C | |
| -90 $^{o}$C | Minimum | 360 $^{o}$C | |
| Flash Point $^{o}$C (ASTM D393) | Minimum | Legal | |
| Gravity API (ASTM D287) | Minimum | 30 | |
| | Maximum | 45 | |
| Pour Point, $^{o}$C (ASTM D97) | Minimum | 6 | |
| | | Below Ambient | |
| Sulfur, Total Weight (ASTM D2788 or D3605 or D1552) | Maximum | 0.5 | |
| Viscosity, Kenematic, cSt (ASTM D445) | Minimum | 1.4 | |
| | Maximum | 20.0 | |
| Water and Sediment, Volume (ASTM D1796) | Maximum | 0.1 | |
| Water Volume | Maximum | 0.1 | |
| Solids 0.8 Micron | Maximum | 10.0 mg 1 | |
| BTU Per Pound Nominal Heating Value | | | |

**ATTACHMENT 1A**

On behalf of Yukon Electrical Company Limited we have been requested to clarify an issue about fuel for Watson Lake, Yukon. We had requested P18 fuel be quoted for twelve months of the year, within our tender document, but have experienced in the past, an alternative product being supplied, other than what was requested. As such we need to know if your Company is quoting P18 during the November to April time frame or is P18 only being available May to October and the balance of the year being P40 or P50 product. Also indicate how YECL is to discern the type of product being received and when, if your product is coded and what the code for the product will be.

# ATTACHMENT B

## YUKON ELECTRICAL COMPANY LIMITED

## FUEL SPECIFICATION

**Bidder's Name:**

**Technical Information Required With Bid**

**for: P40 Fuel Oil**

| Fuel Properties and Characteristics | | Permissible Fuel as Delivered to Site | Guaranteed Fuels as Delivered to Site |
|---|---|---|---|
| Aromatics (ASTM D1319) | Maximum | 35 | |
| Ash Weight (ASTM D482) | Maximum | 2 | |
| Carbon Residur on 10 Bottoms (ASTM D524) | Maximum | 1.05 | |
| Cetane Number (ASTM D613) | Maximum | 35PC 40DI | |
| Cloud Point $^{o}$C (ASTMD97) | Maximum | Not above ambient | |
| Cooper Strip Corrosion (ASSTM D130) | Maximum | No. 3 | |
| Distillation (ASTM D86, D158 or D285) | | | |
| -10 $^{o}$C | Maximum | 282 $^{o}$C | |
| -90 $^{o}$C | Minimum | 360 $^{o}$C | |
| Flash Point $^{o}$C (ASTM D393) | Minimum | Legal | |
| Gravity API (ASTM D287) | Minimum | 30 | |
| | Maximum | 45 | |
| Pour Point, $^{o}$C (ASTM D97) | Minimum | 6 | |
| | | Below Ambient | |
| Sulfur, Total Weight (ASTM D2788 or D3605 or D1552) | Maximum | 0.5 | |
| Viscosity, Kenematic, cSt (ASTM D445) | Minimum | 1.4 | |
| | Maximum | 20.0 | |
| Water and Sediment, Volume (ASTM D1796) | Maximum | 0.1 | |
| Water Volume | Maximum | 0.1 | |
| Solids 0.8 Micron | Maximum | 10.0 mg 1 | |
| BTU Per Pound Nominal Heating Value | | | |

# ATTACHMENT C

## YUKON ELECTRICAL COMPANY LIMITED

## FUEL SPECIFICATION

**Bidder's Name:**

**Technical Information Required With Bid**

**for: P50 Fuel Oil**

| Fuel Properties and Characteristics | | Permissible Fuel as Delivered to Site | Guaranteed Fuels as Delivered to Site |
|---|---|---|---|
| Aromatics (ASTM D1319) | Maximum | 35 | |
| Ash Weight (ASTM D482) | Maximum | 2 | |
| Carbon Residur on 10 Bottoms (ASTM D524) | Maximum | 1.05 | |
| Cetane Number (ASTM D613) | Maximum | 35PC 40DI | |
| Cloud Point °C (ASTMD97) | Maximum | Not above ambient | |
| Cooper Strip Corrosion (ASSTM D130) | Maximum | No. 3 | |
| Distillation (ASTM D86, D158 or D285) | | | |
| -10 °C | Maximum | 282 °C | |
| -90 °C | Minimum | 360 °C | |
| Flash Point °C (ASTM D393) | Minimum | Legal | |
| Gravity API (ASTM D287) | Minimum | 30 | |
| | Maximum | 45 | |
| Pour Point, °C (ASTM D97) | Minimum | 6 | |
| | | Below Ambient | |
| Sulfur, Total Weight (ASTM D2788 or D3605 or D1552) | Maximum | 0.5 | |
| Viscosity, Kenematic, cSt (ASTM D445) | Minimum | 1.4 | |
| | Maximum | 20.0 | |
| Water and Sediment, Volume (ASTM D1796) | Maximum | 0.1 | |
| Water Volume | Maximum | 0.1 | |
| Solids 0.8 Micron | Maximum | 10.0 mg 1 | |
| BTU Per Pound Nominal Heating Value | | | |

# ATTACHMENT

## YUKON ELECTRICAL COMPANY LIMITED

## FUEL SPECIFICATION - WATSON LAKE

**Bidder's Name:**

**Technical Information Required With Bid**

## for: P6 Fuel Oil

**Watson Lake can use a P-6 fuel (Density 855 to 865) year round.**

**The Watson Lake Plant fuel specifications:** Density 855 to 865 with additive for pumping at minus 40 year round
See attached sheet and Diesel fuel typical characteristics. Note: column 2, 41-43, Density- .85 - .86 for fuel specs.

| Fuel Properties and Characteristics | | Permissible Fuel as Delivered to Site | Guaranteed Fuels as Delivered to Site |
|---|---|---|---|
| Aromatics (ASTM D1319) | Maximum | 35 | |
| Ash Weight (ASTM D482) | Maximum | 2 | |
| Carbon Residur on 10 Bottoms (ASTM D524) | Maximum | 1.05 | |
| Cetane Number (ASTM D613) | Maximum | 35PC 40DI | |
| Cloud Point °C (ASTMD97) | Maximum | Not above ambient | |
| Cooper Strip Corrosion (ASSTM D130) | Maximum | No. 3 | |
| Distillation (ASTM D86, D158 or D285) -10 °C | Maximum | 282 °C | |
| -90 °C | Minimum | 360 °C | |
| Flash Point °C (ASTM D393) | Minimum | Legal | |
| Gravity API (ASTM D287) | Minimum | 30 | |
| | Maximum | 45 | |
| Pour Point, °C (ASTM D97) | Minimum | 6<br>Below Ambient | |
| Sulfur, Total Weight (ASTM D2788 or D3605 or D1552) | Maximum | 0.5 | |
| Viscosity, Kenematic, cSt (ASTM D445) | Minimum | 1.4 | |
| | Maximum | 20.0 | |
| Water and Sediment, Volume (ASTM D1796) | Maximum | 0.1 | |
| Water Volume | Maximum | 0.1 | |
| Solids 0.8 Micron | Maximum | 10.0 mg 1 | |
| BTU Per Pound Nominal Heating Value | | | |

# ATTACHMENT D

## YUKON ELECTRICAL COMPANY LIMITED - GENERATION DIESEL FUEL

## SITE DELIVERIES

**Year:**

**TYPE OF PROPOSAL:**

**BIDDER:**

| LOCATION | OVERALL ESTIMATED ANNUAL USAGE | STORAGE CAPACITY | FIX PRORATE ESTIMATED ANNUAL FUEL VOLUME | | | i) BASE PRICE OF FUEL | | | ii) FIRM FREIGHT COST | iii) Fuel Surcharge | iv) NET PRICE DELIVERED TO YECL | | | TOTALS | | | GRAND TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | APR - SEPT USAGE | BALANCE | JAN - MAR OCT - DEC | PRICE PER LITER OF FUEL | | | | | | | | | | | |
| | | | P18 | P40 | P50 | P18 | P40 | P50 | | | P18 | P40 | P50 | P18 | P40 | P50 | |
| **Group A** | | | | | | | | | | | | | | | | | |
| BEAVER CREEK | | | | | | | | | | | | | | | | | |
| DESTRUCTION BAY | | | | | | | | | | | | | | | | | |
| HAINES JUNCTION | | | | | | | | | | | | | | | | | |
| **Group B** | | | | | | | | | | | | | | | | | |
| CARMACKS | | | | | | | | | | | | | | | | | |
| PELLY CROSSING | | | | | | | | | | | | | | | | | |
| ROSS RIVER | | | | | | | | | | | | | | | | | |
| STEWART CROSSING | | | | | | | | | | | | | | | | | |
| **Group C** | | | | | | | | | | | | | | | | | |
| SWIFT RIVER | | | | | | | | | | | | | | | | | |
| TESLIN | | | | | | | | | | | | | | | | | |
| WATSON LAKE | | | | | | | | | | | | | | | | | |
| | **0** | | **0** | **0** | **0** | | | | | | iii) Net Price | i | ii | | | | |

Tax Status:
Federal Excise Tax: Exempt
Goods and Services Tax: Extra at 7
Yukon Territorial Tax: Exempt
Good Hope Lake - BC Provincial Fuel Tax: Extrat at

ATCO Electric

Materials Management, 15th Floor ATCO Centre, 10035 - 105 Street, Edmonton, Alberta, T5J 2V6, Fax: 780-420-7436

July 21, 2008

SupplierName
BoxORSuiteNum
Address
city , Province
PostalCode

Attn: ContactName
Fax: FaxNum

**RE: Quote F-1708, Fuel: Diesel (Generation) - YECL**

You are hereby requested to submit a proposal on the supply of diesel fuel for YUKON ELECTRICAL COMPANY LIMITED. (Further reference to this company shall be as the "Purchaser"). Proposals are to be submitted for the following requirements and include all costs to refine, transport, off-load and meter diesel fuel.

D.P.P. the Purchaser's storage tanks as specified for the various ATCO Group of Companies.

NOTE: ALL QUESTIONS TO BE FAXED INTO PATTY BIDLOCK AT (780) 420-7436.

**Contract Term**

The contract is for 1 (one) year, beginning October 1, 2008 thru September 30, 2009. Through successful negotiation, there may be an option to extend for a second and third year term. The contract may not exceed 3 years in total.

What benefit is there to the Yukon Electrical Company, to enter into a contract for a longer period of time, example: 2 or 3 years.

**Supply Option(s)**

- supply and delivery of diesel fuel to selected locations

Also, please include information or a proposal (if applicable) as to what type of firm price (hedging) options you may have to offer.

What is your minimum fuel requirement for Hedging Agreements? I

Each proposal shall include the following information:

- refinery locations and owner
- supply point to each storage location in Attachment E
- name of carrier who will transport diesel fuel to Purchaser

## Pricing

Prices are to be submitted on Attachment D, attached. For Attachment D prices net prices are to encompass all costs to refine, transport, off-load, meter required too supply diesel fuel, D.P.P. Purchaser's storage facilities.

Prices shall be provided in liters and segmented as follows:

- *crude cost*-price D.P.P. refinery
- *freight cost*-transportation price from refinery or distribution point to Purchaser's storage
- *net*-addition of two (2) factors above to arrive at Purchaser's final delivered price
- Supplier to specify if rack or crude price base is used.

Prices are to be submitted in Canadian funds, corrected to 15 degrees Celsius with all taxes listed extra. Yukon Electrical uses P18, 40 and 50 fuel and requires pricing for these blends.

Pricing should be based on current market conditions. Can pricing be locked in firm for 30 days? Y or N.

## Method of Price Change

Proposals shall be submitted based on prices effective October 1, 2008 and include method of recalculating subsequent changes. Proposals are to include an explanation of how prices are obtained, a method of substantiating changes and reporting changes to the Purchaser. Should prices change during the evaluation period, due to changes in crude, rack or exchange rates, Bidders shall provide to Purchaser a notification of such changes within one (1) day of change.

## Estimated Quantities

Quantities expressed on Attachment D are our best estimates of volumes to be taken during the Term of Contract. Nevertheless, any diesel fuel deliveries taken under contract shall be at Purchaser's absolute discretion and Purchaser shall not be obligated to purchase any specific or aggregate quantity, nor pay any specific or aggregate dollar amount. Purchaser's sole obligation with respect to quantity or expenditures shall be to pay for the fuel requested and received in satisfactory condition.

## Emergency Inventory of Fuel for Yukon Electrical

Successful bidder shall be required to continuously inventory sixty thousand (60,000) liters of seasonal fuel in Watson Lake and at no charge to Purchaser. Fuel shall be for the exclusive use of Purchaser and not stored at Purchasers site.

## Taxes

Purchaser certifies that the diesel fuel shall be used exclusively for the generation of electricity, lighting or heating or operation of microwave stations and is therefore exempt from Federal Excise Tax. Yukon Electrical shall be exempt from Yukon territorial taxes. Fuel for deliveries into British Columbia are subject to provincial fuel tax. Goods and Services Taxes are extra. All Fuel shall be marked.

**Site Conditions and Delivery**

It is the responsibility of each bidder to become familiar with the delivery site location and be suitably equipped for local conditions; including having the necessary spill kits.

Yukon Electrical fuel deliveries will be as requested or prescheduled during the Contract Term.

**Diesel Fuel Quality**

Fuel provided by Bidder shall be subject to random testing to ensure compliance with Purchaser's specification as outlined in Attachment A, B, and C. Bidder shall replace at no cost to Purchaser any diesel found not in accordance with specification.

Bidders shall submit on Attachment A, B, and C guaranteed product properties and characteristics for P18, P40 and P50 offered.

**Contract Terms and Conditions**

Attachment E contains the proposed Terms and Conditions of the Contract. Submit with proposals any exception or deviations to this document.

**Confidentiality of Pricing**

Prices submitted with proposals remain confidential and shall not be revealed to other bidders. The Yukon Utility Board may request price information which the Purchaser is obligated to provide. The information provided the Utility Board shall be those prices agreed in the contract between the Purchaser and successful Bidder.

**Submission of Proposals**

Pricing of all proposals must be submitted on Attachment D attached. All or any combination of options will be considered. A new schedule shall be submitted for each option and in the space provided refer to the type of option being submitted. (i.e. **Supply of all location based on average of previous months crude**).

Proposals shall be accepted for consideration up to and including bid closing **time** identified herein. **Late bids shall not be accepted.** Proposals shall be submitted in a sealed package, distinctly marked on the outside with reference number **F-1708**, to ATCO Electric Ltd., P.O. Box 2426, 15th Floor ATCO Centre, 10035 - 105 Street, Edmonton, AB, T5J 2V6. Proposals shall also be accepted via facsimile transmission to 780-420-7436, provided original documents, enclosures and attachments are received within two (2) working days of bid closing date or via email to (**Quotes atcoelectric.com)**. *Do not send completed documents to either S. Newman's or Buyer's email address*.

Proposals are to be received by Purchasing no later than **August 7, 2008** at **2:00 P.M.** Lowest or any proposal not necessarily accepted.

A copy of this quotation is available in an electronic format. Contact Janet Butler of ATCO Electric via email address janet.butler atcoelectric.com if a copy is required.

Regards,



P.A. (Patty) Bidlock, C.P.P.
Purchasing Coordinator, Transmission & Distribution
ATCO Electric Ltd.
Ph: (780) 420-7135 Fax: (780) 420-7436
Internet Address: patty.bidlock atcoelectric.com

jb
Enclosures

Bcc: Craig Steinbach, Whitehorse

# ATTACHMENT E

## FORM OF CONTRACT

BLANKET ORDER

For the supply of diesel fuel to the following locations as required. This order not to exceed _____dollars in total. Prices below based on starting date of _____.

| LOCATION | EST. USAGE / L | BASE PRICE OF FUEL | | | FIRM FREIGHT COST | FUEL SURCHARGE % | NET PRICE DELIVERED TO YECL |
|---|---|---|---|---|---|---|---|
| | | P18 | P40 | P50 | | | |
| BEAVER CREEK | x | | | | | | |
| DESTRUCTION BAY | x | | | | | | |
| HAINES JUNCTION | x | | | | | | |
| CARMACKS | x | | | | | | |
| PELLY CROSSING | x | | | | | | |
| ROSS RIVER | x | | | | | | |
| STEWART CROSSING | x | | | | | | |
| SWIFT RIVER | x | | | | | | |
| TESLIN | x | | | | | | |
| WATSON LAKE | x | | | | | | |

Supplementary Terms and Conditions

1. Term

1.1 This Blanket Order shall cover the period October 1, 2008to September 30, 2009 unless otherwise extended or terminated prior to scheduled expiry by actions of Purchaser or Supplier, and in accordance with the terms and conditions herein.

1.2 Any agreed extension(s) to the term of this Blanket Order shall be authorized by means of a written revision to this Blanket Order, or a replacement blanket order, at Purchaser's discretion.

1.3 Supplier guarantees supply of product in the event contract is assigned to a third party.

2. Estimated Quantities

2.1 Quantities or dollar values expressed herein or otherwise communicated in writing by Purchaser to Supplier represent Purchaser's best estimate of volumes to be taken or expenditures to be made under this Blanket Order. Nevertheless, any fuel deliveries under this Blanket Order shall be at Purchaser's absolute discretion and Purchaser shall not be obligates to purchase any specific or aggregate quantity, nor to pay any specific or aggregate dollar amount to Supplier.

2.2 Purchaser's sole obligation with respect to quantities or expenditures with Supplier shall be to pay for the fuel requested by Purchaser under this Blanket Order and received in satisfactory conditions under the terms of this Blanket Order.

3. Fuel Quality

3.1 Fuel provided by Supplier under this Blanket Order shall be subject to random testing to ensure compliance with Purchaser's Fuel Specification (Attachment A, B and C) Limited of Purchaser's Request for Proposal). Supplier shall replace at no cost to Purchaser any diesel found not in accordance with specification.

4. Authorization to Supply

4.1 Purchaser shall authorize shipment of fuel under this Blanket Order via telephone call from one of Purchaser's representatives to Supplier's agent at _____.

5. Shipment and Delivery

5.1 Purchaser shall instruct Supplier's representative as to when delivery of the fuel is to be made and the specific delivery location.

5.2 Supplier shall load fuel, seal discharge line, record serial number of seal and type of fuel being delivered on the delivery ticket prior to departure of delivery vehicle.

5.3 Purchaser's representative shall verify serial number of seal applied and recorded on the delivery ticket and witness removal of seal at time of delivery to Purchaser's location. Purchaser's representative shall verify via means of Purchaser's own metering devices or the delivery vehicle meters the quantity of fuel off loaded and confirm agreement with the delivery ticket or record the different quantity on the delivery ticket.

5.4 When delivery is specified for a location not attended by Purchaser's representative, Supplier shall ensure the delivery person separately records the quantity metered by the delivery vehicle as fuel is off loaded and records such quantity on the delivery ticket. Should supplier's delivery vehicle not be equipped with a metering device, delivery person shall record tank levels both prior to and after delivery on delivery ticket.

5.5 Supplier shall not fill tanks greater than ninety (90) percent of the nameplate capacity.

5.6 Any discrepancy between the quantity recorded at time of shipment and that noted by Purchaser's representative, or the delivery person in the Purchaser's representative absence, at time of delivery shall be subsequently resolved to the mutual satisfaction of Supplier and Purchaser, after determination as to the reason for such discrepancy.

5.7. Supplier shall be required at the point of delivery to have various fittings to hookup to Purchasers tanks.

5.8 Contractor shall not assign any obligation or benefit arising from the Contract without Purchasers prior consent. Contractor shall not, without the prior written approval of the Purchaser, assign or subcontract the supply and delivery of fuel or any portion of the supply and delivery of fuel. Contractor shall ensure all permitted Subcontractors agree to be bound by the provisions of this Contract Document with respect to the part of supply and delivery of fuel to be performed by them.

6. Pricing

6.1 Fuel prices shall be as specified herein. Purchaser shall receive written notice (attention: Shirley Newman) from Supplier of any subsequent (daily, weekly, monthly) changes.

6.2 Crude Cost adjustments shall be (daily, weekly, monthly). Supplier shall receive immediate notice if price increase is rejected.

6.3 Prices for freight and margins or overhead shall remain firm for the contract period.

6.4 In the case of rejection of a proposed price increase Supplier and Purchaser shall negotiate a mutually acceptable price increase and Supplier shall continue to supply fuel to Purchaser for a period of not less than thirty (30) days at the price then in effect.

6.5 Any negotiated price shall be retroactively applied to the implementation date originally proposed by Supplier by means of a separate billing for all fuel supplied at the previous price during the negotiation period.

6.6 Failure to negotiate a mutually acceptable price increase within thirty (30) days of rejection of proposed increase shall terminate this Blanket Order and any subsequent additional payment in lieu of price increase for fuel supplied during the negotiation period shall be at Purchaser's absolute discretion.

6.7 Prices and quantities shall be temperature corrected to 15 degrees Celsius.

7. Taxes

7.1 Purchaser is exempt from Federal Excise Tax and such tax shall be excluded from all prices and billing.

We certify that the fuel oil ordered hereby is for use by us exclusively in the generation of electricity or for lighting or heating purposes.

8. Billing

8.1 Supplier shall issue invoices to Purchaser for each shipment made and shall include reference to the delivery location, date of delivery, and this Blanket Order number. Temperature corrected quantity, price per liter, and the Goods and Services Tax shall be indicated separately.

9. Payment

9.1 Purchaser shall make payment to Supplier within thirty (30) days of satisfactory receipt of fuel, or receipt of satisfactory invoice; whichever shall be the later.

9.2 In case of discrepancy between the quantity recorded at time of shipment and that noted by Purchaser at time of delivery, payment shall be made for the lesser quantity within the prescribed time period and any subsequent payment with respect to such discrepancy shall be made within thirty (30) days of resolution to the mutual satisfaction of Supplier and Purchaser.

9.3 Supplier shall provide a current clearance letter fromWCB stating their current status.

10. Termination of Agreement

10.1 Purchaser shall have the right to terminate this Blanket Order at any time by reason of unsatisfactory performance of Supplier, as judged exclusively by Purchaser, or by reason of Supplier’s failure to meet the terms and conditions of this Blanket Order.

10.2 Supplier shall have the right to terminate this Blanket Order at any time by reason of Purchaser's failure to meet the terms and conditions of this Blanket Order.

11. Site Safety

11.1 The Purchaser shall provide the Supplier a Site Safety orientation prior to delivery of fuel to site with yearly reviews.

11.2 Supplier shall provide written proof that their delivery persons have completed WHMIS training and hold TDG certification.

11.3 Supplier shall ensure that prior to connecting the delivery hoses the Supplier’s vehicle shall be electrically bonded to the stations ground grid. Purchaser shall provide connection details for each site.

11.4 Where the Purchaser is of the view that the Supplier or an employee or agent of the Supplier is contravening any rule or regulation relating to safety (contained in either the rules and regulation provided by the Purchaser or legislation) the Purchaser's may give the Supplier written notice to take immediate corrective action and the Supplier shall forthwith take such steps as may be required to comply with such rules or regulation.

11.5 The Purchaser's shall have the right to exclude from the site any person who contravene rules and regulations relating to safety.

11.6 If providing fuel and delivery of same, requires the Contractor to perform services at the designated sites, Contractor shall inform all employees of all safety and environmental rules, regulations and practices in force on Site as provided by the Purchaser; including Purchaser's fitness for work program or Contractor's equivalent alcohol and drug policy if judged acceptable solely by the Purchaser. Fitness for work shall mean the ability to perform work safely and productively free from any physical or mental limitation due to the use of alcohol or drug, health problems, fatigue, illness or injury.

12. Fuel Spills

12.1 Supplier's employee shall immediately report any and all fuel spills, no matter what quatity to the Purchaser by contacting (867) 633-7000.

12.2 Prior to commencement of the contract the Supplier shall inspect and verify the condition of each delivery site. Supplier shall then be accountable not to degrade the site by way of fuel spills.

12.3 Supplier shall be responsible to remediate fuel spills due to their negligence and return site to the condition as it was prior to the spill.

12.4 Supplier shall be responsible for all litigation costs and fines resulting from fuel spills due to negligence on the part of the Supplier.

12.5 Supplier shall have access to Purchaser's spill response kits and shall immediately report the use and removal of material from the kit to the Purchaser's representatives listed in 12.1.

12.6 Supplier shall ensure the appropriate containment is used when connecting and disconnecting delivery hoses. (e.g.: 20 litre pail and absorbent material).

12.7 Supplier shall be in constant attendance and control when fuel is being transferred. Supplier shall monitor and inspect all storage and delivery components while fuel is being transferred. Transfer of fuel shall stop should the Supplier leave the immediate transfer and control area.

12.8 Supplier shall ensure all fuel product delivered by truck shall have a Spill Response Kit available.

In the event the Spill Kit is used, Purchaser's representative shall be notified as outlined in section 12.1.

13. Insurance

13.1 Unless otherwise specified by Owner, Contractor shall obtain comprehensive general liability insurance with a minimum bodily injury and property damage limit of two million dollars ($2,000,000) inclusive. Coverage shall include product and completed operations, Owner's and Contractor's protective liability, tortuous liability, blanket written contractual liability, contingent employer's liability, personal injury, cross liability, Owner and its employees and agents as additional named insurers, broad form property damage, occurrence property damage, forest fire and other fire suppression liability, loss of use without prior physical damage, underground property damage, attached machinery, co-owners and joint venture liability, sudden and accidental pollution liability and automobile liability insurance on all owned, non-owned or hired vehicles covering third party bodily injury, death and property damage, with a combined single limit of two million dollars ($2,000,000) per occurrence.

13.2 Supplier shall maintain Environmental Liability Insurance to a minimum of $1,000,000 during the contract. Confirmation of such insurance shall be provided to Purchaser prior to delivery of fuel.

13.3 Supplier shall maintain Forest Fire/Fire Suppression Insurance with a minimum of $2,000,000.00 during the contract term. Confirmation of such insurance shall be provided to Purchaser prior to the initial delivery of fuel.

14. Governing Laws

14.1 The laws of the province in which the Site is located shall govern contract and the parties hereby agree to the exclusive jurisdiction of the courts of such province or territory.

**Yukon Electrical Company Limited**
**Generating Units**
**December 31, 2007**



| Location | Diesel or Hydro | Unit | In Service | Make | Model | hours | Nameplate Capacity kW | 2007 Peak Demand | Off Grid | STB |
|---|---|---|---|---|---|---|---|---|---|---|
| Beaver Creek | D | 1 | 1989 | Caterpillar | 3406B | 60969 | 250 | 405 | X | |
| | D | 2 | 1993 | Caterpillar | 3412 | 81182 | 330 | | X | |
| | D | 3 | 1991 | Caterpillar | 3412 | 23257 | 400 | | X | |
| Carmacks | D | 1 | 1991 | Caterpillar | | 1712 | 1600 | 849 | | X |
| Destruction Bay | D | 1 | 1999 | Caterpillar | 3408 | 80493 | 220 | 348 | X | |
| | D | 2 | 1992 | Caterpillar | 3412 | 75140 | 330 | | X | |
| | D | 3 | 1995 | Caterpillar | 3406 | 11167 | 170 | | X | |
| Haines Junction | D | 1 | 1997 | Caterpillar | 3516 | 812 | 1750 | 1185 | | X |
| Old Crow | D | 1 | 1998 | Caterpillar | 3508 | 10310 | 600 | 444 | X | |
| | D | 2 | 1993 | Caterpillar | 3412 | 100695 | 330 | | X | |
| | D | 3 | 1994 | Caterpillar | 3406B | 25053 | 170 | | X | |
| Pelly Crossing | D | 1 | 1993 | Caterpillar | 3406 | 32019 | 250 | 468 | X | |
| | D | 2 | 1999 | Caterpillar | 3412 | 50684 | 400 | | X | |
| | D | 3 | 1997 | Detroit Diesel | S60 DDEC III | 70416 | 300 | | X | |
| Ross River | D | 1 | 1989 | Caterpillar | 3516 | 9639 | 1000 | 550 | | X |
| Stewart Crossing | D | 1 | 1994 | Volvo | 100 KG | 28423 | 150 | 80 | | not in service |
| | D | 2 | 1990 | Volvo | T1D61 | 89564 | 85 | | | not in service |
| | D | 3 | 1974 | Caterpillar | 3306 | 41516 | 150 | | | X |
| Swift River | D | 1 | 2003 | Mitsubishi | 6D14 | 55992 | 80 | 57 | X | |
| | D | 2 | 2003 | Mitsubishi | 6D14 | 29997 | 80 | | X | |
| Teslin | D | 1 | 1993 | Caterpillar | 3516 | 8974 | 1500 | 866 | | X |
| Watson Lake | D | 1 | 1999 | Caterpillar | E3512 | 40841 | 700 | 2737 | X | |
| | D | 2 | 1985 | Caterpillar | 3512 | 23457 | 650 | | X | |
| | D | 3 | 1991 | Caterpillar | 3516 | 58346 | 1000 | | X | |
| | D | 4 | 1985 | Caterpillar | 3606 | 123487 | 1500 | | X | |
| | D | 5 | 1997 | Detroit Diesel | S60 DDEC III | 23304 | 300 | | X | |
| | D | 6 | 1999 | Caterpillar | E3512 | 43757 | 700 | | X | |
| Mobile | D | 1 | 1989 | Caterpillar | D398 | | 500 | | | X |
| | D | 2 | 1991 | Caterpillar | 3408 | | 350 | | | X |
| | D | 4 | 1998 | Caterpillar | 3306 | | 230 | | | X |
| | D | 5 | 1999 | Perkins | PL335 | | 30 | | | X |
| Fish Lake | H | 1 | 1952 | Gilkes | Hydraulic Turbo | | 700 | | | |
| | H | 2 | 1958 | Gilkes | Hydraulic Turbo | | 600 | | | |
| | | | | | **YECL Diesel** | | **16105** | | | |
| | | | | | **YECL Hydro** | | **1300** | | | |
| | | | | | **Total** | | **17405** | | | |

**the operational hours were obtained on different days in the month of July 2008**

**YUB-YECL-8**

**Reference:** Labour Costs; Application, Section 5 Operations and Maintenance Expenses

**Issue Sub-Issue:** Labour Costs

**Request:**

(a) For the period 2003 through 2007, please provide a table, showing wage increases year-on-year for the YECL employee association groups compared to similar groups in its counterpart ATCO Electric.

(b) For the period 2003 through 2007, please provide a table illustrating labour inflation in respect of YECL, that compares YECL with Yukon, British Columbia and Alberta labour inflation indices.

(c) Please provide details in regard to the additional travel benefits due to commence in 2009 that YECL employees will be entitled to.

(d) Please provide a table illustrating YECL vacancy rates for the period 2003 through 2007.

(e) In consideration of the tight labour market south of 60 , please explain why a vacancy rate of 1 FTE is reasonable and attainable.

(f) Please provide a table illustrating non-labour inflation for the provinces of Alberta and British Columbia, as well as Yukon for the period 2002 to 2007.

(g) Please provide a schedule of retirements from 2005 to 2009 inclusive.

**Response:**

(a) Please refer to YUB-YECL-8(a) Attachment 1 for a spreadsheet with the negotiated increases of ATCO Electric and Yukon Electrical.

(b) The inflation rate is as follows:

| | BC | AB | Territories |
|---|---|---|---|
| 2003 | 1.3 | 3.0 | 2.5 |
| 2004 | -1.6 | 3.1 | 3.0 |
| 2005 | .5 | 3.0 | 3.0 |
| 2006 | 2.5 | 3.4 | 3.1 |
| 2007 | 3.0 | 4.9 | 3.0 |

The source of this information is from the Government of Canada Website Human Resources and Social development Canada.

The information above may not include market adjustments that may have been provided to employee positions that are extremely competitive in the labor market.

In addition to the above, the following is the information that is provided in LE-YECL-17:

> LE-YECL-17 Attachment 1 is a report from Alberta Finance and Enterprise that provides the information requested. It is important to note that the numbers reflected in the report do not necessarily show market adjustments that can occur to base salaries but rather it would show the economic increases that have been afforded to the various sectors in Alberta and Canada.
>
> In regard to labor inflation data from CEA for the electric utility sector Yukon Electrical was not able to locate such data. However LE-YECL-17 Attachment 2 is a CEA report on the labor market in the Electrical Utility sector. It serves as further information as to why labor cost increases are and will continue to be a likely reality in the industry.

In addition please refer to YUB-YECL-8(b) Attachment 1

(c) The travel benefits are embedded in the collective agreement between Yukon Electrical and the Yukon Electrical Employees Association for in scope positions and in policy for out of scope positions. At the present time each employee receives one flight out for themselves and each eligible dependant up to a maximum of 800.00 per person. There is also an amount that is identified in the collective agreement for the payment made to those employees who drive out rather than fly. There have been no adjustments to the travel benefits for employees in over 10 years.

Yukon Electrical looked at a number of possible options to enhance its benefits package for attraction and retention of employees before settling on an additional flight out. In its research it was obvious that employee compensation packages are varied and that employers consider them as competitively sensitive. However Yukon Electrical recognized that employees in the north generally appreciate assistance when flying or driving out of the territory due to the high cost of travel. Yukon Electrical also wanted to mirror the programs that are in place in the Northwest Territories and northern Alberta through its sister and parent company.

(d) Vacancy rates are calculated based on an approved compliment for FTEs. As such vacancy rates are not applicable given that there were no Board approved FTEs for this period.

(e) Although it is a tight labor market, based on the programs that Yukon Electrical has put into place in recent months the vacancies have been reduced substantially. Yukon Electrical has also begun an apprentice lineman and Field Service Representative program which it is also confident will stabilize its workforce. At the present time Yukon Electrical has only two journeyman lineman vacancies, (one being filled by the end of August) indicating that its approach is helping.

The program enhancements that Yukon Electrical has added are a Community Skills Premium similar to the program implemented by its parent company ATCO Electric and the Northland Companies. This program provides a payment to attract and retain key trades people to northern communities.

In addition, as stated above, Yukon Electrical proposes to enhance its northern benefit package to include one additional flight out for employees and their families. This is also in an effort to match similar benefits in the Northwest Territories and northern Alberta communities as well as some Yukon companies that compete with Yukon Electrical for resources.

There have been no improvements to the northern benefit package in Yukon Electrical for over 10 years.

Carrying an involuntary number of vacancies over the past several years, particularly in key trade positions, has put a burden and strain on the employees who are asked to get the required work completed. Extended on-call responsibilities and a negative impact on quality of life has forced Yukon Electrical to improve its recruiting methods and compensation packages. Part of this means providing overlap where possible for positions prior to an employee leaving to another job or retiring. This change in managing recruitment also places downward pressure on vacancy rates.

These programs are some of the components that are required to attract and retain employees. Yukon Electrical has seen positive results and therefore believes that a 1 FTE vacancy rate is reasonable for the test period.

(f) Please refer to the following table:

**Consumer Price Index (CPI) All-items, 2002 100**

| | Alberta | | British Columbia | | Whitehorse | |
|---|---|---|---|---|---|---|
| | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change | Index | Y-O-Y ( ) Change |
| 2002 | 100.0 | *3.4* | 100.0 | *2.4* | 100.0 | *0.7* |
| 2003 | 104.4 | *4.4* | 102.2 | *2.2* | 101.9 | *1.9* |
| 2004 | 105.9 | *1.4* | 104.2 | *2.0* | 103.0 | *1.1* |
| 2005 | 108.1 | *2.1* | 106.3 | *2.0* | 105.3 | *2.2* |
| 2006 | 112.3 | *3.9* | 108.1 | *1.7* | 106.8 | *1.4* |
| 2007 | 117.9 | *5.0* | 110.0 | *1.8* | 109.5 | *2.5* |

figures are not available for Yukon
Source: Statistics Canada

(g)

| YEAR | ELIGIBLE RETIREMENTS YECL |
|---|---|
| 2005 | 3 |
| 2006 | 0 |
| 2007 | 1 |
| 2008 | 0 |
| 2009 | 1 |

In addition to the above, it is an important to understand that ATCO Electric has approximately 346 employees who are eligible for retirements over the next 10 years. In fact, the ATCO Group has approximately 1,000 employees eligible for retirement over the same time period. This will create a number of promotion and career opportunities for Yukon Electrical employees and it will be increasingly difficult to attract and retain employees necessary to deliver safe, reliable and cost effective service to Yukon customers.

| Year | ATCO Electric Increases | YECL Increases |
|---|---|---|
| 2003 | 3.25% | 3.5% & 4.25% (see note 4) |
| 2004 | 3.25% | 3.25% |
| 2005 | 2.5% & 3.5% (see note 1) | 3.00% |
| 2006 | 2.5% & 3.0% (see note 1) | 2.75% |
| 2007 | 2.5% & 3.25% (see note 1) | 4.75% & 3.5% (see note 5) |
| 2008 | 2.0-3.0% competitive wage adj. + 5.25%<br>7.0% competitive wage adj. + 5.25%<br>5.5% (see note 2) | 4.5% & 3.5% (see note 5) |
| 2009 | 5.5% & 5.25% (see note 3) | |

**Note 1:** 3 yr. collective agreement, 2005-07; 2.5 clerical for all 3 years; All other job classes - 2005 - 3.5 , 2006 - 3.0 & 2007 - 3.25 .

**Note 2:** 2 yr. collective agreement, 2008-09; 2008 - 2 - 3 competitive adjustment for select operational field support (meter and comm. techs, mechanics, maintenance techs.) plus a 5.25 economic increase.
2008 - 7 competitive adjustment for power lineman journeymen, electrical technologists and system control centre operators plus a 5.25 economic increase.
2008 - 5.5 increase for all clerical jobs.

**Note 3:** 2009 - 5.5 increase for all clerical jobs and 5.25 increase for all other job classes.

**Note 4:** 2 yr. collective agreement, 2002-03; 2002 - 3 alignment increase for tech., trades and clerical; plus 3 across the board increase to all wage schedules.
2003 - 4.25 for line and techs. and 3.5 for all other job classes.

**Note 5:** 2 yr. collective agreement, 2007-08; 2007 - 4.75 for tech. and trades (linemen, technologists, plant maintenance and plant operators). All other job classes - 3.5 .
2008 - 4.5 for tech. and trades and 3.5 for all other job classes.

# ADDRESSING THE HUMAN RESOURCE CHALLENGE IN THE ELECTRICITY INDUSTRY

Brief prepared by the Human Resource Committee
of the Canadian Electricity Association

**February 2007**

Canadian Electricity Association canadienne de l'électricité



The voice of Canadian Electricity. La voix de l'électricité canadienne.

**Canadian Electricity Association**
**Association canadienne de l'électricité**
www.canelect.ca

## Executive Summary

A safe, secure, reliable, sustainable and competitively priced supply of electricity is essential to Canada's prosperity. As the critical enabler of the economy and an enhanced quality of life, a strong electricity industry is fundamental to realizing our potential as individuals, as communities and as a nation. Investing in our electricity supply is tantamount to investing in Canada's present and future success.

While the electricity industry consists of a vast infrastructure representing generation, transmission and distribution, at the root of this complex and expansive system is a labour force that is facing significant challenges in the years ahead. An aging workforce and pending retirements in the short and mid-term could have devastating impacts on an industry already challenged by increasing demand, technological change and regulatory instability.

According to the Canadian Electricity Human Resource Sector Study commissioned by the Canadian Electricity Association (CEA) in 2004, almost 40 percent of the electricity sector's non-support staff will be eligible to retire by 2014. A shortage of skilled labour could compromise the electricity sector in a number of ways including reduced reliability, increased cost of production, infrastructure projects delays, and decreased safety and productivity due to less experienced employees and worker shortages.

In this brief, CEA has developed a series of recommendations that provide concrete solutions to addressing the electricity industry's workforce challenges. The Association strongly believes a collaborative effort between the industry and the federal government in three focus areas will secure a strong future for the electricity workforce:

1. We must build our Canadian skills base by investing in education, skills training and apprenticeships, particularly in underrepresented communities.
2. We must ensure trained, skilled workers are able to work and flourish in their area of expertise by streamlining certification and credential recognition, and facilitating workforce mobility.
3. We must attract and retain skilled foreign workers by ensuring successful community and workplace integration.

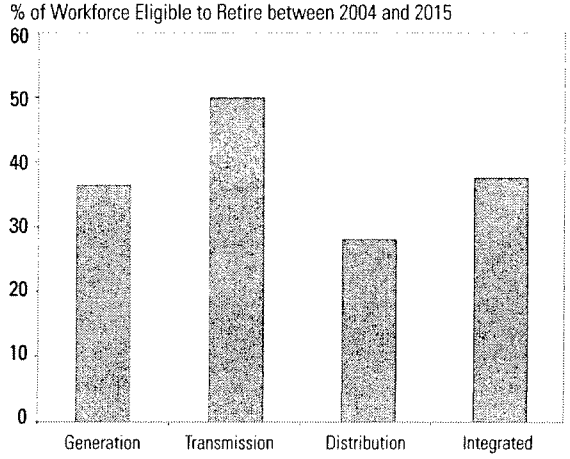
In its economic plan entitled *Advantage Canada*, the federal government acknowledges that people are "the most critical contributor to the national economy over the long term" and recognizes its role in helping individuals and industries reach their full potential *(p. 13)*. The electricity industry is encouraged by the government's intention of investing in Canada's talent pool. It is therefore CEA's intention to assist the government in this effort through the recommendations in this brief.

## I Introduction

For over 125 years, the electricity industry has powered Canada's economy and way of life, and has provided the foundation for our country's growth and prosperity. Ensuring an adequate, skilled and internationally-competitive workforce for the electricity industry is critical to our economic prosperity and quality of life.

The electricity industry currently employs 98,000 people. According to the *Canadian Electricity Human Resource Sector Study* commissioned by the Canadian Electricity Association (CEA) in 2004, almost 40 percent of the electricity sector's non-support staff will be eligible to retire by 2014 *(figure 1)*. Retirements estimates show that the sector will need more than 17,000 people in technical positions in the next 8 years *(Figure 1)*.

***Figure1: A Human Resource Challenge: Eligibility to Retire between 2004 and 2015***




Source: 2004 Canadian Electricity Human Resources Sector Study

Training requirements are also posing a new set of challenges to the industry. The evolution of technologies in the electricity sector is constant with developments such as increased distributed generation, and the introduction of SCADA systems and "green" technologies. These new technologies have created the need for new training and skills development, and "re-skilling" of the existing and future labour force.

In this brief, the CEA has set out to inform the federal government on how the current crisis facing the electricity industry is of critical importance to all Canadians. More importantly, CEA has provided recommendations on how industry and government can work together to ensure a strong electricity future for Canada.

## II Canada's Electricity Industry

Built with vision, innovation and intent, Canada's electricity system distinguishes itself on an international scale. Ranked fifth globally in total electricity generating capacity and production, Canada also has one of the cleanest electricity generation portfolios in the world. Canada is also recognized for its technological innovations in long-distance electric power transmission, in particular in High Voltage Direct Current (HVDC) transmission systems. It is also a world leader in the deployment of advanced distribution technologies. For example Ontario utilities will install 4.5 million smart meters by 2010.

Canada's electricity industry provides an essential service with far-reaching and immediate impact. It underpins and enables growth in other sectors of the economy and contributes significantly to Canada's export revenues. Twenty-four hours a day, 365 days of the year, Canadian utilities must match production from generating plants with customer demand at competitive prices, while maintaining system reliability, meeting environmental objectives, and fulfilling safety and human resource needs. The result is a highly developed system that optimizes generation, transmission and distribution technologies.

### i) Diversified Generation

Canada possesses a diverse generation portfolio, covering a range of mature and

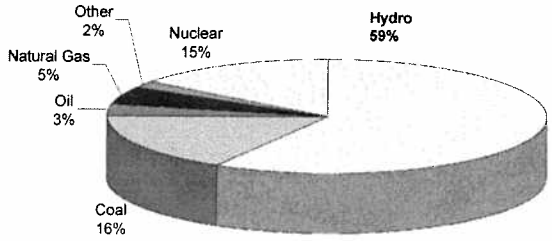
emerging electricity-producing technologies *(Figure 2)*. Hydro power – of which Canada is the global leader – produces the largest share at close to 60% of electrical production, followed by fossil fuels (coal, natural gas and oil) at 28% and nuclear at 12%. Wind, bioenergy and other sources are now being considered as contributors to the overall generation mix, although when combined, represent only 2% of Canadian electricity production.

As jurisdictions look to reducing greenhouse gas and other air emissions, there exists significant potential for Canada to increase the use of hydro, nuclear and emerging renewable sources of power, while also being on the global cutting edge of innovations relating to thermal generation, such as clean coal technologies.

### ii) Rising Demand

In addition to being a world leader in electricity production, Canada is also one of its top consumers. In 2003, Canada used about 3.6% of total world consumption and about 12% of total North American consumption.

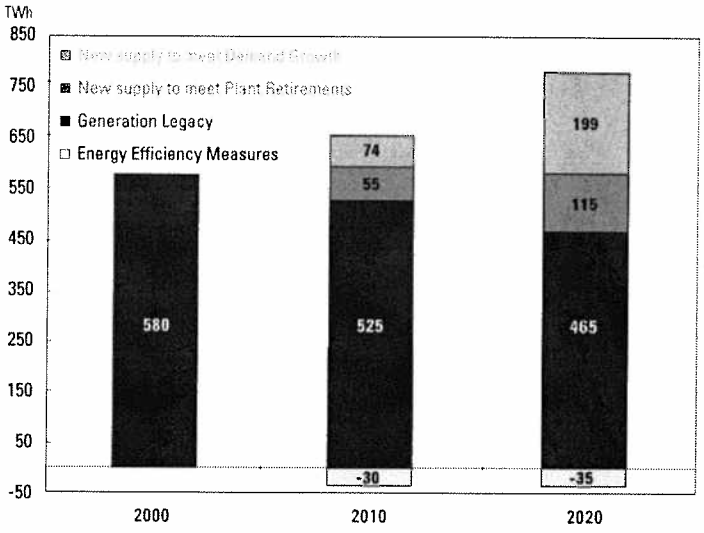
***Figure 1: Net Electricity Generation, 2004 Total = 577 TWh***




Source: Statistics Canada, Electric Power Generation, Transmission and Distribution, 2004 and Report on Energy Supply & Demand in Canada, 2004

The combination of increasing population, economic growth and greater use of electrical equipment means that electricity demand will continue to grow at an annual average rate of 1.5 to 2 percent. According to an average of two National Energy Board (NEB) scenarios produced in 2003, Canada's electricity supply will need to reach 814 TWh in 2020 from its current level of 594 TWh to meet requirements. CEA estimates that energy efficiency efforts could reduce future needed supply to 779 TWh. The increase in supply must also compensate for the anticipated retirement by 2020 of approximately 20 percent of facilities operating in 2000. Thus, an additional 314 TWh must be generated by 2020 to meet both system demand growth and plant replacement needs (Figure 2).

***Figure 2: CEA Generation Projection to 2020***




Source: CEA
Energy Efficiency Measures and New Supply to meet Plant Retirements calculated from average or MARKAL 2001, NRCAN 1999, and NEB 1999 models and New Supply to meet Demand Growth calculated from NEB 2003 Scenarios

A growing economy, rising population and the subsequent rise in electricity demand are creating a need to expand both traditional and new emerging technologies to meet rising demand.

### iii) Human Resource Implications

The impact of impending retirements, rising demand, the need to build new infrastructure and the introduction of new technologies are not without significant consequence to the Canadian electricity workforce. The strain posed by these factors on individual utilities and on the electricity system as a whole could diminish the industry's ability to deliver reliable, safe, sustainable and competitively priced electricity.

A shortage of properly trained and skilled labour could have serious repercussions for the electricity sector in a number of ways including:

- Reduced reliability;
- Increased cost of production;
- Infrastructure project delays;
- Decreased safety and productivity due to less experienced employees and worker shortages.

## III Addressing the Electricity Industry's Human Resource Challenge

CEA welcomes the government's commitment in *Advantage Canada* to support Canada's emergence as an energy superpower in part by making the needed investments in knowledge and people. Canada's energy sector is as much a knowledge industry as is the high tech sector. Trained and experienced workers are essential to ensure the long-term stability of Canada's electricity supply. Recognizing the significant human resource challenges facing the electricity sector, governments and industry must increase their efforts to build our Canadian skills base, ensure trained, skilled workers are able to work and flourish in their area of expertise, and attract and retain skilled foreign workers.

### i) Building a Canadian Skills Base

Growing Canada's domestic labour pool and tapping into our potential as a nation is an important element in addressing the electricity industry's workforce challenges. Increasing participation of under-represented groups, expanding and improving skills training and apprenticeship funding, and raising awareness on electricity-related career choices are critical factors in developing a skilled, educated and adaptable workforce.

**Engaging Non-Traditional Communities**

Increasing the engagement of the non-traditional workforce is an important step in building a dynamic and sustainable Canadian skills base. CEA is encouraged by the federal government's commitment to take action in this area by "eliminating barriers to labour force participation for under-represented groups" *(Advantage Canada, p.50)*

According to the *2004 Canadian Electricity Human Resource Sector Study,* women, visible minorities and Aboriginal workers are currently underrepresented in the electricity sector. Women account for only 25.4% of all electricity employees and 6.1% of trade staff, engineers and managers/supervisors, which is well below the national average where 46.9% of the total workforce is female.

Visible minorities also fare poorly representing only 7% of total electricity sector workers as compared to 12.6% nationally. This labour group is growing at a rapid pace and based on Conference Board of Canada estimates, could reach 18.4% of the labour force by 2016.

While the electricity industry can provide significant employment opportunities for Aboriginal workers in certain jurisdictions, this labour group represents only 2.2% of electricity industry workers, a slightly lower figure than the national average of 2.6% *(Statistics Canada Census).*

**Aboriginal Engagement**

As the development of electricity resources increases in areas with growing Aboriginal populations, there exists the potential for increased electricity sector and government collaboration to further engage Aboriginal communities. Utilities have already benefited

from Aboriginal partnerships established through the course of project development.

For example, the Hydro Northern Training and Employment Initiative was launched as a result of two proposed Manitoba Hydro hydroelectric projects in Northern Manitoba representing $4.0B in construction costs, 2,000 jobs, and is expected to contribute $2.0B to the national Gross Domestic Product. This Initiative is the first large-scale Aboriginal human resource strategy in northern Manitoba to be planned, designed and implemented by northern Aboriginal Partners. A $60.3M multi-year program receiving $22.0M from the federal government through the Aboriginal Skills and Employment Partnership, the Initiative is training and preparing over 1,000 Aboriginal residents for 800 Manitoba Hydro construction and related employment opportunities.

Another example of a pro-active industry-Aboriginal partnership is BC Hydro's Aboriginal Employment and Education Strategy, established as a long term approach to building internal awareness and conducting recruitment outreach with Aboriginal communities in British Columbia. The utility recently created the "trades trainee" role that now provides BC Hydro with an opportunity to work directly with Aboriginal and other youth who are who are inspired to compete in the next recruitment cycle. BC Hydro is also meeting with Aboriginal educational and employment groups across B.C. to develop partnerships to support students and develop regional training programs. Last summer First Nations students were hired as Youth Trades workers and received a half day of high school tutoring and then gained a half day work experience at a generation station. This initiative was widely supported by the school principal and the community.

The Hydro Northern Training and Employment Initiative and BC Hydro's Aboriginal Employment and Education Strategy clearly demonstrate the value for Aboriginal communities and for the electricity industry, of supporting comprehensive and consistent approaches to Aboriginal engagement and partnerships throughout the country. The federal government's role as a facilitator in fostering new partnerships between Aboriginal communities and the electricity sector is a significant contributor to success.
Recommendation: CEA encourages the federal government to support the creation of a national strategy to engage, support and train Aboriginal peoples in the electricity sector.

**Enhancing Apprenticeships and Skills Training**
By enhancing the quality, efficiency and availability of apprenticeships, skills training programs, student aid and scholarships, the federal government can assist in increasing the participation of all Canadians in the electricity workforce and meeting labour needs.

CEA welcomes the federal government's Apprenticeship Incentive Program announced in the 2006 Federal Budget which includes a tax credit for employers hiring an apprentice and the Apprenticeship Tax Grant. While these developments are steps in the right direction, they only apply to "Red Seal" trades, thus limiting their applicability in the electricity sector.

Recommendation: CEA calls on the federal government to expand the application of the tax credit for employers hiring an apprentice and the Apprenticeship Tax Grant included in the 2006 Federal Budget to reach a broader range of trades.

Apprentices are required to invest a significant amount of unpaid time and experience work interruptions during the term of their apprenticeship, which can last up to 5 years to complete. The concerns raised by the lost income can be a disincentive to potential apprentices, particularly for northern and Aboriginal students, and students from disadvantaged communities seeking pre-apprenticeship upgrading in order to qualify to apply for an apprenticeship. Depending on the type of apprenticeship and the jurisdiction in

which they live, some students may have to fund their own schooling and lose their qualification for Employment Insurance due to the timing or structuring of work placement hours. Such lost income can lead to lower participation and higher attrition rates. To ensure the successful completion of apprenticeship programs in order to develop a highly skilled Canadian workforce, the federal government must look at options to help defer the financial hardships faced by apprentices through changes to provisions in the Employment Insurance Act.

Recommendation: CEA encourages the federal government to modify provisions in the Employment Insurance Act that act as barriers to apprentices to earn income during the duration of the apprenticeship program.

### ii) Enabling Opportunity and Success

CEA shares the government of Canada's vision identified in *Advantage Canada* of creating opportunity and incentives for Canadians to succeed, excel and contribute to a strong and growing national economy. With the development of a new wave of infrastructure projects and the introduction of new technologies, the electricity industry is a significant contributor to Canada's *"Knowledge"* and *"Infrastructure" Advantage.*

However, the electricity sector's ability to meet the supply and demand challenge, build new infrastructure and integrate new technologies is dependant upon an adequate and skilled workforce. Trained and experienced workers are essential to ensure the long-term stability of Canada's electricity supply. Recognizing the significant human resource challenges facing the electricity sector, governments and industry must increase their efforts to address issues such as recruiting and retaining workers, facilitating school-to-work transitions and developing sector and career awareness strategies.

#### Raising Career Awareness

Increasing awareness of the career choices and opportunities available in the electricity sector is a critical factor in the industry's ability to attract Canadians in all communities and all jurisdictions. The federal government has an important role to play in improving labour market programming to help Canadians develop the skills they need and employers want.

Through its participation in the Electricity Sector Council, CEA is actively involved in efforts to increase career awareness in underrepresented communities as well as in the population at large. One such effort is the work currently underway to expand the reach of the successful "Trade Up" program developed jointly by Hydro One, Ontario Power Generation, Bruce Power and the Power Workers Union. Comprised of a comprehensive kit including a student guide, lesson plans, information on trades and hands-on learning activities, the "Trade Up" campaign promotes skilled trade careers in the electricity sector and encourages teachers, counselors, parents and students to consider apprenticeships as an option.

While the "Trade Up" program is a good example of a collaboration between industry and labour to raise career awareness in Ontario, campaigns such as this must be developed on a national scale and tailored to the needs and values of targeted communities.

Recommendation: In recognition of the critical role electricity plays in the economy and daily lives of Canadians, CEA calls on the federal government to provide financial support of Electricity Sector Council Program initiatives aimed at increasing career awareness in the electricity sector.

#### Occupational Standards and Certification Recognition

Currently, the standards defining trades and occupations within the electricity industry are not evenly recognized throughout the country. Differences regarding certification and the recognition of various positions in the sector, as well as non uniform trade names and job

descriptions act as barriers to workforce mobility within Canada and impede effective comparative work to support best practices in human resources management.

In *Advantage Canada*, the government of Canada has identified "facilitating workforce mobility" (p. 48) as a priority. CEA believes support of national occupational standards for the electricity sector is an important step in removing mobility barriers and improving opportunities.

CEA is encouraged by the federal government's support of the Electricity Sector Council's occupational standard project and encourages the government to continue its support in this area.

Recommendation: CEA calls on the federal government to maintain support to the Electricity Sector Council for the establishment of national occupational standards for the electricity industry.

**Ensuring a Workforce Aligned with the Needs of the Economy**

The capacity to accurately forecast labour market demand and workforce supply is a critical factor in the ability of all industries to respond to the needs of Canada's economy. Labour market information is particularly germane to the electricity sector which faces a host of adjustments in the coming years including pending retirements, rising demand, increased energy conservation, the introduction of new technologies and increased environmental regulation.

In this changing market environment, there is clearly a need for the government of Canada to work with the provinces, territories and the private sector to ensure training and skills development in the electricity sector are aligned with the needs of the economy. This will require governments to enhance labour market information available to Canadians.

As a first step, we commend the federal government's support of the Electricity Sector Council's *Electricity Industry Labour Market Information System* (LMIS) project. Through a three-year phased approach, this multi-layered project will conduct an industry level labour market assessment with sufficient specificity to measure and forecast current and future need for diverse groups and key occupations.

Through the continued support of initiatives such as the Electricity Sector Council's LMIS project, the federal government can help the electricity industry plan its workforce, analyze its needs, identify training requirements and mitigate business risk related to human capitol management. The resulting operational system will better equip the electricity industry to adjust and align its labour practices to support a thriving Canadian economy.

Recommendation: CEA encourages the federal government to continue to support initiatives to assist the electricity industry analyze and plan its workforce, identify training requirements, and mitigate business risk related to human capital management.

### iii) Attracting and Retaining Foreign Workers

In *Advantage Canada*, the federal government recognizes that slowing labour force growth and emerging skills shortage have created the need to introduce more workers into the labour force *(p. 49)*. Canadian utilities are increasingly turning to internationally trained workers to broaden their candidate pool and are developing programs to ensure their successful integration. For instance, BC Hydro actively recruits internationally trained professionals (ITP) in B.C. and supports these new hires in a number of ways including: creating intermediate opportunities that help ITPs gain Canadian experience; encouraging structured development plans (i.e. with formal mentoring); and linking ITPs with an internal support group

and other resources such as HR providers and the Hydro Employee Multicultural Society.

Attracting skilled workers to Canada is critical in addressing the electricity sector's human resource needs. Moreover, the federal government must examine ways to make it easier for foreign students and temporary workers to stay in Canada. Current barriers impeding foreign-trained workers from entering the workforce include inhibitive security clearances and visa restrictions, particularly in the areas of transmission and generation, and foreign credential recognition. Other obstacles include: poor advanced preparation prior to immigration; requirements for Canadian work experience; lack of recognition of prior work experience and qualifications, and lack of relevant language skills.

**Support for Qualification Programs**
Recognizing the contribution of foreign-trained workers to filling the labour gap in the electricity industry, Manitoba Hydro has been actively involved with the Internationally-Educated Engineers Qualification (IEEQ) Program at the University of Manitoba. This innovative program provides immigrants with engineering credentials obtained outside of Canada to meet part of the licensing requirements for professional engineering practice in Manitoba. This year, the IEEQ Team at Manitoba Hydro developed formal employment systems including bursary supports (two $1500 bursaries), up to six co-op opportunities and a career development program that supports one full-time opportunity per year. The team also actively promotes IEEQ graduates to line management for consideration for current complement vacancies.

The IEEQ model shows tremendous potential for assisting foreign-trained engineers and other workers on a national scale. By broadening the educational scope and expanding models such as IEEQ nationwide, the successful integration of immigrants in the electricity sector labour force would be significantly improved and employer needs would be better met.

Recommendation: CEA encourages the federal government to support the establishment of internationally-educated qualification programs in educational institutions throughout the country.

**Foreign Credential Recognition**
HRSDC's Foreign Credential Recognition program is an important component of the Internationally Trained Worker Initiative and should be enhanced to ensure processes are fair, appropriate and consistent. Of particular interest to the electricity industry is the continued support of programs such as the Canadian Council of Professional Engineers's initiative to develop and implement an action plan to more quickly and efficiently integrate international engineering graduates into the Canadian labour market.

Greater funding in the field of immigrant labour market integration is also needed to accelerate and improve foreign credentials evaluation in the country of origin, and improve linkages between stakeholders and jurisdictions.

Recommendation: CEA calls on the federal government to support the establishment of a comprehensive pre-qualification process for foreign-trained workers in their country of origin. This could be achieved through the development of a process based on the existing accreditation infrastructure developed by various unions in the electricity industry.

Recommendation: CEA calls on the federal government to examine ways to make it easier for foreign students and temporary workers to stay in Canada.

**Easing Visa Restrictions**
CEA believes that Citizenship and Immigration Canada should increase efforts to attract skilled workers to Canada through focused initiatives such as easing visa restrictions for low risk applicants who have a strong interest in work opportunities in Canadian trades.

Recommendation:
CEA encourages the federal government to increase efforts to attract skilled workers through easing visa restrictions for low risk applicants where there is a strong interest in work opportunities in Canadian trades.

**The Immigration Point System**
The Immigration Point System should also be better aligned with Canadian labour market information and should be amended to recognize the value of trade workers. The need for, and value of skilled trades people must be reflected in Canada's immigration system.

Recommendation: CEA calls on the federal government to better align the Immigration Point System with Canadian labour market information, and to recognize the value of trade workers within the Point System.

**Bridge to Work**
Enhanced funding is required for a national Bridge to Work program that can provide consistent, Canada-wide support to foreign trained workers, from pre-employment to successful workplace integration. Initiatives providing comprehensive career information aimed at foreign trained workers need to be encouraged and supported so that such workers understand the processes involved in order to successfully work in Canada in their field of choice.

Recommendation: CEA encourages the federal government to establish a comprehensive national Bridge to Work program to support foreign trained workers, from pre-employment to successful workplace integration.

## IV Conclusion

The electricity industry could face serious workforce challenges in the coming years and now is the time for industry and government to find solutions. CEA strongly believes the federal government has a leadership role in ensuring our electricity supply is in the hands of a skilled, adequate and internationally-competitive workforce.

In this brief CEA has explored various avenues where the electricity industry and the federal government, along with stakeholders and communities, can change the course of a potential labour shortage. Through its recommendations, the Association proposes a list of policy initiatives that will ensure the Canadian electricity industry can maintain and enhance its human and electricity potential.

CEA is prepared to develop detailed implementation plans and programs to operationalise any and all of the recommendations which HRSDC deems to be worth pursuing.

## Summary of Recommendations

### 1. Building a Canadian Skills Base

**Aboriginal Engagement**

- CEA encourages the federal government to support the creation of a comprehensive national strategy to engage, support and train Aboriginal peoples in the electricity sector.

**Enhancing Apprenticeships and Skills Training**

- CEA calls on the federal government to expand the application of the tax credit for employers hiring an apprentice and the Apprenticeship Tax Grant included in the 2006 Federal Budget to reach a broader range of trades.
- CEA encourages the federal government to modify provisions in the Employment Insurance Act that act as barriers to apprentices to earn income during the duration of the apprenticeship program.

### 2. Enabling Opportunity and Success

**Raising Career Awareness**

- In recognition of the critical role electricity plays in the economy and daily lives of Canadians, CEA calls on the federal government to provide financial support of Electricity Sector Council Program initiatives aimed at increasing career awareness in the electricity sector.

**Occupational Standards and Certification Recognition**

- CEA calls on the federal government to maintain support to the Electricity Sector Council for the establishment of national occupational standards for the electricity industry.

**Ensuring a Workforce Aligned with the Needs of the Economy**

- CEA encourages the federal government to continue to support initiatives to assist the electricity industry analyze and plan its workforce, identify training requirements, and mitigate business risk related to human capital management.

### 3. Attracting and Retaining Foreign Workers

**Support for Qualification Programs**

- CEA encourages the federal government to support the establishment of internationally-educated qualification programs in educational institutions throughout the country.

**Foreign Credential Recognition**

- CEA calls on the federal government to support the establishment of a comprehensive pre-qualification process for foreign-trained workers in their country of origin. This could be achieved through the development of a process based on the existing accreditation infrastructure developed by various unions in the electricity industry.
- CEA calls on the federal government to examine ways to make it easier for foreign students and temporary workers to stay in Canada.

**Easing Visa Restrictions**

- CEA encourages the federal government to increase efforts to attract skilled workers through easing visa restrictions for low-risk applicants where there is a strong interest in work opportunities in Canadian trades.

**The Immigration Point System**

- CEA calls on the federal government to better align the Immigration Point System with Canadian labour market information, and to recognize the value of trade workers within the Point System.

**Bridge to Work**

- CEA encourages the federal government to establish a comprehensive national Bridge to Work program to support foreign trained workers, from pre-employment to successful workplace integration.

**YUB-YECL-9**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 62600 Hydro Generation

**Quote**: Cost increase from 2005 to 2006 mainly due to a one-time catch-up of 1998 2006 water license fees. (Schedule 5.2, Line No. 5)

**Preamble**: The Board would like more detail.

**Request:**

(a) Please explain in respect of the cost increase from 2006 to 2007, what is meant by This increase is offset by a one-time catch-up in 2006 of 1998 to 2006 water license fees to the government ( 27) (Schedule 5.2, Line No. 8-9.)

(b) Please explain in respect of the cost increase from 2008 to 2009, what the additional inspections and type of inspections are to meet the requirements of the new water license.

**Response:**

(a) The Yukon Water Board advised Yukon Electrical in 2006, that due to a clerical error, Yukon Electrical had not been invoiced since 1998 for 2 water licenses. Correcting invoices from the Yukon Water Board were processed in 2006.

(b) The three year temporary water license renewal recommendations, as detailed in YUB-YECL-09 (b) Attachment 1 and the YUB-YECL-09 (b) Attachment 2-YESAB decision document 2007-0150. Based on the cumulative directives of these documents Yukon Electrical forecasts an increased focus on the operation of the Fish Lake Hydro facility. Some of the activities are listed below:

- Frequently inspect Louise Lake Containment dike year round.
- Install and monitor Piezometers at Louise Lake Dike.
- Investigate seepage near Ditch unit 1 overflow structure.

- Inspections of penstock unit 1 for corrosion.
- Inspect anchor points for penstock unit 1
- Inspect and clean spill basin at unit 2 head pond

It should be noted that there are a number of studies required as a condition of the relicensing process. However as a result of water flow and water level studies, the daily operating regime will change, requiring additional time.

Draft

Report to

Yukon Electric Company Limited
Whitehorse, Yukon

# Dam Safety Review

For

## Fish Lake Hydro

H-326604
Rev 1

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Prepared by: Joe Groeneveld, P. Eng. November 6, 2007
Date

Hatch Energy Approval

Approved by: Lance Bendiak, P.Eng November 6, 2007
Date

# Disclaimer

This report has been prepared by Hatch Ltd. for the sole and exclusive use of Yukon Electrical Company Limited (the "Client") for the purpose of assisting the management of the Client in making decisions with respect to the Fish Lake Hydroelectric Project; and shall not be (a) used for any other purpose, or (b) provided to, relied upon or used by any third party.

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# 1. Introduction

The Fish Lake Hydro development is located to the west of the city of Whitehorse, and includes the following components:

- Fish Lake control structure (including associated dikes)
- Control structures related to Jackson Creek interconnection
- Louise Lake Control structure
- Power Plant No. 1
- Power Plant No. 2

Earlier studies by Jacobson Engineering highlighted a number of concerns related to infrastructure containing the main reservoir for the development – Fish Lake. The report recommended that the main dike at the north end of the lake be upgraded (including upgrading of rip rap protection), and that an emergency spillway be constructed to minimize surcharge during the passage of large flood events. The purpose of the current study was to conduct a dam safety review of the major structures, with particular emphasis on the major water retaining structure formed by the Fish Lake control structures.

The safety assessment of a dam comprises an evaluation of the ability of a water retaining structure to withstand all forces that it could be expected to experience during its lifetime. For this purpose a number of criteria have been established to allow a systematic evaluation and classification of structures with respect to the potential failure risk it presents. These criteria have been derived from the most frequently observed types of dam failures and incorporate a classification system that addresses the following:

- hazard classification
- flood passage capability assessment
- dam break flooding assessment
- structural integrity and stability assessment.

The hazard classification of a dam is determined by the degree of exposure of developments located downstream of the dam, in terms of loss of life and flood damage in the event of dam failure. Based on this assessment an Incremental Hazard Potential (IHP) is determined and a corresponding Inflow Design Flood (IDF) is assigned. Incremental Hazard Potential is also referred to as Incremental Consequence Category (ICC). It must be reiterated that IHP is determined by the potential hazard that will occur in case of failure of the dam and not the magnitude of the flood event.

A spill structure is rated on the basis of its capacity and ability to respond to emergency flood conditions. These ratings are compared to the IHP and IDF requirements.

The objective of this review was to identify an appropriate hazard classification for each major water retaining component of the facility, and to assess any deficiencies related to the development's performance in passing the recommended Inflow Design Flood. The various minor components of the Fish Lake hydro development were also reviewed, but the review for these smaller structures was limited to a condition assessment similar to that performed in previous inspections. This report presents the results of this dam safety review.

## 2. General Description of the Fish Lake Hydro Facility

The Fish Lake hydro facility was built in 1948 with a Pelton impulse turbine/generator set (250kW) at Plant #1. In 1953 an additional Turgo Impulse turbine/generator set (700kW) was added to the extended Plant #1 building, and in the next year the Plant #2 with a Francis turbine/generator set (600kW) was also installed. Currently only the last two units are operational with a combined capacity of 1300 kW.

Layout of the Fish Lake hydro facility is shown on Figure 1. Spring and summer runoff from Fish Creek watershed is stored in Fish Lake - the primary storage reservoir, for winter release through a gated steel culvert. As the reservoir is getting full, part of inflow is released for summer generation. Fish Lake and the Plants #1 and #2 are interconnected by a combination of more than 6 miles of natural creek channels and manmade channels.

Part of the natural stream of Fish Creek, canal Ditch #3 and a concrete control structure connect Fish Lake with Louise Lake which serves as a secondary storage reservoir. Runoff from Bonus Creek is intercepted by a diversion dam and flow to Fish Creek to augment the flow volume.

From Louise Lake, water passes through another concrete control structure, canal Ditch #2, part of the Porter Creek and canal Ditch #1 to reach #1 Head Pond, where the concrete #1 Intake structure directed water into the #1 steel penstock that leads to #1 Power House. Only the newer second unit is operational in Plant #1. An overflow structure is located at upper end of Ditch #1.

A fish farming company – Icy Water Ltd. has added an intake structure at the north end of the Plant #1 discharge channel and diverts most of the tailwater for their operation. After going through the fish tanks, the diverted water is discharged back further downstream to West McIntyre Creek that leads to the #2 Head Pond. The remaining tailwater flows to the south and joins West McIntyre Creek. Water from Ditch #1 overflow structure and runoff not intercepted by the ditches are collected by Porter Creek where Icy Waters takes part of this water for their operation and discharges the water back to West McIntyre Creek further downstream.

A portion of West McIntyre Creek was blocked by a dam to form #2 Head Pond where #2 Intake structure and a spillway are located. #2 penstock is partly woodstave and partly steel. Tailwater from the unit in #2 Power House is discharged back to McIntyre Creek.

# 3. Project Hydrology

The purpose of the hydrologic analysis was to estimate peak flood flows and hydrographs for major flood events on the Fish Lake basin. The design flows were used for the flood routing and subsequent dam safety assessment analysis that is described later in Section 4. Since hydrological records at the dam are not complete, peak flows and hydrographs were estimated using regional statistical flood frequency analysis methods.

## 3.1 Climate

The Fish Lake basin is located in a sub arctic continental climate zone, and could be classified as semi-arid in nature. The climate is characterized by relatively large seasonal and daily fluctuations in temperature, and low to moderate precipitation amounts. Winters can be harsh and cold, and average annual snowfall within the basin is approximately 135 cm. Total rainfall in the basin averages approximately 155 mm, bringing the total annual average precipitation to approximately 265 mm.

As with any typical northern river system, streamflow within the basin is generated through the spring melt of winter snowpacks and rainfall which may occur during the spring, summer, and fall seasons.

## 3.2 Available Data

Data available for these hydrological studies consists of the following:

### 3.2.1 Meteorological Data

Although there are no precipitation stations located within the Fish Lake basin, a number of stations surround the basin, operated by the Meteorological Services of Canada (MSC). These stations are listed in Table 3.1 below.

**Table 3.1**
**Summary of MSC Meteorological Stations**

| Station | Years of Record | Average Annual Precipitation (mm) |
|---|---|---|
| Annie Lake Robinson | 1976 – 2002 | 236 |
| Carcross | 1907 – 2002 | 241 |
| Marsh Lake | 1994 – 2002 | 259 |
| Whitehorse A | 1942 – present | 265 |

### 3.2.2 Streamflow Data

Although daily water level records are available at the Fish Lake dam from 1996 onwards (shown in Figure 2), information on water releases through the structure was not available. Back calculation of the Fish Lake releases based on the available water level record would require continuous information on the gate setting for the control structure. Since this information was not available, it was necessary to construct flood inflow hydrographs based on the use of regional analysis techniques.

Historical discharge data was required for the regional flood assessment. Data was available for the Water Survey of Canada Gauging Stations listed in Table 3.2 below. The location of each of these stations is shown in Figure 3.

**Table 3.2**
**Summary of Water Survey of Canada Stations**

| Station | Years Available |
|---|---|
| Tagish Creek | 15 |
| Pine Creek | 15 |
| Watson River | 16 |
| M'Clintock River | 40 |
| Lubbock River | 40 |

## 3.3 Regional Flood Frequency Analysis

Historical records of Fish Lake flows are not available for use in determining flood frequency flows. For this reason a "regional flood frequency analysis" was required to estimate the Inflow Design Flood for the project.

In conducting a regional analysis, historical streamflow data which may exist for a number of gauged river basins in an area are used to establish an estimate of flood frequency for similar ungauged catchments. Typically a relationship will exist between drainage basin discharge or volume and drainage basin area for similar catchment types, and the purpose of this analysis was to estimate such a relationship for basins in this area.

Water Survey of Canada records were examined for stations which could be used in the analysis of Fish Lake flows. Five stations were identified in the immediate area which had suitable record length, and which displayed reasonably similar runoff characteristics. The drainage basins used in the regional analysis ranged in area from 57 $km^2$ to 1770 $km^2$. Table 3.3 lists the stations used for analysis.

**Table 3.3**
**Summary of Stations Used in Regional Analysis**

| No. | Station Description | Water Survey of Canada Gauge No. | Drainage Area ($km^2$) | Mean Annual Flow ($m^3/s$) |
|---|---|---|---|---|
| 1 | TAGISH CREEK | 09AA011 | 76.9 | 0.3 |
| 2 | PINE CREEK | 09AA008 | 697 | 5.1 |
| 3 | WATSON RIVER | 09AB009 | 1150 | 5.1 |
| 4 | M'CLINTOCK RIVER | 09AB008 | 1700 | 9.8 |
| 5 | LUBBOCK RIVER | 09AA007 | 1770 | 4.2 |

A volume based frequency analysis was conducted for each of the stations listed in Table 3.3. It was recognized early on that with the very large lake area associated with Fish Lake, it would be the volume of a potential flood event that would drive the most critical response on Fish Lake rather than the peak inflow rate. Furthermore, it was judged that critical flood events on the lake are likely the result of multiple events involving both snowmelt and rainfall, and that these events may be distributed over a significant time frame.

The procedures used in conducting the volume analysis were based on those recommended in USBR publication "Flood Hydrology". The basic steps undertaken consisted of the following.

- Each basin's flow records were analyzed to determine, for each water year, the flow volume observed for each open water season. For the purpose of this analysis, the open water season was defined as the period from May to October.
- Using the data generated in the above step, a statistical computer program was used to provide estimates of the annual flow volume over the summer period for the 1:2, 1:100 year, and 1:1000 year return periods.
- A logarithmic plot was then prepared for each return period comparing the open water flood volume with the drainage basin area of each gauge. An envelope line was then drawn on each plot, and this line was used to estimate flood potential for other catchment areas (e.g. Fish Lake). Figure 4 illustrates a sample plot prepared for the 100 year return period.
- The flood volume associated with each return period was then converted into a daily inflow hydrograph. This was done based on a review of watershed response observed at the Tagish Creek gauging station. The Tagish Creek gauge was selected as a proxy station for this analysis, since it is closest in size to that of Fish Creek, and it was judged that runoff patterns on the Fish Lake basin would be similar in nature. Therefore the historical flow record at Tagish Creek was reviewed, and three of the most severe runoff events were identified and plotted (see Figure 5). Of these three, the 1957 flow hydrograph was eventually selected as the critical runoff pattern to be used in transforming the summer flow volume for each event into daily flows. This was done by simply prorating the 1957 flow hydrograph until the May to October flow volume matched that of each of the 1:2, 1:100, and 1:1000 year flood volumes identified for the Fish Lake basin.

Figure 6 illustrates the final Fish Lake inflow hydrographs for the 1:2, 1:100, and 1:1000 year floods.

Estimates of peak flood inflow (due to local runoff) were also prepared for the Louise Lake dam, and also for the reservoir of Power plant No. 2. Potential flood flows for these smaller reservoirs were estimated taking into consideration the much smaller local drainage basin area associated with each, rainfall intensity curves for the area, the location of available overflow areas along the canal system into existing creeks and streams, and the properties of the local soils. Based on this analysis, it is estimated that peak inflows to the Louise Lake dam would be 4.1, and 10 $m^3/s$ respectively for the 1:2 and 1:100 year floods respectively. It is estimated that peak inflows to Headpond #2 would be 1.1, and 3.0 $m^3/s$ for the 1:2 and 1:100 year floods respectively. It should be noted that the above flows represent inflows in excess of the powerplant diversion flows which may be occurring at the time of the event.

# 4. Hazard Classification Assessment

The consequences of dam failure are assessed in terms of the incremental hazard posed by a dam structure, based on guidelines and procedures given in the Canadian Dam Association guidelines. The Hazard Potential Classification (HPC) can be defined as the potential for increase in loss of life, property damage, and disruption of social and economic activities caused by failure of the dam structure above that which would have occurred without failure of the dam.

The following steps were followed in establishing the Hazard Classification for the Fish Lake dam, the largest water retaining structure in the system:

- Development of a flood routing models
- Preliminary dambreak analysis and estimation of downstream impacts
- Selection of the consequence category.

Each of these is discussed in more detail below.

## 4.1 Development of Flood Routing Models

Two separate models were used in these analyses to i) assess the performance of the Fish Lake discharge facilities in passing a given flood event, and ii) roughly estimate the impacts should the dam ever fail. The two models selected and used were the:

- FLDRT Model. The FLDRT model is a proprietary Hatch program that is used to simulate the passage of a flood event through a specific development. Using supplied information on the inflow hydrograph, stage discharge hydrographs for all outlet structures (separate rating curves for each structure can be entered), and the stage storage relationship for the reservoir, the program will route a specific flood event through the system based on standard level pool routing techniques.
- HECRAS Hydrodynamic Program. The HECRAS model was set up and utilized to perform a simplified dambreak analysis in this study for the Fish Lake dam. This model is becoming an industry standard for performing such analyses, and contains many of the same features as it's predecessor, the National Weather Service dam break modeling program - DAMBRK. Given a set of user specified breach parameters for any structure, the model can be used to simulate the development of a breach in a dam, and then to route the resultant flood wave through a downstream reach. For Fish Lake, the model was setup to simulate passage of a dam break flood wave along a reach extending from the Fish Lake dam down to the Takhini River – the point at which it is estimated these breach flows would enter this much larger stream. Further details on the setup of the HECRAS model are provided in section 4.2 below.

Both models require the input of common key parameters, including the storage relationship of the upstream reservoir, and the discharge capacity of the dam's outlet facilities. The development of each of these is further discussed below.

### 4.1.1 Assessment of Discharge Capacity

**Fish Lake Dam**

The discharge facility at the Fish Lake dam consists of a single 0.86 m diameter gated culvert. This is the only formal discharge outlet for the lake. However, there is also a low section of the crest at the site of the access road to the to the east of the control structure. This low section is approximately 70 m in width, and would be the first section of the dam to overtop during a large flood event.

Discharge rating curves were derived for both the control structure and the dike overflow section. Available drawings, confirmed through site observations, were used to determine required parameters for this analysis.

The rating curve for the culvert control structure was developed based on standard culvert hydraulic theory, assuming it would act under inlet control. The invert for the culvert was estimated to be elev. 27.45 m (Local datum). The final rating curve for the outlet structure, assuming a fully open culvert, is shown in Figure 7.

Calculation of the flow over the dam crest at the overflow section was based on use of the general weir equation:

$$Q = CLH_e^{3/2}$$

Where,

C = discharge coefficient, based on weir shape
L = effective length of crest (m)
He = actual head being considered (m).

C was approximated to be a value of 1.6 (metric), and the weir was assigned a length of approximately 70 m based on recent crest surveys. The crest elevation of the overflow section was estimated to be elev. 30.75 m (local datum).

Figure 8 illustrates the discharge capacity of the overflow section. All numbers are with respect to local datum.

**Louise Lake Dam**

During times of flood, excess flow is released at Louise Lake through an emergency overflow spillway located on the west corner of the lake. The invert for this spillway is estimated to be at the Louise Lake FSL of 30.3 m, and the structure is 3.048 m wide. The spillway is capable of passing 3 $m^3/s$ with a 1 m surcharge to elev. 31.3 m, and 13.8 $m^3/s$ at incipient overtopping of the dam crest (estimated to be 32.3 m). This is close to the predicted inflow and no flood routing analyses were necessary.

**Headpond #2 Dam**

Spill flows at the Headpond #2 dam are released either through a 24 inch diameter low level outlet, or through an overflow spillway located along one bank of the reservoir. The overflow spillway consists of a 3.65 m wide chute, with an invert elevation of 796.44 m (0.6 m below the FSL elv. of 797.1 m). In the absence of flood, stoplogs are typically placed in the overflow structure to maintain the project FSL. It is estimated that the combined capacity of these two structures is approximately 5 $m^3/s$ at the project FSL assuming, the outlet is fully opened, and that all spillway stoplogs have been removed. With a 0.6 m surcharge, the combined capacity of the two outlets rises to 10.7 $m^3/s$. This is substantially larger than the predicted inflow and no flood routing analyses were necessary.

### 4.1.2 Stage/Storage Relationships

**Fish Lake**
At its normal supply level, the area of the Fish Lake reservoir is approximately 1386 ha. A stage storage curve was developed for the lake based on this estimate of lake area.

**Louise Lake**
At its normal supply level, the area of the Louise Lake reservoir is approximately 51.8 ha . The stage storage relationship for this lake was based on this lake area.

**Headpond No. 2**
At its normal supply level, the area of the Headpond #2 reservoir is approximately 4 ha. The stage storage relationship for this lake was based on this lake area.

## 4.2 Dambreak Analysis/Estimation of Impacts

**Fish Lake Dam**
To assist in assessing the potential damage which may result from a failure of the Fish Lake dam, a simplified dam break model was setup using the HEC-RAS hydrodynamic backwater model. The purpose of this analysis was to identify approximate flow and stage increases in the downstream channel should the dam fail. Storage information input to the model was based on the data summarized in section 4.1.2. Simplified cross sections were entered into the model to roughly represent the anticipated path of the flood flows in the downstream channel. It was judged that in the event of a breach, released flows would quickly exceed the capacity of Ditch 3, and would result in overtopping and breaching of the canal bank. The uncontrolled release would then return to the original watercourse of Fish Creek, would pass through Franklin Lake, into Jackson Creek, into the Ibex River, and would eventually discharge into the Takhini River some 35 km downstream of the Fish Lake dam. Figure 9 illustrates the expected path of the breach outflows. As a worst case scenario, it was assumed that a breach width of 15 m would form – this is roughly equivalent to 5 times the height of the dam at it's deepest point near to the control structure. Breach parameters were selected based on recommendations made by the Federal Energy and Regulatory Commission (FERC) in Table 1, Chapter II, of their 1993 publication. These guidelines suggest that the maximum breach width not exceed 5 times the breach height, that breach side slopes of 1H:1V be adopted, and that a formation time of 1 hour be utilized in the analysis.

The results of the analyses indicate flows as high as 190 $m^3/s$ may be released by the breaching dam into the downstream channel. Figure 10 illustrates the approximate discharge hydrograph immediately downstream of the dam site, and also for locations 8 km (approximate location of Franklin Lake) and 35 km downstream of the dam. As shown, because of the relatively steep nature of the downstream channel, and the large volume of water being supplied by Fish Lake, the peak does not attenuate appreciably in magnitude with distance downstream of the dam. This preliminary run indicates that initial stage increases may approach 2 m downstream of the dam, and that similar increases are possible at other downstream locations.

To assess potential loss of life should the dam fail, 1:50,000 scale topographic maps were studied to identify any susceptible development in downstream areas. The maps indicate that there is little development along the downstream water course that could be impacted. There are no permanent residences, and impacts would be limited to possible day users of Franklin Lake, or users of any trails located along the downstream water course. Based on the level of detail shown on the current mapping, it is not possible to tell how near to the stream these

trails are, but any users would have ample warning of the increasing flows, and would be able to stay clear of the stream during such an event. Therefore, the risk for loss of life to occur is considered to be low.

Recreational use of the upstream lake would be impacted, and there may be a short term impact on the lake fish population due to the uncontrolled lowering of lake levels. Economic losses would include property damage related to breach failure (the costs to rebuild the dam and canal itself), and the loss in generation incurred by the utility until the dam and canal can be rebuilt.

It should be noted that the above represents a worst case breach scenario. Should a breach occur during a major flood, it is more likely that the dam would breach along the roadway access section, where the dyke is shallow (approximately 1 m high). The crest elevation of this section of the dam is lower than other sections of the embankment, and would be the first to overtop. Should the breach occur here, uncontrolled outflows to downstream areas would be considerably smaller, and impacts would be reduced accordingly.

**Louise Lake Dam**

In the event that the main embankment at the Louise Lake dam were to breach, the reservoir would be released to flow through the spillway discharge channel, back towards Franklin Lake, into Jackson Creek, and from there would follow a path identical to that described above for the Fish Lake breach. Given the limited storage area of the reservoir however, breach flows would peak and quickly begin to dissipate as the overall head (and water volume) in the reservoir drops.

Although dambreak runs were not performed for this case, it is expected that the impacts on downstream areas would be significantly reduced from those described above for the Fish Lake breach. Breach flood flows would dissipate relatively quickly with time and distance downstream of the dam. Given the remote area of the site, it is expected that the potential for loss of life to occur would be low. Likewise, damage estimates would be limited to the costs to rebuild the dam, and any lost generation incurred by the utility until the dam can be rebuilt.

**Headpond #2 Dam**

In the event that the main embankment at the Headpond #2 dam were to breach, the reservoir would be released into a tributary to McIntyre Creek which would eventually join with the main stem of the creek approximately 500 m downstream of the dam. From this point, breach flows would follow the natural course of McIntyre Creek, and flow for a distance of 6 km before discharging into the Yukon River. Based on existing 1:50,000 scale mapping, and satellite imagery of the area, there is little permanent infrastructure downstream of the dam that would be impacted. Breach flows would cross the Alaska Highway approximately 2.5 km downstream of the dam, and may temporarily flood two secondary road crossings located near to the Yukon River (depending on the size of the roadway culverts). However, given the limited storage area of the reservoir, breach flows would peak and quickly begin to fade as the overall head (and water volume) in the reservoir drops.

Although dambreak runs were not performed for this case, it is expected that the impacts on downstream areas would be minimal. Breach flood flows would dissipate relatively quickly with time and distance downstream of the dam and it is expected that the potential for loss of life to occur would be low. Likewise, damage estimates would include costs to rebuild the dam, repair any damage to downstream streamflow crossings, and any lost generation incurred by the utility until the dam can be rebuilt.

## 4.3 Selection of Consequence Category

The consequence classification for the Fish Lake structures was selected based on the 2007 Dam Safety Guidelines, and the impacts of failure discussed in section 4.2. Table 4.1 summarizes the CDA selection criteria.

**Table 4.1**
**CDA Dam Classification Criteria**

| Dam Class | Population at Risk (note 1) | Incremental Losses | | |
|---|---|---|---|---|
| | | Loss of Life (note 2) | Environmental and Cultural Values | Infrastructure and Economics |
| Low | None | 0 | Minimal short term loss<br>No long term loss | Low economic losses; area contains limited infrastructure or services |
| Significant | Temporary | Unspecified | No significant loss or deterioration of fish or wildlife habitat<br><br>Loss of marginal habitat only<br>Restoration or compensation in kind highly possible | Losses to recreational facilities, seasonal workplaces, and infrequently used transportation routes |
| High | Permanent | 10 or fewer | Significant loss or deterioration of important fish or wildlife habitat<br><br>Restoration or compensation in kind highly possible | High economic losses affecting infrastructure, public transportation, and commercial facilities |
| Very High | Permanent | 100 or fewer | Significant loss or deterioration of critical fish or wildlife habitat<br><br>Restoration or compensation in kind possible but impractical | Very high economic losses affecting important infrastructure or services (e.g. highway, industrial facility, storage facilities for dangerous substances) |
| Extreme | Permanent | More than 100 | Major loss of critical fish or wildlife habitat<br><br>Restoration or compensation in kind impossible | Extreme losses affecting critical infrastructure or services (e.g. hospitals, major industrial complex, major storage facilities for dangerous substances) |

**Note 1**: Definitions for population at risk:

**None** – There is no identifiable population at risk, so there is no possibility of loss of life other than through unforeseeable misadventure

**Temporary** – People are only temporarily in the dam breach inundation zone (e.g. seasonal cottage use, passing through on transportation routes, participating in recreational activities)

**Permanent** – The population at risk is ordinarily located in the dam breach inundation zone (e.g. as permanent residents); three consequence classes (high, very high, and extreme) are proposed to allow for more detailed estimates of potential loss of life to assist in decision making if the appropriate analysis is carried out)

**Note 2.** Implication for loss of life:

> **Unspecified** – The appropriate level of safety required at a dam where people are temporarily at risk depends on the number of people, the exposure time, the nature of their activity, and other conditions. A higher class could be appropriate, depending on the requirements. However the design flood requirement, for example, might not be higher if the temporary population is not likely to be present during the flood season.

Based on a review of these criteria, it is recommended that the consequence classification for all of the Fish Lake structures (i.e. Fish Lake Dam, Louise Lake Dam, and Headpond #2) be selected as LOW. There is very little risk to loss of life should any of the structures fail, and third party economic losses would also be low. Although there may be some temporary loss of fish habitat, these structures would likely be rebuilt quickly, minimizing overall impacts on the upstream lake fishery.

# 5. IDF Selection and Review of IDF Passage

## 5.1 Inflow Design Flood Selection

The Inflow Design Flood (IDF) for the Fish Lake structures were selected based on recommendations contained in Table 6-1 of the 2007 CDA guidelines. This table's recommendations are reproduced in Table 5.1 below.

**Table 5.1**
**Recommended Inflow Design Flood (IDF)**

| Dam Classification | Recommended IDF |
|---|---|
| Low | 100 year flood |
| Significant | Between 100 and 1000 year flood |
| High | 1/3 between 1:1000 year flood and PMF |
| Very High | 2/3 between 1:1000 year flood and PMF |
| Extreme | PMF |

Based on the Hazard Classification selected for the Fish Lake structures (LOW), it is recommended that the 1:100 year flood be selected as the project's IDF.

## 5.2 Capability of Project to Pass Inflow Design Flood

**Fish Lake Dam**
The main structures of the Fish Lake Dam must be capable of safely passing an IDF equivalent to the 100 year flood event for the site. The recommended IDF hydrograph is summarized in Figure 11.

In routing the flood hydrograph through Fish Lake, the following operational assumptions were made:

- At the start of the flood event, it was assumed that the lake would initially be at an elevation of 29.5 m local datum. This represents a drawdown of approximately 0.5 m from FSL ( elev. 30 m). It was judged, based on a review of the hydrological response of gauged stations, that major flood events on these northern basins would involve both melt of the winter snowpack as well as spring or early summer rainfall. Therefore, the critical event would likely begin in the early spring – a time when the Fish Lake reservoir would be at it's lowest point in the annual cycle.
- It was assumed that Fish Lake outflows would initially be limited to a riparian flow release of 0.15 $m^3/s$. Local runoff between the Fish Lake site and the downstream powerplants would likely provide sufficient water for these units during the early part of the spring freshet, and therefore it was considered possible that flow releases would not be high initially.
- It was assumed that once the reservoir reached the FSL of 30.0 m, that the outlet control structure would be fully opened, releasing discharges approaching and eventually exceeding 2 $m^3/s$. We understand that a release of this magnitude may exceed the current capacity of the downstream diversion channel (Ditch #3). However, it was assumed that in such an emergency, the safety of the dam would take priority over that of the downstream canal.
- It was also assumed that a natural overflow area would continue be maintained at the location of the existing access road, to the east of the main dam. This overflow area would begin to be mobilized once the water level exceeded elev. 30.75 m.

Figure 12 illustrates the resulting inflow and outflow hydrograph for the Fish Lake Dam during passage of the IDF under this operational scenario. Figure 13 illustrates the resulting lake level. As shown, the peak water level reached on Fish Lake during passage of the IDF is elev. 30.74 m. The peak outflow from the lake is 2.4 $m^3/s$. It should be noted that all of this flow would be released from the outlet structure, and that although the water level would rise to the point of overtopping the overflow section, it would not actually flow over the crest of the dam at this location. Freeboard requirements for the dam during passage of the IDF are discussed in the following section.

**Louise Lake Dam**

The main structures at the Louise Lake dam must be capable of passing the 1:100 year flood event, which is estimated to have a peak inflow of 10 $m^3/s$. In passing this event, it is assumed that:

- Louise Lake would initially be at it's FSL of 30.3 m
- The settings of the control structure releasing water into Ditch no. 2 would be unchanged, and therefore releases through this structure would continue to equal the original inflow to the lake through Ditch 3.
- Inflows to Louise Lake through Ditch 3 would be limited to the overall canal capacity of Ditch 3, and may in fact drop to nothing if the canal bank were to breach in any area, or if the Ditch 3 control structure gate were used to control inflows.
- All water would be released through the emergency spillway overflow, or stored within the reservoir.

In assessing the capability of the Louise Lake structure to pass this event, it is noted that the capacity of the overflow structure is approximately 10 $m^3/s$ when the lake is surcharged to a level of 31.9 m. This would represent the maximum stage the lake may rise to, discounting any routing effects within the lake. Therefore it is a conservative estimate of surcharge and the existing outlet capacity is adequate.

**Headpond #2**

The main structures at Headpond #2 must be capable of passing the 1:100 year flood event, which is estimated to have a peak inflow of 3 $m^3/s$ (on top of initial diversion flows being passed through Ditch 2). In passing this event, it is assumed that:

- Headpond #2 would initially be at it's FSL of 797.05 m
- The low level outlet was operational and could be mobilized as required to pass these flood flows.
- Stoplogs could be removed from the emergency bypass spillway as required to mobilize capacity.
- Initial discharges to the Power plant through Ditch 2 would be near long term averages (approximately 1.1 $m^3/s$.
- Power plant 2 was not operating.

In assessing the capability of the Headpond #2 outlet facilities to pass this event, it is noted that the combined capacity of the outlet and emergency spillway is approximately 10.7 $m^3/s$ when the lake is surcharged by 0.6 m to a level of 797.65 m. This is far in excess of expected flood inflows. In fact, with everything operational, the structures can pass the flood event without surcharge above the FSL. If the stoplogs are not removed from the bypass spillway, surcharge on the upstream reservoir may reach 0.6 m above FSL (796.65 m).

## 5.3 Freeboard Analyses

Calculations were also undertaken to estimate freeboard allowances at the Fish Lake dam. These allowances have been estimated based on recommendations contained within the 2007 CDA guidelines. The CDA guidelines recommend that freeboard at a facility be sufficient to contain wind and wave effects on the upstream reservoir for the following two conditions:

- With the reservoir at its normal full supply level, any embankment crest elevation must be sufficiently high to prevent overtopping by 95 % of wind generated waves for a wind event with an Annual Exceedance Probability (AEP) of 1 in 1000 years
- With the reservoir at its maximum surcharge level during passage of the IDF (1:100 year flood for the Fish Lake Dam), any embankment crest elevations must be sufficiently high to prevent overtopping by 95 % of wind generated waves for a wind event with an AEP of between 1:2 and 1:100 years

Regarding the latter requirement, the CDA guidelines recommend adoption of a coincident 1:100 year wind during passage of the IDF for LOW consequence dams.

To assess freeboard requirements for the Fish Lake dam, hourly wind speed data was obtained for the Meteorological Services of Canada (MSC) station located at Whitehorse. This station is in close proximity to the Fish Lake Dam and therefore was used for estimates of wind speed. The AES program DSWind was used to process wind speed return periods. This was done by grouping the data according to direction and fitting it to a Gumbel distribution. The fitted model was then used to derive wind speeds for each return period of interest. The wind speeds used in this study were then increased according to standard procedures to reflect an "over water" condition.

Fetch lengths for the dam were estimated based on existing 1:50,000 topographic mapping of the reservoir. These estimates were made based on procedures recommended within the USACE Shore Protection Manual. Lake depths for Fish Lake were estimated using available bathymetric charts (See Figure 14). Due to the orientation of the reservoir, it was found that the critical wind direction for the Fish Lake Dam is from the South. The critical orientation for Louise Lake is from the North East, whereas the critical orientation for Headpond #2 is from the South West.

As shown in Figure 14, the reservoir depths within Fish Lake in the area immediately upstream of the dam are less than 5 m. This was confirmed during the recent site inspections and dike surveys. Observations gathered during these activities indicated the level of the approach to be approximately elev. 27.5 m in front of the control structure. In other more western sections of the dam, the apron is shallower as evidenced in Figure 15. The shallow nature of the approach in this area is demonstrated by the small shrubs seen growing within the reservoir some distance upstream of the dike. The water depth over the shelf fronting western sections of the dam was estimated to be approximately 1 m at the time of the inspection. The inspection was held on June 5th, and the water level on Fish Lake at that time was estimated to be 29.8 m (local datum). Therefore the invert elevation of the upstream apron is estimated to be approximately 28.8 m in these areas.

This shallow shelf can have a significant effect on wave runup, as it will cause larger waves to break prior to reaching the dike face. This will reduce the effective runup on the dike, as much of the wave's energy will be dissipated on this shallow foreshore prior to reaching the dike's side slope. Therefore runup was calculated for westernmost sections of the dam separately from those calculations undertaken for eastern sections:

- Eastern Sections - without the upstream apron. For these deeper regions, is was assumed that waves are able to propagate right up to the embankment slope before breaking.

- Western Sections - with the upstream apron. For western regions, it was assumed that the upstream apron extends upstream of the dam for a distance of 10 m, and is at elevation 28.8 m.

It was also assumed that in the absence of flood, the Fish Lake reservoir would normally be at or below elev. 30.0 m, and this level was adopted as the FSL for this analysis. In passing the IDF for this project, it is estimated that the reservoir could surcharge to elev. 30.74 m.

The upstream slope of each dike was set to 3H:1V based on proposed construction drawings. Figure 16 illustrates a typical cross section of the Fish Lake dyke as published earlier by Jacobson Engineering. Past surveys of the dike indicate the existing crest elevation varies along its length, from a high of 31.5 m near the center of the structure, to a low of 30.75 m near the east abutment.

The results of the analysis for Fish lake are summarized in Tables 5.2 and 5.3.

**Table 5.2**
**Summary of Freeboard Requirements – Extreme Wind**

| Condition | Reservoir Level (m) | Wind Event | Setup (m) | Runup (m) | Total (m) | Maximum Uprush Elev. (m) | Remaining Freeboard (Based on minimum crest elev. of 30.75 m) (m) |
|---|---|---|---|---|---|---|---|
| Eastern Areas Without Apron | 30.0 | 1:1000 yr | 0.04 | 0.69 | 0.73 | 30.73 | 0.02 |
| Western Areas With Apron | 30.0 | 1:1000 yr | 0.04 | 0.24 | 0.28 | 30.28 | 0.47 |

**Table 5.3**
**Summary of Freeboard Requirements – IDF Passage**

| Condition | Reservoir Level (m) | Wind Event | Setup (m) | Runup (m) | Total (m) | Maximum Uprush Elev. (m) | Remaining Freeboard (Based on minimum crest elev. of 30.75 m) (m) |
|---|---|---|---|---|---|---|---|
| Eastern Areas Without Apron | 30.74** | 1:100 yr | 0.03 | 0.58 | 0.61 | 31.35 | -0.60 |
| Western Areas With Apron | 30.74** | 1:100 yr | 0.03 | 0.58* | 0.61 | 31.35 | -0.60 |

* Waves do not break on the apron.
** Maximum water level during passage of IDF.

In reviewing these results, existing freeboard allowances appear to be sufficient under normal operating conditions, but may be deficient under flood passage conditions by up to 0.60 m.

The results of the analysis for Louise Lake are summarized in Tables 5.4.

**Table 5.4**
**Summary of Freeboard Requirements – Louise Lake**

| Condition | Reservoir Level (m) | Wind Event | Setup (m) | Runup (m) | Total (m) | Maximum Uprush Elev. (m) | Remaining Freeboard (Based on minimum crest elev. of 32.3 m) (m) |
|---|---|---|---|---|---|---|---|
| Normal Operating Condition | 30.3 | 1:1000 yr | 0.01 | 0.53 | 0.54 | 30.84 | 1.46 |
| IDF Passage | 31.9 | 1:100 yr | 0.00 | 0.44 | 0.44 | 32.34 | -0.04 |

In reviewing these results, existing freeboard allowances appear to be sufficient under normal operating conditions and under IDF passage.

The results of the analysis for the Headpond #2 Dam are summarized in Tables 5.5.

**Table 5.5**
**Summary of Freeboard Requirements – Headpond #2**

| Condition | Reservoir Level (m) | Wind Event | Setup (m) | Runup (m) | Total (m) | Maximum Uprush Elev. (m) | Remaining Freeboard (Based on minimum crest elev. of 797.97 m) (m) |
|---|---|---|---|---|---|---|---|
| Normal Operating Condition | 797.05 | 1:1000 yr | 0.00 | 0.16 | 0.16 | 797.21 | 0.76 |
| IDF Passage | 797.65 | 1:100 yr | 0.00 | 0.14 | 0.14 | 797.79 | 0.18 |

In reviewing these results, existing freeboard allowances appear to be sufficient under normal operating conditions and under IDF passage.

## 5.4 Recommended Full Supply Level

The currently proposed FSL for the Fish Lake reservoir is elev. 30 m (local datum). At this level, freeboard allowances on the existing structures are sufficient to contain wind and wave effects caused by a 1:1000 year wind event. However, in order to provide adequate protection during the passage of the project IDF, the dam crest must be raised by 0.6 m, to a level of approximately 31.4 m.

As a large flood event on Fish Lake is a relatively slow occurring event (over several weeks), we recommend a contingency plan to address the deficiency in freeboard on Fish Lake dam be developed by Yukon Electric Company Limited until the dam heightening is implemented. One possible alternative to consider is stockpiling sandbags which can be placed on the dam crest as required to maintain freeboard.

It should be noted that it would be possible to operate at a higher FSL, but this would require an additional increase in the dam crest elevation. For example, if the dam crest were raised to elev. 31.9 m, as proposed in the Jacobson engineering study, the FSL for the project could conceivably be raised by 0.5 m to elev. 30.5 m. The optimization of the FSL for the project is the subject of a second study currently being conducted by Hatch Energy.

# 6. Structure Inspections – Fish Lake to Plant #2

Lance Bendiak and Paul Oblander (Hatch Ltd.), accompanied by Brock Coulthard (Yukon Electrical Company Limited), inspected the Fish Lake Hydro Facility on June 5, 2007. The weather was dry and warm (about 10 to 15°C). The purpose of the inspection was to update the 2005 inspection report of the hydro facility structures as required by the Yukon Territory Water Board.

The 2005 inspection report has been used as a basis for this report. Prior to the site inspection an inspection of available drawings for the facilities were reviewed. Other detailed files were not reviewed.

Most of structures within the system appeared to be in good or reasonable operation condition. Due to a lack of original design and construction information, investigation and monitoring are recommended for certain structures; while maintenance is required on some specific structures. Please see detailed comments on individual structures below.

## 6.1 Fish Lake Dyke

### *6.1.1 General Description*

The dyke is about 600 m (2000 ft) long with a height between 1.8 m (6.1 ft) to 2.7 m (8.7 ft) above the foundation level, and the crest width varies between 2.5 m (8.2 ft) to 10 m (32.8 ft). The upstream side of the dyke has some angular riprap but is badly eroded by wave action and has resulted in a steep face; while the downstream side has an approximate slope of 2H:1V (See photos 1 to 4). We understand that planning and design for upgrading the dyke has been completed by YECL.

There is no drawing available showing original cross section and what the dyke was constructed of. Three boreholes drilled in January 2003, found the dyke material to be mainly angular to sub-angular gravely and sandy till with 15 to 20% of fines. The foundation materials are between sands and sandy gravely till with 18 to 35% fines. Bedrock was probably between 4.0 m (13 ft) to 5.5 m (18 ft) below base of the dyke. Based on the granular nature of the dyke fill and foundation materials, there is seepage of water during high water level, as exemplified by existence of the wet swamp area downstream from dyke toe and beyond. Insufficient freeboard was also an issue during high lake levels but this is addressed in the previous sections of this report.



Photo 1 – U/S Face of Dyke



Photo 2 - Riprap



Photo 3 – D/S of Dyke



Photo 4 – Dyke Crest

The lake water level is regulated by a gated 900 mm (36 in) corrugated steel culvert (about 14 m (46 ft) long and at 1.1% gradient) that is located at middle of the dyke. The dyke upstream face around the culvert is protected by stoned fill gabion mattresses. A removable trash screen and walkway are supported by a steel frame at upstream end of the culvert. A staff gauge attached to east leg of the steel frame is regularly used to monitor the lake level. The control gate is housed in a vertical corrugated steel shaft protected by an insulated steel box. Flow capacity of this culvert is discussed in previous sections of this report. The original 1950 regulating gate was a timber structure and it is not clear when this structure was replaced by the gated culvert. (See photos 5 and 6)



Photo 5 – U/S Gatewell



Photo 6 – D/S Gatewell

One of the 1950 drawings show there was an outlet at the west end of the dyke to spill excess inflow back to Fish Creek. This outlet can no longer be found. There are low areas at both ends of the dyke that serve as emergency spillways. These low areas are not protected for washout but should spilling occur would relatively safely release large floods downstream to Fish Creek.

### 6.1.2 Recommendation

It is recommended at the following be carried out:

a. Previously planned construction to add riprap, to increase width and height of the dyke and to add an emergency spillway should be updated and completed.
b. Inspect the gated culvert control structure for remaining service life and carry out replacement or life extension (corrosion protection) as required.
c. Extend the staff gauge to the new dyke crest level, and check the staff gauge against a known stable bench mark for elevation.
d. Cut existing trees and shrubs that are growing on the existing dyke, and cut regularly to prevent trees and shrubs from growing on the new dyke.

## 6.2 Fish Creek

### 6.2.1 General Description

Fish Creek was not inspected, except the area close to the Fish Lake dyke.

Downstream of the Fish Lake dyke, the lower end of the control culvert discharge releases water into the natural Fish Creek which is a shallow stream with sand and gravel bed. The area next to the dyke toe is swampy and is full of willows. The valley floor has a very gentle slope toward the Creek. It is expected that most of the leakage through the dyke and foundation will end up in this creek within a kilometre from the dyke. Thus the seepage water is not lost but is still being collected by the system for generation.

Some 5 km (3 miles) from the Fish Lake the flow is directed into a canal known as Ditch #3. Fish Creek drops more than 60 m (200 ft) in elevation between the lake and Ditch #3. Most of this drop occurs within last 1.5 km (1 mile) of the creek where the creek bed is lined with cobbles and boulders that characterizes a fast moving stream.

### 6.2.2 Recommendation

No recommendations.

## 6.3 Bonus Creek Diversion Dam

### 6.3.1 General Description

This small gravel and earth fill dam diverts the flow from Bonus Creek towards Fish Creek to augment total flow to the system. Due to problems of access, this structure was not inspected. There is no drawing available for this dam.

### 6.3.2 Recommendation

It is recommended at the following be carried out:

a) Locate and document condition of this structure.

## 6.4 Ditch #3 Diversion Structure

### *6.4.1 General Description*

At the upstream end of Ditch #3, the timber Ditch #3 Diversion Structure used to release excessive water to Franklin Lake was removed in spring 2003 and the gap plugged by extension of the Ditch #3 embankment. This structure was not inspected.

### *6.4.2 Recommendation*

No recommendations.

## 6.5 Ditch #3

### *6.5.1 General Description*

Ditch #3 is an approximate 1,300 m (4,300 ft) long cut and fill canal in sandy gravely till that diverts water from Fish Creek towards Louise Lake. Over the length, the ditch drops only 2.1 m (7 ft) in elevation. Typical ditch bottom design width was 1.2 m (4 ft) with 1:1 slope at all faces. Typical minimum cut was 1.8 m (6 ft) while the embankment fill height at the canal side is only about 0.6 m (2 ft). The fill embankment has a 4.3 m (14 ft) wide crest roadway (see drawing dated Dec.20, 1948).

The lower one third of the fill embankment was walked and the toe intermittently inspected for sign of spring. The toe was dry with no sign of wetness. Trees and shrubs are growing on both downstream face and the crest and occasionally on the upstream face. Due to the steep design slopes, undercutting by erosion has occurred and the ditch bottom is a lot wider than 1.2 m (4 ft) (around 2.4 m (8 ft) average) and probably higher than the design elevation due to sedimentation.



Photo 7 – Canal Bank



Photo 8 – Canal Crest

In the spring of 2001, a section of the ditch embankment about 120 m (400 ft) from downstream end failed. The cause of failure is believed to be due to excessive inflow to the ditch prior to the drop structure gate being raised, and the excessive inflow subsequently overtopped the failed section that has the lowest crest elevation. Sandy gravely till was used for the repair, the new embankment is about 4.5 m (15 ft) high at the downstream end with 1:2 slopes and a 4.0 m (13 ft) wide berm at bottom 1/3 of the height. No wet spot could be found at the toe area (See photos 7 and 8).

### *6.5.2 Recommendation*

It is recommended that the following be carried out:

a. Cut all existing trees and shrubs on crest and upstream/downstream faces of the embankment.

## 6.6 Ditch #3 Drop Structure and Control Gate

### *6.6.1 General Description*

At end of Ditch #3, there is a concrete flip bucket Drop Structure with timber Control Gate (see drawing YECL-1 Rev.3, dated Jun 27, 1989). This structure dissipates energy and drops the water from Ditch #3 down 5.0 m (16.5 ft) to a short canal that connects to Louise Lake. The structure is in good operation condition, except that there is slight undercutting at bottom of left wall (west side) close to the flip bucket where velocity is high (See photos 9 and 10). In winter, gate will be installed at this drop structure to choke down the flow and increase water level in Ditch #3 so that formation of frazil ice is greatly reduced by slower flow velocity and ice sheet cover at top of water.



Photo 9 – Inlet



Photo 10 – Outlet

### 6.6.2 Recommendation

It is recommended that the following be carried out:

a. Since the Ditch #3 Diversion Structure has been removed, controlling the gate at the Ditch #3 Drop structure to limit rise of water level within the Ditch #3 during spring thaw period became more important than ever. Monitoring of inflow to Ditch #3 in spring has to be carried out as often as required.

## 6.7 Louise Lake Containment Dyke

### 6.7.1 General Description

The secondary storage reservoir in the system is Louise Lake (also known as Jackson Lake) which is actually two lakes jointed by a short creek. At southerly end of Louise Lake there is about a 150 m (490 ft) long and 7.3 m (24 ft) high earth and rock fill structure that has no drawing available in the files. This is the highest structure in the whole Fish Lake Hydro system. (See photos 11 and 12).

From survey, the dyke is about 7.3 m (24 ft) high and has a 1.7:1 slope on both slope faces. Lake water level was about 2.0 m (6.5 ft) below the dyke crest. The dyke appeared to be stable, and although it has only gravel/cobbles on the upstream face there was no sign of wave erosion. Shallow digging confirmed that upper portion of the dyke at both faces have sand and rounded gravel fill. At downstream toe, the face is covered with rounded to sub-rounded cobbles and small boulders which were not that stable for walking because of the steep slope.



Photo 11 – D/S slope



Photo 12 – Crest of Dam



Photo 13 – D/S toe



Photo 14 – Seepage

Toe of the dyke is covered by a pond that had water depth of 0.9 m (3 ft) to 1.5 m (5 ft). The shore line of the pond suggested that the high pond water level would be 1.5 m (5 ft) higher than observed, and there is no outlet for this pond. Above the pond level some areas of dyke toe and the original ground in general had grass that thrives in wet environment. At left junction (south side) between abutment and the dyke, there is a small spring emerging from the cobbles about 0.9 m (3 ft) above the pond level. It appeared the pond was being partly fed by this spring and seepage through the dyke/abutments and foundation. Sand and gravel with some fines (till) were confirmed by shallow digging at right abutment.

### *6.7.2 Recommendation*

It is recommended that the following be carried out:

a. Carry out a geotechnical investigation to confirm the dyke fill and foundation materials and then analyse seepage and slope stability of the dyke.
b. Install piezometers in the dyke, foundation and abutments to monitoring seepage conditions.
c. Also carry out topographic survey of the dyke.
d. Frequently inspect this dyke to note seepage conditions (this includes winter when seepage emerge point generally will move higher).

## 6.8 Louise Lake Emergency Dyke and Timber Control Structure

### *6.8.1 General Description*

This is a 3.0 m (10 ft) high earth fill dyke that includes a 1.2 m (4 ft) deep cut-off trench. The dyke was originally to be 3.7 m (12 ft) wide at crest, but was built about two times the design width (see drawing dated Dec.20, 1948).

The control structure was re-built with pressure treated timber in 1990. The structure is 3.0 m (10 ft) wide and 2.0 m (6.6 ft) height with cut-off wall at both ends and middle. Stop logs can be inserted at steel guides at upstream end to control lake level (see as-built drawing YECL-3 Rev. 1, dated Nov.27, 1990).
This structure is in good condition.



Photo 15 – Control Structure


Photo 16 – Dyke & Structure

### *6.8.2 Recommendation*

No recommendations.

## 6.9 Louise Lake Outlet Structure

### *6.9.1 General Description*

This structure is actually located at about mid-length of Ditch #2. The original timber outlet structure was replaced by a concrete structure in 1958 (see drawings 3821-A, dated Oct.10, 1960; drawing 3821-B, dated Sept.13 1960, and drawing 3821-C, dated March 5, 1958). The structure has an opening 3.7 m (12 ft) in height and 1.4 m (4.5 ft) in width. There are 5.5 m (18 ft) long upstream wing walls on each side and 4.9 m (16 ft) long "L" shaped downstream wing walls. The timber control gate is supported by four concrete beams bridging across the opening. Water is released from below the gate, and goes into a concrete stilling basin before discharge to the riprap lined apron. Minimum 0.8 m (2.6 ft) length of creosoted timber sheet piles driven into the ground were used as cut-off under the upstream wing walls and there are three lines of cut-off under the main outlet structure slab.

The structure appeared to be functioning properly. Due to age of the concrete, there are considerable freeze and thaw damage and spalling is occurring at water line at upstream south corners and downstream splash zone. The lowest cross beam has vegetation growing on it. There is some bank erosion at end of downstream wing wall at right hand (south) side, and is reducing the seepage path from the upstream wing wall. (See photos 17 to 20).

Remains of the old timber structure are still visible at the downstream channel bed. Since the creosoted timber cut-offs have been under groundwater table all the time, they should still be relatively intact. The Bench Mark No.2 installed in 1960 is still on the structure.



Photo 17 – Inlet



Photo 18 – Inlet Detail



Photo 19 – Outlet



Photo 20 – Outlet Detail

### *6.9.2 Recommendation*

It is recommended that the following be carried out:

a. Add sufficient riprap (for maximum discharge flow) to stop further bank toe erosion at south side of the downstream channel.
b. Remove the vegetation that is grown on top of the cross beams.
c. Chip out the freeze and thaw damages and spalling areas, and patch the areas with cement mortar.

## 6.10 Ditch #2

### *6.10.1 General Description*

This is a 180 m (600 ft) long canal that takes the flow from the raised Louise Lake into the head of Porter Creek (see Drawing 3821, dated Dec.20, 1948). About half of the Ditch length is submerged in water upstream of the Louise Lake outfall structure. From observation at Louise Lake Outfall Structure and contour plan, the Ditch #2 appears to be entirely created by excavation in non-plastic sandy silty till with some rounded to sub-rounded gravel and cobble. The canal slopes are about 2:1 with depth up to 5.2 m (17 ft) (See photo 21).



Photo 21 – U/S of Outlet Structure

Porter Creek between Ditches 1 and 2 is about 4 km (2.4 miles) long.

### *6.10.2 Recommendation*

No recommendations.

## 6.11 Ditch #1

### *6.11.1 General Description*

Ditch #1 is a 500 m (1600 ft) long cut and fill canal that intercepts Porter Creek and brings the water to #1 Intake. Over the length the Ditch drops only 0.6 m (2 ft) (see drawing dated Dec. 20, 1948). Original cross section of this Ditch is not available.

Up to the overflow structure (about 2/3 length) was walked. South (right hand) side of the canal embankment is formed by fill and the crest is about 6 m (20 ft) wide and there was only 0.6 m (2 ft) of water in the Ditch and Ditch height varies between 1.2 m (4 ft) to 1.8 m (6 ft). Tress up to 9 m (30 ft) high are growing on the downstream slope of this embankment. No wet spots were found by occasional checks at toe, except upstream of the Ditch #1 Overflow Structure (see section 6.12 below).

North (the left hand) side of the canal is lined with a 6 m (20 ft) wide access road. The exposed excavation faces show that the soils at Ditch #1 are mainly sandy till with small amount of gravel and cobble. The ditch bottom has been regularly dredged, and piles of sand have been dumped at the fill embankment side. At #1 Head Pond, the ditch embankment is highest (about 4.3 m (14 ft)), but no wet area was detected at toe. The upstream bank has vegetation growth and has no sign of erosion.

### *6.11.2 Recommendation*

It is recommended that the following be carried out:

a. Cut all existing trees and shrubs on crest and faces of the south embankment.
b. Survey embankment crest elevation along the whole Ditch #1 length to discover low sections for topping up to prevent overtopping.

## 6.12 Ditch #1 Overflow Structure

### *6.12.1 General Description*

This structure is located at head of Ditch#1 where Porter Creek is intercepted by Ditch #1. The original diversion timber box structure was replaced by a horse shoe shape corrugated steel culvert (1.2 m (4.1 ft) rise and 1.9 m (6.2 ft) span) surrounded by concrete and the 3.0 m (10 ft) to 4.9 m (16 ft) long steel sheet pile wing walls. The 9 m (30 ft) long culvert has no provision to raise the canal level. At downstream end of this overflow structure, there is a 5.0 m (16.5 ft) long timber mat for erosion protection. In front of the timber mat there is a small pool of water that was fed by small seepage/run-off collected by the Porter Creek bed that is running along toe of the embankment upstream of the Overflow Structure Gravel and small cobbles lined the creek bed in front of this pond. (See photos 22 and 23).



Photo 22 – Overflow Structure Inlet



Photo 23 – Overflow Structure Exit

There is no drawing available for this structure to determine when it was installed.

### 6.12.2 Recommendation

It is recommended that the following be carried out:

a. The seepage/flow at toe of Ditch#1 embankment upstream of the overflow structure should be investigated to find the source(s).
b. Assess condition of the timber mat and replace it with riprap on geotextile at appropriate time.

## 6.13 #1 Intake Structure

### 6.13.1 General Description

The original timber pressure box was replaced by a concrete structure in 1974 which was again replaced in 1993 by the current concrete sub-structure. The two compartment structure measures 5.6 m X 3.2 m (18.3 ft X 10.5 ft) in plan and 3.4 m (11 ft) in depth and with 1.5 m (5 ft) wing wall at both downstream sides. There are two trash screens at the south side wall, and the penstock compartment can be blocked off by stop logs.

In 1963 the top end of steel penstock was enlarged from 760 mm to 915 mm (30" to 36") (see drawing 6490 dated May 28. 1963) which was cast into the concrete wall. A 400 mm (16") vent pipe was also added to the 915 mm (36") pipe (see Drawing FISHLAKE -1 Rev. A, dated April 27, 1993). There is a control gate at end of the penstock and the structure is covered by a heated metal cladding building (See photo 24).



Photo 24 – Intake

### 6.13.2 Recommendation

It is recommended that the following be carried out:

a. Confirm that stoplogs are functional and can be fully closed.

## 6.14 #1 Penstock

### *6.14.1 General Description*

This steel penstock is completely buried in the ground with minimum of 0.6 m (2 ft) fill, except were it cross the Porter Creek where the twin pipes 450 mm and 500 mm (18" and 20") day lighted for about 7.5 m (25 ft). The penstock started at elevation 960 m (3145 ft) and has a gross head of 133 m (435 ft).

The drawings available only show the original woodstave and steel arrangement of the 1962 twin pipe proposals. There were five anchorage points along the length with the last one at the Plant#1 power house. Other than the 400 mm (16") vent pipe at top and turbine shut-off valve just upstream of both turbines, there seems to be no other valve on the penstock.

The penstock details listed below are from the 1985 water licence application: 493 m (1618 ft) of 812 mm (32") steel; 240 m (787 ft) of 760 mm (30") steel pipe; 172 m (546 ft) of 672 mm (26.5") steel pipe, 137 m (550 ft) of twin 460 mm (18") and 510 mm (20") steel pipes. The twin pipes joint back together about 15 m (50 ft) above Plant#1 into a single 460 mm (18") pipe. Pipe thickness was not mentioned.

### *6.14.2 Recommendation*

It is recommended that the following be carried out:

a. The penstock should be uncovered at selected locations for corrosion inspection and pipe thickness.
b. Find and uncover the anchorage points for inspection.

## 6.15 #1 Power House

### *6.15.1 General Description*

#1 Power House consists of concrete substructure and a timber superstructure. The Power house was enlarged in 1953 to accommodate the second unit with attachment for a two car garage and an upstairs apartment (see drawing dated Jan.4, 1953). Currently only the second 700kW unit is in operation and tail water is discharge into an 2.4 m (8 ft) wide and 2.1 m (7 ft) high concrete/stone masonry channel that direct water to the south to join West McIntyre Creek. Both are however, in reasonably good shape. (See photos 25 and 26).

West of power house, Porter Creek turns to north and there is a discarded timber diversion structure that used to divert water into West McIntyre Creek at the south.

A fish farming company – (Icy Waters Ltd.) has added an intake structure at the north end of the discharge channel, and diverts most of the tail water for their operations. After going through fish tanks, the diverted water is discharged back further downstream to West McIntyre Creek that leads to the #2 Head Pond. The remaining tail water flows to south and joins West McIntyre Creek. Water from Ditch#1 overflow structure and runoff not intercepted by the ditches are collected by Porter Creek where Icy Waters also takes part of this water for their operation and discharges the water back to West McIntyre Creek further downstream.

The discharge channel has some freeze thaw damage and it appeared part of the masonry wall was covered by a layer of concrete not too long ago. Stop logs can be installed in this channel to regulate the flows.



Photo 25 – Powerhouse Equipment



Photo 26 – Powerhouse Outlet

### *6.15.2 Recommendation*

No recommendations.

## 6.16 #2 Head Pond Dam

### *6.16.1 General Description*

#2 Head Pond was formed by a dam blocking West McIntyre Creek. The 85 m (280 ft) long dam has a maximum depth of 10 m (32 ft) (includes 2 m (7 ft) cut-off trench in bedrock), and 3: 1 slope at both faces. The dam consists of a wide clayey till core with 5 m (16 ft) width cut-off trench in bedrock, and decomposed granite toe drain and upstream shell. The dam surfaces are protected by an 450 mm (18") layer of coarse copper mine tailing rock in cobble size.

The 7.3 m (24 ft) wide dam crest serves as access a road to #2 Power house. There is 1 m (3 ft) of freeboard at high operating water level. A stop log controlled overflow spillway with concrete slab cover and channel excavated through bedrock is located off the dam at north side. Spilled water goes to the former West McIntyre Creek. Both the 760 mm (30") steel penstock pipe and 610 mm (24") low level spill pipe penetrate the dam with two cut-off collars in the dam core. There is a concrete stilling basin at downstream end of the 610 mm (24") spill pipe (see drawings dated Aug. 30, 1954). (See photos 27 and 28).

Shrubs and grasses are growing on the upstream slope of the dam and shore of head pond, and there is no sign of wave erosion. Pond water level was raised by several stop logs at the spillway. There were some tree branches and other debris accumulated within the spillway behind the stop logs. The masonry walls that formed the spillway have some freeze thaw damage.

The concrete spill pipe stilling basin was full of water with small amount flowing away. There was small amount of water seeping out from the mine tailing fill around the stilling basin. Water loving grasses were generally growing around the basin and downstream of it. These indicate that there is some leakage which is most probably through the rock joints under and around the dam. The copper mine tailing rocks have oxidized and generally have some green patches on surface that indicates existence of acidic condition.



Photo 27 – Headpond Dam and Intake



Photo 28 – D/S Slope of Dam

### *6.16.2 Recommendation*

It is recommended that the following be carried out:

a. Repair the freeze thaw damage by chipping and patching with mortar.
b. Remove all trees and shrubs on both faces of the dam, within 6 m (20 ft) of the dam toe; and around and below the spillway channel.
c. Clean the stilling basin to check existence of outlet hole at east wall. If there is no existing hole, drill/core a 75 to 100 mm (3 to 4 inch) hole at bottom of east wall of the spill pipe stilling basin so that no seepage water will accumulate in the basin. Clean the basin regularly, so that this hole is not blocked by debris.

## 6.17 #2 Intake Structure

### *6.17.1 General Description*

The 1954 built 6.7 m (22 ft) high concrete structure is located at upstream toe of the #2 Head Pond Dam. The structure measures 4.0 m (13 ft) long and 3.1 m (10.2 ft) wide, with 2.4 m (8 ft) thick base block sitting on bedrock and upstream guiding apron that is 3.0 m (10 ft) long and 7.8 m (25.7 ft) wide at the front. The intake is equipped with an inclined trash rack and stop log guide for dewatering. A cat walk connects the Intake with the dam crest. There is minor freeze and thaw concrete damage at water line.

Both the 915 mm (36") penstock and 610 mm (24") spill pipe were cast into the structure and are controlled by wooden gate inside the heated timber building. There is a 100 mm (4") penstock vent pipe that ends inside the building. It is our understanding that the penstock inlet valve was not designed to close fully which allows for the passage of a riparian flow through the penstock. However, should there be any type of penstock failure whether minor or catastrophic, the water flow into the penstock cannot be completely stopped.

### 6.17.2 Recommendation

It is recommended that the following be carried out:

a. Repair the freeze thaw damage by chipping and patching with mortar as required.
b. Current stoplogs are inadequate. Review dimensions of the inlet structure, stoplog guides, etc and design stoplogs. Permanent stop logs should be manufactured from either steel or concrete and be placed in the stop log guides so that the installation of the remaining wooden stoplogs can be performed with relative ease and safety. We would recommend the use of steel with appropriate seals attached because of the limited access to the stop log guides. Note that some stoplogs may be placed in the stoplog guides and left on a permanent basis.
c. The existing penstock inlet valve does not close completely and should be assessed to determine if the valve should be either replaced or rehabilitated. If the valve is to be rehabilitated the options are to assess the existing stem to see if it can be reused with a shorted pedestal beneath the actuator gear box, or whether the stem itself requires replacement.

## 6.18 #2 Penstock

### 6.18.1 General Description

The available drawings are showing contradicting information about the penstock. The penstock details listed below are from the 1985 water licence application: 46 m (150 ft) of 914 mm (36") steel pipe that passes through the Head Pond dam, 274 m (900 ft) of 914 mm (36") woodstave pipe, 229 m (750 ft) of 838 mm (33") woodstave pipe and approximately 152 m (500 ft) of 914 mm (36") steel pipe, and 15.2 m (50 ft) of tapered steel pipe that changes from 760 mm (30") to 460 mm (18") immediately above the #2 Power House. Pipe thickness was not mentioned. The woodstave pipes lay directly on grade, and there are some concrete anchors for the steel pipes on the steep slope. Location of these anchor points is unknown, as most of the steel pipes are buried 0.9 m (3 ft) in the ground. The woodstave pipe was walked for the entire length, while only the upper and lower steel sections can be inspected.

The penstock upstream end is buried under the dam. The exposed woodstave penstock is in fair condition, while most of the creosote has disappeared from exterior surface, particularly at top of the pipe. The steel woodstave pipe bands were in good shape and not overly rusty even at leaking sections.

There are many small leaks and some were sealed with plate and screws. There are five major sections that leakage water was either ponding next to the pipe or running along the pipe and drained to hill edge. The worst location was at about chainage 10+50 downstream from the rock canyon where the pipe is sitting in a very narrow bench cut of till. Leakage water was running along the bench and down a very steep slope, washing the soils away. This section of penstock was replaced with steel penstock in the fall of 2005. Other major leakage sections are upstream from this and most of them are next to the rock canyon so draining to the edge is not a concern, but ponding is. (See photos 29 to 36).



Photo 29 – Typical Woodstave



Photo 30 – Typical Leak



Photo 31 – Wood stave prior to Replacement with Steel in 2005



Photo 32 – Wood stave prior to Replacement with Steel in 2005



Photo 33 – Steel Repair 2005



Photo 34 – Steel Repair Backfilled

The condition of the remaining woodstave penstock was assessed at the connection points with the steel penstock replacement section. The condition of the woodstave pipeline was relatively good considering its age and the seasonal stresses and vandalism that the pipeline has suffered. The condition of the untouched runs of woodstave was consistent with expectations with minor degradation of the interior wooden surfaces. Alternately there appears to have been a period of time when the various leaks and damage were being patched using rubber sheets with steel cover plates screwed down to the woodstave. These areas show a very advanced state of decay with some of the areas witnessed having virtually no wood remaining. The present methods being used to patch the various leaks is a more acceptable procedure with the hoops being slackened and rubber sheets backed by steel plates being affixed by retightening the hoops. In addition to this repair method the use of the remaining Oakum from the recent construction/repair will allow for repairs to additional leaks that have previously been difficult to stop.

Between chainage 13+40 and 17+70 ft, the woodstave pipe is located in a deep cut trench in till, and the pipe is partially buried by soil and rock washed down from the steep cut faces. The slopes have been trimmed and stabilized in this area in the fall of 2005. At end of the cut trench, there is a heated shed that houses three valves (presumably for air, vacuum and pressure relief).



Photo 35 – Slopes prior to Trim



Photo 36 – Slopes after Trim

Further downstream, the pipe is covered by an access road embankment. The joint between woodstave and original steel pipes was not leaking at the time of inspection although it has been known to leak slightly. The leakage water apparently runs a short distance down the slope and disappears into the ground. The steel pipe has only some slight rust.

Close to bottom of the hill above the #2 Powerhouse, a short section of the steel pipe is exposed. There is some slight rust where the paint has been lost. There is a turbine shut-off valve in #2 Power House just upstream of the turbine. (See photos 37 and 38).



Photo 37 – Slope US of Powerhouse



Photo 38 – Slope US of Powerhouse

### *6.18.2 Recommendation*

It is recommended that the following be carried out:

a. Periodically inspect the woodstave pipe and seal the leakages by appropriate method. Reinforce the decay wood with appropriate means or consider complete wood stave replacement.
b. Ponding water next to pipe should be drained away by ditching.
c. Cut all shrubs along the route 0.9 m (3 ft) tree free zone both sides) and remove any vegetation growing on the pipe.

## 6.19 #2 Power House

### *6.19.1 General Description*

#2 Power House was built in 1954 and consists of a concrete substructure and a timber superstructure. The powerhouse was extended 1.8 m (6 ft) in length some time later. The single horizontal Francis turbine/generator set is rated at 600kW. (See photos 39 and 40).

A steep hill with weather granite bedrock leads the steel penstock to the power house The floor slabs next to the discharge channel have settled up to 50 mm (2"). The discharge channel has some freeze thaw damages). The power house is still functionally adequate.



Photo 39 – Powerhouse Equipment



Photo 40 – Powerhouse Outlet

### *6.19.2 Recommendation*

No recommendations.

# 7. Conclusions and Recommendations

The dam safety review of the Fish Lake hydropower project has been completed, and the following points summarize major conclusions reached as a part of this analysis:

- The incremental consequences of failure resulting from breach development in the Fish Lake Dam, Louise Lake Dam, and Headpond #2 Dam are limited. Therefore the Hazard Classification selected for each of these structures is "LOW".

- The IDF selected for each of these structures is the 1:100 year flood.

- Hydrological studies were performed to estimate the 1:100 year flood event for the Fish Lake dam, Louise Lake Dam, and Headpond #2 Dam. The final hydrograph for the Fish Lake event was developed based a regional assessment of flood potential, and is shown in Figure 11.

- An assessment was make of the ability of each structure to pass the IDF in it's current state. For Fish Lake, It was determined that in passing the IDF, water levels on the lake would surcharge up to elev. 30.74 m (local datum). Freeboard analyses indicate this degree of surcharge would result in a freeboard deficiency of 0.60 m during passage of the IDF. Therefore it is recommended that the dam height be raised to mitigate this deficiency.

- As a large flood event on Fish Lake is a relatively slow occurring event (over several weeks), we recommend a contingency plan to address the deficiency in freeboard on Fish Lake dam be developed by Yukon Electric Company Limited until the dam heightening is implemented. One possible alternative to consider is stockpiling sandbags which can be placed on the dam crest as required to maintain freeboard.

- Freeboard analyses also indicate that wind and wave allowances are adequate for normal operating conditions on Fish Lake, based on a project FSL of 30.0 m.

- Freeboard analysis indicate that wind and wave allowances are adequate under both normal operating conditions and during IDF passage for both the Louise Lake dam and Headpond #2.

The inspection of the entire Fish Lake Hydro development was completed in June 2007. The structures are generally in good or reasonable operation condition. Investigation and monitoring are recommended for certain structures while maintenance is required on some others. Refer to Section 6 of this report for detailed structure specific recommendations.

We recommend that a program be developed by Yukon Electric Company Limited to implement the recommendations of the inspections referred to in Section 6 over the next three to four years. Once the program is developed it should be reviewed and statuses updated on a semi-annual basis.

# Appendix A

## Figures




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Yukon
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# *Yukon Environmental & Socioeconomic Assessment Act*
# Decision Document Final

This document meets the Yukon government's requirements as a Decision Body as set out in the *Yukon Environmental & Socioeconomic Assessment Act*

## Decision Document Issued By

| | |
|---|---|
| **YG Decision Body:** | Territorial Minister, as authorized under section 7, to Director, Energy Solutions Centre, Energy, Mines and Resources |
| **Federal Decision Body(ies):** | *[where applicable]* |
| **First Nation Decision Body(ies):** | *[where applicable]* |

## Project

| | | |
|---|---|---|
| **Project Name :**<br>Operation of the Fish Lake Generating Station | | YESAA File Number<br>2007-0150 |
| **Proponent Name:** | Yukon Electrical Co. Ltd. | |
| Project Description:<br>Continued operation and maintenance of the Fish Lake hydroelectric generating station, including<br>- ongoing operations of existing structures including control of flows in the system,<br>- regular maintenance activities of the hydro system including removal of beaver dams, brushing, mostly along ditch #3 and ditch #1, removal of debris in trash racks, and regular maintenance of the turbines. | | |

## Other Decision Bodies

| | |
|---|---|
| **Other Decision Body Consultation:** | *[list decision bodies consulted, where applicable]*<br>*N/A* |
| **Consolidated Decision Document:** | ☐ N/A<br>X No<br>☐ Yes *[list the decision bodies whose decision documents were consolidated, where applicable]* |

## Non-Self Governing First Nations

| | |
|---|---|
| **Non-self governing First Nation Consultation:** | *[list First Nation consulted, where applicable]*<br><br>N/A |

Yukon
Government

## Decision

| | |
|---|---|
| Pursuant to YESAA s. 75, 76 and 80, the Yukon government has considered the assessment of this project and: | |
| | a) Yukon government accepts the following recommendation (inserted below)<br>• *[List Terms and Conditions and responsible YG department, where applicable]* |
| | b) Yukon government rejects the following recommendation (inserted below) for the following reason(s):<br>• *[List specific reasons]* |
| X | c) Yukon government varies the recommendation (inserted below) by changing the following term(s) and condition(s) for the reason(s) specified:<br><br>**The following terms and conditions remain unchanged:**<br><br>6. Maintenance/repair of the generating units and/or channels shall maintain minimum riparian flows adequate for fish and fish habitat downstream of work area.<br>7. No heavy equipment shall be used for brushing along the ditches.<br>8. Excavated sediment from dredging of ditch #1 shall be stockpiled along the upslope side of the ditch.<br>9. Excavated materials and debris should be disposed of above the high water mark and located such that they do not enter any watercourse.<br>10. To the extent possible, ensure adequate lake levels to prevent fish stranding.<br>11. To the extent possible, ensure adequate minimum water discharge and riparian flow to maintain fish habitat and prevent fish stranding.<br>12. To the extent possible, ensure adequate fish control measures at the overflow spillway to Franklin Lake to prevent the entrainment, entrapment and/or stranding of fish.<br>13. Investigate fish control mechanisms (eg. fish screen) that would prevent potential entrapment, entrainment, and/or stranding of fish in the channel between Louise Lake and Franklin Lakes.<br>14. Investigate minimum flow rates at control gates, minimum riparian flows within channels and low level supply level of lakes that will effectively minimize, reduce, or control fish entrapment and maintain fish habitat for fish species and their lifecycle stages in the system.<br>15. Monitor discharge volumes from specific system components, including Fish Lake control gate, Louise Lake control gate, Louise Lake spillway, Plant #1 and Plant #2.<br>16. Monitor water levels of Fish Lake and Louise Lake.<br>18. Correlate Fish Lake levels with the amount of inundation to settlement lands adjacent to Fish Lake. Identify a preferred operating range from the perspective of landowner(s).<br>20. At a minimum, adhere to the Canadian Dam Associations "Dam Safety Guidelines" to conduct necessary studies, identify necessary upgrades, and/or continue maintenance of Fish Lake Hydro infrastructure.<br><br>**The following terms and conditions are changed with reasons provided:**<br><br>1. The Minimum Low Supply Level of Fish Lake shall be 28.5m (93.5 ft) as referred to |

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Government

| | |
|---|---|
| | bench mark 1L321, G804, BM 1956 set in standard post to arbitrary elevation of 100 feet and located on the easterly side of Lot 321, G 804.<br>2. Minimum discharge from Fish Lake through the control gate into Ditch #3 shall be 0.15 m3/s.<br>3. Minimum Low Supply Level of Louise Lake shall be 29 m (91.5 ft) as referred to the top of a standard post in concrete marked 7L281, G804, BM1, 1960 set at arbitrary elevation of 100 feet and located on the southerly side of Lot 281, G804.<br>4. Minimum discharge from Louise Lake through the Louise Lake Control structure into Porter Creek shall be 0.1 m3/s.<br>5. Maintain minimum riparian flows of at least 0.08 m3/s through water channels.<br>17. The Full Supply Level of Fish Lake shall be 30.0m (98.4 ft) as referred to bench mark 1L321, G804, BM 1956 set in standard post to arbitrary elevation of 100 feet and located on the easterly side of Lot 321, G 804.<br><br>**Reason for change:**<br>The above terms and conditions are too prescriptive. Setting the specific levels will be left up to the Waterboard process.<br><br>**To be replaced with:**<br>Minimum Low Supply Levels, Full Supply Levels, and discharge levels at Fish Lake and Minimum Low Supply Levels and discharge levels at Louise Lake through the Louise Lake Control structure and Franklin Lake shall be set such that fish habitat be protected and minimum riparian flows through water channels be maintained.<br><br>**The following term and condition is being removed:**<br><br>19. Identify any areas of heritage importance that are not included within the established Settlement Land Parcels. Correlate Fish Lake levels with the amount of inundation to areas of heritage importance adjacent to Fish Lake. Identify a preferred operating range from the perspective of landowner(s).<br><br>**Reason for removal:**<br>The above proposed mitigation has been satisfied through comprehensive work completed by the Yukon government Heritage Branch in collaboration with Kwanlin Dun First Nation Elders. This work identified areas of significant archaeological and heritage importance in the larger Fish Lake area. The result of this collaboration is documented in the 1994 "Lu Zil Män Fish Lake - Uncovering the Past" report which is referenced in the project proposal and the Kwanlin Dun First Nation submission. |

## Dates

| | |
|---|---|
| **Project Recommendation Issued:**<br>**October 2, 2007** | **Decision Document Issued:**<br>**October 29, 2007** |

## Recommendation Received From

| | | |
|---|---|---|
| Designated Office | X | Location: Whitehorse |
| Executive Committee | | |

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Government

| | | |
|---|---|---|
| Panel | | a) Panel of the YESAB |
| | | b) CEAA Panel |
| | | c) Joint Panel (YESAB and other assessment body) |

**Authority**
By signing below, the Yukon government has exercised its authority as per YESAA s. 75 or s. 76 to issue a decision document on this project.

Name: Robert Collins Position: Acting Director, Energy Solutions Centre

Signature: _____ Date: October 29, 2007
Original signed by [Delegated YG Decision Body]

**Copies Forwarded to (as required by YESAA s. 81)):**

- ☐ Other Decision Bodies [list]_____
- x Project Proponent [name]_____
- ☐ DAP Branch, Executive Council Office
- X YESAB Designated Office [location] Whitehorse_____
- ☐ YESAB Executive Committee [when applicable]_____
- ☐ Minister Environment (Canada) [when applicable]_____
- ☐ Yukon Surface Rights Board [when applicable]_____
- X Yukon Water Board [when applicable]_____
- ☐ Land Use Planning Commission: [when applicable]_____
- ☐ Independent Regulatory Agency [when applicable]_____
- ☐ Other Body/Person as Required [list] _____

**YUB-YECL-10**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 84600 Diesel Generation

**Quote**: Costs increase from 2007 to 2008 mainly due to scheduled diesel overhaul costs ( 167). (Schedule 5.2, Line No. 48.)

**Preamble**: The Board would like more detail to understand the genesis of the diesel maintenance expenses that are illustrated in Schedule 5.2.

**Request:**

(a) Please provide greater detail such as vintage, operational hours, and size of the generation plant as well as generator manufacturer.

(b) Please explain the sustained increases for diesel maintenance costs for the test period.

**Response:**

(a) Please refer to YUB-YECL-7 (c) Attachment 1

(b) This is due to increased overhaul activity according to Yukon Electrical's scheduled maintenance program, as well as labour and other inflation as shown on schedule 5.2.

**YUB-YECL-11**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 87100 Brushing

**Quote**: Costs increase from 2005 to 2006 due to additional brushing activity ( 56) and labour cost increases due to increased brushing activity ( 19). (Line No. 66-67.)

Costs increase from 2006 to 2007 mainly due to an enhanced brushing program ( 40), labour cost increase due to increased brushing activity ( 11) (Line No. 69-70.)

Costs increase from 2007 to 2008 due to increases to the labour compliment (Line No. 73.)

**Preamble**: The Board would like to have a greater understanding of YECL's brushing program.

**Request:**

(a) Please provide an in-depth description of YECL's brushing program.

(b) Was the 2005 to 2006 increase due to brushing that was scheduled but not performed in the previous year?

(c) Please explain the difference between additional brushing activity (Schedule 5.2, Line No. 66) vs increased brushing activity (Schedule 5.2, Line No. 70).

(d) What is the enhanced brushing program that YECL is referring to? Please describe the enhancements.

(e) Were there increases to the brushing labour compliment for 2008 permanent?

**Response:**

(a) Yukon Electrical's brushing program is best described as maintenance of power line right of ways (ROW's) by the removal of vegetation and second growth trees within the right of way. Each year brushing requirements are identified through patrols of lines completed by operational staff, and customer input, as well, trouble areas are identified through outage and reliability data.

Yukon Electrical uses a number of methods to complete the brushing requirements, including community based contract crews supervised by Yukon Electrical staff, Qualified Utility Arborists and Utility Tree Trimmers, Bucket truck aerial trimmers, and Hydro Axe Mowers. In most cases usable fuel wood greater than 4 inches in diameter is stacked along the right of way for use of property owners and general public. The debris and vegetation are removed by burning when possible or chipping with a wood chipper.

Yukon Electrical uses a number of local contractors to complete the brushing requirements. Three Whitehorse based companies are used mainly with support from contract crews supplied by First Nations within the smaller rural communities around Yukon.

In recent years Yukon Electrical has enhanced the brushing program to include the widening of many existing R.O.W'S to upgrade R.O.W widths to today's standards. The brushing program also includes the identification and removals of Danger Trees from outside of the R.O.W. Danger Trees are trees which are dead or leaning into the R.O.W. Danger Trees also include trees that have damaged root systems from a previous high wind event, they pose an obvious risk to falling on the line.

For further information please refer to YUB-YECL (a) Attachment 1, 2 and 3. Yukon Electrical applies the same criteria as used by its parent company, ATCO Electric Ltd., adapted for Yukon Electrical.

(b) No.

(c) Additional brushing activity in 2006 refers to more volume of brushing and resources to complete the program.

The increased brushing activity in 2007 refers to more Yukon Electrical labour required as a result of both the enhanced program in 2007 as well as additional brushing undertaken by contactors.

(d) In the past the brushing program focused mainly on the maintenance of existing right of ways and removal of second growth trees and vegetation along the R.O.W. Yukon Electrical enhanced its brushing program in 2005 to include widening the R.O.W's wherever possible to increase clearances to power lines consistent with current standards. Today's brushing program also includes the identification and removal of danger trees . Danger trees are trees outside of the R.O.W which are dead, leaning or have damaged root systems caused by high winds, they pose an obvious risk of falling on the line.

(e) The labor complement was not specifically increased to manage the brushing program and related administrative requirements, however a percentage of specific job classes were allocated to the brushing program. It is proposed that the increases will be permanent for the brushing function.

ATCO Electric

**DISTRIBUTION LINE MAINTENANCE STANDARDS**

| ORIGINAL DATE | REVISION NO. | PAGE | INDEX NO. |
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| | EFFECTIVE DATE 97-10-20 | | |

| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Foreword |

These right-of-way preparation and maintenance standards have been established to achieve corporate objectives of customer service, public safety, worker protection, facility protection, system integrity, compliance with legislation and environmental stewardship. The maintenance standards promote an integrated vegetation management program for distribution rights-of-way and facilities.

ATCO Electric

**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Index |

## 4.0 RIGHT OF WAY MAINTENANCE

*4.1 General Safety Requirements*

*4.2 Rights-of-Way*
- *4.2.1 Right of Way Width*
- *4.2.2 Right of Way Vegetation Maintenance*
- *4.2.3 Standard for Hazard Tree Removal on Crown Lands*
- *4.2.4 Planning Distribution Lines for tree freeing (VCE)*
- *4.2.5 Standard for Fire Suppression on Crown Lands*

*4.3 Environmental Protection*
- *4.3.1 General Program Requirements*
- *4.3.2 Specific Requirements*

*4.4 Standard for Distribution Right-of-Way Patrols and Inspections*

*4.5 Landowner Consenting*

*4.6 Contracting*
- *4.6.1 Contract Packages*
- *4.6.2 Hiring of Contractors*

*4.7 Limit of Approach*

*4.8 Herbicide Application*
- *4.8.1 Selection of Pesticide Products*
- *4.8.2 Applicators*
- *4.8.3 Application*

*4.9 Transportation, Storage and Disposal of Pesticide Products and Containers*

*4.10 Mechanical Work*
- *4.10.1 Mowing*
- *4.10.2 Trimming*
- *4.10.3 Slashing*

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**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| RIGHT-OF-WAY MAINTENANCE | Index |

***4.11 Weed Control on ATCO Electric Property, Public Lands or Private Lands***

***4.12 Substations, Yards and Storage Facilities***

***4.13 Standard for Disposal of Wood Debris and Salvage of Timber***
- ***4.13.1 Agricultural Areas***
- ***4.13.2 Forested Areas***

***4.14 Acts and Regulation***

***4.15 Glossary of Terms***

***4.16 Appendices/Samples***
- ***4.16.1 Sample Final Sign Off Form***
- ***4.16.2 Sample Request for Approval Form***
- ***4.16.3 Sample Request for Approval Form***
- ***4.16.4 Sample TFA Request Form***
- ***4.16.5 Sample Forms***
  - ***a) Final Sign Off***
  - ***b) Request for Approval***
  - ***c) TFA Request***
  - ***d) Timber Salvage***
  - ***e) Wood Purchase Agreement***
  - ***f) Wildfire Reporting***
  - ***g) Wildfire Investigation Report***
  - ***h) Tree Voucher Letter***
  - ***i) May be Planted Near a Powerline***
  - ***j) DO NOT Plant Near a Powerline***
  - ***k) Job Observation/Inspection***

***4.17 Approval***

ATCO Electric

**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | General Safety Requirements |

### *4.1.1 General Safety Requirements*

*PURPOSE: To outline the general safety requirements related to vegetation maintenance activities.*

1. Vegetation control around energized facilities is hazardous work. All activities are to be carried out with diligence and the proper attention to the governing safety legislation, standards, policies and manuals – the ones that apply directly are as follows:

   Occupational Health and Safety Act
   Safety Standards Manual
   Electrical and Communication Utility Code
   Motor Transport Act
   TDG Act
   WHMIS

2. All work is to be properly planned and documented in a Job Start Up form with hazards and barriers identified and detailed descriptions of the communication and evacuation plans. For small jobs of 5 days duration or less, the Tailboard meeting summary may serve as the JSA.

3. All workers are to be properly trained, oriented to job sites and made aware of specific hazards and barriers.

4. All contractors are to be properly assessed and supervised to reduce the risk of incidents. The Forest Operations Department is to maintain a list of all contractors evaluated, any noted concerns and recommendations or conditions for work for each contractor.

5. Safe Limits of Approach for persons and equipment to energized electrical equipment must be maintained at all times. See *Section 4.7* for Safe Limits of Approach distances.

6. Wherever practicable, work is to be inspected regularly by the Forest Operations coordinator or designate, and a summary of the inspection is to be made and kept on file. A copy of the inspection summary with any recommended follow up actions should also be provided to the contractor.

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Right-of-Way |

## *4.2 Rights-of-Way*

### *4.2.1 Right-of-Way Width*

*PURPOSE: To outline the standard right-of-way widths to be maintained for various distribution voltage levels.*

**TABLE A:** Distribution power line Right-of-Way Widths requirements Right-Of-Way Width Maintenance Requirements

| **Voltage (Phase to Phase)** | **Location** | **Primary** | **VCE** |
|---|---|---|---|
| 25 kV | Road Allowance | 7.5 m | Variable (based on tree height) |
| | Cross-Country | 15.0 m | Variable (based on tree height) |
| | Section & ¼ Section Line | 15 m | Variable (based on tree height) |
| 14.4kV | Road Allowance | 7.5 m | N/A |
| | Cross-Country | 15 m | Variable (based on tree height) |
| | Section & ¼ Section Line | 15 m | Variable (based on tree height) |

* Where mature stands of tall trees or side slopes are located, right-of-way widths may exceed the widths outlined in Table A. Vegetation on VCE's is typically maintained at a less frequent cycle than the primary right-of-way due to the decreased hazard from re-growth situated further from the electrical facilities.

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**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Right-of-Way |

### *4.2.2 Right-Of-Way Vegetation Maintenance*

*PURPOSE: To outline the standards for maintenance on distribution rights-of-way.*

1. Objectives of right-of-way vegetation management are to:

   - create a safe environment for the public at all times,
   - create a safe working environment for ATCO Electric employees and contracted workers,
   - maintain the integrity and security of facilities
   - provide access to rights-of-way and electric facilities,
   - provide constant reliability and integrity of service to ATCO Electric's customers,
   - reduce outages,
   - prevent tree to line contacts and prevent forest fires,
   - minimize environmental impacts, and
   - comply with legislation

2. Distribution right-of-way maintenance will follow the "Industry Standards and Good Practices for Vegetation Management" guidelines produced by the Industrial Vegetation Management of Alberta (IVMAA). These Industry standards will be used when planning and implementing vegetation management programs, and will strengthen our commitment to safety, customer service and the environment. ATCO Electric Ltd. will support the IVMAA by maintaining an active membership in the association.

3. On Crown land, right-of-way maintenance activities are governed by operating conditions on the easement. The operating conditions ensure minimal surface damage and satisfactory reclamation. Operating conditions are on file with ATCO Electric, Lands and Properties Group and are referenced by legal land description. Complete files are also held at the Public Lands Division Office in Edmonton.

4. On private land, conditions may be imposed on a case-by-case basis by the landowner during the consenting process. Occasionally, there may be formal agreements in place between the landowner and the Company. Any such agreements would be on file with the Lands and Properties Group.

5. Only lands held under power lines easement are to be maintained on an on-going basis. Where no easement is in place over private lands, the easement width noted in Table 1 is to be maintained.

ATCO Electric

**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Right-of-Way |

6. Disposal standards must meet ATCO Electric requirements and the standards outlined by governing agencies. Specific conditions may be required in approval documents (e.g. easements and landowner consents).

7. Where possible, compatible vegetation is to be retained.

8. There are specific, different requirements governing maintenance on provincially administered lands in the agricultural area. These are:

   i. Authorization is required from Public Lands Division prior to right-of-way maintenance on unoccupied public land in the White Area. On occupied public land lessee consent is required as well as authorization from Public Lands Division.

   ii. The Surface Rights Act Chapter S-27.1, Section 14(1) and (2) provides that an operator or his employee can enter upon any crown or other land to conduct a survey provided they have notified or have made reasonable attempt to notify the owner or occupant. Compensation is payable for any damages to the land or improvements resulting from the entry.

9. Comprehensive vegetation management:

   In order to meet objectives for distribution line right-of-way maintenance, a broad suite of treatment methods are utilized. These include general and selective herbicide treatments as well as mechanical methods such as hand slashing, mowing, mulching and trimming.

   Mechanical treatments of large areas of the right-of-way, such as mowing, mulching and hand slashing are typically based on a three to five year rotation. Mechanical treatments may be followed by a herbicide program within three years, depending on the height of the vegetation, which varies according to species, microclimate, soil conditions, aspect, slope, etc.

   Individual tree trimming programs are designed to maintain limit of approach distances between re-growth and power lines. Treatment cycles are usually around three or four years depending on growth rates and landowner constraints.

   Where they are permitted, herbicide programs are typically completed within 2 or 3 years of initial clearing or mechanical right-of-way treatment. Where possible, the right-of-way will be maintained on a three or four year herbicide program thereafter. This cycle is dependent on tree species, growth rates and type of herbicide used.

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**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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|---|---|
| RIGHT-OF-WAY MAINTENANCE | Right-of-Way |

In order to complete programs, patrols are completed on geographic areas prior to the end of each cycle. The standard for right-of-way patrols and inspections is described in detail in Section 4.4.

10. Target species

Trees and shrubs will mature to heights that interfere with the safe and reliable operation of the distribution system must be removed or maintained. Lower growing shrubs may also be removed if access is limited.

In forested areas, low growing shrubs and grasses are promoted for ground cover and wildlife habitat.

In agricultural areas, the rights-of-way are maintained in grass or used as cropland.

The following is a list of tree species that commonly pose problems in right-or-way maintenance due to their heights are maturity:

| | |
|---|---|
| - Aspen Poplar | Populus tremuloides |
| - Balsam Poplar | Populus balsamifera |
| - White Birch | Betula papyrifera |
| - White Spruce | Picea glauca |
| - Black Spruce | Picea mariana |
| - Balsam Fir | Abies balsamea |
| - Tamarack | Larix laricina |
| - Lodgepole Pine | Pinus contorta |
| - Jack Pine | Pinus banksiana |

ATCO Electric

**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Right-of-Way |

### *4.2.3 Standard for Hazard Tree Removal on Crown Lands*

*PURPOSE: To outline the standard for hazard tree removal on Crown lands.*

1. Distribution facilities are to be maintained free of hazard trees.

2. Hazard trees are trees that have the potential of contracting or passing within the Limits of Approach of the distribution line and are defined in the ATCO Electric/ASRD Wildfire Agreement. Hazard trees must be removed or topped to ensure line safety and reduce the risk of fire.

3. Hazard tree removals are governed by the Fire Control Plan, which is updated annually and submitted to ASRD for approval. As much as possible, the removal of individual hazard trees should be carried out in conjunction with regularly scheduled maintenance programs.

4. Approval of specific hazard tree removal projects on Crown lands in the Green Zone of Alberta is granted by the local office of Alberta Sustainable Resource Development. Authority is granted in the form of a Letter of Authority or Temporary Field Authorization (TFA). However, if groups of hazard trees are being removed, a vegetation control easement (VCE) may be required.

5. Hazard trees are salvaged only if directed by ASRD. Usually salvage is not required unless the quantity of timber is sufficient and access is reasonable. Otherwise, individual trees may be felled, limbed, bucked and positioned in contact with the ground.

6. The removal of individual hazard trees does not usually result in timber damage costs to ATCO Electric. However, if trees are to be salvaged, timber damage is payable to the Forest Management Agreement holder (FMA) or to the Provincial Government. In that case, the timber becomes the property of ATCO Electric. There is no obligation to provide first right-of-refusal to any forest agreement holder, unless that was an agreement made in the original consent.

7. Consent to remove hazard trees is required from the forest license agreement holder (FMA, TL, etc.) whether individual or groups of trees are removed. Approvals may also be required from other agencies (Department of Fisheries and Oceans, Ministry of Environment, etc.).

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**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| RIGHT-OF-WAY MAINTENANCE | Right-of-Way |

8. If a VCE is required, potentially affected trappers must be notified by Registered Mail. Due to the fact that heavy equipment and log haul may be required, crossing and road use agreements may be required with pipeline companies or other third parties.

9. For VCE applications, the approval process is usually led by the Lands and Properties Group. An application for a VCE, containing an appropriate survey plan of the area to be cleared along with an Environmental Field Report (EFR), must be submitted to ASRD, Public Lands Division in Edmonton.

10. Removal of individual hazard trees does not entitle ATCO Electric to maintain the cleared area in the future. A VCE, however, grants the right to maintain the cleared area and requires rehabilitation upon surrender.

11. All line clearing activities are to be coordinated through the respective Forest Operations Coordinator and District office.

12. Once an individual hazard tree removal program is complete for a line or geographic area an acknowledgement of the work completed is required from ASRD. This acknowledgement will limit ATCO's liability in the event of a tree related fire in the future. Therefore, acknowledgement letters must be filed accordingly.

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| RIGHT-OF-WAY MAINTENANCE | Right-of-Way |

### *4.2.4 Planning Distribution Lines for Tree Freeing (VCE)*

*PURPOSE* *To outline the standard for maintaining a tree free 25kV or 14.4 kV distribution right-of-way.*

1. Some distribution line rights-of-way may be selected for maintenance at a "tree free" width.

2. Candidate power lines are selected for tree freeing based on the following criteria:
   - significance of service,
   - remoteness, and
   - degree of risk from adjacent stands.

   The local forest operations coordinator will evaluate potential tree-free candidate lines in consultation with the local servicemen.

3. On private land, additional tree free widths will be negotiated with the land owner.

4. On Crown land, authority must be granted by the Crown, through a VCE.

5. Identified lines are ranked according to priority and reviewed with the local Forest Officer for general agreement on the list of candidate areas.

6. The list is submitted to the Senior Forester in Edmonton for review and scheduling.

7. The senior forester will develop a five year plan for completion of the projects and include it in the Fire Control Plan.

8. Co-coordinator will proceed with tree free projects in their area in accordance with the schedule developed by the Senior Forester.

9. Although VCE's will be obtained from ASRD for every tree free project, TFA's may be sought for early entry after an application for a VCE has been submitted (in some cases, a forest officer may grant early entry prior to VCE application, although this is rare).

10. Timber will be salvaged according to direction from ASRD, typically based on information contained in the EFR. A field review by the Forest Officer may be required.

11. VCE areas are not typically maintained for distribution lines but specific hazards will be addressed if identified during patrols.

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| RIGHT-OF-WAY MAINTENANCE | Right-of-Way |

### *4.2.5 Standard for Fire Suppression on Crown Lands*

*PURPOSE: To outline the Maintenance Standard for fire suppression on Crown lands.*

1. During the fire season, company and contractor vehicles shall be equipped, at minimum, with a serviceable shovel, axe and a backpack pump of at least five liters liquid capacity. All ATV's shall be equipped with a collapsible shovel. All vehicles or work sites with three or more employees must meet additional fire fighting equipment requirements, as indicated in Table 1302-1, Section 1302 of the *Safety Standards Manual*.

2. The Forest and Prairie Protection Act requires that any person carrying on or having charge of an industrial or commercial operation in or within one kilometre of any public land shall have on hand fire fighting equipment in accordance with the regulations capable of controlling and suppressing any fire that may occur directly or indirectly as a result of the operation (See the Table A, below from the Forest and Prairie Protection Regulations, Part I). Note that ASRD may require a fire control plan and burning permit for any burning.

**TABLE A**

| Required Equipment for Fire Control | Men Employed at the Site of Operations | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6-10 | 11-20 | 21-30 | 31-40 | 41+ |
| Shovels | 1 | 1 | 2 | 2 | 3 | 5 | 10 | 15 | 20 | Same as 31-40 plus increase by Minister |
| Backpack with Pump | 0 | 0 | 1 | 2 | 3 | 5 | 10 | 15 | 20 | |
| Axe or Pulaski | 0 | 1 | 1 | 1 | 2 | 5 | 10 | 15 | 20 | |
| Fire Pump | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | |
| Fire Hose (metres) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 450 | 450 | |
| Power saws | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | |

3. All fires, regardless of size, must be reported to the Sustainable Resource Development and AE's Forest Operations group as soon as possible. This also pertains to fires extinguished by employees, contractors or others.

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4. The fire season is from April 1 to October 31 or as established by the Minister of Forests. During the fire season, no person shall light an outdoor fire on land in a permit area unless that person is a holder of an existing fire permit.

5. Outside the fire season, brushing debris and non-salvage timber may be disposed of by burning, upon approval of ASRD.

6. Contractors working on behalf of ATCO Electric in right-of-way clearing and burning, are required to verify that all fires are extinguished. A return trip to all burn locations is required to ensure that holdover fires do not exist.

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| RIGHT-OF-WAY MAINTENANCE | Environmental Protection |

## *4.3 Environmental Protection*

*PURPOSE: To outline the standards to achieve good environmental stewardship in right-of-way vegetation management.*

*4.3.1.General Program Requirements*

1) All programs will meet all applicable environmental legislation requirements.

2) All programs will follow the guidelines set forth in the Industrial Vegetation Management Association of Alberta's Industry Standards and Good Practices for Vegetation Management (Current Edition)

3) All programs will follow the Corporate Principles and Policies (HSE 2P Manual) and the Safety Standards Manual.

*4.3.2 Specific Requirements*

The applicable provincial legislation for environmental protection are:

- the *Species at Risk Act* (SARA) which is concerned with the protection of at-risk and endangered species, and
- the *Fisheries Act* which is concerned with the protection of fish and fish habitat

Both Alberta Environment and Department of Fisheries and Oceans have published guides and best practices for activities in and around water bodies. All right-of-way clearing and maintenance activities are to comply with these documents.

1. Buffers

To ensure herbicide products do not enter water courses, buffers will be maintained at all watercourses. Buffer widths will be determined by the specific herbicide used, as well as the application technique. (Refer to the AEP Code of Practice for Pesticides for specific references)

- All broadcast foliar applications require a 30 meter buffer to all watercourses.
- The use of Tordon 101 requires a buffer of 30 meters.

- Garlon 4 (triclopyr), Roundup (glyphosate) and Dycleer 24 (dicamba + 2,4-D) can be applied between 5 and 30 horizontal meters of an open body of water if using backpacks or a method that treats individual woody plants. Treatments are limited to less than 30% of the total vegetation present.

2. Water Body Crossings

To minimize soil compaction and damage to water quality and fish habitat, ATCO Electric will follow the Guidelines for Waterbody Crossings issued by Alberta Environment and the Best Practices for Waterbody Crossings issued by the Department of Fisheries and Oceans.

3. Soil Erosion

Erodible soils and steep slopes will be managed to encourage a dense cover of compatible species. Woody plants provide a far more extensive root system than most grasses, forbs and sedges. Compatible woody plants are to be fostered on the right of way in areas prone to soil erosion. In these areas woody shrubs should not be removed. Surface water movement over slopes should be controlled to minimize erosion. Use of properly situated diversion ditches will help minimize the likelihood of soil erosion and allow a plant community to establish. 6. Native vegetation is to be retained on all erosion prone sites. Selective hand removal should be considered for non-compatible vegetation.

4. Soil Compaction

Heavy equipment can damage soil through compaction and rutting which can lead to erosion. The use of heavy equipment should be avoided on slopes, near water bodies, and erosion prone areas. If heavy equipment must be used, low ground pressure equipment is preferred.

5. Habitat

Many species of wildlife utilize the right of way for habitat. Maintenance should be scheduled at times that minimize impacts to animals. Where possible, habitat enhancement should be considered for rare or endangered species. AEP Fish and Wildlife can assist with providing useful information pertaining to species requirements.

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| RIGHT-OF-WAY MAINTENANCE | Environmental Protection |

6. Emergency Spill Response

Crews working with heavy equipment, herbicides, fuels/oil or other substances shall be equipped with spill response kits in accordance with the requirements of Section 1203 and Appendix D of the Safety Standards Manual. WHMIS and TDG regulations must be followed where applicable.

Unauthorized releases must be reported as per the Safety Standards Manual, Section 1203 and the HSE 2P Manual.

7. Environmental Stewardship

Work sites shall be kept clean at all times. All litter and excess materials are to be removed from the right-of-way areas. Right-of-way and facility sites are to be maintained and kept in an environmentally acceptable condition.

Heavy equipment should be in good repair, without leaks, and must be inspected for cleanliness by the contractor prior to the start of each project. ATCO Electric coordinators will also inspect the condition of equipment during general contract inspections.

Fuel shall be transported and stored only in appropriate containers. Fueling should only take place in areas where any releases will not reach any natural water body.

Herbicides shall be handled in accordance with all applicable legislation and practice manuals, Namely

i. The Environmental Protection and Enhancement Act,
ii. the Pesticide Sales, Handling, and Use and Application Regulation,
iii. the Pesticide (Ministerial) Regulation (AR 43/97), and
iv. the Code of Practice for Pesticides

The safe handling of pesticides is dealt with in greater detail in Sections 4.9 and 4.10

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| RIGHT-OF-WAY MAINTENANCE | Patrol/Inspection |

***4.4 Standard for Distribution Right-of-Way Vegetation Patrols and Inspections***

*PURPOSE: To specify the standard for patrolling and inspecting distribution rights-of-way and for the consenting of activities*

Overall, right-of-way patrols are completed in order to gather information that will allow for the development of appropriate vegetation treatments and schedules. By scheduling the right treatments at the right times, the Company can:

a) Provide for the economic, orderly, and efficient operation of the distribution system,
b) Comply with the requirements of the Hydro and Electrical Energy Act, which seeks the observance of safe and efficient practices in the distribution of electric energy.

1. The immediate objectives of distribution right-of-way patrols and inspections are to:

a) Document the condition of the right-of-way
b) Confirm that work is being carried out as planned
c) Identify and correct environmental damage

2. Once the physical condition of the right-of-way is documented, a maintenance schedule can be developed. The objectives of the maintenance activities are to provide for:

a) Access to Facilities

Right-of-way are maintained to ensure physical access to the right-of-way and to permit visual assessments of the electrical facilities.

b) Public and Worker Safety

Right-of-way maintenance activities are scheduled to prevent and eliminate hazards to employees and the public. Safety hazards noted during patrols are to be corrected as soon as possible.

c) Security of Facilities

Tree and tree-related contacts can result in outages, threaten system integrity and physical integrity. Therefore, distribution rights-of-way must be maintained free of hazards wherever possible. This includes removing or altering trees within striking distance of any electrical facility. Patrols and subsequent maintenance activities must be conducted at regular intervals to ensure that vegetation does not grow to the point where security is threatened.

d) Identification of Potential Fire Hazards

In addition to threatening the integrity of the distribution system, hazard trees represent a high risk of fire in the event of a line contact. Regular patrols and maintenance activities serve to reduce the risk of fire from hazard trees. Hazard reduction programs are described in detail in the annual Wildfire Agreement Plan between ATCO Electric Ltd. and ASRD.

e) Correction of Environmental Damage

Soil erosion, rutting, and compaction, or conditions with the potential to damage water bodies, must be corrected. Once a problem or potential problem has been identified, a reclamation plan is developed to address the cause. Plans may range from minimal soil stability work to the relocation of facilities and should include a schedule of monitoring. The plan should be implemented in a timely manner. Reclamation problems identified by Alberta Forestry Lands and Wildlife must also be rectified as soon as possible.

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| RIGHT-OF-WAY MAINTENANCE | Patrol/Inspection |

3. Timing of patrols and inspections:

a) The distribution system is maintained on a geographic area basis, generally by customer class (e.g. by city, rural, oilfield, etc.). An on-the-ground distribution right-of-way patrol or inspection is completed at least once in every three year period. At that time, every site along the right-of-way is viewed and the condition of the vegetation is documented. Every site is assigned a year by which time the vegetation must be treated in order to maintain required clearances between treatments or, in the case of spray, the last year by which chemicals can still be applied. The operation and rules for clearances are contained in the table below:

| **Operation** | **Guide for Scheduling Treatments (maximums)** |
|---|---|
| Trim | Section 10-002(2) Subsection 3.1.7 of the ECUC. These distances must be maintained at all times, including the time between trims:<br>1. Vertical distance of 2.0m and horizontal distance of 1.0m plus distance to prevent flashover to any part of a tree that will support a person,<br>2. Vertical distance of 0.6m and horizontal distance of 0.3m plus distance to prevent flashover to any part of a tree that will <u>not</u> support a person,<br>Where the line is operated <750 volts, and is metal sheathed, polyethylene covered or insulated - up to but not touching. |
| Mow/Slash | Same as for vertical clearance on Trim |
| Grass Mow | Estimated size of brush not to exceed 2.5 centimetres diameter or 2.5 metres in height |
| Spray | Not to exceed:<br>**<u>1.5m</u>** in height adjacent to a <u>numbered highway</u> or **<u>2.5m</u>** adjacent to a <u>road</u> (unless < 30% of the woody plants being controlled on a one kilometre span exceed the heights specified in that section and any vegetation > 4m height is removed > 1 year after treatment).<br>**4.0m** on a <u>cross-country ROW</u><br>(see Section 12 of the *Code of Practice for Pesticides*) |

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| RIGHT-OF-WAY MAINTENANCE | Patrol/Inspection |

Site specific information and experience are required to determine the subsequent treatment due to the variable growth rates of vegetation throughout the province.

A three to five year period year period is the maximum allowable, based on experience, to capture the vegetation condition in time for appropriate treatment. Vegetation must be treated before it becomes an obstacle for safe and efficient operation of the system, or becomes expensive to maintain because of its proximity to energized facilities. In the case of herbicide programs, patrols must be completed in time for programs to proceed before the vegetation reaches a maximum treatable height.

4. Notation and data collection:

a) A written or data record outlining the maintenance requirements for each site is prepared. This notation will log all comments and field instructions pertaining to the required field work. Field notation will be ATCO Electric standard brushing notation, guided by project specifications and survey brushing notes.

b) Worksites are identified by property boundaries and physical features and referenced to known locations or markers, if available. Water courses and water bodies should be referenced to known locations, structure numbers or aerial markers. Some cross-country distribution lines have an aerial marker every tenth structure so that significant reference points can be recorded in relation to the distribution power lines. Buffer areas are to be retained where possible along all water courses and water bodies.

c) Treatment is described by brush species, height, area, the operation to be conducted and the year by which the treatment should be completed. Factors affecting the completion of the work (access, ground conditions, government requirements, etc.) are also be recorded. Maps, drawings, and landowner conditions complete the information.

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| RIGHT-OF-WAY MAINTENANCE | Landowner Consenting |

## *4.5 Landowner Consenting*

*PURPOSE: To outline the procedure for gaining access to private or public lands for right-of-way maintenance.*

1. ATCO Electric will make reasonable attempts to obtain permission from all affected land owners and occupants prior to vegetation management on distribution line rights-of-way. If the lands are covered by easements, and the work required warrants immediate attention, the work may proceed without consent under the direction of the Forest Operations Coordinator or supervisor.

2. Verbal consent for access and maintenance is acceptable, but a signed permission form is preferred. Verbal consents must be documented on a permission form. In either case, the date the permission was obtained must be recorded on the form.

3. Where personal contact is made, the landowner or occupant shall be provided a copy of the permission form.

4. Consenting may be performed either by the Company or a contractor.

5. Substandard work arising from consents that are unclear, misrepresent either the landowner conditions or the work to be undertaken, or omit relevant and necessary information are the responsibility of the consenting company. If the consenting is performed by ATCO Electric, the company would be responsible to resolve landowner or occupant concerns. All consenting companies shall carry insurance that insurance meets ATCO Electric requirements.

6. The consent form shall describe the location and scope of the work, the conditions and concerns of the landowner, the landowner or occupant address and the name of the person that granted permission.

7. Liability resulting from deviations from the work described in the consent form shall be the responsibility of the contracting company performing the field work.

8. For locations that will require repeat vegetation maintenance, the consenter will attempt to obtain a permanent consent from the land owner.

9. Consenters may not negotiate an interest in land. The sites requiring land interest must be identified to the Forest Operations Coordinator. Such interests may only be negotiated by an ATCO Electric Land Agent.

10. Where work is required within the traditional territory of aboriginal people, ATCO Electric will consult appropriately with the affected community.

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| RIGHT-OF-WAY MAINTENANCE | Contracting |

## *4.6 Contracting*

### *4.6.1 Contract Packages*

*PURPOSE: To define the requirements and information to be supplied to contractors prior to initiating work*

1) ***Maps*** are supplied to the contractor assigned to do the work as part of the tender package and should depict:

   a) Location of the power line
   b) Legal land locations
   c) Location item numbers
   d) Topographical information such as water bodies, access roads, and developments

2) Completed ***landowner permission forms*** constitute the work instructions for each of the land locations

3) The ***workplan*** summarizes the treatments and areas contained in the permission forms.

4) **Easements**.

5) ***Work Specifications*** serves as the standards for work quality, cleanup requirements and general expectations of the contractor. Specifications shall give clear direction on work quality expected and also any operational concerns (See Appendix 4.15.1, 4.15.2 and 4.15.3 for sample work specifications).

6) The ***contract***. All maintenance work is carried out under an hourly, unit rate or lump sum contract (See Appendix 4.15.4 for sample contracts).

7) The ***Pre-job Safety Analysis***. Prior to the start of work, a job safety analysis (JSA) must be completed by the contractor and approved by AE. Copies of the JSA must be kept on site by the crews performing the work. JSA's form part of the contract documents.

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| RIGHT-OF-WAY MAINTENANCE | Contracting |

## *4.6.2 Hiring of Contractors*

*PURPOSE: To outline the requirements for the procurement of right-of-way maintenance contractors.*

### *4.6.2(1) General Requirements*

All work done around energized electrical equipment will be completed under the supervision of a certified Utility Tree Trimmer (UTT), or a Tree Worker (UTW) unless otherwise authorized by the Forest Operations Coordinator. UTTs and UTWs must be certifies by the IVMAA or other body acceptable to the Chief Electrical Inspector, Electrical Protection Branch, Alberta Labor.

### *4.6.2(2) Health Safety and Environment (HSE) 2-P's Manual*

All hiring of contractors will follow the guidelines as set out in the Health, Safety and Environment 2P's Manual.

### *4.6.2(3) Prequalification*

ATCO Electric Ltd. maintains a list of pre-qualified contractors that are routinely engaged in the completion of maintenance work. Other, non-prequalified and unlisted contractors are utilized on as "as-needs" basis. Whether pre-qualified or not, all contractors either meet the requirements of the HSE 2-P's Manual, or are provided direct supervision by the company.

If a contractor's services are absolutely essential and the contractor does not hold a valid COR and is not pre-qualified, then at a minimum, the contractor must have a satisfactory safety system in place and have competent workers. If there is any doubt about the contractor's safety system or the competence of its workers, ATCO Electric will provide direct supervision of the contracted work.

***4.6.2(4) Insurance***

The coordinator in charge will assure current requirements in the following are up to date and valid Insurance.

a) General Liability-minimum of $2 million Comprehensive General Liability (CGL) must include non-owned auto which covers any and all leased vehicles, blanket contractual liability which covers liability assumed by the contractor.
b) Auto-owned (and not owned if not included in GL) Automobile liability with a minimum inclusive limit of $2 million.
c) Forest Fire Fighting-minimum liability of $2,000,000 for each occurrence (sublimit of CGL).

*Note: a copy of current contractors with insurance requirements can be obtained from AE Risk Management.*

***4.6.2(5) One Time Job Under $10,000 Value***

It is ATCO Electric policy that all employers with which it contracts shall be responsible for its own WCB insurance premiums. Further, all contracted employers must, under the terms of the contract, provide verification of such coverage when requested. If this requirement is specifically waived, it must be confirmed in writing and the responsibility for WCB premium payment defaults to ATCO Electric. Incidents involving contracted employers and WCB claims ultimately impact on ATCO Electric's experience rating and related premiums.

Where a contractor does not have WCB coverage, they can still be used for simple (i.e. not complex or high hazard), one-time jobs valued at less than $10,000. The following is a list of minimum standards or actions for such instances:

a) Contact ATCO Electric Corporate Risk Management to inform them of the contractor and the job description (provide a copy of the Purchase order, if requested)

b) Contact Corporate Health & Safety to inform them of the work to cover the contractor working under AE's WCB.

c) Conduct a worksite orientation with all contractor employees to ensure they are aware of the hazards and have appropriate barriers in place.

d) Ensure a jobplan/tailboard is completed

WCB is checked by Accounts Payable prior to the payment of the invoice. If it is a one man company, or small contractor, then Accounts Payable will add the amount to payroll and cover the contractors employees under AE's WCB (i.e. as temporary employees).

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**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| RIGHT-OF-WAY MAINTENANCE | Limit of Approach |

## *4.7 Limits of Approach*

*PURPOSE: To outline the clearance required to be maintained from energized electrical equipment and apparatus during right of way maintenance work. All work must be performed in accordance with Division H of the ECUC.*

**TABLE 2-1 (ECUC)**
**SAFE LIMIT OF APPROACH DISTANCES FROM OVERHEAD POWER LINES FOR PERSONS AND EQUIPMENT**

| Operating Voltage of Overhead Power Line Between Conductors | Safe Limit of Approach Distance For Persons and Equipment |
|---|---|
| 0 - 750 V Insulated or Polyethyline Covered Conductor (1) | 0.3 m |
| Above 750 V Insulated Conductors (1)(2) | 1.0 m |
| 0 - 40 kV | 3.0 m |
| 69, 72 kV | 3.5 m |
| 138, 144 kV | 4.0 m |
| 230, 240 kV | 5.0 m |
| 500 kV | 7.0 m |

Note: (1) Conductors must be insulated or covered throughout their entire length to comply with these groups.
(2) Conductors must be manufactured to rated and tested insulation levels.

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| RIGHT-OF-WAY MAINTENANCE | Limit of Approach |

**TABLE 4-5 (ECUC)**
**LIMITS OF APPROACH DISTANCES IN MILLIMETERS FOR UTILITY TREE TRIMMERS**

| Voltage Level | | | Utility Tree Trimmers | | |
|---|---|---|---|---|---|
| Nominal Voltage to Ground kV | Nominal Voltage Phase to Phase kV | Maximum Operating Voltage Phase to Phase kV | Limit of Approach for Utility Tree Trimmers and Conducting Objects to Exposed Energized Parts mm | Limit of Approach for Rated insulated Tools to Exposed Energized Parts mm | Limits of Approach for rate, insulating booms mm |
| Column 1 | Column 2 | Column 3 | Column 4 (1) | Column 5 (2) | Column 6(3) |
| 2.4 | 4.16 | 4.58 | 1050 | 40 | 500 |
| 8 | 13.8 | 15.18 | 1100 | 120 | 550 |
| 14.4 | 25 | 27.50 | 1200 | 210 | 650 |
| 19.9 | 34.5 | 37.95 | 1300 | 290 | 750 |
| | 69, 72 | 79.2 | 1600 | 610 | 1050 |
| | 138, 144 | 158.4 | 1900 | 920 | 1350 |
| | 230, 260 | 285 | 2400 | 1410 | 1850 |
| | 500 | 550 | 3700 | 2710 | 3150 |

Note: (1) Limit of approach distances in Column 4 have been calculated using IEEE minimum tool distances plus 1000mm safety factor, rounded to the nearest 50mm.
(2) Limit of approach distances in Column 5 have been calculated using IEEE minimum tool distances, rounded to the nearest 10 mm.

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| RIGHT-OF-WAY MAINTENANCE | Limit of Approach |

**TABLE 4-6 (ECUC)**
**TREE TO ENERGIZED ELECTRICAL EQUIPMENT OR LINES**
**DISTANCES IN MILLIMETERS FOR UTILITY TREE TRIMMERS**
**UTILITY TREE WORKERS AND OTHER WORKERS**

| Voltage Level | | | Utility Tree Trimmers, Utility Tree Workers and Other Workers |
|---|---|---|---|
| Nominal Voltage to Ground kV | Nominal Voltage Phase to Phase kV | Maximum Voltage Phase to Phase kV | Tree to Energized Electrical Equipment or Lines Distance for Slashing and Brushing mm |
| Column 1 | Column 2 | Column 3 | Column 4 (1) |
| 2.4 | 4.16 | 4.58 | 800 |
| 8 | 13.8 | 15.8 | 850 |
| 14.4 | 25 | 27.50 | 950 |
| 19.9 | 34.5 | 37.95 | 1050 |
| | 69, 72 | 79.20 | 1350 |
| | 138, 144 | 158.4 | 1650 |
| | 230,260 | 285 | 2150 |
| | 500 | 550 | 3450 |

Note: (1) Tree to energized electrical equipment or line distances in Column 4 have been calculated using IEEE tool distances plus 750 mm safety factor, rounded to the nearest 50mm.

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| RIGHT-OF-WAY MAINTENANCE | Limits of Approach |

**TABLE 4-7 (ECUC)**
**TREE TO ENERGIZED ELECTRICAL EQUIPMENT OR LINES**
**DISTANCES IN MILLIMETERS FOR UTILITY TREE TRIMMERS**
**USING RATED INSULATED TOOLS**

| Voltage Levels | | | Utility Tree Trimmers | |
|---|---|---|---|---|
| Nominal Voltage to Ground<br>kV | Nominal Voltage Phase to Phase<br>kV | Maximum Operating Voltage Phase to Phase<br>kV | Tree to Energized Electrical Equipment or Lines Distance Using Rated Insulated Tools<br>mm | Tree to energized Electrical Equipment or Lines Distance Using Rated Insulated Tools from a Rated Insulated Aerial Device<br>mm |
| Column 1 | Column 2 | Column 3 | Column 4 (1) | Column 5 (2) |
| 2.4 | 4.16 | 4.58 | 350 | not touching |
| 8 | 13.8 | 15.18 | 400 | not touching |
| 14.4 | 25 | 27.50 | 500 | not touching |
| 19.9 | 34.5 | 37.95 | 600 | not touching |
| | 69, 72 | 79.2 | 900 | 600 |
| | 138, 144 | 158.4 | 1200 | 900 |
| | 230, 260 | 285 | 1700 | 1400 |
| | 500 | 550 | 3000 | 2700 |

Note: (1) Tree to energized electrical equipment or lines distances in column 4 have been calculated using IEEE minimum tool distances plus 300 mm safety factor, rounded to the nearest 50mm

(2) Tree to energized electrical equipment or lines distances in Column 5 for 69 kV lines and higher have been calculated using IEEE minimum tool distance rounded to the nearest 50 mm.

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|---|---|
| RIGHT-OF-WAY MAINTENANCE | Herbicides |

## *4.8 Herbicide Application*

*PURPOSE: To outline the requirements governing herbicide application on distribution right of ways.*

*The legislated requirements regarding the storage and handling of pesticide products is found in the Alberta Environmental Protection and Enhancement Act, Pesticide Sales, Handling, Use and Application Regulation (126/93)*

### *4.8.1 Selection of pesticide products*

- All herbicides used will be registered with a valid PCP identifier label.
- All herbicides used must have an industrial label registration.
- Herbicides used on agricultural lands may have an agricultural or industrial label registration.
- Herbicides must be selected based on their characteristics. The criteria considered are toxicity, persistence, efficacy, selectivity, mobility, and cost.
- Non-residual herbicides should be used in areas with high water tables, next to tree line or sensitive vegetation, or where hazards may be associated with the potential migration of the product.
- Residual herbicides may be used where there is no anticipated migration of the herbicide, or in controlled site areas.
- As much as possible, selective herbicides will be used in order to control only incompatible Vegetation.
- Non-selective herbicides may be used to obtain total vegetation control in areas of bare ground.

### *4.8.2 Applicators*

- All persons hired to apply pesticides must possess a valid Alberta Industrial Class applicators certificate, or be under the direct on site supervision of an individual who possesses the certificate.
- Applicators will be under the employment of a contractor who has a current Service Registration with AEP Pesticide Chemicals Branch.

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| RIGHT-OF-WAY MAINTENANCE | Herbicides |

***4.8.3 Application***

Due to the fact that herbicides are applied by contract crews using a variety of equipment, the application procedures reside with the contractor. At the JSA or pre-job meeting, the Forest Operations Coordinator will ensure that the contractor has detailed procedures available for the following:

1. Handling storage
2. Transportation
3. Disposal of used containers
4. Mixing of herbicide solutions
5. Application techniques
6. Personal protective equipment
7. Unauthorized release response and clean-up

Registered herbicide products shall be applied at recommended label rates and conform to provincial and federal legislation as well as IVMAA Standards and Good Practices. Only registered herbicide tank mixtures will be allowed. The mixture must be on the label or approved in writings by AE.

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Pesticide Products and Containers |

## *4.9 Transportation, Storage and Disposal of Pesticide Products and Containers*

*PURPOSE: To outline the standard for disposal of pesticide products and pesticide product containers.*

1. Disposal of pesticide products and pesticide product containers is addressed by the Alberta Environmental Protection and Enhancement Act, administered by Alberta Environment.

2. Container disposal sites have been established throughout the province for the collection of used pesticide containers. At least one container disposal site is located in each municipality throughout the province. These sites are to be the only places where used pesticide product containers are to be deposited. Plastic containers are not to be burned or buried and metal containers are not to be buried or flattened and left. The contractor must contact the local district agriculturist to determine both permanent and temporary container collection sites. This requirement will be included in the JSA.

3. Pesticide product containers that are not re-useable are to be:

   a) Triple Rinsed: Pour rinseade back into the spray tank.

   b) Punctured: Pesticide containers, once triple rinsed, are to be punctured so as not to be re-used.

   c) Deposited: Provincially approved pesticide container disposal sites are the only sites where pesticide containers are to be deposited.

4. Containers of pesticide products are not to be cached in the forested or agricultural areas. Only sites approved by Alberta Environment may be used for temporary storage.

5. The Clean Water Act requires that no water contaminants are to be permitted to enter water at any time, unless approved by Alberta Environment.

6. Alberta Environment and ATCO Electric Ltd. shall be notified of all unintentional emissions or discharges of agricultural chemicals or substances containing agricultural chemicals on or into the natural environment that are not as previously approved by Alberta Environment or recommended by the manufacturer. Alberta Environment 1-800-222-6514.

7. Excess herbicide spray solution is to be applied to non-compatible vegetation in a section of the right of way in a manner that avoids excessive concentration of active ingredient.

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Mechanical Work |

## *4.10 Mechanical Work*

*PURPOSE: To outline the specific safety observances required for mechanical vegetation control.*

### *4.10.1 Mowing*

- Areas to be mowed must be pre-mowed to the limits of approach of the operator.
- Workers must be qualified and competent to do the work. The mower operator should have at least Electrical Safety Awareness training as offered by the IVMAA through Old's College.

### *4.10.2 Trimming*

- Workers must have a valid Utility Tree Trimmer certificate or be under the direct supervision of a certificate holder.
- Crews must be competent in the operation of aerial devices and rescue techniques.
- Climbing and other trim crews must follow ATCO Electric Transmission Department Policy Trimming Operations in Trees.

### *4.10.3 Slashing*

- Crew must be under the supervision of a Utility Tree Worker or Utility Tree Trimmer as per the OH&S Act and ECUC.

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| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Weeds |

## *4.11 Weed Control on ATCO Electric Property, Public Lands or Private Lands*

*PURPOSE: To outline the standard required for weed control on public, private and ATCO-owned property.*

1. The Weed Control Act of Alberta authorizes inspectors to issue orders for land occupants or owners to destroy all restricted or noxious weeds growing or located on the land as often as necessary to prevent the spread, growth, ripening or scattering of the restricted weeds, and to control all noxious weeds.

2. The Weed Control Act indicates that no person shall deposit or permit to be deposited any weed seeds or material containing weed seeds in any place where they might grow or spread.

3. Concerning public lands the holder of a disposition shall, with respect to the land contained in this disposition:

   a) Use only First Class Seed that is free and clear of all noxious and restricted weeds.

   b) Cut, keep down and destroy all noxious and restricted weeds.

4. When movement of machinery or vehicles is likely to cause the spread of restricted, noxious or nuisance weeds they are not to be moved. Vehicles are to be cleaned and weeds or weed seeds destroyed.

5. On private lands weed control is the responsibility of the landowner.

6. On privately owned lands where ATCO Electric has easement but annual rental payments for distribution facilities are not made, it is appropriate that ATCO Electric assist with weed control by incurring all or part of the application cost. However, ATCO Electric employees should not supply chemical product to private landowners.

7. In municipal Districts and Counties where distribution lines are located on the road allowance, weed control on the road allowance area is the responsibility of the municipality.

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**DISTRIBUTION LINE MAINTENANCE STANDARDS**

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| RIGHT-OF-WAY MAINTENANCE | Weeds |

8. Schedule of Restricted and Noxious Weeds in Alberta.
Note: Local authorities may make by-laws designating weeds to a higher category within the municipal boundaries.

**Restricted Weeds:**

Red bartsia – Odontites serotina
Diffuse knapweed - Centaurea diffusa
Spotted knapweed - Centaurea maculosa
Nodding thistle - Carduus nutans
Eurasian Water Milfoil - Myriophyllum spicatum
Doddler - Cuscuta spp.
Yellow star-thistle - Centaurea solstitialis.

**Noxious Weeds:**

Russian knapweed - Centaurea repens
Field bindweed - Convolvulus arvensis
White Cockle - Lychnis alba
Bladder campion - Silene cucubalus
Cleavers - Galium aparine
Hoary cress - Cardaria spp
Knawel - Scleranthus annuus
Perennial sow thistle - Sonchus arvensis
Cypress spurge - Euphorbia cyparissias
Leafy spurge - Euphorbia esual
Stork's bill - Erodium cicutarium
Canada thistle - Cirsium arvense
Toadflax - Linaria vulgaris
Persian darnel - Lolium persicum
Scentless Chamomile - Matricaris maritima
Common tansy - Tanacetum vulgare
Blueweed -Echium vulgare L.
Ox-eye daisy - Chrysanthemum leucanthemum.
Spreading dogbane - Apocynum androsaemifolium.
Field scabious - Knautia arvensis.
Hound's tongue - Cynoglossum officinale.
Tall buttercup - Ranunculus acris.
Purple loosestrife - Lythrum salicaria

Weed Control Act of Alberta 138/80

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| RIGHT-OF-WAY MAINTENANCE | Vegetation Maintenance on Facilities |

## *4.12 Substations, Yards and Storage Facilities*

*PURPOSE: To outline the standard for vegetation maintenance at substations, yards and storage facilities.*

Permanent facility site vegetation records are to be established for each substation and storage facility location receiving herbicide treatment. The following information should be stored:

- Name of facility
- Legal land location
- Area
- Soil conditions
- Vegetation present at site and adjacent vegetation
- Soil stability
- Environmental concerns
- Arial pictures and sketch of substation and yard sites

Methods of vegetation control can include removal of hazard trees, mowing, digging and burning of weeds, picking of flower heads before seed dispersal and herbicide control. Decisions on methods of control should be made as to the most effective means of controlling the non-compatible vegetation. Besides hazard tree removal, the preferred method of control for distribution facilities is by the use of herbicide.

Substation and communication sites should be inspected annually, if possible, for the presence of noxious and restricted weeds. Inspections should not be less frequent than once in each three year period.

Selection of herbicide control should be dependent on soil type, adjacent land use, potential run-off problems and type of vegetation.

Herbicide vegetation management consists of non-selective bare ground or selective vegetation control. Herbicides used are non-residual, short- or long-term residual. For best results, short and long term treatments should be alternated over time.

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| RIGHT-OF-WAY MAINTENANCE | Vegetation Maintenance on Facilities |

Vegetation maintenance on substation sites should include:

- Bare ground vegetation control for all graveled areas. This could include non-selective residual or non-selective non-residual herbicides.
- Bare ground vegetation control for access roads using non-selective non-residual herbicides or non-selective short term residual herbicides.
- Woody vegetation and weed control for all remaining property using selective non-residual or selective residual herbicides.

Vegetation maintenance on yards and storage facilities should include:

- bare ground vegetation control on graveled areas using non-selective non-residual herbicides or non-selective short term residual herbicides.
- Woody vegetation and weed control for all remaining property using selective non-residual or selective residual herbicides.

No person shall enter a substation except under the direct supervision of a qualified utility employee or a utility employee who has completed P.S.S.P. training and is granted access by their supervisor. Contracted employees may be granted access, without supervision, to complete herbicide work inside substations, if the proper training has been completed. See Section 300 of the TSOP - Substation/Site Entry

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|---|---|
| RIGHT-OF-WAY MAINTENANCE | Wood Debris and Timber Salvage |

## *4.13 Standard for Disposal of Wood Debris and Salvage of Timber*

*PURPOSE: To outline the standard for disposal of woody debris and salvage timber from Distribution Right-Of-Way Maintenance Programs.*

### *4.13.1 Agricultural Areas*

1. The consenter will confirm with the landowner the method for dealing with salvage wood. If the landowner so desires, wood is to be cut into pre-determined lengths and piled on the landowners property. Otherwise, all woody debris must be destroyed on site by means acceptable to the landowner or completely removed from the property.

2. If woody debris is to be chipped, the wood chips should remain at the work site if approval is obtained from the landowner or municipality. Otherwise, wood chips should be removed from the property and disposed of at an approved facility.

3. Wood chips shall not be dumped in large piles but evenly distributed over the work area, and wood chips are not to be larger than 8cm x 6cm x 1.5cm (72cu cm). Rails resulting from mowing or mulching operations shall not exceed 1 meter length or 10 cm diameter.

4. Care is to be taken to ensure that wood chips or other debris will not block culverts or result in landowner concern.

5. Burning of brush piles is not recommended as a procedure in agricultural areas because of the risk of uncontrolled wildfire. Automobile tires are not to be used for burning. Brush piles are to be promptly disposed of by chipping, mowing or mulching.

6. Any burning done in the agricultural areas must be authorized by the respective municipal government. During the fire season (usually from April 1 to October 31) the contractor must obtain a fire permit before igniting a fire in the Forest Protection Area. In the White Zone, the municipality may require burning permits at other times of the year.

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| RIGHT-OF-WAY MAINTENANCE | Wood Debris and Timber Salvage |

### *4.13.2 Forested Areas*

1. Total disposal of woody debris by burning (preferred method), mulching or chipping is required. Every fire must be controlled and attended by a responsible person or persons approved by a Forest Officer or Fire Guardian. Disposal of wood by chipping and dispersal of wood chips should be considered as an option to suppress re-growth of non-compatible vegetation. If volume of re-growth is low then falling of trees and bucking to the ground may be a viable option.

2. The volume, utilization standards, and species of salvageable timber will be determined by Alberta Forest Service at the District Office or Ranger Station. Special conditions may be negotiated on an individual basis.

3. When road access is available and timber volumes are sufficient, salvage of both coniferous and deciduous species may be a requirement.

4. After twelve months, timber decks become the property of Crown unless other arrangements have been made with Alberta Forest Service Timber Management Regulation AR60/73, Section 110.

5. Log decks are to be positioned in landing areas so that they are readily accessible for pick-up and do not create a roadside hazard. Refer to the requirements of Forest Management Companies regarding salvage. Timber decks are not to be positioned beneath power lines and power lines are not to be constructed over timber decks as future moving may create a safety hazard.

6. Care should be taken to ensure that smoke from burning operations does not create a road hazard. Approval from Alberta Transportation and Utilities is required when burning brush near primary roadways.

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| RIGHT-OF-WAY MAINTENANCE | Acts and Regulation |

## *4.14 Acts and Regulation*

*PURPOSE: Acts and Regulations which are pertinent to Right of Way Maintenance.*

**Provincial**

- Weed Control Act
- Alberta Environmental Protection and Enhancement Act and Regulations
- Forest and Prairie Production Act
- Surface Rights Act
- Electrical Communication Utility Code
- Occupational Health and Safety Act and Regulations
- Public Health Act
- Motor Transport Act
- Highway Traffic Act
- Fire Code

**Federal**

- Migratory Birds Act
- Species at Risk Act
- Fisheries Act
- Canadian Environmental Protection
- TDG Act
- Pest Control Products Act
- Aviation Regulations and Air Navigation Orders
- WHMIS

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| RIGHT-OF-WAY MAINTENANCE | Glossary of Terms |

| | |
|---|---|
| 2 **P** | The health, safety and environment Policies, Practices Procedures manual. |
| **Access:** | The right to enter privately owned land from a public way. |
| **AEP** | Alberta Environmental Protection-can include the forestry, fish and wildlife and pesticide management branch. |
| **AEPEA** | Alberta Environmental Protection and Enhancement Act. |
| **Agricultural Chemical:** | Any substance or mixture of substances intended, sold or represented for use as a fertilizer, pesticide, plant growth regulator or soil supplement or any other substance or mixture of substances used to control plant or animal pests or to promote or control plant growth, except drugs and medicines intended for human or veterinary use, and includes any substances defined in the regulations as an agricultural chemical. |
| **Active Ingredient:** | The concentration of chemical in a formulated product that is responsible for action. |
| **Annual Plant:** | The entire life cycle of the plant is completed in a single growing season. |
| **AE** | **ATCO Electric** |
| **Bed and shore** | Land that is or has been covered by water to the extent that:<br>(i) No vegetation grows on the land, or<br>(ii) The vegetation that grows on the land is aquatic vegetation that must be partially submerged in water for part of its life cycle to survive. |
| **Biennial Plant:** | A plant that normally requires two growing seasons to complete the life cycle. Only vegetative growth occurs the first year often resulting in the formation of an over wintering rosette. The flowering and fruiting occur in the second year. |
| **Consenter/Permissioner:** | An individual employed by the company to contact landowners and occupants, discuss company initiatives regarding the project, address landowner/occupant concerns and obtain approval to proceed with the project at hand. |

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| RIGHT-OF-WAY MAINTENANCE | Glossary of Terms |

**Compatible Vegetation:** Plant species that demonstrates growth characteristics which compliment the operation and maintenance of a power lines system. These plants are generally low growing, perennial and at times compete to displace incompatible plant species.

**Crown Land:** Land owned by the federal or provincial government.

**Dangerous Good:** A product, substance or organism specified in the regulations or included by its nature in any of the classes listed in the regulations.

**Easement:** A non-possessing interest acquired by one person on the land of another, permitting partial use of the other's land for a specific purpose, such as a Right-of-Way across it.

**ECUC:** Electrical and Communication Utility Code.

**Forest Management Agreement:** The Minister of Forestry Lands and Wildlife with approval of the Lieutenant Governor in Council may enter into a forest management agreement with any person to enable that person to enter on forest lands for the purpose of establishing, growing and harvesting timber in a manner designated to provide a perpetual sustained yield.

**Forest Management Areas:** Refers to public lands which a forest management agreement or forest management lease has been entered into. The area refers to a tract of forest land over which a company has been given management rights to establish, grow and harvest trees on a perpetual sustained yield basis for a defined period of time.

**Forest Protection Area:** A tract of public land which for the purpose of facilitating fire control was by an Order of the Lieutenant Governor in Council designated as a "forest protection area."

**Fire Guardian:** A person appointed as a fire guardian by the Minister or by a Municipal District under the Forest and Prairie Protection Act.

**Green Area:** Means the area outlined and colored green on a map annexed to the Order Classifying Public Lands dated April 16, 1963 and published in the Alberta Gazette on April 30, 1963, as amended from time to time.

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| RIGHT-OF-WAY MAINTENANCE | Glossary of Terms |

**Hazardous Substance:** A product or substance that is included in Division 2 of Class 9 in List II of Schedule II of the Transportation of Dangerous Goods Regulation.

**Hazard Trees:** These are trees that are dead, diseased or not wind firm that because of their condition pose an immediate danger to the normal operation of the electrical facility.

**Herbicide:** A pesticide product used to destroy or inhibit plant growth.

**Industrial Applicator:** An individual licensed by Alberta Environment to apply pesticides on public land.

**Incompatible Vegetation:** Quick growing plant species that have growth potential sufficient to interfere with the safe and reliable supply of electric power.

**Inspection:** A site specific inspection of the right of way to review completed work or detail required work. This may be completed in conjunction with or apart from the fly by or drive by patrol.

**I.V.M.A.A.:** The Industrial Vegetation Management Association of Alberta.

**Lessor:** The person who grants the use of property by way of a lease to a tenant.

**Non-residual herbicide** A herbicide which is not persistent in soil and is only active upon contact with plants above ground.

**Notation:** A system of characters, symbols and abbreviations used in an art or science to express technical facts or quantities.

**Noxious Weed:** A plant that is designated under the regulations or a bylaw as a noxious weed and includes noxious weed seeds.

**Nuisance Weed:** A plant that is designated under the regulations or a bylaw as a nuisance weed and includes nuisance weed seeds.

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| RIGHT-OF-WAY MAINTENANCE | Glossary of Terms |

**Open Body of Water:** The bed and shore of an irrigation canal, drainage canal, reservoir, river, stream, creek, lake, marsh or other body of water, but does not include the following:

(i) Water works system;
(ii) Reservoirs, lakes, marshes or other bodies of water that are completely surrounded by private land, that have an area of less than 4 hectares and have no outflow of water beyond the private land;
(iii) Reservoirs, lakes, marshes or other bodies of water that are located on public land, that have an area of less than 0.4 hectares, and have no outflow of water;
(iv) Irrigation and drainage canals that are completely surrounded by private land and have no outflow beyond the private land;
(v) Roadside ditches;
(vi) Water system;
(vii) Storm drainage systems;
(viii) Dry streams having a bed and shore averaging 0.5 metres or less in width within the boundaries of the treatment area.

**Owner:** The person in whose name a certificate of title to land is issued under the land titles act or if no certificate of title to the land is issued, the Crown or other body administering the land.

**Patrol:** A fly by or drive by of facilities at which time a cursory review is completed.

**Perennial:** A plant which persists from year to year and usually produces reproductive structures in two or more different years.

**Pesticide:** Any substance intended for controlling insects, rodents, fungi, weeds, and other forms of plants or animal life that are considered to be pests. Antibiotic drugs are not considered pesticides, and vice versa.

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**Pesticide Applicator:** An individual licensed by Alberta Environment or an individual working under the direct supervision of a licensed applicator to apply a pesticide product(s) to control a pest.

**Pesticide Permit:** An authorization from Alberta Environment to apply a given pesticide(s) for the control of certain pest species on Crown Lands.

**Product Identification Number:** A Product Identification Number (P.I.N.) in respect of dangerous goods described in Column I of an item of a list, and specified in Column II of that item in the Transportation of Dangerous Goods Control Regulation.

**PSSP** Power system safety program. Training which is required for entry into substations being granted.

**Public Lands:** Land of the Crown in right of Alberta.

**Qualified Utility Employee** Means a power line or station utility employee trained and experienced to work safely on energized electrical equipment or lines in accordance with the requirements of the safety rules while performing duties assigned by an employer.

**Residual Herbicide:** Persists in soil, kills re-growth and or germinating seedlings over an extended time.

**Restricted Weed:** A plant that is designated under the regulations or a bylaw as a restricted week and includes restricted weed seeds.

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| RIGHT-OF-WAY MAINTENANCE | Glossary of Terms |

**Right-of-Way:** A legal right of passage over another person's ground used by the Electric Utility Company to transmit or distribute electricity. It is the area of land utilized for the construction, security, access and maintenance of the power lines facility. On Crown lands, this area will have a surface disposition as a power lines easement (E.Z.E.) and/or vegetation control easement (V.C.E.) and the right of way may overlap other facilities ie: (L.O.C.) License of Occupation.

**Right of Way Maintenance Program:** The Right of Way Maintenance Program employs a combination of procedures to alter the plant community where necessary along the right of way area so that electrical facilities function as designed recognizing safety and operating requirements.

By use of manual, mechanical, herbicide and biological controls the Right of Way Maintenance Programs endeavor to establish a relatively stable plant community that will result in a reduced requirement for future maintenance.

**Riparian Rights:** The rights of the owners of lands on the banks of watercourses to make advantageous use of the water on, under, or adjacent to their land, including the right to assertions.

**Riparian Vegetation:** Stream side vegetation.

**Selective Herbicide:** A herbicide that is more toxic to some species of plant than others.

**Timber:** All trees living or dead, of any size or species and whether standing, fallen, cut or extracted.

**Timber Deck:** A pile of salvaged logs at a landing area.

**TSOP** Transmission Safe Operating Procedures manual.

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**Utility Tree Trimmer:** An employee certified by the Industrial Vegetation Management Association of Alberta or other agency acceptable to the Chief Electrical Inspector, to remove trees or portions of trees around power lines or other electrical equipment including aerial trimming in accordance with the requirements of the safety rules.

**Utility Employee:** (i) An employee trained to recognize hazards associated with energized electrical equipment or lines and trained and experienced to work safely around energized electrical equipment or lines in accordance with the requirements of the safety rules while performing duties assigned by an employer, and (ii) if an employer designates such duties, an employee trained and experienced to work safely on energized electrical equipment or lines operating at voltages below 750 Volts between conductors in accordance with the requirements of the safety rules.

**Utility Tree Worker:** An employee certified by the Industrial Vegetation Management Association of Alberta or other agency acceptable to the Chief Electrical Inspector, to remove trees or portions of trees around power lines or other electrical equipment not including aerial trimming in accordance with the requirements of the safety rules.

**Water:** All water on or under the surface of the ground.

**Watercourse:** Means

(i) The bed and shore of a river, stream, lake, creek, lagoon, swamp, marsh, or other natural body of water, or

(ii) A canal, ditch, reservoir or other man-made surface feature, whether it contains or conveys water continuous or intermittently, or

(iii) Refer to open body of water definition.

**White Area:** Titled land held under private ownership in non-forested, agricultural areas of the Province.

**Woody Vegetation:** means trees and shrubs.

### *4.16.1 Sample Maintenance Specifications for Mowing, Trimming and Slashing*

1. All limbs or stems which can not be disposed of will be cut into 1m. lengths and piled neatly on the edge of the right of way.

2. All limbs will be disposed of by chipping unless otherwise approved by ATCO Electric and the landowner.

3. Limbs and trees which have the potential to come within the safe limits of approach to the conductor will be roped off to control direction of fall.

4. All mowing should be done as close to the ground as possible.

5. Slash locations should have stump heights of no greater than **8 cm**. or as close to the ground as possible. All stumps left should have flat tops. Areas of steep slopes will have stump heights high enough to hold slashed material on the slopes.

6. Any rails left as the result of mowing will be less than 1.0 meter in length and laid flat to the ground. If rails are longer the area will be re-mowed, slashed or the rails chipped.

8. Chips will be blown back on the right of way and spread to minimize pile depth to **10 cm.** at the time of chipping.

9. All trimmed limbs will be cut flush with the branch collar.

10. All crews will have mobile communications on site at all times to ensure verbal contact with the Forest Operations Coordinator and the system control center in Vegreville.

11. Poles, guys or other obstacles will be marked and have an area cleared around them for a minimum radius of 1.5 meters whenever mowing.

12. All seed used will be **certified** and **cleaned** to be free of weeds. All tags from the seed will be saved and attached to the invoice.

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13. Seeding will be done at such a time to ensure germination and survival of cover. (ie: not from Sept. - Oct.)

14. All seed mixtures will be pre approved by ATCO Electric and the landowner.

### *4.16.2 Sample Specifications for Herbicide Applications*

1. Incompatible vegetation is defined as poplar, aspen alder, spruce and pine, or any tall growing vegetation which has the potential to grow within 4 meters of the conductors.

2. All incompatible vegetation will be controlled with Garlon 4 applied at rate of 6L/Ha or tank mixture of 6L Garlon 4 per 1000L water. All applications must follow label recommendations.

3. Treatments must achieve 90% efficacy after 1 year or re-treatment will occur at the contractor's expense.

4. Areas that are missed during application will be redone the following growing season at the contractor's expense.

5. The contractor will notify all registered trapline holders, by registered mail, at least 10 days before applying herbicide. Copies of letters will be forwarded to ATCO Electric.

6. All crews will have mobile communications on site at all times to ensure verbal contact with the system control centre in Vegreville.

7. All applicators will be supervised by an applicator holding a valid Alberta industrial class applicators certificate.

8. Crown authorities and all landowners that request contact prior to work, will be notified a minimum of 2 days prior to start of application.

9. Applications will follow the guidelines set forth in the IVMAA's third edition of the industry standards and good practices for vegetation management.

10. All off-site damages due to drift, migration or misapplication will be reclaimed at the contractor's expense.

11. Any areas not treated must be recorded, by structure number, and supplied to ATCO Electric with a reason why the area was not treated.

12. Summary records of the application will be supplied at the completion of the job. These will include what herbicides were applied and what lands they were applied to.

13. All work locations not completed as indicated on the permission list will be deducted from the bid price. Holdbacks of 20% minimum will be kept until all work has been completed.

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14. Failure to comply with any Specifications or the Standard Bid Document will result in the crew being shut down until all problems have been corrected.

15. All work locations are to be left neat and tidy, with brush disposal acceptable to both ATCO Electric and the landowner.

16. Crews will conduct Job Safety Analyses and tailboards.

17. All crews will be familiar with the *Electrical and Communication Utility Code* and the *Safe Limits of Approach* for tree work.

18. All crews will be familiar, and comply with, the *Alberta OH&S Act and regulations.*

19. All pipeline crossings must be identified and the pipeline owner contacted prior to crossing the pipeline. Crossing requirements of the pipeline owner will be complied with during the crossing.

### *4.16.3 Sample Specifications for All Distribution Work*

1. All work will be completed and invoiced by the date indicated in the Form of Tender or Contract.

2. Landowner permission forms are regarded as the work instructions. Any deviations must be approved by the Forest Operations Coordinator and arranged with the landowner.

3. The attached ATCO Electric map indicates the location of each brushing site. The patrol notation describes the estimated scope of work required at each location.

4. The contractor will be responsible for any damage to public or private property sustained while completing the identified work.

5. The crew foreman will contact Forest Operations Coordinator as indicated in the job planning meeting, in regard to work progress and, if any difficulties develop.

6. The crew foreman will contact the nearest ATCO Electric service area office and report daily their whereabouts.

7. An operational mobile telephone or ATCO Electric Company radio is required with each brushing crew.

8. Outages are to be arranged a minimum of 48-hrs.in advance with the local ATCO Electric operator in-charge.

9. All work locations will be mapped and the work done on each location will be recorded. This map will be submitted to Forest Operations Coordinator at the completion of the project.

10. The crew foreman will be familiar with and have in his possession, the `SPECIFICATIONS'.

11. Work locations not completed as indicated on the workplan will be deducted from the bid price.

12. The contractor may supply a separate price for all extra work locations not indicated on the attached maps or permission lists. Each location, however, must be approved by ATCO Electric Coordinator.

13. Any changes to brushing activities (as described on the Landowner Permissions form) will be documented (including landowner authorization) on the form, with the revised date and crew foreman signature. Such **changes require prior approval from the Forest Operations coordinator**.

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14. Any deficiencies relevant to these specifications or to the "Landowner Permission" requirements will be neatly documented on the specific "Landowner Permissions" form or on an alternate, acceptable report. These "deficiency documents" will all be returned to Forest Operations prior to inspection (and final payment).

15. The contractor will document the status (i.e. bent, missing, or intact) of survey pins belonging to the Province of Alberta at mow locations. No mowing will take place within 0.3 m (1 foot) of any such survey markers or marker pits. Any disturbance or damage to intact survey markers, or marker pits, will require the contractor to bear the cost of their re-establishment.

16. All stumps will be cut as low as possible (no higher than 8 cm (3 in.)) with flat tops, unless required for slope stabilization.

17. All limbs will be disposed of by chipping, unless otherwise approved by the Forest Operations coordinator.

18. All limbs under or to the side of the power line will be trimmed using directional pruning techniques.

19. A Utility Tree Worker or Utility Tree Trimmer will be in charge of each mow crew, if Limits of Approach for non-certified operators may be violated. Otherwise LOA can be achieved through pre-mowing.

20. A Utility Tree Trimmer will be in charge of each trim crew.

21. A Utility Tree Worker or Utility Tree Trimmer will be in charge of each slash or pre-mow crew.

22. Unless the ATCO Electric “Landowner Permissions” form indicates otherwise, the **minimum** right-of-way widths required on each side of the power line (at ground level) are: 7.5 metres for three phase line, and 6 metres for single-phase line, and **tree limb to conductor clearance after mowing should be 5 metres.**

23. All woody vegetation with potential to grow within 3 metres of the primary conductor, will be removed (i.e. poplar, alder, birch, spruce, pine, and some willow), unless indicated otherwise by the Landowner Permission list.

24. All trimmed limbs will be cut flush with the tree trunk (without damaging the branch collar). All limbs above the power line will be removed. **There will be no work over any energized equipment, or within the Utility Tree Trimmer/Tree worker "limits of Approach” unless specific procedures are approved by ATCO Electric Ltd.**

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25. Remove all woody species growing under guy wires.

26. All guy wires within 3 metres (10 feet) of mow operations will be flagged in advance. A 3-meter (10-foot) diameter area will be cut out around such guy wires prior to mow operations. This area will be closely examined for guy wire "tails." Such "tails" will be brought to the attention of the local district office.

27. All work locations are to be left tidy, with brush disposal acceptable to both ATCO Electric and the landowner. Mowers may have to make two passes, or have larger trees slashed in advance; especially for large willow, or heavy density deciduous areas (when stem diameters are greater than four inches/ten cm). Greater care is required around yard sites; all exposed limbs and roots over two inches (five cm) in diameter should be removed with the ground being reasonably leveled off prior to seeding.

28. Pre-mowing operations include the removal of larger trees on the side (s) of right of way, and is a requirement at some mow locations. This work will be done in advance of mow operations.

29. All activities conducted for ATCO Electric will conform to the following:

    a) The province of Alberta's:

    - Electrical Protection Act
    - Employment Standards Code
    - Environmental Protection and Enhancement Act
    - Occupational Health and Safety Regulations
    - Forest and Prairie Protection Act
    - Surface Rights Act
    - Weed Control Act

    b) The Government of Canada's:

    - Transportation of Dangerous Goods Act
    - Workman's Compensation Act
    - Workplace Hazardous Materials Information System (WHMIS) regulations

    c) The Industrial Vegetation Management Associations of Alberta's (IVMAA):

    - Safety Rules for Trees Near Power Lines

30. **Before any work begins, the contractor must apply a "Job Safety Analysis" for each operation, and the Forest Operations coordinator must approve the plan.** This work plan will include:

    a) A description of the job,
    b) A list of critical activities/site conditions,
    c) A list of the tools/equipment (with test expiry dates) and materials required,
    d) A list of the hazards and methods used to eliminate or control them,
    e) The necessary level of competency-for all workers,
    f) An emergency plan and,
    g) The general sequence of events (at the work site)

    Each work crew will be in possession of, and familiar with, the completed "Work Plan" form when working on this project.

31. Tailboard meetings will be held prior to starting any job where two or more workers are present. They will also be undertaken where the original "Work Plan" changes, or where the job has been interrupted for a period of time. These interruptions could include breakdowns, lunches, etc. Tailboards must be submitted to ATCO Electric with the appropriate invoice. Each tailboard will indicate at a minimum:

    a) Who is in charge of the crew,
    b) What are the tasks that are to be performed,
    c) What the duties are of each crew member,
    d) What are the hazards of each work site,
    e) What are the main hazards in performing each task, and
    f) How are the hazards going to be controlled or eliminated
    g) Emergency response plan in case of injury

32. A **"Start-Up" meeting** will be conducted with a representative of the ATCO Electric District (Service Area) and all contractor foreman. Each brush crew foreman will be in possession of, and familiar with, the completed "Start-up Meeting" form when working on this project. Forest Operations coordinator's approval will be obtained if any changes to the Work Plan are desired by the contractor (including the change of crew members). Any new foreman must review the Work Plan with the Forest Operations coordinator, and be familiar with the "Specifications" and "Work Plan."

33. ATCO Electric reserves the right to audit crews while they are at their work locations for compliance with; these "specification" requirements and government regulations.

34. If an incident occurs, all work must stop and the incident must be reported to Forest Operations Coordinator and the local ATCO Electric Service Area office immediately. Vehicle accidents associated with ATCO Electric's work must also be reported. ATCO Electric has a policy of non-discipline for accident/incident that are reporting.

35. Limbs or trees with potential to contact the power line during removal will be controlled to prevent contact (i.e. rope).

36. Workers are not allowed to be in the bucket of a boom truck or ride on the outside of the cab of a vehicle while it is in motion.

37. ATCO Electric may stop work and void this contract at any time if:

    a) ATCO Electric is not satisfied with work quality,
    b) The rate at which the work is progressing will create difficulties for ATCO Electric in relation to the specified completion date.
    c) Significant problems are created (in ATCO Electric's opinion) by the contractor with land title holders,
    d) Due to contractor negligence, serious problems develop. ATCO Electric will not be responsible to pay the contractor for the work not done, or not done to ATCO Electric's satisfaction, as a result of the above circumstances.
    f) Worker Health and Safety violations occur.

### *4.16.4 General Safety Expectations for Contract Work*

1. **Health, Safety & Environment (HS&E)**

The contractor must comply with the following requirements:

- Conduct *daily* Tailboard meetings with all crews and ensure all members know and understand their roles and responsibilities.
- Complete the required Health Safety and Environment Evaluation appendix and that the Forest Operations Supervisor has deemed it acceptable at this point in time.
- Ensure all workers understand and comply with the contractor's HS&E program.
- Comply as directed by the Forest Operations Supervisor and the District Operator-In-Charge (OIC) to check on and off the system.
- All workers must report for work capable of performing their assigned jobs in a safe and responsible manner.
- All required Personal Protective Equipment (PPE) must be worn and properly maintained while on the jobsite.
- Ensure an alcohol and drug free workplace by prohibiting possession and/or use of these substances on the jobsite.
- Ensure no firearms are present on the jobsite.
- All new employees must be approved by the Forest Operations Supervisor (or their designate) and must undergo pre-job orientation and training prior to commencing work.
- All workers must conduct themselves in a safe and professional manner.
- All ATCO Electric customers are to be treated with the utmost courtesy and tact.
- All workers have the right and duty to refuse any work they deem as unsafe to perform. Should this situation arise, the Forest Operations Supervisor will be contacted immediately.

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2. **Time-Keeping and Invoicing**

a) Daily Time Sheets (in the event of hourly or unit based work)
All daily time sheets must have the following:

- Full names of all workers
- Date
- Start time, end time, and total hours/units/days for workers and equipment
- Summary of type(s) of work conducted
- Signature of designated on-site Foreman

b) Invoices must have the following:

- Date
- Invoice number
- GST number
- Full name and mailing address of business entity
- Total hours/days/units of work completed
- Agreed upon rate of payment
- Totals broken down by “type of work” (ie. Slashing, hazard tree removal, skidding, mowing, etc.)

3. **Miscellaneous Expectations & Conditions**

- ATCO Electric Ltd. does not pay overtime.
- All work is subject to final inspection.
- Unscheduled “Worksite Observations” may be conducted at any time. Full cooperation is required by all workers.
- All subcontractors must be approved by the Forest Operations Supervisor prior to bringing them onto a jobsite.
- Do not use or damage any crossing structures existing on ROW without permission from the Forest Operations Coordinator.
- Report any environmental damage (rutting creeks, oil spills, etc.) or equipment damage (broken insulator, damaged bridge, broken guy wire etc.) to the Forest Operations Coordinator, even if the damage was done by someone else.
- No working alone. All workers must be within eye-sight of another worker at all times.
- A working communication system must be in place (Radio Phone)
- Daily legal location must be maintained on tailboard.
- All required Fire Equipment must be present on site and in working condition.
- Contractor is responsible for obtaining any required work permits or road-use agreements with other commercial stakeholders.

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### *4.16.5 Salvage Tracking Procedures*

Any initial clearing or hazard reduction which has salvage wood should follow these steps for salvage tracking to ensure log decks are not lost and all monies can be tracked and credited back to the proper Work Orders.

There are 4 procedures that will help track salvage wood:

1. ***Contract for the Purchase and Sales of Logs***. This is the contract to sell salvage timber set up between the Wood Purchaser and ATCO Electric for a negotiated price. Within this document there should be a section for the *Origin of the Timber*. In this section the EZE # will be documented, as well as the **W.O.#**. Request the Wood Purchaser have checks reference **W.O.#** and made out to ATCO Electric, as well as referencing **W.O.#** on the **TM 9** records.

2. ***TM 88 Timber Salvage Authority and Records***. This is the document that is completed by the Salvage Purchaser and Land Disposition Holder and sent to Land and Forest Services. The Salvage Purchaser and ATCO Electric each keep a copy. Within this document there is a line that says, "*to remove the timber cut under authority of land use disposition no.*" In this section the EZE # will be documented, put the **W.O.#** here as well.

3. ***Mark log decks***. Mark a few of the butts of the logs with the **W.O.#** and AE when the logs are decked and ready to be hauled. This will ensure that ATCO Electric's decks do not get lost if there are other operations in the area. It will also ensure that if the decks are left for a later haul date, decks of logs will be easier to identify and **W.O.#** will not be forgotten.

4. ***TM 9 Forest Products Hauling Record***. These are the forms that are filled out by the wood hauler at the scales for each load. This records where origin of the logs are (EZE #), species and volume or weight of logs. Request that the hauler or the wood scaler at the mill records the **W.O.#** on the **TM 9**. A copy of the **TM 9** is attached to the checks made out to ATCO Electric.

### *4.16.6 Initial Clearing Specifications - Small Projects*

1. All work will be completed and invoiced by the date indicated in the Form of Tender.
2. Landowner easements/permissions will be regarded as the work instructions. Any deviations from the easements/permissions must be arranged with the landowner and ATCO Electric Project Coordinator.
3. In all instances the right of way is to be cleared of trees and brush for a minimum of 7.5 meters from the centerline or as directed by the survey brushing notes. Stumps on the 7.5 meter from centerline AE right of way will be cut flush or removed. Stumps on the outside of this right of way width are to be cut in accordance with accepted practices and procedures.
4. When mulchers/mowers are not used, no debris longer than 1m (3 feet) left on site.
5. AVOID GRUBBING ROOT SYSTEMS IN SENSITIVE AREAS SUCH AS SLOPES AND WATER BODIES.
6. Crown conditions, if provided, are to be on site with the contractor at all times.
7. The contractor will be responsible for any damage to public or private property sustained while completing the identified work.
8. The crew foreman will contact the AE Project Coordinator as indicated in the job planning meeting in regard to work progress and if any difficulties develop.
9. The crew foreman will contact the nearest AE Operator In–Charge and report as directed by Operator In-Charge.
10. An operational mobile telephone or AE company radio is required with each brushing crew.
11. Outages are to be arranged a minimum of 48 hours in advance with the local AE operator in charge.
12. Burning permits must be obtained from the appropriate authority prior to any burning taking place and all conditions of the permit must be adhered to at all times.
13. The crew foreman will be familiar with and have in his possession the “SPECIFICATIONS.’
14. When in significant quantity (2 or more cords), birch will be limbed and decked in log length.

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15. All salvage is to be topped, limbed, and decked at locations pre-approved by ATCO Electric Ltd.

16. **All** brush greater than **0.5 metres** in height is to be removed.

17. Any changes to brushing activities (as described on the Landowner Easement/Permissions) will be documented (including landowner authorization) with the revised date and crew foreman signature. Such changes require prior approval from the AE Project Coordinator.

18. Complete disposal is required for all non-salvagable wood and debris. Disposal of brush shall be done by burning, mowing or chipping in a manner that is acceptable to AE: Push slash into piles off to one side of the clearing with brush rake attachments to minimize disturbance to ground cover. Maintain 5m minimum clearance to edge of clearing. Windrowed piles will not exceed 20m in length and will be separated by 8m fire breaks. Do not locate piles within 30m of watercourse.

19. Survey stakes are not to be removed or damaged. Necessary resurvey costs will be billed to the contractor.

20. The contractor will document the status (ie. bent, missing, or intact) of survey pins belonging to the Province of Alberta at rotovate locations. No dozing, rotovating or mowing will take place within 1.0 meter of any such survey evidence. Any disturbance or damage to intact survey pins, marker posts or mound and pits will require the contractor to bear the cost of their re-establishment.

21. **Any dead or leaning tree** outside of the power line right-of-way that has the potential to fall on any portion of the power line **will be removed**. Such trees may not have been identified in the brushing notes.

22. All stumps will be cut as low as possible (no higher than 8 cm (3in.)) with flat topes, unless required for slope stabilization.

23. Minimum conductor clearance of **5 metres** from branches or limbs of any tree adjacent to the right-of-way within the White Zone of Alberta.

24. Only the use of propane, diesel or dry wood will be used for burning purposes. Tires will not be allowed for burning of brush.

25. Special care must be taken to ensure rutting from vehicles does not occur on the power line right-of-way.

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26. When working on other company's property (e.g.: roads, well sites) work permits will be obtained prior to entry.

27. All limbs under or to the side of the power line will be trimmed using acceptable industry practices.

28. All activities conducted for AE will conform with the following:

a) The province of Alberta's:
- Electrical and Communication Utility Code
- Employment Standards Code
- Environmental Protection and Enhancement Act
- Occupational Health and Safety Regulations
- Forest and Prairie Protection Act
- Surface Rights Act
- Weed Control Act

b) The Government of Canada's:
- Transportation of Dangerous Goods Act
- Workman's Compensation Act
- Workplace Hazardous Materials Information System (WHMIS) regulations

c) The Industrial Vegetation Management Association of Alberta's (IVMAA):
- Industry Standards and Good Practices for Vegetation Management

d) AE's:
- Standard Bid Document
- Current Master Services Agreement labour rates

29. **Before any work begins the contractor must supply a Work Plan for each type of clearing crew or operation and the AE Project Coordinator must approve the Work Plan**. This work plan will include:
- A description of the job,
- A list of critical activities/site conditions,
- A list of the hazards and methods used to eliminate or control them,
- The necessary level of competency-for all workers,
- An emergency plan and,
- The general sequence of events (at the work site)

Each work crew will be in possession of and familiar with the completed work plan form when working on this project.

30. **Daily tailboard meetings** will be held prior to starting any job where two or more workers are present. They will be undertaken when conditions change or where the work has been interrupted for a period of time. These interruptions could include breakdowns, lunches, etc.. Tailboards must be submitted to AE with the appropriate invoice. Each tailboard will indicate at a minimum:

    - Who is in charge of the crew,
    - What are the tasks that are to be performed,
    - What the duties are of each crew member,
    - What are the hazards at each work site,
    - What are the main hazards in performing each task, and
    - How are the hazards going to be controlled or eliminated

31. A **"Start-Up" meeting** will be conducted with a representative of the AE District (Service Area), and all contractor foremen. Each brush crew foreman will be in possession of, and familiar with, the completed "Start-up Meeting" form when working on this project. AE project coordinator's approval will be obtained if any changes to the Work Plan are desired by the contractor (including the change of crew members). Any new foreman must review the Work Plan with the AE project coordinator, and be familiar with the "Specifications" and "Work Plan."

32. AE reserves the right to audit crews while they are at their work locations for compliance with these specification requirements and government regulations.

33. Any line contact, near miss (with the potential for serious injury) or worker injury, is to be reported to the Project Coordinator and the local AE District office immediately.

34. Limbs or trees with potential to contact the power line during their removal will have preventative measures taken to avoid this.

35. AE may stop work and void this contract at any time:

    - If AE is not satisfied with work quality,
    - If the rate at which the work is progressing will create difficulties for AE in relation to the specified completion date (re: Specification No. 1 above),
    - If significant problems are created by the contractor with land title holders,
    - Due to contractor negligence. AE will not be responsible to pay the contractor for work not done or not done to AE satisfaction as a result of the above circumstances, or
    - Worker Health and Safety violations occur.

### *4.16.7 Initial Clearing Specifications-Large projects*

**SECTION I: WORK SPECIFICATION FOR SALVAGE LOGGING**

General Brushing Standards:

General measures that apply to all brushing, construction, and maintenance activities are provided below. Note that ant of the general or specific measures may be overruled by landowner or leaseholder agreements, or Crown easement conditions.

1. Efforts shall be made to prevent soil erosion, water pollution and forest fires during all stages of construction and maintenance.

2. No oil changes, refueling or lubricating of construction equipment will be conducted within 30 horizontal metres of open water. Spent oils, lubricants and filters etc., will be collected and disposed of at an approved location.

3. All excess construction garbage will be continuously collected and disposed of at an approved facility. Waste containers will accompany each working unit.

**1.1 Access**

1. Do not ford flowing streams.

2. CONFINE ACTIVITIES TO THE ALLOTTED RIGHT-OF-WAY, EXISTING ROADS AND SHOO-FLIES. If possible, confine vehicles to a single trail on the right-of-way. The standard minimum right-of-way for cross-country alignments will be 15m wide. Tree-freeing (removal of standing live and dead trees) will require brushing of an additional width of right-of-way. The additional width is dependent upon tree height. Vehicle traffic will not be allowed on adjacent pipeline rights of ways.

3. Follow traffic accommodation plan along highway 58. Post truck turning sites near junction of highway 58 and Foggy Tower Road. Minimize interference with the flow of traffic.

**1.2 Survey**

1. THE COMPANY WILL STAKE OR FLAG THE RIGHT-OF-WAY at sufficient intervals so that stakes and flags are visible to brushing crews.

2. THE COMPANY WILL STAKE OR FLAG THE BOUNDARIES OF SALVAGE TIMBER STANDS in order so that salvage timber is not lost.

### 1.3 Brushing

1. DO NOT CLEAR VEGETATION BEYOND STAKES OR FLAGGING, AND FELL TREES WITHIN LIMITS OF RIGHT-OF-WAY.

2. CUT TREES AT GROUND LEVEL.

3. AVOID GRUBBING ROOT SYSTEMS IN SENSITIVE AREAS SUCH AS SLOPES and WATER BODIES, except for centrally-located access trail that may be stumped and graded to permit vehicular access for line construction.

4. PILE ALL SLASH MATERIAL. Push slash into piles off to one side of the center line with brush rake attachments to minimize disturbance to ground cover. Maintain 5m minimum clearance to edge of clearing. Do not locate piles within 30m of watercourse.

5. HARVEST SALVAGABLE TIMBER STANDS using chainsaws, feller-bunchers, or other approved equipment. Do not bulldoze salvage timber. Salvage areas to be confirmed by a Forestry representative.

6. Brush will be machine-cleared, slash will be piled for mulching.

## SECTION II: GENERAL RIGHT-OF-WAY CLEARING AND MAINTENANCE STANDARDS

The Applicant's policy is to maintain an area free of incompatible vegetation adjacent to all distribution lines. This includes the cleared area necessary for construction and any danger trees beyond the minimum standard right-of-way. However, it is also the policy to retain compatible vegetation whenever possible in the vicinity of distribution lines.

### 2.1 Salvage Logging

Salvage logging is the removal of merchantable timber from the power line right-of-way. The basic rule that is followed is the requirement that:

> Trees must not infringe on the required clearance to maintain the safe and reliable operation of the distribution facilities.

This applies to all merchantable timber within the flagged right-of-way and all standing danger trees, particularly those which could potentially fall and either damage the conductors and supporting structures directly, or fall within the flashover distance.

Standard right-of-way widths have been devised for areas having tree growth of varying height to ensure that the clearing rule is applied in all situations where trees could pose a problem.

The clearing standards for tree-freeing are based on tree heights in relation to the location of the nearest conductor at maximum sag. An additional allowance is made for tree-freeing within or near poplar tree growth.

Merchantable timber shall be cut, lopped of roots, branches, and tops and shall be neatly decked separately from all other trees and debris.

In the event that a large number of trees are to be decked and no natural clearing is available in the area, the contractor shall clear an area of deciduous or un-merchantable coniferous timber at intervals designated be Alberta Forest Services for that purpose.

Debris from limbing and bucking activities shall be restricted to the right-of-way or designated tree processing or decking area. Keep branches etc. from roadways as much as possible.

## 2.2 Land Use and Environmental Considerations

Under certain circumstances, trees will be cut selectively in the vicinity of water crossings, very Steep erodible slopes and other ecologically sensitive areas to reduce adverse effects on the environment (i.e. to maintain slope stability and minimize siltation in nearby water bodies).

Stumps are to be cut as close to the ground as possible.

Selective tree cutting cannot be done under all situations regardless of how desirable it may be. Over mature and dead trees, especially those growing on thin and/or saturated soils, will not survive if they are isolated from their closed stand conditions. These trees are readily prone to windfall. Such trees would constitute a hazard, and will therefore be removed at the time of construction.

## 2.3 Clearing Method

Merchantable timber stands located within the right-of-way will be logged and decked along the edge of the right-of-way as required. Merchantable timber will be handled in accordance with government requirements.

Additional clearing will be done by hydro-axe. In environmentally sensitive areas such as stream and river crossings, erosion sensitive solids and scenic road crossings, clearing methods may be adjusted to minimize potentially detrimental effects.

The clean-up operation on and off the right-of-way on Crown lands will also be subject to the requirements of the Crown and easement conditions.

## SECTION III: TECHNICAL SPECIFICATIONS FOR SALVAGE LOGGING

### 3.1 Scope of the Work

Work under this specification includes:

1. Supply of labour and supervision to cut and pile timber, logging, skidding, and decking of timber in the designated “salvage areas.” Salvage areas will be along the edge of the right-of-way along the edge of the roadway, or as agreed by the Owner’s Representative or designate.

2. Supply of materials, plant, and tools, and all equipment necessary for the execution of the work.

3. Provision of temporary buildings and services, sanitary facilities, water, heat, light, power and telephone services, lodgings, meals and medical services, transportation of men, materials, and plant.

- All in accordance with the specification requirements.

### 3.2 Documents

The company will supply to the Contractor sufficient drawings, sketches, plans, notes and other information at the Tender stage, and later, as and when required to enable full execution of the contract.

### 3.3 Survey

a) The company shall have the right-of-way center line surveyed before brush clearing. The survey will define the limits of the area to be cleared on the ground and the brushing notes. These limits will be flagged with fluorescent orange/black tape (easement) and fluorescent pink/black (vegetation control or tree-free easement) in the field at 50 metre intervals.

b) The contractor shall preserve all legal iron pins and survey stakes, and shall replace or pay for replacement of any legal survey post or survey stake that is disturbed.

c) The chainage hubs will be used as control reference for as-builts and for progress measurement as well as for measurement of any extra Work and must be preserved.

d) The contractor shall do the Work in accordance with the Environmental Protection Plan, Brushing Notes and easement conditions. Any conflicts between documentation shall be reported to the Company before the Work is done, so that clarification can be given by the Company. If the Contractor does Work where a conflict existed that is obviously wrong without giving prior notice to the Company, it shall be the Contractor's responsibility to rectify such Work at no extra cost to the Company.

e) As soon as practical during clearing, ATCO Electric Brushing Inspectors will identify "danger trees" by flagging with fluorescent tape or marking with blue tree paint. All work necessary for or incidental to the felling, slashing, piling, burning or otherwise disposing of danger trees (including the disposal of merchantable logs) will be paid for at the appropriate tendered unit price for danger trees. Except that where the Brushing Inspector directs that concentrations of danger trees be cleared in accordance with the requirements of a particular clearing standard. Payment for all Work necessary for or incidental to the felling, slashing, piling, burning or otherwise disposing of such danger trees (including the disposal of merchantable logs) will be made at the appropriate tendered unit price for the appropriate clearing standard.

### 3.4 Right-of-way

a) The Company will provide the right-of-way for the distribution line in a timely manner: not to interfere with the construction activity of the Contractor. The Company will also provide all permits and licenses that can only be granted to the Company, such as permits to cross rivers and other water, railways, roads, drainage or irrigation channels, pipelines, power lines and communication tables.

b) The Contractor’s operations are to be limited as nearly as possible to the right-of-way. In the event that additional space is essential for the Contractor's operations, the Contractor shall first obtain written consent from the Company to secure additional space, and then obtain the written consent of the property owners for the use of the extra space required. Agreements made by the Contractor for the use of additional area shall provide that the Company also have the right to use such area. Any damage or costs incurred as a result of the Contractor's operations outside the Company's right-of-way shall be paid by the Contractor, unless mutually agreed beforehand by the Owner’s Representative.

c) The Company shall endeavor to show in its documentation and have its surveyors mark the locations and nature of other pipelines and structures in, or crossing the right-of-way, but it assumes no responsibility for the correctness or completeness of such information. The Contractor shall be held solely responsible for the locating of such pipelines and structures and for avoiding damage to them.

d) Where the right-of-way parallels or crosses previously installed pipelines, buried telephone cables, overhead power lines and towers, structures or other facilities, either owned by the Company or others, it is the responsibility of the Contractor to do the Work without damage to the existing structures and facilities. The Contractor shall not operate equipment over existing lines without written authorization from the Company. In case the Contractor damages or breaks an existing pipeline, structure or facility, he shall be liable for all damages or losses, including product losses and loss of revenue, and shall indemnify and hold the Company harmless from any personal or property claims.

e) The Company will show in its Environmental Protection Plan any special construction requirements in the right-of-way easements or permits and the Contractor shall strictly comply with such requirements.

f) The Company will notify property owners of the imminence of construction. The Contractor shall consult with the Company's Project Brushing Inspector in advance of entering properties to determine procedures that will result in the least damage or interference with the landowner's operation.

g) The Contractor shall supply and/or pay for additional services required by owners at crossings of railroads, roads, canals, or streams, including items arising from operational or safety requirements either during or after completion of construction Work, such as flagging for railroad Work or necessary subsequent maintenance of repair Work which is either impossible to accomplish at the time of construction or resulting from incomplete or inadequate construction.

h) Permission for work crossing of railroads, highways, rivers and other important water courses for the Contractor's men and equipment shall be secured by the Contractor at his expense, before making the crossings.

i) The right of ingress and egress to the right-of-way will normally be limited to places where the right-of-way intersects public roads. The Company may provide the additional access in some cases and, if necessary to the construction operation, the Contractor may request the Company make such special arrangements. There will be no entry onto lands without Company approval.

j) The Contractor is specifically prohibited from entering into any special agreements with landowners without prior written approval from the Company. This restriction is imposed to prevent any arrangements for off right-of-way brush disposal and to control agreements regarding access to the right-of-way. Forms used for any agreements are subject to written approval from the Company, and the Company shall be given co-equal rights to any agreements made by the Contractor to do with use of land, roadways, or other access or crossing privileges.

### 3.5 Expose Pipelines

In order to avoid accidents, it is required that all existing pipelines and other underground facilities be located and appropriately marked ahead of any work on the right-of-way by heavy equipment. The marking should be maintained a minimum of one kilometer ahead of the clearing operations. The Contractor shall only move heavy equipment across a pipeline right-of-way after having complied with all the requirements of that particular "Crossing Agreement."

### 3.6 Alberta Forest Service and Department of Environmental Approval

Before commencement of clearing crown land, the Alberta Forest Service official and the Department of Environment official with authority over the area shall be consulted jointly by the Contractor and the Company to determine particular requirements and to acquire approval of the Contractor's intended clearing procedures.

### 3.7 Clearing Work

Except where restricted clearing is required by the Environmental Protection Plan or the Brushing Notes, merchantable timber across the whole width of the right-of-way shall be salvaged, as well as any areas outside the boundary of the right-of-way that may be designated for timber landing areas, shoofly roads, etc.

Where restricted clearing is called for by the Environmental Protection Plan or the Brushing Notes, the Contractor shall use whatever procedures are necessary to accomplish this, at no extra cost to the Company. The clearing operation shall not cause trees, debris or dirt to go into any waterway. The Contractor shall explain to his workers the damage such disturbance of water may cause fish and fish spawning areas, that they may appreciate the importance of taking care in their Work to protect water quality.

### 3.8 Stumping

Trees shall be cut at ground level to allow for construction and maintenance traffic.

### 3.9 Additional Contractor Responsibilities

a) Provide all necessary notices required notices required by -and comply with- all laws, ordinances, rules and regulations relating to the execution of the Work.

b) Provide fire protection and fighting equipment to eliminate the possibility of damage by fire in connection with the carrying out of the Work, as per the Forest and Prairie Protection Act (1991).

c) Provide, at the Contractor's expense, all facilities and services required for storage, maintenance, protection and security of the equipment and materials used in connection with the Work (including equipment and materials provided to the Contractor by the Company).

d) Keep the site free from accumulations of waste materials or rubbish caused by the Contractor, its Sub-Contractors and their employees or agents.

e) Upon completion of the work, remove from and about the site all tools, surplus materials, equipment, and rubbish belonging to, or caused by, the Contractor, its Sub-Contractors, and their employees or agents. Company approval is necessary before removal of tools and equipment in accordance with part 3.8

f) Provision of lodging, meals, sanitary facilities, first aid and medical facilities and other services.

## SECTION IV: SPECIFIC CONDITIONS

### 4.1 Scope of the Work

The work to be done under this specification consists of the supply of: all labour (including labour required for handling and distributing materials) and supervision; material specified as being furnished by the Contractor; Plant and Tools; all facilities such as temporary buildings, temporary services, sanitary facilities, water, heat, light, power and telephone services; lodgings, meals and medical services; the transportation of Material and Plant, from and at the Site; the warranty of workmanship; the erection and removal of all temporary works and final cleanup of the Site on completion of the Work.

The Contractor shall be responsible for the quality of all workmanship performed by its employees in the execution of the work described in the specification.

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**4.2 Access to the Site (SAMPLE)**

The site is accessible only via provincial roads, municipal roads or rights-of-way and the use by the Contractor of other than designated access routes is strictly prohibited. The Work shall be performed only on that portion of the Site required therefore and as designated by the Company.

The Contractor shall not make private arrangements with landowners with respect to access to the Site. All such arrangements shall be made by the Company although the Contractor may initiate a request for access, to the Company.

The Company may withhold final payment for the Work until it has received a release in form satisfactory to the Company, signed by each property owner adjacent to the Site stating that all claims for land, crop of any other property damages caused or permitted to be caused by the Contractor, Sub-Contractor or by those of whom the Contractor is in law responsible, have been fully paid and resolved or alternatively, until such time as the Company has determined that such property owners have no such claims arising from the performance of the Work. At the Company's discretion, it may remedy any damage to land, crop or any other damages to property adjacent to the Site caused by the Contractor, Sub-Contractor or by those of whom the Contractor is in law responsible and the Company's full cost thereof may be deducted from the final payment for the Work or if such final payment is insufficient to satisfy the Company's claim hereunder, the difference between such amounts shall be a debt due and owing and shall bear interest at the rate of 18% per annum from the date of the Company's request for payment. A statement of the costs incurred by the Company to remedy any damages as provided by this paragraph, certified accurate by a Professional Engineer who is in good standing in the Province of Alberta shall be final and conclusive for all purposes relating hereto.

**4.3 Meals and Lodging**

The Contractor shall be responsible for the provision of meals and lodging for all its personnel engaged in the work.

**4.4 Sanitary facilities**

The Contractor shall supply and maintain all necessary sanitary facilities for all personnel engaged on the Work. These facilities shall comply with the Occupational Health & Safety Act (OHSA).

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**4.5 First Aid and Medical Facilities**

The Contractor shall comply with the laws and regulations of Alberta relating to the provision of first aid and medical facilities (OHSA - First Aid Regulations) for all its personnel engaged on the Work.

The Contractor shall also be responsible for the transportation of its sick or injured personnel to hospital, in the even such necessity arises, at the Contractor's expense.

**4.7 Statutes, Regulations and Permits**

Prior to commencing the work, the Contractor shall familiarize himself with any statutes, by-laws, rules or regulations which may in any way affect or apply to the Work, and shall carry out the Work in accordance therewith.

The Contractor shall also note that the provisions of the OHSA - General Safety Regulations regarding shoring of excavations shall be complied with and will be strictly enforced.

No excavation will be permitted until these requirements have been complied with.

**4.8 Records**

The Contractor shall be responsible for keeping and supplying on a weekly basis, to the Company, all such records of Work as the Company may require throughout the course of the Work, including records of its labour force, Plant, hours worked, rates, for appraisal of the progress of the Work.

Blank forms may be supplied from time to time to the Contractor by the Company for the purpose of recording details of the Work. Any such form shall be completed within the time and to the satisfaction of the Company.

**4.9 Compliance with Standard Specifications**

All material, equipment and articles furnished by the Contractor shall comply with the applicable provisions of the standards of the Canadian Standards Association (CSA) or of the Canadian Government Specification Board (CGSB) and where no such standards exist, they shall comply with the applicable provisions of the standard specifications of the American Society for Testing Materials (ASTM).

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## 4.10 Protective Measures

The Contractor shall take all necessary precautions for the safety of its employees engaged on the Work. It shall erect and properly maintain at all times, as required by the conditions and process of the Work, all necessary safeguards for the protection of workmen and the public, and shall post danger signs warning against unusual hazards and such other hazards as may be designated from time to time by the Company.

The Contractor shall properly and adequately protect the Work, and Plant (inclusive of all material supply by the Company) against loss, damage or deterioration during construction and shall take every precaution against causing damage to property belonging to the Company or third parties located in, upon, or about the Site, and shall indemnify and save harmless the Company from and against all loss, costs, damages, expenses, suits, claims and demands in respect thereof.

The Contractor shall take all necessary precautions and comply with the regulations of all competent authorities during the execution of the Work so as not to trespass upon or cause damage, disturbance, obstruction of access, removal or disturbance of support to land, buildings or other structures or property beyond the Site, and will indemnify and save harmless the Company from and against all loss, costs, damages, expenses, suits, claims and demands arising out of any such trespass, damage, disturbance, obstruction of access, removal or disturbance of support.

The Contractor shall provide all guards, barriers, fencing, lights or danger signs necessary to adequately warn or protect the public, employees of the Contractor or Company, livestock and wildlife, from any injury due to hazards created during the execution of the Work described in this Specification whether on or off the Site.

The Contractor shall supply fire fighting tools and equipment as may be required by Alberta Forest Service regulations. Where the Contractor wishes to dispose of scrap material by burning, it shall observe all burning restrictions imposed by all applicable laws and regulations. The Contractor shall obtain, at its own expense, all necessary burning permits which may be required.

If the Contractor disposes of any scrap material by burning, the Contractor shall be responsible for ensuring that fires do not become established in logs, stumps or in the ground and that such fires are extinguished to the satisfaction of the Company and any governmental body having responsibility or jurisdiction in such matters.

The Contractor shall be strictly liable for any damage resulting from fires caused by it, its employees, officers, agents and others for whom it is responsible and it shall be solely responsible for all charges which may be incurred in extinguishing such fires and indemnify and save harmless the Company from any loss, claim or expense in relation thereto.

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**4.11 Permits to Work**

No inspecting, testing, or operating that is required to take place or be done in, upon, or about, any equipment or facilities owned by the Company and that are or may be electrically charged from any source, shall be permitted unless and until a written "Permit to Work" has been issued for the purpose by the Company. When the inspecting, testing or operating sanctioned by the Permit to Work has been completed, the Contractor shall give written clearance to the Company, stating that Work is complete and all men and equipment have been withdrawn.

**4.12 Explosives**

The Contractor shall not use explosives unless he first obtains approval in writing from the Company of:

a) The type, characteristics and quantity of the explosive that the Contractor proposes to use;
b) The proposed method of transporting, storing, handling and using such explosives, including without limitation, thawing of frozen explosives;
c) The safety procedures proposed to be followed, including without limitation, the signs, sentries and warning devices to be used;
d) The location or locations where the Contractor proposes to use explosives;
e) The proposed location of magazines and other storage facilities for explosives and detonators; and
f) The dates and hours during which the Contractor proposes to carry out blasting procedures.

The Contractor shall at all times exercise the greatest care in carrying out blasting operations. When blasting operations have been completed, all surplus and/or undetonated explosives shall be promptly removed from the Site or placed in a magazine at the Contractor's expense.

**4.13 Extra Work Charges**

a) The Company may:

i) Order work not called for, and outside the general scope of the work required by the contract documents ("Extra Work"), but which is within the capability of the Contractor's existing work force and equipment, or

ii) Make alterations in, additions to or deductions from the Work that falls within the general scope of the Work required by the Contract Documents ("Changes").

And the contractor shall perform the extra work or changes in accordance with the contract documents.

b) No changed shall be affected, or extra work performed, or payment made, unless authorized in writing be the Company and once such authorization is given, the Contractor shall proceed diligently with the work.

c) If the Company orders extra work, the Contractor will provide a lump sum price or unit price for the extra work as requested by the Company and the Company may then:

i) Instruct the performance of the extra work on the basis of the prices so provided by the Contractor; or
ii) Instruct the performance of the extra work on a force account basis as described in paragraph 4.14; or
iii) Withdraw its order for the extra work.

d) If the Company makes changes, either additions or deductions, the amount payable to the Contractor, or credit given by the Contractor, will be determined by agreement between the Contractor and the Company or alternatively, at the Company's option the changes (additions) shall be performed on a force account basis as described in paragraph 4.14.

e) Any claim for an extension or reduction of the time within which the work is to be performed arising from extra work ordered or changes made shall, if possible, be adjusted at the time the Company orders the extra work or makes the changes. If the Contractor and the Company are unable to agree on any extension or reduction, the same shall be determined by arbitration.

**4.14 Force Account Work**

The Company will pay the Contractor in respect of work performed at site on a Force Account Basis the following:

a) Labour

i) Direct wages paid to labour, field supervision (excluding field superintendent) and associated payroll burden;
ii) Transportation, loading and unloading of tools and material; and
iii) Transportation of labour on and about the site; and
iv) Transportation of labour brought to the site specifically for force account work at the request of the Company.

b) Material

Material provided to the Company in respect of such Extra Work to be supplied on the basis of cost of Material as substantiated by the supplier's invoice, including freight and all taxes.

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c) Board and Lodging

An amount calculated at a fixed rate, for providing board and lodging for men employed on force account work (other than operators of construction equipment covered by a rental rate which includes the provision of an operator).

d) Contractor's Tools and Plant

Rentals for the Contractor's construction equipment when used on force account work and when certified as necessary by the Company shall be paid only for Tools and Plant having a value in excess of $500.00 in accordance with the Schedule of Equipment Rental Rates approved by the Company and incorporated herein including additional items of equipment added thereto from time to time with the approval of the Company.

Unless otherwise specified, the rates in the Schedule of Equipment Rental Rates shall include the cost of operators, servicing, fuels, lubricants, maintenance, repairs and all other services and overheads including, in the case of rates including operators, room and board for operators required to operate the equipment at the Site and maintain it in working order.

Rental rates for welding equipment shall include for the provision of all welding rods, fuel, oxygen, acetylene and lubricants.

No payment shall be made for the use of any item of equipment on the Work which is not listed in the Schedule of Equipment Rental Rates or has no rental rate entered against it, except that if the Contractor brings to the Site additional equipment for the construction of the Work and submits a quotation for rental rate which is approved by the Company, such equipment and the approved rate shall be deemed to be entered in the said Schedule.

The rental rates listed in the Schedule of Equipment Rental Rates for each item or equipment will be paid to the Contractor for the number of operating hours the said item or equipment is engaged in the performance of Extra Work or Changes at the request of the Company whether such time is worked on a day shift or a night shift, or both.

One half of the hourly rental rate shall be paid to the Contractor in respect of time during which:

i) The equipment is engaged in traveling from and returning to the place on the Site where the equipment was located when required for Extra Work or Changes;

ii) The equipment is being modified for a different use and restored for its previous uses on completion of the Extra Work or Changes (i.e. changing boom for crane or shovel);

iii) The equipment and operator are ordered by the Company in writing to be held ready for any work required by the Company.

No payment will be made in respect of:

iv) The time during which the equipment is being maintained, repaired or replaced;

v) The time during which the equipment cannot be used because of breakdown, fault of the equipment or Contractor, or because of inclement weather conditions.

vi) The time during which the equipment is not in use except as provided in (a), (b) and (c) above.

e) Sub-Contractors

Any work performed by Sub-Contractors who are not related (as defined in the Income Tax Act, Canada) to the Contractor will be supplied on the basis of cost, substantiated by the Sub-Contractor's invoice, plus a fee of 5% on any amount up to $1,000,000.00 and 2% on any amount over $1,000,000.00. Work performed by Sub-Contractors related to the Contractor without written notification to the Company of such relationship shall be deemed to be fraudulent and provided at no cost to the Company.

f) Service Fee

The Contractor's service fee for Extra Work or Changes performed on a force account basis will be as follows:

| | Fee (expressed as a percentage) |
|---|---|
| Labour | 10% |
| Materials | 10% |
| Sub-Contractors | 5% |
| Non-owned Tools & Equipment | 5% |

The above mentioned fees include payment of the following:

i) Contractor’s profit;
ii) General supervision over and above the field supervision;
iii) General overhead and all head office expenses (including timekeeping costs);
iv) Use of Tools and Plant to value of $500,000 each;
v) Cost of insurance;
vi) Replacement of Contractor owned Tools due to loss or breakage;
vii) Cost relating to field superintendent;
viii) All consumable.

Provided further that no payment will be due back to the Contractor in respect of Work performed on a Force Account Basis:

i) Without the written authority of the Company, or
ii) If not carried out and completed to the satisfaction of the Company, or
iii) If the Contractor has not obtained the approval of the Company before incurring any obligation or making any expenditure on account of such Work.

The Contractor shall keep proper account records of the cost to the Contractor of Extra Work and Changes performed on a Force Account Basis in such form and detail as shall be satisfactory to the Company, and such accounts and records, together with all invoices, receipts and vouchers, shall at all times be open to audit and inspection by the Company or its authorized representatives (who may make copies thereof and take extracts therefrom). The Contractor shall furnish the Company or his authorized representatives with all such information about the accounts as he or they may require.

Daily time sheets shall be prepared in triplicate by the Contractor showing breakdown of hours in accordance with the Company's costing system and listing the names, hours worked and rates of pay for each workman, and hours and rates for equipment engaged on the Extra Work or Changes performed and these shall be submitted daily to the Company for checking. One copy of these time sheets when approved, shall be retained by the Company. The Contractor's monthly billing for labour shall be substantiated with copies of these approved time sheets.

## 4.15 Unit Price Adjustment

If the Tender is submitted on the basis of specifically described portions of the Work ("Units of Work") at a specified price for each unit ("Unit Firm Price") and by estimating such Units of Work ("Estimated Quantity") then, in the event the number of Units of Work required to perform the Work is greater or less than the Estimated Quantity, the successful Bidder agrees to perform all Units of Work required to fully complete the Work and the Contract Prices shall be adjusted as follows:

a) In the event the number of any individually described Units of Work required to perform the Work are greater, but not more than 25% greater than the Estimated Quantity of such Units of Work set forth in the Schedule of Prices forming part of the Tender and provided the Company has in writing expressly authorized the said further Work, the Contractor price shall be increased by an amount equal to the product determined by multiplying the difference between the actual Units of Work required to perform the Work and the Estimated Quantity of Units of Work by the appropriate Unit Firm Price; or

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b) In the event the number of any individually described Units of Work required to perform the Work are less, but not more than 25% less than the Estimated Quantity of such Units of Work set forth in the Schedule of Prices forming part of the Tender and provided the Company has in writing expressly authorized the said further Work, the Contractor price shall be decreased by an amount equal to the product determined by multiplying the difference between the actual Units of Work required to perform the Work and the Estimated Quantity of Units of Work by the appropriate Unit Firm Price; or

c) In the event the number of any individually described Units of Work required to perform the Work exceed or are less than the Estimated Quantity by more than 25%, the Unit Firm Price for such individually described Units of Work may be varied upon the agreement of each of the Company and the successful Bidder or failing agreement by arbitration in accordance with paragraph 3.37 of the General Conditions. Any disagreement between the successful Bidder and the Company as to the variation of a Unit Firm Price pursuant to this sub-paragraph shall not excuse the successful Bidder from supplying all Units of Work required to perform the Work as requested by the Company and during the period of disagreement, the Company shall pay for all Units of Work at the Unit Firm Price as set forth in the Schedule of Prices forming part of the Tender.

Where prices quoted are subject to an adjustment in any instance not specified above, the Bidder shall show the proportion of the prices which are adjustable and shall indicate the formula or formulae to be utilized for adjustment purposes (a formula shall include the applicable indices, their sources and the base index).

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### 4.16 Lump Sum Contract

If the Tender is submitted on a Lump Sum basis, the Contract Price shall be a fixed price not subject to measurement or recalculation should the actual quantities of Work and Material differ from any estimates available at the time of delivery, except in regard to Work performed or Material supplied pursuant to paragraphs 4.13 or 4.14 hereof.

### 4.17 Damages and Claims

The Company shall bear the responsibility on the Site and on lands associated with the access facilities to and from the Site for any damages caused to crops, timber, fences, gates, roadways, ditches, pipelines, other structures and the environment which may be affected by carrying out the Work by the Contractor, provided that such damages are occasioned, in the sole opinion of the Company, in the normal course of conduct of the Work carried out in a prudent and conscientious manner. The Contractor shall bear all responsibility for and indemnify and save harmless the Company for any and all losses, damages, costs, claims and demands by whomsoever, made or brought in connection with the carrying out of the Work except as specified therein including, without limiting the generality of the foregoing, all losses, damages, costs, claims and demands resulting from the negligent conduct of the Work by the Contractor, its employees and agents.

The Contractor shall promptly inform the Company in writing of any claims or demands for loss or damage for personal injury or death or loss or damage to property or the environment arising in connection with the carrying out of the Work and, upon having satisfied any such claims or demands obtain a release in respect thereof naming the Company as one of the parties released.

### 4.18 Contractor's Superintendent

The Contractor shall provide all necessary supervision during the execution of the Work, and shall employ and appoint a competent, experienced and authorized representative or agent, herein referred to as the "Superintendent". Such Superintendent shall be fluent in the use of the English language. The Contractor shall inform the Company of this appointment together with all details of his qualifications and experience.

During execution of the Work, the Superintendent shall be continuously on duty at the Site during working hours, unless otherwise requested by the Company, to supervise the due and proper execution of the Work and to receive from time to time on behalf of the Contractor, orders and instructions from the Company relating thereto.

If double shift work is necessary, or if the Superintendent is unavoidably or necessarily absent, the Contractor shall provide an assistant Superintendent, who shall possess sufficient and similar qualities of competence and experience, to take charge on a temporary basis. Any permanent replacement of the Superintendent shall be by agreement with the Company.

When personal supervision becomes difficult for Work in remote areas, the Superintendent may delegate the supervision function to a competent person, provided such person is instructed in all matters concerning the proper execution of the Work. However, the Superintendent must maintain good communication with all supervisors and be fully informed of the progress and all other aspects of the Work and shall visit all work areas regularly.

**4.19 Contractor's Liability**

The Contractor shall be strictly liable for:

a) All damage howsoever caused to the Work and all Material forming part thereof from the date the Contractor commences the Work until the date that the Company makes final payment therefore or the date of the issuance of a Completion Certificate, whichever shall first occur;

b) Any injury (including loss of life), loss or damage to any person or property caused by or resulting from defective Plant, Material, workmanship, fabrication, or construction or by anything done, or omitted to be done, or permitted to be done by the Contractor, any Sub -Contractor, or any of their respective officers, servants, agents or employees;

c) The repair, replacement or compensation to the satisfaction of the owner of any gate, fence, bride, culvert, crop, landscaping, livestock, or other property, whether on or off the Site, damaged by the Contractor, any Sub-Contractor, or any of their respective officers, servants, agents or employees; and

d) Any damage and disruption to any legal or other survey monuments, stakes, benchmarks, mounds or pins established by the Company, any government authority or any other firm, person or corporation.

And in the event the Contractor does not, to a standard and in all respects to the satisfaction of the Company, promptly satisfy the liabilities set forth above, the Company may, as the agent of the Contractor expend such monies, perform such repairs and do all such things it deems necessary in its sole discretion to satisfy the obligations of the Contractor provided by this paragraph 3.12.

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## 4.20 Miscellaneous Responsibilities of the Contractor

Without limiting any other obligation of the Contractor specified elsewhere in the Contract Documents, the Contractor shall:

a) Provide and pay for all Material, labour, water, Tools, Plant, transportation, equipment power and heat necessary for the execution of the Work except as may be otherwise specifically provided by the Technical Specification;

b) Obtain and pay for all necessary temporary permits or licenses and field locates of utilities required for the execution of the Work, i.e. equipment transport permits, fire permits, camp licenses and sewage permits. The Company shall obtain all building permits, crossing agreements and access permits required for the execution of the Work;

c) Give all necessary notices and comply with, all laws, ordinances, rules and regulations relating to the execution of the Work;

d) Provide at the Contractor's expense, all facilities and services required for the storage, maintenance, protection and security of the equipment and materials forming part of the Work (including equipment and materials provided to the Contractor by the Company);

e) Keep the Site free from accumulations of waste materials or rubbish caused by the Contractor, its Sub-Contractors and their employees or agents;

f) Upon completion of the Work, remove from and about the Site all tools, surplus materials, equipment and rubbish belonging to, or caused by, the Contractor, its Sub-Contractors and their employees or agents;

g) Take precautions to prevent the disturbance of official monuments, posts, stakes, pins marking property lines, or other survey markers;

h) Provide sufficient fire protection and fighting equipment to protect the Work in the event of fire;

i) Exercise all precautions to protect from injury, persons or property in carrying out the Work; and

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**4.21 Liens**

If, during the progress of the Work, the Contractor shall allow any indebtedness to accrue (for labour or materials or Sub-Contractors or others) which results or may result in any lien or liens upon the property of the Company or upon any property in which the Company has a legal or beneficial interest, the Company may withhold from the Contractor such sum as the Company deems appropriate to protect the Company until such indebtedness is paid. If a lien or liens are filed or claimed against any such property as a result of the Work, the Company may, but shall not have the obligation to, obtain discharge of the same by payment into Court of such sum as may be necessary to obtain such discharge and any such payment shall be deemed to be a payment to the Contractor on account of the Contract Price.

### *4.16.5 Sample Forms*

a) Final Sign Off:

ATCO Electric

REMEMBER TO CHANGE ADDRESS IN FOOTER

Date

(Name of local office) Forest Protection Division
Address

ATTN: **Name of Forest Officer**

RE: Hazard Tree Removal in the (insert name) area

ATCO Electric has successfully concluded its 2005 hazard tree program in the (insert area name) area. All identified hazard trees as detailed in our previous letter dated (insert date of letter of application), have been removed.

To fulfill our requirements as per the Wildfire Agreement, we require written acknowledgement from Forest protection Division that the work has been completed. Signing the second page of this letter will fulfill this requirement. Please sign accordingly and return a copy of to me at (insert fax number).

If you require further documentation, or have any questions or concerns, please contact me at (insert telephone #) or by email at (insert email address).

Thank you.

Name of Co-ordinator
Location

cc. Insert name and address of local forest officer

### *4.16.5 Sample Forms*

a) Final Sign Off:

ATCO Electric

**Sign-off**

ATCO Electric and Sustainable Resource Development Acknowledges that Hazard Tree Removal has been completed and approved for the attached townships in the Fox Creek Service Area.

**Completed Townships**

| Township | # HT's removed | Township | # HT's removed |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |

_____ _____
ATCO Representative Sustainable Resource Development

_____ _____
Position Position

_____ _____
Signature Signature

ATCO Electric

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b) Request for Approval:

ATCO Electric

REMEMBER TO CHANGE ADDRESS IN FOOTER

Date

(Name of local office) Public Lands and Forests Division
Address

ATTN: **Name of Forest Officer**

RE: Hazard Tree Removal in the (insert name) area

Please accept this correspondence as a formal request for an approval letter from Sustainable Resource Development to remove individual hazard trees in the (insert name of area) area. The hazard trees have been marked in the field with a painted blue dot and their locations are marked by corresponding item numbers on accompanying maps.

The townships that we are seeking approval in are:

List townships - for example:
56-5-W6M
56-6-W6M
56-8-W6M
57-5-W6M
57-6-W6M
57-7-W6M
57-8-W6M
58-5-W6M
58-8-W6M

In total, (insert total number of trees to be removed) hazard trees have been identified and these occur sporadically throughout the townships. ATCO Electric identifies hazard trees as those trees that are dead or dying, show visible signs of defects or otherwise pose an imminent threat to ATCO Electric's facilities. Considering the sporadic locations and general poor condition of these trees, ATCO Electric deems them to be non-salvageable.

I trust this letter with the accompanying maps and patrols provides the information you need to make your determination. If you need further information or would like to discuss the proposal, please contact me at (insert telephone #) or by e-mail at (insert email). Thank you.

Insert Name of Coordinator

.cc (insert name of local FPD official), Forest Protection Division

Attach. Patrol
Maps

ATCO Electric

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c) TFA Request:

**TFA REQUEST**

**Company Name**: _____ **Date**: _____

**Disposition Number**: _____

**TO:** _____

**FROM:** _____

**PHONE:** _____ **FAX:** _____

**RE: Request Details:**

**Legal Description:**

***Date TFA Required:*** _____

**Additional Clearing Dimensions/Area: New cut:** _____
(ie. length x width = ____ Ha)
**Existing:** _____

**Vegetation Type:**

**Merchantable Timber Present: Yes No If yes, volume cu. m**

**Request for Timber Salvage Waiver: Yes No**

**Woody Debris Disposal Method:**

***Terrain/Soil Description:*** _____

**Any Watercourses in Area: Yes No Distance:**

**Watercourse Crossing(s) Required: Yes No Type:**

**Reclamation Planned:**

**Comments**: _____

_____

*** See Attached Map Sketch**

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d) Timber Salvage (TM88):

Alberta
SUSTAINABLE RESOURCE DEVELOPMENT
LAND AND FOREST SERVICE

(REV. 04/01) TM 88
File No. 16 T.L.

## TIMBER SALVAGE AUTHORITY AND RECORDS

**A. To Be Completed by the Salvage Purchaser.**

In the matter of timber salvage records, this is to certify that:

I, _____ of _____

have been authorized by an agreement with _____

to remove the timber cut under authority of land use disposition no. _____

located in

Section(s) _____ Twp. _____ Rge. _____ W. _____ Mer.

Section(s) _____ Twp. _____ Rge. _____ W. _____ Mer.

Section(s) _____ Twp. _____ Rge. _____ W. _____ Mer.

I am conversant with the provisions of sections 117, 118, 119 and 120 of The Timber Management Regulations and will establish complete and accurate records on Forms TM9 of all logs or trees salvaged from the above described lands and of all quantities of forest products manufactured from these logs or trees before any quantity is removed from my production sites. I further agree that I will be responsible for all Form TM9 records to be established, their retention, and to make them available on request of a Forest Officer for inspection at any time.

Dated at _____, in the Province of _____

this day of _____, 19____.

TM 9 serial numbers for this salvage as authorized by completed TM 75. _____

_____
*SIGNATURE OF SALVAGE PURCHASER*

_____
*TITLE*

**B. To Be Completed by the Land Disposition Holder.**

This authorizes _____ of _____

to remove salvage material as indicated above. This does not exempt said company from being responsible for compliance with debris disposal measures as per the Forests Act, 1971.

_____
*SIGNATURE OF DISPOSITION HOLDER*

_____
*DATE*

_____
*TITLE*

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e) Wood Purchase Agreement:

**WOOD PURCHASE AGREEMENT**
**This Agreement is made between**

**ATCO ELECTRIC LTD.**
**10405 Jasper Avenue**
**Box 2426**
**Edmonton, Alberta**
**T5J 2V6**

NAME:
ADDRESS:

PHONE: _____ FAX: _____

Contact Person: _____
Phone or Cell: _____

Location Hauled From: _____
Area of Province: _____
Location Hauled To: _____

Spruce:_____ Poplar:_____
Estimated Quantity to Be Hauled: _____
Haul Rate:_____ per tonne or $ _____ per hour

Haul Arrangements: _____

Payment Terms: _____

Agreed to on this ___ day of _____ by

ATCO ELECTRIC LTD. For Customer

ATCO Electric

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f) Wildfire Reporting form:

## Wildfire Reporting Form

If fire is **inside** the Forest Protection Area Phone Forest Service at **310-FIRE**

If fire is **outside** the Forest Protection Area phone **(911)** or local Fire Department

**IMPORTANT INFORMATION TO REPORT:**

Name & Contact Number of Person Reporting: _____

Date & Time Discovered: _____

Location: _____

Fire Type: Ground Fire – burning in ground or duff
Surface Fire – running through grass or brush
Crown Fire – burning up the trunk or through tree tops

Fuel Type: Grass Brush Trees (Type) _____

Wind Speed/Direction: _____

Topography: _____

Approximate Size: _____

Water Nearby? _____

Number of people/equipment at fire: _____

Helicopter Landing Spots: _____

Other Information:

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g) Wildfire Investigation Report:

**Appendix III**

**Wildfire Investigation Report**

Forest Operations File Number: _____
SWMS: _____
SRD Fire Number: _____

General Information

Date of Ignition (YY/MM/DD/24hr): _____
Legal Location: _____
Service Area: _____
Fire Size (estimate): _____
Type of fuel (i.e. grass, black spruce 8m): _____

Weather at the Time of Ignition
Temp: _____
Wind Speed: _____
Wind Direction: _____

Ignition Source:
Tree Contact _____
Fuse _____
Facility (i.e. conductor failure 3 phase, 1 phase) _____
Other (i.e. construction crew) _____ Specify: _____

Which area(s) is the fire located within?
The Forest Protection Area: _____
The Green Zone: _____
National Park: _____
Provincial Park: _____

Private Lands: _____
Municipal Lands: _____
County or ID Lands: _____
Aboriginal Lands: _____

Specify which fire suppression organization(s) actioned the fire (i.e. Forest Service, County/ M.D.
Fire Department): _____

Describe Damages: _____

Detailed Tree Information

Tree fell into conductor or facility: _____
Tree Species:
(Spruce, Black Spruce, Pine, Fir, Larch, Apen, Poplar, Birch) _____
Tree class (dominant, co-dom., intermediate, suppressed): _____
Condition of tree (live, dead, visible signs of defect, exposed to wind, etc.): _____

Tree grew into conductor: _____
Tree height (meters): _____

Distance from base of tree to conductor (meters): _____
Distance from R.O.W. edge to centerline (meters): _____

Describe the tree and powerline locations in relation to each other and in relation to other facilities or clearings (i.e. tree was west of powerline and the powerline was located on the west side of an oilfield road): _____

General Comments _____

*Please attach a sketch*

Person Completing Investigation Report: _____
Detailed Field Investigation Completed: _____

Wildfire Investigation Report **Forest Operations Group** Revised June 21, 2002

h) Tree Voucher Letter

ATCO Electric

**Subject: ATCO Electric Tree Voucher Gift Certificates**

Dear Landowner:

Please find enclosed the tree vouchers redeemable at Dunvegan Gardens in Grande Prairie. They can be used to replace the trees we have removed from your property as per our agreement. Please check the enclosed list of trees suitable for planting within 8 meters (26 feet) of the powerline and those that must be planted beyond 8 meters. These certificates can be used for any merchandise; they do not have to be used for trees.

Thank you for participating in this program and helping us reduce maintenance costs to keep the powerlines in a safe and reliable condition.

Thanks,

Utility Forester, Forest Operations
ATCO Electric
Engineering

10035 - 105 Street, Edmonton, Alberta, Canada T5J 2V6
Tel: 780-420-7310 Fax: 780-420-7400
www.atcoelectric.com

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i) May be Planted Near a Powerline

| **Caution:** | **Tree Name** | **Height at Maturity** |
|---|---|---|
| May plant near a power line* | Pincherry (Prunus pensylvanica)** | 5 m (16ft) |
| | Western Chokecherry (Prunus virginiana melanocarpa)** | 5 m (16 ft) |
| * May require trimming under most favorable soil and climatic conditions. | Black Cherry (Prunus serotina) | 6 m (20 ft) |
| | Tartarian maple (Acer tataricum)** | 6 m (20 ft) |
| | Amur maple (Acer ginnala)** | 4 m (13 ft) |
| | Flowering crabapples (Malus baccata)** | 5 m (16 ft) |
| ** Suitable for planting in Chinook region. | Hawthorns (Crataegus sp.)** | 5 m (16 ft) |
| | Snowy mountain ash (Sorbus decora)** | 5 m (16 ft) |
| | Green's mountain ash (Sorbus scopulina) | 5 m (16 ft) |
| | French pussy-willow (Salix caprea)** | 5 m (16 ft) |
| | Mugo pine (Pinus Mugo rostrata)** | 6 m (20 ft) |
| | Pyramidal white cedar (Thuja o. 'Pyramidalis') | 5 m (16 ft) |
| | Montgomery blue spruce (Picea pungens 'Montgomery') | 3 m (10 ft) |
| | Caragana (Caragana arborescens)** | 3 m (10 ft) |
| | Hedge cotoneaster (Cotoneaster lucidus)** | 2 m (7 ft) |
| | Highbush cranberry (Viburnum trilobum)** | 3 m (10 ft) |
| | Nannyberry (Viburnum Lentago)** | 5 m (16 ft) |
| | Dogwood (Cornus sp.)** | 3 m (10 ft) |
| | Elder (Sambucus sp.)** | 4 m (13 ft) |
| | Honeysuckle (Lonicera sp.)** | 3 m (10 ft) |
| | Lilac (Syringa sp.)** | 5 m (16 ft) |
| | Saskatoon (Amelanchier alnifola) | 4 m (13 ft) |

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j) DO NOT Plant Near a Powerline

| **Do Not** | **Tree Name** | **Height at Maturity** |
|---|---|---|
| Plant within eight metres of a power line | Trembling aspen (Populus tremuloides) | 18 m (60 ft) |
| | Balsam poplar (Populus balsamifera) | 20 m (65 ft) |
| | Northwest poplar (Populus x. 'Northwest') | 20 m (65 ft) |
| | Plains cottonwood (Populus deltoides) | 30 m (90 ft) |
| | White spruce (Picea glauca) | 15 m (50 ft) |
| | Blue spruce (Picea p. 'Glauca') | 15 m (50 ft) |
| | Manitoba maple (Acer Negundo) | 14 m (45 ft) |
| | Laurel leaved willow (Salix pentandra) | 15 m (50 ft) |
| | Golden leaved willow (Salix alba vitellina) | 15 m (50 ft) |
| | Sharp leaf willow (Salix acutifolia) | 10 m (35 ft) |
| | Green ash (Fraxinus pensylvanica 'lanceolata') | 15 m (50 ft) |
| | Patmore green ash (Fraxinus pensylvanica 'Patmore') | 15 m (50ft) |
| | American elm (Ulmus Americana) | 20 m (65 ft) |
| | Brandon elm (Ulmus Americana 'Brandon') | 15 m (50 ft) |
| | Siberian elm (Ulmus pumila) | 12 m (40 ft) |
| | Paper birch (Betula papyrifa) | 12 m (40 ft) |
| | European white birch (Betula pendula) | 12 m (40 ft) |
| | Cut-leaved weeping birch (Betula pendula 'Gracilis') | 20 m (65 ft) |
| | Slender weeping birch (Betula pendula 'Tristis') | 12 m (40 ft) |

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k) Job Observation:

ATCO Electric

## Job Observation/Inspection

| Date | Project # | Location | Progress to date (% complete) |
|---|---|---|---|
| Y / M / D | | | |

**Job Being Performed**

**This is a: Job Observation / Contract Inspection / or both (circle one)**

**Risk Level Legend**
**High** - Fatal, Disabling Injury
**Medium** - Medical Treatment Injury
Low - First Aid Injury

**Job Safety Planning Tailboard**

**Written, well communicated, high risk hazards and barriers identified and rated, effective emergency plan**

| | Imp. Opp. | N/A | Well Done | Comments |
|---|---|---|---|---|
| Job Steps | | | | |
| High Risk Hazards Identified | | | | |
| Barriers/Controls Identified, Implemented & Rated | | | | |
| Procedures used, as described & applicable | | | | |
| Job Changes Identified | | | | |
| Emergency Response Plan | | | | |
| Understanding/Signatures | | | | |

**Critical Tasks**

| | Imp. Opp. | N/A | Well Done | Comments |
|---|---|---|---|---|
| Fall Protection | | | | |
| Insulated Tools/Clearances | | | | |
| Traffic Accommodation & Control | | | | |

**Tools & Equipment**

| | Imp. Opp. | N/A | Well Done | Comments |
|---|---|---|---|---|
| Personal Protective Equipment (PPE) | | | | |
| Tools & Equipment | | | | |

**Training**

| | Imp. Opp. | N/A | Well Done | Comments |
|---|---|---|---|---|
| Special Training Required (Chainsaw, ATV, etc.) | | | | |
| Certificates Available | | | | |
| Recent Training or Safety Initiatives | | | | |

**Job Tasks**

| | Imp. Opp. | N/A | Well Done | Comments |
|---|---|---|---|---|
| Meets Specifications | | | | |
| Meets Permit/Consent Requirements | | | | |
| Meets Landowner Expectations | | | | |
| Environmental Protection | | | | |
| Site Clean-up/Debris disposal | | | | |
| Changes Identified (and previously reported?) | | | | |
| Timesheets/Vegetation Reports current & properly filled out | | | | |

**Job Progress**

| | Imp. Opp. | N/A | Well Done | Comments |
|---|---|---|---|---|
| Productivity (Amount of work matches days worked?) | | | | |
| Job Progress matches expectations | | | | |
| Efficient scheduling of work sites (esp. travel) | | | | |

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DISTRIBUTION LINE
MAINTENANCE STANDARDS

| ORIGINAL DATE | REVISION NO. | PAGE | INDEX NO. |
|---|---|---|---|
| 97-05-20 | R0 | 96 | 4.16 |
| | EFFECTIVE DATE 97-10-20 | | |

| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Appendices |

**On-Site Discussion** (& clarify issues identified above)

Observer's comments (SWMS – Safety Issues)

Observer's comments (Contract Performance Issues)

Worker's comments

**Follow-Up Actions Required (SWMS – Safety Issues)**

| What | Who | When |
|---|---|---|
| | | |
| | | |
| | | |
| | | |

**Follow-Up Actions Required (Contract Performance Issues)**

| What | Who | When |
|---|---|---|
| | | |
| | | |
| | | |
| | | |

| | |
|---|---|
| Observer's Name (print) | Signature |
| Name of foreman/UTT/UTW (and number of people on crew) | |
| Manager Review Signature | Date input into SWMS (or N/A) |

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**DISTRIBUTION LINE MAINTENANCE STANDARDS**

| ORIGINAL DATE | REVISION NO. | PAGE | INDEX NO. |
|---|---|---|---|
| 97-05-20 | R0 | 97 | 4.17 |
| | EFFECTIVE DATE 97-10-20 | | |

| SUBJECT | INDEX DESCRIPTION |
|---|---|
| RIGHT-OF-WAY MAINTENANCE | Approvals |

## *4.17 Approvals*

Re-written and updated by: Don Bouzane

Checked by:

Recommended by:

Approved by: ----------

Date of Approval: ----------

ATCO Electric

# SPECIFICATIONS (MAINTENANCE BRUSHING)

1. All work will be completed and invoiced by the date indicated in the Form of Tender or Contract.

2. Landowner permission form will be regarded as the work instructions. Any deviations from the permissions must be arranged with the landowner and Forest Operations Coordinator.

3. The attached ATCO Electric map indicates the location of each brushing site. The patrol notation describes the estimated scope of work required at each location.

4. The contractor will be responsible for any damage to public or private property sustained while completing the identified work.

5. The crew foreman will contact Forest Operations Coordinator as indicated in the job planning meeting, in regard to work progress and, if any difficulties develop.

6. The crew foreman will contact the nearest ATCO Electric service area office and report daily their whereabouts.

7. An operational mobile telephone or ATCO Electric Company radio is required with each brushing crew.

8. Outages are to be arranged a minimum of 48-hrs.in advance with the local ATCO Electric operator in-charge.

9. All work locations will be mapped and the work done on each location will be recorded. This map will be submitted to Forest Operations Coordinator at the completion of the project.

10. The crew foreman will be familiar with and have in his possession, the `SPECIFICATIONS'.

11. Any work locations not completed as indicated on the permission list will be deducted from the bid price.

12. The contractor may supply a separate price for all extra work locations not indicated on the attached maps or permission lists. Each location, however, must be approved by ATCO Electric Coordinator.

13. Any changes to brushing activities (as described on the Landowner Permissions form) will be documented (including landowner authorization) on

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the form, with the revised date and crew foreman signature. Such changes require prior approval from the Forest Operations coordinator.

14. Any deficiencies to these specifications or to the "Landowner Permission" requirements will be neatly documented on the specific "Landowner Permissions" form or on an ATCO Electric "Brushing Status Report" form. These "deficiency documents" will all be returned to Forest Operations prior to its inspection (and final payment).

15. Any deficiencies to these specifications on Public Land (not documented on a "Landowner Permissions" form) will be documented by the contractor

16. The contractor will document the status (i.e. bent, missing, or intact) of survey pins belonging to the Province of Alberta at mow locations. No mowing will take place within 0.3 m (1 foot) of any such survey markers or marker pits. Any disturbance or damage to intact survey markers, or marker pits, will require the contractor to bear the cost of their re-establishment.

17. All stumps will be cut as low as possible (no higher than 8 cm (3 in.)) with flat tops, unless required for slope stabilization.

18. All limbs will be disposed of by chipping unless otherwise approved by Forest Operations coordinator.

19. All limbs under or to the side of the power line will be trimmed using directional pruning techniques.

20. A Utility Tree worker or Utility Tree Trimmer will be in charge of each Mow crew.

21. A Utility Tree Trimmer will be in charge of each Trim crew.

22. A Utility Tree worker or Utility Tree Trimmer will be in charge of each Slash or Pre-mow crew.

23. Unless the ATCO Electric "Landowner Permissions" form indicates otherwise, the **minimum** Right-of Way width to be maintained on either side of single and three phase power lines (at ground level) is 7.5 metres, except for single phase lines in rurals, which may be maintained at 6 metre width. In all cases, **tree limb to conductor clearance after mowing should be 5 metres.**

24. All woody vegetation with potential to grow within 3 metres of the primary conductor, will be removed (i.e. poplar, alder, birch, spruce, pine, and some willow), unless indicated otherwise by the Landowner Permission list.

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25. All trimmed limbs will be cut flush with the tree trunk (without damaging the branch collar). All limbs above the power line will be removed. **There will be no work over any energized equipment, or within the Utility Tree Trimmer Tree worker "limits of Approach".**

26. Remove all woody species growing under guy wires.

27. All guy wires within 3 metres (10 feet) of mow operations will be flagged in advance. A 3-meter (10-foot) diameter area will be cut out around such guy wires prior to mow operations. This area will be closely examined for guy wire "tails." Such "tails" will be brought to the attention of the local district office.

28. All work locations are to be left tidy, with brush disposal acceptable to both ATCO Electric and the landowner. Mowers may have to make two passes, or have larger trees slashed in advance; especially for large willow, or heavy density deciduous areas (when stem diameters are greater than four inches ten cm). Greater care is required around yard sites; all exposed limbs and roots over two inches (five cm) in diameter should be removed with the ground being reasonably leveled off prior to seeding.

29. Pre-mowing operations include the removal of larger trees on the side (s) of right of way, and is a requirement at some mow locations. This work will be done in advance of mow operations.

30. All activities conducted for ATCO Electric will conform to the following:
    a) The province of Alberta's:
        - Electrical Protection Act
        - Employment Standards Code
        - Environmental Protection and Enhancement Act
        - Occupational Health and Safety Regulations
        - Forest and Prairie Protection Act
        - Surface Rights Act
        - Weed Control Act
    b) The Government of Canada's:
        - Transportation of Dangerous Goods Act
        - Workman's Compensation Act
        - Workplace Hazardous Materials Information System (WHMIS) regulations
    c) The Industrial Vegetation Management Associations of Alberta's (IVMAA):
        - Safety Rules for Trees Near Power Lines

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31. **Before any work begins, the contractor must supply a "Job Safety Analysis" for each Operation, and the Forest Operations coordinator must approve the plan.** *This work plan will include:*
    *a) A description of the job,*
    *b) A list of critical activities/site conditions,*
    *c) A list of the tools/equipment (with test expiry dates) and materials required,*
    *d) A list of the hazards and methods used to eliminate or control them,*
    *e) The necessary level of competency- for all workers,*
    *f) An emergency plan and,*
    *g) The general sequence of events (at the work site).*

    Each work crew will be in possession of, and familiar with, the completed "Work Plan" form when working on this project).

32. **Tailboard meetings** will be held prior to staring any job where two or more workers are present. They will also be undertaken where the original "Work Plan" changes or where the job has been interrupted for a period of time. These interruptions could include breakdowns, lunches, etc. Tailboards must be submitted to ATCO Electric with the appropriate invoice. *Each tailboard will indicate at a minimum:*
    *a) Who is charge of the crew,*
    *b) What are the tasks that are to be performed,*
    *c) What the duties are of each crew member,*
    *d) What are the hazards at each work site,*
    *e) What are the main hazards in performing each task, and*
    *f) How are the hazards going to be controlled or eliminated.*
    *g) Emergency response plan in case of injury*

33. A **"Start-Up" meeting** will be conducted with a representative of the ATCO Electric District (Service Area), and all contractor foreman. Each brush crew foreman will be in possession of, and familiar with, the completed "Start-up Meeting" form when working on this project. Forest Operations coordinator's approval will be obtained if any changes to the Work Plan are desired by the contractor (including the change of crew members). Any new foreman must review the Work Plan with the Forest Operations coordinator, and be familiar with the "Specifications" and "Work Plan."

34. ATCO Electric reserves the right to audit crews while they are at their work locations for compliance with; these "specification" requirements and government regulations.

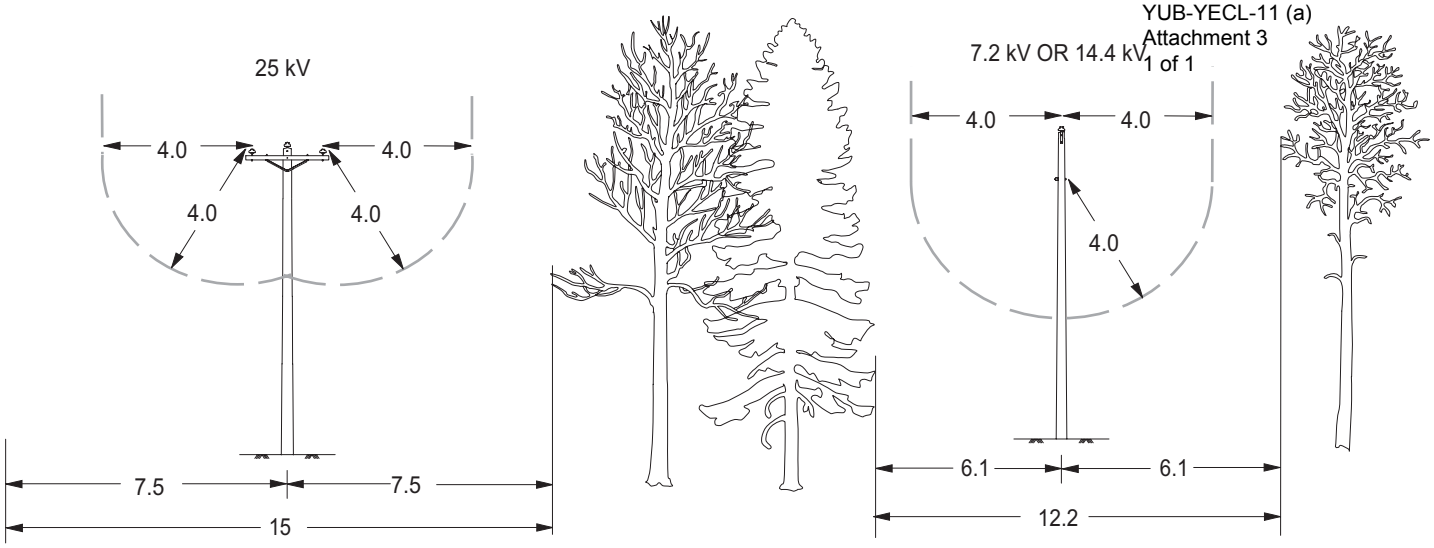
35. All work must stop if any incident occurs and reported to Forest Operations Coordinator and the local ATCO Electric Service Area office immediately. Vehicle accidents associated with ATCO Electric's work must also be reported. ATCO Electric has a policy of non-discipline for accident incident that are reporting.

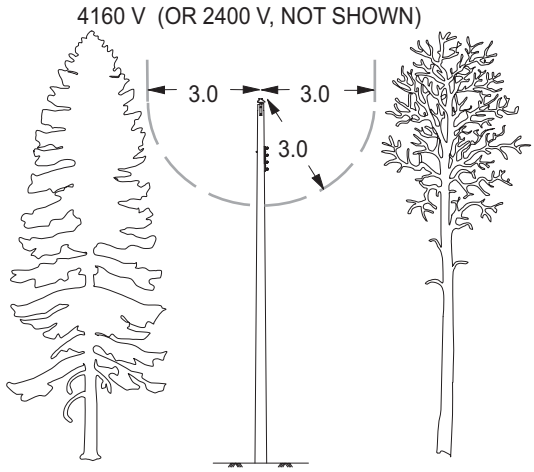
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36. Limbs or trees with potential to contact the power line during their removal, will have preventative measures taken to avoid this (ie. rope).

37. Workers are not allowed to be in the bucket of a boom truck or ride on the outside of the cab of a vehicle while it is in motion.

38. ATCO Electric may stop work and void this contract at any time if:
   a) ATCO Electric is not satisfied with work quality,
   b) The rate at which the work is progressing will create difficulties for ATCO Electric in relations to the specified completion date.
   c) Significant problems are created (in ATCO Electric's opinion) by the contractor with land title holders,
   d) Due to contractor negligence, serious problems develop. ATCO Electric will not be responsible to pay the contractor for work not done, or not done to ATCO Electric's satisfaction, as a result of the above circumstances.
   f) Worker Health and Safety violations occur.




| VOLTAGE | RIGHTS-OF-WAY WIDTH | TREE TO CONDUCTOR CLEARANCE |
|---|---|---|
| 2400 V | - | 3 m |
| 4160 V | - | 3 m |
| 7200 V | 12.2 m (6.1 m EACH SIDE) | 4 m |
| 14400 V | 12.2 m (6.1 m EACH SIDE) | 4 m |
| 24940Y/14000 V | 15.0 m (7.5 m EACH SIDE) | 4 m |

- RIGHTS-OF-WAY WIDTH SHALL BE DETERMINED BY MEASURING THE HORIZONTAL DISTANCE AT RIGHT ANGLE AND GROUND LEVEL FROM THE CENTRE-LINE OF THE POWERLINE TO THE NEAREST BRANCH OF THE CLOSEST TREE. THIS IS DONE ON EACH SIDE OF THE CENTRELINE, IF APPLICABLE.
- TREE TO CONDUCTOR CLEARANCES ARE TO BE DETERMINED BY ESTIMATING THE DISTANCE FROM THE CONDUCTOR TO THE NEAREST TREE BRANCH.
- TREE BRANCHES ARE NOT TO EXTEND OVER THE CONDUCTOR REGARDLESS OF VERTICAL CLEARANCE.
- THE RIGHTS-OF WAY IS TO BE CLEARED OF VEGETATION WHICH IS INCOMPATIBLE WITH THE OPERATION OF AN ELECTRICAL SYSTEM. (TALL GROWING PLANT SPECIES i.e. POPLAR, SPRUCE, etc.)
- WOOD IS TO BE SALVAGED, OR DISPOSED OF, IN AN ACCEPTABLE MANNER.

(DISTRIBUTION MAINTENANCE STANDARDS 4.3.1.)

Dimensions in m

**ATCO Electric**

Prepared By: **HM** Oct, 2007

Reviewed By:
Original Reviewed By: Bob Chanasyk
November 21, 2007

Approved By:
Original Approved By: Garth Ryland
October 30, 2007

PROFESSIONAL ENGINEER ALBERTA G. C. RYLAND APEGGA Permit # P0850

Right-of-Way Site Preparation

# SC34-1

SECTION 1

THIS DRAWING IS THE PROPERTY OF ATCO ELECTRIC AND CONTAINS PROPRIETARY AND CONFIDENTIAL INFORMATION WHICH MUST NOT BE DUPLICATED, USED OR DISCLOSED WITHOUT PRIOR WRITTEN CONSENT OF ATCO ELECTRIC.

**YUB-YECL-12**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 87300 Maintenance

**Quote**: Costs increase from 2005 to 2006 mainly due to filling vacancies in 2006 and labour allocation to 71100 in 2005. (Line No. 80.)

Costs increase from 2007 to 2008 due mainly to additional labour as a result of new hires ( 136), vacancy reductions ( 120) (Line No. 82.)

These programs relate to Core certification and environmental requirements. Many of these programs are mandated by outside agencies or are a result of changes to industry standard. The increases also relate to enhanced patrols of lines and the introduction of planned maintenance programs designed to support system performance. (Line No. 84-87.)

**Preamble**: The Board would like to have a greater understanding regarding YECL's maintenance costs.

**Request:**

(a) Please provide vacancy rates for the period 2002 to 2007 for Account 87300.

(b) Please provide detailed explanation regarding in regard the 600 (60 ) increase in maintenance costs when comparing 2009 to 2007.

(c) What is Core certification?

(d) Please explain what is meant by enhanced patrol of lines .

(e) Please provide further detail and explanation regarding the need for expenditures relating to the introduction of planned maintenance programs designed to support system performance .

(f) Did previous programs not support system performance? Please explain.

**Response:**

(a) Vacancy rates are calculated based on an approved complement for FTEs. As such vacancy rates are not applicable for this period, given that there were no Board approved FTE.

(b) The variance explanation can generally be found in Schedule 5.2 lines 73 to 82. To further assist with this Information Request Yukon Electrical, to the extent possible, has provided a further breakdown based on the maintenance costs that make up the referenced variance. The chart below includes labour and other costs associated with each program.

| **Program Cost Item** | **2007 to 2008 Variance ( 000)** |
|---|---|
| 1. Core Certification (Safety Program) | 50 |
| 2. Enhanced Line patrols | 60 |
| 3. Pole Plant program | 50 |
| 4. Ground Rod testing | 50 |
| 5. Skills Premium (Attraction Retention) | 75 |
| 6. Field Service Representative | 25 |
| 7. Operations Admin Support (General, New Programs) | 20 |
| 8. Inflation (labour, fringe, other) | 120 |
| Subtotal | 450 |
| Inflation Increase between 2008 and 2009 | 150 |
| Total variance 2007-2009 | **600** |

As discussed in its application Yukon Electrical has hired certain new positions required to provide safe and reliable service to customers. These positions include, Planned Program and HS&E Supervisor, Operations Administration

Support, Field Service Rep and a journeyman lineman. Yukon Electrical's process allocates employee labour to the various activities where the employee is expected to work. This accounts for the new hire cost increase shown in Schedule 5.2. The filling of lineman vacancies, due to an increased recruitment effort and the community skills premium that has been offered, accounts for the costs for vacancy reduction and attraction and retention pay. This labour then accounts for the forecast increase to fringe, labour inflation (annual pay increases) and a portion of non-labour inflation for increased truck charges. The implementation of new planned maintenance programs account for a portion of the increased costs as well. Details of the programs are attached as YUB-YECL-12(b) Attachment 1; however Yukon Electrical applies the program components to its own unique system needs.

The variance between 2008 and 2009 is essentially inflation as outlined in Schedule 5.2 of Yukon Electrical's application.

(c) The Certificate of Recognition (**COR**) Program is an occupational health and safety certification program for all Yukon employers. Its primary intent is to support employers to provide a safe workplace for employees both small and large in the health, safety and well being of its employee's.

The program is designed to:

- Assist companies in the development and maintenance of a company-wide safety program, policies and procedures.
- Introduce standardized training and compliance with the new Yukon Occupational Health and Safety Regulations came to effect November 1, 2006
- Monitor the safety program through annual audits.
- Certain organizations such as the City of Whitehorse, require their contractors to be COR certified in order to be a qualified contractors.

For more information please contact the following web sites

www.yukonsafety.com www.wcb.yk.ca or email work.safe gov.yk.ca

(d) Any time that Yukon Electrical employees are in an area they asses and monitor the power lines and equipment for any noticeable abnormalities that will require immediate attention. An enhanced line patrol is a dedicated walk up and visual inspection performed by one of our qualified utility employees, with corresponding maps and inspection reports on hand. The various components inspected include poles, hardware, anchors, guy wires, insulators, conductors, grounding, line clearances and the vegetation in the area. Although Yukon Electrical has always completed some form of line patrol the program has been enhanced in order to provide an added level of diligence to the process.

(e) Yukon Electrical is implementing these maintenance programs in order to support ongoing system performance. These programs are pole test and treat, ground rod testing and a lightning arrestor program. Increased costs for these programs are for labour, materials, data management and contractor services. By focusing more effort on planned programs and maintenance practices Yukon Electrical will provide a higher level of reliability for its customers in the long term; and an added level of safety and security in the short and long term.

(f) Previous maintenance programs did support system performance to a certain extent. However, in recent years there have been learnings that support a new or improved approach when it comes to maintenance of a power system. In addition, there has been an increased requirement to improve safety for employees and the public, as well as, a general requirement to demonstrate a higher level of due diligence than may have been the case in the past. Over time processes improve, new methods of doing work evolve and new equipment is installed on the power system. A prudent utility responds to the such changes before past practices cause issues or problems. Modern maintenance programs and approaches also have built in mechanisms for tracking trends and actions which are of great assistance in overall system planning.

ATCO Electric

# DISTRIBUTION SYSTEM

# INSPECTION PROGRAM

**Prepared by:** Jay Trenaman — **Revised:** July 5, 2007

**Maint. Supt. Approval:** Blair Howell — **Date:** July 9, 2007

**Manager Approval:** Howard Werden — **Date:** July 9 2007

**Revision Date: July 2007**

**This program remains the property of ATCO Electric**

| ATCO Electric | Company Division: Distribution Regions<br>Target Audience: District - Service Areas | |
|---|---|---|
| **Document Title:** | **Distribution System Inspection and Maintenance** | Number: AP 1110 |
| **Category:** | Maintenance Management | Type: Administrative Practices |
| **Revision Date:** | January 30, 2010 | |
| **Document Owner:** | Manager, Standards | |
| **Signature:** | | |

## PART I – Program Outline

### 1.0 Purpose

To provide a process for inspecting and repairing the ATCO Electric distribution system and ensure it is in a safe and reliable operating condition meeting corporate standards as well as regulatory requirements.

Public safety is of the utmost concern and attention should be focused not only on the structure but also to observations of surrounding events or areas that could cause conflict in the short or long term. These could include man made or natural events that change the original engineering planning and allow the public to inadvertently encroach safe limits of approach.

The report that is generated will assist in providing overall effective planning strategies for ongoing work activities as well as provide documentation for accurately tracking inspections, maintenance activities and repairs.

This process will be used for day to day activities where a substandard condition is identified. The response will be dictated by the critical nature of the associated safety risks to ATCO Electric and the general public.

### 1.1 Program Category Levels

There are three categories identified in the Distribution System Inspection and Maintenance Program. They are as follows:

| Category | Activity |
|---|---|
| Emergency / Critical | unplanned conditions / immediate repairs / secure area |
| Inspection | ongoing visual inspection to ensure system security |
| Maintenance | close scrutiny hands-on physical maintenance by critical evaluation or schedule |

**Personnel have the duty to identify and report any substandard problem or concern identified with any line, equipment or right of way on the distribution system.**

Lines showing evidence of failures or where a problem is suspected are to be inspected immediately. For example, following unplanned extensive outages that may have caused significant equipment damage, an inspection must be conducted to ensure system security and public safety.
Other problems not affecting system reliability, such as missing guy guards, loose or broken grounds, and hardware should still be repaired immediately after appropriate hazard assessments and measures have been implemented.

## 1.2 Emergency / Critical

Substandard conditions that have been identified by customer calls, daily travel, or during the inspection activity must be acted upon immediately to protect the general public and/or other workers. A risk assessment shall be conducted and if determined as urgent, shall be corrected immediately or the area secured.

Documentation of the condition, and work activities shall be completed on the Service Interruption , and Maintenance. Request Form with the information entered into Maximo.

The following flowchart identifies the process required to complete emergency or unplanned maintenance activities.

### Emergency or Critical Process

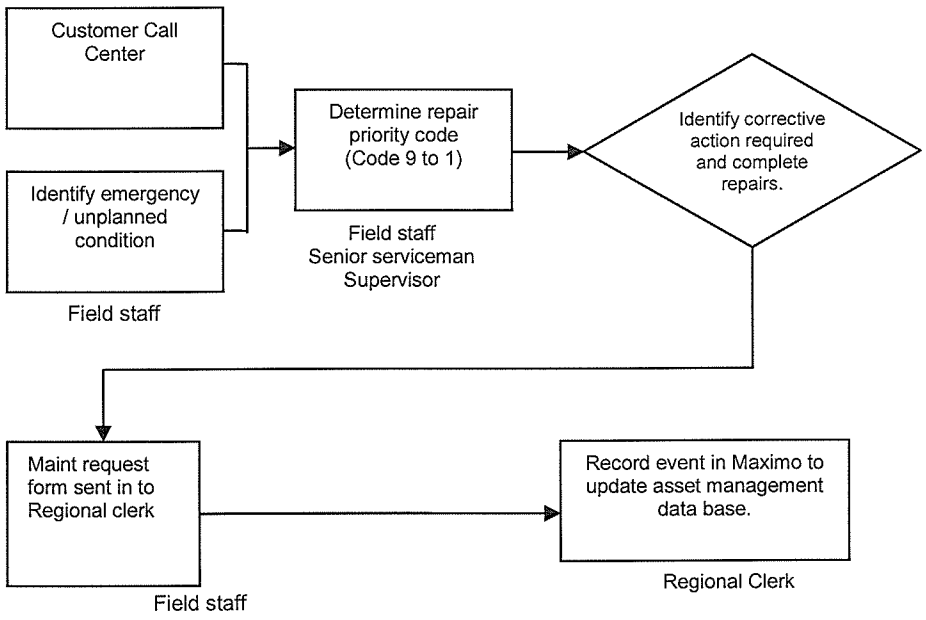

Customer Call Center
Identify emergency / unplanned condition
Field staff
Determine repair priority code (Code 9 to 1)
Field staff
Senior serviceman
Supervisor
Identify corrective action required and complete repairs.
Maint request form sent in to Regional clerk
Field staff
Record event in Maximo to update asset management data base.
Regional Clerk

Figure 1

### 1.3 Inspection

Inspections are completed to:

- identify system problems and make sure repairs are initiated in a planned, proactive and timely manner
- assess the present condition of the distribution system, right-of-way and identify conditions which may affect the safe operation of the system (i.e., encroachment of buildings/trees)
- assess the effectiveness of products, maintenance programs and operating procedures
- meet legal obligations under the Alberta Electrical and Communication Utility Code (ECUC), Pipeline/Gas Field, Transport Canada Aircraft Navigation and, Navigable Water Regulations. (water crossings)
- reduce risk and legal liability due to damage, failure or the evolution of unsafe conditions and hazards

Information gathered and its accuracy during the inspection is used to:

- ensure all substandard conditions are identified, documented, examined and repaired
- report the existence of conditions that may result in injury, loss of life or property
- perform and record repairs that require immediate action (eg. installing guy guards)
- report and record conditions that may result in service interruptions
- establish maintenance and capital budget schedules
- document maintenance activities that will need to be completed at a later date.

An inspection of the Distribution System must be completed at least once each year. The Regional O&M Superintendent in consultation with the Maintenance Supervisor may request additional activities based on findings.
For example:

- infrared scanning to detect hot spots
- unusual sagging conductors
- excessive insulator contamination
- vegetation growth presenting an immediate or potential threat to the system. In this case it must be reported to meet obligations under the Wildfire Agreement and to limit risk and liability on private land.

### 1.4 Maintenance

The appropriate maintenance activities will be determined from the results of the inspections. This is a physical activity performed by either climbing or using an aerial device on overhead systems or physically entering or opening a cubicle, transformer lid, etc on underground systems completing the necessary maintenance.

Observations found and maintenance or repairs that have been completed must be recorded on the corresponding System Inspection form (see Appendix section of this document).

The following flowchart identifies the process required to complete the planned inspection and maintenance activities.

### Planned System Inspection and Maintenance Program Process

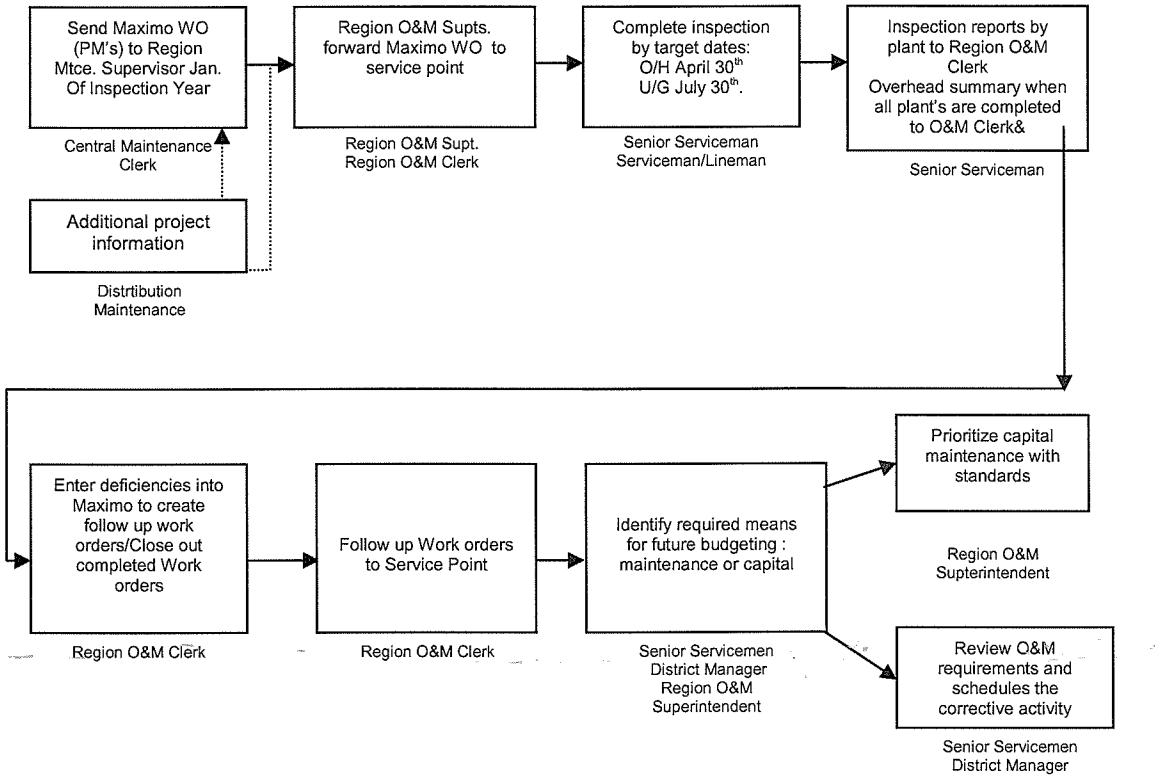



**Figure 2**

## PART II – Additional Inspection and Maintenance Criteria

### 2.0 Purpose

This section shall identify additional criteria pertaining to the inspection and maintenance programs. For detailed Directives on an individual maintenance program and/or Work Procedures, refer to the corresponding internal document.

### 2.1 Personnel

Trades personnel must have the ability to produce quality workmanship using approved work practices and should be dedicated to this project.

Trades personnel in this function must:

- **apply** his skill and knowledge in making observations of substandard conditions
- **complete** the System Inspection Training Module coordinated through the Region O&M Supterintendent
- **determine** and develop barriers to allow inspections and repairs to be completed safely
- **document** repairs that have been completed and items that are to be repaired at a later date
- **forward** the 'original' Distribution Inspection Summary form and System Inspection Report to the Sr. Serviceman indicating all substandard conditions have been addressed
- **ensure** REA inspection and reporting meets REA contract obligations

A Senior Serviceman must:

- **review** and sign off the inspection and maintenance documents
- **send** 'original' Inspection Report with coded information to Regional O&M clerk for entry into Maximo (as soon as each plant is completed)
- **send** a copy of the Summary Report to the: (when all plants have been inspected) Regional Maintenance Clerk to close the Maximo work order

The Region O&M Superintendent must:

- **ensure** the inspection and maintenance reports are entered into Maximo
- **ensure** the regional maint. Clerk runs a capitital and maintenance management plan from data entered in maximo.
-

## 2.2 Reference Material Requirements

The following is a list of additional resources available:

- ATCO Electric's
  - Construction Standards Manual
  - Power System Work Standards
  - System Inspection and Maintenance Program
  - Safety Standards Manual
  - Work Procedures
  - Directives
  - Administrative Practices

## 2.3 Activity Coding

A priority code must be assigned to each outstanding repair by the Inspector, determined by the severity of the risk, and identified in Maximo or on the inspection form.

| Priority | Color | Activity |
|---|---|---|
| 9 | red | Emergency Maintenance (Immediate Action). |
| 8 | orange | Corrective Maintenance (1 to 7 days) |
| 7 | yellow | Scheduled Maintenance (7-30 days). |
| 6-5 | blue | Scheduled Maintenance (1-3 months) |
| 4-3-2-1 | green | Scheduled Maintenance (current or next budget cycle/3 months to 3 years) |
| 0 | | Structure or component is in good condition. No follow-up action required. |

Such documentation of repairs must be kept on hard copy or electronically for a minimum of 11 years.

## 2.4 Account Coding

The following account numbers are to be used for reporting:

| Project # | Task # | Category |
|---|---|---|
| | | **Overhead lines** |
| D0---1 | 87302 | overhead line patrol / inspection |
| D0---1 | 87350 | immediate maintenance from overhead line patrol / inspections |
| D0---1 | 87351 | follow-up maintenance from overhead line patrol / inspections |
| | | **Underground systems** |
| D0---1 | 87402 | patrolling underground system components |
| D0---1 | 87450 | immediate maintenance from underground system inspections |
| D0---1 | 87451 | follow-up maintenance from underground system inspections |

## 2.5 Program Audits

It is the responsibility of the Standards Maintenance Superintendent to audit portions of the system annually by randomly selecting plant numbers on a rotating basis schedule.

The audit is recorded electronically or on a separate inspection form and the field information compared with the inspection report submitted by the region/service area.

A copy of the final report will be reviewed with the Region Maintenance Superintendent, District Manager and Standards Manager.

# 2.6 Workflow Responsibility Matrix

| Activity Task | MGR STDS | District Mgr. & Region Supt.Group Lead | Standardw Mtce. Supt. | Standards Mtce. Sup. | Region Supt & District Mgr. | Group Leader | Trades | Regional Clerk |
|---|---|---|---|---|---|---|---|---|
| Program Approval | D | I | A | C | I | I | I | I |
| Program Management | I | I | D/I | D | D | I | I | I |
| Issue work request –Program Mtce scheduler | I | I | I | D/A | D | I | I | A |
| Issue Preventative Maintenance schedule | I | I | I | D | I | I | A | A |
| Complete inspection | I | I | I | I | C/D | D | A | I |
| Documentation of information | I | I | I | I | I | A | A | A |
| Produce final inspection reports | I | I | I | I | C | D | A | A |
| Produce Summary Report | I | I | I | I | D/A | D/A | A | A |
| Review and approve final inspection reports | I | D | I | I | D | D/A | C | I |
| Close Maximo work order | I | I | I | I | D | I | I | A |
| Develop maintenance plan | I | I | C/I | D | D | A | A | A |
| Issue follow-up work orders | I | I | I | I | D | A | A | A |
| Review follow-up work order | I | I | I | I | D | A | A | A |
| Close Follow-up work order | I | I | I | I | D | A | I | A |
| Produce year end report | C | A | D | A | A | C | I | A |
| Perform program audit | I | I | D | A | C | I | I | A |

| Legend | | |
|---|---|---|
| D | decision | the individual who is ultimately responsible |
| A | action | the individual who actually completes the task, the doer |
| C | consult | the individual to be consulted before the decision is made |
| I | inform | the individuals informed after the decision has been made |

## PART III– Appendix

Included in this appendix are the following forms:

| Document ID | Document Name |
|---|---|
| A | System Inspection Overhead Report |
| B | System Inspection Underground Report |
| C | System Inspection Overhead Clearance Report |
| D | System Inspection Street Lighting Report |
| E | N/A System Inspection Outstanding Maintenance |
| F | Annual Summary Report |
| G | Maintenance Work Request form |
| H | Forest Operations Hotspot Reporting form |

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**YUB-YECL-13**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 87700 Transformer Repair and Replacement

**Quote**: Costs increase from 2005 to 2006 mainly due to higher unplanned repairs... (Line No. 114.)

...

Costs increase from 2006 to 2007 mainly due to higher unplanned repairs (Line No. 116.)

**Preamble**: The Board would like more detail regarding this account.

**Request:**

(a) Please explain sustained transformer repair and replacement costs for the period 2006 to 2009 when compared to 2005.

(b) As part of the explanation for (a), YECL, if it chooses, may provide detail in regard to transformer repair and replacement costs for the period 1997 through 2004.

**Response:**

(a) These expenditure reflect two activities, refurbishment of voltage regulators and refurbishment and or minor repair of transformers. If the repair can be completed by Yukon Electrical's local staff or repaired by a third party at a reasonable cost, it will be charged to this activity. Professional judgment is exercised when it comes to repair of transformers with minor damage or failure vs replacement. Contributing factors in these decisions include if the transformer is of a unique voltage or size, as well, it's availability from a vendor is a consideration. The forecast put forward in the test period is reflective of previous experience in this activity.

(b) This activity was not tracked separately or consistently prior to 2006.

**YUB-YECL-14**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 87800 Street Light Maintenance

**Quote**: Costs increase from 2006 to 2007 mainly due to increases in number of lights and age of street light infrastructure as well as maintenance of new types of lights such as waterfront decorative lighting ( 31). (Line No. 122-123.)

**Preamble**: The Board would like a better understanding regarding the various types of lights, i.e. street lights and decorative lighting, available in YECL's service territory.

**Request:**

(a) Please provide detailed explanation as to the various types of street lighting and affiliated maintenance and ownership contracts that are available to customers in YECL's service territory.

(b) Please provide detailed explanation as to the various types of decorative lighting and affiliated maintenance and ownership contracts that are available to customers in YECL's service territory.

**Response:**

(a) Please refer to YUB-YECL-14 Attachment 1 for the various types of streetlighting options currently in service in the City of Whitehorse and throughout the territory. In summary these schedules represent the various types of rate options depending on the initial purchase agreement and in some cases, location of the light. In regard to ownership, typically all lights are owned, operated, maintained and replaced at the end of life or after damaged by Yukon Electrical with the exception of a small number of streetlights on Robert Service Way and along Main street in Whitehorse. The other exception relates to streetlights owned by the Yukon Government which are typically on the Alaska Hwy. The streetlights not owned by Yukon Electrical are charged an energy only rate.

(b) Yukon Electrical has a number of styles of decorative lighting based upon customer requests. The ownership arrangement regarding decorative lights is essentially the same as mentioned in response to a) above. Investment in the streetlights by Yukon Electrical is based on the Electric Service Regulations. The currently approved investment level is 700.00 per light. In regard to decorative lighting not owned by Yukon Electrical, a verbal operating, emergency response and repair agreement is in place between Yukon Electrical and the owners where Yukon Electrical will complete requested work on a cost recovery basis.

**THE YUKON ELECTRICAL COMPANY LIMITED**
**STREET LIGHTS**
**NON-GOVERNMENT RATES**

**Effective Dec 1, 2006**
**Supercedes Mar 1, 2006**

**Rate Schedule 6XXX** **SIC Codes 31010, 31020, 32010, 32020**

| Rate Code | Monthly Amount | Monthly Cons | Description |
|---|---|---|---|
| 6110 | $16.11 | 72 | 175 W Mercury Vapor |
| 6120 | $19.83 | 97 | 250 W Mercury Vapor |
| 6130 | $27.37 | 159 | 400 W Mercury Vapor |
| 6140 | $12.33 | 40 | 100 W High Pressure Sodium |
| 6180 | $19.87 | 101 | 250 W High Pressure Sodium |
| 6190 | $27.36 | 159 | 400 W High Pressure Sodium |
| 6210 | $16.11 | 72 | 175 W Mercury Vapor |
| 6220 | $19.83 | 97 | 250 W Mercury Vapor |
| 6230 | $27.37 | 159 | 400 W Mercury Vapor |
| 6350 | $12.33 | 40 | 100 W High Pressure Sodium |
| 6360 | $14.83 | 59 | 150 W High Pressure Sodium |
| 6380 | $19.87 | 101 | 250 W High Pressure Sodium |
| 6390 | $27.36 | 159 | 400 W High Pressure Sodium |
| 6400 | $14.83 | 59 | 150 W High Pressure Sodium |
| 6580 | $21.05 | 101 | 250 W High Pressure Sodium - High Mast |
| 6590 | $28.54 | 159 | 400 W High Pressure Sodium - High Mast |
| 6600 | $13.59 | 51 | 125 W Mercury Vapor |
| 6610 | $16.11 | 72 | 175 W Mercury Vapor |
| 6620 | $19.83 | 97 | 250 W Mercury Vapor |
| 6630 | $27.37 | 159 | 400 W Mercury Vapor |
| 6640 | $10.81 | 27 | 70 W High Pressure Sodium |
| 6650 | $12.33 | 40 | 100 W High Pressure Sodium |
| 6660 | $14.82 | 59 | 150 W High Pressure Sodium |
| 6680 | $19.87 | 101 | 250 W High Pressure Sodium |
| 6720 | $18.71 | 97 | 250 W Mercury Vapor - Energy Only |
| 6730 | $28.72 | 159 | 400 W Mercury Vapor - Energy Only |
| 6780 | $18.75 | 101 | 250 W High Pressure Sodium - Energy Only |
| 6790 | $28.72 | 159 | 400 W High Pressure Sodium - Energy Only |

**Values shown exclude GST**

**YUKON ELECTRICAL COMPANY LIMITED**
**STREET LIGHTS**
**GOVERNMENT RATES**

**Effective Dec 1, 2006**
**Supercedes Mar 1, 2006**

**Rate Schedule 6XXX** **SIC Codes 31010, 31020, 32010, 32020**

| Rate Code | Monthly Amount | Monthly Cons | Description |
|---|---|---|---|
| 6121 | $19.83 | 97 | 250 W Mercury Vapor |
| 6131 | $27.37 | 159 | 400 W Mercury Vapor |
| 6141 | $12.33 | 40 | 100 W High Pressure Sodium |
| 6181 | $19.87 | 101 | 250 W High Pressure Sodium |
| 6191 | $27.36 | 159 | 400 W High Pressure Sodium |
| 6221 | $19.83 | 97 | 250 W Mercury Vapor |
| 6231 | $27.37 | 159 | 400 W Mercury Vapor |
| 6351 | $12.33 | 40 | 100 W High Pressure Sodium |
| 6361 | $14.83 | 59 | 150 W High Pressure Sodium |
| 6381 | $19.87 | 101 | 250 W High Pressure Sodium |
| 6401 | $14.83 | 59 | 150 W High Pressure Sodium |
| 6581 | $21.05 | 101 | 250 W High Pressure Sodium - High Mast |
| 6591 | $28.54 | 159 | 400 W High Pressure Sodium - High Mast |
| 6721 | $18.71 | 97 | 250 W Mercury Vapor - Energy Only |
| 6781 | $18.75 | 101 | 250 W High Pressure Sodium - Energy Only |
| 6791 | $28.72 | 159 | 400 W High Pressure Sodium - Energy Only |

**Values shown exclude GST**

**YUB-YECL-15**

**Reference:** Application, Schedule 5.2

**Issue:** 87500 Meter and Meter Testing

**Quote:** Costs decrease from 2006 to 2007 mainly due to less one-time costs related to Automated Metering Reading (AMR) feasibility study ( 19) and less miscellaneous material issues and payables ( 18). (Line No. 106-107.)

Costs decrease from 2008 to 2009 due to savings from AMR. (Line No. 111.)

**Preamble**: The Board would like to gain a better understanding regarding meters and meter testing.

**Request:**

(a) Please provide the business case drivers that led YECL to perform an AMR feasibility study in 2006.

(b) Who performed the study and what were the study parameters?

(c) Please provide the results of the AMR feasibility study and the resultant analysis performed by YECL that led to the decision by YECL to incorporate AMR.

(d) Please provide details in regard to what YECL has implemented and plans to implement in the future in respect of AMR as a result of the feasibility study.

(e) Please explain the savings from AMR that are forecast in 2009.

(f) Please provide an explanation as to what is meant by less miscellaneous material issues and payables . (Schedule 5.2, Line No. 107.)

**Response:**

(a) In 2006, Yukon Electrical recognized it was likely going to have to migrate off its legacy billing system in the next few years. While billing systems options had yet to be evaluated, Yukon Electrical set about the task of reviewing AMR options that might be incorporated into a new billing system process. Given that ATCO Electric, Yukon Electrical's parent company, had successfully implemented a Two Way Automatic Communications System (TWACS) AMR system in Alberta, Yukon Electrical wanted to complete testing to confirm whether this technology would work on Yukon Electrical's distribution system in the Whitehorse area as well as south to Teslin, Carcross and Tagish or, conversely, whether a different option was preferable. Based on the testing completed, Yukon Electrical was able to confirm the TWACS technology would work in the Yukon and was the best solution available. As part of the review of billing system options, service providers were told their product needed to be compatible with both manual meter reading and TWACS AMR options.

(b) The study testing work was performed by technologists from Yukon Electrical, ATCO Electric as well as the AMR product supplier. As noted in part (a), the work was completed to confirm whether the technology would work on Yukon Electrical's distribution system.

(c) Please refer to YUB-YECL-15(c) Attachment 1 for a copy of the business case.

(d) Please refer to the business case in part (c).

(e) Meter and meter testing costs are forecast to decrease in 2009 as a result of the implementation taking place during the year. Please see Schedule 5.1 line 15. Please refer to the business case in part (c) for the analysis of all costs associated with proceeding with AMR as compared to the status quo meter reading option.

(f) This 18,000 refers to inventory issues and other expenses related to the testing of meters. This amount included some costs associated with the Automated Meter Reading feasibility work.

# Automated Meter Reading ("AMR")
# Business Case
# Yukon Electrical Company Limited

# Automatic Meter Reading (AMR) Business Case
# Yukon Electrical Company Limited

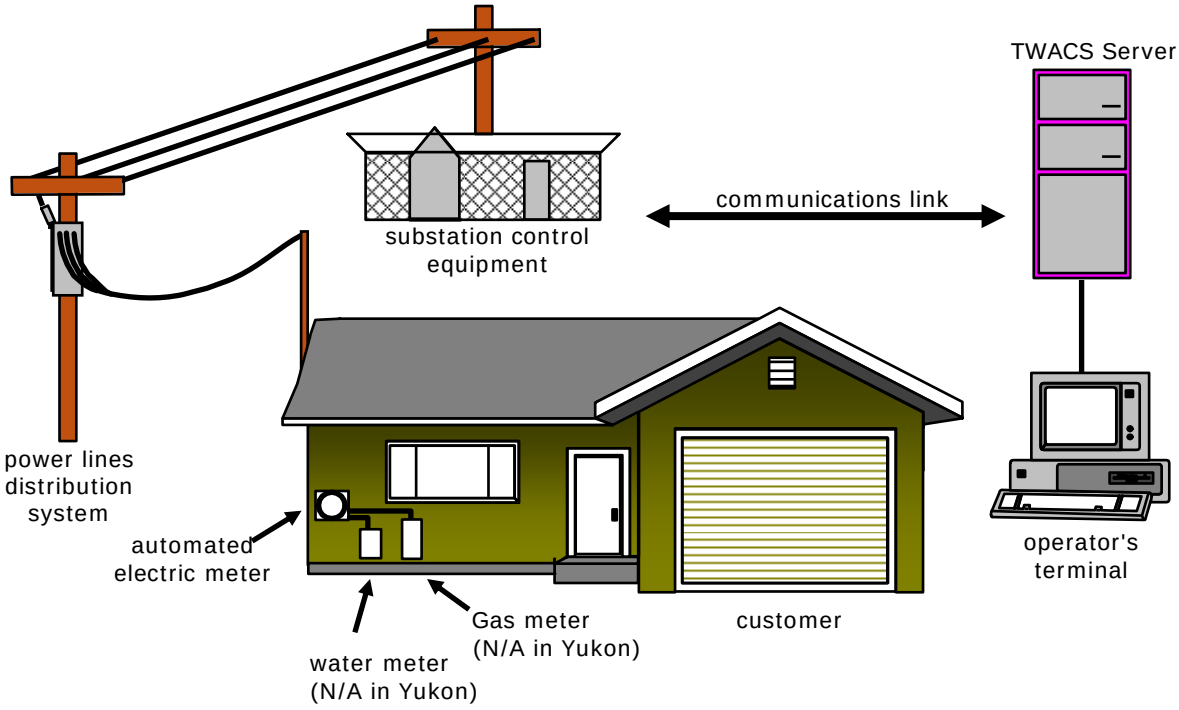
## Summary

This project is to convert approximately 13,200 conventional residential and commercial meters to AMR in Whitehorse area as well south to Teslin, Carcross and Tagish. The benefits of the conversion will be improved customer service, long term savings over the life of the system, more environmentally friendly as well as the installation of metering technology that will support the eventual implementation of Time-of-Use rates.

## Background

ATCO Electric has extensive experience in the implementation, operation and support of a system wide AMR system using a powerline frequency carrier technology known as "TWACS" (Two-Way Automatic Communication System) by Aclara. Although this business case is based on using this same technology as ATCO Electric, another powerline carrier AMR technology ("Turtle") was investigated. The choice of TWACS was mainly predicated on the fact that ATCO Electric has an established process and team in place to deal with its own AMR system and that there would be minimal incremental charges being incurred and allocated to Yukon Electrical. Furthermore, given Yukon Electrical's small size and limited northern based technical resources, Yukon Electrical was not prepared to go it alone with a different technology platform.

# How TWACS AMR works




**Project Description**

The project consists of installing TWACS substation communication equipment ("SCE") on two 34.5kV buses (one at Whitehorse Substation S150 and one at McIntyre Substation S170) and replacing approximately 11,176 residential and 2,024 commercial conventional meters with AMR meters. By installing three SCE's at these locations, TWACS AMR will be achieved for all customers fed by McIntyre, Logan, Laberge, Porter Creek, Mountain View, Services, Arkell, Riverdale, Lewes, McRae, Teslin and Shipyard substations.

**Project Cost**

The cost of the project is estimated to be $4.185M

**Project Schedule**

This project is scheduled to be started in 2008 and completed in 2009.

**Business Drivers**

- Accuracy - AMR results in increased customer service by being able to provide an accurate meter reading at any time and eliminates any access or privacy concerns;
- Savings - AMR is expected to result in long term customer savings;
- Access - AMR eliminates the need to access the meter on a regular basis thereby reducing the risk of animal bites to staff and customer complaints. AMR enables 24/7 access to meter readings;
- Customer Service and Planning - AMR provides voltage readings and momentary outages (blinks) at the AMR meters which can be used for engineering studies, operational requirements and customer conflicts;
- Operations - AMR technologies have advanced to include an Outage system, remote disconnect, re-connect systems that can enhance operations and service as there will no longer be a need to physically go to the meter site; and
- Technology Infrastructure - In conjunction with the new billing system, AMR moves Yukon Electrical's metering and billing technologies forward towards being able to offer Time-of-Use rates.

**Specific Benefits (All available once system is up and running by end of 2009)**

- Improved accuracy of meter readings as chances of human error are eliminated;
- Reduction of billing inquiries or disputes from customers when readings are accurate;
- AMR meters are capable of hourly readings thereby providing to ability to produce load profiles and Time-of-Use rates;
- Reduction in manual re-estimations and cancellation/rebilling when readings are more accurate;
- Reduction in off-cycle meter reading requests when actual reads are missed or customer moves;
- Improved monitoring of meter performance such as stopped or failing meters;
- Improved customer service due to bills based on accurate monthly meter readings;

- Improved opportunity to utilize the AMR system to perform value added distribution system O&M functions such as:
    - remote disconnect/reconnect
    - voltage readings at the meter
    - momentary outage counts (blinks) at the meter
    - outage assessment
- AMR system can be used to provide water AMR services to the City of Whitehorse. Yukon Electrical has approached the City of Whitehorse regarding this opportunity and has been advised the City is studying its options.
- *Although all of the benefits above are enabled by AMR technology, some of the items would require additional business cases and revenue requirement prior to implementation.*

**Risk of Not Proceeding**

- More meter reading errors than otherwise will take place;
- O&M costs will increase over time due to inflation;
- Load profiling would require some other technology; and
- No opportunity to implement Time-of-Use Rates

**Risk of Proceeding**

- Ensuring there are sufficient resources in place to implement the project in 2009.

**Recommendation**

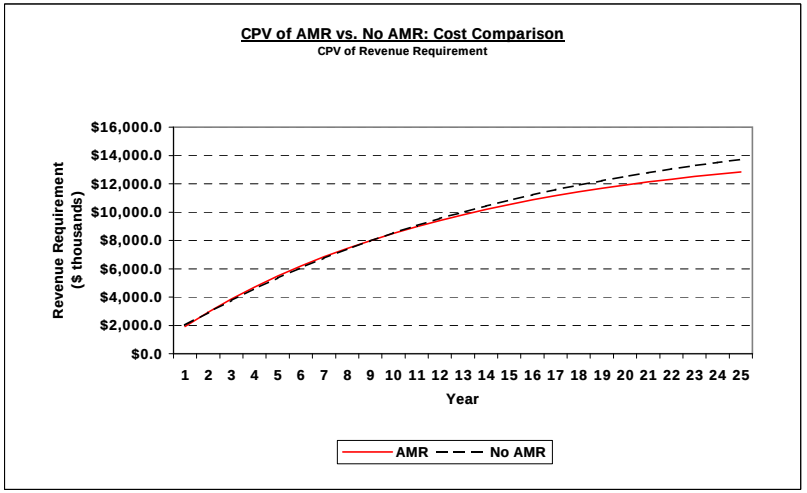
- Proceed with deployment of TWACS AMR technology in 2009.

**Cost Comparison:** **YECL AMR Project**

| | AMR | No AMR |
|---|---|---|
| **Revenue Requirement** | | |
| **CPV @ Year 5** *(thousands)* | **$5,484.5** | **$5,358.2** |
| **CPV @ Year 25** *(thousands)* | **$12,831.6** | **$13,733.0** |

**2010**

| **Capital Cost Summary** | **AMR** | **No AMR** |
|---|---|---|
| *($000's)* | | |
| **Generation Incremental** | | |
| **Generation Existing** | | |
| **Distribution** | **$4,185.0** | **$0.0** |
| **Transmission** | | |
| **Total** | **$4,185.0** | **$0.0** |




Graph Data:

**Societal**

| Year | AMR | No AMR |
|---|---|---|
| 1 | $1,914.6 | $2,008.3 |
| 2 | $2,934.3 | $2,923.7 |
| 3 | $3,863.6 | $3,785.3 |
| 4 | $4,711.1 | $4,595.8 |
| 5 | $5,484.5 | $5,358.2 |
| 6 | $6,190.7 | $6,074.8 |
| 7 | $6,836.2 | $6,748.4 |
| 8 | $7,426.5 | $7,381.1 |
| 9 | $7,966.7 | $7,975.4 |
| 10 | $8,490.1 | $8,533.4 |
| 11 | $8,969.5 | $9,057.1 |
| 12 | $9,411.2 | $9,548.6 |
| 13 | $9,818.4 | $10,009.6 |
| 14 | $10,194.0 | $10,442.1 |
| 15 | $10,540.4 | $10,847.6 |
| 16 | $10,860.2 | $11,227.8 |
| 17 | $11,155.4 | $11,584.1 |
| 18 | $11,428.1 | $11,918.1 |
| 19 | $11,680.0 | $12,231.0 |
| 20 | $11,912.8 | $12,524.1 |
| 21 | $12,128.1 | $12,798.6 |
| 22 | $12,327.2 | $13,055.8 |
| 23 | $12,510.0 | $13,296.5 |
| 24 | $12,677.6 | $13,521.9 |
| 25 | $12,831.6 | $13,733.0 |

**Assumptions: YECL AMR Project**
**AMR Cost Impact**

A Distribution Incremental Capital Structure and Cost

| | Return | Ratio | B.T. Cost | A.T. Cost |
|---|---|---|---|---|
| Debt | 6.600% | 52.50% | 0.0347 | 0.0347 |
| Preferred | 0.000% | 0.00% | 0.0000 | 0.0000 |
| Common | 9.250% | 47.50% | 0.0666 | 0.0439 |
| TOTALS | | | 10.122% | 7.86% |

B Income Taxes 34.00%

C Depreciation Rates: 4.54%

D Long Term Escalation Rat 3.0%

E US Exchange Rate 1.05

F All analysis are based on 25 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis

H Total number of AMR Meters (178,314 AMR + 13200 Yukon) 191,514

I Incremental Capital Cost: *All costs are inflated to the year that they occur.*

| | | | Input Starting Year | Jan-09 | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 |
| J | **METERS:** | | Unit Cost | Jan-09 | Jan-10 | Jan-11 | Jan-12 | Jan-13 | Jan-14 | Jan-15 | Jan-16 | Jan-17 | Jan-18 | Jan-19 | Jan-20 | Jan-21 | Jan-22 | Jan-23 | Jan-24 | Jan-25 | Jan-26 | Jan-27 | Jan-28 | Jan-29 | Jan-30 | Jan-31 | Jan-32 | Jan-33 | Jan-34 | Jan-35 |
| | # of Residential Meters to be installed | | | 11,176 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| | # of Commercial Meters to be installed | | | 2,024 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 |
| | # Spare Residential Meters | 0% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | # Spare Commerical Meters | 0% | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1 | Cost of Residential AMR Module and Meters | | $135.44 /meter | $1,513,677 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 | $20,316 |
| 2 | Cost of Commercial Meter | | $343.00 /meter | $694,232 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 | $51,450 |
| 3 | Cost of Commercial AMR Module | | $195.00 /meter | $394,680 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 | $17,355 |
| 4 | Retrofitting Costs | | $15.00 /meter | $198,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 | $1,335 |
| 5 | Installation - Residential Meters and Module | | $16.50 /meter | $184,404 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 | $2,475 |
| 6 | Installation - Commercial Meters and Module | | $54.50 /meter | $110,308 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 | $4,851 |
| | | | $0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | -$0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | -$0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | $0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 7 | Meter Read Verification | 5% | $36.00 /hr | $23,760 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 | $430 |
| 8 | Test Set & Spares Equipment | | | $18,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Contingency | 10% | | $313,706 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 | $9,821 |
| 10 | Project Management | 5% | | $156,853 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 | $4,911 |
| | Subtotal | | | $3,607,621 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 |
| K | **SUBSTATIONS:** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | # of Substations required *(costs for Two MUTs per Line)* | | | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Electrical Design | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Structural Design | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Major Apparatus Engineering | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Technical & Business Support | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Construction Labour & Expenses | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Commissioning | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Trouble Shooting | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Telecommunication - Engineering | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Telecommunication - Fiber Optic Materials | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | DCSI Equipment | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | MTU | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Electrical Materials | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Structural Materials | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Warehouse & Trucking | | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11 | DCSI Materials | | $41,000 /sub | $82,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12 | Installation & Materials | | *$210,000 /sub* | $420,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13 | Contingency | 10% | | $50,279 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14 | Project Management | 5% | | $25,100 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Subtotal | | | $577,379 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **TOTAL Capital** | | | **$4,185,000** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** | **$112,943** |
| L | **Allocated AMR O&M Costs:** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | O&M Acct#71212 - DCSI TNS Maintenance Support | | $0.44 /meter | $0 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 | $5,808 |
| 16 | O&M Acct#71214 - Annual Sample Verification Process | | $0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 17 | O&M Acct#72107 - I-Tek User Fees (Email & Server Storag | | $0.13 /meter | $0 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 | $1,716 |
| 18 | O&M Acct#72109 - PCs & Monitors | | $0.09 /meter | $0 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 | $1,188 |
| 19 | O&M Acct#72118 - I-Tek Support for TNS Server | | $0.68 /meter | $0 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 | $8,976 |
| 20 | Labour Acct#71211 - AMR Meter Reading | | $1.39 /meter | $0 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 | $18,348 |
| 21 | Labour Acct#71214 - AMR Verification | | $0.03 /meter | $0 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 | $396 |
| 22 | Labour Acct#71215 - AMR Substation Troubleshoot & Sup | | $0.71 /meter | $0 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 | $9,372 |
| 23 | Labour Acct# 71250 - AMR Special Meter Reading | | $0.23 /meter | $0 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 | $3,036 |
| 24 | Conventional Manual Meter Reading Costs During Deploym | | | $471,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 | $200,000 |
| 25 | Conventional Meter Testing During Deployment | | | $115,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 | $75,000 |
| 26 | Customer Applications & Service Orders | | | $450,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 | $365,000 |
| 27 | Data Cap Costs | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Subtotal | | | $1,036,000 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 | $688,840 |

M **CCA Tax Savings**
If CCA > Depreciation, then Income Tax Savings = (CCA - Depreciation) x Tax Rate

| | | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Beg UCC | | $4,185,000 | $3,766,500 | $3,013,200 | $2,410,560 | $1,928,448 | $1,542,758 | $1,234,207 | $987,365 | $789,892 | $631,914 | $607,180 | $587,393 | $571,564 | $558,900 | $548,769 | $540,664 | $534,181 | $528,994 | $524,844 | $521,524 | $518,869 | $516,744 | $515,044 | $513,685 | $512,597 | $511,726 |
| | Capital Additions | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 | $112,943 |
| | CAA | 20% | $418,500 | $753,300 | $602,640 | $482,112 | $385,690 | $308,552 | $246,841 | $197,473 | $157,978 | $137,677 | $132,730 | $128,773 | $125,607 | $123,074 | $121,048 | $119,427 | $118,130 | $117,093 | $116,263 | $115,599 | $115,068 | $114,643 | $114,303 | $114,031 | $113,814 | $113,640 |
| | End UCC | | $3,766,500 | $3,013,200 | $2,410,560 | $1,928,448 | $1,542,758 | $1,234,207 | $987,365 | $789,892 | $631,914 | $607,180 | $587,393 | $571,564 | $558,900 | $548,769 | $540,664 | $534,181 | $528,994 | $524,844 | $521,524 | $518,869 | $516,744 | $515,044 | $513,685 | $512,597 | $511,726 | $511,030 |
| | CCA | | $418,500 | $753,300 | $602,640 | $482,112 | $385,690 | $308,552 | $246,841 | $197,473 | $157,978 | $137,677 | $132,730 | $128,773 | $125,607 | $123,074 | $121,048 | $119,427 | $118,130 | $117,093 | $116,263 | $115,599 | $115,068 | $114,643 | $114,303 | $114,031 | $113,814 | $113,640 |

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Depreciation | | $94,999 | $189,999 | $189,999 | $189,999 | $189,999 | $189,999 | $189,999 | $189,999 | $189,999 | $189,999 | $189,999 | $193,445 | $196,993 | $200,649 | $204,414 | $208,292 | $212,286 | $216,400 | $220,638 | $225,003 | $229,498 | $234,129 | $226,098 | $213,413 | $202,063 | $151,666 |
| CCA less Depreciation | | $323,500 | $563,301 | $412,641 | $292,113 | $195,691 | $118,553 | $56,842 | $7,474 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Allowable Inc Tax Savings / (Cost) | 34.00% | $109,990 | $191,522 | $140,298 | $99,318 | $66,535 | $40,308 | $19,326 | $2,541 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| A Beg Bal (Savings) | | $0 | $62,628 | $161,575 | $213,598 | $228,943 | $215,804 | $180,739 | $128,993 | $64,763 | $2,291 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| B Allowable Inc Tax Savings | | $109,990 | $191,522 | $140,298 | $99,318 | $66,535 | $40,308 | $19,326 | $2,541 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C Inc Tax Payable | | $47,363 | $92,575 | $88,274 | $83,974 | $79,673 | $75,373 | $71,072 | $66,772 | $62,471 | $58,171 | $53,870 | $51,288 | $48,678 | $46,042 | $43,377 | $40,684 | $37,961 | $35,207 | $32,422 | $29,604 | $26,752 | $23,866 | $20,945 | $18,276 | $15,968 | $13,993 |
| Carry Fwd (savings) | | $62,628 | $161,575 | $213,598 | $228,943 | $215,804 | $180,739 | $128,993 | $64,763 | $2,291 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Inc Tax Payable | | $47,363 | $92,575 | $88,274 | $83,974 | $79,673 | $75,373 | $71,072 | $66,772 | $62,471 | $58,171 | $53,870 | $51,288 | $48,678 | $46,042 | $43,377 | $40,684 | $37,961 | $35,207 | $32,422 | $29,604 | $26,752 | $23,866 | $20,945 | $18,276 | $15,968 | $13,993 |
| **Actual Inc Tax Savings** (Lesser of A+B or C) | | **$47,363** | **$92,575** | **$88,274** | **$83,974** | **$79,673** | **$75,373** | **$71,072** | **$66,772** | **$62,471** | **$2,291** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| Taxes Payable after savings | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $55,879 | $53,870 | $51,288 | $48,678 | $46,042 | $43,377 | $40,684 | $37,961 | $35,207 | $32,422 | $29,604 | $26,752 | $23,866 | $20,945 | $18,276 | $15,968 | $13,993 |

**Inflated Costs**

| 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-09 | Jan-10 | Jan-11 | Jan-12 | Jan-13 | Jan-14 | Jan-15 | Jan-16 | Jan-17 | Jan-18 | Jan-19 | Jan-20 | Jan-21 | Jan-22 | Jan-23 | Jan-24 | Jan-25 | Jan-26 | Jan-27 | Jan-28 | Jan-29 | Jan-30 | Jan-31 | Jan-32 | Jan-33 | Jan-34 | Jan-35 |
| $1,513,677 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $27,303 | $28,122 | $28,966 | $29,835 | $30,730 | $31,652 | $32,601 | $33,579 | $34,587 | $35,624 | $36,693 | $37,794 | $38,928 | $40,095 | $41,298 | $42,537 | $43,813 |
| $694,232 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $69,144 | $71,219 | $73,355 | $75,556 | $77,823 | $80,157 | $82,562 | $85,039 | $87,590 | $90,218 | $92,924 | $95,712 | $98,584 | $101,541 | $104,587 | $107,725 | $110,957 |
| $394,680 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $23,324 | $24,023 | $24,744 | $25,486 | $26,251 | $27,039 | $27,850 | $28,685 | $29,546 | $30,432 | $31,345 | $32,285 | $33,254 | $34,252 | $35,279 | $36,338 | $37,428 |
| $198,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,794 | $1,848 | $1,903 | $1,960 | $2,019 | $2,080 | $2,142 | $2,207 | $2,273 | $2,341 | $2,411 | $2,483 | $2,558 | $2,635 | $2,714 | $2,795 | $2,879 |
| $184,404 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,326 | $3,426 | $3,529 | $3,635 | $3,744 | $3,856 | $3,972 | $4,091 | $4,214 | $4,340 | $4,470 | $4,604 | $4,742 | $4,885 | $5,031 | $5,182 | $5,338 |
| $110,308 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,519 | $6,714 | $6,916 | $7,123 | $7,337 | $7,557 | $7,784 | $8,017 | $8,258 | $8,505 | $8,761 | $9,023 | $9,294 | $9,573 | $9,860 | $10,156 | $10,461 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $23,760 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $578 | $595 | $613 | $632 | $651 | $670 | $690 | $711 | $732 | $754 | $777 | $800 | $824 | $849 | $875 | $901 | $928 |
| $18,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $313,706 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $13,199 | $13,595 | $14,003 | $14,423 | $14,855 | $15,301 | $15,760 | $16,233 | $16,720 | $17,221 | $17,738 | $18,270 | $18,818 | $19,383 | $19,964 | $20,563 | $21,180 |
| $156,853 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,599 | $6,797 | $7,001 | $7,211 | $7,428 | $7,651 | $7,880 | $8,116 | $8,360 | $8,611 | $8,869 | $9,135 | $9,409 | $9,691 | $9,982 | $10,282 | $10,590 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $3,607,621 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $151,787 | $156,340 | $161,030 | $165,861 | $170,837 | $175,962 | $181,241 | $186,678 | $192,279 | $198,047 | $203,988 | $210,108 | $216,411 | $222,904 | $229,591 | $236,479 | $243,573 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $82,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $420,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $50,279 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $25,100 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $577,379 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $4,185,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $151,787 | $156,340 | $161,030 | $165,861 | $170,837 | $175,962 | $181,241 | $186,678 | $192,279 | $198,047 | $203,988 | $210,108 | $216,411 | $222,904 | $229,591 | $236,479 | $243,573 |
| $0 | $5,982 | $6,162 | $6,347 | $6,537 | $6,733 | $6,935 | $7,143 | $7,357 | $7,578 | $7,805 | $8,040 | $8,281 | $8,529 | $8,785 | $9,049 | $9,320 | $9,600 | $9,888 | $10,184 | $10,490 | $10,805 | $11,129 | $11,463 | $11,806 | $12,161 | $12,525 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $1,767 | $1,821 | $1,875 | $1,931 | $1,989 | $2,049 | $2,110 | $2,174 | $2,239 | $2,306 | $2,375 | $2,447 | $2,520 | $2,596 | $2,673 | $2,754 | $2,836 | $2,921 | $3,009 | $3,099 | $3,192 | $3,288 | $3,387 | $3,488 | $3,593 | $3,701 |
| $0 | $1,224 | $1,260 | $1,298 | $1,337 | $1,377 | $1,419 | $1,461 | $1,505 | $1,550 | $1,597 | $1,644 | $1,694 | $1,745 | $1,797 | $1,851 | $1,906 | $1,964 | $2,022 | $2,083 | $2,146 | $2,210 | $2,276 | $2,345 | $2,415 | $2,487 | $2,562 |
| $0 | $9,245 | $9,523 | $9,808 | $10,103 | $10,406 | $10,718 | $11,039 | $11,371 | $11,712 | $12,063 | $12,425 | $12,798 | $13,182 | $13,577 | $13,984 | $14,404 | $14,836 | $15,281 | $15,739 | $16,212 | $16,698 | $17,199 | $17,715 | $18,246 | $18,794 | $19,358 |
| $0 | $18,898 | $19,465 | $20,049 | $20,651 | $21,270 | $21,908 | $22,566 | $23,243 | $23,940 | $24,658 | $25,398 | $26,160 | $26,945 | $27,753 | $28,586 | $29,443 | $30,326 | $31,236 | $32,173 | $33,139 | $34,133 | $35,157 | $36,211 | $37,298 | $38,417 | $39,569 |
| $0 | $408 | $420 | $433 | $446 | $459 | $473 | $487 | $502 | $517 | $532 | $548 | $565 | $582 | $599 | $617 | $635 | $655 | $674 | $694 | $715 | $737 | $759 | $782 | $805 | $829 | $854 |
| $0 | $9,653 | $9,943 | $10,241 | $10,548 | $10,865 | $11,191 | $11,526 | $11,872 | $12,228 | $12,595 | $12,973 | $13,362 | $13,763 | $14,176 | $14,601 | $15,039 | $15,490 | $15,955 | $16,434 | $16,927 | $17,435 | $17,958 | $18,496 | $19,051 | $19,623 | $20,212 |
| $0 | $3,127 | $3,221 | $3,318 | $3,417 | $3,520 | $3,625 | $3,734 | $3,846 | $3,961 | $4,080 | $4,203 | $4,329 | $4,458 | $4,592 | $4,730 | $4,872 | $5,018 | $5,169 | $5,324 | $5,483 | $5,648 | $5,817 | $5,992 | $6,172 | $6,357 | $6,547 |
| $471,000 | $206,000 | $212,180 | $218,545 | $225,102 | $231,855 | $238,810 | $245,975 | $253,354 | $260,955 | $268,783 | $276,847 | $285,152 | $293,707 | $302,518 | $311,593 | $320,941 | $330,570 | $340,487 | $350,701 | $361,222 | $372,059 | $383,221 | $394,717 | $406,559 | $418,756 | $431,318 |
| $115,000 | $77,250 | $79,568 | $81,955 | $84,413 | $86,946 | $89,554 | $92,241 | $95,008 | $97,858 | $100,794 | $103,818 | $106,932 | $110,140 | $113,444 | $116,848 | $120,353 | $123,964 | $127,682 | $131,513 | $135,458 | $139,522 | $143,708 | $148,019 | $152,460 | $157,033 | $161,744 |
| $450,000 | $375,950 | $387,229 | $398,845 | $410,811 | $423,135 | $435,829 | $448,904 | $462,371 | $476,242 | $490,529 | $505,245 | $520,403 | $536,015 | $552,095 | $568,658 | $585,718 | $603,289 | $621,388 | $640,030 | $659,231 | $679,008 | $699,378 | $720,359 | $741,970 | $764,229 | $787,156 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $1,036,000 | $256,305 | $263,994 | $271,914 | $280,072 | $288,474 | $297,128 | $306,042 | $315,223 | $324,680 | $334,420 | $344,453 | $354,786 | $365,430 | $376,393 | $387,685 | $399,315 | $411,295 | $423,633 | $436,342 | $449,433 | $462,916 | $476,803 | $491,107 | $505,840 | $521,016 | $536,646 |

| Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $0 | $4,310,550 | $3,995,880 | $3,292,605 | $2,713,106 | $2,235,600 | $1,842,134 | ##### | ##### | ##### | $849,239 | $840,479 | $837,482 | $839,361 | $845,386 | $854,964 | $867,608 | $882,919 | $900,576 | $920,317 | $941,931 | $965,248 | $990,135 | ##### | ##### | ##### | $1,103,585 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $151,787 | $156,340 | $161,030 | $165,861 | $170,837 | $175,962 | $181,241 | $186,678 | $192,279 | $198,047 | $203,988 | $210,108 | $216,411 | $222,904 | $229,591 | $236,479 | $243,573 |
| $0 | $431,055 | $799,176 | $658,521 | $542,621 | $447,120 | $368,427 | $303,584 | $250,153 | $206,126 | $185,027 | $183,730 | $183,599 | $184,458 | $186,161 | $188,589 | $191,646 | $195,252 | $199,343 | $203,868 | $208,785 | $214,060 | $219,668 | $225,587 | $231,802 | $238,301 | $245,074 |
| $0 | $3,879,495 | $3,196,704 | $2,634,084 | $2,170,485 | $1,788,480 | $1,473,707 | ##### | ##### | $824,504 | $815,999 | $813,090 | $814,913 | $820,764 | $830,063 | $842,338 | $857,203 | $874,346 | $893,512 | $914,496 | $937,134 | $961,296 | $986,878 | ##### | ##### | ##### | $1,102,084 |
| $0 | $431,055 | $799,176 | $658,521 | $542,621 | $447,120 | $368,427 | $303,584 | $250,153 | $206,126 | $185,027 | $183,730 | $183,599 | $184,458 | $186,161 | $188,589 | $191,646 | $195,252 | $199,343 | $203,868 | $208,785 | $214,060 | $219,668 | $225,587 | $231,802 | $238,301 | $245,074 |
| $0 | $97,849 | $201,570 | $207,617 | $213,846 | $220,261 | $226,869 | $233,675 | $240,685 | $247,906 | $255,343 | $263,003 | $275,806 | $289,292 | $303,499 | $318,470 | $334,247 | $350,877 | $368,407 | $386,890 | $406,380 | $426,935 | $448,615 | $446,223 | $433,824 | $423,074 | $327,082 |
| $0 | $333,205 | $597,606 | $450,904 | $328,776 | $226,859 | $141,558 | $69,909 | $9,468 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $113,290 | $203,186 | $153,307 | $111,784 | $77,132 | $48,130 | $23,769 | $3,219 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $66,442 | $176,557 | $240,407 | $265,407 | $257,682 | $222,286 | $163,405 | $84,501 | $3,079 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $113,290 | $203,186 | $153,307 | $111,784 | $77,132 | $48,130 | $23,769 | $3,219 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $48,784 | $98,213 | $96,460 | $94,513 | $92,363 | $89,999 | $87,410 | $84,585 | $81,511 | $78,177 | $74,569 | $73,124 | $71,486 | $69,643 | $67,581 | $65,286 | $62,744 | $59,938 | $56,851 | $53,467 | $49,767 | $45,730 | $41,336 | $37,152 | $33,434 | $30,177 |
| $0 | $64,506 | $171,415 | $233,405 | $257,677 | $250,176 | $215,812 | $158,645 | $82,039 | $2,990 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $48,784 | $98,213 | $96,460 | $94,513 | $92,363 | $89,999 | $87,410 | $84,585 | $81,511 | $78,177 | $74,569 | $73,124 | $71,486 | $69,643 | $67,581 | $65,286 | $62,744 | $59,938 | $56,851 | $53,467 | $49,767 | $45,730 | $41,336 | $37,152 | $33,434 | $30,177 |
| $0 | $48,784 | $98,213 | $96,460 | $94,513 | $92,363 | $89,999 | $87,410 | $84,585 | $81,511 | $3,079 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $75,097 | $74,569 | $73,124 | $71,486 | $69,643 | $67,581 | $65,286 | $62,744 | $59,938 | $56,851 | $53,467 | $49,767 | $45,730 | $41,336 | $37,152 | $33,434 | $30,177 |

**Assumptions: YECL AMR Project**
**Conventional Meter Cost Impact**

A Distribution Incremental Capital Structure and Cost

| | Return | Ratio | B.T. Cost | A.T. Cost |
|---|---|---|---|---|
| Debt | 6.600% | 52.500% | 0.0347 | 0.0347 |
| Preferred | 0.000% | 0.000% | 0.0000 | 0.0000 |
| Common | 9.250% | 47.500% | 0.0666 | 0.0439 |
| TOTALS | | | 10.122% | 7.859% |

B Income Taxes 34.00%

C Depreciation Rates: 4.54%

D Long Term Escalation Rate 3.0%

E US Exchange Rate 1.05

F All analysis are based on 25 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis.

H Incremental Capital Cost:

Input Starting Construction Year **Jan-09**

| | Unit Cost | Year 0 Jan-09 | Year 1 Jan-10 | Year 2 Jan-11 | Year 3 Jan-12 | Year 4 Jan-13 | Year 5 Jan-14 | Year 6 Jan-15 | Year 7 Jan-16 | Year 8 Jan-17 | Year 9 Jan-18 | Year 10 Jan-19 | Year 11 Jan-20 | Year 12 Jan-21 | Year 13 Jan-22 | Year 14 Jan-23 | Year 15 Jan-24 | Year 16 Jan-25 | Year 17 Jan-26 | Year 18 Jan-27 | Year 19 Jan-28 | Year 20 Jan-29 | Year 21 Jan-30 | Year 22 Jan-31 | Year 23 Jan-32 | Year 24 Jan-33 | Year 25 Jan-34 | Year 26 Jan-35 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| # of Residential Meters to be installed/replaced | | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| # of Commercial Meters to be installed/replaced | | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 | 88 |
| 1 Cost of Residential Meter | $36.50 /meter | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 | $9,125 |
| 2 Cost of Commercial Meter | $345.00 /meter | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 | $30,360 |
| 3 Installation - Residential Meters | $16.50 /meter | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 | $4,125 |
| 4 Installation - Commerical Meters | $54.50 /meter | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 | $4,796 |
| 5 Freight and Customs Cost (in CDN) | $5.00 /meter | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 | $1,690 |
| | $0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $0.00 /meter | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Subtotal | | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 | $50,096 |
| **SUBSTATIONS:** | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| # of Substations required *(costs for Two Bus Sub)* | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1 Electrical Design | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2 Structural Design | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 3 Major Apparatus Engineering | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4 Technical & Business Support | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 Construction Labour & Expenses | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6 Commissioning | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 7 Trouble Shooting | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 Telecommunication - Engineering | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 Telecommunication - Fiber Optic Materials | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 10 DCSI Equipment | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11 MTU | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12 Electrical Materials | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13 Structural Materials | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14 Warehouse & Trucking | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15 | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 16 | $0, /sub | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Subtotal | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **TOTAL Capital** | | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** | **$50,096** |

I **Conventional O&M Costs:**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Manual Meter Reading Costs | Acct 712 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 | $471,000 |
| 2 Meter Test Costs | Acct 875 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 | $115,000 |
| 3 Customer Applications & Service Orders | Acct 711 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 | $450,000 |
| 4 Data Cap Costs | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6 | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 7 | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Subtotal | | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 |
| - | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Subtotal | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| TOTAL O&M | | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 | $1,036,000 |
| Total Cash Flow | | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 | $1,086,096 |

**Inflated Costs**

| 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-09 | Jan-10 | Jan-11 | Jan-12 | Jan-13 | Jan-14 | Jan-15 | Jan-16 | Jan-17 | Jan-18 | Jan-19 | Jan-20 | Jan-21 | Jan-22 | Jan-23 | Jan-24 | Jan-25 | Jan-26 | Jan-27 | Jan-28 | Jan-29 | Jan-30 | Jan-31 | Jan-32 | Jan-33 | Jan-34 | Jan-35 |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| $9,125 | $9,399 | $9,681 | $9,971 | $10,270 | $10,578 | $10,896 | $11,223 | $11,559 | $11,906 | $12,263 | $12,631 | $13,010 | $13,400 | $13,802 | $14,216 | $14,643 | $15,082 | $15,535 | $16,001 | $16,481 | $16,975 | $17,484 | $18,009 | $18,549 | $19,106 | $19,679 |
| $30,360 | $31,271 | $32,209 | $33,175 | $34,170 | $35,196 | $36,251 | $37,339 | $38,459 | $39,613 | $40,801 | $42,025 | $43,286 | $44,585 | $45,922 | $47,300 | $48,719 | $50,180 | $51,686 | $53,236 | $54,834 | $56,479 | $58,173 | $59,918 | $61,716 | $63,567 | $65,474 |
| $4,125 | $4,249 | $4,376 | $4,507 | $4,643 | $4,782 | $4,925 | $5,073 | $5,225 | $5,382 | $5,544 | $5,710 | $5,881 | $6,058 | $6,239 | $6,427 | $6,619 | $6,818 | $7,023 | $7,233 | $7,450 | $7,674 | $7,904 | $8,141 | $8,385 | $8,637 | $8,896 |
| $4,796 | $4,940 | $5,088 | $5,241 | $5,398 | $5,560 | $5,727 | $5,898 | $6,075 | $6,258 | $6,445 | $6,639 | $6,838 | $7,043 | $7,254 | $7,472 | $7,696 | $7,927 | $8,165 | $8,410 | $8,662 | $8,922 | $9,190 | $9,465 | $9,749 | $10,042 | $10,343 |
| $1,690 | $1,741 | $1,793 | $1,847 | $1,902 | $1,959 | $2,018 | $2,078 | $2,141 | $2,205 | $2,271 | $2,339 | $2,410 | $2,482 | $2,556 | $2,633 | $2,712 | $2,793 | $2,877 | $2,963 | $3,052 | $3,144 | $3,238 | $3,335 | $3,435 | $3,538 | $3,645 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $50,096 | $51,599 | $53,147 | $54,741 | $56,383 | $58,075 | $59,817 | $61,612 | $63,460 | $65,364 | $67,325 | $69,345 | $71,425 | $73,568 | $75,775 | $78,048 | $80,389 | $82,801 | $85,285 | $87,844 | $90,479 | $93,193 | $95,989 | $98,869 | $101,835 | $104,890 | $108,037 |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $50,096 | $51,599 | $53,147 | $54,741 | $56,383 | $58,075 | $59,817 | $61,612 | $63,460 | $65,364 | $67,325 | $69,345 | $71,425 | $73,568 | $75,775 | $78,048 | $80,389 | $82,801 | $85,285 | $87,844 | $90,479 | $93,193 | $95,989 | $98,869 | $101,835 | $104,890 | $108,037 |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| $471,000 | $485,130 | $499,684 | $514,674 | $530,115 | $546,018 | $562,399 | $579,271 | $596,649 | $614,548 | $632,985 | $651,974 | $671,533 | $691,679 | $712,430 | $733,803 | $755,817 | $778,491 | $801,846 | $825,901 | $850,678 | $876,199 | $902,485 | $929,559 | $957,446 | $986,169 | $1,015,754 |
| $115,000 | $118,450 | $122,004 | $125,664 | $129,434 | $133,317 | $137,316 | $141,435 | $145,679 | $150,049 | $154,550 | $159,187 | $163,963 | $168,881 | $173,948 | $179,166 | $184,541 | $190,077 | $195,780 | $201,653 | $207,703 | $213,934 | $220,352 | $226,962 | $233,771 | $240,784 | $248,008 |
| $450,000 | $463,500 | $477,405 | $491,727 | $506,479 | $521,673 | $537,324 | $553,443 | $570,047 | $587,148 | $604,762 | $622,905 | $641,592 | $660,840 | $680,665 | $701,085 | $722,118 | $743,781 | $766,095 | $789,078 | $812,750 | $837,133 | $862,247 | $888,114 | $914,757 | $942,200 | $970,466 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $1,036,000 | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | $2,234,229 |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| $1,036,000 | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | $2,234,229 |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| $1,086,096 | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | ####### | $2,342,265 |

**YECL AMR Project**
**AMR Cost Impact**

08-20-2008

| Year | Jan-09 | Jan-10 | Jan-11 | Jan-12 | Jan-13 | Jan-14 | Jan-15 | Jan-16 | Jan-17 | Jan-18 | Jan-19 | Jan-20 | Jan-21 | Jan-22 | Jan-23 | Jan-24 | Jan-25 | Jan-26 | Jan-27 | Jan-28 | Jan-29 | Jan-30 | Jan-31 | Jan-32 | Jan-33 | Jan-34 | Jan-35 | Jan-36 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **REVENUES:** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Revenue Requirement | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Revenue:** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| **CAPITAL:** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **METERS:** | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 Cost of Residential AMR Module and Mete | 756,839 | 756,839 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13,652 | 14,061 | 14,483 | 14,917 | 15,365 | 15,826 | 16,301 | 16,790 | 17,293 | 17,812 | 18,346 | 18,897 | 19,464 | 20,048 | 20,649 | 21,269 | 21,907 |
| 2 Cost of Commercial Meter | 347,116 | 347,116 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 34,572 | 35,609 | 36,678 | 37,778 | 38,911 | 40,079 | 41,281 | 42,520 | 43,795 | 45,109 | 46,462 | 47,856 | 49,292 | 50,771 | 52,294 | 53,862 | 55,478 |
| 3 Cost of Commercial AMR Module | 197,340 | 197,340 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11,662 | 12,012 | 12,372 | 12,743 | 13,125 | 13,519 | 13,925 | 14,343 | 14,773 | 15,216 | 15,673 | 16,143 | 16,627 | 17,126 | 17,640 | 18,169 | 18,714 |
| 4 Retrofitting Costs | 99,000 | 99,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 897 | 924 | 952 | 980 | 1,010 | 1,040 | 1,071 | 1,103 | 1,136 | 1,170 | 1,206 | 1,242 | 1,279 | 1,317 | 1,357 | 1,398 | 1,440 |
| 5 Installation - Residential Meters and Modu | 92,202 | 92,202 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,663 | 1,713 | 1,764 | 1,817 | 1,872 | 1,928 | 1,986 | 2,045 | 2,107 | 2,170 | 2,235 | 2,302 | 2,371 | 2,442 | 2,516 | 2,591 | 2,669 |
| 6 Installation - Commercial Meters and Mod | 55,154 | 55,154 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,259 | 3,357 | 3,458 | 3,562 | 3,668 | 3,778 | 3,892 | 4,009 | 4,129 | 4,253 | 4,380 | 4,512 | 4,647 | 4,786 | 4,930 | 5,078 | 5,230 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 Meter Read Verification | 11,880 | 11,880 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 289 | 298 | 307 | 316 | 325 | 335 | 345 | 356 | 366 | 377 | 388 | 400 | 412 | 425 | 437 | 450 | 464 |
| 8 Test Set & Spares Equipment | 9,000 | 9,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 Contingency | 156,853 | 156,853 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6,599 | 6,797 | 7,001 | 7,211 | 7,428 | 7,651 | 7,880 | 8,116 | 8,360 | 8,611 | 8,869 | 9,135 | 9,409 | 9,691 | 9,982 | 10,282 | 10,590 |
| 10 Project Management | 78,427 | 78,427 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,300 | 3,399 | 3,501 | 3,606 | 3,714 | 3,825 | 3,940 | 4,058 | 4,180 | 4,305 | 4,435 | 4,568 | 4,705 | 4,846 | 4,991 | 5,141 | 5,295 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUBSTATIONS:** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Electrical Design | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structural Design | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Major Apparatus Engineering | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Technical & Business Support | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction Labour & Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commissioning | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Trouble Shooting | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Telecommunication - Engineering | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Telecommunication - Fiber Optic Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DCSI Equipment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Electrical Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structural Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Warehouse & Trucking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 DCSI Materials | 41,000 | 41,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 Installation & Materials | 210,000 | 210,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 Contingency | 25,140 | 25,140 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 Project Management | 12,550 | 12,550 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Capital** | 2,092,500 | 2,092,500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 75,893 | 78,170 | 80,515 | 82,931 | 85,419 | 87,981 | 90,621 | 93,339 | 96,139 | 99,024 | 101,994 | 105,054 | 108,206 | 111,452 | 114,795 | 118,239 | 121,786 |

| **Operations & Maintenance:** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Allocated AMR O&M Costs:** | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 O&M Acct#71212 - DCSI TNS Maintenanc | 0 | 5,982 | 6,162 | 6,347 | 6,537 | 6,733 | 6,935 | 7,143 | 7,357 | 7,578 | 7,805 | 8,040 | 8,281 | 8,529 | 8,785 | 9,049 | 9,320 | 9,600 | 9,888 | 10,184 | 10,490 | 10,805 | 11,129 | 11,463 | 11,806 | 12,161 | 12,525 | 0 |
| 16 O&M Acct#71214 - Annual Sample Verific | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 O&M Acct#72107 - I-Tek User Fees (Emai | 0 | 1,767 | 1,821 | 1,875 | 1,931 | 1,989 | 2,049 | 2,110 | 2,174 | 2,239 | 2,306 | 2,375 | 2,447 | 2,520 | 2,596 | 2,673 | 2,754 | 2,836 | 2,921 | 3,009 | 3,099 | 3,192 | 3,288 | 3,387 | 3,488 | 3,593 | 3,701 | 0 |
| 18 O&M Acct#72109 - PCs & Monitors | 0 | 1,224 | 1,260 | 1,298 | 1,337 | 1,377 | 1,419 | 1,461 | 1,505 | 1,550 | 1,597 | 1,644 | 1,694 | 1,745 | 1,797 | 1,851 | 1,906 | 1,964 | 2,022 | 2,083 | 2,146 | 2,210 | 2,276 | 2,345 | 2,415 | 2,487 | 2,562 | 0 |
| 19 O&M Acct#72118 - I-Tek Support for TNS | 0 | 9,245 | 9,523 | 9,808 | 10,103 | 10,406 | 10,718 | 11,039 | 11,371 | 11,712 | 12,063 | 12,425 | 12,798 | 13,182 | 13,577 | 13,984 | 14,404 | 14,836 | 15,281 | 15,739 | 16,212 | 16,698 | 17,199 | 17,715 | 18,246 | 18,794 | 19,358 | 0 |
| 20 Labour Acct#71211 - AMR Meter Reading | 0 | 18,898 | 19,465 | 20,049 | 20,651 | 21,270 | 21,908 | 22,566 | 23,243 | 23,940 | 24,658 | 25,398 | 26,160 | 26,945 | 27,753 | 28,586 | 29,443 | 30,326 | 31,236 | 32,173 | 33,139 | 34,133 | 35,157 | 36,211 | 37,298 | 38,417 | 39,569 | 0 |
| 21 Labour Acct#71214 - AMR Verification | 0 | 408 | 420 | 433 | 446 | 459 | 473 | 487 | 502 | 517 | 532 | 548 | 565 | 582 | 599 | 617 | 635 | 655 | 674 | 694 | 715 | 737 | 759 | 782 | 805 | 829 | 854 | 0 |
| 22 Labour Acct#71215 - AMR Substation Trou | 0 | 9,653 | 9,943 | 10,241 | 10,548 | 10,865 | 11,191 | 11,526 | 11,872 | 12,228 | 12,595 | 12,973 | 13,362 | 13,763 | 14,176 | 14,601 | 15,039 | 15,490 | 15,955 | 16,434 | 16,927 | 17,435 | 17,958 | 18,496 | 19,051 | 19,623 | 20,212 | 0 |
| 23 Labour Acct# 71250 - AMR Special Meter | 0 | 3,127 | 3,221 | 3,318 | 3,417 | 3,520 | 3,625 | 3,734 | 3,846 | 3,961 | 4,080 | 4,203 | 4,329 | 4,458 | 4,592 | 4,730 | 4,872 | 5,018 | 5,169 | 5,324 | 5,483 | 5,648 | 5,817 | 5,992 | 6,172 | 6,357 | 6,547 | 0 |
| 24 Conventional Manual Meter Reading Costs | 471,000 | 206,000 | 212,180 | 218,545 | 225,102 | 231,855 | 238,810 | 245,975 | 253,354 | 260,955 | 268,783 | 276,847 | 285,152 | 293,707 | 302,518 | 311,593 | 320,941 | 330,570 | 340,487 | 350,701 | 361,222 | 372,059 | 383,221 | 394,717 | 406,559 | 418,756 | 431,318 | 0 |
| 27 Conventional Meter Testing During Deploy | 115,000 | 77,250 | 79,568 | 81,955 | 84,413 | 86,946 | 89,554 | 92,241 | 95,008 | 97,858 | 100,794 | 103,818 | 106,932 | 110,140 | 113,444 | 116,848 | 120,353 | 123,964 | 127,682 | 131,513 | 135,458 | 139,522 | 143,708 | 148,019 | 152,460 | 157,033 | 161,744 | 0 |
| 28 Customer Applications & Service Orders | 450,000 | 375,950 | 387,229 | 398,845 | 410,811 | 423,135 | 435,829 | 448,904 | 462,371 | 476,242 | 490,529 | 505,245 | 520,403 | 536,015 | 552,095 | 568,658 | 585,718 | 603,289 | 621,388 | 640,030 | 659,231 | 679,008 | 699,378 | 720,359 | 741,970 | 764,229 | 787,156 | 0 |
| 29 Data Cap Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 30 CCA Tax Savings | 0 | -48,784 | -98,213 | -96,460 | -94,513 | -92,363 | -89,999 | -87,410 | -84,585 | -81,511 | -3,079 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total O&M** | 1,036,000 | 660,722 | 632,578 | 656,254 | 680,782 | 706,191 | 732,512 | 759,776 | 788,017 | 817,269 | 922,664 | 953,516 | 982,121 | 1,011,585 | 1,041,932 | 1,073,190 | 1,105,386 | 1,138,548 | 1,172,704 | 1,207,885 | 1,244,122 | 1,281,445 | 1,319,889 | 1,359,485 | 1,400,270 | 1,442,278 | 1,485,546 | 0 |

**YECL AMR Project**
**AMR Cost Impact**

| Year | Jan-09 | Jan-10 | Jan-11 | Jan-12 | Jan-13 | Jan-14 | Jan-15 | Jan-16 | Jan-17 | Jan-18 | Jan-19 | Jan-20 | Jan-21 | Jan-22 | Jan-23 | Jan-24 | Jan-25 | Jan-26 | Jan-27 | Jan-28 | Jan-29 | Jan-30 | Jan-31 | Jan-32 | Jan-33 | Jan-34 | Jan-35 | Jan-36 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **YEARLY DEPRECIATION:** | **Rates** | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 |
| **METERS:** | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Cost of Residential AMR Module and Mete | 4.540% | 34,360 | 68,721 | 68,721 | 68,721 | 68,721 | 68,721 | 68,721 | 68,721 | 68,721 | 68,721 | 68,721 | 69,341 | 69,979 | 70,637 | 71,314 | 72,011 | 72,730 | 73,470 | 74,232 | 75,017 | 75,826 | 76,659 | 77,517 | 78,401 | 69,138 | 20,676 | 21,297 |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cost of Commercial Meter | 4.540% | 15,759 | 31,518 | 31,518 | 31,518 | 31,518 | 31,518 | 31,518 | 31,518 | 31,518 | 31,518 | 31,518 | 33,088 | 34,704 | 36,370 | 38,085 | 39,851 | 41,671 | 43,545 | 45,475 | 47,464 | 49,512 | 51,621 | 53,794 | 56,032 | 58,336 | 60,708 | 63,156 |
| Cost of Commercial AMR Module | 4.540% | 8,959 | 17,918 | 17,918 | 17,918 | 17,918 | 17,918 | 17,918 | 17,918 | 17,918 | 17,918 | 17,918 | 18,448 | 18,993 | 19,555 | 20,133 | 20,729 | 21,343 | 21,975 | 22,626 | 23,297 | 23,988 | 24,700 | 25,432 | 26,187 | 26,965 | 27,766 | 28,590 |
| Retrofitting Costs | 4.540% | 4,495 | 8,989 | 8,989 | 8,989 | 8,989 | 8,989 | 8,989 | 8,989 | 8,989 | 8,989 | 8,989 | 9,030 | 9,072 | 9,115 | 9,160 | 9,205 | 9,253 | 9,301 | 9,351 | 9,403 | 9,456 | 9,511 | 9,567 | 6,257 | 1,319 | 1,359 | 1,399 |
| Installation - Residential Meters and Modu | 4.540% | 4,186 | 8,372 | 8,372 | 8,372 | 8,372 | 8,372 | 8,372 | 8,372 | 8,372 | 8,372 | 8,372 | 8,447 | 8,525 | 8,605 | 8,688 | 8,773 | 8,860 | 8,950 | 9,043 | 9,139 | 9,238 | 9,339 | 9,444 | 9,551 | 8,423 | 2,519 | 2,594 |
| Installation - Commercial Meters and Mod | 4.540% | 2,504 | 5,008 | 5,008 | 5,008 | 5,008 | 5,008 | 5,008 | 5,008 | 5,008 | 5,008 | 5,008 | 5,156 | 5,308 | 5,465 | 5,627 | 5,794 | 5,965 | 6,142 | 6,324 | 6,511 | 6,704 | 6,903 | 7,108 | 7,319 | 7,536 | 7,760 | 7,991 |
| | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Meter Read Verification | 4.540% | 539 | 1,079 | 1,079 | 1,079 | 1,079 | 1,079 | 1,079 | 1,079 | 1,079 | 1,079 | 1,079 | 1,092 | 1,105 | 1,119 | 1,134 | 1,148 | 1,164 | 1,179 | 1,195 | 1,212 | 1,229 | 1,247 | 1,265 | 1,284 | 1,303 | 1,154 | 451 |
| Test Set & Spares Equipment | 4.540% | 409 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 817 | 430 | 0 | 0 | 0 | 0 |
| Contingency | 4.540% | 7,121 | 14,242 | 14,242 | 14,242 | 14,242 | 14,242 | 14,242 | 14,242 | 14,242 | 14,242 | 14,242 | 14,542 | 14,850 | 15,168 | 15,496 | 15,833 | 16,180 | 16,538 | 16,907 | 17,286 | 17,677 | 18,080 | 18,494 | 18,922 | 19,362 | 19,815 | 20,282 |
| Project Management | 4.540% | 3,561 | 7,121 | 7,121 | 7,121 | 7,121 | 7,121 | 7,121 | 7,121 | 7,121 | 7,121 | 7,121 | 7,271 | 7,425 | 7,584 | 7,748 | 7,916 | 8,090 | 8,269 | 8,453 | 8,643 | 8,838 | 9,040 | 9,247 | 9,461 | 9,681 | 9,907 | 10,141 |
| **SUBSTATIONS:** | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Electrical Design | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structural Design | 0.000% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Major Apparatus Engineering | 0.000% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Technical & Business Support | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction Labour & Expenses | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commissioning | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Trouble Shooting | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Telecommunication - Engineering | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Telecommunication - Fiber Optic Materials | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DCSI Equipment | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTU | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Electrical Materials | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structural Materials | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Warehouse & Trucking | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DCSI Materials | 4.540% | 1,861 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 3,723 | 1,960 | 0 | 0 | 0 | 0 |
| Installation & Materials | 4.540% | 9,534 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 19,068 | 10,038 | 0 | 0 | 0 | 0 |
| Contingency | 4.540% | 1,141 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 1,202 | 0 | 0 | 0 | 0 |
| Project Management | 4.540% | 570 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 600 | 0 | 0 | 0 | 0 |
| **Total Depreciation** | | 94,999 | 189,999 | 189,999 | 189,999 | 189,999 | 189,999 | 189,999 | 189,999 | 189,999 | 189,999 | 189,999 | 193,445 | 196,993 | 200,649 | 204,414 | 208,292 | 212,286 | 216,400 | 220,638 | 225,003 | 229,498 | 234,129 | 226,098 | 213,413 | 202,063 | 151,666 | 155,901 |

| **ACCUMULATED DEPRECIATION:** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **METERS:** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cost of Residential AMR Module and Mete | 0 | 34,360 | 103,081 | 171,802 | 240,523 | 309,244 | 377,965 | 446,686 | 515,407 | 584,128 | 652,849 | 721,570 | 790,911 | 860,890 | 931,527 | 1,002,840 | 1,074,852 | 1,147,582 | 1,221,052 | 1,295,284 | 1,370,301 | 1,446,127 | 1,522,786 | 1,600,303 | 1,678,704 | 1,747,842 | 1,768,518 | 1,789,815 |
| Cost of Commercial Meter | 0 | 15,759 | 47,277 | 78,795 | 110,313 | 141,832 | 173,350 | 204,868 | 236,386 | 267,904 | 299,422 | 330,940 | 364,028 | 398,732 | 435,102 | 473,187 | 513,038 | 554,709 | 598,254 | 643,729 | 691,193 | 740,704 | 792,325 | 846,119 | 902,151 | 960,487 | 1,021,198 | 1,084,354 |
| Cost of Commercial AMR Module | 0 | 8,959 | 26,878 | 44,796 | 62,715 | 80,633 | 98,552 | 116,470 | 134,389 | 152,307 | 170,225 | 188,144 | 206,592 | 225,585 | 245,140 | 265,274 | 286,003 | 307,346 | 329,321 | 351,948 | 375,245 | 399,233 | 423,933 | 449,365 | 475,552 | 502,517 | 530,283 | 558,873 |
| Retrofitting Costs | 0 | 4,495 | 13,484 | 22,473 | 31,462 | 40,451 | 49,441 | 58,430 | 67,419 | 76,408 | 85,397 | 94,387 | 103,417 | 112,488 | 121,603 | 130,763 | 139,968 | 149,221 | 158,522 | 167,874 | 177,277 | 186,733 | 196,244 | 205,811 | 212,068 | 213,387 | 214,746 | 216,145 |
| Installation - Residential Meters and Modu | 0 | 4,186 | 12,558 | 20,930 | 29,302 | 37,674 | 46,046 | 54,418 | 62,790 | 71,162 | 79,533 | 87,905 | 96,353 | 104,878 | 113,483 | 122,171 | 130,944 | 139,804 | 148,755 | 157,798 | 166,937 | 176,175 | 185,514 | 194,957 | 204,508 | 212,931 | 215,450 | 218,044 |
| Installation - Commercial Meters and Mod | 0 | 2,504 | 7,512 | 12,520 | 17,528 | 22,536 | 27,544 | 32,552 | 37,560 | 42,568 | 47,576 | 52,584 | 57,740 | 63,048 | 68,514 | 74,141 | 79,934 | 85,899 | 92,041 | 98,365 | 104,876 | 111,581 | 118,484 | 125,592 | 132,911 | 140,447 | 148,207 | 156,198 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Meter Read Verification | 0 | 539 | 1,618 | 2,697 | 3,775 | 4,854 | 5,933 | 7,012 | 8,090 | 9,169 | 10,248 | 11,326 | 12,418 | 13,524 | 14,643 | 15,776 | 16,925 | 18,088 | 19,268 | 20,463 | 21,675 | 22,904 | 24,151 | 25,416 | 26,700 | 28,003 | 29,156 | 29,607 |
| Test Set & Spares Equipment | 0 | 409 | 1,226 | 2,043 | 2,860 | 3,677 | 4,495 | 5,312 | 6,129 | 6,946 | 7,763 | 8,581 | 9,398 | 10,215 | 11,032 | 11,849 | 12,667 | 13,484 | 14,301 | 15,118 | 15,935 | 16,753 | 17,570 | 18,000 | 18,000 | 18,000 | 18,000 | 18,000 |
| Contingency | 0 | 7,121 | 21,363 | 35,606 | 49,848 | 64,090 | 78,332 | 92,575 | 106,817 | 121,059 | 135,301 | 149,544 | 164,086 | 178,936 | 194,104 | 209,600 | 225,433 | 241,613 | 258,151 | 275,058 | 292,344 | 310,021 | 328,101 | 346,595 | 365,517 | 384,878 | 404,693 | 424,974 |
| Project Management | 0 | 3,561 | 10,682 | 17,803 | 24,924 | 32,045 | 39,166 | 46,287 | 53,408 | 60,530 | 67,651 | 74,772 | 82,043 | 89,468 | 97,052 | 104,800 | 112,717 | 120,807 | 129,076 | 137,529 | 146,172 | 155,010 | 164,050 | 173,298 | 182,758 | 192,439 | 202,346 | 212,487 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **SUBSTATIONS:** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Electrical Design | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structural Design | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Major Apparatus Engineering | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Technical & Business Support | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction Labour & Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commissioning | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Trouble Shooting | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Telecommunication - Engineering | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Telecommunication - Fiber Optic Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DCSI Equipment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Electrical Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structural Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Warehouse & Trucking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DCSI Materials | 0 | 1,861 | 5,584 | 9,307 | 13,030 | 16,753 | 20,475 | 24,198 | 27,921 | 31,644 | 35,367 | 39,089 | 42,812 | 46,535 | 50,258 | 53,981 | 57,703 | 61,426 | 65,149 | 68,872 | 72,595 | 76,317 | 80,040 | 82,000 | 82,000 | 82,000 | 82,000 | 82,000 |
| Installation & Materials | 0 | 9,534 | 28,602 | 47,670 | 66,738 | 85,806 | 104,874 | 123,942 | 143,010 | 162,078 | 181,146 | 200,214 | 219,282 | 238,350 | 257,418 | 276,486 | 295,554 | 314,622 | 333,690 | 352,758 | 371,826 | 390,894 | 409,962 | 420,000 | 420,000 | 420,000 | 420,000 | 420,000 |
| Contingency | 0 | 1,141 | 3,424 | 5,707 | 7,989 | 10,272 | 12,555 | 14,837 | 17,120 | 19,403 | 21,685 | 23,968 | 26,251 | 28,533 | 30,816 | 33,099 | 35,381 | 37,664 | 39,947 | 42,229 | 44,512 | 46,795 | 49,077 | 50,279 | 50,279 | 50,279 | 50,279 | 50,279 |
| Project Management | 0 | 570 | 1,709 | 2,849 | 3,988 | 5,128 | 6,267 | 7,407 | 8,547 | 9,686 | 10,826 | 11,965 | 13,105 | 14,244 | 15,384 | 16,523 | 17,663 | 18,802 | 19,942 | 21,081 | 22,221 | 23,361 | 24,500 | 25,100 | 25,100 | 25,100 | 25,100 | 25,100 |
| | | 94,999 | 284,998 | 474,997 | 664,996 | 854,995 | 1,044,994 | 1,234,993 | 1,424,992 | 1,614,991 | 1,804,990 | 1,994,989 | 2,188,434 | 2,385,427 | 2,586,076 | 2,790,490 | 2,998,782 | 3,211,068 | 3,427,469 | 3,648,107 | 3,873,109 | 4,102,608 | 4,336,737 | 4,562,834 | 4,776,247 | 4,978,310 | 5,129,976 | 5,285,877 |

| **PROPERTY IN SERVICE (beg yr):** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| METERS: | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cost of Residential AMR Module and Mete | 0 | 756,839 | 1,479,317 | 1,410,596 | 1,341,875 | 1,273,154 | 1,204,433 | 1,135,712 | 1,066,991 | 998,270 | 929,549 | 860,828 | 805,759 | 750,479 | 694,983 | 639,264 | 583,315 | 527,129 | 470,700 | 414,019 | 357,081 | 299,875 | 242,396 | 184,634 | 126,581 | 68,228 | 19,739 | 20,331 |
| Cost of Commercial Meter | 0 | 347,116 | 678,473 | 646,955 | 615,437 | 583,919 | 552,400 | 520,882 | 489,364 | 457,846 | 426,328 | 394,810 | 397,864 | 400,386 | 402,359 | 403,767 | 404,594 | 404,822 | 404,432 | 403,406 | 401,726 | 399,371 | 396,322 | 392,557 | 388,055 | 382,794 | 376,751 | 369,903 |
| Cost of Commercial AMR Module | 0 | 197,340 | 385,721 | 367,802 | 349,884 | 331,965 | 314,047 | 296,128 | 278,210 | 260,291 | 242,373 | 224,455 | 218,198 | 211,762 | 205,140 | 198,329 | 191,321 | 184,111 | 176,692 | 169,060 | 161,206 | 153,125 | 144,809 | 136,252 | 127,447 | 118,386 | 109,060 | 99,464 |
| Retrofitting Costs | 0 | 99,000 | 193,505 | 184,516 | 175,527 | 166,538 | 157,549 | 148,559 | 139,570 | 130,581 | 121,592 | 112,603 | 104,510 | 96,405 | 88,284 | 80,149 | 72,000 | 63,834 | 55,653 | 47,455 | 39,240 | 31,007 | 22,757 | 14,488 | 6,199 | 1,259 | 1,297 | 1,336 |
| Installation - Residential Meters and Modu | 0 | 92,202 | 180,218 | 171,846 | 163,474 | 155,102 | 146,730 | 138,358 | 129,986 | 121,614 | 113,242 | 104,871 | 98,162 | 91,427 | 84,666 | 77,878 | 71,062 | 64,218 | 57,343 | 50,438 | 43,501 | 36,532 | 29,530 | 22,493 | 15,421 | 8,312 | 2,405 | 2,477 |
| Installation - Commercial Meters and Mod | 0 | 55,154 | 107,804 | 102,796 | 97,788 | 92,780 | 87,772 | 82,764 | 77,756 | 72,748 | 67,740 | 62,732 | 60,984 | 59,185 | 57,334 | 55,430 | 53,472 | 51,457 | 49,383 | 47,250 | 45,055 | 42,796 | 40,472 | 38,081 | 35,620 | 33,087 | 30,481 | 27,799 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Meter Read Verification | 0 | 11,880 | 23,221 | 22,142 | 21,063 | 19,985 | 18,906 | 17,827 | 16,748 | 15,670 | 14,591 | 13,512 | 12,723 | 11,929 | 11,130 | 10,327 | 9,518 | 8,705 | 7,887 | 7,063 | 6,234 | 5,399 | 4,558 | 3,712 | 2,859 | 2,000 | 1,134 | 431 |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Set & Spares Equipment | 0 | 9,000 | 17,591 | 16,774 | 15,957 | 15,140 | 14,323 | 13,505 | 12,688 | 11,871 | 11,054 | 10,237 | 9,419 | 8,602 | 7,785 | 6,968 | 6,151 | 5,333 | 4,516 | 3,699 | 2,882 | 2,065 | 1,247 | 430 | 0 | 0 | 0 | 0 | 0 |
| Contingency | 0 | 156,853 | 306,585 | 292,343 | 278,100 | 263,858 | 249,616 | 235,374 | 221,131 | 206,889 | 192,647 | 178,405 | 170,762 | 163,017 | 155,168 | 147,211 | 139,143 | 130,961 | 122,661 | 114,239 | 105,692 | 97,017 | 88,209 | 79,265 | 70,179 | 60,949 | 51,570 | 42,037 | 0 |
| Project Management | 0 | 78,427 | 153,293 | 146,171 | 139,050 | 131,929 | 124,808 | 117,687 | 110,566 | 103,445 | 96,323 | 89,202 | 85,381 | 81,509 | 77,584 | 73,606 | 69,572 | 65,480 | 61,330 | 57,119 | 52,846 | 48,509 | 44,105 | 39,632 | 35,090 | 30,475 | 25,785 | 21,018 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SUBSTATIONS: | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Electrical Design | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structural Design | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Major Apparatus Engineering | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Technical & Business Support | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction Labour & Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Commissioning | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Trouble Shooting | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Telecommunication - Engineering | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Telecommunication - Fiber Optic Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DCSI Equipment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Electrical Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structural Materials | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Warehouse & Trucking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DCSI Materials | 0 | 41,000 | 80,139 | 76,416 | 72,693 | 68,970 | 65,247 | 61,525 | 57,802 | 54,079 | 50,356 | 46,633 | 42,911 | 39,188 | 35,465 | 31,742 | 28,019 | 24,297 | 20,574 | 16,851 | 13,128 | 9,405 | 5,683 | 1,960 | 0 | 0 | 0 | 0 | 0 |
| Installation & Materials | 0 | 210,000 | 410,466 | 391,398 | 372,330 | 353,262 | 334,194 | 315,126 | 296,058 | 276,990 | 257,922 | 238,854 | 219,786 | 200,718 | 181,650 | 162,582 | 143,514 | 124,446 | 105,378 | 86,310 | 67,242 | 48,174 | 29,106 | 10,038 | 0 | 0 | 0 | 0 | 0 |
| Contingency | 0 | 25,140 | 49,138 | 46,855 | 44,572 | 42,290 | 40,007 | 37,724 | 35,442 | 33,159 | 30,876 | 28,594 | 26,311 | 24,028 | 21,746 | 19,463 | 17,180 | 14,898 | 12,615 | 10,332 | 8,050 | 5,767 | 3,484 | 1,202 | 0 | 0 | 0 | 0 | 0 |
| Project Management | 0 | 12,550 | 24,530 | 23,391 | 22,251 | 21,112 | 19,972 | 18,833 | 17,693 | 16,553 | 15,414 | 14,274 | 13,135 | 11,995 | 10,856 | 9,716 | 8,577 | 7,437 | 6,298 | 5,158 | 4,019 | 2,879 | 1,739 | 600 | 0 | 0 | 0 | 0 | 0 |
| **Total Project Ratebase** | 0 | 2,092,500 | 4,090,000 | 3,900,001 | 3,710,002 | 3,520,003 | 3,330,004 | 3,140,005 | 2,950,006 | 2,760,007 | 2,570,008 | 2,380,009 | 2,265,904 | 2,150,629 | 2,034,151 | 1,916,433 | 1,797,437 | 1,677,127 | 1,555,461 | 1,432,400 | 1,307,901 | 1,181,922 | 1,054,417 | 925,343 | 807,451 | 705,490 | 618,223 | 584,796 | |

**YECL AMR Project**
**AMR Cost Impact**

| | Return | Ratio | B.T. Cost | A.T. Cost |
|---|---|---|---|---|
| Debt | 6.600% | 53% | 0.0347 | 0.0347 |
| Preferred | 0.000% | 0% | 0.0000 | 0.0000 |
| Common | 9.250% | 48% | 0.0666 | 0.0439 |
| Tax Rate | 34.000% | | 10.122% | 7.859% |

**CASH FLOWS SUMMARY:**

| Year | | Revenue Requirements Ratebase | Return | Dep'n | Inc. Tax | O&M | Total | Revenue Allowance | Surplus (Deficit) | CPV at 10.122% | Used Year |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | Jan-09 | 0 | 0 | 0 | 0 | 1,036,000 | 1,036,000 | 0 | (1,036,000) | (1,036,000) | 0 |
| 1 | Jan-10 | 2,092,500 | 164,444 | 94,999 | 47,363 | 660,722 | 967,528 | 0 | (967,528) | (1,914,595) | 1 |
| 2 | Jan-11 | 4,090,000 | 321,423 | 189,999 | 92,575 | 632,578 | 1,236,574 | 0 | (1,236,574) | (2,934,291) | 2 |
| 3 | Jan-12 | 3,900,001 | 306,491 | 189,999 | 88,274 | 656,254 | 1,241,019 | 0 | (1,241,019) | (3,863,586) | 3 |
| 4 | Jan-13 | 3,710,002 | 291,560 | 189,999 | 83,974 | 680,782 | 1,246,315 | 0 | (1,246,315) | (4,711,064) | 4 |
| 5 | Jan-14 | 3,520,003 | 276,628 | 189,999 | 79,673 | 706,191 | 1,252,492 | 0 | (1,252,492) | (5,484,457) | 5 |
| 6 | Jan-15 | 3,330,004 | 261,697 | 189,999 | 75,373 | 732,512 | 1,259,580 | 0 | (1,259,580) | (6,190,737) | 6 |
| 7 | Jan-16 | 3,140,005 | 246,765 | 189,999 | 71,072 | 759,776 | 1,267,613 | 0 | (1,267,613) | (6,836,187) | 7 |
| 8 | Jan-17 | 2,950,006 | 231,834 | 189,999 | 66,772 | 788,017 | 1,276,622 | 0 | (1,276,622) | (7,426,474) | 8 |
| 9 | Jan-18 | 2,760,007 | 216,902 | 189,999 | 62,471 | 817,269 | 1,286,641 | 0 | (1,286,641) | (7,966,710) | 9 |
| 10 | Jan-19 | 2,570,008 | 201,971 | 189,999 | 58,171 | 922,664 | 1,372,804 | 0 | (1,372,804) | (8,490,142) | 10 |
| 11 | Jan-20 | 2,380,009 | 187,039 | 189,999 | 53,870 | 953,516 | 1,384,424 | 0 | (1,384,424) | (8,969,484) | 11 |
| 12 | Jan-21 | 2,265,904 | 178,072 | 193,445 | 51,288 | 982,121 | 1,404,925 | 0 | (1,404,925) | (9,411,212) | 12 |
| 13 | Jan-22 | 2,150,629 | 169,013 | 196,993 | 48,678 | 1,011,585 | 1,426,269 | 0 | (1,426,269) | (9,818,431) | 13 |
| 14 | Jan-23 | 2,034,151 | 159,859 | 200,649 | 46,042 | 1,041,932 | 1,448,482 | 0 | (1,448,482) | (10,193,978) | 14 |
| 15 | Jan-24 | 1,916,433 | 150,608 | 204,414 | 43,377 | 1,073,190 | 1,471,589 | 0 | (1,471,589) | (10,540,447) | 15 |
| 16 | Jan-25 | 1,797,437 | 141,256 | 208,292 | 40,684 | 1,105,386 | 1,495,618 | 0 | (1,495,618) | (10,860,206) | 16 |
| 17 | Jan-26 | 1,677,127 | 131,801 | 212,286 | 37,961 | 1,138,548 | 1,520,596 | 0 | (1,520,596) | (11,155,423) | 17 |
| 18 | Jan-27 | 1,555,461 | 122,240 | 216,400 | 35,207 | 1,172,704 | 1,546,551 | 0 | (1,546,551) | (11,428,080) | 18 |
| 19 | Jan-28 | 1,432,400 | 112,569 | 220,638 | 32,422 | 1,207,885 | 1,573,513 | 0 | (1,573,513) | (11,679,991) | 19 |
| 20 | Jan-29 | 1,307,901 | 102,785 | 225,003 | 29,604 | 1,244,122 | 1,601,513 | 0 | (1,601,513) | (11,912,818) | 20 |
| 21 | Jan-30 | 1,181,922 | 92,884 | 229,498 | 26,752 | 1,281,445 | 1,630,580 | 0 | (1,630,580) | (12,128,081) | 21 |
| 22 | Jan-31 | 1,054,417 | 82,864 | 234,129 | 23,866 | 1,319,889 | 1,660,748 | 0 | (1,660,748) | (12,327,174) | 22 |
| 23 | Jan-32 | 925,343 | 72,720 | 226,098 | 20,945 | 1,359,485 | 1,679,248 | 0 | (1,679,248) | (12,509,981) | 23 |
| 24 | Jan-33 | 807,451 | 63,456 | 213,413 | 18,276 | 1,400,270 | 1,695,414 | 0 | (1,695,414) | (12,677,583) | 24 |
| 25 | Jan-34 | 705,490 | 55,443 | 202,063 | 15,968 | 1,442,278 | 1,715,752 | 0 | (1,715,752) | (12,831,605) | 25 |
| 26 | Jan-35 | 618,223 | 48,585 | 151,666 | 13,993 | 1,485,546 | 1,699,790 | 0 | (1,699,790) | (12,970,169) | 26 |
| 27 | Jan-36 | 584,796 | 45,958 | 155,901 | 13,237 | 0 | 215,095 | 0 | (215,095) | (12,986,091) | 27 |
| 28 | Jan-37 | 550,681 | 43,277 | 161,000 | 12,464 | 0 | 216,741 | 0 | (216,741) | (13,000,661) | 28 |
| 29 | Jan-38 | 389,681 | 30,624 | 119,515 | 8,820 | 0 | 158,960 | 0 | (158,960) | (13,010,364) | 29 |
| 30 | Jan-39 | 270,165 | 21,232 | 103,343 | 6,115 | 0 | 130,690 | 0 | (130,690) | (13,017,608) | 30 |
| 31 | Jan-40 | 166,822 | 13,110 | 67,295 | 3,776 | 0 | 84,181 | 0 | (84,181) | (13,021,846) | 31 |
| 32 | Jan-41 | 99,527 | 7,822 | 65,675 | 2,253 | 0 | 75,749 | 0 | (75,749) | (13,025,308) | 32 |
| 33 | Jan-42 | 33,853 | 2,660 | 33,852 | 766 | 0 | 37,279 | 0 | (37,279) | (13,026,855) | 33 |
| 34 | Jan-43 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (13,026,855) | 34 |
| 35 | Jan-44 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (13,026,855) | 35 |
| 36 | Jan-45 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (13,026,856) | 36 |
| 37 | Jan-46 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (13,026,856) | 37 |
| 38 | Jan-47 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (13,026,856) | 38 |
| 39 | Jan-48 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (13,026,856) | 39 |
| 40 | Jan-49 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (13,026,856) | 40 |

**YECL AMR Project**
**Conventional Meter Cost Impact**

08-20-2008

| Year | Jan-09 | Jan-10 | Jan-11 | Jan-12 | Jan-13 | Jan-14 | Jan-15 | Jan-16 | Jan-17 | Jan-18 | Jan-19 | Jan-20 | Jan-21 | Jan-22 | Jan-23 | Jan-24 | Jan-25 | Jan-26 | Jan-27 | Jan-28 | Jan-29 | Jan-30 | Jan-31 | Jan-32 | Jan-33 | Jan-34 | Jan-35 | Jan-36 | Jan-37 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **REVENUES:** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Revenue Requirement | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Revenue:** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| **CAPITAL:** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1) meter replacement | 25,048 | 50,847 | 53,170 | 55,562 | 57,229 | 58,946 | 60,715 | 62,536 | 64,412 | 66,344 | 68,335 | 70,385 | 72,496 | 74,671 | 76,911 | 79,219 | 81,595 | 84,043 | 86,564 | 89,161 | 91,836 | 94,591 | 97,429 | 100,352 | 103,362 | 106,463 | 109,657 | 112,947 | 57,308 |
| 2) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Capital** | 25,048 | 50,847 | 53,170 | 55,562 | 57,229 | 58,946 | 60,715 | 62,536 | 64,412 | 66,344 | 68,335 | 70,385 | 72,496 | 74,671 | 76,911 | 79,219 | 81,595 | 84,043 | 86,564 | 89,161 | 91,836 | 94,591 | 97,429 | 100,352 | 103,362 | 106,463 | 109,657 | 112,947 | 57,308 |

| **O&M:** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manual Meter Reading Costs | 471,000 | 485,130 | 499,684 | 514,674 | 530,115 | 546,018 | 562,399 | 579,271 | 596,649 | 614,548 | 632,985 | 651,974 | 671,533 | 691,679 | 712,430 | 733,803 | 755,817 | 778,491 | 801,846 | 825,901 | 850,678 | 876,199 | 902,485 | 929,559 | 957,446 | 986,169 | 1,015,754 | 1,046,227 | 1,077,614 |
| Meter Test Costs | 115,000 | 118,450 | 122,004 | 125,664 | 129,434 | 133,317 | 137,316 | 141,435 | 145,679 | 150,049 | 154,550 | 159,187 | 163,963 | 168,881 | 173,948 | 179,166 | 184,541 | 190,077 | 195,780 | 201,653 | 207,703 | 213,934 | 220,352 | 226,962 | 233,771 | 240,784 | 248,008 | 255,448 | 263,112 |
| Customer Applications & Service Or | 450,000 | 463,500 | 477,405 | 491,727 | 506,479 | 521,673 | 537,324 | 553,443 | 570,047 | 587,148 | 604,762 | 622,905 | 641,592 | 660,840 | 680,665 | 701,085 | 722,118 | 743,781 | 766,095 | 789,078 | 812,750 | 837,133 | 862,247 | 888,114 | 914,757 | 942,200 | 970,466 | 999,580 | 1,029,567 |
| Data Cap Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total O&M** | 1,036,000 | 1,067,080 | 1,099,092 | 1,132,065 | 1,166,027 | 1,201,008 | 1,237,038 | 1,274,149 | 1,312,374 | 1,351,745 | 1,392,297 | 1,434,066 | 1,477,088 | 1,521,401 | 1,567,043 | 1,614,054 | 1,662,476 | 1,712,350 | 1,763,721 | 1,816,632 | 1,871,131 | 1,927,265 | 1,985,083 | 2,044,636 | 2,105,975 | 2,169,154 | 2,234,229 | 2,301,255 | 2,370,293 |

**YECL AMR Project**
**Conventional Meter Cost Impact**

| Year | Jan-09 | Jan-10 | Jan-11 | Jan-12 | Jan-13 | Jan-14 | Jan-15 | Jan-16 | Jan-17 | Jan-18 | Jan-19 | Jan-20 | Jan-21 | Jan-22 | Jan-23 | Jan-24 | Jan-25 | Jan-26 | Jan-27 | Jan-28 | Jan-29 | Jan-30 | Jan-31 | Jan-32 | Jan-33 | Jan-34 | Jan-35 | Jan-36 | Jan-37 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **YEARLY DEPRECIATION:** | **Rates** | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 |
| 1) meter replacement | 4.540% | 1,137 | 3,446 | 5,860 | 8,382 | 10,980 | 13,656 | 16,413 | 19,252 | 22,176 | 25,188 | 28,291 | 31,486 | 34,778 | 38,168 | 41,659 | 45,256 | 48,960 | 52,776 | 56,706 | 60,754 | 64,923 | 69,218 | 73,641 | 78,197 | 82,890 | 87,723 | 92,701 | 97,829 |
| 2) | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3) | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4) | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5) | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6) | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7) | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8) | 4.540% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Depreciation** | | 1,137 | 3,446 | 5,860 | 8,382 | 10,980 | 13,656 | 16,413 | 19,252 | 22,176 | 25,188 | 28,291 | 31,486 | 34,778 | 38,168 | 41,659 | 45,256 | 48,960 | 52,776 | 56,706 | 60,754 | 64,923 | 69,218 | 73,641 | 78,197 | 82,890 | 87,723 | 92,701 | 97,829 |

| **ACCUMULATED DEPRECIATION** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1) meter replacement | 0 | 1,137 | 4,583 | 10,442 | 18,825 | 29,805 | 43,461 | 59,874 | 79,126 | 101,303 | 126,491 | 154,782 | 186,268 | 221,046 | 259,213 | 300,873 | 346,129 | 395,089 | 447,865 | 504,571 | 565,325 | 630,248 | 699,466 | 773,106 | 851,303 | 934,193 | 1,021,916 | 1,114,617 | 1,212,447 |
| 2) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| **PROPERTY IN SERVICE (beg yr)** | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1) meter replacement | 0 | 25,048 | 74,758 | 124,483 | 174,185 | 223,033 | 270,998 | 318,056 | 364,179 | 409,339 | 453,507 | 496,654 | 538,748 | 579,758 | 619,651 | 658,395 | 695,954 | 732,294 | 767,376 | 801,165 | 833,620 | 864,702 | 894,370 | 922,582 | 949,293 | 974,458 | 998,032 | 1,019,966 | 1,040,211 |
| 2) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Project Ratebase** | 0 | 25,048 | 74,758 | 124,483 | 174,185 | 223,033 | 270,998 | 318,056 | 364,179 | 409,339 | 453,507 | 496,654 | 538,748 | 579,758 | 619,651 | 658,395 | 695,954 | 732,294 | 767,376 | 801,165 | 833,620 | 864,702 | 894,370 | 922,582 | 949,293 | 974,458 | 998,032 | 1,019,966 | 1,040,211 |

**YECL AMR Project**
**Conventional Meter Cost Impact**

| | | Return | Ratio | B.T. Cost | A.T. Cost |
|---|---|---|---|---|---|
| | Debt | 6.600% | 53% | 0.0347 | 0.0347 |
| | Preferred | 0.000% | 0% | 0.0000 | 0.0000 |
| | Common | 9.250% | 48% | 0.0666 | 0.0439 |
| | Tax Rate | 34.000% | | 10.122% | 7.859% |

**CASH FLOWS SUMMARY:**

| | Year | Revenue Requirements | | | | | | Revenue Allowance | Surplus (Deficit) | CPV at 10.122% | Used Year |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Ratebase | Return | Dep'n | Inc. Tax | O&M | Total | | | | |
| 0 | Jan-09 | 0 | 0 | 0 | 0 | 1,036,000 | 1,036,000 | 0 | (1,036,000) | (1,036,000) | 0 |
| 1 | Jan-10 | 25,048 | 1,968 | 1,137 | 567 | 1,067,080 | 1,070,753 | 0 | (1,070,753) | (2,008,331) | 1 |
| 2 | Jan-11 | 74,758 | 5,875 | 3,446 | 1,692 | 1,099,092 | 1,110,105 | 0 | (1,110,105) | (2,923,739) | 2 |
| 3 | Jan-12 | 124,483 | 9,783 | 5,860 | 2,818 | 1,132,065 | 1,150,525 | 0 | (1,150,525) | (3,785,271) | 3 |
| 4 | Jan-13 | 174,185 | 13,689 | 8,382 | 3,943 | 1,166,027 | 1,192,041 | 0 | (1,192,041) | (4,595,843) | 4 |
| 5 | Jan-14 | 223,033 | 17,528 | 10,980 | 5,048 | 1,201,008 | 1,234,564 | 0 | (1,234,564) | (5,358,166) | 5 |
| 6 | Jan-15 | 270,998 | 21,297 | 13,656 | 6,134 | 1,237,038 | 1,278,126 | 0 | (1,278,126) | (6,074,845) | 6 |
| 7 | Jan-16 | 318,056 | 24,995 | 16,413 | 7,199 | 1,274,149 | 1,322,757 | 0 | (1,322,757) | (6,748,373) | 7 |
| 8 | Jan-17 | 364,179 | 28,620 | 19,252 | 8,243 | 1,312,374 | 1,368,489 | 0 | (1,368,489) | (7,381,138) | 8 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | Jan-18 | 409,339 | 32,169 | 22,176 | 9,265 | 1,351,745 | 1,415,356 | 0 | (1,415,356) | (7,975,419) | 9 |
| 10 | Jan-19 | 453,507 | 35,640 | 25,188 | 10,265 | 1,392,297 | 1,463,391 | 0 | (1,463,391) | (8,533,390) | 10 |
| 11 | Jan-20 | 496,654 | 39,031 | 28,291 | 11,241 | 1,434,066 | 1,512,629 | 0 | (1,512,629) | (9,057,122) | 11 |
| 12 | Jan-21 | 538,748 | 42,339 | 31,486 | 12,194 | 1,477,088 | 1,563,108 | 0 | (1,563,108) | (9,548,584) | 12 |
| 13 | Jan-22 | 579,758 | 45,562 | 34,778 | 13,123 | 1,521,401 | 1,614,863 | 0 | (1,614,863) | (10,009,649) | 13 |
| 14 | Jan-23 | 619,651 | 48,697 | 38,168 | 14,025 | 1,567,043 | 1,667,933 | 0 | (1,667,933) | (10,442,094) | 14 |
| 15 | Jan-24 | 658,395 | 51,742 | 41,659 | 14,902 | 1,614,054 | 1,722,358 | 0 | (1,722,358) | (10,847,603) | 15 |
| 16 | Jan-25 | 695,954 | 54,693 | 45,256 | 15,753 | 1,662,476 | 1,778,178 | 0 | (1,778,178) | (11,227,772) | 16 |
| 17 | Jan-26 | 732,294 | 57,549 | 48,960 | 16,575 | 1,712,350 | 1,835,435 | 0 | (1,835,435) | (11,584,114) | 17 |
| 18 | Jan-27 | 767,376 | 60,306 | 52,776 | 17,369 | 1,763,721 | 1,894,172 | 0 | (1,894,172) | (11,918,056) | 18 |
| 19 | Jan-28 | 801,165 | 62,962 | 56,706 | 18,134 | 1,816,632 | 1,954,434 | 0 | (1,954,434) | (12,230,951) | 19 |
| 20 | Jan-29 | 833,620 | 65,512 | 60,754 | 18,869 | 1,871,131 | 2,016,266 | 0 | (2,016,266) | (12,524,074) | 20 |
| 21 | Jan-30 | 864,702 | 67,955 | 64,923 | 19,572 | 1,927,265 | 2,079,715 | 0 | (2,079,715) | (12,798,631) | 21 |
| 22 | Jan-31 | 894,370 | 70,286 | 69,218 | 20,244 | 1,985,083 | 2,144,831 | 0 | (2,144,831) | (13,055,757) | 22 |
| 23 | Jan-32 | 922,582 | 72,503 | 73,641 | 20,882 | 2,044,636 | 2,211,662 | 0 | (2,211,662) | (13,296,524) | 23 |
| 24 | Jan-33 | 949,293 | 74,603 | 78,197 | 21,487 | 2,105,975 | 2,280,261 | 0 | (2,280,261) | (13,521,941) | 24 |
| 25 | Jan-34 | 974,458 | 76,580 | 82,890 | 22,056 | 2,169,154 | 2,350,680 | 0 | (2,350,680) | (13,732,960) | 25 |
| 26 | Jan-35 | 998,032 | 78,433 | 87,723 | 22,590 | 2,234,229 | 2,422,974 | 0 | (2,422,974) | (13,930,476) | 26 |
| 27 | Jan-36 | 1,019,966 | 80,157 | 92,701 | 23,086 | 2,301,255 | 2,497,200 | 0 | (2,497,200) | (14,115,332) | 27 |
| 28 | Jan-37 | 1,040,211 | 81,748 | 97,829 | 23,545 | 2,370,293 | 2,573,415 | 0 | (2,573,415) | (14,288,319) | 28 |
| 29 | Jan-38 | 999,690 | 78,563 | 100,431 | 22,627 | 0 | 201,622 | 0 | (201,622) | (14,300,626) | 29 |
| 30 | Jan-39 | 899,259 | 70,671 | 100,431 | 20,354 | 0 | 191,456 | 0 | (191,456) | (14,311,239) | 30 |
| 31 | Jan-40 | 798,828 | 62,778 | 100,431 | 18,081 | 0 | 181,290 | 0 | (181,290) | (14,320,364) | 31 |
| 32 | Jan-41 | 698,397 | 54,885 | 100,431 | 15,808 | 0 | 171,124 | 0 | (171,124) | (14,328,186) | 32 |
| 33 | Jan-42 | 597,966 | 46,993 | 100,431 | 13,535 | 0 | 160,958 | 0 | (160,958) | (14,334,867) | 33 |
| 34 | Jan-43 | 497,535 | 39,100 | 100,431 | 11,261 | 0 | 150,792 | 0 | (150,792) | (14,340,551) | 34 |
| 35 | Jan-44 | 397,104 | 31,207 | 100,431 | 8,988 | 0 | 140,627 | 0 | (140,627) | (14,345,364) | 35 |
| 36 | Jan-45 | 296,673 | 23,315 | 100,431 | 6,715 | 0 | 130,461 | 0 | (130,461) | (14,349,419) | 36 |
| 37 | Jan-46 | 196,242 | 15,422 | 100,431 | 4,442 | 0 | 120,295 | 0 | (120,295) | (14,352,815) | 37 |
| 38 | Jan-47 | 95,811 | 7,530 | 95,811 | 2,169 | 0 | 105,509 | 0 | (105,509) | (14,355,519) | 38 |
| 39 | Jan-48 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (14,355,519) | 39 |
| 40 | Jan-49 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (0) | (14,355,519) | 40 |

**YUB-YECL-16**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 71300 Customer Billing & Accounting

**Quote**: Costs increase from 2007 to 2008 due to implementing the new ATCO-CIS billing system. The new system conversion is planned to be completed by July 2008. (Line No. 191-192.)

Costs increase from 2008 to 2009 due to full year impact of the new ATCO-CIS billing system costs. (Line No. 194.)

**Preamble**: The Board would like to gain a better understanding of the new ATCO-CIS billing system.

**Request:**

(a) Please explain what is meant by due to full year impact of the new ATCO-CIS billing system costs .

(b) Please provide a detailed explanation and analysis as to the benefits that YECL customers can expect to accrue as a result of YECL implementing the new ATCO-CIS billing system when the previous and new systems are compared?

(c) Has YECL considered looking at other vendor billing systems? If not, why not? If so, what were the results of the comparison shopping?

(d) Please provide any studies or supporting evidence that show ATCO-CIS as the least-cost alternative.

(e) On an annual basis, excluding the capital component, what is the cost customer of operating the ATCO-CIS system? In similar terms, does YECL know the annual cost customer for billing at YEC?

(f) Please explain the benefits accruing to YECL customers from the implementation of the ACTO-CIS system.

**Response:**

(a) Yukon Electrical's 2008 customer billing is being completed by two systems the legacy system for the first portion of the year and ATCO-CIS for the last portion of the year. Given that ATCO-CIS's operating and maintenance costs are higher than what is being charged for the legacy system in the first part of 2008, the average cost for billing is increasing between 2007 and 2008. As ATCO-CIS will be in place throughout 2009, there will be an increase in the average cost for billing between 2008 and 2009.

(b) Please refer to YUB-YECL-16(b) Attachment 1 for a copy of the Business Case that details the Business Functionality Requirements Evaluation, Technical Feasibility Requirements Evaluation, Ongoing Support Evaluation and Cost Evaluation of the billing options that were reviewed by Yukon Electrical as part of ATCO's North of Sixty Utility Group. It is important to convey the change in billing systems was not predicated on the legacy system not meeting the business needs of the North of Sixty Utility Group. The need to review new billing options was necessitated due unsustainable cost increases as a result of ATCO's large Alberta based utilities migrating off the legacy system's technology platform. This change effectively meant the North of Sixty Companies would be responsible for 100 of the costs associated with operating and maintaining the legacy system.

As detailed in the Business Case, the choice to go with ATCO-CIS was predicated on the system being the preferred choice with respect to ATCO's North of Sixty Companies' Business Functionality Requirements as well as the cost to convert, operate and maintain the system being comparable to the non-related party options.

Some of the more notable features of ATCO-CIS that were not available with the legacy system are as follows:

- Ability of a Customer Service Advisor to on line recalculate previous bills
- ATCO-CIS is windows based which will make is easier to export excel files to customers
- Customer accounts can be bundled (e.g. school boards, RCMP, effectively any customer with multiple service locations)

- There is sufficient space to have all charges itemized - total transparency to customers
- Consumption histogram will be printed on the customer's bill

(c&d) Yukon Electrical, as part of the ATCO's North of Sixty Companies evaluation of options, spent considerable time and effort reviewing other vendor billing systems. Please refer to YUB-YECL-16(b) Attachment 1 for a copy of the Business Case that details the Business Functionality Requirements Evaluation, Technical Feasibility Requirements Evaluation, Ongoing Support Evaluation and Cost Evaluation of the billing options that were reviewed by Yukon Electrical as part of ATCO's North of Sixty Utility Group. In addition to the two potential affiliate solutions, Old CIS and ATCO CIS, four external suppliers were approached to provide cost and other information on their respective billing solutions. One external supplier chose not to file a response to the RFP. A second external supplier was not short listed for further evaluations as its solution did not meet the specified minimum requirements. While Old CIS continued to meet the business functionality requirements of the North of Sixty Companies, the ongoing use of this solution was determined not to be cost effective. This result was due to the larger based ATCO utilities migrating off the system and North of Sixty Companies having to bear 100 of the ongoing operational and capital costs associated with maintaining the Old CIS system. The remaining three billing system solutions were then subjected to a detailed fit analysis based on the evaluation criteria and weightings that were included in the business case. The forecast capital and ongoing operating costs, technical feasibility and ongoing support of Vendor 1, Vendor 2 and ATCO CIS were relatively consistent between each of the three options. The decision to proceed was, therefore, based on ATCO CIS having the highest score for the Business Functionality Requirements. YUB-YECL-16(c) Attachment 1 shows the underlying criteria and scores used to develop each of the 15 weighted scores at page 5 or 34 of the business case. Supporting comments were provided whenever an evaluated score was less than the maximum score.

(e) Please refer to Schedule 5.3 line 11 for the costs associated with billing system services. The number of customers, excluding street and sentinel lights, is on Schedule 2.1 line 39. For 2009, the annual cost per customer is 31.24 ( 484,000 15,490)

With the exceptions of 1998 and 1999, ATCO has continuously provided Yukon Energy billing system services with the legacy system since Yukon Energy's inception in the 1980's. The current fee of 130,000 per year has been offered and accepted for 2008 and 2009. Per Yukon Energy's 2005 Required Revenues and Related Matters Application Tab 7 Filing Schedules, Schedule 11, line 26, Yukon Energy forecast 1,749 firm retail customers in 2005. (Note: This figure would exclude street and sentinel light customer similar to Yukon Electrical.) Using these figures, the annual cost per customer is 74 ( 130,000 1,749). Yukon Electrical is unable to confirm whether the figures provided in this calculation accurately reflect Yukon Energy's total forecast costs and or customers in 2008.

(f) Please refer to (b) and (c).

# North of 60 Billing System Replacement Project

# Business Case

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**APPENDIX A – BUSINESS FUNCTIONALITY REQUIREMENTS**

**APPENDIX B – TECHNICAL FEASIBILITY REQUIREMENTS**

**APPENDIX C– REVENUE REQUIREMENT MODEL**

# 1 Background Summary

The North of 60 Companies (The Yukon Electrical Company Limited, Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited), collectively known as N60, were advised in 2006 that ATCO I-Tek Business Services intended on retiring the Customer Information System (Old CIS) that had been serving the N60 companies since the 1970's.

Old CIS is a 30 plus year old vendor product based on IMS data base technology that was purchased by ATCO to provide customer care and billing functionality to all of ATCO's utility customers. This technology has not been used to develop new systems. As of 2008, ATCO's Alberta based utilities will have migrated off IMS to database systems that utilize relational database technology. This has meant that N60, as well as the non-affiliated Yukon Energy Corporation, are the only remaining utility companies using Old CIS and the IMS database technology. While Old CIS meets N60's current business needs, the loss of the Alberta based utilities has meant a loss of economies of scale and exposed N60 to the full cost of running and supporting Old CIS and the IMS database.

Due to this situation, a N60 project team was set up in 2006 to define the business functionality requirements for N60 and identify Customer Information System options. This team was sponsored by the General Manager N60 and included key N60 supervisory billing staff. ATCO I-Tek provided assistance on the technical requirements and estimating requirements as this skill set was not available within N60.

Once N60's business functionality requirements were defined, the first phase of the process was to perform a market investigation that identified vendors that provided Customer Care and Billing Services to companies with similar profiles as N60. Based on the information presented in the vendors' responses, a high level comparison and rating was performed on each vendor's product.

Two external vendors were selected for the short list. Based on confidentiality agreements, N60 is not a liberty to disclose the names of the short listed external vendors nor any of the detailed information they provided. A parent company solution, ATCO CIS, as well as the forecast cost of going it alone with the Old CIS were also included with the short list. Each of the vendors was invited to provide a four-day in depth presentation of their product's functionality. The presentations gave N60 and the vendors an opportunity to determine what type of customizations and interfaces would be needed to support N60's business and technical functionality requirements.

# 2 Evaluation Approach

The N60 evaluation consisted of six main activities:

- Requirements gathering
- Market investigation & evaluation of third-party solutions and ATCO CIS
- Estimation of implementation and ongoing costs for vendor solutions
- Estimation of implementation and ongoing costs of ATCO CIS.
- Estimation of ongoing costs of remaining status quo on Old CIS
- Evaluation of Potential Solutions

The evaluation was based on the following criteria and weighting (relative importance) of each criteria, with the weighted points totaling 100.

| Evaluation Criterion | Weighted Point |
|---|---|
| Business Functionality | 60 |
| Technical Feasibility | 5 |
| Ongoing Support | 5 |
| Cost | 30 |
| **Total** | **100** |

Refer to **Appendix A** for the Business Functionality Requirements document.

Refer to **Appendix B** for the Technical Feasibility Requirements document.

Refer to **Appendix C** for the forecast costs of the four options.

# 3 Evaluation Results

### 3.0.1 Business Functionality Requirements Evaluation

Based on the Business Functionality Requirements detailed in Appendix A, the project team performed an evaluation to determine if the business requirements were met by the vendor's product without modification.

The following captures the weighted score of each business functionality category.

| Id# | Business Functionality Major Category | Vendor #1 | Vendor #2 | ATCO CIS | Old CIS | *Maximum Possible Weighted Score* |
|---|---|---|---|---|---|---|
| BR-1 | Core Structure | 4 | 4 | 20 | 20 | *20* |
| BR-2 | Customer Mgmt. | 19 | 21 | 35 | 35 | *35* |
| BR-3 | Service Order Mgmt. | 28 | 18 | 40 | 40 | *40* |
| BR-4 | Billing Accuracy Function | 172 | 200 | 220 | 220 | *220* |
| BR-5 | Automation | 12 | 14 | 40 | 40 | *40* |
| BR-6 | Accounts Receivable Mgmt. | 16 | 16 | 20 | 20 | *20* |
| BR-7 | General Ledger Mgmt | 12 | 16 | 20 | 20 | *20* |
| BR-8 | Credit and Collections | 12 | 8 | 20 | 20 | *20* |
| BR-9 | Payment Remittance | 12 | 16 | 20 | 20 | *20* |
| BR-10 | Meter Management | 12 | 8 | 20 | 20 | *20* |
| BR-11 | Meter Reading Mgmt. | 20 | 28 | 40 | 40 | *40* |
| BR-12 | Route/cycle Mgmt. | 12 | 12 | 20 | 20 | *20* |
| BR-13 | Query and Reporting | 10 | 8 | 20 | 20 | *20* |
| BR-14 | System Administration | 48 | 46 | 80 | 80 | *80* |
| BR-15 | Usability | 84 | 58.5 | 95 | 95 | *95* |
| | **Total Requirement Weighted Score** | **473** | **473.5** | **710** | **710** | ***710*** |
| | **Business Functionality Criterion Weighted Score Out of 60** | **40.0** | **40.0** | **60** | **60** | **60** |

### 3.0.2 Technical Feasibility Requirements Evaluation

ATCO I-Tek defined the technical requirements and the importance rating on behalf of N60 because ATCO I-Tek is the IT service provider for the ATCO Group of Companies. ATCO I-Tek also evaluated the technical requirements for each potential solution.

The following table captures the weighted score of each technical feasibility category.

| Id# | Technical Feasibility Major Category | Vendor #1 | Vendor #1 | ATCO CIS | Old CIS | *Maximum Possible Weighted Score* |
|---|---|---|---|---|---|---|
| TF-1 | Technical Architecture | 16 | 12 | 20 | 8 | *20* |
| TF-2 | Configuration of Workstations | 32 | 35 | 35 | 19 | *35* |
| TF-3 | Configuration of Application Servers | 28 | 25 | 26 | 7 | *35* |
| TF-4 | Configuration of Database and Database Servers | 24 | 32 | 35 | 13 | *35* |
| TF-5 | Shared Hosting Environment | 0 | 6 | 10 | 8 | *10* |
| TF-6 | Systems Integration | 8 | 6 | 16 | 15 | *25* |
| TF-7 | Security | 18 | 32 | 40 | 27 | *45* |
| TF-8 | Redundancy, Backup and Recovery | 25 | 21 | 35 | 19 | *35* |
| TF-9 | Performance and Monitoring | 3 | 2 | 5 | 3 | *5* |
| TF-10 | Network Communication | 28 | 26 | 22 | 30 | *30* |
| TF-11 | Configuration, installation , distribution, and licensing | 18 | 18 | 30 | 24 | *30* |
| TF-12 | Change Management | 28 | 24 | 35 | 15 | *35* |
| | **Total Requirement Weighted Score** | **228** | **239** | **309** | **188** | ***340*** |
| | **Technical Feasibility Criterion Weighted Score Out of 5** | **3.4** | **3.5** | **4.5** | **2.8** | **5.0** |

### 3.0.3 Ongoing Support Evaluation

Ongoing Support describes the level and type of support N60 will receive after the implementation of the potential solution. It includes the service level and the availability of user groups, help desks, system documentation, clearly defined response times and system maintenance. These items support the day to day operations of N60.

Ongoing support evaluation results:

| Ongoing Support Requirement | Vendor #1 | Vendor #2 | ATCO CIS | Old CIS |
|---|---|---|---|---|
| User support offered during N60 business hours | 12 | 12 | 16 | 16 |
| Vendor production outage response time commitments | 12 | 12 | 16 | 16 |
| System upgrades | 16 | 16 | 16 | 8 |
| Documentation and usability | 12 | 12 | 16 | 16 |
| Access to User Groups | 16 | 16 | 16 | 16 |
| **Maximum Weighted Score** | 80 | 80 | 80 | 80 |
| **Total Requirement Weighted Score** | **68** | **68** | **80** | **72** |
| **Business Functionality Criterion Weighted Score Out of 5 (Maximum/Total Score * 5)** | **4.3** | **4.3** | **5** | **4.5** |

### 3.0.4 Cost Evaluation

Implementation and ongoing operations and maintenance costs were forecast for each option and input into the revenue requirement model. (See Appendix C) Given the forecast costs for Vendor 1, Vendor 2 and ATCO CIS were all relatively close to each other, each of these options was given the maximum value. Old CIS was given a minimum value as the ongoing "going it alone" cost to maintain and support the system was clearly not going to be economic to N60.

| Evaluation Criteria | Maximum Value | Vendor #1 | Vendor #2 | ATCO CIS | Old CIS |
|---|---|---|---|---|---|
| Cost | 30 | 30 | 30 | 30 | 0 |

### 3.0.5 Evaluation Criteria Summary

The following outlines the total criteria weighted score for each potential solution:

| Evaluation Criteria | Maximum Value | Vendor #1 | Vendor #2 | ATCO CIS | Old CIS |
|---|---|---|---|---|---|
| Business Functionality | 60 | 40.0 | 40.0 | 60 | 60 |
| Technical Feasibility | 5 | 3.4 | 3.5 | 4.5 | 2.8 |
| Ongoing Support | 5 | 4.3 | 4.3 | 5 | 4.5 |
| Cost | 30 | 30 | 30 | 30 | 0 |
| **Total** | **100** | **77.7** | **77.8** | **99.5** | **67.3** |

# 4 Conclusions and Recommendation

Upon completion of this analysis, a number of conclusions are apparent:

- The legacy system, Old CIS, is not a cost effective solution.
- The forecast capital and ongoing operating costs, technical feasibility and ongoing support of Vendor 1, Vendor 2 and ATCO CIS are relatively consistent between each of the three options.
- Based on the Business Functionality Requirements detailed in Appendix A and the scores awarded in section 3.0.1, ATCO CIS meets the highest amount of N60's business needs in every one of the fifteen categories.

Based on investigative and analytical work completed, it is recommended that N60 proceed with the implementation of ATCO-CIS in 2008.

# APPENDIX A – Business Functionality Requirements

| Business Function Description | Mandatory = M Optional = 0 |
|---|---|
| **1. CUSTOMER MANAGEMENT** | |
| Customer Management provides the facilities necessary for managing customer, account and service location related activities. Typically this includes setting up new services, activating the accounts for billing, consolidating accounts, issuing customer correspondence and terminating service. | M |
| | |
| A customer may have many customer accounts served at many locations. | M |
| | |
| ***1.1 Customer Maintenance*** | |
| Customer Maintenance provides the facilities necessary to maintain data pertaining, to the customer's profile. | M |
| | |
| **1.1.1 Record Customer Data** | |
| Customer data is recorded when a customer applies for service. The information typically recorded about the customer is name, mailing address, and contacts, phone numbers, identification, critical use conditions and other related customer data. | M |
| | |
| **1.1.2 Specify Consolidated Accounts** | |
| This process provides the means to group or consolidate one or more billing accounts to a particular customer. The reason for consolidating accounts is to create one monthly invoice for all the selected accounts as opposed to generating one invoice per account. The billing accounts underlying a consolidated account are for meters billed in **different** billing cycles. The consolidated invoice includes details for each account. | M |
| | |
| **1.1.3 Specify Statement Accounts** | |
| This process provides the means to group multiple billing accounts in the **same** cycle to a particular customer. The reason for grouping statement accounts is to provide a monthly statement for all the selected accounts provided that these accounts are for meters on the same billing cycle. (i.e. for one particular area or community) One invoice is generated for each individual account. One statement is produced per month. | M |
| | |
| ***1.2 Account Maintenance*** | |
| Account Maintenance provides the facilities necessary for the administration of customer accounts. Typically this includes: | |
| > Account set-up (before meter installation). | M |
| > Turn-on. | M |
| > Turn off. | M |
| > Temporary disconnect (seasonal or non-payment). | M |
| > Inactive account with meter. | M |

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| > Inactive account without meter. | M |
| | |
| Different types of accounts include: | |
| > Normal account level meter. | M |
| > Unmetered (flat rate) - energy and demand are estimated values required for billing calculations. | M |
| > Outdoor lights (with or without meter) - consumption is estimated for rider calculation and sales reporting. | M |
| > Manually billed industrial or secondary energy accounts assigned non-standard rates. | M |
| > Subtract metered accounts. | M |
| > Company use accounts (non-billing but consumption to be recorded and reported). | M |
| Payment Options: | |
| > Pre-authorized payment plan (from bank accounts and credit cards). | M |
| > Average monthly payment plan. | M |
| | |
| **1.2.1 Record Account Data** | |
| Account data information is recorded when a customer applies for service. The information typically recorded is the customer name, any aliases, employer, phone numbers, mailing address for invoice delivery, the type of service, type of business as defined in the Standard Industrial Class Code (SIC), rate code, special use conditions and other related account data. Recording of personal data such as dob or health care number | M |
| | |
| For rental properties, recording owner/property management company information is required. (COIN) | M |
| | |
| This also provides for the recording of contract data, the account billing frequency and any billing exemptions that may apply such as late penalty charge category code, applicable provincial or federal taxes, and riders or exemptions therefrom. Franchise tax billing option required. | M |
| | |
| **1.2.2 Assign Location** | |
| A customer name can be associated with multiple locations. | M |
| The search function must allow for search by account number, last or business name or civic address. An expanded search function providing search by phone number, mailing address, date of birth. Legal or rural address, or “sounds like” name is desirable. | M |
| | |
| **1.2.3 Turn-On Account** | |
| The turn-on function is used to activate the account for billing purposes. A connect fee and security deposit may be optionally assessed and the appropriate rate schedule is assigned. | M |
| This function **MUST** create service field orders. Field order production must be automatically assigned by location and or company. | M |
| | |
| **1.2.4 Administer Outdoor Lights** | |

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|---|---|
| The outdoor light function is used to set-up and administer outdoor lights. A customer can be billed different monthly rates for outdoor lights depending on the type and size of the lamps. Outdoor lights are normally connected before the meter and consumption is not recorded as part of the monthly meter reading. However, an average monthly kilowatt-hour value is assigned to each light rate code and must be reported as consumption for monthly statistics. For example, a 100 watt HPS sentinel light has a base charge of $11.64, a 14.63% rider charge of $2.18 and GST of $.97. For regulatory purposes, the system must also record consumption of 40 kWh even though this was not a "measured" amount. | M |
| A customer should receive one bill for both metered energy as well as any light charges. | M |
| | |
| There must also be a function to bill lights on an account without a meter. This type of account will typically have to calculate a bill combining several different types of light rate codes. | M |
| | |
| **1.2.5 Administer Equalized Payment Plan (Budget) Accounts** | |
| This function allows for the set-up, monitoring, and removal of accounts on the equalized payment plan. The billing system would calculate potential budget amount based on previous year's consumption. | M |
| | |
| Ideally, the settlement date for budget accounts does not have to be the same for all accounts. | O |
| | |
| Monitoring refers to the process of assessing whether the monthly budget amount is set too high or too low. Ideally, the customer makes 12 equal payments during the year. System must be able to report budget customers monthly. A mass change mechanism to increase/decrease budget amount is desirable. | M |
| | |
| **1.2.6 Temporary Off Accounts** | |
| The temporary off function is used to temporarily deactivate an account. The temporary offs are issued for delinquent accounts, vacation, safety, special usage or seasonal peak load customers. | M |
| | |
| In the case of a delinquent temporary off, a final invoice may be required after a predetermined number of days. | M |
| | |
| This function **MUST** create service field orders. | M |
| | |
| **1.2.7 Final/Transfer Accounts** | |
| The final function is used to finalize an account. A final invoice is prepared to bill the customer's account to a specified date and reading. | M |
| | |
| When finalizing an account, any deposit amount held will automatically be applied to the final invoice amount if the customer is not establishing a new account. If the customer's final accounts receivable results in a credit balance, a refund cheque will automatically be initiated by the system. | M |
| | |

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| The transfer function is used when the customer is transferring from one service location to another. The final invoice accounts receivable is transferred to the customer's "moving to" account. In addition, current customer data must transfer. (I.e. credit data, deposit data, budget data, and customer data.) | M |
| | |
| This function **MUST** create service field orders. | M |
| | |
| ***1.3 Location Maintenance*** | |
| Location Maintenance provides the facilities necessary to record data for service locations. Typically this includes setting up a new service location, installing a meter or outdoor lights and recording related activity. | M |
| | |
| A new service location number is automatically assigned to create a location record if no service has previously existed at a service location. | M |
| | |
| A location can be associated with both an incoming and an outgoing customer account, but must assign a unique identifier to each customer. | M |
| | |
| **1.3.1 Record Location Data** | |
| This function is used to establish a new service location and maintain existing locations. The information typically recorded about location includes: | M |
| Service address, annual consumption, transformer size, meter number and location, meter reading cycle, route and sequence, community identifier, customer contribution (if applicable), source of power and load information. | M |
| | |
| All metering devices in commission at the premise (i.e. current transformers or potential transformers) are recorded for billing multiplier calculation. | M |
| | |
| **1.3.2 Install Meter** | |
| The meter install function is used to record meter information pertaining to the meter installed at the service location. A control function must ensure a meter can only be assigned to one location at any given point in time and ensure the meter used is "in stock"/inventory for the specified company. | M |
| | |
| This function **MUST** create service field orders | M |
| | |
| **1.3.3 Change Meter** | |
| The meter change function is used to record the exchange of a meter at the service location. The removed meter will be returned to meter stock or retired. | M |
| | |
| The meter change will record the new meter information and calculate consumption for the removed meter as well as the new meter, for the subsequent billing. If consumption falls outside the edit and validation parameters pre-set in the system, a warning must be generated. The change function must be available for inactive accounts. | M |
| | |
| The meter change could be the result of a faulty meter, routine meter change program, damaged meter or load change. | M |
| | |

| | |
|---|---|
| This function **MUST** create service field orders. | M |
| | |
| **1.3.4 Remove Meter** | |
| The remove meter function is used to record the fact that a meter has been removed from a location and returned to meter stock. The billing system will create an account record to maintain the service information on the account. | M |
| | |
| The remove meter function can be used separately or in conjunction with a meter change. | M |
| This function **MUST** create service field orders. | |
| | M |
| **1.3.5 Install/Remove Outdoor Lights** | |
| The install/remove outdoor lights function is used to record information pertaining to the outdoor light installation and removal at the service location. Outdoor lights may or may not be metered. | M |
| | |
| This function **MUST** create service field orders. | M |
| | |
| ***1.4 Customer Communication*** | |
| Customer Communication provides the facilities necessary for administrating customer correspondence. Typically this includes monthly system generated bill messages related to aged accounts receivable, budget and pre-authorized payment customers. This function must also offer a minimum of two adhoc bill messages that can target specific customer groups (i.e. by community or rate class). | M |
| | |
| A function must exist to support/facilitate customer surveys. Requirements include the ability to select customers on the basis of various criteria such as community, rate class or consumption levels. | O |
| | |
| **2. SERVICE ORDER MANAGEMENT** | |
| Service Order Management supports all service orders initiated by customers, employees and the system. The term " Field Service Orders" includes customer contacts, requests for field services, investigations, requests for follow-up actions, etc. | M |
| | |
| Field service orders are categorized to support statistical information and the measurement of customer service response times. This facility **must** automatically print field service orders, once initiated, for action. A pending service order report will be automatically produced for the designated responsible party(ies) for periodic follow-up. | M |
| | |
| Field service orders are not work orders. Work orders are used for capital additions, as well as repair and maintenance. This activity has implications on the capital assets and depreciation. Field service orders have no such implications. | |
| | |
| ***2.1 Template Maintenance*** | |
| A template defines the types of service orders, their generic priorities, escalation procedures, the designated responsible persons or departments, the print location, etc. | M |
| | |
| The template also defines the conditions under which the system will initiate the prompt for follow-up action orders. | |
| | |
| ***2.2 Service Order Maintenance*** | |

| | |
|---|---|
| Service Order Maintenance provides the facilities necessary to initiate, query, change, print, cancel, complete, close and reactivate service orders. It also sets the priority and automatically routes the order to the responsible party(ies) based on manually input directives or defaults to the template assignment. | M |
| | |
| The system reviews the status of the orders on a regular basis and the escalation procedures defined in the template are implemented when necessary. | M |
| | |
| Query can be by company, by service area, by location, by account, by category, by status, etc., provided there is sufficient security authorization. | M |
| | |
| When a service order is changed, cancelled or reactivated, an audit trail is required of the changes made, the reasons for change, cancellation/re-activation and the person who initiated the action is maintained. | M |
| | |
| Service orders **MUST** be printed locally at a designated printer. | M |
| | |
| ***2.3 Produce Statistics*** | |
| Daily, monthly and yearly statistics such as volume of service orders by category, service orders completed, outstanding, cancelled, etc., will be produced for the head office, districts, agencies, departments or responsibilities. | M |
| | |
| ***2.4 Balance and Control*** | |
| The system will ensure that service orders initiated, completed orders, outstanding orders and the cancelled orders can be reviewed and monitored on a timely basis. | M |
| | |
| Facilities are provided for supervisors and/or authorized employees to administer service orders. Typically, the facilities will be used for general leveling of workload, monitoring of service order completions and service orders pending. | M |
| | |
| ***3. BILLING*** | |
| Billing is the processing required to calculate and adjust bills for each service and to produce individual or consolidated invoices for each customer. Billing can be triggered by cycle, by date or by event, depending on the profile of the service account. | M |
| | |
| An operator manual and/or process and procedures manual must be supplied for account billing, error message and correction, data field identification, credit and collections, and cash system procedures. | M |
| | |
| ***3.1 Maintain Rates*** | |
| Rates are designed to bill various types of accounts. Each rate may contain a number of charge components. Current components include: | M |
| 1.) Basic customer charge or demand charge | |
| 2.) Unit charge based on consumption - may be stepped | |
| 3.) Riders as a percentage of a base rate or based on consumption | |
| 4.) Income tax rebate | |
| 5.) GST (invoice must provide subtotal before GST) | |

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| 6.) Territorial Sales Tax or Municipal Franchise Tax | |
| 7.) Territorial Rate Relief or Territorial Support (percentage of customer and or unit charge. May include a claw back mechanism if consumption exceeds defined parameters). | |
| 8.) Optional green rates must be supported as designed to allow for elective customer choices to support energy conservation initiatives. | |
| 9.) Time of use rates must be supported as designed to allow for elective customer initiatives. | |
| | |
| | |
| New rates are added as required by business requirements. Existing rates are modified upon regulatory approval. | M |
| | |
| Rates and or riders no longer in effect should be retained by the system to allow proper automatic calculation for customers who require billing adjustments that straddle change dates. | M |
| | |
| Strong date-effectiveness features are required for rates. | M |
| | |
| ***3.2 Manage Rate Tests*** | |
| This function provides the ability to test the impact of approved rates on the customer accounts. Users can specify the version of rates, riders, taxes etc. to be used in the rate test. Users can also choose to enter generic billing data or select actual production account data for testing. Rates and Pricing will continue to use existing rate design software to design and develop rates. Data file will be provided for this software from the billing system. | M |
| The objectives include: | |
| > Understanding revenue impact. | |
| > Ensuring that rate relief values are correctly set and ensure billing accuracy. | |
| | |
| Users control the elevation of tested rates into the production environment. Proper backup and recovery facilities are provided to support the elevation. Historical rates must be retained for cancel rebill functionality. | M |
| | |
| ***3.3 Bill Customers*** | |
| **3.3.1 Bill Utility Service** | |
| ***3.3.1.1 Calculate/Estimate and Validate Consumption*** | |
| Consumption is used for tracking energy usage and for billing. Units of usage (Energy kWh's and demand kW's) are measured by meter reading, then converted into energy consumption by applying a billing multiplier. | M |
| | |
| For non-metered services, such as outdoor lights, consumption is estimated based on the number of lights and the voltage of the light bulb. All applicable billing components such as riders are calculated on this estimated consumption as required. This estimated consumption value is reported for sales purposes. | M |
| | |
| For non-metered services, such as TV amplifiers, consumption and demand are estimated based on the number of units. The applicable general service rate is applied to the estimated value. This consumption value is also reported for revenue purposes. | |

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|---|---|
| Meters can measure energy or peak demand usage during the billing period. Normally, consumption is calculated for each register on the meter over the billing period. One of the exceptions is the time-of-use meters. Multiple sets of readings are recorded daily based on the time interval agreement. Consumption is calculated for each interval by day. Consumption for the corresponding intervals are accumulated and maintained separately. | M |
| | |
| The billing multiplier for each meter is made up of a number of components. If one of the components changes during the billing period, more than one billing multiplier will be calculated. | M |
| | |
| The actual units of usage are calculated from valid meter readings recorded for the billing period. If there is a billing multiplier change during the billing period, readings will be taken at the time of change. The billing multipliers will be applied to the corresponding portions of the usage. | M |
| | |
| In the absence of valid meter readings, the consumption is estimated based on a formula involving the days of usage, estimate factors, annual consumption, etc. A variable estimate code must be available to identify accounts that cannot be estimated. | M |
| | |
| Consumption is validated using established reasonable high/low ranges. The ranges are determined based on the estimated consumption of the meter for the billing period. A daily report must be produced for follow up on consumption outside established parameters. | M |
| | |
| ***3.3.1.2 Calculate Charges*** | |
| The billing rate determines which pricing factors to use for various charges. If the billing rate changes during a billing period, the consumption is prorated based on the number of days used before and after the rate change. The previous and current pricing factors are applied to the appropriate prorated portions of the consumption. The same principle applies if the service account is assigned a different rate (code) during a billing period. | M |
| | |
| Flat rate billing for outdoor lights is based on a fixed charge per mantle. Different sizes of lights are billed at different rates. Appropriate other charges for rate components may be calculated on this fixed charge (e.g. Rider calculated on a base charge). | M |
| | |
| Other billings are based on usage and metering arrangements. An account may be billed on a combination of energy and demand usage. Calculations vary according to the design of the rates. In the case of time-of use meters, different rates can be applied to the same meter based on different time measurement intervals. | M |
| | |
| The billing demand may be estimated or measured and will have a minimum approved charge value. An example of this type of calculation is the following approved rate for Yukon Electrical. The other N60 utilities may have different calculation types and values. | M |
| (a) The highest metered demand during the billing period. | |
| (b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September. | |
| (c) The estimated demand. | |

| | |
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| (d) 5 kW. | |
| | |
| Some customers have contract agreements for selected service accounts. The contract terms which affect billing are applied to the billing process. This may impact both demand and energy charges. | M |
| | |
| ***3.3.1.3 Record Manual Bill*** | |
| When a bill for a service is manually calculated, the normal billing process is suppressed or replaced. A staff member must be able to manually enter the charge components as calculated. | M |
| | |
| ***3.4 Bill Corrections*** | |
| A customer's current and prior bills may need to be corrected for reasons such as over-estimating consumption or bills calculated using an incorrect rate assignment. | M |
| | |
| Corrections can be performed by: | |
| 1. Manually applying net revenue adjustments when an automatic function is not available. | M |
| 2. Automatic system adjustment applies when previous month's bill factors were incorrect. The billing period may span multiple months. | M |
| 3. Manual re-bill initiated by customer service staff. Calculation is system generated. (i.e. no bill was produced in the first place) | M |
| | |
| An automatic or manual re-bill initiates the normal billing process. | M |
| | |
| **3.4.1 Cancel Billing** | |
| In order to re-bill, the erroneous bills must be cancelled first. The system will also initiate cancellations when billing accounts recording actual meter readings compares the previous bill and finds estimated bill too high. The entire previous month's bill is cancelled and a new bill calculated. This process must be provided for multiple billing periods as accounts may be estimated for several months. Charge components must be credited to appropriate GL accounts. | M |
| | |
| **3.4.2 Adjust Revenue/Consumption** | |
| Revenue adjustments apply to valid bills. The revenue adjustment is used to net adjust any of the charge components in current or prior bills. | M |
| | |
| ***3.5 Produce Invoice*** | |
| North of Sixty invoice customers for the services provided. Invoices are sent to the bill payer identified at account set up time. | M |
| | |
| North of Sixty places high value on an invoice which: | |
| > Communicates clearly to customers and is accurate. | M |
| > Is aesthetically pleasing. | M |
| > Identifies each component of bill calculation by line item with descriptor for each charge e.g. Energy charge, demand charge, riders, taxes, etc. (GST must be shown as a separate value after a subtotal of charges before GST) | M |
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|---|---|
| Note: A 13-month consumption history histogram would be a desirable feature. | O |
| | |
| Given that North of Sixty are largely distribution companies purchasing wholesale power from a generator, it would also be desirable to break out the genco vs. the disco components of the bill. | O |
| | |
| **3.5.1 Produce Regular Invoice** | |
| Regular invoices are produced when the service accounts are billed. Every service account is associated with a meter reading route. The route is read on a particular day of the month. This day is associated with a billing cycle number. The billing cycle number determines the billing cut-off day of the month. | M |
| | |
| The account balance forward less the payments made since the last invoice, current period charge components, adjustments, service charges and deposits are all listed and totaled as the invoice amount. | M |
| | |
| Budget accounts are invoiced a predetermined fixed amount rather than the current period charges as calculated. **(Note: Due to recent GST audit results, consideration should be given to calculating GST based on the predetermined fixed amount rather than the bill calculated on consumption.)** The cumulative amount due to / from a budget customer is disclosed on each month's invoice. | M |
| | |
| The payment due date and potential late payment penalty accessed is also printed on the invoice. The calculation method and value varies among the 3 N60 companies. | M |
| | |
| **3.5.2 Produce Consolidated Invoices** | |
| Some customers have multiple service accounts and prefer to receive one consolidated invoice for all or some of their service accounts. The services accounts are billed in different billing cycles and the regular invoices can be suppressed. | M |
| | |
| The consolidated invoice is produced on a pre-determined cycle agreed upon between the customer and North of Sixty. Any adjustments after the billing date and prior to the invoice date are included in the invoice. | M |
| | |
| **3.5.3 Produce Invoice on Alternate Media** | |
| Customers are provided with detailed billing information on all service accounts on the media requested (i.e. hardcopy or disc). The report can also provide subtotals by cost centre/department as defined by the customer. | M |
| | |
| **3.5.4 Produce Usage Statement** | |
| Customers are provided with system generated summary billing information for each of the previous 12 months. This is typically used by: | M |
| > customers operating in-home businesses as part of their year-end accounting and tax processes. | |
| > Realtors for the package of information for prospective buyers. | |
| | |
| **3.5.5 Maintain Global Messages** | |
| Facilities are provided to enter message text, set priority, and define effective and expiry dates and the selection criteria for the designation of messages. May be different for all companies. | M |
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| Messages must be approved by a pre-defined responsibility such as Corporate Communications prior to being printed. Once approved, no further changes are allowed until the approval is revoked. | M |
| | |
| **3.5.6 Maintain Account Messages** | |
| Facilities to enter account-specific message, which will print on the next invoice and then, are deleted. | O |
| | |
| ***3.6 Maintain Accounts Receivable*** | |
| Each charge component billed will credit or debit the service account accounts receivable. Any cancel, cancel/rebill or manual adjustment will also adjust accounts receivable accordingly. For customers with multiple service accounts, a consolidated accounts receivable must also be maintained. | M |
| | |
| ***3.7 Electronic Posting to General Ledger*** | |
| All revenue, adjustments, tax obligations, service charges, deposits, etc. are accumulated and posted electronically to the appropriate general ledger accounts. | M |
| | |
| A table, which is used to assign the appropriate general ledger account numbers to corresponding items, is maintained. If a general ledger account number is changed, the table must be modified accordingly. | M |
| | |
| The electronic posting should provide sufficient detail for audit as well as resolution of reconciliation problems between the general ledger and the billing system. | M |
| | |
| ***3.8 Manual Posting to General Ledger*** | |
| Sufficient system generated hard copy detail should be available to prepare daily, weekly and/or monthly journal entries not provided by the electronic posting process. It is desirable that manual journal entries are limited and the electronic journal cover all possible requirements. However, manual posting functionality must be available for exceptions. | M |
| | |
| **4. ACCOUNTS RECEIVABLE MANAGEMENT** | |
| Accounts Receivable Management provides the facilities necessary for managing the customer's accounts receivable. It is an important control item at the individual account level as well as at the North of Sixty Companies level. An interface is required to update the appropriate accounts in the GL. | M |
| | |
| The accounts receivable function manages the sum of all due amounts for the balance of an account. The total accounts receivable of all accounts reflects the amount owed to each of the North of Sixty Companies. This data is always managed with controls and audit trails. | M |
| | |
| ***4.1 Transfer Accounts Receivable*** | |
| The accounts receivable transfer function is used to transfer an accounts receivable amount "to" or "from" a customer's account. With each type of transfer there are two options available (i.e.: transfer partial or total charges or credits). | M |
| | |
| Tracer data is created at the transfer "from" and transfer "to" accounts for cross-reference and audit trail purposes. | M |
| | |
| Some reasons for accounts receivable transfers are: | |

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|---|---|
| 1. Customer requested transfer from one account to another. | |
| 2. Customer moving from one location to another. | |
| 3. Charges or credits removed from a customer's account. | |
| 4. Charges or credits transferred to a customer's account. | |
| 5. Payment corrections. | |
| 6. Account balance transferred to write-offs. | |
| | |
| ***4.2 Adjust Miscellaneous Accounts Receivable*** | |
| The miscellaneous accounts receivable function is used to post miscellaneous charges or credits such as connect charges, write-off adjustments, returned cheque charges, penalty charges and special rate refunds to a customer's account. | M |
| | |
| ***4.3 Refund Accounts Receivable*** | |
| The refund accounts receivable function is used to generate a refund when a customer's account has a credit balance as a result of an overpayment, an application of the deposit or a special rate refund. The credit balance of the account is reduced by any existing accounts receivable. | M |
| | |
| The refund may be initiated either at the customer's request or by a North of Sixty Company in the case of a finalized account. | M |
| | |
| This function also provides for the managing of variable interest rates applied to refunds. | M |
| | |
| Refund cheques are produced automatically for all final accounts with credit balances and sent for manual review by staff. | M |
| | |
| ***4.4 Post Payments*** | |
| Post Payments provides the facility necessary to post payments to a customer's account. | M |
| | |
| Payments are automatically posted to specific accounts receivable items such as deposit, service fee, 30, 60, & 90-day arrears, current charge, fees and budget arrears in a predetermined order. This function must provide for manual override. Payments received for consolidated accounts will be allocated automatically to each individual account. | M |
| | |
| The accounts receivable for the customer's account is reduced by the applicable payment amount. If the payment amount is in excess of the balance due, the result will be a credit balance in the customer's accounts receivable. This credit balance may be used to reduce the accounts receivable balance on another account. | M |
| | |
| The post payment facility will prevent the posting of duplicate batch payments. | M |
| | |
| Unpostable batch payments are identified for further investigation and clearance. A suspense account must be available for default posting. | M |
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| ***4.5 Process Returned Cheque*** | |

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|---|---|
| Returned Cheque/pre-authorised payment processing provides the facility necessary to record and maintain returned item data. Typically this includes recording the returned item amount, date, reason and optional service charge. The account receivable must be updated accordingly. | M |
| | |
| When a payment is returned by a financial institution, the account receivable of a customer's account is adjusted to reflect the amount of the bank returned cheque. A service fee may be assessed to the customer's account depending on the reason for return. | M |
| | |
| ***4.6 Accounts Receivable Ageing*** | |
| Accounts Receivable Ageing provides the facility necessary to age and maintain accounts receivable items such as 30, 60, & 90-day arrears and fees for all accounts. An analysis of each customer's account receivable at cycle billing determines the ageing process. | M |
| | |
| ***4.7 Calculate Late Payment Penalties*** | |
| This facility provides the means to assess, charge, or waive late payment penalties. Penalty is calculated based on the penalty charge base (aged receivable balance) less all payments posted as of statement date. If the outstanding balance of an account is not cleared until after the payment due date, a penalty charge may be applied. Late payment charges are waived due to automatic adjustments or manual adjustments. The account receivable for the customer's account is increased by the penalty amount charged. Penalties must be reported to a separate GL revenue account and may differ in both calculation and rate between the N60 companies. | M |
| | |
| ***4.8 Maintain Payment and Credit History*** | |
| A customer's payment history must be retained on the system for a pre-determined period of time even if status of the account changes from active to closed: | M |
| > Support process of determining the security deposit amount due for a new account application. | |
| > Reduce bad debt write offs by limiting credit to customers with a poor payment record. | |
| | |
| ***4.9 Electronic Posting To General Ledger*** | |
| This function provides the facility necessary to post accounts receivable items such as payments, refunds, returned cheques and write-offs to the general ledger. | M |
| | |
| A table, which is used to assign the appropriate general ledger account number, is maintained. If a general ledger account number is changed, the table must be modified accordingly. | M |
| | |
| ***4.10 Manual Posting To General Ledger*** | |
| Sufficient system generated hard copy reports must be available to prepare daily, weekly and/or monthly journal entries covering the above noted transactions. | M |
| | |
| **5. GENERAL LEDGER MANAGEMENT** | |
| General Ledger Management provides the facilities necessary for managing North of Sixty Companies financial transactions. All companies maintain a separate General Ledger. | |
| | |

| | |
|---|---|
| The general ledger function manages all journal entries received from other systems. This function produces analytical and financial reports. This data is always managed with controls and audit trails. | |
| | |
| ***5.1 Manage Chart of Accounts*** | |
| The chart of accounts function is used to establish and de-activate chart of account codes. | M |
| | |
| ***5.2 Manage Cost Centers*** | |
| The cost centres function is used to establish and de-activate cost centre codes. | M |
| | |
| ***5.3 Proof Journal Entries*** | |
| The proof journal entries function is used to validate journal entries and to generate error reports about the journal entries received from sub-systems. | M |
| | |
| The errors are typically addressed by the financial accounting staff in consultation with the staff responsible for the originating system. | |
| | |
| ***5.4 Post Journal Entries*** | |
| The post journal entries function is used to update valid journal entries received from sub-systems. | M |
| | |
| ***5.5 Produce Financial Statements*** | |
| The produce financial statements function is used to produce the following reports: | M |
| 1. Income statement. | |
| 2. Balance sheet. | |
| 3. Sources and uses of funds statement. | |
| | |
| These reports can be produced in various styles: | |
| 1. Comparative year to year or year to budget. | |
| 2. At various levels of detail and/or consolidation. | |
| | |
| These reports are used: | |
| 1. For financial performance management. | |
| 2. As input to the corporate financial consolidation processes. | |
| | |
| ***5.6 Produce Analytical Reports*** | |
| The produce analytical reports function is used to produce the reports that support the following processes: | M |
| 1. Account analysis. | |
| 2. Balance and control of the general ledger. | |
| | |
| The styles of reports can include: | |
| 1. Tabular. | |
| 2. Chart. | |
| | |

| | |
|---|---|
| **6. CREDIT AND COLLECTIONS MANAGEMENT** | |
| Credit and Collections Management provides the facilities necessary for managing activities related to deposits, credit tracking and collection actions for delinquent customer accounts. This facility will enable North of Sixty Companies to equitably carry out established policies with minimal manual intervention. Must provide a facility for recording customer payment arrangements. Must also provide a mechanism to exclude/suspend customer accounts from collection activities based on customer type or needs. Requirements may vary between companies and communities. | M |
| | |
| ***6.1 Deposit Maintenance*** | |
| Deposit Maintenance provides the facilities necessary for managing, refunding and transferring of customer's security deposits. | M |
| | |
| **6.1.1 Manage Deposits** | |
| This function will provide the facilities necessary for recording and maintaining all pertinent information about deposits and the depositor. | M |
| | |
| A deposit may be required when a customer applies for service or as a result of credit review at collection order time. The deposit will be held in trust by North of Sixty Companies until the customer establishes a satisfactory credit rating. | M |
| | |
| The system will automatically calculate a suggested deposit amount based on three (3) times the account's estimated average monthly bill amount. A human decision is required to determine the deposit requested based on the customer's credit history. This amount may differ from the suggested amount. The requested deposit is applied to the customer's account and is billed to the customer. | M |
| | |
| The system will prompt for action if a deposit requires review for refund or increase based on credit and payment history. | M |
| | |
| **6.1.2 Calculate Interest** | |
| This function allows for the automatic calculation of accrued interest on security deposits by the system. The system will apply interest earned on the deposit to the account receivable amount as directed. | M |
| | |
| The interest rates to be applied to deposit refunds will vary on a regular basis. The system must have a facility to modify the interest rate. | M |
| | |
| **6.1.3 Refund Deposits** | |
| This function allows for the refunding of security deposits and interest earned to date. | M |
| | |
| Deposit is refunded to a customer with interest when: | |
| 1. The customer's account is finalized. | M |
| 2. A satisfactory credit rating has been established based on payment habits. | M |
| 3. At the customer's request with staff approval. | M |
| | |
| Deposit can be refunded in three ways: | |
| 1. Applied as a credit to the customer's account receivable. | M |

| | |
|---|---|
| 2. A system generated refund cheque upon anniversary date based on specified credit/payment history | M |
| 3. A system generated refund cheque if a credit balance remains after account is finalized. | M |
| | |
| **6.1.4 Transfer Deposits** | |
| Deposits can be transferred from one account to another in whole or part. Deposit transfers can also occur as result of the customer moving from one location to another. | M |
| | |
| ***6.2 Credit Maintenance*** | |
| Credit Maintenance provides the facilities necessary, for the customer applying for service, to establish credit, or for an existing customer to re-establish credit. This facility will support credit tracking, recording of guarantees and the maintenance of energy assistance programs. | M |
| | |
| **6.2.1 Credit Tracking** | |
| This process provides the means to analyze a customer's accounts receivable and credit status. This will determine the eligibility of the credit rating update and actions to be taken in case of delinquency. | M |
| | |
| The credit rating upgrading or downgrading formula is based on past payment habits and collection activities. | M |
| | |
| **6.2.2 Record Guarantee** | |
| This function allows for the maintenance of all pertinent information regarding the guarantee amount and the guarantor. | O |
| | |
| The guarantee amount may be used to reconcile the customer's account in the case where there is default of payments. | O |
| | |
| ***6.3 Collection Maintenance*** | |
| Collection Maintenance provides the facilities necessary to review delinquent accounts and perform the necessary follow up. This facility allows for the automatic and/or manual production of final disconnect notices, production of collection orders, managing credit extensions and managing write-offs. Adequate system space must be available to record historical information on actions performed both manually and system generated. The system must allow for manual control of a customer's case. Printing options must be available for different types of collection orders/letters. | M |
| | |
| **6.3.1 Produce Final Disconnect Notices** | |
| In a predetermined time period after a delinquent customer's last invoice, an analysis is performed to verify if a payment was received. If still delinquent, a Final Disconnect Notice will be produced advising the customer that service will be discontinued if the account is not paid. This function allows for the creation of different case types based on credit and payment history as well as customer class. Customized notices can be created based on case type. Collection actions may be suppressed manually or by certain conditions on the account, such as a payment arrangement. This function must allow for customized parameters to be set for each service area. | M |
| | |
| **6.3.2 Produce Collection Orders** | |

| | |
|---|---|
| If a customer has not cleared the delinquent balance within the specified number of days after issuing the final disconnect notice a collection order is prepared automatically based on preset parameters. The collection order is printed for the necessary field action follow-up. Different types of collection orders are necessary depending on community location and weather conditions. | M |
| | |
| **6.3.3 Record Payment Arrangements** | |
| This function allows North of Sixty to arrange a credit extension agreement with a delinquent customer. Agreements will be made according to length of time to pay, amounts to be paid, eligible charges, etc. This function allows adequate system space to record data regarding payment arrangements and automatically produces a review if arrangements are not kept. The system will suspend all collection actions during this time. | M |
| | |
| **6.3.4 Manage Write-offs** | |
| This process provides the facilities necessary to administer written-off accounts. | M |
| | |
| All accounts with an unpaid balance for a period longer than a specified number of days after final invoice preparation are automatically written-off against the allowance-for-bad-debts account. Must provide facility to force account to write off as required. | M |
| | |
| The written-off account is transferred into the uncollectible or unclaimed monies file after a specified period of time. Historical record retained for audit purposes. | M |
| | |
| Any finalized account with a zero balance or any account written-off will be retained for historical reference. Purging of records will be managed as required. | M |
| | |
| The original account number is retained as tracer data. Subsequent payments are accepted for written-off accounts and are reported separately for accounting purposes. | M |
| | |
| Unpaid final invoices, after a specified number of days, maybe turned over to a collection agency for possible collections. This process will normally be system controlled, but must allow for manual control. | |
| | |
| ***6.4 Electronic Posting to General Ledger*** | |
| This process provides the means to automatically post deposit and write-off amounts to general ledger account. | M |
| | |
| A table, which is used to assign the appropriate general ledger account number, is maintained. If a general ledger account number is changed, the table must be modified accordingly | M |
| | |
| **6.4.1 Manual Posting to General Ledger** | |
| This process must provide sufficient system generated hard copy detail to prepare the necessary journal entries to post payments and write off amounts to general ledger. | M |
| | |
| **7. PAYMENT REMITTANCES MANAGEMENT** | |

| | |
|---|---|
| Payment Remittances Management provides the facilities to record payments, credits/debits and returned cheques for the purpose of updating customer and company accounts. | M |
| | |
| ***7.1 Process Remittances*** | |
| Payment Remittances provides the facilities to process payment activities through the following sub-systems. These sub-systems allow for the processing of payments, credits/debits and returned cheques. | M |
| | |
| Remittance Processors: Hardware and software to process large volumes of payments and adjustments received through the mail and from Financial Institutions. | O |
| | |
| Online Cash Registers: Hardware and software to process medium volumes of payments and adjustments received at authorized payment locations. | M |
| | |
| Data Entry Terminal: Terminals and software to process small volumes of payments and adjustments received at authorized locations. | M |
| | |
| Using these devices means customer account validation is performed either on-line or during the batch update process. | M |
| | |
| Types of remittances will include: | M |
| 1. Cash. | |
| 2. Cheques. | |
| 3. Pre-authorized bank payments – EFT (system must create file to interface with banking system software). | |
| 4. Debit card. | |
| 5. Credit card. | |
| | |
| Other types of remittances may also include: | O |
| 1. Pre-authorized bank payments from credit card. | |
| 2. E-Billing (both “biller-direct” or third party bill consolidators.) | |
| | |
| **7.1.1 Process Payments** | |
| This function allows for the processing of the following payments: | M |
| | |
| 1. Regular utility payments that will credit the customer's account receivable. | |
| 2. Non-utility payment to the financial system general ledger (i.e. transformer rentals, purchase of power poles, etc.). | |
| 3. non-utility charge to the financial system general ledger (i.e. bank charges, cash shortages) | |
| 4. Non- utility payment for non-electric sales accounts (i.e. cookbooks, hats, etc.). | |
| | |
| All details pertaining to the payment, such as source number, receipt number, type of payment, location of where the payment was made, etc., will be recorded. | M |
| | |

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|---|---|
| Payments can be directed to specific accounts receivable items such as deposit, service fee, 30, 60, 90-day arrears, current charge, budget arrears, etc. | M |
| | |
| **7.1.2 Process Credit/Debit Adjustments** | |
| This function allows for the processing of a manual entry to adjust a payment amount or to reverse an incorrect entry. | M |
| | |
| **7.1.3 Process Returned Cheques** | |
| This function provides the facilities necessary to process returned items that are returned from a financial institution and must be charged back to the customer's account. A service charge must be optional based on reason for returned item. | M |
| | |
| ***7.2 Communicate With Remittance Sub-Systems*** | |
| This function will provide the facilities necessary to interface with external systems for processing payments. This will include pre-authorized payments and payments made at banks. It may also include credit/debit card payments and electronic funds transfers. | M |
| | |
| ***7.3 Balance And Control Remittances*** | |
| Balance and Control Remittances provide the facilities necessary to reconcile remittances processed in the billing system to funds recorded in the general ledger bank account. | M |
| | |
| Each collecting office currently balances daily payment (Daily Cash Report – DCR) totals to their bank deposit. These totals are then summarized and reconciled to the general ledger and the monthly bank statement. | M |
| | |
| Various balancing and control reports are produced in a timely manner to support this function. | M |
| | |
| **8. METER MANAGEMENT** | |
| The Meter Management function manages all in-stock and in-service meters. In-stock meters are inventory at the Meter Shop or held at various Service Points while in-service meters are installed at the customer locations, at company facilities, etc. The meter sample testing and seal extension programs are currently managed by ATCO Electric and it is anticipated that this service will continue to be provided by AE. | |
| | |
| ***8.1 Purchase Meters*** | |
| The meter purchase function is used for adding new meters to the meter inventory. A standard type size format indicates meter characteristics. A number is added to the type size indicator to create a unique identifier for each meter. All inventoried meters must be recorded in ATCO-CIS to support the functions performed by ATCO Electric. | M |
| | |
| Meters can be purchased individually or in large quantities. | M |
| | |
| ***8.2 Maintain Meter/Device Details*** | |
| This function will maintain the characteristics for the various meter and device types and must accommodate automatic meter reading devices. | M |
| | |

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|---|---|
| The information recorded for meters includes the meter number, assigned company number, manufacturer's serial number, purchase date, cost and other characteristics associated for that type of meter. Company equipment installed at the premise (CT's & PT's) must be recorded in the system. | M |
| | |
| Bar Coding could be used to facilitate the recording of meter and device details directly from the manufacturer. | O |
| | |
| ***8.3 Track Meters/Devices In Service and In Stock*** | |
| This function will track the movement of meters in-service and in stock/inventory. It will also record all pertinent information on the meters such as purchase price and date, internal multiplier, demand high scale, number of dials, current/potential transformer requirements, next expected test year, etc. | M |
| | |
| Meter purchases will initially put all meters into stock while meter removes and changes will move meters from in-service to stock/inventory. | M |
| | |
| Meter installs and changes will record the movement of meters from meter stock/inventory to an in-service account. The facility will be in place to track all meters that are installed at a particular location. This function must allow only one active unique location per meter to prevent duplicate premises assigned to one meter. | M |
| | |
| This function will also track the movement of a meter from the date purchased to the date retired. It will also provide for recording a meter back into stock on an immediate basis. | M |
| | |
| ***8.4 Maintain Meter/Device Relationships*** | |
| This function will provide the facility to record devices that are attached to specific meters. This information will be useful for reporting the location of recording devices used by Load Research, etc. | M |
| | |
| ***8.5 Sample Meters*** | |
| Meter sampling is a process required under the Electricity Inspection Regulations Act (Measurements Canada) to randomly select meters for the purpose of verifying the accuracy of those meters. | M |
| | |
| The facility will be in place to generate recall orders for selected meters from the sample group. | M |
| | |
| ***8.6 Test Meters*** | |
| The meter test function is used to record test results. | M |
| | |
| Meter tests, as a result of new purchases, periodic testing or customer requests are posted to the in-service meter or in-stock meter. | M |
| | |
| History will be retained on all test results (i.e. dates, proof readings, and follow-up actions). | M |
| | |
| ***8.7 Retire Meters*** | |
| The meter retirement function is used for retiring meters from the in-stock meter inventory. As these meters are no longer serviceable & tracking is no longer required. | M |

| | |
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| | |
| All meters that are to be retired must be removed from active service and returned to stock prior to retirement. | M |
| | |
| ***8.8 Balance And Controls*** | |
| All meter purchase transactions, meter tests, and meters retired, will be controlled by the meter department and held in an equipment group in ATCO-CIS | M |
| | |
| In the case of meters purchased, the purchased date and purchase order number will be retained as part of the purchase transaction. | M |
| | |
| When purchasing mass quantities of meters, a batch header is used to verify the number and total cost of meters within each batch. | M |
| | |
| Meter inventory is reconciled by manually counting the meters in stock and verifying to the number of meters recorded within the system. | M |
| | |
| Meter seal information will be recorded as required to track possible energy diversion. | M |
| | |
| **9. METER READING MANAGEMENT** | |
| Meter Reading provides the facilities necessary to accurately and systematically track consumption at each service after a meter is installed. The ITRON Premier Plus 4 Genesis Portable Computer (G5) is in use in the field. Computer Aided Dispatch (CAD) currently used as interface between PP4 server and billing system. CAD will be retired at end of 2007. Replacement system being developed to be in-service by 2008. | |
| | |
| ***9.1 Route Maintenance*** | |
| Route Maintenance is used to maintain the route and read sequence assignments and to ensure that the number of meters assigned to each route is reasonable. | M |
| | |
| Routes may be split or combined. Re-routing is the change of the assigned meter reading route number. Each meter in the route must be assigned a unique route sequence number. Re-sequencing is required when changes are required in the assignment or as a result of re-routing. Functionality for mass changes must be available. | M |
| | |
| ***9.2 Schedule Meter Reading*** | |
| Meter reading schedules must be produced for meters to be read on-cycle. Readings must be co-coordinated with billing cycles. Off-cycle readings (event driven, i.e. special reads, finals, turn-ons, etc.) must be allowed for billing purposes. This function must allow for the excluding of specified routes and/or individual accounts. This function must allow for different reading schedules by company to accommodate unique holidays etc. | M |
| | |
| ***9.3 Record Meter Reading*** | |
| The meter reading function records consumption readings and other meter reading data for each service. Meter readings may be entered at any time during the month and a facility must exist to record the interim readings for historical reference. | M |

| | |
|---|---|
| Meter reading will be used to complete turn-on/turn-off orders (i.e. readings that have same date as the service request). | M |
| | |
| High/low consumption validation for consumption and demand is performed when the reading is captured by the GPC and at bill calculation time. A report of exceptions must be produced for follow up action. | M |
| | |
| ***9.4 Communicate with Meter Reading Sub-Systems*** | |
| This function provides for the interface to external meter reading sub-systems (i.e. ITRON, AMR, etc.). | M |
| | |
| ***9.5 Produce Performance-Statistics*** | |
| Route statistics are produced to assist in managing route assignments and route sites. This includes the number of meters to be read, by type of account in each route, the number and percentage of actual reads, number of skips and the actual read time of each route. | M |
| | |
| Statistics are also produced to monitor various performance standards associated with reading meters data. (I.e. number of meters read, time required to read a route, etc.). | M |
| | |
| ***9.6 Balance And Controls*** | |
| The meter reading route header precedes each batch of meter readings to verify the number of meter readings within that batch. Meters that are not actually read must be identified for follow-up action. | M |
| | |
| The number of transactions transmitted through meter reading devices must balance to the number of transactions received by the mainframe in an upload/download situation. | M |
| | |
| **10. ORGANIZATION SUPPORT** | |
| Organization Support provides the facilities necessary to support activities related to identifying customer growth and energy conservation. | |
| | |
| Departments, within North of Sixty, that use customer-billing data for additional activities, perform these functions. This data typically includes number of customers by rate class, sales by service area and rate class, average consumption by customer, etc. Pricing and Engineering have been identified as the major areas using this data. This will assist them in performing their business functions. | |
| | |
| ***10.1 Pricing Support*** | |
| Pricing Support provides the facilities necessary to support rate development, pricing analysis, conservation services and product support. | O |
| | |
| **10.1.1 Rate Development** | |
| This function will provide the facilities necessary to perform rate comparisons for individual customers or various rate classes. System must have ability to provide a data file to interface with software used by rate design group. | M |
| | |
| This will enhance the capabilities to supply the customer or a group of customers with the best applicable rate. | M |

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| **10.1.2 Marketing Analysis** | |
| This function will provide the facilities necessary for recording and maintaining customer profiles. This will serve to identify potential new customers and retain customer information if the customer becomes active. | O |
| | |
| **10.1.3 Conservation Services** | |
| This function provides the facilities necessary to support demand side management. This includes promoting energy efficient products, and the analysis of the facilities owned by customers at their own locations. | O |
| | |
| ***10.2 Engineering Support*** | |
| The Engineering Support function will provide for the recording and maintenance of company owned facilities and their locations. It will also provide their distribution relationship for load research and distribution planning. | O |
| | |
| ***10.3 Geographic Coding*** | |
| This function will provide the capability to identify all company facilities and their grid relationships. This will serve to bridge the information into the Automatic Mapping & Facilities Management System (AM/FM). | O |
| | |
| **11. QUERY/REPORTING** | |
| Query/Reporting provides the facilities necessary to support routine and ad hoc requests for information. | O |
| | |
| ***11.1 Routine Query Support*** | |
| Query support provides the facilities necessary to search for information on customers by account number, civic address, service locations, last name, business name, phone number, mailing address, second account name holder, etc. | M |
| | |
| ***11.2 Ad Hoc Query Support*** | |
| Query support provides the facilities necessary to provide information not routinely required such as a search of accounts by SIC code, consumption levels, rate code, business name, location, etc. | O |
| | |
| ***11.3 Routine Reporting Support*** | |
| Routine reporting support provides the facilities necessary to regularly answer predictable questions about selected groups of items such as routes and sequences, budget accounts, pre-authorized payment customers, etc. | M |
| | |
| The routine reports are a set of reports, which can be run with user selection input at any time. Historical reports must be stored and made available for printing for a period of time based on the anticipated need for access/reprinting. | M |
| | |
| ***11.4 Ad Hoc Reporting Support*** | |
| Ad hoc reporting support provides the facilities necessary to easily construct queries, which answer questions about individual or selected groups of items such as accounts by SIC code, consumption levels, rate code, business name, location, etc. | O |
| | |
| The ad hoc reports are created using a tool kit, which can be run with user selection input at any time. Crystal reports are the I-Tek standard at this time. | |

| | |
|---|---|
| **12. SYSTEM SUPPORT** | |
| This function provides support and general-purpose services that are utilized by other functional areas of CIS. It includes capabilities such as task queuing through use of the electronic work queue, task re-directing, ad hoc reporting, on-line report viewing and selection, local printing, message broadcasting, etc. | |
| | |
| ***12.1 Maintain System Security*** | |
| System Security provides system administrators the facilities to control system access. For each user ID, it includes functions such as granting system access, defining the boundary of data access and administering levels of access, such as inquiry, update, control, approval, etc., for each business activity. The system must have the capability of restricting access by user to accounts between companies held in a single database. | M |
| | |
| ***12.2 Maintain System Parameters*** | |
| This function provides the user system administrator the facilities to administer all system parameters. | M |
| | |
| System parameters include general operational and functional specific parameters. Some parameters apply to North of Sixty as a whole and others vary between service areas. | M |
| | |
| General operational parameters, such as billing schedule, meter reading schedule, due dates, rate tables, global messaging, plant and community tables, etc., control the day-to-day operations of the system. These parameters must be flexible to meet the specific needs of the individual company even though the accounts are held in a single database. | M |
| | |
| Functional specific parameters are non-static parameters, which support the business functions. Some examples are the validation criteria for data elements, the interest percentage of deposit refund, the default credit rating for new customers, the late payment penalty charge percentage, the number of days after final invoices for reminder notices, etc. These parameters must be flexible to meet the specific needs of the individual company even though the accounts are held in a single database. | M |
| | |
| ***12.3 Balance System Controls*** | |
| Balance and control procedures are established to ensure the system and data integrity. | M |
| | |
| Balances and controls are performed by the system at individual function/subsystem. Out of balance conditions are identified and reported and prompt for action notifications are generated. A procedure manual must be provided defining error reasons and possible solutions. The balance detail reports are also available for on-line viewing. | M |
| | |
| The balance procedures include monetary and control item count balancing. The global control procedures are in place to enforce system operation controls; data validation criteria, system parameters controls, and security access privileges, system activity controls and error correction controls. | M |
| | |
| ***12.4 System Reporting*** | |
| System Reporting provides the facilities to request for ad hoc and production reports and to view reports on-line with the option to print at designated locations. Error and exception reports will be minimized through task queuing. | O |

| | |
|---|---|
| ***12.5 Audit Trail*** | |
| This function provides an audit trail of data added, changed, deleted and transferred. A record of the date, time and the person responsible is maintained for each update to the data. Record of all daily activities including all cash transactions, billing input, adjustments, etc. must be provided on suitable medium such as CD or microfiche. | M |
| | |
| ***12.6 Manage Data*** | |
| The Manage Data function provide the facilities to archive on-line data off-line, recall off-line historical data, purge historical data exceeding retention criteria, recover data after system failure and apply mass updates to data. A facility must be in place to store archived data as system is purged. Currently microfiche is used but is not the preferred medium of choice. | M |

# APPENDIX B – Technical Feasibility Requirements

| | |
|---|---|
| TR1-Technical Architecture | Ability to comply with and integrate with ATCO's preferred technical Architecture |
| TF2-Configuration of workstations | Ability to run on standard hardware and software platforms in use within ATCO<br>Ability to run in a managed workstation infrastructure |
| TF3-Configuration of Application Servers | Ability to install and run on ATCO's standard application server hardware and software platforms<br>Ability to maintain support for existing and new versions of application server operating system |
| TF4- Configuration of Database and Database Server | Ability to install and run on ATCO's standard database server hardware and software platforms<br>Provides adequate information that database can be supported by existing staff |
| TF5- Shared Hosting Environment | Provides adequate protection within the layers the allows this application infrastructure to execute in a shared resource model |
| TF6- Systems Integration | Provides an interface into the application logic that can be called by other applications<br>Provides an interface into the data layer that can be queried by other applications |
| TF7- Security | Ability to integrate into existing security infrastructure<br>Supports the use of a common user repository outside of the application<br>Ability to conform to existing security policies and controls |
| TF8- Redundancy, Backup and Recovery | Ability to integrate into existing backup and recovery tools and processes<br>Ability to integrate with existing Disaster Recovery tools and processes<br>Ability to run in a fault tolerant mode |
| TF9- Performance and Monitoring | Provides a standard interface or set of tools to monitor health of the application |
| TF10- Network Communication | Uses standard protocols and technologies for communication between layers of the application<br>Optimized for use in low bandwidth infrastructures |
| TF11- Configuration, Installation, Distribution and Licensing | Provides standard approaches to installation and configuration of the application on all platforms<br>Provides the tools or flexibility for ATCO to remain license compliant |
| TF12- Change Management | Vendor provides a well established and reasonable release cycle for updates<br>Application updates can conform to existing ATCO change management guidelines |

**North of 60 CIS project evaluation**

**Scenario 3 - ATCO CIS**

**Option 4 Description**

Cost Impact

**Assumptions:**

1 Financial Parameters

Distribution Incremental Capital Structure and Cost

| | Return | Ratio | B.T. Cost | A.T. Cost |
|---|---|---|---|---|
| Debt | 6.60% | 52% | 3.43% | 3.43% |
| Preferred | 0.00% | 0% | 0.00% | 0.00% |
| Common | 9.25% | 48% | 6.78% | 4.44% |
| TOTALS | | | 10.21% | 7.87% |

Depreciation Rates:

| | |
|---|---|
| Transmission | **0.00%** |
| Distribution | **0.00%** |
| Communication | **0.00%** |
| "D" Other | **10.00%** |

Source: D. Business Case Assumptions

| Income Taxes and Escalation | 2006 | 2007 | 2008 | 2009 | >= 2010 |
|---|---|---|---|---|---|
| Federal and Provincial Income Tax | | | 34.50% | 34.00% | 33.00% |
| Escalation | | | | | |
| Capital (T&D) | | 0.0% | 0.0% | 0.0% | 0.0% |
| O & M (T&D) | | 5.0% | 5.0% | 5.0% | 5.0% |
| (50/50 blend of rate of labour & materials) | | | | | |

Source: 2008 Business Case Assumptions — 2008 Income Taxes: 34.50%

2 All analysis are based on 10 years of costs.

3 Embedded distribution capital and O&M costs are not considered in analysis.

4 Base Year: 2008
In-Service Date: 2008

5 Incremental Capital Spending:

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual Escalation Factor | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | |
| Compounded Escalation Factor | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | |
| ISD Index | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| Enter capital expenditures in 2008 dollars | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 |
| **Distribution Other** | $1,488,207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| (inflated) | $1,488,207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Capital Cost Before AFUDC (2007$) | $1,488,207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Capital Cost Before AFUDC (Nom$) | $1,488,207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

**Distribution Other**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Opening Balance | | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 |
| Capital Addition | $1,488,207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| RATEBASE | $1,488,207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

**Total Rate Base**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Opening Balance | $0 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 | $1,488,207 |
| Capital Addition | $1,488,207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| RATEBASE | $1,488,207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

7 Incremental Operation and Maintenance Costs:

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual Escalation Factor | 1.050 | 1.050 | 1.050 | 1.050 | 1.050 | 1.050 | 1.050 | 1.050 | 1.050 | 1.050 | 1.050 | 1.050 |
| Compounded Escalation Factor | 1.050 | 1.103 | 1.158 | 1.216 | 1.276 | 1.340 | 1.407 | 1.477 | 1.551 | 1.629 | 1.710 | 1.796 |
| ISD Index | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

**O&M Manual Input (2008$)**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Other O&M | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $0 |
| | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $493,207 | $0 |

**Escalated Manually Input O&M (Nom$)**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Other O&M | $517,868 | $543,761 | $570,949 | $599,497 | $629,471 | $660,945 | $693,992 | $728,692 | $765,126 | $803,383 | $843,552 | $0 |
| | $517,868 | $543,761 | $570,949 | $599,497 | $629,471 | $660,945 | $693,992 | $728,692 | $765,126 | $803,383 | $843,552 | $0 |

## Vendor 1

This table rates the vendors ability to meet the requirement out of the box.

Points on evaluation criteria
0-Optional
1-required low
2-required medium
3-required high
4-mandatory

1 = Not answered, or doesn't meet requirement
2 = Partially meets requirement, on the low end
3 = Partially meets requirement
4 = Partially meets requirement, on the high end
5 = Fully meets or exceeds requirement

| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| Section A. Business Requirements | | | | | | | |
| BR-1 Core Structure | | | | | | | |
| 1 | Ability to separate data by company, and allow company specific rules and security, in a cost effective, efficient manner. | M | 4 | 1 | 4 | 20 | Software could not offer separation of four companies into one database. Instead data would be manipulated to achieve a quasi four company solution, which didn't offer secure separation by company. |
| BR-2 Customer Management | | | | | | | |
| 2 | Ability to capture and display owner contact information, ensuring prescribed procedures for assigning responsibility. | M | 4 | 2.5 | 10 | 20 | Software required modification to notify Customer Service Representative that a landlord or owner exists. I.e.. could not address the requirement out of the box. |
| 3 | Ability to retain existing customer account number and meter number. | R3 | 3 | 3 | 9 | 15 | The old CIS account number would be converted to a 'location #', and would have been for information purposes only. The customer # (i.e.. account) would be populated a random number by conversion. |
| BR-3 Service Order Management | | | | | | | |
| 4 | Ability to provide different service order templates, and the conditions under which the system will initiate the prompt for follow-up action orders. | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 5 | Ability to print service orders to local N60 offices. | M | 4 | 2 | 8 | 20 | Software required modification to meet the business requirement. |
| BR-4 Billing Accuracy and Functionality | | | | | | | |
| 6 | Ability to calculate an Initial Bill | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |

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| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| 7 | Ability to calculate an Final Bill | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 8 | Ability to calculate a normal bill | M | 4 | 4 | 16 | 20 | Software required modification to calculate a 'monthly' bill and allow different demand calculations (ratchets) for each N60 company. |
| 9 | Ability to perform multi-month calculations | M | 4 | 3 | 12 | 20 | Software required modification to calculate multiple fixed charges for multi-month bill. (e.g. System unable to deal with multiple month cancel rebills.) |
| 10 | Ability to support Consolidated Accounts (cycles not =). | M | 4 | 3 | 12 | 20 | Software required modification to support Consolidated Billing. |
| 11 | Ability to support Statement Accounts (cycle is =). | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 12 | Ability to perform budget billing. | M | 4 | 4 | 16 | 20 | Software required modification to automate budget and settlement process. |
| 13 | Ability to prorate charges. | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 14 | Ability to calculate charges to un-metered accounts. | M | 4 | 3 | 12 | 20 | Software required modification to handle estimated consumption and demand for unmetered charges. |
| 15 | Ability to calculate charges for Outdoor Lights. Billing and Reporting | M | 4 | 3 | 12 | 20 | Software required modification to report outdoor light sales consumption. |
| 16 | Ability to Cancel/Rebill historical charges. | M | 4 | 3 | 12 | 20 | Software required modification to automate cancel/rebills. Currently labour intensive process. |
| BR-5 Automation | | | | | | | |

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| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| 17 | Automation of Bill Process & Report Generation. | M | 4 | 1 | 4 | 20 | Software offered no billing automation to process cycle billing and report generation. Would have resulted in increased N60 staff. (ATCO CIS offered fully automated solution) |
| 18 | Ability to interface with external systems and produce data files. | M | 4 | 2 | 8 | 20 | Software required modification to interface with AMR/TWACS, Itron and ATCO CIS (for Equipment). |
| BR-6 Accounts Receivable Management | | | | | | | |
| 19 | Ability to transfer, adjust, refund, and post A/R. | M | 4 | 4 | 16 | 20 | Given vendors four company database solution, ability to accurately report or post A/R was questionable. (e.g. When one N60 company accept a payment on behalf of another N60 company.) |
| BR-7 General Ledger Management | | | | | | | |
| 20 | Ability to interface with Financial systems, and provide tools for reconciliation between sub-ledger (CIS) and general ledger. | M | 4 | 3 | 12 | 20 | Vendor solution interfaced with ATCO General Ledger Application via MS Great Plains, rather than directly to ATCO's G/L Application. Four company database solution also reduced this rating. |
| BR-8 Credit and Collections Management | | | | | | | |
| 21 | Ability to manage deposits, credit tracking and collection actions for delinquent customers. Includes write-off. | M | 4 | 3 | 12 | 20 | Vendor solution required modification to reprint collection orders, and couldn't accommodate different deposit interest calculations for each company. Deposit refunds required significant manual effort. |
| BR-9 Payment Remittance Management | | | | | | | |

## Vendor 1

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5 = Fully meets or exceeds requirement

| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| 22 | Ability to process payments - Online and Cashiering Functionality | M | 4 | 3 | 12 | 20 | Software required modification to handle application of credits over multiple accounts and additional payment source codes. |
| 23 | Ability to support preauthorized payment plans, either from customer bank account or credit card. | O | 0 | 5 | 0 | 0 | Vendor indicated they could meet requirements. |
| BR-10 Meter Management | | | | | | | |
| 24 | Ability to manage all in-stock, and in-service meters. Includes purchases, maintain meter details, track meters, test, and retire. | M | 4 | 3 | 12 | 20 | Software required modification to interface with ATCO CIS and modification to enter certain metering components. |
| BR-11 Meter Reading Management | | | | | | | |
| 25 | Ability to support current interfaces to Itron, via Computer Aided Dispatch. Ability to interface to AMR (TWACS). | M | 4 | 2 | 8 | 20 | Software required modification to accept reads and meter reader notes from TWACS and Premiere Plus. |
| 26 | Ability to estimate demand and energy reads. | M | 4 | 3 | 12 | 20 | Software required modification to determine estimated demand, estimates from interim reads, and variable demand calculations, by company. |
| BR-12 Route/cycle Management | | | | | | | |
| 27 | Ability to manage route and cycle scheduling and organization. | M | 4 | 3 | 12 | 20 | Software offered no automation for scheduling downloads and file transfers of route and cycle information. |
| BR-13 Query and Reporting | | | | | | | |
| 28 | Ability to generate reports and queries to support the organization (both predefined and adhoc). This item would support queries needed to identify customer growth and energy conservation, plus rates and forecasting activities, etc. Includes canned and ADHOC reporting | M | 4 | 2.5 | 10 | 20 | Software required modification to develop all reports and automate. |

## Vendor 1

This table rates the vendors ability to meet the requirement out of the box.

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5 = Fully meets or exceeds requirement

| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| BR-14 System Support | | | | | | | |
| 29 | Ability to perform edits during batch jobs and on-line entry. e.g.. Valid community/rate combinations, high/low edits, etc | M | 4 | 1 | 4 | 20 | Software required modification to develop edit and validation controls. |
| 30 | Ability to perform rate testing on global rate components (e.g. GST), by rate code, by community, by company, etc. using consumption levels or specific accounts loaded into testing environment. Ability to update rate codes/components, and elevate to production environment. | M | 4 | 3 | 12 | 20 | Software required modification to support variable rate components for demand ratcheting, deposit interest, and late pay fee calculation. |
| 31 | Ability to provide an audit trail of data added, changed, deleted and transferred. A record of the date, time and the person responsible is maintained for each record change. | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 32 | Ability to provide a data file to I-Tek to interface with printing software to produce regular customer bills as well as collection correspondence. | M | 4 | 3 | 12 | 20 | No interface was available to transport the statement data file to ATCO's bill print software. |
| BR-15 Usability | | | | | | | |
| 33 | Ability to offer Generic Screen presentation. | R3 | 3 | 4.5 | 13.5 | 15 | Multiple windows were needed to view one business function. |
| 34 | Ability for users to define fields. | R3 | 3 | 4 | 12 | 15 | Limited capability for user to define fields. |
| 35 | Ability for users to easily use the system. | R3 | 3 | 5 | 15 | 15 | Met business requirement. Score equal to ATCO CIS. |
| 36 | Ability to easily train staff. | R3 | 3 | 4 | 12 | 15 | Limited ability for users to define fields and introduction of new terminology. |
| 37 | Ability to provide documentation (online and provision of manual). | M | 4 | 4.5 | 18 | 20 | Some modification required to the documentation to meet the N60 operational needs. |
| 38 | Ability of windows to be flexible and customizable. | R3 | 3 | 4.5 | 13.5 | 15 | Limited capability for user to customize windows. |
| | | Totals | 142 | | 473 | 710 | |
| | Business Requirements - Total Weighted Score 60% | | | | | 40.0 | |

## Vendor 2

This table rates the vendors ability to meet the requirement out of the box.

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5 = Fully meets or exceeds requirement

| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| Section A. Business Requirements | | | | | | | |
| BR-1 Core Structure | | | | | | | |
| 1 | Ability to separate data by company, and allow company specific rules and security, in a cost effective, efficient manner. | M | 4 | 1 | 4 | 20 | Software could not offer separation of 4 companies. Instead data would be manipulated to achieve a quasi four company solution, which didn't offer secure separation by company. |
| BR-2 Customer Management | | | | | | | |
| 2 | Ability to capture and display owner contact information, ensuring prescribed procedures for assigning responsibility. | M | 4 | 3 | 12 | 20 | Software required modification to meet N60's business requirement. |
| 3 | Ability to retain existing customer account number and meter number. | R3 | 3 | 3 | 9 | 15 | The old CIS account number would be converted to a Customer #, with some modification (resulting in a number, not identical to old CIS). |
| BR-3 Service Order Management | | | | | | | |
| 4 | Ability to provide different service order templates, and the conditions under which the system will initiate the prompt for follow-up action orders. | M | 4 | 2.5 | 10 | 20 | Software required modification to meet the business requirement. (i.e.. to generate different orders based on operational activity.) |
| 5 | Ability to print service orders to local N60 offices. | M | 4 | 2 | 8 | 20 | Software required modification to meet the business requirement. |
| BR-4 Billing Accuracy and Functionality | | | | | | | |
| 6 | Ability to calculate an Initial Bill | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 7 | Ability to calculate an Final Bill | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 8 | Ability to calculate a normal bill | M | 4 | 4 | 16 | 20 | Software required modification to allow different demand calculations (ratchets) for each N60 company. |

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| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| 9 | Ability to perform multi-month calculations | M | 4 | 4 | 16 | 20 | Vendor indicated they could meet requirement, but did not receive evidence to support this. |
| 10 | Ability to support Consolidated Accounts (cycles not =). | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 11 | Ability to support Statement Accounts (cycle is =). | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 12 | Ability to perform budget billing. | M | 4 | 4 | 16 | 20 | Software required modification to automate budget and settlement process. |
| 13 | Ability to prorate charges. | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 14 | Ability to calculate charges to un-metered accounts. | M | 4 | 4 | 16 | 20 | Vendor indicated they could meet requirement, but did not receive evidence to support this. |
| 15 | Ability to calculate charges for Outdoor Lights. Billing and Reporting | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 16 | Ability to Cancel/Rebill historical charges. | M | 4 | 4 | 16 | 20 | Vendor indicated they could meet requirement, but did not receive evidence to support this. |
| BR-5 Automation | | | | | | | |
| 17 | Automation of Bill Process & Report Generation. | M | 4 | 1 | 4 | 20 | Software offered no billing automation to process cycle billing and report generation. Would have resulted in increased N60 staff. (ATCO CIS offered fully automated solution) |
| 18 | Ability to interface with external systems and produce data files. | M | 4 | 2.5 | 10 | 20 | Software required modification to interface with ATCO CIS. |

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|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| BR-6 Accounts Receivable Management | | | | | | | |
| 19 | Ability to transfer, adjust, refund, and post A/R. | M | 4 | 4 | 16 | 20 | Given vendors four company solution, ability to accurately report or post A/R was questionable. |
| BR-7 General Ledger Management | | | | | | | |
| 20 | Ability to interface with Financial systems, and provide tools for reconciliation between sub-ledger (CIS) and general ledger. | M | 4 | 4 | 16 | 20 | Four company database solution reduced this rating. |
| BR-8 Credit and Collections Management | | | | | | | |
| 21 | Ability to manage deposits, credit tracking and collection actions for delinquent customers. Includes write-off. | M | 4 | 2 | 8 | 20 | Software required modification to automate deposit review. |
| BR-9 Payment Remittance Management | | | | | | | |
| 22 | Ability to process payments - Online and Cashiering Functionality | M | 4 | 4 | 16 | 20 | Software required modification to handle additional payment source codes. |
| 23 | Ability to support preauthorized payment plans, either from customer bank account or credit card. | O | 0 | 5 | 0 | 0 | Vendor indicated they could meet requirements. |
| BR-10 Meter Management | | | | | | | |
| 24 | Ability to manage all in-stock, and in-service meters. Includes purchases, maintain meter details, track meters, test, and retire. | M | 4 | 2 | 8 | 20 | Software required modification to interface with ATCO CIS , modification to split the meter number, and to enforce meter/company relationship. |
| BR-11 Meter Reading Management | | | | | | | |
| 25 | Ability to support current interfaces to Itron, via Computer Aided Dispatch. Ability to interface to AMR (TWACS). | M | 4 | 3 | 12 | 20 | Software required modification to import, store and report meter reading data (including meter reader notes). |
| 26 | Ability to estimate demand and energy reads. | M | 4 | 4 | 16 | 20 | Software required modification to create and apply different calculations for different companies. |
| BR-12 Route/cycle Management | | | | | | | |
| 27 | Ability to manage route and cycle scheduling and organization. | M | 4 | 3 | 12 | 20 | Software offered no automation for scheduling downloads and file transfers of route and cycle information. |

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| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| BR-13 Query and Reporting | | | | | | | |
| 28 | Ability to generate reports and queries to support the organization (both predefined and adhoc). This item would support queries needed to identify customer growth and energy conservation, plus rates and forecasting activities, etc. Includes canned and ADHOC reporting | M | 4 | 2 | 8 | 20 | Software required modification to develop all reports and automate. Their reporting structure, based on the four company database solution was uncertain. |

## Vendor 2

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| Id# | Description | Req'mt Rank | Weight | Score | Weighted Score | Maximum Score | Comments |
|---|---|---|---|---|---|---|---|
| | | | (0-4) | (1-5) | | | |
| BR-14 System Support | | | | | | | |
| 29 | Ability to perform edits during batch jobs and on-line entry. e.g.. Valid community/rate combinations, high/low edits, etc | M | 4 | 1 | 4 | 20 | Software required modification to develop edits. |
| 30 | Ability to perform rate testing on global rate components (e.g. GST), by rate code, by community, by company, etc. using consumption levels or specific accounts loaded into testing environment. Ability to update rate codes/components, and elevate to production environment. | M | 4 | 3 | 12 | 20 | Software required modification to support variable rate components for demand ratcheting, deposit interest, and late pay fee calculation. |
| 31 | Ability to provide an audit trail of data added, changed, deleted and transferred. A record of the date, time and the person responsible is maintained for each record change. | M | 4 | 5 | 20 | 20 | Met business requirement. Score equal to ATCO CIS. |
| 32 | Ability to provide a data file to I-Tek to interface with printing software to produce regular customer bills as well as collection correspondence. | M | 4 | 2.5 | 10 | 20 | No interface was available to transport the statement data file to ATCO's bill print software. In addition, modification was needed to create four different bill presentation templates. |
| BR-15 Usability | | | | | | | |
| 33 | Ability to offer Generic Screen presentation. | R3 | 3 | 2.5 | 7.5 | 15 | Screen presentation was static, with no tool available to easily change. |
| 34 | Ability for users to define fields. | R3 | 3 | 5 | 15 | 15 | Met business requirement. Score equal to ATCO CIS. |
| 35 | Ability for users to easily use the system. | R3 | 3 | 2.5 | 7.5 | 15 | Screens appeared cluttered. |
| 36 | Ability to easily train staff. | R3 | 3 | 2.5 | 7.5 | 15 | Vendor system appeared more complicated, plus given that screens were static, the training would not easily be delivered, and required introduction of new terminology. |
| 37 | Ability to provide documentation (online and provision of manual). | M | 4 | 3 | 12 | 20 | Significant modification required to the documentation to meet the N60 operational needs. |
| 38 | Ability of windows to be flexible and customizable. | R3 | 3 | 3 | 9 | 15 | Limited capability for user to customize and create flexible windows. |
| | | Totals | 142 | | 473.5 | 710 | |
| | Business Requirements - Total Weighted Score 60% | | | | | 40.0 | |

**YUB-YECL-17**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 71400 Revenue Collection, 72100 Administrative and 72300 Insurance

**Quote**: offset by decreased payment agent costs from closure of payment agents in some communities outside Whitehorse ( 9) (Line No. 199-120.)

Costs increase from 2008 to 2009 due to the commencement of accepting credit cards for customer payments. (Line No. 205.)

**Preamble**: The Board would like to gain a better understanding of the YECL's revenue collection.

**Request:**

(a) Please provide position descriptions and the functions performed by YECL payment agents.

(b) Please provide the drivers and or study upon which YECL based its decision to not use payment agents in some communities outside of Whitehorse.

(c) Please provide a more detailed explanation as to the 96 increase from 2008 to 2009 because of the commencement of accepting credit cards for customer payments. (Line No. 196.)

(d) Please detail the increased financial reporting requirements and account for the 80 increase. (Line No. 218.)

(e) Are the increased financial reporting requirements in (d) for internal purposes?

(f) Please provide the model of the CGL corporate allocation methodology and describe in detail any changes to previous allocations of CGL. (Line No. 234.)

**Response:**

(a) YUB-YECL-17(a) Attachment 1 is a copy of the standard contract that Yukon Electrical has with its payment agencies. The contract outlines the key responsibilities that are to be performed by the payment agent.

(b) All of the payment agent contracts that were cancelled were done so at the sole discretion of the payment agent. This was for a number of reasons including closing of the business or for lack of resources to continue to collect the payments on behalf of Yukon Electrical.

Yukon Electric did try and seek out competent replacement agents for those who had cancelled their contracts however in many cases none were found. Presently Yukon Electrical has contracts with 5 payment agents in communities outside of Whitehorse.

In communities without a payment agent Yukon Electrical has a contract with a major financial institution to act as a payment agent for customers. In addition Yukon Electrical has many other options in place for customers to pay their bills including preauthorized payment, online and telephone banking.

Based on the above there was no study required as Yukon Electrical did not make the decision to terminate the payment agency contracts.

(c) Approximately 80k of the 96k variance between 2008 and 2009 is as a result of the credit card program. The calculation used by Yukon Electrical for the credit card program is as follows:

Approx. Residential Revenue 14M x 30 (customer usage) x 1.9 (average credit card fee) 80K.

The 30 number comes from the number of customers who typically use the credit card option. It came from actual experience of Northland Utilities in the Northwest Territories and an average take up experienced by other northern utilities.

The remaining variance in this activity is labor inflation and fringe.

(d) The increased costs were rounded to 80 on Schedule 5.2. The actual increases are outlined on Schedule 5.3 and are:

| | 2007 | 2008 | Increase |
|---|---|---|---|
| Regulatory Rider Applications | -- | 12 | 12 |
| Financial Reporting & Regulatory Phase I | 26 | 87 | 61 |
| | | | 73 |

This increase of 73,000 relates to increases in Regulatory Phase I and Rider Application costs and not just financial reporting requirements as outlined in the IR. The increases are moderate and translate into an approximate 0.4 FTE. The increase is required as a result of the increased time being spent in supporting Regulatory filings. To avoid rate spikes this estimate has been based on the time spent in a two year period. Support for regulatory filings includes support for:

- Preparation of Application, Information Responses and Updates if any;
- Preparation and review of rebuttal evidence (if required);
- Review of Intervenor Evidence and preparations of IR's, review of IR Responses
- Presentation of company witnesses;
- All aspects of Rider applications;
- Preparation and review of Argument and Reply; and
- Annual Report on Finances.

Support for financial reporting requirements has also increased and includes support for:

- Monthly financial and management reports; and
- Compliance with company policy with regards to preparation of reports including proposed implementation of IFRS.

In total, it is important to note that this support in the test period comprises approximately 0.75 FTE of the total 1.67 FTEs providing Head Office support.

(e) No, both the regulatory Phase I and Rider Application as well as financial reporting requirements are for internal and external purposes. External purposes are for such things as External Control Certification Compliance and International Financial Reporting Standards.

(f) CGL Allocation: In 2006 ATCO Group undertook a review of the Commercial General Liability allocation methodology. The previous method of allocation was very inconsistent in its approach. A different rate was charged to each ATCO subsidiary company based on factors which ranged from solely payroll or solely revenue, to kilometres of pipeline, number of customers or MW hrs of electricity generated. This method did not take into account the risks associated with a particular type of operation.

In discussion with ATCO's insurance broker it was determined it would be a more consistent and a more equitable approach to allocate the premium based on the factors an insurance company would utilize to underwriter the risk. These factors include revenue, payroll number of employees, loss experience and the risks associated with the particular operations of the company. Each factor was assigned a percentage of the total premium in the following manner: revenue 15 , payroll 15 , number of employees 15 , loss history 20 and operational risks 35 . The resulting premium in each of the factors is then allocated proportionately amongst the ATCO Group of Companies.

This change in allocation methodology has been reviewed and approved by our insurance company.

In conjunction with the review of the Commercial General Liability allocation methodology we also obtained separate stand alone premium estimates from our insurance brokers as follows:

- 2006: 100M limit of liability 145,000 annual premium (premium estimate from insurance broker)
- 2007: 50M limit of liability 130,000 annual premium (premium estimate from insurance broker)

- 2008: 5M limit of liability 90,000 to 115,000
  (indicative terms direct from insurance company)

Please refer to YUB-YECL-17(f) Attachment 1 which outlines the total insurance costs and costs allocated to YUKON Electrical Company for each type of insurance on an actual cost basis for the year 2005-2007 and on a forecast basis for the years 2008 2009.

THIS PAYMENT AGENCY AGREEMENT is effective

BETWEEN: THE YUKON ELECTRICAL COMPANY LIMITED
100-1100 1st Avenue, Whitehorse, Yukon.

AND:

(Herein after referred to as the 'Agent')

Whereas:

The Yukon Electrical Company Limited and the Agent wish to enter into an agency relationship on the terms and conditions set out in this agreement.

THE PARTIES AGREE AS FOLLOWS:

AGENCY

1. (1) The Yukon Electrical Company Limited names as its agent in to provide services to The Yukon Electrical Company Limited's customers on the terms and conditions in this Agreement.

AGENT SERVICES

2. Agent shall:
   (a) accept and hold in trust The Yukon Electrical Company Limited's cash and cheque payments from customers for their bills.
   (b) give customers a receipt when accepting payment.
   (c) direct all customers with inquiries on service and accounts to call The Yukon Electrical Company
   (d) on a bi-weekly basis, the Agent shall submit payment to The Yukon Electrical Company Limited office in Whitehorse.

CONFIDENTIALITY AND PRIVACY OF INFORMATION

3. (1) All information in this Agreement and in any form whatsoever disclosed or received by The Yukon Electrical Company Limited's customers or potential customers, or prepared by the Agent under this Agreement (the "Information") is or becomes the sole property of The Yukon Electrical Company Limited.

(2) Agent shall:

(a) maintain the Information and all parts of the Information in strict confidence;

(b) restrict disclosure of the Information and all parts of the Information to its employees and other persons with a need to use the Information for the purpose of performing this Agreement and who have been properly instructed by the Agent to maintain the Information in strict confidence and to use it only in accordance with this Agreement;

(c) not use the Information or any part of the Information, except for the purpose of performing this Agreement;

(d) not make or cause to be made any copy of the Information or any part of the Information, except for internal use as may be necessary in performing this agreement; and

(e) keep the Information and all parts of the Information in a secure place to prevent access to it by unauthorized persons.

(f) comply with laws governing privacy and access to information for the Yukon Territory and by the laws of Canada.

COMPENSATION

4. (1) The Yukon Electrical Company Limited shall pay the Agent $ dollars) monthly for services rendered.

(2) The Agent shall not charge or collect any additional fee from customers for any service contemplated by this Agreement.

TITLE

5. Title to all equipment and supplies that comes into Agent's possession under this agreement is and shall at all times remain with The Yukon Electrical Company Limited and the Agent shall have no right of property therein except to use said equipment and supplies in accordance with this agreement.

COMPLIANCE WITH LAWS

6. Agent shall comply with all applicable laws, regulation and other governmental requirements that may affect performance of the Agent's obligations under this Agreement.

GOVERNING LAW

7. This Agreement, shall be governed by and construed in accordance with the laws of the Yukon Territory and by the laws of Canada.

TERMINATION

8. (a) This Agreement shall end when either party gives thirty (30) days written notification to the other. The Yukon Electrical Company Limited may end this Agreement immediately by giving notice to that effect without incurring any liability to the Agent, if Agent:

   (1) commits any act of fraud or theft against The Yukon Electrical Company Limited or its customers;
   (2) does not comply with any provision under this Agreement;
   (3) moves or suspends transaction of its usual businesses or declares bankruptcy;
   (4) breaches confidentiality and privacy clause.

By signing below, the Parties have caused this Agreement to be executed by their duly authorized representatives as of the effective date noted above.

**THE YUKON ELECTRICAL COMPANY LIMITED**

**SCHEDULE 2:**

**YUKON ELECTRICAL COMPANY**

**INSURANCE PREMIUMS ACTUAL FORECAST**

| | | Actual | | | | | | | | | FORCAST | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | YECL | Total Premium | | YECL | Total Premium | | YECL | Total Premium | | YECL | Total Premium | | YECL | Total Premium | |
| COVERAGE | TERM | 2005 Expenses | 2005 Expenses | YECL of Total Premium | 2006 Expenses | 2006 Expenses | YECL of Total Premium | 2007 Expenses | 2007 Expenses | YECL of Total Premium | 2008 Expenses | 2008 Expenses | YECL of Total Premium | 2009 Expenses | 2009 Expenses | YECL of Total Premium |
| **Property Program:** | | | | | | | | | | | | | | | | |
| Property | July 1 - July 1 | 57,161 | 6,200,711 | | 57,382 | 6,548,140 | | 59,564 | 7,058,625 | | 61,899 | 7,356,074 | | 65,923 | 7,843,219 | |
| Property Insurance: TD&P | July 1 - July 1 | 62,299 | 1,775,445 | | 61,393 | 1,764,707 | | 59,414 | 1,696,796 | | 59,216 | 1,656,731 | | 63,065 | 1,764,614 | |
| Property: Renewal Credits | July 1 - July 1 | (4,517) | (287,769) | | (7,302) | (481,736) | | (17,124) | (1,219,031) | | | | | | | |
| **Subtottal:** | | **114,943** | **7,688,387** | **1** | **111,473** | **7,831,111** | **1** | **101,854** | **7,536,390** | **1** | **121,115** | **9,012,805** | **1** | **128,988** | **9,607,833** | **1** |
| **Liability Program:** | | | | | | | | | | | | | | | | |
| Commercial General Liability | July 1 - July 1 | 26,055 | 834,224 | | 23,081 | 793,917 | | 24,040 | 1,162,500 | | 27,322 | 786,625 | | 28,756 | 808,227 | |
| Umbrella 30M | July 1 - July 1 | 23,050 | 737,500 | | 19,982 | 687,501 | | 20,938 | 675,000 | | 23,796 | 685,126 | | 25,045 | 703,942 | |
| Excess Liability ( 175M) | July 1 - July 1 | 25,815 | 827,501 | | 25,268 | 871,501 | | 28,010 | 903,000 | | 31,834 | 916,545 | | 33,505 | 941,717 | |
| Excess Liability ( 135M) | July 1 - July 1 | 10,224 | 278,969 | | 11,303 | 389,693 | | 12,416 | 400,273 | | 14,106 | 406,139 | | 14,847 | 417,297 | |
| **Subtotal:** | | **85,143** | **2,678,194** | **3** | **79,634** | **2,742,612** | **3** | **85,404** | **3,140,773** | **3** | **97,058** | **2,794,435** | **3** | **102,153** | **2,871,183** | **4** |
| Other: | | | | | | | | | | | | | | | | |
| Automobile | July 1 - July 1 | | | | | | | | | | 5,956 | 428,860 | | 6,135 | 441,726 | |
| Automobile Aggregate | Jan 1 - Jan 1 | | | | | | | | | | 4,166 | 300,000 | | 4,166 | 300,000 | |
| Employment Practices Liability | Oct 1 - Oct 1 | 957 | 96,992 | | 818 | 85,088 | | 785 | 85,091 | | 540 | 58,546 | | 556 | 60,302 | |
| CRIME | Oct 1 - Oct 2 | 2,338 | 163,350 | | 2,640 | 182,655 | | 2,672 | 182,655 | | 1,848 | 126,299 | | 1,940 | 132,614 | |
| Travel Accident Foreign Medical | Jan1 - Jan 1 | 224 | 82,030 | | 230 | 54,150 | | 109 | 38,000 | | 111 | 38,760 | | 115 | 39,923 | |
| **Subtotal:** | | **3,519** | **342,372** | **1** | **3,688** | **321,893** | **1** | **3,566** | **305,746** | **1** | **12,621** | **952,465** | **1** | **12,912** | **974,565** | **1** |
| **TOTAL** | | **203,605** | **10,708,953** | **2** | **194,795** | **10,895,616** | **2** | **190,824** | **10,982,909** | **2** | **230,794** | **12,759,705** | **2** | **244,053** | **13,453,581** | **2** |

**YUB-YECL-18**

**Reference:** Application, Schedule 5.2

**Issue Sub-Issue:** 72600 Training & Safety

**Quote**: Costs increase from 2007 to 2008 mainly due to increased labour for HS&E management position and other staff labour ( 102). (Line No. 250-251.)

**Request:**

(a) Has the HS&E management position, alluded to in Schedule 5.2, Line No. 250, been filled?

(b) Was this a new or vacant position?

(c) If the position has been filled, was it filled internally or externally?

(d) Explain the new national transport safety compliance-training program and the need for such training by YECL personnel.

**Response:**

(a) Yes it was filled.

(b) The Planned Program and HSE Supervisor position is a new position.

(c) This was filled internally.

(d) The National Safety Code (NSC) for Motor Carriers was developed by the member jurisdictions of Canadian Council of Motor Transport Administrators (CCMTA) on behalf of the Government of Canada in conjunction with the motor carrier industry. The NSC is a set of uniform, national minimum safety standards pertaining to the operation of commercial vehicles.

Yukon Electrical is classified as a commercial carrier and is subject to the NSC. The NSC dictates requirements for driver performance, hours of service, vehicle

maintenance and the documentation associated with these activities. Training of drivers and supervisors is required for hours of service, pre and post trip inspections, NSC compliance, load securement, Transportation of Dangerous goods and the required annual vehicle permits and inspections. Further information is available on the YTG web site. www.gov.yk.ca (under Transportation Services)

**YUB-YECL-19**

**Reference:** Taxes Other Than Income; Application, page 6-1

**Issue:** 2008 Increase over 2007

**Quote:** Property tax increases are primarily due to inflation. (Line No. 6-7)

**Request:**

What other factors have caused property taxes to increase? Please provide actual property taxes for 2005.

**Response:**.

The primary cause of property tax increases is from the City of Whitehorse's 2008 budget forecast of 7.5 increase in property taxes in 2008 and 4 in 2009.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**YUB-YECL-20**

**Reference:** Depreciation; Application, page 7-1

**Issue:** Reduction in Forecast Depreciation Costs

**Quote:** The impact of the depreciation study is a reduction in forecast depreciation expense of 270,000. (Line No. 10-11.)

**Request:**

Please prepare a table similar to Schedule 7.2 comparing the previous depreciation method with the current method showing the savings of 270,000.

**Response:**

The depreciation method itself has not changed. The recommended service lives and net salvage percentages from the depreciation study are changes from the approved parameters used to calculate depreciation rates since the last GRA. YUB-YECL-20 Attachment 1 provides the calculation of depreciation expense by account using the 2007 depreciation rates. There is also a decrease of 51,000 in the amortization of differences using the recommended parameters as shown in Schedule 7.4 of the Application. The total reduction is calculated as follows:

| | **( 000 s)** | |
|---|---|---|
| Schedule 7.2 per Application | 4,580 | |
| YUB-YECL-20 Attachment 1 | 4,809 | |
| | 229 | |
| Reduction in Amortization of Differences | 51 | |
| Total Reduction | 280 | (Correction to Page 7-1) |

**Yukon Electrical Company Limited**
**2008 - 2009 General Rate Application**
**Calculation of Depreciation Expense 2008 using 2007 Actual Depreciation Rates**

| Line No. | Acct. | Description | Cross Ref. | 2008 Opening PPE | Depreciation Rate | Depreciation on Opening Balance | Capital Additions | Depreciation on Capital Additions | 2008 Total Depreciation |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | Production - Hydro | | | | | | | |
| 2 | | | | | | | | | - |
| 3 | 422 00 | Hydro Structures | | 259 | 2.29 | 6 | 589 | 7 | 13 |
| 4 | 423 00 | Hydro Resv, Dams & Waterways | | 757 | 2.29 | 17 | - | - | 17 |
| 5 | 425 00 | Hydro Generators | | 273 | 2.29 | 6 | - | - | 6 |
| 6 | 426 00 | Hydro Accessory Electrical Equip | | 105 | 2.29 | 2 | - | - | 2 |
| 7 | 427 00 | Hydro Misc Equip | | 24 | 2.29 | 1 | - | - | 1 |
| 8 | | Total Production - Hydro | | 1,418 | | 32 | 589 | 7 | 39 |
| 9 | | | | | | | | | |
| 10 | | Production - Diesel | | | | | | | |
| 11 | 442 00 | Structures and improvement - Other | | 1,498 | 2.96 | 44 | - | - | 44 |
| 12 | 444 00 | Fuel Holders, Proucers, & Acc. Equipment - Other | | 2,137 | 4.55 | 97 | 64 | 1 | 98 |
| 13 | 445 00 | Generating Equipment & Prime Mover - Other | | 8,444 | 3.93 | 332 | 259 | 5 | 337 |
| 14 | 446 00 | Accessory Electric Equipment - Other | | 2,142 | 4.02 | 86 | 68 | 1 | 87 |
| 15 | 447 00 | Misc. Power Plant Equipment - Other | | 643 | 4.25 | 27 | 20 | - | 27 |
| 16 | | Total Production - Diesel | | 14,864 | | 586 | 412 | 7 | 593 |
| 17 | | | | | | | | | |
| 18 | | Transmission | | | | | | | |
| 19 | 457 00 | Substation Equipment | | 1,401 | 2.71 | 38 | - | - | 38 |
| 20 | | Total Transmission | | 1,401 | | 38 | - | - | 38 |
| 21 | | | | | | | | | |
| 22 | | Distribution Plant | | | | | | | |
| 23 | 471 00 | Land Rights | | 929 | 1.52 | 14 | - | - | 14 |
| 24 | 473 00 | Poles, Towers & Fixtures | | 22,740 | 4.82 | 1,096 | 1,689 | 41 | 1,137 |
| 25 | 474 00 | Overhead Conductor | | 15,092 | 4.32 | 652 | 1,186 | 26 | 678 |
| 26 | 474 10 | Services - Overhead | | 2,306 | 3.09 | 71 | 183 | 3 | 74 |
| 27 | 475 00 | Underground Conductor | | 17,426 | 2.09 | 364 | 1,385 | 14 | 378 |
| 28 | 475 10 | Services - Underground | | 2,547 | 3.35 | 85 | 202 | 3 | 88 |
| 29 | 476 10 | Meters | | 1,263 | 9.00 | 114 | 248 | 11 | 125 |
| 30 | 476 30 | AMR - Meters | | 8 | 4.03 | - | - | | - |
| 31 | 477 10 | Substation Equipment | | 3,132 | 2.73 | 86 | - | - | 86 |
| 32 | 478 10 | Street Lighting | | 7,699 | 4.89 | 376 | 497 | 12 | 388 |
| 33 | 478 20 | Sentinel Lights | | 285 | 2.16 | 6 | | - | 6 |
| 34 | 479 10 | Line Transformers | | 17,596 | 4.01 | 706 | 1,311 | 26 | 732 |
| 35 | | Total Distribution Plant | | 91,023 | | 3,570 | 6,702 | 136 | 3,706 |
| 36 | | | | | | | | | |
| 37 | | General Plant | | | | | | | |
| 38 | 482 00 | Structures & Improvements | | 3,184 | 2.80 | 89 | 199 | 3 | 92 |
| 39 | 483 00 | Office Furniture & Equipment | | 220 | 6.17 | 14 | (25) | - | 14 |
| 40 | 483.20 | Computer Equipment | | 37 | 20.33 | 8 | 0 | - | 8 |
| 41 | 484 00 | Transportation & Mobile Equipment | | 2,207 | 5.94 | 131 | 147 | 4 | 135 |
| 42 | 485 00 | Tool & Work Equipment | | 501 | 9.80 | 49 | (9) | - | 49 |
| 43 | 486 00 | Communication Structures & Equipment | | 491 | 4.96 | 24 | 102 | 3 | 27 |
| 44 | 488 20 | Company Housing | | 388 | 1.08 | 4 | 19 | - | 4 |
| 45 | 491 00 | Franchise & Consent | | 1 | 0.00 | - | - | - | - |
| 46 | 496 xx | New ATCO-CIS | | - | 10.00 | - | 1,595 | 80 | 80 |
| 47 | 496 05 | Oracle Financials | | 235 | 10.00 | 24 | | - | 24 |
| 48 | | Total General Plant | | 7,266 | | 343 | 2,028 | 90 | 433 |
| 49 | | | | | | | | | |
| 50 | | Plant Studied | | 115,972 | | 4,569 | 9,730 | 240 | 4,809 |
| 51 | | Plant Not Studied - Land | | 479 | | | | | |
| 52 | | Total Plant | S.8.6 L.6 | 116,451 | | | | | |

**YUB-YECL-21**

**Reference:** Depreciation Schedule 7.1

**Issue:** Depreciation Expense

**Preamble:** Annual increases in depreciation expense are as follows:

| | |
|---|---|
| Depreciation Expense Increase Over 2005 | 4.7 |
| Depreciation Expense Increase Over 2006 | 6.9 |
| Depreciation Expense Increase Over 2007 | 4.7 |
| Depreciation Expense Increase Over 2008 | 10.8 |

**Request:**

(a) Please explain the variation in the increases to depreciation expense. For example, why is rate of increase in depreciation expense for 2009 more that double that for 2008?

(b) Explain Line No. 3 of Schedule 7.1.

**Response:**

(a) The change in depreciation expense tracks the growth in Property, Plant and Equipment with the exception of 2008. The reason for the lower increase from 2007 to 2008 forecast is that depreciation expense for 2008 is calculated using the lower depreciation rates from the latest depreciation study. As was noted on Page 7-1 of the Application and as detailed in response to YUB-YECL-20, the impact of the new depreciation study is a reduction in forecast 2008 depreciation expense of 280,000.

(b) When vehicles owned by Yukon Electrical are used in the construction of its PP&E, the costs, including vehicle depreciation, are capitalized. Thus these vehicle depreciation costs are not recovered on a current basis but form part of the capitalized costs of the plant constructed and are depreciated over the service life of those assets.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**YUB-YECL-22**

**Reference:** Depreciation Schedule 7.4

**Issue:** YFR Curve

**Request:**

Please explain the YFR curve and further describe what the amortization of differences entails? How are the amounts for each line item for the amortization of differences determined?

**Response:**

The YFR curve is meant to indicate either the year of final retirement or the IOWA curve type that is used to the forecast retirement dispersion pattern of the assets within the account. The procedure used in the estimation of the IOWA curve type is presented in the Gannett Fleming report stating at page II-3. The combination of the IOWA curve type and the Life estimate will form the IOWA curve as presented for each account in the Gannett Fleming report starting at page IV-2.

The use of a year of final retirement in the development of depreciation rates is meant to forecast the year at which plant may retire due to economic or non-physical forces of retirement. It is also often used to establish an economic planning horizon over which assets are depreciated. In the development of the depreciation rates for Yukon Electrical, only account 425.0 Hydro Equipment was subjected to a YFR calculation. The calculation of the depreciation accrual rate incorporating the use of a Year of Final Retirement (or Probable Retirement Year) for this account is provided at page VI-2 of the Gannett Fleming report.

The net salvage and deprecation rates by account are presented for informational purposes. The amounts of amortization of accumulated depreciation variances for 2008 and 2009 are summarized from the calculations presented in Table 2 of the Gannett Fleming report. For 2006 and 2007 amounts the same calculation was performed using the depreciation parameters from the previously approved depreciation study. The concept of amortizing accumulated depreciation variances is discussed in YUB-YECL-23.

**YUB-YECL-23**

**Reference:** Depreciation Gannett Fleming Study, Section 7, Attachment 1, pg. 2

**Quote:** The depreciation rates are based on the straight-line whole life method using the equal life group procedure.

**Request:**

Please explain the whole life method and the equal life group procedure. Why was this particular estimation technique chosen? Under what conditions is a change in estimation technique warranted?

**Response:**

The calculation of depreciation accrual rates for mass property assets requires the selection of a depreciation method, a grouping procedure and a basis upon which to apply the depreciation rates. In the circumstance of Yukon Electrical, Gannett Fleming has recommended the continuation of the straight line method of depreciation, the equal life group procedure for grouping of assets and the application of the parameters on a remaining life basis. As the selection of these depreciation calculation parameters underpins the booked amount of accumulated depreciation, Gannett Fleming does not recommend changes to these policies unless a significant tolling issue results from the continued use of the practices.

Each of these required depreciation policy selections is discussed below.

Methods of Depreciation. Depreciation, in public utility regulation, is the loss in service value not restored by current repairs or covered by insurance. The determination of annual depreciation accrual rates must consider the amount of service value which an asset or group of assets will lose during the year in which the rates are to be applied. Most assets render service on a relatively uniform basis during each year of life that is the usefulness of an asset does not change over the period of time that the asset is in service. In such circumstances use of a straight line method of depreciation is appropriate. Other methods of depreciation such as the declining balance method (which assumes that an asset is more useful in its early years than later in its life) or sum of the years digits (which assumes an exponential raise in the usefulness of an

asset over its life) are not generally accepted for rate making purposes, although they can be used for financial disclosure or income tax purposes.

Grouping Procedures. When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group.

In the average service life procedure, the rate of annual depreciation is based on the average life or average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life. In this procedure, the accrued depreciation is based on the average service life of the group and the average remaining life of each vintage within the group derived from the area under the survivor curve between the attained age of the vintage and the maximum age.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

A simplistic example highlighting the differences in the two procedures is presented on the following page. The example assumes an account with two assets, each costing with an original cost of 1,000 for total investment of 2,000. The example also assumes that one of the assets has a life estimate of 5 years and the second has a 15 life expectancy. As such the asset balance from years 1 through 5 is 2,000 and 1,000 for the years 6 through 15. The average service life for the account would be determined by taking the average of the 5 and 15 year life estimates for an average of 10 years.

In the following example, using the average service life procedure where the rate of annual depreciation is based on the average life or average service life of the group, the rate applied to the surviving balances of the group's cost balance is calculated as follows:

| | | | | | |
|---|---|---|---|---|---|
| 100 | (original Cost) | 0 | (No salvage has been assumed) | 10 years (Average Service Life) | |
| 10 | | | | | |

Therefore the annual accrual for years 1 through 5 is 200 ( 2,000 account balance X 10 ). In the years 6 through 15, following the 1,000 retirement at the end of year 5 the annual accrual is 100 ( 1,000 X10 )

In the equal life group procedure, the property group is subdivided according to service life with each group being depreciated over its specific estimate. As such in the example the annual accrual is developed specifically for each of the two groups, and the requirement for each group is summed to determine the overall expense for the account. As such for years 1 through 5 the annual accrual is determined as follows:

| | | | |
|---|---|---|---|
| | 1,000 (Cost of the first group) | 5 years (life of the first group) | 200 |
| Plus | 1,000 (cost of the second Group) | 15 years (life of the second group) | 67 |
| | 267 ( 200 | 67) | |

In the years 6 through 15 following the retirement of the first asset, the depreciation is 67, being the appropriate amount for the asset remaining in service.

It should be noted that in the example, both procedures result in the full collection of the entire 2,000 investment and the accumulated depreciation balances are zero after the retirement of the second asset. However, using the ASL procedure, if all of the accumulated depreciation is allocated to the first asset, there has been no collection for the second asset at the end of the fifth year. In contrast, when using the ELG procedure an appropriate amount ( 67 X5 years) has been collected towards the recognition of the consumption of the service value of the second asset in addition to fully depreciating the first asset by the time of retirement.

**Example providing the differences in the ASL and ELG Procedures**

| | | Average Service Life (ASL) | | Equal Life Group (ELG) | |
|---|---|---|---|---|---|
| Year | Asset Balance | Annual Accrual | Accumulated Deprn | Annual Accrual | Accumulated Deprn |
| 1 | 2000 | 200 | 200 | 267 | 267 |
| 2 | 2000 | 200 | 400 | 267 | 534 |
| 3 | 2000 | 200 | 600 | 267 | 801 |
| 4 | 2000 | 200 | 800 | 267 | 1068 |
| 5 | 2000 | 200 | 0(1) | 267 | 335(2) |
| 6 | 1000 | 100 | 100 | 67 | 402 |
| 7 | 1000 | 100 | 200 | 67 | 469 |
| 8 | 1000 | 100 | 300 | 67 | 536 |
| 9 | 1000 | 100 | 400 | 67 | 603 |
| 10 | 1000 | 100 | 500 | 67 | 670 |
| 11 | 1000 | 100 | 600 | 66 | 736 |
| 12 | 1000 | 100 | 700 | 66 | 802 |
| 13 | 1000 | 100 | 800 | 66 | 868 |
| 14 | 1000 | 100 | 900 | 66 | 934 |
| 15 | 1000 | 100 | 0 | 66 | 0 |
| Total | | 2000 | | 2000 | |

(1) Calculated as follows: 800 200 - 1,000 (retirement of first asset)
(2) Calculated as follows: 1,068 267 - 1,000 (retirement of the first asset)

Gannett Fleming views that the ELG procedure better aligns the consumption of the service value of the assets to the resultant depreciation expense. Furthermore, the ELG does result in enhanced generational equity between the users of the two assets. However, the ELG procedure does result in an increased level of depreciation expense early in the account's life.

While some interveners and regulators have not been willing to approve the ELG procedure, given the high level of depreciation expense early in the asset's life, many a number of regulators have allowed the procedure.

Application Basis. Once a method of depreciation (i.e. straight-line) and a grouping procedure (i.e. the ELG procedure) have been established the actual depreciation rate calculation can be made. Use of the whole life basis develops the annual and calculated depreciation calculations assuming that the current depreciation parameters

have been in place from age zero of an asset's life through to the end of the maximum age of the asset account's life. Use of the whole life basis results in new plant additions being properly depreciated on the basis of the most current estimated depreciation parameters. These calculations are presented in Table 1 of the Gannett Fleming report.

As there have been changes in both the assets average service life and net salvage estimates over the many years of the asset accounts life, and given that not all assets retire at the precise timing estimated in depreciation studies, a variance between the calculated and booked accumulated depreciation amounts exists, as presented in table 2 of the Gannett Fleming report. In order to adjust for the variance between the calculated and actual amounts of accumulated depreciation, table 2 of the Gannett Fleming report amortizes the variance over the estimated composite remaining life of the account.

**YUB-YECL-24**

**Reference:** Depreciation Gannett Fleming Study, Section 7, Attachment, pg. 7

**Quote:** The combination of the historical trend and the estimated future trend yielded a complete pattern of life characteristics from which the average service life was derived.

A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement was obtained through contact with Company personnel.

**Request:**

(a) For each asset type was there a significant difference between the historical trend and the estimated future trend? If so, why would such a difference occur?

(b) Were the reasons for past retirements and the expected future causes of retirement consistent? If not please provide details where the reasons were not consistent.

(c) What statistical analysis was used to determine the appropriateness of the curve selected? For each of the graphs in the study provide the $R^2$ for the graph selected.

(d) For each of the graphs in the study was the curve with the best $R^2$ selected? If not which graphs did not use the curve with the best $R^2$?

**Response:**

(a) Results of the retirement rate analysis for each account are presented in account order stating at page IV-2 of the Gannett Fleming report. In the following accounts there were virtually no retirement history, therefore no historic trend could be estimated. In these circumstances the average service life estimates

were based on the discussions held with operation staff, the experience of Gannett Fleming, or experience of peers:

- Account 425.0 Hydro Equipment
- Account 442.0 Structure and Improvements Production plant
- Account 447.0 Misc. Power Plant Equipment
- Account 471.0 Land Rights
- Account 471.0 Underground Conduit
- Account 475.1 Underground Services
- Account 476.3 AMR meters
- Account 477.1 Distribution Substation Equipment
- Account 488.2 Company Houses

In the circumstances of the remaining accounts, either a sufficient amount of retirement history was observed for a meaningful stub curve to be developed or a full life cycle was studied. A stubbed survivor curve refers to a circumstance where a complete life history of retirement trends cannot be developed. However, a sufficient amount of history can be observed over which a full IOWA curve may be estimated, usually through a period of significant retirement activity. An example of such a stubbed IOWA curve can be found at page IV-8 for Account 473.0 Poles, towers and Fixtures. In the fitting of IOWA curves to accounts without a complete retirement history a significant amount of consideration is given to the discussions with operating staff in order to develop a full life estimate, and to period over which retirement transactions have occurred.

(b) Yes. In the circumstances of limited retirement history, the reasons for the limited history were because the assets have not yet reached an age where it is expected that replacement is necessary.

(c&d) The selected IOWA curves were based on the results of a Retirement Rate Analysis . The process used in the retirement rate analysis is described in the Gannett Fleming report at page II-3. The results of the retirement rate analysis were fit to smoothed IOWA curves using the procedure as described starting at page II-18 of the Gannett Fleming report.

This question asks for the $R^2$ for each of the curves selected. Gannett Fleming is not aware of this terminology for the selection of IOWA curves. One method

commonly used to smooth IOWA curves is based on the development of the sum of the squared differences between the IOWA curves and the results of the retirement rate analysis at each of the aged observation points studied. A statistically developed Best Fit can then be established by choosing the IOWA curve with the smallest amount of squared differences.

As indicated in part (a) of this response, a number of accounts had virtually no retirement experience, and a number of additional accounts had limited retirement experience and developed stubbed curves. In these circumstances the use of statistical fitting methods develops meaningless IOWA curve selections, often as long as many hundreds of years. As such, Gannett Fleming did not rely on such statistical fitting techniques in this study.

## YUB-YECL-25

**Reference:** Depreciation Gannett Fleming Study, Section 7, Attachment 1, pg. 7

**Quote:** The net salvage estimates were based on judgment that incorporated analyses of historical data, a review of policies and outlook with Company management, a general knowledge of the electric industry, and comparisons of the net salvage estimates from studies of other electric utilities.

**Request:**

(a) Upon your review of the company policies, in your opinion, could any changes in policy occur which would extend the life of the assets?

(b) Within your comparison with other electric utilities, where any other northern electric utilities included in the comparison?

**Response:**

(a) No. It should be noted however, that the purpose of the Gannett Fleming interviews is to understand the policy and then determine its impact on average service life, not to evaluate the policy.

(b) Gannett Fleming has recently completed depreciation studies for the NorthWest Territories Power Corporation, Northland Utilities (NWT) Limited, Northland Utilities (Yellowknife) Ltd, and the Yukon Energy Corporation. While these northern utilities were specifically considered, other utilities considered as peers were ATCO Electric, Manitoba Hydro, and BC Hydro.

## YUB-YECL-26

**Reference:** Depreciation Gannett Fleming Study, Section 7, Attachment 1, pg. 32

**Issue:** Underground Conduit

**Quote:** The previously approved estimate for this account was the Iowa 54-R3, has been slightly adjusted to the Iowa 50-R4 to better fit industry retirement trends.

**Request:**

(a) Statistically, how strong is the correlation between the YECL experience and the industry retirement trend? Would another curve provide a better $R^2$?

(b) How does the new curve conform to the expectation of the company's engineering staff?

(c) Which component provides the greatest influence to the survivor curve estimate, historical trend, industry trend, or company expectations? How is the weighting for each component decided?

**Response:**

(a) This account has experienced extremely few retirements. As indicated in the retirement rate analysis presented at page IV-30 of the Gannett Fleming report, only minimal retirements have occurred in this account. The 6,645 retired to date in this account, account for only .038 of the over 17 million of investment. No statistical fit can be made for this level of retirement experience for any IOWA curve.

The following are the IOWA curves used by the peer group of utilities for this account. The recommended IOWA 50-R4 conforms well to this group of peer companies:

- Yukon Energy Corporation 40-R2.5
- NorthWest Territories Power Corporation NTPC 25-R3
- Northland Utilities (NWT) Limited 50-R4
- Northland Utilities (Yellowknife) Limited 50-R3
- ATCO Electric 55-R4
- Manitoba Hydro 45-R3
- BC Hydro 45-SQ

(b) The revised 50-R4 IOWA curve selections was discussed with and agreed to by the engineering and operational staff.

(c) With regard to this account, the average service life was developed by considering the following factors in the order provided below, however no statistical weighting technique was used:

i. Company expectations
ii. Industry trends
iii. Gannett Fleming experience
iv. Historic trend

**YUB-YECL-27**

**Reference:** Gannett Fleming Study, Section 7, Attachment 1, pg. 43

**Issue:** Meters

**Request:**

(a) Please explain why there is no estimated survivor curve for meters.

(b) Explain how a 10-year amortization period for meters was deemed appropriate.

**Response:**

(a) These older technology meters are being replaced over the next few years with new AMR technology. As such, these meters have no average service life remaining. Given the large amount of net book value remaining, YECL has accepted the advice of Gannett Fleming to amortize the net book value as at December 31, 2007 over a period longer than the estimated remaining life in order to minimize the tolling impact of this replacement program. Given this amortized treatment, there is no requirement to develop an IOWA curve for this account.

(b) Over the past 1 to 2 years this type of replacement program for meters has been initiated by many electric distribution utilities. In most cases the issue regarding a large loss on retirement has arisen. It is the experience of Gannett Fleming that a 10 year period is generally accepted as a reasonable period over which to recover this loss in tolls, while not materially impacting level of the toll. While the issue and appropriate amortization period is currently before a number of regulatory Boards, the use of a longer amortization period than the remaining life of the asset group is recommended by Gannett Fleming as a reasonable solution to this issue.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**YUB-YECL-28**

**Reference:** Return on Rate Base, Application, page 8-2 and schedule 8.4

**Issue:** Other Post Employment Benefit Plans (OPEB)

**Quote:** For these benefits, Yukon Electrical is assessed a percentage of its payroll at a rate calculated for the plan as a whole.

Prior to 2008 only the pension plan was on the cash basis. (Line No. 20-23.)

**Request:**

(a) Please provide 10 years history of actual OPEB paid and the corresponding percentage of payroll.

(b) For the current application, what percentage of payroll is calculated as OPEB?

(c) In Schedule 8.4, are the line 13 charges the payroll assessment for OPEB? Describe what the cash payments represent.

(d) Please explain the dramatic increase in charges from 2006 to 2007 for line 20 in schedule 8.4.

**Response:**

(a) In accordance with Board Order 2008-5, YECL does not believe that information prior to 2003 is required to test the revenue requirement in the test period. However, to be helpful to the Board, YECL has provided the information as follows:

**Other Post Employment Benefit Accrual**
**Continuity Schedule**

| Year | Opening Balance | Accrued | Cash Payments | Year-End Balance | Percent of payroll |
|---|---|---|---|---|---|
| **1999** | - | - | - | - | |
| **2000** | - | (63) | 17 | (46) | *3.14%* |
| **2001** | (46) | (71) | 24 | (93) | *2.99%* |
| **2002** | (93) | (82) | 24 | (151) | *3.15%* |
| **2003** | (151) | (104) | 27 | (228) | *3.77%* |
| **2004** | (228) | (103) | 25 | (306) | *3.44%* |
| **2005** | (306) | (117) | 28 | (395) | *3.70%* |
| **2006** | (395) | (123) | 28 | (490) | *3.71%* |
| **2007** | (490) | (103) | 56 | (537) | *3.02%* |

(b) As Yukon Electrical has proposed to account for OPEB on the cash basis in the test period, a percentage of payroll has not been calculated for the accrual. The cash basis assures that the cash outlay is expensed and therefore an accrual based on a percentage of payroll is not applicable.

(c) For the years 2003-2007, line 13 is an assessment of payroll as outlined in (a) above. For the test years, line 13 is not an assessment of payroll. Line 13 equals the cash payment such that the OPEB liability does not change during the test period.

(d) As explained in Schedule 5.2, Lines 16-19 of the Application, the increase in the defined benefit plan is due to the fact that 27 of pensionable earnings are now required as a result of the actuarial valuation that was completed for the years 2007-2009. Also please refer to YUB-YECL-28(d) Attachment 1.

26 June 2007

# Actuarial Valuation for Funding Purposes as at December 31, 2006

## Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies - Plan 2

MERCER
Human Resource Consulting

OSFI Registration Number: 56344
CRA Registration Number: 0955138

MMC Marsh & McLennan Companies

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1

# Executive Summary

## Valuation Results

The valuation has revealed an unfunded liability of $1,115,400 as at December 31, 2006. This compares to a funding excess of $1,789,300 at December 31, 2003. The two most significant sources of the decline in the funding excess were changes in actuarial assumptions and the absence of employer contributions to the Plan, offset by investment returns greater than assumed.

The employer's portion of the normal actuarial cost has increased over the intervaluation period, from 15.23% of pensionable payroll (after reflecting the January 1, 2005 amendment) to 22.69%. This increase reflects a change in assumptions and the general increasing effect due to aging of the plan membership, leveraged somewhat by the effect of the dollar limit on employee contributions.

## Contributions for 2007 - 2009

The unfunded liability must be funded over a period of not more than 15 years, by special payments made at least quarterly. The *Income Tax Act* would permit the entire amount to be funded immediately. Expressed as a percentage of pensionable earnings, the necessary payments to amortise the unfunded liability ranges from a minimum of 3.83% to a maximum of 12.63%.

Combined with the normal actuarial cost, the employers' contributions for the next three years must fall between 26.52% and 35.32% of their respective members' pensionable earnings.

## Actions Required

A copy of this report must be filed with the Office of the Superintendent of Financial Institutions and the Canada Revenue Agency.

The employers must immediately commence contributions to the Plan, with a retroactive adjustment to January 1, 2007.

The next valuation for funding purposes must be completed no later than December 31, 2009.

## Plan Identification Information

***Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies – Plan 2***

*Registration number with OSFI: 56344*

*Registration number with CRA: 0955138*

# 2

# The Valuation Process

## Purpose of the Valuation

This valuation was conducted for the purpose of certifying Plan solvency and ongoing costs as required under the *Pension Benefits Standards Act, 1985*, and for the purpose of certifying ongoing Plan costs as required under the *Income Tax Act*.

The valuation results presented in this report are not intended to necessarily be appropriate for accounting for pension expense in accordance with generally accepted accounting principles, nor are they intended to necessarily be appropriate for use by regulatory agencies other than those charged with regulation of the two statutes indicated above.

## Intended Users of the Report

We were retained by Canadian Utilities Limited to conduct the valuation and prepare this report. It is intended that the principal users of the report will be management of Canadian Utilities Limited and the participating employers, the Superintendent of Financial Institutions and his staff, and the staff of the Canada Revenue Agency.

## Sources of Data

Data are provided to us annually in electronic form by Canadian Utilities Limited as to active members of its registered pension plans as at December 31. These data include dates of birth and hire, accumulated contributions and service, pensionable earnings for the just completed calendar year, and other relevant information. The data also indicates employees who ceased to be active Plan members during the immediate preceding calendar year. Since the data provided encompasses all defined benefit plans sponsored by Canadian Utilities Limited, inter-plan membership transfers are readily apparent.

These data are compared by us to similar data provided the year earlier. Our comparison included checks that all previous members were accounted for, that the principal data elements had not changed, and that salaries had increased by a reasonable amount. We also verified that the data for all individuals appearing in the data for the first time were consistent with them being new Plan members. We also compared our counts of member data records to the manual record tallies provided by Canadian Utilities Limited. Any discrepancies found were reported to Canadian Utilities and satisfactory explanations received.

Data as to inactive members has been accumulated by us for the past several years. Each year we add the members who became inactive during the past year as indicated on the electronic data provided. We were also provided with manual records as to inactive members who had died during the calendar year, and adjusted the previously accumulated data accordingly. We also were provided with electronic data of the amounts actually being paid by Sun Life to existing pensioners and survivors, before and after the upcoming cost-of-living adjustments. This electronic data also reveals changes such as deaths and matrimonial property divisions, which provides a cross-check for the adjustments described above.

We have been supplied with custodial statements prepared by RBC Dexia for the three years ended December 31, 2006. We were also provided with a statement prepared by Canadian Utilities Limited of individuals terminating in 2006, whose benefit entitlements were not paid from the fund until sometime in 2007. This statement formed the basis for adjusting the market value of assets reported by RBC Dexia for outstanding termination payments. Since we are involved in calculating the appropriate amount of asset to be transferred in respect of membership transfers between plans, we are able to utilize information already in our files for outstanding inter-plan transfer payments.

In our opinion, the data upon which this valuation is based are sufficient and reliable for the purpose of this valuation.

## Significant Changes Since the Last Valuation

The last valuation was conducted as at December 31, 2003, with a supplemental solvency valuation conducted as at December 31, 2004. Since then the *Income Tax Act* (ITA) has been amended to increase the maximum pension permitted from registered pension plans. Prior to the amendment, the last scheduled DB limit was the 2005 limit of $2,000 per year of service, with increases to be in line with average wages thereafter. The amendment scheduled additional values of $2,111 in 2006, $2,222 in 2007, $2,333 in 2008 and $2,444 in 2009, with increases thereafter with the average industrial wage. The effect of this Income Tax amendment has been reflected in this valuation.

Not a significant impact

The Plan was amended effective January 1, 2005 to reduce the member contribution rate to 2.8% on earnings up to the YMPE and 4% on earnings above the YMPE, to a maximum of $2,000. This amendment, which had no effect on the Plan's actuarial liabilities was contemplated in the previous valuation.

A new Canadian Institute of Actuaries Standard of Practice For Determining Pension Commuted Values ("CIA Standard") was released in February 2004. The effective date of the new CIA Standard was on February 1, 2005. The new CIA Standard changed the assumptions to be used to value the solvency liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of the new CIA Standard has been reflected in this valuation.

As part of the funding valuation of CUL Plan 1 as at December 31, 2004, a project was undertaken to review the assumption setting process for both funding and accounting purposes, to harmonize the assumptions where possible, and to reflect the fact that both this Plan and the defined benefit portion of CUL Plan 1 are closed to new entrants. The outcome of this review has resulted in significant changes to the assumptions used for this valuation in comparison to those used three years ago. In particular, the discount rate reflects the expectation that the Plan's funding requirements will eventually become dominated by the solvency rather than going concern model, a situation which is anticipated to arise somewhere around the year 2020. In total, changes in assumptions and methods reduced the Plan's net financial position by about $3.5 million.

lower discount rate as no new entrants plan is dominated by solvency model

After checking with representatives of Canadian Utilities Limited, to the best of our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation.

## Valuation Assumptions and Methods

A detailed explanation of the valuation basis can be found in Appendix B. The following table presents a brief summary of the important assumptions made and actuarial methods employed for this valuation.

| Assumption / Method | Description |
|---|---|
| Long Term Inflation: | 2.50% per annum |
| Discount Rate: | 6.25% per annum initially, then 4.40% starting in 2020 |
| Individual Salary Increases: | |
| Economic Component: | 4.00% per annum for 5 years, 3.50% per annum thereafter |
| Promotion & Merit: | Age graded scale based on Plan experience (1992 Experience Scale) |
| YMPE Increases: | 2.75% per annum |
| Increases in Maximum Benefit: | $2,222.22 per year of service for retirements in 2006 increasing as scheduled in the Income Tax Act to $2,444.44 per year of service in 2009, and thereafter at 2.75% per annum beginning in 2010 |
| Escalation of Pensions: | 2.50% per annum |
| Retirement: | Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55. |
| Mortality: | Males: Uninsured Pensioner 1994 Mortality Table with generational mortality projection from 2004 |
| | Females: Uninsured Pensioner 1994 Mortality Table |
| Terminations: | 100% of Plan experience 1983 through 1985 |
| Proportion Married: | Based on current marital status |
| Spousal Age Difference: | Male partners are 4 years older than female partners |
| Expenses: | None |
| Asset Valuation Method: | Market related method in which recognition of 50% of realised and unrealised capital gains is deferred over a 3 year period |
| Actuarial Cost Method: | Projected Unit Credit Actuarial Cost Method |

In our opinion, the assumptions are, in aggregate, appropriate for the purposes of this valuation. Nevertheless, emerging experience will differ from the assumptions, and the resulting gains and losses will be revealed in future valuations.

# 3

# Financial Position of the Plan

## Going Concern Basis

When conducting a valuation on a going concern basis, we determine the relationship between the respective values of assets and accumulated benefits, assuming the Plan will be maintained indefinitely.

## Financial Position

The results of the valuation as at December 31, 2006, in comparison with those of the previous valuation as at December 31, 2003, are summarised in the following table:

Financial Position — Going Concern Basis

| | 2006.12.31 | 2003.12.31 |
|---|---|---|
| **Actuarial Value Of Assets** | $25,717,100 | $24,537,800 |
| **Actuarial Liabilities** Present value of accrued benefits for: | | |
| Active Members | $16,569,700 | $15,631,500 |
| Retired Members & Survivors | 10,102,600 | 7,010,900 |
| Former Vested Members | 160,200 | 106,100 |
| Total Actuarial Liability | $26,832,500 | $22,748,500 |
| **Funding Excess (Unfunded Liability)** | **($ 1,115,400)** | **$ 1,789,300** |

## Reconciliation of Financial Position

The following table provides an approximate reconciliation of the Plan's current financial position, a unfunded liability of $1,115,400 as at December 31, 2006, to its previous position, a funding excess of $1,789,300 as at December 31, 2003. Because of the way in which the decisions concerning assumption changes came about, this reconciliation reflects the accumulation of three individual years of results, with assumption changes occurring throughout the period.

### Reconciliation of Financial Position

| | | |
|---|---|---|
| Funding Excess at December 31, 2003 | | $1,789,000 |
| Interest on Funding Excess | | 221,000 |
| Employer Contributions less than Normal Cost | | (1,780,000) |
| Plan Experience Different from Assumed, relating to: | | |
| • Investment Income, net of expenses | $2,382,000 | |
| • Economic increases to pensioners | (161,000) | |
| • Salary and YMPE increases | (42,000) | |
| • Termination of employment | 61,000 | |
| • Mortality | (78,000) | |
| • Retirement | 46,000 | |
| • Transfer to and from other Plans | (61,000) | |
| Net Experience Items | | 2,147,000 |
| Changes in actuarial assumptions and methods | | (3,504,000) |
| Data & status changes, other miscellaneous changes | | 12,000 |
| (Unfunded Liability) at December 31, 2006 | | $(1,115,000) |

Rate is 6% to 2020 then 4.5% as dominated by annuity purchases

Discount rate 2.4
mortality .4
inflation
(higher) 1.0
---
3.8
OTHER
Wages (.4)
(lower
3%v2.75%
---
3.5

See page 23 for explanation of changes to assumptions

For mortality people are living longer for example on page 29of 46 of the attachment if you live to 105 you have a better than 50:50 chance to make it to 106. Actually women have an almost 60% chance of making it to 106

## Solvency Basis

When conducting a solvency valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities on a solvency basis, determined in accordance with the *Pension Benefits Standards Act, 1985*. The values of the Plan's assets and liabilities on a solvency basis are related to the corresponding values calculated as though the Plan were wound up and settled on the valuation date. Appendix B contains a discussion of the circumstances under which Plan benefits may be settled on a Plan termination, and the assumptions and methods that would appropriate for determining the solvency position of the Plan as at December 31, 2006.

The following table shows the Plan's current financial position on a solvency basis, as compared to that shown in the supplementary solvency valuation conducted as at December 31, 2004.

Financial Position — Solvency Basis

| | 2006.12.31 | 2004.12.31 |
|---|---|---|
| **Value Of Assets Available for Benefits:** | | |
| Market Value of Assets per Trustee | $26,762,600 | $27,371,000 |
| Transfer (to) from CUL Plan 1 outstanding | 72,900 | (4,472,000) |
| Benefits and other items payable | (99,400) | (19,000) |
| Estimated windup expenses | (50,000) | (50,000) |
| Net Assets Available for Benefits | $26,686,100 | $22,830,000 |
| **Solvency Liabilities** Present value of accrued benefits for: | | |
| Active Members | $ 8,430,500 | $ 7,856,000 |
| Inactive Members: | | |
| Retired Members & Survivors | $11,465,300 | $ 8,914,000 |
| Former Vested Members | 179,700 | 128,000 |
| Total Inactive Members | $11,645,000 | $ 9,042,000 |
| Total Solvency Liability | $20,075,500 | $16,898,000 |
| **Solvency Excess (Shortfall)** | **$ 6,610,600** | **$ 5,932,000** |

The solvency ratio, which is the net assets available for benefits divided by the total solvency liability, is 1.3.

# 4

# Funding Requirements

## Normal Actuarial Cost

The estimated value of the benefits that will accrue on behalf of the active members during 2006, in comparison with the corresponding value determined in the previous valuation as at December 31, 2003, restated to reflect the effect of the January 1, 2005 amendment, is summarised below:

**Employers' Share of Normal Actuarial Cost**

| | 2007 | 2004 |
|---|---|---|
| Actuarial present value of benefits to be earned for service in the next 12 months | | |
| Retirement Benefits | $712,030 | $691,100 |
| Death Benefits | 10,550 | 14,800 |
| Termination Benefits | 7,030 | 6,700 |
| Total Normal Actuarial Cost | $729,610 | $712,600 |
| Expected Employee Contributions | $ 68,990 | $102,400 |
| Employers' share of the Normal Actuarial Cost | $660,620 | $610,200 |
| Expected Annual Payroll | $2,911,460 | $4,033,800 |
| Normal Actuarial Cost as a Percentage of Payroll: | | |
| Employee | 2.37% | 2.54% |
| Employer | 22.69% | 15.13% |
| Total | 25.06% | 17.67% |

The increase in the total normal actuarial cost, expressed as a percentage of payroll, is consistent with the increase in the average age of the Plan membership and the change in actuarial assumptions, while the decrease in the employees' share is due to the effect of the $2,000 contribution limit. The increase in the employers' share of the normal actuarial cost is due to the increase in the total normal actuarial cost, plus the decrease in the employees' share.

## Minimum Employer Contributions

The valuation has revealed an unfunded liability of $1,115,400 as at December 31, 2006. The *Pension Benefits Standards Act, 1985* requires that this unfunded liability be amortized over no longer than 15 years by special payments of at least $114,090 per annum, paid on a quarterly (or more frequent) basis. The solvency ratio as at December 31, 2003 exceeds 1.0, so no additional employer contributions are required in respect of the solvency position of the Plan.

The minimum special payments of $114,090 per annum represent 3.83% of expected 2007 pensionable payroll. Combined with the 22.69% normal actuarial cost, the minimum annual employer contribution over the next three years is 26.52% of pensionable payroll.

## Maximum Employer Contributions

Maximum contributions to the Plan are governed by the provisions of the *Income Tax Act*. Where an unfunded liability exists, the maximum contribution permitted is equal to the normal actuarial cost, plus the full amount of the unfunded actuarial liability.

The unfunded actuarial liability of $1,115,400 represents 12.63% of expected pensionable payroll over the three year period 2007, 2008 and 2009. Combined with the 22.69% normal actuarial cost, the maximum average annual employer contribution over the next three years is 35.32% of pensionable payroll.

## Allocation of Contributions Among Employers

The total contributions to the Plan, when greater than nil, are allocated among the participating employers on the basis of pensionable payroll. That is to say, the contribution rate, if any, is established as a percentage of pensionable payroll for the Plan as a whole, and each participating employer contributions that percentage of the pensionable payroll associated with its own employees.

Final rate set was 27% which is in the range

We understand that Canadian Utilities Limited intends to establish a contribution rate of 28% of pensionable payroll for the three year period until the next valuation, which contribution rate falls between the minimum required rate of 26.52% and the maximum permitted rate of 35.32%.

# 5

# Actuarial Opinion

**Actuarial Opinion with Respect to
the Actuarial Valuation as at December 31, 2006
of the Retirement Plan for Employees of
Canadian Utilities Limited and Participating Companies – Plan 2**

OSFI Registration 56344
Canada Revenue Agency 0955138

Based on the results of this valuation, we hereby certify that, as at December 31, 2006:

- the employers' normal actuarial cost for 2007 and subsequent years up to the next actuarial valuation should be calculated as 22.69% of members' pensionable earnings;
- the employers' normal actuarial cost for 2007 is estimated to be $660,600, and member required contributions for 2007 are estimated to be $69,000;
- the Plan would be fully funded on a going concern basis as at December 31, 2006, on the basis of the assumptions and methods described in this report, if its assets were augmented by $1,115,400, which augmentation must be accomplished over a period of not more than 15 years by special payments, made at least quarterly, of at least $114,090 per annum;
- the Plan has a solvency ratio in excess of 1.0 as at December 31, 2006, and would be fully funded were it to be wound up as at the valuation date;
- the next valuation of the Plan must be completed as at a date no later than December 31, 2009, until which time the employers should make contributions of not less than 26.52% and not more than 35.32% of their respective members' pensionable earnings;

- in our opinion,
  - the data on which the valuation is based are sufficient and reliable for the purposes of the valuation,
  - the assumptions are, in aggregate, appropriate for the purposes of determining the funded status of the Plan as at December 31, 2006 on going concern and solvency bases, and determining the minimum funding requirements, and
  - the methods employed in the valuation are appropriate for the purposes of determining the funded status of the Plan as at December 31, 2006 on going concern and solvency bases, and determining the minimum funding requirements.
- this report has been prepared, and our opinions given, in accordance with accepted actuarial practice; and
- all assumptions made for the purposes of the valuation were reasonable at the time the valuation was prepared.



Malcolm Kern
F.C.I.A., F.S.A.

26 June 2007



Carole Richards
F.C.I.A., F.S.A.

26 June 2007

Appendix A

# Plan Assets

## Asset Values at December 31, 2006

The following schedules show how the assets of the Plan are invested. Amounts are taken from the RBC Dexia statements as at December 31, 2006, adjusted for refunds and transfers outstanding.

| | Book Value | Market Value |
|---|---|---|
| **Equities:** | | |
| Canadian | $5,097,605.98 | $8,069,559.68 |
| US | 3,590,483.96 | 3,985,247.28 |
| International | 3,075,443.44 | 4,025,139.40 |
| Accrued Dividends | 13,691.02 | 13,691.02 |
| **Total Equities** | **$11,777,224.40** | **$16,093,637.42** |
| **Fixed Income:** | | |
| Bonds | $5,185,645.98 | $5,327,445.11 |
| Mortgages | 628,644.99 | 629,246.69 |
| Pooled Fixed Income Fund | 3,386,653.13 | 3,394,587.69 |
| Short Term | 1,273,081.91 | 1,273,081.91 |
| Cash and Equivalents | 3,252.32 | 3,252.32 |
| Accrued Interest | 41,341.17 | 41,341.17 |
| **Total Fixed Income** | **$10,518,619.50** | **$10,668,954.89** |
| Pending Trades | 16.04 | 15.82 |
| **Value at December 31, 2006** | **$22,295,859.94** | **$26,762,608.13** |
| Outstanding Benefit Payments | (99,465.42) | (99,465.42) |
| Outstanding Transfer (to) from CUL Plan 1 | 72,923.00 | 72,923.00 |
| **Adjusted Value at December 31, 2006** | **$22,269,317.52** | **$26,736,065.71** |

## Asset Transactions Since Last Valuation

The pension fund transactions for the period from January 1, 2004 to December 31, 2006 are summarised as follows, without adjustment for amounts outstanding at year end:

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| Market Value at January 1 | $25,220,398 | $27,370,803 | $24,728,757 |
| Members' contributions | 113,656 | 78,548 | 71,753 |
| Employers' contributions | 0 | 0 | 0 |
| Net Transfers | 158,228 | (4,605,712) | (306,011) |
| Investment income | 836,335 | 794,677 | 890,471 |
| Net capital gains (losses) | 1,940,407 | 1,778,213 | 2,117,925 |
| Pensions paid | (571,706) | (600,277) | (662,079) |
| Lump-sum refunds | (231,415) | 0 | (2,738) |
| Administration fees | (95,100) | (87,495) | (75,470) |
| Market Value at December 31 | $27,370,803 | $24,728,757 | $26,762,608 |

We have tested the pensions paid, the lump-sum refunds and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

## Investment Returns

We have calculated the investment return of the funds over the intervaluation period, both on a gross basis and a net after expenses basis. Separate calculations were conducted on book values and market values. The market value and book value calculations used average year end asset values before adjusting for items in transit. The return on actuarial values has been calculated excluding the effect of the change in asset valuation method.

| Based on Average Year End | Gross Return Before Expenses | Net Return After Expenses |
|---|---|---|
| Book Values | 7.08% | 6.75% |
| Market Values | 11.45% | 11.14% |
| Actuarial Values | 10.48% | 10.15% |

Appendix B

# Actuarial Methods and Assumptions

## Actuarial Methods – Going Concern

### Valuation of Assets

For this valuation, we have continued to use an adjusted market value method to determine the actuarial value of Plan assets, but we have revised the adjustment methodology. Under this method, 50% of realised and unrealised capital gains (losses) arising during a given year are recognised immediately and 50% of realised and unrealised capital gains (losses) arising during a given year are spread on a straight-line basis over 3 years. As a result, the asset value produced as at December 31, 2006 recognises the following percentages of the realised and unrealised capital gains (losses) that arose during the past 3 years:

| Gains / Losses Arising in Year | Unrecognised Portion |
|---|---|
| 2006: | 50% of 67% |
| 2005: | 50% of 33% |
| before 2005: | 0% |

In the previous valuation we utilized a similar approach, except that the full amount of realized and unrealized gains and losses were spread over the 3 year period.

The asset values produced by this method are related to the market value of the assets, with the advantage that, over time, the market-related asset values will tend to be more

stable than market values. To the extent that more capital gains than losses will arise over the long term, the actuarial value will tend to be lower than the market value.

The actuarial value of the assets, determined as at December 31, 2006 under the adjusted market value method, is $25,717,100. This value was derived as follows:

**Actuarial Value of Assets as at December 31, 2006**

| | | | |
|---|---|---|---|
| **Market value of assets (net of outstanding items)** | | | **$26,736,066** |
| **(LESS) / PLUS unrecognised capital (gains) / losses** | **(Gain) / Loss** | **Unrecognised Portion** | |
| 2006: | (2,117,925) | 50% of 67% | (709,505) |
| 2005: | (1,778,213) | 50% of 33% | (309,470) |
| **Actuarial value of assets** | | | **$25,717,091** |

## Valuation of Actuarial Liabilities

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the *projected unit credit actuarial cost method.* Under this method, we determine the actuarial present value of benefits accrued in respect of service prior to the valuation date, including ancillary benefits, based on projected final average earnings. This is referred to as the *actuarial liability*. For each individual Plan member, accumulated contributions with interest are established as a minimum actuarial liability.

The *funding excess* or *unfunded liability*, as the case may be, is the difference between the actuarial value of assets and the actuarial liability. An unfunded liability will be amortised over no more than 15 years through special payments as required under the *Pension Benefits Standards Act, 1985*. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the Plan or by legislation.

This actuarial funding method produces a reasonable matching of contributions with accruing benefits. Because benefits are recognised as they accrue, the actuarial funding method aims at keeping the Plan fully funded at all times. This promotes benefit security, once any unfunded liabilities and solvency deficiencies have been funded.

## Normal actuarial cost

The *normal actuarial cost* is the actuarial present value of projected benefits to be paid under the Plan with respect to service during the year following the valuation date.

The employers' share of the normal actuarial cost is the total normal actuarial cost reduced by the members' required contributions.

The employers' normal actuarial cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the normal actuarial cost for an individual member will increase each year as the member approaches retirement. Consequently, the normal actuarial cost of the entire group, expressed as a percentage of the members' required contributions, can be expected to increase steadily in the absence of new entrants, with occasional decreases if significant retirements result in a reduction of the average age.

## Employers' Contribution

In summary, the employers' contributions under the actuarial methodology are determined as follows:

**Employers' Contributions**

| With a funding excess | With an unfunded liability |
|---|---|
| Normal actuarial cost | Normal actuarial cost |
| MINUS | PLUS |
| Any funding excess applied to cover the Employers' normal actuarial cost | Payments to amortise any unfunded liability |

The legislative and regulatory context under which the Plan operates will impose constraints upon the degree of contribution adjustment that arises from funding excess and / or unfunded actuarial liabilities.

# Actuarial Assumptions – Going Concern

The actuarial value of benefits is based on economic and demographic assumptions. At each valuation, we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them if necessary. Emerging experience will nonetheless differ from the assumptions, resulting in gains or losses that will be revealed and considered in future actuarial valuations.

For this valuation, we have used the following assumptions, which are identical to those used in the previous valuation:

## Economic Assumptions

### Long Term Inflation

The general long term rate of price inflation in Canada, as measured by the consumer price index, has only indirect influence on the cost of benefits to be provided by the Plan. Nevertheless, it is useful to state an explicit assumption as to the long term rate of inflation, as a point of reference for developing an internally consistent set of assumptions about other economic events that have a more direct impact on Plan costs.

For this valuation, we have assumed an average rate of price inflation of 2.5% per annum, consistent with the observed difference between the yield rates on long term real and nominal government bonds. In the previous valuation we assumed price inflation of 2.0% per annum.

### Investment Return

The calculation of the actuarial liability involves discounting benefits expected to be paid at various dates in the future back to a common point in time, the valuation date. The discount rate used in this process normally should be based upon the expected rate of return of the underlying Plan assets. This assumption should be selected with regard to the very long term nature of the liabilities of the Plan, and should not be unduly influenced by short term economic conditions.

In setting this assumption, we have observed that as at the valuation date the current asset mix policy would be expected to produce returns of 6.75% per annum, after an allowance of 0.35% for expenses, for as long as the current asset mix policy remains in effect. From this return we have subtracted 0.50% as a margin for adverse future contingencies, resulting in an initial discount rate of 6.25% per annum.

We have also observed that the defined benefit program is closed to new entrants, and eventually the funding requirements under the *Employment Pension Plans Act* will become dominated by the solvency or windup considerations, which in turn are dominated by annuity purchase rates. The rates inherent in annuity purchase rates are not dissimilar from the returns expected from an investment portfolio of long term corporate bonds. Such a portfolio would, at the valuation date, be expected to produce returns of 5.10% before expenses and margin.

For this valuation, therefore, we have assumed an initial discount rate of 6.25% per annum until 2020, at which time solvency considerations are expected to dominate. The assumed discount rate for years beginning in 2020 is 4.40% per annum, after allowing 0.35% for expenses and 0.35% for margin. The previous valuation used an assumption of 6.0% per annum for all years.

If the fund achieves higher investment returns than assumed, gains will be revealed at subsequent valuations. If the fund achieves lower investment returns, losses will emerge.

## Escalation of Pensions

Pensions in payment to individuals who retired with Company consent, and their survivors, are increased each January 2 by an amount determined by the Company, having consideration to the rate of increase in the consumer price index, to a maximum of 3% per annum. For the past several years, the actual increase has been based on the increase in the all Canada consumer price index for August over the previous August. For January 2, 2007, the actual increase was 2.1%, and was reflected in this valuation.

We have assumed that this practice will continue in the future. Therefore, consistent with the assumption of annual inflation of 2.5% per annum, we have assumed that future increases in pensions will occur at the rate of 2.5% per annum. In the previous valuation, the assumption was that pensions would increase at 2.0% per annum.

## Increases in Average Wages and YMPE

The benefits provided under the Plan are affected by the YMPE under the Canada Pension Plan, which grows at the rate of average wage increases in Canada. For this valuation, we have assumed this to be 2.75% per annum, being equal to price inflation plus 0.25% for overall productivity gains. The previous valuation assumed increases of 3.0% per annum.

## Increase in Income Tax Act Maximum

The *Income Tax Act* limits benefits to $2,222.22 per year of service for individuals retiring in 2007. This amount is scheduled to increase to $2,333.33, and $2,444.44 times years of service in 2008 through 2009 respectively, and the *Income Tax Act* contains provisions for the dollar limit to be increased annually by the rate of increase in the average industrial wage, beginning in 2010.

For this valuation we have assumed that the maximum benefit limit will increase at the rate of 2.75% per annum, with the first such increase occurring in 2010. The previous valuation assumed increases of 3.0% per annum from the 2005 level that was then the last scheduled level.

## Individual Salary Increases

An assumption as to individual salary increases is necessary in the valuation since the formula for determining the pension to be received is based on the member's average earnings in his highest 60 months of earnings.

Individual salary increases can generally be considered to result from general economic conditions, plus non-economic factors such as merit and promotion. Observing the higher levels of economic activity, price inflation, and wage growth in the local markets in which the participating employers to this plan operate in comparison to increases in average wages in Canada, we have assumed that in the longer term, the economic portion of salary increases will be 4.00% per annum for five years, 3.50% per annum thereafter. The previous valuation utilized an assumed economic increase of 3.00% per annum.

In addition to the general economic factors, individuals will tend to receive increases as they gain experience, win promotions, and generally progress through the ranks of the organization. For this valuation we have assumed that such merit and promotion increases will be in accordance with the 1992 Experience Scale, with higher increases at lower ages. The following table indicates the rate of promotion and merit increases assumed at sample ages.

| Age | Merit & Promotion | Age | Merit & Promotion |
|---|---|---|---|
| 25 | 6.02% | 40 | 1.07% |
| 30 | 3.08% | 50 | 0.47% |
| 35 | 1.75% | 60 | 0.24% |

## Demographic Assumptions

### Retirement

For this valuation we have assumed that active members will retire when their age and service sum to 90 years, provided that retirement does not occur after 65 or before 55. Individuals who have already attained this condition are assumed to retire immediately.

Retirements earlier than assumed will result in losses to the Fund, while later retirements will result in gains to the Fund. These gains and losses will be revealed in subsequent valuations.

### Mortality

The rates of mortality assumed in a valuation serve two purposes: firstly, to determine what portion of the current membership will survive to retirement age, and secondly, to forecast the remaining lifetime of members once they reach retirement. Typically, the incidence of mortality both before and after retirement is assumed to be in accordance with some appropriate and recently published standard table, such as the Uninsured Pensioner 1994 Mortality Table (UP94).

In conjunction with the overall assumption review project, we consulted the Society of Actuaries studies of group annuity mortality, reflecting the same types of sources as used in the creation of the UP94 table. Those studies indicated that recent female mortality continued to be slightly higher than predicted by the UP94 table, and no improvement in mortality was observed during the study period. The studies did observe improvement in male mortality, but much less than predicted by the AA Scale accompanying the UP94 Table.

Taking the information in these studies into account, we have assumed that female mortality will be in accordance with the UP94 Table without projection, and that male mortality will be in accordance with the UP94 Table with generational projection at approximately half the rate set out in the AA Scale. For technology reasons, we have approximated our male mortality assumption by using the UP94 table with generational projection for mortality improvement using the full AA Scale, but only from 2004.

The previous valuation assumed mortality in accordance with the UP94 Table without projection for either males or females.

The following table shows the assumed number of deaths per 1,000 at selected ages.

**Mortality Rates Per 1,000 Employees**

| Age | Males (in 2007) | Females |
|---|---|---|
| 25 | .69 | .31 |
| 35 | .90 | .51 |
| 45 | 1.63 | 1.05 |
| 55 | 4.49 | 2.47 |
| 65 | 14.98 | 9.23 |
| 75 | 38.36 | 24.39 |
| 85 | 102.38 | 72.84 |
| 95 | 249.69 | 200.23 |
| 105 | 440.59 | 415.18 |

To the extent that deaths occur earlier or more frequently than predicted by the assumed rates, gains will emerge to be revealed at subsequent valuations. Deaths occurring later or less frequently than assumed will result in losses to the Plan and Fund.

## Termination of Employment

In the mid-1980s, a detailed review of termination experience was conducted, from which a table of termination rates by age and gender was developed. In the intervening period we have collected data annually concerning actual termination experience in relationship to the experience table, and adjusted the termination assumption as a multiple of that table in accordance with the trends seen developing in that ongoing data review.

Most recently, actual experience appears to be reasonably well predicted by the unadjusted 1983-85 experience table. We have therefore assumed for this valuation that future terminations will occur at 100% of the rates in the table developed from Plan experience in the period from 1983 – 1985. The previous valuation used 75% of the rates from this same table.

The following table shows the number of terminations assumed per 10,000 employees at each age.

## Termination Rates Per 10,000 Employees

| Age | Male | Female | Age | Male | Female |
|---|---|---|---|---|---|
| 20 | 1,000 | 800 | | | |
| 21 | 800 | 900 | 36 | 350 | 800 |
| 22 | 800 | 900 | 37 | 350 | 750 |
| 23 | 700 | 950 | 38 | 350 | 700 |
| 24 | 500 | 1,050 | 39 | 350 | 600 |
| 25 | 400 | 1,050 | 40 | 300 | 500 |
| 26 | 400 | 1,050 | 41 | 300 | 400 |
| 27 | 400 | 1,250 | 42 | 250 | 300 |
| 28 | 400 | 1,300 | 43 | 200 | 250 |
| 29 | 400 | 1,350 | 44 | 150 | 200 |
| 30 | 400 | 1,300 | 45 | 100 | 150 |
| 31 | 400 | 1,150 | 46 | 80 | 100 |
| 32 | 350 | 900 | 47 | 40 | 80 |
| 33 | 350 | 850 | 48 | 30 | 60 |
| 34 | 350 | 800 | 49 | 20 | 40 |
| 35 | 350 | 800 | 50 | 10 | 20 |

### Proportion Married & Age of Spouse

Because the Plan provides benefits to the spouse of a member in certain circumstances, it is necessary to make assumptions as to the likelihood of a member having a spouse in those circumstances.

For this valuation, we have assumed that any member who currently has a spouse will also have a spouse at retirement or earlier death. Any member who does not currently have a spouse, has likewise been assumed not to have one at retirement or earlier death.

Where a pension has commenced and the spouse's date of birth is known, the actual age of the spouse is used in the valuation. Otherwise, male partners in a marital relationship have been assumed to be 4 years older than the female partner.

### Expenses of the Plan

The discount rate was established after allowing 0.35% per annum for expenses, including both investment management expenses and other administrative expenses that have historically been paid from the fund.

## Actuarial Methods – Solvency

When conducting a solvency valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities on a plan windup basis, determined in accordance with the *Pension Benefits Standards Act, 1985*. The values of the Plan's assets and liabilities on a solvency basis are related to the corresponding values calculated as though the Plan were wound up and settled on the valuation date.

Under the terms of the Plan, as amended effective June 1, 2003, benefits are determined using earnings and service which exclude any earnings earned or service rendered after the date of plan termination.

For this valuation, we have considered that benefits payable to members who have already retired, and their survivors, would be settled by the purchase of appropriate life annuities. Such life annuities are assumed to provide for future increases consistent with the pattern developed over the last several years, but applied as a constant annual rate of increase determined on the basis of market expectations of inflation at the date of windup. We have also considered that benefits payable to members who have terminated employment prior to the valuation date, but not yet commenced to receive a pension, would be settled by a lump sum transfer amount calculated in accordance with Section 3800 of the Canadian Institute of Actuaries Standards of Practice. Benefits to terminated members who are eligible to commence the receipt of a pension would be settled by either method, whichever was more favourable to the member.

With respect to members still employed as at the assumed termination date, we have considered that any such member who would already be already eligible to retire would retire with Company consent, and have benefits settled by annuity purchase as for a member already retired. Any active member not eligible to retire immediately, would be treated as if his or her service had terminated on the valuation date, with full vesting, and be entitled to a lump sum transfer amount as described for inactive members who had not yet commenced receipt of benefits. In either case, the benefit provided to an active member would include any benefit that might arise through the application of the 50% rule.

Finally, we have assumed that any situation resulting in termination of this Plan and requiring the purchase of annuities for retired members would also result in the termination of all or a part of CUL Plan 1, and the resultant purchase of annuities for those retired members. Consequently, we have assumed that annuities for this Plan could be purchased as part of a larger group of related annuities.

## Actuarial Assumptions – Solvency

We have observed that, as at December 31, 2006, the guidance provided by the Canadian Institute of Actuaries is that non-indexed immediate annuities be assumed to be available, priced on a level interest assumption of 4.60% per annum. We have also observed that Section 3800 of the Canadian Institute of Actuaries Standards of Practice implies an inflation rate based on the difference between the interest rates applicable for non-indexed and fully indexed benefits.

The interest rates to be used for pension commuted values under Section 3800 for events occurring in December, 2006 are 4.75% for 10 years and 4.75% thereafter for non-indexed benefits and 2.25% for 10 and 2.25% thereafter for fully indexed benefits. In comparison, the technically implied inflation rate applicable as at December 31, 2006, calculated without the two month lag and before rounding, amounted to 2.28% for 10 years and 2.39% thereafter. We have therefore assumed that indexed annuities could be purchased based on a interest rate of 4.60% (as for non-indexed annuities) less an allowance for indexing of 2.50%.

The following table shows the assumptions that would be made in this valuation for solvency purposes, compared to those made in the going concern valuation.

| Assumption / Method | Solvency Basis | Going Concern Basis |
|---|---|---|
| Escalation of indexed pensions: | 2.50% per annum | 2.5% per annum |
| Interest Rate for lump sum transfers: | 4.75% for 10 years, 4.75% thereafter | 6.25% per annum initially, then 4.40% starting in 2020 |
| Interest Rate for annuity purchases: | 4.60% per annum | 6.25% per annum initially, then 4.40% starting in 2020 |

| Assumption / Method | Solvency Basis | Going Concern Basis |
|---|---|---|
| Mortality: | Uninsured Pensioner 1994 Mortality Table, projected to 2015 | Males: Uninsured Pensioner 1994 Mortality Table with generational mortality projected from 2004<br><br>Females: Uninsured Pensioner 1994 Mortality Table |
| Proportion Married: | Based on current marital status | Based on current marital status |
| Spousal Age Difference: | Male partners are 4 years older than female partners | Male partners are 4 years older than female partners |
| Expenses: | Windup expenses of $50,000 | None |
| Asset Valuation Method: | Market value | Market related method with 50% of realised and unrealised capital gains recognised over a 3 year period |
| Actuarial Cost Method: | Projected Unit Credit Actuarial Cost Method | Projected Unit Credit Actuarial Cost Method |

Appendix C

# Membership Data

## Membership Statistics

The following table shows some of the more important statistics regarding the membership covered by the current and previous valuations.

| | 2006.12.31 | 2003.12.31 |
|---|---|---|
| **Active Members:** | | |
| Number of Males* | 31* | 46* |
| Number of Females | 9 | 10 |
| Number with Spouses | 35 | 49 |
| Average Age | 49.6 | 48.9 |
| Average Pensionable Service | 20.9 | 19.6 |
| Average Prior Year Earnings | $77,317 | $73,950 |
| **Vested Former Members:** | | |
| Number | 4 | 3 |
| Average Age | 50.1 | 49.6 |
| Total Monthly Base Pension | $1,769 | $1,330 |
| **Retired Members & Survivors:** | | |
| Number | 33 | 29 |
| Average Age | 69.9 | 68.6 |
| Total Monthly Base Pension | $58,564 | $48,197 |

* Includes 1 member currently accruing benefits under another plan.

## Membership Changes

The following table shows the changes in active membership since the last valuation:

| | |
|---|---|
| Active Members at December 31, 2003 | 56 |
| New Entrants | |
| Transfers from Other CUL Plan | 6 |
| Retirements | (5) |
| Deaths | |
| Terminations | (3) |
| Transfers to Other CUL Plan | (14) |
| Active Members at December 31, 2006 | 40 |

## Distribution of Active Members Accruing Benefits

| Earnings By Age Groups | | | | Earnings By Service Groups | | | |
|---|---|---|---|---|---|---|---|
| Age Group | Count | Earnings | Average | Service Group | Count | Earnings | Average |
| 0-29 | 0 | 0 | 0 | 0-4 | 0 | 0 | 0 |
| 30-39 | 4 | 329,293 | 82,323 | 5-9 | 0 | 0 | 0 |
| 40-44 | 4 | 291,253 | 72,813 | 10-14 | 5 | 360,900 | 72,180 |
| 45-49 | 10 | 880,820 | 88,082 | 15-19 | 12 | 891,240 | 74,270 |
| 50-54 | 10 | 819,610 | 81,961 | 20-24 | 7 | 552,538 | 78,934 |
| 55+ | 11 | 642,698 | 58,427 | 25+ | 15 | 1,158,996 | 77,266 |
| Total | 39 | 2,963,674 | 75,992 | Total | 39 | 2,963,674 | 75,992 |

## Service Groups By Age Groups

| Age Group | Service Group | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 0-4 | 5-9 | 10-14 | 15-19 | 20-24 | 25-29 | 30-34 | 35-39 | 40+ | Total |
| 0-19 | | | | | | | | | | 0 |
| 20-24 | | | | | | | | | | 0 |
| 25-29 | | | | | | | | | | 0 |
| 30-34 | | | | | | | | | | 0 |
| 35-39 | | | 2 | 1 | 1 | | | | | 4 |
| 40-44 | | | 1 | 3 | | | | | | 4 |
| 45-49 | | | | 3 | 1 | 5 | 1 | | | 10 |
| 50-54 | | | 1 | 2 | 3 | 2 | 2 | | | 10 |
| 55-59 | | | 1 | 2 | | 1 | 1 | 1 | | 6 |
| 60-64 | | | | 1 | 2 | 1 | | | 1 | 5 |
| 65+ | | | | | | | | | | 0 |
| Total | 0 | 0 | 5 | 12 | 7 | 9 | 4 | 1 | 1 | 39 |

Appendix D

# Summary of Plan Provisions

## Introduction

The Predecessor Plan was effective January 2, 1962. On December 31, 1986 the Predecessor Plan was split into three parts, covering employees in the Yukon (Plan 2), the Northwest Territories (Plan 3) and elsewhere (Plan 1). Plan 2A was established effective April 1, 1987 to cover Yukon based employees who had previously been employed by the Northern Canada Power Commission (NCPC).

Effective January 1, 1994, Plan 2 was amended to extend coverage to all current and former members of Plan 2A and Plan 3. Liabilities under Plan 2A and Plan 3 were assumed by Plan 2 in exchange for a transfer of assets.

Effective December 30, 2003, the Plan was extended to cover employees located in Ontario.

This valuation is based on the Plan provisions in effect on December 31, 2006. The following is a summary of the Plan's main provisions in effect on December 31, 2006. It is not intended as a complete description of the Plan.

## Eligibility for Membership

The Plan covers salaried employees based in the Yukon, the Northwest Territories, Nunavut and Ontario upon appointment to permanent staff. This typically occurs after 6 months service. In the event that a salaried employee is not appointed to permanent staff earlier, participation in the Plan will commence upon completion of two years service provided earnings exceed 35% of the YMPE in two consecutive calendar years.

Participation in the Plan is compulsory for all eligible employees who are not participating in another registered pension plan of the employer. Exceptions to compulsory participation can be made on religious grounds.

Currently, all active Yukon based Plan members are employed by Yukon Electrical Company Limited, a subsidiary of ATCO Electric Ltd., all active Northwest Territories based Plan members are employed by ATCO Electric Ltd., and all active Ontario based Plan members are employed by ATCO Power Ltd.

Some individuals who were employed by NCPC immediately prior to April 1, 1987 elected to have their pension benefit entitlements under the PSSA transferred to the Plan. For these members, pensionable service under the Plan includes service that was pensionable under the PSSA. Service with NCPC counts for determination of vested rights whether or not the individual member elected to transfer his PSSA benefit entitlements to the Plan.

## Contributions

Members contribute 2.8% of earnings up to the YMPE and 4.0% of earnings over the YMPE, up to an annual maximum contribution of $2,000. Disabled members and certain executive members are not required to contribute.

The employer is required to contribute whatever additional funds are required to properly fund the benefits promised under the Plan.

## Retirement Dates

### Normal Retirement Date

The normal retirement date is the second day of the month following the month in which age 65 is attained.

### Early Retirement Date

A member may retire early after attaining age 55, provided the member has completed at least 2 years of Plan membership.

### Postponed Retirement

A member who remains employed with the company after age 65 may elect to commence receipt of pension or continue to accrue benefits under the Plan up to the earlier of his actual retirement and age 69.

## Retirement Benefits

### Normal Retirement

The annual pension benefit at normal retirement is equal to:

(a) 1.4% of annual final average earnings up to the YMPE, times years of pensionable service; **plus**

(b) 2.0% of annual final average earnings in excess of the YMPE, times years of pensionable service.

Annual final average earnings are calculated over the 60 consecutive months for which earnings are highest. The YMPE is calculated over the same period.

The formula applicable to members who joined the Plan prior to January 2, 1966 contains other components not described above. However, no remaining active members are affected by those provisions.

### Early Retirement

If a member retires from active service with the consent of the Company, a reduced early retirement benefit is payable, as follows:

(a) if age and service sum to 90 years or more, no reduction applies;

(b) otherwise, the pension payable is equal to the normal retirement pension times a percentage from the following table:

| Age at Retirement | Percentage |
|---|---|
| 64 | 100 |
| 63 | 100 |
| 62 | 100 |
| 61 | 97 |
| 60 | 94 |
| 59 | 88 |
| 58 | 82 |
| 57 | 76 |
| 56 | 70 |
| 55 | 64 |

If retirement is not from active service, or if Company consent is not obtained, an actuarial reduction applies.

Female participants employed prior to June 1, 1972 are entitled to a bridge benefit payable to age 65. However, no active members remain to whom this provision applies.

## Maximum Pension Limits:

The Plan provides that the pension payable at the time of commencement must not exceed the defined benefit limit prescribed under the Income Tax Act, multiplied by years of pensionable service (with service rendered prior to January 1, 1992 limited to 35 years). Reductions to this maximum apply if retirement occurs before age 60, before completion of 30 years service, and before attainment of age and service summing to 80. The maximum provision automatically reflects any increases to the defined benefit limit that occur in the Income Tax Act and Regulations.

## Escalation of Pensions after Retirement:

Pensions in payment to individuals who retired directly from active service with Company consent, and their survivors, are increased each January 2 by an amount determined by the Company, having consideration to the rate of increase in the consumer price index, to a maximum of 3% per annum. For the past several years, the actual increase has been based on the increase in the all Canada consumer price index for August over the previous August.

# Survivor Benefits

## Death Before Retirement

If a member dies prior to becoming fully vested, the member's spouse, or the member's beneficiary if there is no surviving spouse, will receive a refund of the member's contributions with interest.

If a member dies after becoming fully vested, the member's spouse, or the member's beneficiary if there is no surviving spouse, will receive a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value.

If a member, other than an Ontario based member, with a spouse dies after becoming fully vested and after age 55, the spouse shall receive a benefit equal to that described above, but not less than:

(a) the value of the member's required contributions made prior to January 1, 1987, plus interest; plus

(b) the value of any additional voluntary contributions made by the member, plus interest; plus

(c) the commuted value of the 60% surviving spouse's benefit to which the spouse would have been entitled in respect of service after January 1, 1987 had the member retired on the date of death; plus

(d) a refund of any required contributions made after January 1, 1987, plus interest, which exceed 50% of the commuted value of the deferred pension to which the member would have been entitled in respect of service after January 1, 1987 had he retired on the date of death.

Certain of these amounts must be transferred to the spouse's locked-in RRSP.

## Death After Retirement

The normal form of pension for single employees guarantees a return of the member's own contributions with interest up to retirement date.

For married employees, the normal form of pension provides a continuing survivorship pension to the member's spouse. If retirement occurs prior to July 1, 1987, the spouse's benefit is 50% of the member's benefit. If retirement occurs after July 1, 1987 the spouse's benefit is 60%.

## Termination Benefits

Benefits become fully vested after 2 years of membership.

If termination occurs prior to full vesting, a refund of the member's contributions with interest is made.

If termination occurs after full vesting, the member is entitled to a deferred pension commencing at normal retirement date, or alternatively the commuted value thereof may be transferred to the member's locked-in RRSP. If the member's own contributions exceed 50% of the commuted value of the deferred pension, the excess is available as an additional benefit.

If termination occurs after age 45 but before full vesting, the member may elect to transfer the value of a deferred pension to his locked-in RRSP instead of receiving a lump sum refund. The 50% contribution test does not apply.

Appendix E

# Commuted Value Basis

## Basis for Calculating Commuted Values upon Termination of Employment

**Interest:**

| | |
|---|---|
| First 10 Years | month end value of the nominal rate of interest on 7 year Government of Canada benchmark bond (CANSIM series B14070) in the second calendar month preceding the month in which the computation date falls, converted from a nominal rate compounded semi-annually to an annual effective rate, plus 0.50% and rounded to the nearest multiple of ¼%. |
| Subsequent Years | month end value of the nominal rate of interest on long term Government of Canada benchmark bond (CANSIM series B14072) in the second calendar month preceding the month in which the computation date falls, converted from a nominal rate compounded semi-annually to an annual effective rate, plus half the difference between that rate and the corresponding rate based on the 7 year benchmark bond, plus 0.50% and rounded to the nearest multiple of ¼%. |

| | |
|---|---|
| **Mortality Before Retirement:** | None |
| **Mortality After Retirement:** | UP94 Table projected to 2015, sex distinct rates |
| **Retirement Age:** | Age 65, or actual age if retiring directly from active service |
| **Proportion Married:** | Married at retirement if married at termination |
| **Age of Spouse:** | Actual Age |
| **Calculation Valid for:** | 8 months from date of termination, if increased with interest at the rate applicable for the first 10 years. After 8 months, a new commuted value must be calculated. |

Appendix F

# Employer Certification

With respect to the report on the actuarial valuation of the *Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies – Plan 2*, as at December 31, 2006, I hereby certify that, to the best of my knowledge and belief:

- a copy of the official Plan documents and of all amendments made up to December 31, 2006, were provided to the actuary;
- the membership data provided to the actuary includes a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2006, and
- all events subsequent to December 31, 2006 that may have an impact on the results of the valuation have been communicated to the actuary.

_____ _____

Date Signed

_____

Name

_____

Title

MERCER
Human Resource Consulting

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222 Third Avenue SW
Calgary, Alberta
Canada T2P 0B4
403 269 4945

Mercer Human Resource Consulting Limited

MMC Marsh & McLennan Companies

**YUB-YECL-29**

**Reference:** Return on Rate Base, Application, page 8-3

**Issue:** Capital Additions

**Request:**

Please explain and account for the difference between Capital Additions and Expenditures.

**Response:**

Capital Expenditures are capital related disbursements that occur in the fiscal year. The project's associated with these disbursements may or may not be capitalized (rate based) as of December 31. If a project is not capitalized, it remains in work-in-progress.

Capital Additions relate to those projects that are capitalized (rate based) in a given year. The amount capitalized will include expenditures incurred in the year the project was capitalized and may also include expenditures (work-in-progress) relating to a prior year.

For further information please refer to Schedule 9.1 in the Application.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company



**YUB-YECL-30**

**Reference:** Return on Rate Base, Application, page 8-5, 8-6

**Issue:** Working Capital

**Request:**

Please explain and quantify the increase in inventory from 2006 to 2007. Show inventory values for the years 2005 to 2007 inclusive and for each of the test years 2008 and 2009.

**Response:**

The increase in inventory from 2006 to 2007 as explained on page 8.6 of the application and outlined on Schedule 8.9, represents an increase in the 3 year average. This three year average increased in 2007 as the 2004 inventory amount of 1,289 was replaced with the 2007 inventory amount of 1,849. The increase in inventory from 2004 to 2007 is a result of increased prices during that three year period as well as increased levels of inventory to support projects.

Please refer to YUB-YECL-30 Attachment 1 for inventory values from 2004-2009.

# Yukon Electrical
# Inventory
# 000 s

| | Annual | 3-Year Average |
|---|---|---|
| 2004 | 1,289 | |
| 2005 | 1,474 | |
| 2006 | 1,784 | 1,516 |
| 2007 | 1,849 | 1,702 |
| 2008 | 1,940 | 1,858 |
| 2009 | 2,036 | 1,942 |

**YUB-YECL-31**

**Reference:** Prepared Testimony of Foster Associates Inc., page 13

**Issue:** Cost of Debt

**Quote:** The 2007-2008Q1 average masks the widening spreads over the period. As investors have become more risk-averse, and the outlook for the economy has deteriorated, credit spreads have widened considerably since the end of 2006. (Line No. 350-352.)

**Request:**

(a) The spreads discussed are over similar term Government of Canada bonds. Please provide the change in the bond rate over the same period.

(b) Earlier on page 13, it was indicated that CU Inc. has been able to raise new 30-year debt on average at approximately 120 basis points over a similar term Government of Canada bond during 2007 and the first quarter of 2008. How does that reconcile to the 157 basis point spread at the end of March 2008?

(c) Would the U.S. mortgage crisis have any effect on these spreads?

**Response:**

(a) The indicated spreads referenced at lines 350-352 are relative to the long-term Canada bond yield. The yields on the long-term Canada bond for the period 2006Q1 to 2008Q1 are presented in the table below:

**Average Long-Term Canada Yield**

| | 2006 | 2007 | 2008 |
|---|---|---|---|
| **Q1** | 4.23 | 4.17 | 4.07 |
| **Q2** | 4.54 | 4.35 | |
| **Q3** | 4.21 | 4.45 | |
| **Q4** | 4.07 | 4.21 | |

The bond yields for the sample of A rated Canadian utilities for the same period are presented in the table below:

**Yield for Sample of A Rated Utilities**

| | 2006 | 2007 | 2008 |
|---|---|---|---|
| **Q1** | 5.4 | 5.4 | 5.8 |
| **Q2** | 5.7 | 5.6 | |
| **Q3** | 5.4 | 5.8 | |
| **Q4** | 5.3 | 5.7 | |

(b) The 120 basis points is an average over the entire period referenced. See lines 350 to 354 and Schedule 1 of Ms. McShane's evidence.

(c) Yes, in large part; the U.S. mortgage crisis can be viewed as the trigger for a broad repricing of risk across financial markets. It is unclear whether this bursting of the latest bubble in the market will result in a permanent increase in spreads due to investors being more cautious than they had been since approximately late 2004. Further, spreads are likely somewhat wider than they were in the past due to the elimination of the Foreign Property Rule, which had the effect of keeping domestic bond yield spreads relatively low. While the FPR was in place, institutions like pension funds focused their Canadian content investments on bonds, and their foreign investment on equities. With the FPR no longer in place, Canadian debt issuers will have to compete with yields offered globally.

**YUB-YECL-32**

**Reference:** Prepared Testimony of Foster Associates Inc., page 13

**Issue:** Cost of Debt

**Preamble:** The recent differential between the TransAlta Corporation cost of long-term debt and the CU Inc. cost of long-term debt of approximately 233 basis points provides a perspective on the potential magnitude of the benefits to ratepayers of Yukon Electrical's affiliation with CU Inc. (Line No. 367-370.)

**Request:**

(a) Would you describe TransAlta's core operations as that of a regulated utility?

(b) Would a fully regulated utility present less risk than a non-regulated company?

**Response:**

(a) No.

(b) It depends on the combination of business and financial risk. The cost of debt of TransAlta represents the cost of debt to a company whose combined business and financial risks are such that it has achieved debt ratings in the BBB category. A regulated utility with similar debt ratings would face a similar cost of debt.

**YUB-YECL-33**

**Reference:** Prepared Testimony of Foster Associates Inc., page 14

**Issue:** Cost of Debt

**Quote:** As a true stand-alone entity, Yukon Electrical would not be able to obtain investment grade debt ratings given its small size. (Line No. 370-372.)

**Request:**

(a) Does CU Inc. raise investment grade debt for ATCO Gas, ATCO Electric Ltd., ATCO Pipelines and other affiliates as well as for YECL?

(b) If CU Inc. did not include ATCO GAS and ATCO Pipelines in its portfolio (that is if it was substantially smaller), would it maintain the same investment grade rating?

(c) Incrementally, does YECL contribute to the size CU Inc. and therefore CU Inc.'s ratings benefit from having YECL as part of the portfolio?

**Response:**

(a) Yes.

(b) Ms. McShane cannot state with certainty whether the loss of ATCO Gas and ATCO Pipelines would reduce CU Inc.'s ratings, but in part the credit ratings are a function of its diversification across regulated industry sectors rather than size. If ATCO Gas and ATCO Pipelines were removed, CU Inc. would be operating in the electric utility industry, and thus benefit less from diversification. Consequently, it is likely that its ratings would be lower without ATCO Gas and ATCO Pipelines.

(c) Yes, in principle Yukon Electrical would contribute to the size of CU Inc., and thus provide some small contribution to the size and diversification of the entity which provides its debt. That fact does not detract from the conclusion that on its own, Yukon Electrical would not be able to achieve the low level of debt costs from which it benefits from its affiliation with CU Inc.

**YUB-YECL-34**

**Reference:** Prepared Testimony of Foster Associates Inc., page 14

**Issue:** Compatibility of Capital Structure with Business Risks

**Quote:** The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework that can lead to the failure to recover a compensatory return on, and or the return of, the capital investment itself. (Line No. 380-383.)

**Request:**

(a) For the last 20 years, how many times has YECL or its parent (ATCO Electric Ltd.) not made its regulatory return?

(b) For the past 20 years, how many times has YECL or its parent (ATCO Electric Ltd.) exceeded its regulatory return?

(c) If a company consistently meets or exceeds its regulatory return, does this imply a lower business risk?

(d) If a company consistently meets or exceeds its regulatory return, does this imply a lower regulatory risk?

(e) If a company consistently meets or exceeds its regulatory return, does this imply a lower financial risk?

**Response:**

(a&b) In the last 20 years YECL has not made its regulatory return in 15 years and exceeded the regulatory return in five years.

The regulated return for ATCO Electric is not relevant to the current proceeding.

(c&d) No. Consistently earning the allowed return, as, for example, is possible for some NEB-regulated pipelines operating under a full cost of service method of regulation, does not eliminate longer-term risks. Each year, the risk of earning or not earning the approved return is subject to a large variety of circumstances that are unpredictable for the subject year. The after the fact result achieved does not reduce the risk.

(e) No. The ability to earn the allowed return is not a financial risk. It is a business regulatory risk.

**YUB-YECL-35**

**Reference:** Prepared Testimony of Foster Associates Inc., page 2

**Issue:** Benchmark ROE

**Quote:** However, the benchmark ROE is viewed as below the level consistent with a fair and reasonable return. (Line No. 49-50.)

**Request:**

(a) Please provide any regulatory decision supporting that view.

(b) Please provide other sources that support that view.

**Response:**

(a) The comment was not based on regulatory decisions. Please see lines 949-963.

(b) The following files containing the requested documentation are attached:

YUB-YECL-35(b) Attachment 1 - BMO Taylor 2007 ROE Assessment December 2006

YUB-YECL-35(b) Attachment 2 - CEPA - Perspective on Canadian Gas Pipeline ROEs 2-08

YUB-YECL-35(b) Attachment 3 - CIBC World Markets Time to Lighten Up 12-3-01

YUB-YECL-35(b) Attachment 4 - Conference Board Opening Power Markets March 2004

YUB-YECL-35(b) Attachment 5 - Gordon-Makholm -- Allowed Return on Equity in Canada & US NERA

| | |
|---|---|
| YUB-YECL-35(b) Attachment 6 - | Major-Priddle -- Fair Return Standard for Return on Investment Canadian Gas Utilities |
| YUB-YECL-35(b) Attachment 7 - | NEB Hydrocarbon Transportation 2007 |
| YUB-YECL-35(b) Attachment 9 - | NEB Hydrocarbon Transportation 2006 |
| YUB-YECL-35(b) Attachment 8 - | NEB Hydrocarbon Transportation 2005 |

# Pipelines/ Gas & Electric Utilities

**Industry Rating Pipelines:** **Market Perform**

**Industry Rating Gas & Electric Utilities:** **Market Perform**

**December 7, 2006**
Toronto, Ontario

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## 2007 ROEs Decline to Unprecedented Levels; Ontario Gets Reprieve

### Highlights

- The ugly got uglier – actual 2007 allowed ROEs declined by an average of 0.37% versus the average allowed return on equity for 2006. The average actual allowed return on equity in 2007 is 8.65% versus 9.01% in 2006.
- The announced allowed returns are fully reflected in our diluted EPS estimates over the 2007 and 2008 forecast period.
- Although we believe that the allowed returns established by the automatic adjustment mechanisms set out herein likely violate the Fair Return Standard and are confiscatory, they are in line with expectations and therefore neutral to our outlook.
- Companies with material exposure to these automatic adjustment mechanisms include Canadian Utilities Limited, Pacific Northern Gas, Gaz Metro L.P., Fortis Inc. and TransCanada Corporation. Companies with limited exposure to ROE adjustment mechanisms include: Enbridge Inc., Duke Energy, and TransAlta Corporation.
- There are a number of companies in our coverage universe with no exposure to these automatic adjustment mechanisms: Caribbean Utilities, and Emera Inc. The pipeline and power trusts/limited partnerships in our coverage universe generally do not have a material exposure to these mechanisms.
- On November 23, the Ontario Energy Board abandoned its generic licence amendment proceeding, the purpose of which, among other things, was to codify its approach to determining the allowed return on equity. The Board has also rejected the implementation of an alternative approach to determine the allowed return on equity for Ontario's local electricity distribution utilities. We believe that this alternative approach was seriously flawed and had no basis in reality.
- We rate the units of Fort Chicago Energy Partners, LP, Inter Pipeline Fund, and Northland Power Income Fund Outperform. We also rate the shares of Pacific Northern Gas Ltd., and Caribbean Utilities Co. Ltd. Outperform.
- We remain restricted on the units of Calpine Power Income Fund.

**This report was prepared by an Analyst employed by a Canadian affiliate, BMO Nesbitt Burns Inc., and who is not registered/qualified as a research analyst under NYSE/NASD rules. For disclosure statements, including the Analyst's Certification, please refer to pages 10 to 12.**

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The allowed rates of return on equity (ROE) for many of the pipeline and energy utility companies in our coverage universe are established by an automatic adjustment mechanism in the fall of each year and are highly dependent on forecast interest rates for the prospective fiscal period. As discussed below, the 2007 allowed ROEs for various jurisdictions have now been established and allowed ROEs, on a cumulative basis, have reached unprecedented lows.

## A. The Calculations

Table 1 sets out the key variables that drive each of the automatic adjustment mechanisms, by regulator.

***Table 1**: Key Input Assumptions*

| Regulator | Year Formula Effective | Month of Consensus Economics | Base GOC Yield | Equity Risk Premium | Adjustment Factor | 2004A ROE | 2005A ROE | 2006A ROE | 2007E ROE | Change 2007 vs. 2006 |
|---|---|---|---|---|---|---|---|---|---|---|
| National Energy Board | 1995 | November | 9.25% | 3.00% | 75% | 9.56% | 9.46% | 8.88% | 8.46% | -0.42% |
| British Columbia Utilities Commission - Terasen Gas (BCGU) | 2006 | November | 5.25% | 3.90% | 75% | 9.15% | 9.03% | 8.80% | 8.37% | -0.43% |
| British Columbia Utilities Commission - Terasen Gas (Centra) | 2006 | November | 5.25% | 4.60% | 75% | 9.65% | 9.53% | 9.50% | 9.07% | -0.43% |
| British Columbia Utilities Commission - PNG West Division/Tumbler Ridge | 2006 | November | 5.25% | 4.55% | 75% | 9.80% | 9.68% | 9.45% | 9.02% | -0.43% |
| British Columbia Utilities Commission - PNG Ft. St. John/Dawson Creek/FortisBC | 2006 | November | 5.25% | 4.30% | 75% | 9.55% | 9.43% | 9.20% | 8.77% | -0.43% |
| Alberta Energy and Utilities Board | 2005 | November | 5.68% | 3.92% | 75% | 9.60% | 9.50% | 8.93% | 8.51% | -0.42% |
| Ontario Energy Board - Enbridge Gas Distribution | 1998 | October | 7.25% | 3.40% | 75% | 9.69% | 9.57% | 8.74% | 8.39% | -0.35% |
| Ontario Energy Board - Union Gas[1] | 1998 | October | 7.25% | 3.55% | 75% | 9.62% | 9.63% | 8.92% | 8.53% | -0.39% |
| Regie de l'energie[2] | 1999 | August | 5.76% | 3.84% | 75% | 9.45% | 9.69% | 8.95% | 8.73% | -0.22% |
| Nova Scotia Utilities and Review Board | | | | Formula Not Presently In Use | | | | | | |
| Island Regulatory and Appeals Commission | | | | | | | | | | |
| Newfoundland and Labrador Board of Commissioners of Public Utilities[3] | 2000 | Oct/Nov | 5.60% | 4.15% | 80% | 9.75% | 9.24% | 8.77% | 8.60% | -0.17% |

Notes:
(1) Issue of Consensus Economics used to calculate allowed ROE has varied.
October stipulated in June 29, 2006 Reasons for Decision re: 2007 Rates.
(2) Excludes 0.57% of Allowed Incentive Return in 2003, 1.51% in 2004, 1.95% in 2005, 0.38% in 2006, and approximately 0.75% in 2007
(3) Return on Equity for Newfoundland Power Inc. Fixed for two-years at 9.75% in decision dated June 20, 2003. Total Return Calculation methodology.
Source: BMO Capital Markets

As set out in Table 1, the allowed ROEs established for the 2007 period are an average of 0.37% lower than in 2006. The primary reason for the decline in allowed return is the precipitous drop in the implied forecast 30-year bond yield arising from: (i) reduction in the underlying Consensus Estimate for 2007 versus 2006 to 4.15% from 4.55%; and (ii) decline in the observed spreads between the 10-year and 30-year government of Canada bond yields, as published in the National Post throughout October of 2006 versus a similar period in 2005, to approximately 7 basis points from approximately 23 basis points.

Tables 2, 3, and 4 highlight the calculation of the allowed 2007 actual ROE for the National Energy Board (NEB), Alberta Energy and Utility Board (AEUB), and the British Columbia Utilities Commission (BCUC). Table 5 highlights our estimate of the allowed return on equity for Enbridge Gas Distribution, as per the automatic adjustment mechanism notionally used by the Ontario Energy Board (OEB). We note that that the OEB, unlike its utility peer group, does not publish or release the calculation for the allowed return for the utilities subject to its purview. We note that the formulas appear to vary between Union Gas and Enbridge Gas Distribution and also between the electricity and natural gas sectors.

***Table 2**: Calculation of the 2007 Actual ROE – Multi-Pipeline Cost of Capital*

| Description | | |
|---|---|---|
| 2006 Calculated Return on Equity | | 8.88% |
| 2006 Forecast Yield | | 4.78% |
| | | |
| November 2006 Consensus Forecast - 3 Months Out | | 4.10% |
| November 2006 Consensus Forecast - 3 Months Out | | 4.20% |
| | Average | 4.15% |
| Average Spread between 10-year and 30-year GOCs[1] | | 0.07% |
| Forecast Long-Term (30-year) GOC Bond Yield - 2007 | | 4.22% |
| | | |
| | 2007 Forecast Yield | 4.22% |
| | Less: 2006 Forecast Yield | 4.78% |
| | Difference | -0.56% |
| | | |
| | Times 75% Adjustment Factor | -0.42% |
| | Plus: 2006 Approved Return on Equity | 8.88% |
| | Equals 2007E Approved Return on Equity | 8.46% |

Note:
(1) Calculated by using the 10-year and 30-year Government of Canada bond yields published daily in the National Post throughout October of the current year
Source: BMO Capital Markets

***Table 3**: Calculation of the 2007 Actual ROE – AEUB*

| Description | | |
|---|---|---|
| Calculated Return on Equity Per Decision | | 9.60% |
| Forecast Yield Per Decision | | 5.68% |
| | | |
| November 2006 Consensus Forecast - 3 Months Out | | 4.10% |
| November 2006 Consensus Forecast - 3 Months Out | | 4.20% |
| | Average | 4.15% |
| Average Spread between 10-year and 30-year GOCs[2] | | 0.07% |
| Forecast Long-Term (30-year) GOC Bond Yield - 2007 | | 4.22% |
| | | |
| | 2007 Forecast Yield | 4.22% |
| | Less: 2006 Forecast Yield | 5.68% |
| | Difference | -1.46% |
| | Times 75% Adjustment Factor | -1.10% |
| | Plus: Approved Return on Equity | 9.60% |
| | Equals 2007E Approved Return on Equity | 8.51% |

Note:
(2) Calculated by using the 10-year and 30-year Government of Canada bond yields published daily in the National Post throughout October of the current year
Source: BMO Capital Markets

***Table 4**: Calculation of the 2007 Actual ROE – BCUC*

| Description | | |
|---|---|---|
| 2006 Calculated Return on Equity | | 8.80% |
| | | |
| November 2006 Consensus Forecast - 3 Months Out | | 4.10% |
| November 2006 Consensus Forecast - 3 Months Out | | 4.20% |
| | Average | 4.15% |
| Average Spread between 10-year and 30-year GOCs | | 0.07% |
| Forecast Long-Term (30-year) GOC Bond Yield - 2007 | | 4.22% |
| | | |
| | Benchmark Return per G-14-06 | 9.145% |
| | Long-Term (30-year)GOC Bond Yield Decision | 5.25% |
| | | |
| | 2007 Forecast Yield | 4.22% |
| | Less: Bond Yield from Decision | 5.25% |
| | Difference | -1.03% |
| | Times 75% Adjustment Factor | -0.77% |
| | Plus: Approved Return on Equity Decision | 9.145% |
| | Equals 2007E Approved Return on Equity | 8.37% |

Source: BMO Capital Markets

***Table 5**: Calculation of the 2007E ROE for Enbridge Gas Distribution – OEB*

| Description | | |
|---|---|---|
| 2006 Calculated Return on Equity | | 8.74% |
| 2006 Forecast Yield | | 4.70% |
| | | |
| November 2006 Consensus Forecast - 3 Months Out | | 4.10% |
| November 2006 Consensus Forecast - 12 Months Out | | 4.20% |
| | Average | 4.15% |
| Average Spread between 10-year and 30-year GOCs | | 0.08% |
| Forecast Long-Term (30-year) GOC Bond Yield - 2006 | | 4.23% |
| | | |
| | 2007 Forecast Yield | 4.23% |
| | Less: 2006 Forecast Yield | 4.70% |
| | Difference | -0.47% |
| | Times 75% Adjustment Factor | -0.35% |
| | Plus: 2006 Approved Return on Equity | 8.74% |
| | Equals 2007E Approved Return on Equity | 8.39% |

Source: BMO Capital Markets

## B. Allowed Returns are Confiscatory

We believe on a collective basis, that the allowed returns as established by the formulas highlighted above are confiscatory and likely violate the Fair Return Standard. This standard, as established by Canada's Supreme Court and accepted by the National Energy Board in 1971, states that a fair or reasonable rate of return should:

1. be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable earnings standard);
2. enable the financial integrity of the regulated enterprise to be maintained and permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the financial integrity and capital attraction standards); and
3. achieve fairness from the viewpoint of the customers and from the viewpoint of present and prospective investors (appropriate balance of customer and investor interests).

We believe that regulators have consistently refused to give weight to a number of arguments that would result in higher allowed returns, solely on the basis that to do so would result in higher customer rates.

- The North American capital markets are increasingly integrated and investors have the ability to invest in utility assets north and south of the border.
- There is merit incorporating U.S. market metrics into the analysis and that the Canadian benchmark equity portfolio (the S&P/TSX) may not meet the theoretical requirement for a diversified market portfolio.
- The returns on comparable investments with similar risk, whether they be Canadian or U.S. examples, should be considered.
- The allowed return on equity and deemed equity must satisfy all aspects of the Fair Return Standard and that no part of the Standard has priority.

- The continued reliance on a derived 30-year government of Canada bond yield may not be a relevant proxy for the cost of debt (and/or a proxy for the risk free rate) for two key reasons: (i) the observed and anticipated reduction in the supply of government of Canada securities and the continued conversation in the financial market that the government may cease to issue debt securities at the long end of the curve may result in distortions in the market cost of these securities and thus the observed yields; and (ii) that corporate debt issuers do not have access to the debt capital market at government yield levels.

- No pipeline or energy utility in our regulated coverage universe has issued equity in the last five years to fund, on an unlevered basis, a dollar-for-dollar equity investment in utility rate base. Continued assertions by regulators that utilities have adequate access to capital are not credible with respect to the equity component, as access to equity has not been tested over the ensuing period. For example, On September 16, 2003, Fortis Inc. announced that it planned to acquire the assets of Aquila British Columbia and Aquila Alberta for $1.36 billion, including assumed debt. The company financed the transaction by assuming approximately $689 million of utility debt and issued approximately $170 million of holdco debt, $200 million of holdco preferred shares and new equity of approximately $350 million. Despite the levered nature of the transaction and the prospect for above average rate base growth at the two target utilities, the common shares of Fortis Inc. declined by 5% at the time the transaction was announced and the transaction was initially widely expected to be dilutive until 2006.

- None of the pipeline projects highlighted in our May 24, 2006, report entitled "Exchanging Fire", save and except the Canadian portion of the Southern Access Pipeline (with an approximate cost of $160 million versus an estimated cost to Enbridge of projects currently permitted and/or under way of $8 billion), are expected to earn the National Energy Board multi-pipeline decision return on equity. We note that in many instances, the market-based tolling arrangements with shippers result in a risk profile similar to that of the benchmark pipeline, the TransCanada Mainline pipeline.

- Continued investment in utility rate base by the owners of utilities is not an acquiescence that the allowed return on equity is appropriate and that investment may relate to other obligations including the utility's obligation to be the supplier or supply or last resort and fulfil the obligation to serve, maintain the safe and reliable operation of the utility, and may be fulfilling specific conditions of its operating licence.

- A failure by utility companies to annually litigate the allowed return on equity "formula" does not constitute acceptance of the adequacy of the allowed return. Rather, we believe that the lack of annual litigation reflects the cost of the process, the time required to pursue litigation that detracts from management's ability to focus on the efficient operation of the business and the potential damage to important utility regulatory and customer relationships.

- The evidenciary standard is too high and almost impossible to meet. Moreover, we believe that notwithstanding decisions from the Supreme Court that stipulate otherwise, utility regulators continue to rely heavily on their quasi-judicial and expert status to impose a bare-bones return on equity and drive down the deemed capital structure of

the utility in order to protect customers from prices, without the fear of reconsideration upon appeal. Regulators must establish the cost of equity and deemed equity not because they are experts in this regard, but in order to establish just and reasonable rates. The regulator is not permitted to consider the effects on customers in the determination of the allowed ROE and capital structure, and we do not believe that the regulator is permitted to factor in other policy objectives into its determination of the allowed return on equity; i.e., we do not believe that the regulator is permitted to reduce the allowed return on equity and/or deemed equity for small utility companies in order to encourage consolidation or any other specific policy objective. We believe in these situations, that the inclusion of these other factors in the assessment of cost of equity and designation of deemed equity, unlawfully transfers value to utility ratepayers from its legitimate owner, the utility shareholders.

## C. Ontario Gets a Reprieve

On November 23, the Ontario Energy Board (OEB) issued a notice to participants regarding its Multi-year Electricity Distribution Rate Setting Plan, including the Cost of Capital, 2nd Generation Incentive Regulation Mechanism and Generic Licence Amendment Proceeding. The Board indicated that, pursuant to Staff and Panel recommendations, the Board discontinue its code-based approach (November 17 and November 20, 2006 respectively); that in the interests of achieving a more timely setting of electricity distribution rates for the 2007 rate year, the Board will instead implement its cost of capital and 2nd generation incentive regulation policies by means of guidelines. As a result, the Board discontinued the generic licence amendment proceeding, which was commenced on the Board's own motion.

On November 30, the Board issued a Draft Report on the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors and Associated Guidelines. The draft report details the Board's policies on cost of capital and 2nd generation incentive regulation, and draws on the work of Board staff and the input of interest parties since this consultation was initiated in April 2006. Also included are guidelines to assist parties in understanding how the policies will be implemented and information for distributors in preparing their rate applications for the 2007 rate year.

The Draft Report contains the following highlights with respect to the cost of equity capital and deemed capital structure:

- The Board has determined that the current approach to setting ROE will be maintained. The ROE will be determined based on the Long Canada Bond Forecast rate plus an equity risk premium. The Board's current approach has been in place for six years. The consultation process undertaken by the Board included a review of one method that would have required more time and greater costs for its implementation. We also note that the range of ROE produced by this alternative method was unacceptably low; well below the various rates of return discussed previously. The Board concluded that none of the approaches reviewed is better than the Board's current method.
- The Board's method will continue to include an implicit premium of 50 basis points (0.5%) for floatation and transaction costs.

- The current method was established in 1999 as part of a review of cost of capital. The ROE calculated at that time is the starting point for the calculation and is 9.35% (as per Hydro One Network Inc.'s RP-1998-0001 Decision). This formula is $ROE_t$ = 9.35% + 0.75 ($LCBF_t$ – 5.50%). The Long Canada Bond Forecast will use the average of the January consensus forecast of the 10-year Government of Canada bond yield 3 months ahead and 12 months ahead plus the difference between the observed yields on the 30-year Government of Canada bond yield and the 10-year Government of Canada bond yield as published by the Bank of Canada during the month of January (2007).
- No incentive returns for capital investments are appropriate at this time.
- No earnings sharing mechanisms are appropriate for second generation incentive rate making.
- The Board will include an adjustment to rates in 2008, 2009 and 2010 to transition distributors from their existing capital structures to a single deemed capital structure of 40% equity and 60% debt:
  - o For distributors starting at equity of 35%, the equity component will move in equal increments over two years until it reaches 40%.
  - o For distributors starting at equity of 45%, the equity component will move in equal increments over two years until it reaches 40%; and
  - o For distributors starting at equity of 50%, the equity component will move in equal increments over three years until it reaches 40%.

We believe that the following points are relevant about the draft guidelines:

- The current formula is not expected to result in a return on equity that is materially higher than the formulas previously discussed. We reiterate that the existing formulas result in an allowed return on equity that likely violates the Fair Return Standard and we believe them to be confiscatory.
- We are not convinced that a "one-size fits all" capital structure is appropriate and we are concerned that the Board's policy objectives of regulatory efficiency and LDC consolidation are driving force behind the single deemed capital structure approach. This may not be appropriate.
- We are not disappointed by the Board's decision to abandon the Licence Amendment proceeding and the rejection of the alternative approach to determining the return on equity. This latter item was seriously flawed and had no basis in reality. We set out our views on this approach in comments/reports dated June 27, August 8 and September 7, 2006.

# D. Comparable Equity Securities

**Canadian Gas Utilities**

| Company | TSX Ticker | Price (C$) 5-Dec-06 | Shares O/S (mm) | Market Cap. (mm) | Earnings per Share 2004A | 2005A | 2006E | 2007E | P/E Ratios 2004A | 2005A | 2006E | 2007E | Dividend Rate | Yield | 12-Month Target | Total Return | Rating |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Duke Energy Corp.[2] | DUK[5] | $32.69 | 1089.6 | $35,618 | $1.32 | $1.73 | $1.78 | $1.95 | 16.8 | 16.1 | 18.3 | 16.8 | $1.28 | 3.9% | $32.00 | 1.8% | Market Perform |
| Enbridge Inc. | ENB | 40.55 | 339.7 | 13,775 | 1.56 | 1.56 | 1.76 | 1.81 | 16.7 | 21.8 | 23.0 | 22.4 | 1.20 | 3.0% | 40.00 | 1.6% | Market Perform |
| Enbridge Income Fund | ENF.UN | 12.00 | 34.6 | 416 | 0.30 | 0.44 | 0.54 | 0.55 | 40.4 | 30.8 | 22.2 | 21.8 | 0.96 | 8.0% | 11.50 | 3.8% | Market Perform |
| Fort Chicago Energy Partners L.P. | FCE.UN | 10.75 | 133.7 | 1,437 | 0.74 | 0.59 | 0.64 | 0.47 | 14.1 | 20.9 | 16.8 | 22.9 | 0.93 | 8.7% | 11.00 | 11.0% | Outperform |
| Gaz Métro[4] | GZM.UN | 15.80 | 117.5 | 1,857 | 1.40 | 1.30 | 1.25 | 1.25 | 15.4 | 16.7 | 12.6 | 12.7 | 1.24 | 7.8% | 16.50 | 12.3% | Market Perform |
| Inter Pipeline Fund | IPL.UN | 8.39 | 199.5 | 1,674 | 0.46 | 0.48 | 0.67 | 0.48 | 17.6 | 20.1 | 12.5 | 17.5 | 0.84 | 10.0% | 8.50 | 11.3% | Outperform |
| Pacific Northern Gas Ltd. | PNG | 18.50 | 3.6 | 67 | 1.38 | 1.72 | 1.04 | 1.52 | 14.3 | 11.4 | 17.8 | 12.2 | 0.80 | 4.3% | 20.00 | 12.4% | Outperform |
| Pembina Pipeline Income Fund | PIF.UN | 15.60 | 121.9 | 1,902 | 0.53 | 0.65 | 0.81 | 0.84 | 23.5 | 22.0 | 19.3 | 18.6 | 1.32 | 8.4% | 15.00 | 4.6% | Market Perform |
| TransCanada Corp. | TRP | 39.38 | 487.7 | 19,206 | 1.55 | 1.70 | 1.86 | 1.89 | 17.9 | 19.1 | 21.2 | 20.8 | 1.33 | 3.4% | 38.50 | 1.1% | Market Perform |
| **Group Average** (Excl. ENF, FCE, GZM, IPL and PIF) | | | | | | | | | **16.4** | **17.1** | **20.1** | **18.1** | | **3.6%** | | **4.2%** | |

**Canadian Electric Utilities**

| Company | TSX Ticker | Price (C$) 5-Dec-06 | Shares O/S (mm) | Market Cap. (mm) | Earnings per Share 2004A | 2005A | 2006E | 2007E | P/E Ratios 2004A | 2005A | 2006E | 2007E | Dividend Rate | Yield | 12-Month Target | Total Return | Rating |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Caribbean Utilities Co. Ltd.[2,3] | CUP.U | $12.44 | 25.2 | $314 | $0.77 | $0.13 | $0.87 | $0.87 | 16.1 | NMF | 14.3 | 14.4 | $0.66 | 5.3% | $13.00 | 9.8% | Outperform |
| Emera Inc. | EMA | 22.91 | 110.4 | 2,528 | 1.16 | 1.04 | 1.15 | 1.14 | 15.7 | 18.2 | 19.9 | 20.1 | 0.89 | 3.9% | 22.00 | -0.1% | Market Perform |
| Fortis Inc. | FTS | 28.80 | 103.4 | 2,979 | 0.99 | 1.10 | 1.28 | 1.39 | 15.6 | 18.6 | 22.5 | 20.7 | 0.78 | 2.7% | 29.25 | 4.3% | Market Perform |
| **Group Average** | | | | | | | | | **15.8** | **18.4** | **18.9** | **18.4** | | **4.0%** | | **4.7%** | |

**Canadian Multi-Utilities**

| Company | TSX Ticker | Price (C$) 5-Dec-06 | Shares O/S (mm) | Market Cap. (mm) | Earnings per Share 2004A | 2005A | 2006E | 2007E | P/E Ratios 2004A | 2005A | 2006E | 2007E | Dividend Rate | Yield | 12-Month Target | Total Return | Rating |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ATCO Ltd.[1] | ACO/X | $48.73 | 51.8 | $2,525 | $2.17 | $2.46 | $3.13 | $2.77 | 11.7 | 14.4 | 15.6 | 17.6 | $0.82 | 1.7% | NA | NA | NR |
| Atlantic Power Corporation[6] | ATP.UN | 10.00 | 46.4 | 464 | (0.57) | (0.01) | 0.02 | 0.23 | NMF | 13.2 | 16.6 | 14.0 | 1.06 | 10.6% | $10.00 | 10.6% | Market Perform |
| Boralex Power Income Fund | BPT.UN | 8.55 | 59.1 | 505 | 0.50 | 0.50 | 0.55 | 0.50 | 21.1 | 21.5 | 15.6 | 17.1 | 0.90 | 10.5% | 9.00 | 15.8% | Market Perform |
| Calpine Power Income Fund | CF.UN | 10.89 | 61.7 | 672 | 0.81 | 0.76 | R | R | 13.5 | 13.3 | R | R | R | R | R | R | Restricted |
| Cdn Hydro Developers, Inc. | KHD | 5.80 | 120.5 | 699 | 0.06 | 0.00 | 0.06 | 0.07 | 44.4 | NMF | 99.1 | 86.6 | 0.00 | 0.0% | 5.60 | -3.4% | Market Perform |
| Canadian Utilities Ltd. | CU | 46.19 | 126.6 | 5,849 | 1.98 | 2.03 | 2.59 | 2.57 | 14.4 | 17.4 | 17.8 | 18.0 | 1.20 | 2.6% | 42.00 | -6.5% | Market Perform |
| Creststreet Power & Income Fund LP | CRS.UN | 4.40 | 11.5 | 51 | | (0.54) | (0.00) | 0.02 | | NMF | NMF | NMF | 0.65 | 14.8% | 4.25 | 11.4% | Underperform |
| EPCOR Power, L.P. | EP.UN | 24.84 | 48.4 | 1,203 | 2.25 | 1.83 | 1.81 | 1.27 | 15.1 | 19.2 | 13.7 | 19.5 | 2.52 | 10.1% | 25.50 | 12.8% | Market Perform |
| Great Lakes Hydro Income Fund | GLH.UN | 18.75 | 48.3 | 905 | 1.03 | 0.75 | 1.08 | 1.03 | 16.5 | 25.0 | 17.3 | 18.2 | 1.25 | 6.7% | 16.25 | -6.7% | Underperform |
| Innergex Power Income Fund | IEF.UN | 12.03 | 24.7 | 297 | 0.46 | 0.46 | 0.54 | 0.47 | 25.5 | 28.5 | 22.4 | 25.6 | 0.98 | 8.1% | 11.50 | 3.7% | Market Perform |
| Northland Power Income Fund | NPI.UN | 12.20 | 62.1 | 757 | 0.57 | 0.91 | 0.61 | 0.73 | 21.5 | 13.4 | 20.0 | 16.7 | 1.08 | 8.9% | 13.00 | 15.4% | Outperform |
| Maxim Power Corp.[1] | MXG | 6.80 | 43.9 | 299 | 0.50 | 0.30 | 0.21 | 0.24 | 7.6 | 24.3 | 32.4 | 28.3 | 0.00 | 0.0% | NA | NA | NR |
| TransAlta Corp. | TA | 25.61 | 200.6 | 5,137 | 0.62 | 0.88 | 1.01 | 1.20 | 27.6 | 24.1 | 25.3 | 21.3 | 1.00 | 3.9% | 22.00 | -10.2% | Underperform |
| TransAlta Power L.P. | TPW.UN | 7.10 | 75.1 | 533 | 0.48 | (0.04) | 0.49 | 0.37 | 19.8 | NMF | 14.4 | 19.0 | 0.80 | 11.2% | 6.50 | 2.7% | Underperform |
| **Group Average** (Excl. KHD, MXG, IPS, LPs and Income Trusts) | | | | | | | | | **17.9** | **18.6** | **19.6** | **19.0** | | **2.7%** | | **-8.3%** | |

Notes:
NA = Not Applicable, NMF = Not Meaningful, NR = Not Rated
[1] Estimates from First Call
[2] All figures in U.S. Dollars
[3] Caribbean Utilities' year-end is April 30
[4] Gaz Metro's year-end is Sept. 30
[5] Ticker on the New York Stock Exchange
[6] Represents Income Participating Securities (IPS). Share price, Market Cap and Dividend in C$; all else in US$.
Source: BMO Capital Markets

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**Company Specific Disclosures**

| | | | |
|---|---|---|---|
| Atlantic Power Corp. (ATP.UN-TSX) | 2, 3, 7, 9, 10AC | Fort Chicago Energy L.P. (FCE.UN-TSX) | 9, 10C |
| Boralex Power Income Fund (BPT.UN-TSX) | 11 | Fortis Inc. (FTS-TSX) | 2, 3, 7, 9, 10AC |
| Calpine Power Income Fund (CF.UN-TSX) | 1, 3, 7, 10A | Gaz Metro Limited Partnership (GZM.UN-TSX) | 1, 2, 3, 7, 9, 10AC |
| Canadian Hydro Developers Inc. (KHD-TSX) | 2, 3, 7, 10A | Great Lakes Hydro Income Fund (GLH.UN-TSX) | |
| Canadian Utilities (CU-TSX) | 2, 3, 7, 9, 10AC, 11, 12 | Innergex Power Income Fund (IEF.UN-TSX) | 9, 10C |
| Caribbean Utilities Co. Ltd. (CUP.U-TSX) | 5, 7, 9, 10AB | Inter Pipeline Fund (IPL.UN-TSX) | 2, 3, 7, 9, 10AC |
| Countryside Power Income Fund (COU.UN-TSX) | | Macquarie Power Income Fund (MPT.UN-TSX) | |
| Creststreet Power & Inc. Fund (CRS.UN-TSX) | 2, 3, 7, 10A | Northland Power Income Fund (NPI.UN-TSX) | 2, 3, 7, 9, 10AC |
| Duke Energy Corp. (DUK-NYSE) | 2, 3, 7, 9, 10AC | Pacific Northern Gas (PNG-TSX) | |
| Emera Inc. (EMA-TSX) | 9, 10C | Pembina Pipeline Income Fund (PIF.UN-TSX) | 9, 10C |
| Enbridge Inc. (ENB-TSX; ENB-NYSE) | 2, 3, 4, 7, 9, 10AC | TransAlta Corporation (TA-TSX; TAC-NYSE) | 2, 3, 4, 5, 7, 9, 10AC, 11, 12 |
| Enbridge Income Fund (ENF.UN-TSX) | | TransAlta Power L.P. (TPW.UN-TSX) | 9, 10C |
| EPCOR Power, L.P. (EP.UN-TSX) | 2, 3, 7, 9, 10AC | TransCanada Corporation (TRP-TSX; TRP-NYSE) | 2, 3, 5, 7, 9, 10AC, 12 |

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(S) = speculative investment;

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CEPA
Canadian Energy Pipeline Association
Association canadienne de pipelines d'énergie

# Perspective on Canadian Gas Pipeline ROEs

February 2008

## Scope

This document outlines key facts and views regarding return on equity (ROEs) on Transmission Pipelines in Canada, with a specific focus on gas pipelines. It has been prepared by the Canadian Energy Pipeline Association (CEPA) to support engagement and discussion of ROE issues amongst CEPA members who are operating natural gas transmission systems and with associated policy makers, regulators and stakeholders.

## Summary

Several Canadian regulatory jurisdictions have in existence similar formulas to determine allowed rates of return on common equity (ROEs) for utility and pipeline assets. While there is merit (eg. efficiency, link to debt markets) in using a formula approach to ROE, the ROEs that result from the current formulas are too low, causing unfair returns. This paper, which is focused on ROEs for natural gas transmission pipelines, provides the facts supporting this position, and other background information to generate discussion on this topic.

The background information provided includes the legal obligation for regulators to provide fair returns on invested capital, the methods that can be used to estimate an appropriate ROE, and the ROE formulas currently in place.

The following facts are presented to support the position that gas pipeline ROEs are too low:

- U.S. and Canadian gas pipelines had similar ROEs at the time ROE formulas came into use, but now U.S. gas pipelines have much higher ROEs, despite a relative increase in the business risk of Canadian gas pipelines;
- U.S. local gas distribution companies (LDCs) had similar ROEs at the time ROE formulas came into use, and now U.S. LDCs have much higher ROEs despite being less risky;
- ROEs contractually negotiated for Canadian pipelines are consistently higher, and the difference is likely greater than can be accounted for by additional risks inherent to negotiated settlements;
- Analysis of Canadian stock market data shows that investors expect higher returns; and
- Since the ROE formulas were originally adopted, capital markets have changed in ways that have led investors to require higher equity returns than those resulting from single-variable ROE formulas.

To assist the discussion, this paper also addresses some common challenges to the assertion that ROEs are too low.

CEPA intends this paper to be complementary to a paper issued by the Canadian Gas Association (CGA) in May 2007. The CGA's paper addresses ROEs from the perspective of

natural gas LDCs. CGA members also have formula-generated ROEs, and suffer from unfair rates of return as a result.

**Background**

Who is the Canadian Energy Pipeline Association (CEPA)?

CEPA represents Canada's energy transmission pipeline companies. Its members transport 97 of Canada's daily crude oil and natural gas production from producing regions to markets throughout Canada and the U.S. CEPA members operate over 20 billion in assets and project 1 billion per year of capital investments over the next 2 decades. Collectively, total assets are projected to double over the next 15 years in order to meet the needs of energy producers and consumers. In order to ensure that the Canadian gas pipeline industry continues to be maintained and expanded to meet these needs, sufficient returns are required on capital invested.

The Fair Return Standard

Regulators allow the recovery of all prudently incurred and reasonable costs required to provide service. These costs include the cost of capital employed, for which regulators are required to provide a fair return. The fair return standard is based on court rulings on cost of capital matters, and has three elements. A return is fair if 1) it enables the utility to attract capital on reasonable terms, 2) maintains the financial integrity of the regulated entity, and 3) is comparable to the returns available to enterprises of similar risk.

The fair return standard is not only a legal requirement but it is also based on sound economic theory. It ensures that necessary regulated systems remain financially healthy and that its investors are compensated appropriately and equitably.

The first two parts of the fair return standard, capital attraction and financial integrity, are related but distinct tests. The capital attraction standard ensures the regulated entity can attract the capital it requires to grow and maintain its system. The financial integrity standard requires that the return allowed be sufficient to assure confidence in the financial soundness of the regulated

entity. In approving a cost of capital, regulators must consider the financial soundness of the regulated entity and the risk that it could be unable to attract capital on reasonable terms. This should have nothing to do with the ownership of the regulated entity. The company which owns the regulated entity may be stronger or weaker financially, and may have more or less difficulty raising capital than the regulated entity would. To address this, regulators follow the stand-alone principle whereby cost of capital decisions are made for the regulated entity as if it were a stand alone company.[i] In other words, the regulator asks how financially sound the regulated entity is and whether it could raise capital on its own; the financial soundness and ability of the parent company to raise capital are irrelevant.

The third part of the fair return standard, that the return be comparable to that of entities with similar risk, has clearly not been met in recent decisions. Too often regulators have used differences between comparators as reasons *not* to compare rather than as considerations in *how* to compare. Regulators have rejected comparison to US pipelines,[ii] oil pipelines,[iii] or to pipelines who have negotiated their rates through settlement agreements.[iv] There are few sources for comparators, and it is circular to compare to other pipelines whose returns are also based on an ROE generated the same way. Thus, where differences exist, the onus is on regulators to exercise reasoned judgment and consider differences while making comparisons. Otherwise, the fair return standard, which legally requires comparisons, is not met.

The fair return standard applies to the overall cost of capital, comprised of the cost of debt and the cost of equity. This paper focuses on ROE because debt rates are rarely contentious, equity ratios have been deemed by Canadian regulators based on individual business risks, and since ROEs are set by formulas which apply to many pipelines.

Methods of Estimating an Appropriate ROE

Setting an appropriate ROE is a challenge that requires regulators to not only understand and measure risk, but to put a price on risk differences based on an understanding of how risk is being priced in the capital market. Academics do not agree on a single method or test to determine an appropriate ROE. They have a number of methods to estimate the cost of capital, each with its own underlying theory and its own unique shortcomings. Estimating an appropriate ROE with any of these methods involves the challenge of gathering an appropriate sample. While the results of all methods have been considered by regulators in the past, the

most recent EUB and NEB decisions have relied primarily or solely on Equity Risk Premium (ERP) based methods.[v, vi]

The methods of estimating cost of capital fall in three broad categories: the Comparable Earnings (CE), Discounted Cash Flow (DCF), and Equity Risk Premium methods. The CE method compares the actual ROEs earned by companies with comparable risk. While this method relies on accounting data which can be affected by accounting concepts such as accruals and gains and losses on sales, it is a straight-forward application of the comparable return standard.

The DCF method is universally accepted in the U.S. and universally given little or no weight in Canada recently. It is based on the constant dividend growth model and the theory that the appropriate cost of equity is the risk-adjusted discount rate applied to dividends to obtain the current value of a stock. The formula is;

$$Price = \frac{Next\ Year's\ Expected\ \ per\ unit\ Dividends}{ROE\ -\ Growth\ \ Rate}$$

This formula is then rearranged to back-out an estimate of the ROE from data on the current stock price, expected dividends, and the projected growth rate. After selecting a sample, the main challenge of this method is determining estimates of future growth rates. These estimates normally rely on economic growth forecasts and dividend growth forecasts published by equity analysts. One advantage of this method is that investors and investment analysts routinely use the formula above in making valuations. The DCF method is also a forward-looking test, unlike most other tests.

The ERP method determines an ROE as the sum of a risk-free rate of return plus a risk premium. The theory is that the risk-free rate of return compensates investors for the time value of money while the risk premium compensates for any additional amount of risk. The Capital Asset Pricing Model (CAPM) is the traditional ERP model, and is represented by the following formula:

$$ROE = RF + \beta \times MRP$$

where RF is the risk-free rate of return, MRP is the market risk premium which is the market-determined price for the average amount of risk, and β is the entity's risk relative to the average market risk. The unique challenge with this CAPM method is estimating β and the MRP through statistical analysis of stock market data.

A relatively new ERP method is the Fama-French model. It is based on evidence that the CAPM model underestimates the return on equity for low beta stocks and for high value stocks (stock with a low market to book ratio).[vii] These biases of the CAPM model would cause an underestimation of the appropriate ROE for a Canadian gas pipeline. To correct for these biases in the CAPM model, the Fama-French model adds variables for company size and company value to the traditional CAPM model. The formula for this method is;

$$ROE - RF = \alpha + \beta_1 SMB + \beta_2 HML + \varepsilon$$

where

- $\alpha$ is the abnormal returns of the company's stock;
- SMB is the size factor (small market capitalization returns minus big market capitalization returns);
- HML is the book-to-market factor (high B M returns minus low B M returns);
- $\beta_1$ and $\beta_2$ are the respective sensitivities of stock to the SMB and HML risk factors; and
- ε is the diversifiable or firm specific risk.

Another approach to estimating cost of equity that can be combined with these methods is the After-Tax Weighted Average Cost of Capital (ATWACC) method. It is based on the premise that the overall after tax cost of capital is constant over a wide range of capital structures. Based on this premise, either an ATWACC should be approved by the regulator or ROE and capital structure should be considered together, not in isolation, to result in a fair return. ATWACC's are a real-world measure, since businesses consider whether the ATWACC of a project is above or below a hurdle rate of return when considering whether or not to proceed with that project.

There are many methods and variations of methods which can be used to estimate the cost of capital. However, when parties prepare evidence for a cost of capital proceeding, they typically present a method that has been accepted in the past. If new methods are disregarded because they are new, regulators will end up with a very narrow, and possibly outdated view when evaluating cost of capital evidence.

Current ROE Formulas

The British Columbia Public Utilities Commission (BCUC) was the first Canadian regulator to establish a formula ROE and was followed by the NEB and three other provincial regulators. These regulators use virtually identical ERP-based formulas to set approved ROEs each year by adjusting the previous year's ROE by a proportion of the change in the forecast long-term Government of Canada bond yields (a measure of the risk-free rate of return). The table below provides the results of these formulas in 2007 and 2008, which are very similar, and average 8.51 in 2007 and 8.78 in 2008.

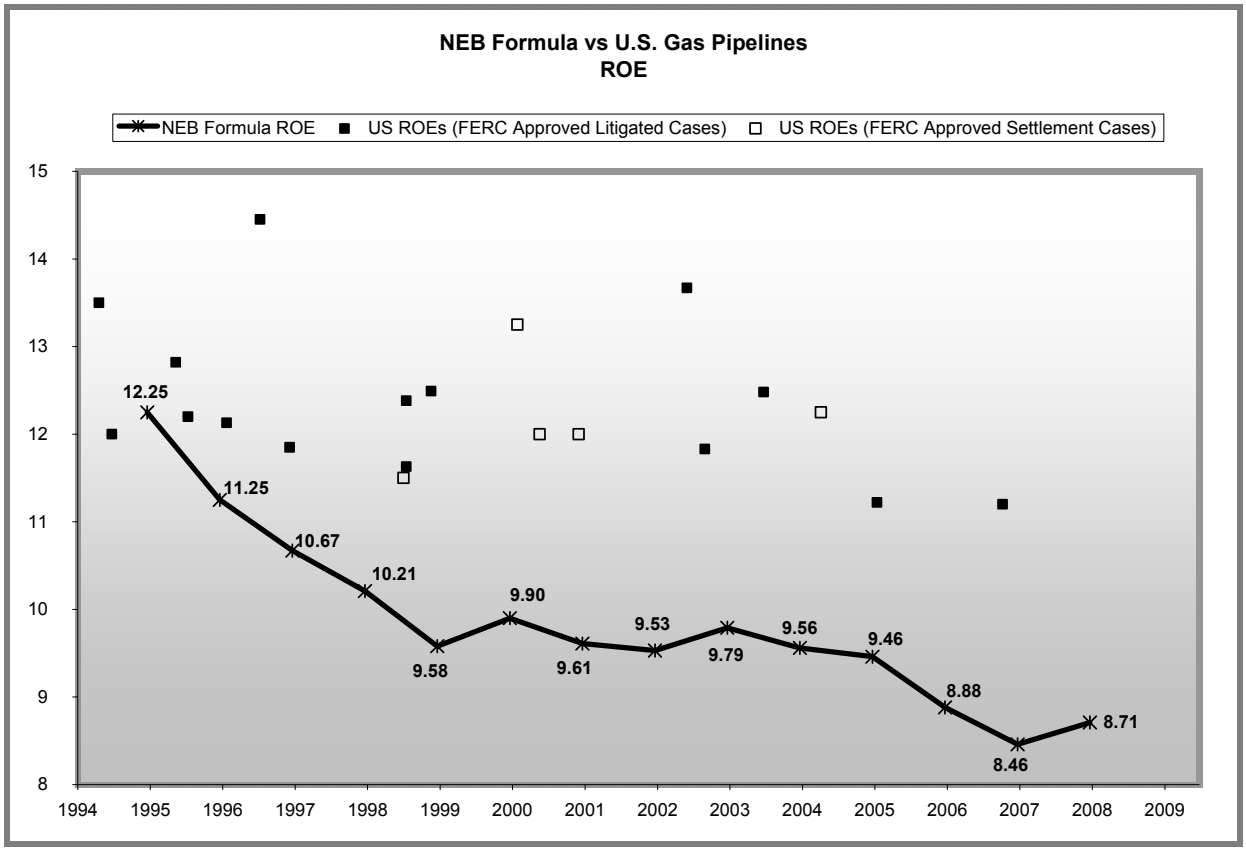
**Approved Formula ROEs**

| Jurisdiction | | Formula Implemented | 2007 ROE | 2008 ROE |
|---|---|---|---|---|
| National Energy Board | | 1995 | 8.46 | 8.71 |
| Alberta Energy and Utilities Board | | 2004 | 8.51 | 8.75 |
| British Columbia Utilities Commission | | 1994 | 8.37 | 8.62 |
| Ontario Energy Board | Enbridge | 1997 | 8.41 | not available |
| | Union | 1997 | 8.54 | not available |
| Qu bec r gie de l' nergie for Gaz M tro | | 1999 | 8.76 | 9.05 |

As bond yields have dropped, so have the formula generated ROEs. The ROE in the 1995 base year of the NEB Formula was 12.25 , and has fallen by 379 basis points relative to 2007. The ROE awarded for the 2004 base year of the EUB formula was 9.60 , and has fallen by 109 basis points relative to 2007.

**Growing Gap Relative to U.S. ROEs**

Formula ROEs have dropped in Canada, while gas pipeline ROEs approved by the U.S. Federal Energy Regulatory Commission (FERC) have not, as shown below.




*Source: FERC Decisions*

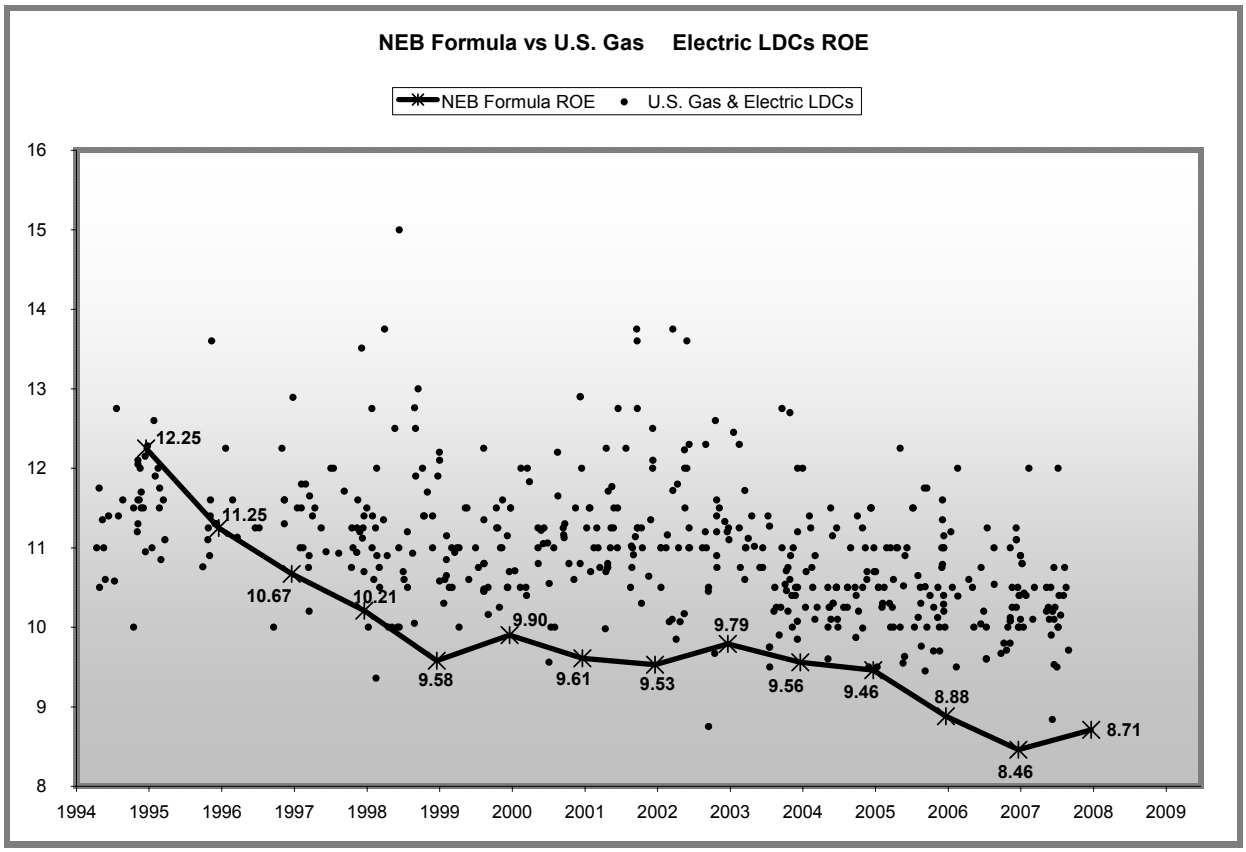
Over this time period, Canadian pipelines have faced increasing risks as they have entered a competitive age and faced increased supply risk, while U.S. gas pipelines have not faced such structural changes. In any event, it would be difficult to argue that U.S. gas pipelines have experienced an increase in relative risk since 1995.

U.S. gas pipeline ROEs are relevant for comparison. Markets continue to globalize, and investors can now switch their investments between Canada and the U.S. as easily as switching between sectors within the same country. There are also no material differences in fiscal or monetary policy to affect comparability. In other words, higher ROEs are easily available to Canadian investors who invest in U.S. gas pipelines instead of Canadian gas pipelines. Comparison to U.S. regulated entities is logical since they a have similar regulatory model.

Whether subject to Canadian or U.S. FERC regulation, a gas pipeline faces the same long term risk of failing to recover the capital invested.

As mentioned, the FERC uses the DCF methodology to set approved ROEs for gas pipelines. Like all methods, the DCF method includes the challenge of finding an appropriate comparator group. Recent merger and acquisition activity in the U.S. had limited the DCF sample, or proxy group. As a result, the FERC began adding LDCs to its proxy group, and making ROE adjustments to account for the greater risk of pipelines relative to LDCs. The FERC recently issued a Policy Statement proposing that pipelines organized as Master Limited Partnerships ( MLPs ) be included in the proxy group to increase its size.[viii] Based on research by the Interstate Gas Association of America, including MLPs in the sample should tend to increase the ROEs that result from the DCF test.[ix]

The NEB formula ROE has also dropped significantly in relation to the ROEs of U.S. gas and electric LDCs. A recent Concentric Energy Advisors report prepared for the OEB concluded that there are no significant differences that would lead to a difference in investor required returns for Canadian and U.S. LDCs.[x] By extension it can be concluded that U.S. LDCs are less risky than Canadian gas pipelines, since gas pipelines have no franchises and greater supply, market and competitive risk. The figure below shows that the NEB formula return has dropped significantly and is now below the ROEs awarded to U.S. gas and electric LDCs.




*Source: Public Utilities Fortnightly*

A gap has clearly grown between Canadian and U.S. ROEs, which cannot be explained by changes in relative risk.

**Gap Relative to Negotiated Canadian ROEs**

Pipelines and their customers often negotiate an explicit ROE for a new or an existing pipeline. These ROEs are invariably higher than the formula ROEs at the time. The ROE negotiated in a single settlement reflects a negotiated trade-off between ROE and other risk factors. However, the fact that all settled ROEs are significantly higher than the alternative formula ROE suggests that pipelines and their customers are able to agree that formula ROEs do not appropriately reflect the cost of equity capital. It is worth noting that for U.S. gas pipelines, the ROEs determined in litigated cases and settlements are very similar, as shown above.

While Canadian pipelines may accept increases in short-term risk in some settlements, this cannot explain a 200 to 400 basis point premium over the formula ROE. The following table shows some negotiated ROEs. ROEs established as a premium to the NEB formula would be reset upon a change in the NEB formula. Note that several of these examples are for oil pipelines, where transportation costs have historically been small in relation to the value of the commodity in comparison to gas pipelines, and where settlements have been more prevalent.

| Pipeline Pipeline Project | ROE |
|---|---|
| Alliance (2000 to 2014) | 11.25 |
| M&NP (2007 settlement) | 13 |
| Trans Mountain (2006 to 2010 Settlement) | 10.75 |
| Alberta Clipper | NEB Formula ROE 225 Basis Points |
| Line 4 Extension | NEB Formula ROE 225 Basis Points |
| Mackenzie Valley | NEB Formula ROE 221 Basis Points |
| Southern Lights | 12 |

The evidence suggests that in Canada, formula returns are a floor for negotiations, and not a level that parties consider a reasonable benchmark. As a result, they affect the returns that are negotiated, as the fall-back to settlement.

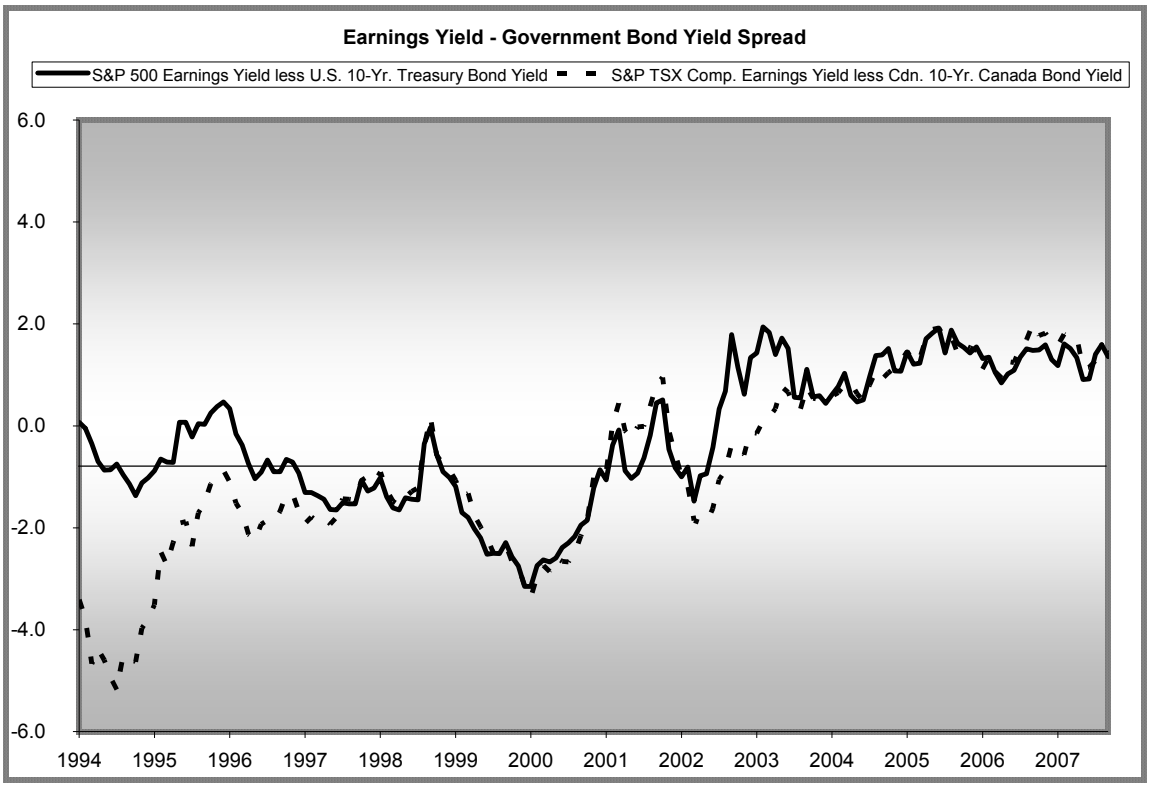
**Analysis of Canadian Stock Market Data**

CEPA retained Dr. Stephen Gaske, a cost of capital expert, to conduct an ERP-based analysis as a further indication of whether current formula-based ROEs are reasonable. His analysis, appended to this paper, is a straightforward analysis of two samples of Canadian stocks. His Energy Transportation Sample (consisting of Emera, Enbridge, Fortis, TransCanada, Canadian Utilities, Westcoast and Terasen while still public) has an average equity risk premium over the past 23 years of 7.6 , which results in an 11.88 ROE when added to current long term bond yield. In his opinion, this result appears more reasonable than the ROEs currently produced by Canadian ROE formulas. Dr. Gaske also evaluates equity risk premiums over time, and finds that the moving averages for both samples have been increasing. These results support

CEPA's position that the current formula-based ROEs are too low, and that it is time to open up broader discussion on this topic.

**Changes in Financial Markets**

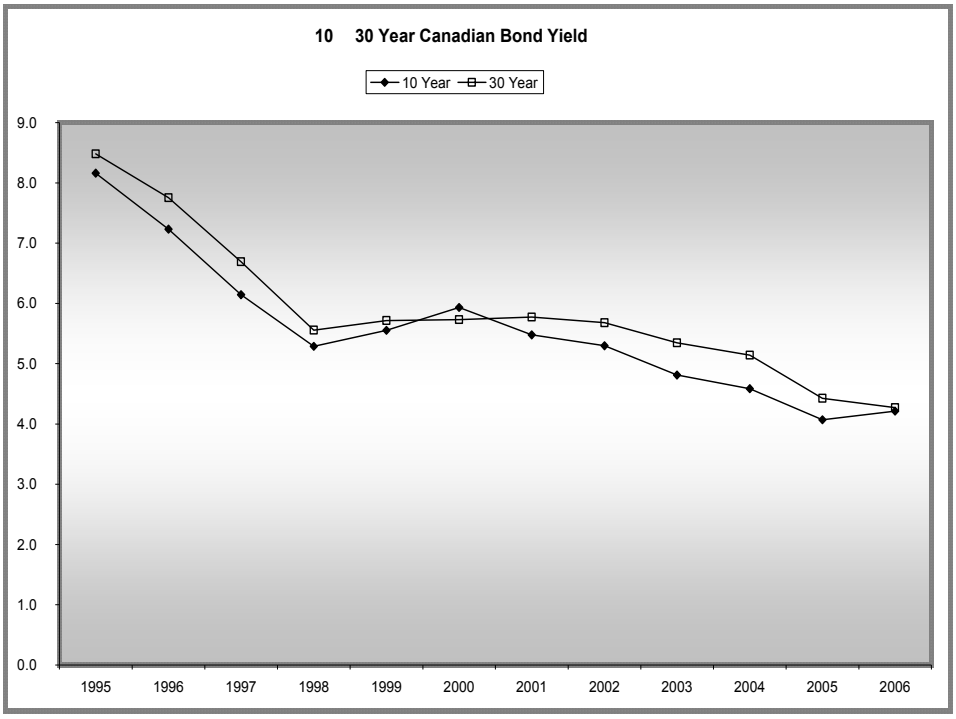
The ROE required to meet the fair return standard depends on the price investors put on differences in risk and the accessibility of capital, which are determined in competitive capital markets. Its determination is too complex to be captured by any single-variable formula. Capital markets have changed significantly since ROE formulas were established, increasing the returns required by investors. This is visible in the following figure which shows an increasing spread between earnings yields and long-term bond yields since ROE formulas came into use.[xi]

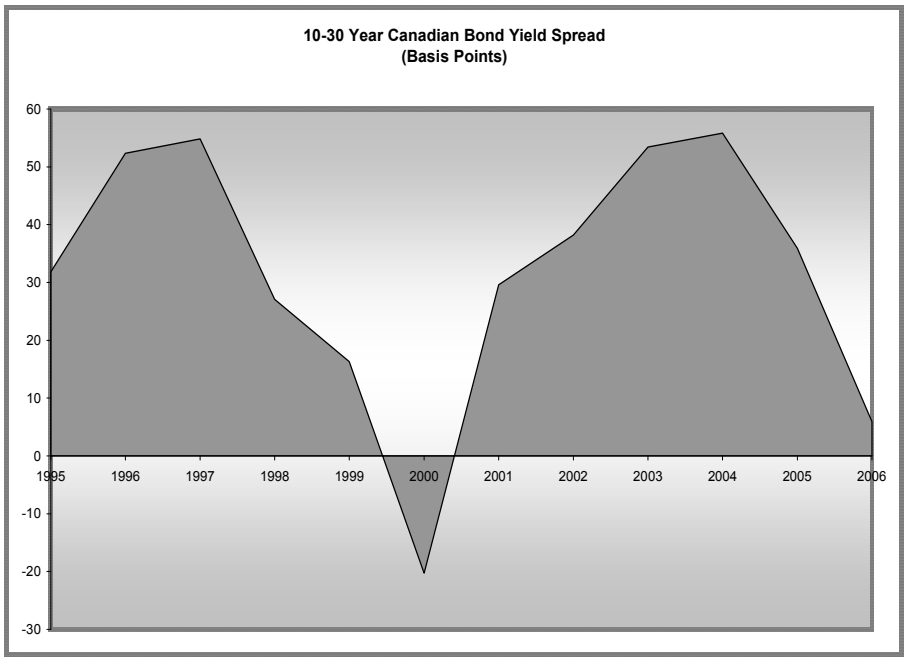



Not only have capital markets changed in ways not captured by ROE formulas, but the one variable they do rely on may no longer be a good measure of the risk-free rate of return. Since the federal government has been reducing the amount of federal debt, and the supply of long

term government bonds has decreased while the economy has been growing, the price of bonds has increased and bond yields have been reduced. Thus, improved government finances have artificially reduced pipeline ROEs.

The following figures show the decline in bond yields and the current low spread between 10 and 30 year bond yields.






It would be a coincidence if a single variable formula set as long as 13 years ago generated a reasonable ROE today. It is equally unlikely that a reasonable return result could be set for the year 2021 with a formula determined today.

**Potential Questions**

In order to advance discussion on this topic, this section addresses some questions that may be raised in response to this paper.

Why have gas pipelines not applied for higher ROEs if they are too low?

Each company has its own motivations, but there are some common reasons. ROE litigation is costly and contentious, and the evidentiary standard may be high given the subjective nature of the matter. Settlements are typically preferred if they result in an increase in ROE relative to the formula result. Settlements allow pipelines and their customers to collaborate on other matters instead of opposing each other in lengthy, adversarial proceedings.

Why does investment continue if the ROE is too low?

As long as a gas pipeline operates, its owners will continually invest to maintain safe operations. Investments are also made to serve new customers. These are long term investments, and are made with the expectation that the returns will be fair over the life of the asset. Expansions and extensions are also required in order to avoid bypass by a competing pipeline, which would undermine the value of the initial investment.

Without an improvement in formula-based returns, Canadian pipeline infrastructure investment is being put at risk, along with the development of Canada's natural resources. If investors begin to lose faith that a regulator will award reasonable returns, they will be less likely to invest in that jurisdiction. It could take many years of corrected action by regulators before investors regain confidence, during which economic development could be impeded.

Why are entities earning formula ROEs purchased for more than book value if ROEs are too low?

Recent purchases above book value have suggested to some that formula-based returns are higher than the cost of capital to investors. Apart from the fact that book values are an accounting construct, there are a number of other reasons investors would pay more than book value for an asset. A few examples are creative financing, expectations of higher returns (either by regulatory change or settlement incentives), and strategic value. There have also been cases where, in hindsight, too much has been paid for a regulated asset.[xii]

Why are stock prices and credit ratings unharmed if ROEs are too low?

There is no gas pipeline in Canada which trades on the stock market as a pure play gas pipeline. They are all held by parent companies with other assets or include other non-regulated assets. Considering the stock prices and debt ratings of a parent company is not consistent with the stand-alone principle described above. While some regulated entities may be rated by credit ratings agencies, these ratings are affected by the credit quality of the parent organization.

Further, there is evidence that the investment community is concerned about the ROEs awarded to gas pipelines, as described in the NEB's 2007 Hydrocarbon Transportation System Assessment:

> Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.[xiii]

## Conclusion

Canadian gas pipelines are being awarded formula ROEs that result in unfairly low returns. U.S. gas pipelines and LDCs, and Canadian pipelines who settle their returns, have ROEs 200 to 400 basis points higher than formula ROEs. Dr Gaske's conclusion is within this range, based on a simple ERP-based statistical analysis of utility index data. It is no surprise that formulas are unable to track the dynamics of a capital market, which incorporates the expectations of investors based upon all available information. The time has come for stakeholders to engage in discussion on this matter, and to consider the potential consequences of awarding low ROEs for energy infrastructure.

## Endnotes

[i] The EUB describes the stand alone principle as follows: *The Board accepts that the underpinning of the stand-alone principle is that the regulated utility should not be subsidizing its non-utility operations or operations of members of its corporate family, neither should the non-regulated activities subsidize the utility operations"* EUB Decision 2003-061, AltaLink Management Ltd. and TransAlta Utilities Corporation Transmission Tariff for May 1, 2002 April 30, 2004 TransAlta Utilities Corporation Transmission Tariff for January 1, 2002 April 30, 2002 August 3, 2003, p 83.

[ii] See for instance, NEB Reasons for Decision RH-2-2004 Phase II. TransCanada Pipelines Cost of Capital pp. 70-71. April 2005; EUB Decision 2004-052 Generic Cost of Capital p.26. July 2, 2004.

[iii] NEB Reasons for Decision RH-2-2004 Phase II. TransCanada Pipelines Cost of Capital pp. 68-69. April 2005.

[iv] NEB Reasons for Decision RH-2-2004 Phase II. TransCanada Pipelines Cost of Capital pp. 68. April 2005 EUB Decision 2004-052 Generic Cost of Capital p.27. July 2, 2004

[v] The NEB used to consider the DCF and CE methods, but in the early 1990s shifted to giving most or all weight on the results of the ERP method. The NEB primarily considered a Comparable Earnings evaluation of Canadian industrials in RH-1-78 and RH-1-79. In RH-4-81, RH-3-82, and RH-2-83, the NEB made ROE determinations based on its consideration of all of the evidence presented which included multiple estimation methods. Decision RH-1-84 states The Board is of the view that the determination of an appropriate rate of return on equity involves the use of methods that are subject to the exercise of judgment. The Board made similar comments in RH-2-85, RH-3-86, and RH-1-88 Part II. In the RH-2-89 decision the Board found that the results of DCF test should be given weight in assessing a fair rate of return on equity despite limitations of the approach. In the early 1990's the Board placed the primary weight on the ERP method and placed less weight on the CE and DCF methods (decisions RH-1-91 and RH-2-92). In RH-4-93 the Board put little or no weight on the results of the CE and DCF methods, stating that these tests may prove useful under different economic conditions. In the last NEB ROE decision, RH-2-94, the Board decided to give primary weight to the results of the equity risk premium test.

[vi] The EUB once gave some weight to the results of the DCF test, but most recently placed no weight on the results of the DCF test. From 1990 to 1994, the EUB gave less weight to the results of the DCF method than the ERP method. For instance Decision E94060 states "The Board has in the past found that none of the methods advocated by the expert witnesses necessarily yields or provides a precise measurement of the fair rate of return on equity. However, the Board considers the results of each method helpful in its deliberations The Board has taken note of the caution expressed by each of the expert witnesses respecting the use of the DCF method in today's economic environment. The Board accepts that less weight should be placed on the absolute results of the DCF method under current economic conditions. The EUB moved from less weight to little weight on DCF results in Decision U96001, also because of the effects economic conditions at the time may have had on the results of the DCF test. In the Board's Generic Cost of Capital Decision (Decision 2004-052), the results of the DCF test were given no weight, as the Board was convinced by interveners that the analysts' earnings forecasts used in the development of the DCF estimates have been biased high.

[vii] Eugene F. Fama and Kenneth R. French, The Capital Asset Pricing Model: Theory and Evidence Journal of Economic Perspectives, Volume 18, Number 3, Summer 2004, Pages 43-44.

[viii] FERC, Proposed Policy Statement on Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity, Issued July 19, 2007.

[ix] Smead, Richard G of Navigant Consulting Inc. paper prepared for the Interstate Natural Gas Association of America, Allowed Returns on Equity in the Interstate Gas Pipeline Industry: Issues and Options Regarding the FERC DCF Approach, August 24, 2006.

[x] Concentric Energy Advisors, A Comparative Analysis of Returns on Equity of Natural Gas Utilities, prepared for the Ontario Energy Board, pp. 3, 57, 58.

[xi] The Earnings Yield is earnings in the stock market divided by the sum of stock prices. This measure can be compared to the yield on debt.

[xii] On August 2, 2005 Kinder Morgan announced that it had agreed to acquire Terasen for US 5.6 billion or 2.6x estimated 2005 book value per share. Since then, Kinder Morgan has moved aggressively to divest non-core assets

acquired in the Terasen Inc. transaction. On February 26, 2007, it announced that it has agreed to sell Terasen Gas Inc. to Fortis Inc. for C 3.7 billion and on March 5, 2007, Kinder Morgan announced that it has agreed to sell the Corridor Pipeline and the 1.8 billion expansion of that pipeline to Inter Pipeline Fund for 760 million and 300 million of assumed debt relating to the expansion.. On April 30, 2007, Kinder Morgan Energy Partners completed the purchase of the Trans Mountain Pipeline system from Kinder Morgan for US 550 million plus US 450 million of assumed debt. In its Form 10-Q filing for the period ending March 31, 2007, Kinder Morgan Inc. announced that it has recorded a goodwill impairment charge of US 377.1 million relating to the Trans Mountain transaction. This charge is in addition to the US 650.5 million impairment charge recorded in its Form 10-K filing, resulting from the Terasen Inc. - Fortis Inc. transaction.

[xiii] NEB, Canadian Hydrocarbon Transportation System: Transportation Assessment, July 2007, p. 40.

Canadian Energy Pipeline Association
Association canadienne de pipelines d'énergie

# Appendix

# Risk Premium Analysis
# Dr. Stephen Gaske

Canadian regulators currently set the rate of return on common equity for regulated pipelines by using equity risk premium formula ROEs calculated each year by adding a percentage of the change in yields on Bank of Canada bonds to the previous year's ROE. The risk premium approach explicitly recognizes that pipeline equity is riskier than long term Bank of Canada bonds, and therefore that the expected return on equity should be higher in the pipeline industry than the yield on Bank of Canada bonds. Although there is no doubt about the need for a risk premium, the difficult problem for a regulator is to determine the size of the premium that is required in order for a pipeline to attract capital on reasonable terms. However, just as bond yields change from year to year, the required level of the premium also changes continually in response to (i) changes in the financial market in general, and (ii) to changes in the risks of pipelines in particular.

The formula currently used to estimate ROEs can generally be written:

ROE in Year 2 ROE in Year 1 75 of the change in the forecast bond yield

This formula mechanically adjusts the allowed ROE in response to changes in interest rates. The allowed ROE moves up and down at 75 of the change in the forecast bond yield. As a result, the size of the risk premium is adjusted each year by an amount equal to -25 of the change in the bond yield. The mechanical adjustment in the size of the risk premium is designed to make a rough adjustment for changes in the financial market in general by assuming that the risk premium is greater when interest rates are relatively low and that a smaller risk premium is required when interest rates are relatively high. While this might be a reasonable representation of how the required risk premium is likely to react in the short run to changes in financial market conditions (for which changes in the interest rate is intended to be a rough proxy), there is nothing in this formula that allows the risk premium to adjust in the long run if the relative risks of pipelines change over time. Consequently, it may be necessary to re-calibrate the formula periodically.

To test whether the current formula is reasonably accurate, and to determine whether the required risk premium may have changed significantly through the years, this analysis reviews bond yields and market returns on utility common equity for various time periods during the 51 year period 1956-2006. Market returns on common equity were evaluated with two indices:

1. The S&P TSX Capped Utilities Index (S&P TSX Utility Sample), for which data are available for the 1956-2006 time period. The S&P TSX Utility Sample currently consists of Algonquin Power Income Fund, ATCO Ltd., Canadian Utilities Limited, Emera Inc., Energy Savings Income Fund, EPCOR Power L.P., Fortis Inc., Northland Power Income Fund, TransAlta Corp., and TransAlta L.P.

2. A sample with a focus on corporations with pipeline or other energy transportation assets (Energy Transportation Sample). The Energy Transportation Sample is a better proxy for gas pipelines since it does not include less relevant utility companies (those that are primarily energy retailers or power producers), and includes pipeline companies not includes in the S&P TSX Utility Sample (Enbridge, TransCanada, and, for years in which they were traded, Westcoast and Terasen). Therefore the Energy Transportation Sample consists of Emera, Enbridge, Fortis, TransCanada, Canadian Utilities, Westcoast and Terasen. Data for this sample is only available starting in 1983.

The Total Returns used in these two indices are calculated each year by dividing the dividends plus changes in stock price during the year, by the stock price at the beginning of the year. Both indices are constructed using the assumption that all dividends are reinvested in the company.

Risk premiums were calculated each year by subtracting the Bank of Canada bond yield from the Total Return experienced by each stock sample.

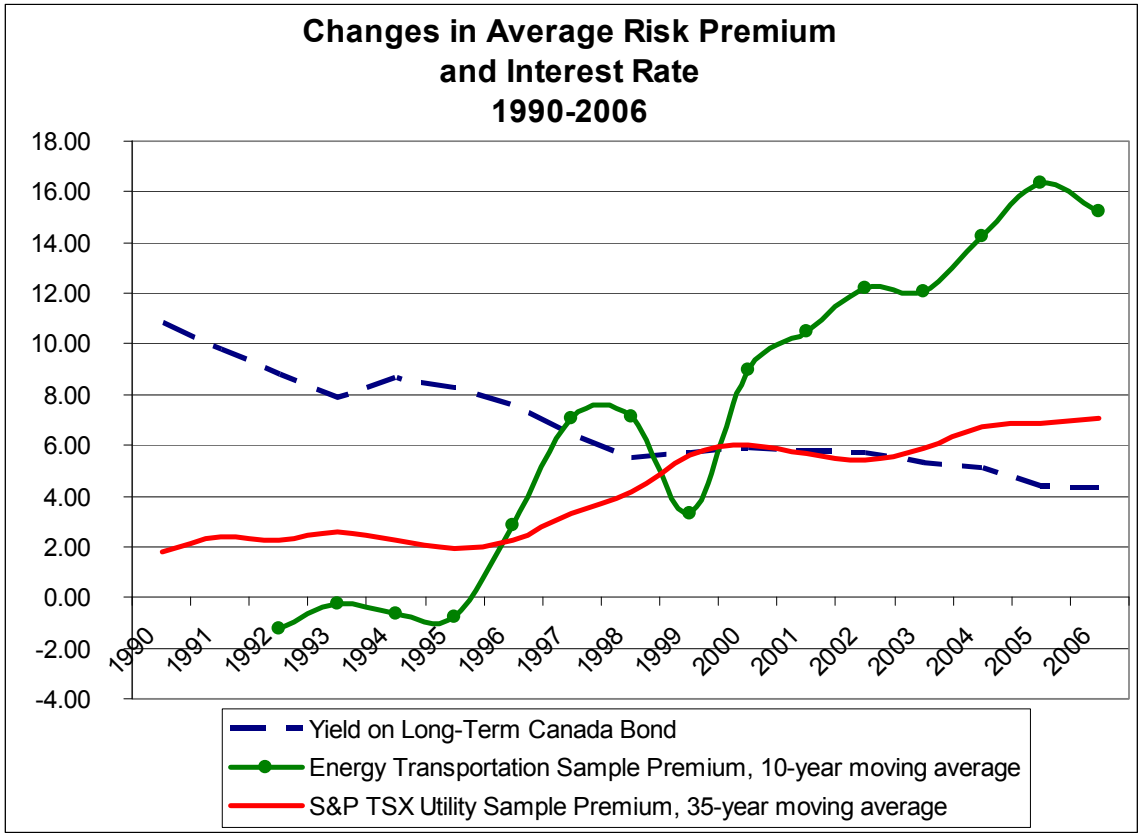
The Energy Transportation Sample experienced an average risk premium of 7.6 percent between 1983 and 2006. The S&P TSX Utility Sample experienced an average risk premium of 5.12 percent over the period 1956-2006, and 9.53 percent over the period 1983-2006. These results are shown in Exhibit 1, and summarized in the Table below:

**Average Total Returns and Risk Premiums**

| | Long Term Canada Bond Yield | Energy Transportation Sample | | S&P TSX Utility Sample | |
|---|---|---|---|---|---|
| | | Total Return | Risk Premium | Total Return | Risk Premium |
| 1983-2006 Average | 7.95 | 15.55 | 7.60 | 17.48 | 9.53 |
| 1956-2006 Average | 7.68 | not available | not available | 12.79 | 5.12 |

When evaluating pipelines, the Energy Transportation Sample should be a better indicator of required returns than a broader sample. Consequently, the 7.6 percent average risk premium for pipelines should be a better estimate of the required risk premium than risk premiums calculated for the S&P TSX Utility Sample. Adding the 4.28 percent bond yield from 2006 to the 7.6 percent risk premium would produce an allowed rate of return of 11.88 percent. This is hardly an excessive rate of return, and appears to be far more reasonable than the ROEs currently resulting from Canadian ROE formulas.

Analysis of both indices suggests the required risk premium has increased significantly since the 1990's. The chart below shows the moving averages of the risk premiums for both indices, which have increased while the yield on long term bonds has decreased.



# Exhibit 1
# Total Returns and Risk Premiums

| | | Energy Transportation Sample | | | S&P TSX Utility Sample | | |
|---|---|---|---|---|---|---|---|
| Year | Yield on Long-Term Canada Bond | Annual Return | Risk Premium | 10-Yr. Moving Average Premium | Annual Return | Risk Premium | 35-Yr. Moving Average Premium |
| 1956 | 3.63 | | | | 0.17 | -3.46 | |
| 1957 | 4.11 | | | | -3.43 | -7.54 | |
| 1958 | 4.15 | | | | 9.81 | 5.66 | |
| 1959 | 5.08 | | | | 0.21 | -4.87 | |
| 1960 | 5.19 | | | | 26.81 | 21.62 | |
| 1961 | 5.05 | | | | 19.17 | 14.12 | |
| 1962 | 5.11 | | | | -0.72 | -5.83 | |
| 1963 | 5.09 | | | | 6.19 | 1.10 | |
| 1964 | 5.18 | | | | 21.59 | 16.41 | |
| 1965 | 5.21 | | | | 4.23 | -0.98 | |
| 1966 | 5.69 | | | | -13.17 | -18.86 | |
| 1967 | 5.94 | | | | 5.07 | -0.87 | |
| 1968 | 6.75 | | | | 7.41 | 0.66 | |
| 1969 | 7.58 | | | | -8.62 | -16.20 | |
| 1970 | 7.91 | | | | 23.34 | 15.43 | |
| 1971 | 6.95 | | | | 4.29 | -2.66 | |
| 1972 | 7.23 | | | | -0.44 | -7.67 | |
| 1973 | 7.56 | | | | -4.14 | -11.70 | |
| 1974 | 8.90 | | | | 14.38 | 5.48 | |
| 1975 | 9.04 | | | | 5.75 | -3.29 | |
| 1976 | 9.18 | | | | 15.02 | 5.84 | |
| 1977 | 8.70 | | | | 19.00 | 10.30 | |
| 1978 | 9.27 | | | | 27.28 | 18.01 | |
| 1979 | 10.21 | | | | 12.61 | 2.40 | |
| 1980 | 12.48 | | | | 5.74 | -6.74 | |
| 1981 | 15.22 | | | | -0.55 | -15.77 | |
| 1982 | 14.26 | | | | 35.90 | 21.64 | |
| 1983 | 11.79 | 25.63 | 13.84 | | 40.97 | 29.18 | |
| 1984 | 12.75 | 5.46 | -7.29 | | 24.31 | 11.56 | |
| 1985 | 11.04 | 18.95 | 7.91 | | 10.04 | -1.00 | |
| 1986 | 9.52 | -3.48 | -13.00 | | 11.48 | 1.96 | |
| 1987 | 9.95 | 9.97 | 0.02 | | 1.07 | -8.88 | |
| 1988 | 10.22 | 7.87 | -2.35 | | 5.63 | -4.59 | |
| 1989 | 9.92 | 18.44 | 8.52 | | 22.07 | 12.15 | |
| 1990 | 10.85 | 6.35 | -4.50 | | 0.58 | -10.27 | 1.78 |
| 1991 | 9.76 | 3.90 | -5.86 | | 27.02 | 17.26 | 2.37 |
| 1992 | 8.77 | -0.52 | -9.29 | -1.20 | -2.24 | -11.01 | 2.27 |
| 1993 | 7.85 | 31.45 | 23.60 | -0.23 | 23.52 | 15.67 | 2.56 |
| 1994 | 8.63 | -2.65 | -11.28 | -0.62 | -6.04 | -14.67 | 2.28 |
| 1995 | 8.28 | 14.77 | 6.49 | -0.77 | 18.44 | 10.16 | 1.95 |
| 1996 | 7.50 | 30.69 | 23.19 | 2.85 | 32.68 | 25.18 | 2.27 |
| 1997 | 6.42 | 48.56 | 42.14 | 7.07 | 37.33 | 30.91 | 3.32 |
| 1998 | 5.47 | 4.07 | -1.40 | 7.16 | 36.55 | 31.08 | 4.17 |
| 1999 | 5.69 | -24.02 | -29.71 | 3.34 | 72.34 | 66.65 | 5.61 |
| 2000 | 5.89 | 57.96 | 52.07 | 8.99 | 18.70 | 12.81 | 6.00 |
| 2001 | 5.78 | 14.68 | 8.90 | 10.47 | -25.19 | -30.97 | 5.66 |
| 2002 | 5.66 | 13.79 | 8.13 | 12.21 | -3.86 | -9.52 | 5.41 |
| 2003 | 5.28 | 27.71 | 22.43 | 12.10 | 22.92 | 17.64 | 5.90 |
| 2004 | 5.08 | 14.99 | 9.91 | 14.21 | 18.01 | 12.93 | 6.73 |
| 2005 | 4.39 | 32.08 | 27.69 | 16.33 | 25.78 | 21.39 | 6.90 |
| 2006 | 4.28 | 16.64 | 12.36 | 15.25 | 7.36 | 3.08 | 7.06 |
| AVERAGE: | | | | | | | |
| 1983-2006 | 7.95 | 15.55 | 7.60 | | 17.48 | 9.53 | |
| 1956-2006 | 7.68 | | | | 12.79 | 5.12 | |

# APPENDIX 'E'

Return on Equity: Allowed Returns for Canadian Gas Utilities.

Canadian Gas Association. (CGA)

CIBC World Markets

Equity Research

# Pipelines And Utilities

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December 3, 2001

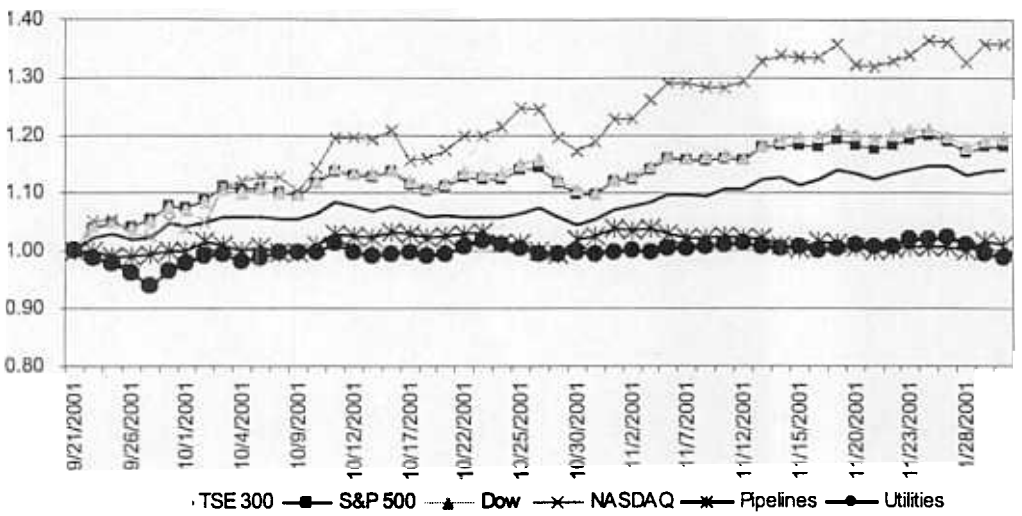
# Time To Lighten Up

*All figures in Canadian dollars, unless otherwise stated.*

## Investment Conclusion

- The recent broad market rally from September 21 lows likely signals the start of a new bull market phase and as such has significant implications for pipeline and utility stocks. In the near term, we expect a consolidation of recent market gains during which pipeline and utility stocks may outperform again; however, we would use this as an opportunity to trim exposure to the group. We would focus remaining exposure on those companies with the best potential earnings growth and, in particular, those that effectively use performance-based regulation and strategic acquisitions and increase the proportion of nonregulated assets and operations in their business mix.

**Figure 1. Sector Performance Relative To Broader Indices**




Prices as of market close November 30, 2001.
Source: Starquote.

- November saw the markets rally and the start of a rotation into more cyclical stocks. As a result, the pipelines and utilities underperformed the TSE in November; while the TSE 300's total return was 8.0%, that of the utilities was virtually zero, and the pipelines was negative 1.3%. Contributing to the underperformance was the back-up in long Canada bond yields, which have risen by approximately 40 basis points from recent lows. Pipeline and utility stocks are highly *negatively* correlated with long Canada bond yields. Figure 1 shows the relative performance of the sector to broader indices from the September 21 low, and figures 2 and 3 show individual company performance in November and year-to-date. The sector underperformed in the month, even after accounting for the dividend yield, as shown in Figure 4.

*See page 2 for state/provincial restrictions.*

- The shock of the failure of Enron and the uncertainty about any possible domino effect has put pressure on the stock prices of energy merchants and may continue to overhang the sector, and potentially the broader market, until the situation is clearer. We note, however, that all of the companies in our universe have indicated that they do not have any direct material exposure to Enron. We expect that other marketers should be able to step in and fill the gap left if EnronOnline were to be permanently turned off, although we are less certain of the duration and magnitude of any reduced liquidity and resultant increased volatility in the power and gas markets.

- Over the next 12 months, as an economic recovery unfolds, there will likely be upward pressure on short- and long-term interest rates. At the same time, a recovery will continue to diminish the defensive appeal of these stocks and highlight the better relative growth prospects of more cyclical or economically sensitive sectors. As well, we continue to have valuation concerns about the distribution utilities, which are trading at about a 2.1-multiple-point premium and a 90-basis-point yield discount compared to U.S. comparables with similar growth rates and risk profiles (see Table 1).

**Table 1. Canadian Valuation Premium**

| | 2002 P/E | Dividend Yield |
|---|---|---|
| Canadian Gas & Electric Utilities | 13.9 | 4.4% |
| U.S. Gas & Electric Utilities | 11.8 | 5.3% |

Source: CIBC World Markets.

- **TransAlta** (TA – Buy) A recession will reduce industrial power demand, which will likely prolong recent weakness in electricity prices; however, with most of TA's output contracted long term and at fixed prices, our recommendation has been premised on expectations of growth in TA's generation portfolio and the enhanced returns achievable from its Alberta generation assets in a deregulated environment. With its dividends providing about a 4.3% yield, the stock now offers excellent income and downside protection while preserving the longer-term upside. In the mean time, the weaker balance sheets of some of its competitors may facilitate acquisition opportunities.

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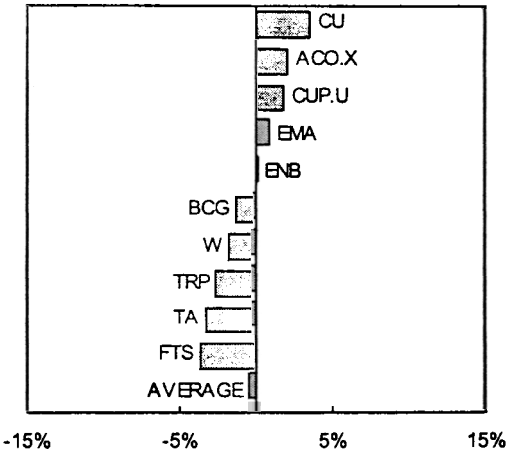
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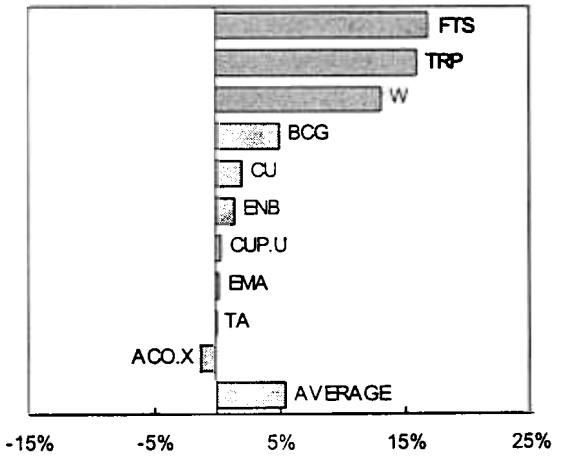
- **Enbridge** (ENB – Buy) has demonstrated the strongest and most consistent EPS growth of the sector. It is benefiting from incentive regulation at Consumers Gas, from the recently completed Midcoast Energy acquisition, and from rising oil production in Western Canada, which will boost demand for its oil pipeline. Confidence in the latter outcome is heightened by customers' recent requests that Enbridge proceed with the third phase of the Terrace expansion. We believe that the recent purchase of 25% of the Spanish energy transportation company (CLH) indicates the increasing contribution and strength of Enbridge's international operations.

**Figure 2. Monthly Stock Price Performance**




Prices as of market close November 30, 2001.
Source: Starquote.

**Figure 3. Year-To-Date Stock Price Performance**




Prices as of market close November 30, 2001
Source: Starquote.

Figure 4. Total Return Of Pipelines And Utilities

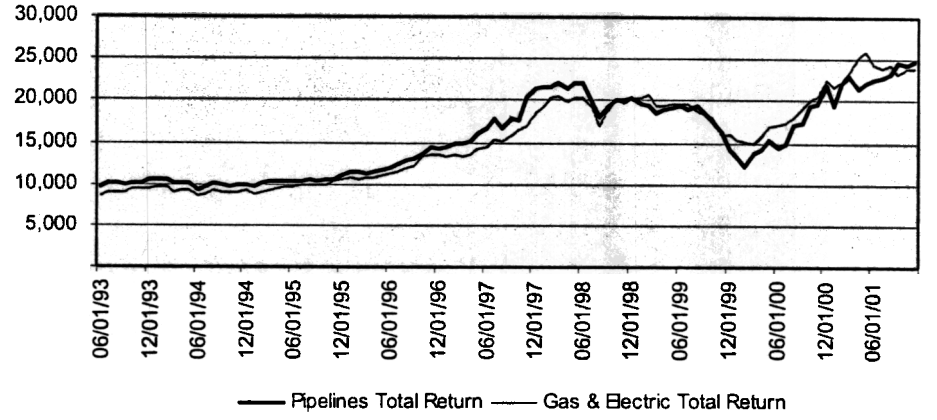



Chart data up to November 30, 2001.
Source: Bloomberg.

Figure 5. Pipeline And Utility Yields Relative To 10-Year Government Bond Yield

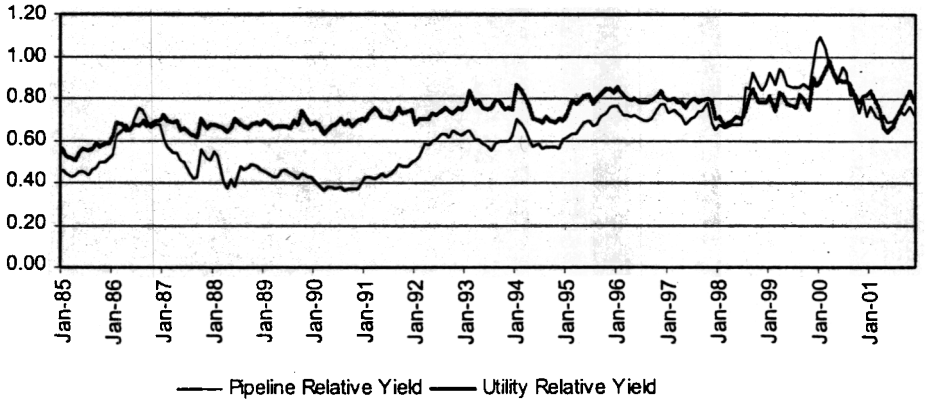



Chart data up to November 30, 2001.
Source: Bloomberg, CIBC World Markets.

## Multi-Pipeline ROE Determined

The return on equity (ROE) adjustment mechanism approved in the National Energy Board's (NEB) multi-pipeline (MPP) cost-of-capital decision can now be calculated, as the November Consensus Forecast of government bond yields has been published. Based on our calculation shown in Table 2, the MPP ROE should be 9.53% for 2002 versus 9.61% in 2001. Last month we estimated the ROE to be 9.65%, but anticipated that the forecasted bond yields would fall; we have therefore already incorporated a lower ROE into our company valuation models.

**Table 2. National Energy Board ROE**

| | November Calculation | Our High-End Estimate Last Month |
|---|---|---|
| Feb 2002 Gov't. 10-yr. Bond | 4.90 | 5.10 |
| Nov 2002 Gov't. 10-yr. Bond | 5.40 | 5.50 |
| Avg. 2002 Gov't. 10-yr. Consensus | 5.15 | 5.30 |
| Spread – 30-yr. and 10-yr. Can. Gov't. Bonds | 0.48 | 0.48 |
| Forecast 2002 30-yr. Bond | 5.63 | 5.78 |
| Forecast 2001 30-yr. Bond | 5.73 | 5.73 |
| Difference X 0.75 | (0.08) | 0.04 |
| 2001 Approved ROE | 9.61 | 9.61 |
| ***2002 Approved ROE*** | ***9.53%*** | ***9.65%*** |

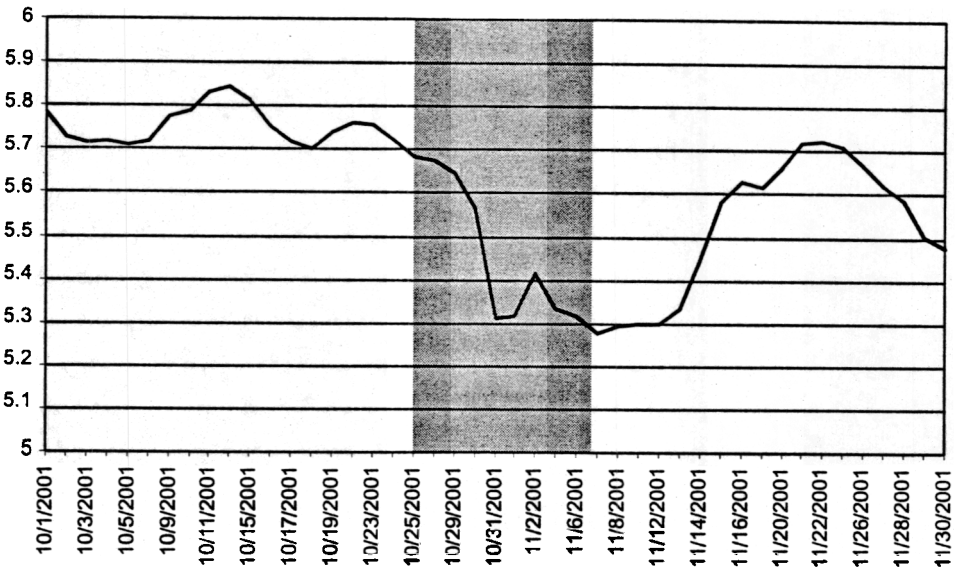
Source: Bloomberg, Consensus Economics, NEB, CIBC World Markets.

On November 9, we reduced our earnings estimates for Fortis after the Newfoundland Board of Public Utility Commissioners reduced the allowed return on equity for Newfoundland Power to 9.05% — the lowest return awarded to any Canadian utility. This return was based on a snapshot bond-yield formulaic approach to determining rates (as opposed to the NEB's consensus forecast approach). The snapshot was of Canada bond yields in the last five days of October and the first five days of November, and this time period is shaded in Figure 6.

The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.

In our view, the return produced by the Newfoundland Board of Public Utility Commissioners and that produced by the NEB formula, increases the significance of applications by TransCanada PipeLines to the NEB and by Consumers Gas to the Ontario Energy Board (OEB) for an increase in allowed returns. It will be important for investors to watch these proceedings closely.

Figure 6. Long Canada Government Bond Yields




Source: Bloomberg.

## Sector's Direct Exposure To Enron Very Limited

We are not changing our earnings estimates, target prices, or ratings, for companies in our universe as a result of their counterparty exposure to Enron. Last month we noted that companies in our universe had reassured us that they did not have any material exposure to Enron, and more recently, companies have once again reassured us that the direct exposure is immaterial (we estimate less than 1% of revenues); however, there is lingering uncertainty about the possibility of a domino effect in the energy trading markets. We expect that other marketers should be able to step in and fill the gap if EnronOnline were to be permanently turned off, although we are less certain about the duration and magnitude of any reduced liquidity and resultant increased volatility in the power and gas markets.

Companies trading in EnronOnline are typically subject to a "master agreement" that provides for netting out of the contracts, and Table 3 summarizes approximate net positions. Enron bought the future output of one of TransAlta's generating plants (in a contract worth approximately $294 million), but this contract is guaranteed by the Alberta provincial balancing pool. Enron also has contracted for firm capacity on TransCanada's pipelines, but the company believes that if one shipper were to default, that this would be absorbed by the other system's shippers and not the company's shareholders.

**Table 3. Summary Of Exposure To Enron**

| Company | Net Position | Disclosure of Net Impact | Est. % Revenue |
|---|---|---|---|
| Enbridge Inc. | Payable to Enron | approximately $9 mln. USD (through Midcoast acquisition) | 0.31% |
| TransAlta | Neutral | payable and receivable of US$10 mln. nets out | 0.02% |
| TransCanada PipeLines | NA | "not material" – company declined to define "material" | NA |

Source: Companies, CIBC World Markets.

We believe that the competition will attempt to step in and fill the gap Enron is sure to leave. An industry publication on November 30 suggested that JP Morgan Chase and Citibank were in serious talks on November 29 to take over all or part of Enron's multi-hundred-billion-dollar notional book of trading positions. It is expected that the banks would primarily warehouse existing contracts as they wind down over the next decade or so, but could potentially continue over-the-counter (OTC) commodities derivatives trading at a lower level. Creditors with recourse to nontrading assets, however, would perhaps contest the potential bailout. We note that other trading platforms such as Intercontinental Exchange (ICE), while stretched in the shorter term, could step in to provide liquidity.

## Recent Sector Activity

### Enbridge Expands Into Europe

On November 26, Enbridge announced that it had signed a letter of intent to purchase 25% of the common shares of Spanish transportation company Compañía Logistica de Hidrocarburos CLH, S.A. (CLH) for approximately C$530 million. That same day, we published our favourable views on the transaction, namely that it would be immediately accretive to earnings, that it was in line with both the corporate and international strategies, and that it created options for future partnerships with large integrated oil companies. We increased our 2002 and 2003 EPS estimates slightly, and retained our target price of $50 and our Buy rating.

### Companies Sign On To Alaska Highway Pipeline

On November 15, six U.S. and three Canadian companies announced the signing of a memorandum of understanding to develop a proposal for the Alaska Highway pipeline, which they expect to put before Alaska North Slope producers by year end. The Canadian companies are TransCanada, Westcoast, and Foothills.

This has not changed our investment outlook for companies in our universe, as we note that the producers, not the pipeline companies, will drive the decision as to which route and which partners make most economic sense for Northern Gas. Furthermore, gas delivery is not expected before 2008. We also note that the large number of proposed LNG projects could provide 7 Bcf/day to 8 Bcf/day of supply by 2010 and keep gas prices in the range of US$3.00/Mcf to US$3.50/Mcf. At this price, it will be difficult for Alaska gas to compete via the highway route. For example, Enbridge estimates the transportation cost alone of the highway route at US$2.39/Mcf and the over-the-top route at US$2.07/Mcf.

### TransCanada Mainline Tolls And Tarriffs Approved

As expected, the NEB has approved TransCanada's 2001 and 2002 Mainline tolls and tariff application, which was based on an agreement supported by the bulk of TransCanada's customers. The agreement fixes most of the elements of TransCanada's Mainline revenue for 2001 and 2002, and retains TransCanada's immunity from volume fluctuations. Yet to be decided is the cost of capital that TransCanada will be allowed to recover in each year. This will be the subject of a hearing that will begin in February. We are maintaining our $21.00 target price and Hold rating.

### Milestone Completed In Duke Acquisition Of Westcoast

On November 21, an announcement was made by Westcoast that Duke Energy has received approval from the British Columbia Utilities Commission (BCUC) to acquire indirect control of the public utilities owned wholly or in part by Westcoast Energy and regulated

by the BCUC, namely Pacific Northern Gas, Pacific Northern Gas (N.E.), Centra Gas British Columbia, and Centra Gas Whistler.

Duke and Westcoast also announced that they had received a request for additional information and documents from the Federal Trade Commission (FTC) review of the proposed acquisition of Westcoast Energy by Duke Energy. This request is routine and the companies do not expect the request to have a material impact on the timing of the consummation of the proposed acquisition. If the acquisition arrangement is approved by Westcoast Energy's common shareholders and option-holders, subsequent to the B.C. Supreme Court and finally the other conditions of closing being satisfied or waived, the companies expect the acquisition will be completed during Q1/2002.

### Ontario Government Considers Not-For-Profit Option For Hydro One

We note the recent media buzz around the proposal to create a not-for-profit structure for Hydro One. The province is considering all options, including one that could raise up to $14 billion in bonds — approximately $5 billion of which would be available (after repaying Hydro One's existing debt and equity investors) to pay down part of the Old Ontario Hydro's $21 billion in stranded debt. Before this month, the prevailing options were thought to be either the outright sale to another utility company or an initial public offering (IPO) to private investors and stock exchange listing. The not-for-profit option is purported to result in $2 billion – $4 billion more in initial stranded debt retirements.

Hydro One management is opposed to the not-for-profit option, not so much for the lack of ability to use employee share options as incentives, but more for the ramifications for its strategy to become a major player in the North American electricity market. Under this option it would likely not have to pay taxes, which American transmission companies would likely argue was an unfair competitive advantage for Hydro One. Also, without financial flexibility, Hydro One might have fewer resources to invest in new connections to the North American power grid, which could result in the Ontario power market becoming less fully integrated with the North American grid. At first blush this would lower electricity prices in Ontario, if excess energy is bottled up in Ontario. Over the longer term, however, the cost to consumers could increase if inadequate transmission capacity discouraged construction of sufficient generation to meet growing demand.

Some of the province's largest electricity consumers appear to favour the not-for-profit option based on the assumption that this would reduce the special levy on consumption to pay off the stranded assets. For example, currently the levy is approximately 15% of electricity consumed for large consumers such as Dofasco. We believe that this view is erroneous as the levy would not be reduced until the stranded debt is fully defused or repayed. Moreover, there is no assurance that the levy would end significantly earlier as higher up front proceeds from the bond issue could be offset in the long run by lower provincial income tax payments.

Environmentalist groups' responses have been mixed—with some in favour and others opposed.

We favour privatization, as we believe that all stakeholders would be best served over the longer term. While large industrial consumers think they might benefit in the short term through a reduced stranded debt levy, over the longer term the isolation of the Ontario power market and probable broader under investment in new technologies could drive prices up. We believe that agency issues both on the economic as well as environmental front would be mitigated if management were to be accountable to shareholders and not the broad taxpayer base through the government.

The Ontario power market is expected to be deregulated by May 2002, and we believe that a for-profit transmission company could best serve this market. Power companies feel that way as well. TransAlta recently stated that it would not invest further in Ontario until there was more certainty and clarity around deregulation in the province. Bruce Power publicly stated its belief that a private transmission company would have a more efficient, robust, and reliable infrastructure. We note that we are in good company, as Alan Greenspan, the U.S. Federal Reserve chairman, spoke on November 14 to the U.S. Chamber of Commerce about the importance of increased flexibility in electricity transmission and market forces in balancing supply and demand. He cited the need for a vibrant energy policy to foster long-term economic growth, which we believe applies to Ontario as well.

### Hydro One To Partner In Merchant Transmission Line Under Lake Erie

Hydro One seems to be operating with the expectation that it will be privatized, as it is acting on its mandate to competitively connect to markets outside Ontario. On November 27, Hydro One and TransEnergie U.S., a subsidiary of Hydro-Quebec, proposed the construction of a 975-MW merchant power line under Lake Erie that could be ready for commercial service by the summer of 2004. The proposed line would be high-voltage direct current (HVDC), enabling power to flow in both directions and originate at a substation not far from the 3,920-MW and coal-fired Nanticoke generation complex, and terminate at one of two substations, either in Ohio or Pennsylvania. Because it would be a merchant line, funding would come from the sale of transmission rights and not impact the cost of transmission within Ontario.

Although Hydro One has 17 interconnections with other systems, congestion in the past led to price spikes in the U.S. Midwest markets in the summers of 1998 and 1999. Ontario typically experiences demand peaks in the winter and is capable of exporting demand south of the border in the summer. Advocates of the new line argue that not only will the new connection increase reliability within the Ontario system, it will also encourage the growth of new generation within Ontario and spur interest in outside generators to send power into the province.

### Ontario Electricity Deregulation On Schedule

Deregulation of the retail markets is progressing as scheduled, with the December 14, 2001 deadline for several applications by distributors and wholesale market participants approaching. By that date, distributors must forward a self-certification and market readiness submission to the OEB. Wholesale market participants must file fully executed participant and connection agreements, as well as proof of secure exchange of information capabilities with the IMO. Furthermore, codes, rules, and regulatory approvals are due by the middle of December[1]. This will trigger the market readiness recommendation and government consultation phase, which is due to be completed in mid-January[2].

---

This milestone will define operation of the wholesale and retail markets, including the following: 1) market rules of the IMO–administered markets; 2) IMO market manuals, technical standards, and interfaces; 3) retail settlement and other OEB codes and standards, including structures of the various rates to be approved by the OEB, and 4) approvals by the OEB of individual rate applications.

2 The OEB and the IMO will advise the Minister of Energy, Science and Technology regarding the readiness of the market participants under the current schedule based on: 1) the readiness of individual market participants; 2) the stability of both wholesale and retail market design, as confirmed in relevant design testing; 3) the readiness of the IMO market systems; and 4) results of self-certification filings by licensed distributors.

## Third-Quarter Results

Earnings season came to a completion with the release of Caribbean Utilities' earnings on November 20. Table 4 highlights actual and forecast Q3 EPS for 2001 and actual EPS for 2000. Detailed commentary is available in our Research Highlight for each company, generally published one business day after the earnings reporting date.

**Table 4. Third-Quarter EPS Results**

| | Report Date | Actual 2001 | Our Estimate | Consensus Estimate | Actual 2000 |
|---|---|---|---|---|---|
| Enbridge | November 8 | $0.42 | $0.46 | $0.47 | $0.28 |
| TransCanada PipeLines | October 30 | 0.34 | 0.34 | 0.34 | 0.32 |
| Westcoast Energy | October 21 | 0.46 | | 0.20 | 0.22 |
| ATCO | November 1 | 0.82 | 0.73 | NA | 0.74 |
| BC Gas | November 8 | (0.58) | | (0.39) | (0.34) |
| Canadian Utilities | October 31 | 0.65 | 0.63 | 0.63 | 0.64 |
| Caribbean Utilities (US$) | November 20 | 0.24 | 0.23 | 0.22 | 0.23 |
| Emera | November 2 | 0.17 | 0.16 | 0.14 | 0.06 |
| Fortis | October 31 | 0.79 | 0.55 | 0.48 | 0.47 |
| TransAlta | October 18 | 0.25 | 0.27 | 0.25 | 0.32 |

Source: CIBC World Markets, First Call.

## Table 5. Comparable Valuation, Ratings, And Target Prices – November 30, 2001

| Stock Rec. | Symbol | Company | Fiscal Year | Price | 52-Week High | 52-Week Low | Mkt. Cap. ($ mlns.) | Recent BV | P/BV | EPS 2000 | EPS 2001E | EPS 2002E | EPS 2003E | EPS Growth 00-03 | P/E 2001E | P/E 2002E | P/E 2003E | Current Dividend | Yield | Total Implied Return | 12-mo. Target Price |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Pipelines** | | | | | | | | | | | | | | | | | | | | | |
| Buy | ENB | Enbridge Inc. | Dec.31 | $44.30 | $45.55 | $33.90 | $7,159 | $14.67 | 3.02 | $2.17 | $2.46 | $2.80 | $3.09 | 12.5% | 18.0 | 15.8 | 14.3 | $1.40 | 3.2% | 16.0% | $50.00 |
| Hold | TRP | TransCanada PipeLines | Dec.31 | 19.97 | 21.13 | 14.80 | 9,512 | 11.01 | 1.81 | 1.22 | 1.39 | 1.47 | 1.51 | 7.4 | 14.4 | 13.6 | 13.2 | 0.90 | 4.5 | 9.7 | 21.00 |
| | W | Westcoast Energy | Dec.31 | 41.00 | 42.29 | 29.90 | 5,059 | 22.76 | 1.80 | 2.51 | | | | | – | – | – | 1.36 | 3.3 | N/A | N/A |
| | | **Average Pipelines** | | | | | | | | | | | | | **16.2** | **14.7** | **13.8** | | **3.7%** | | |
| **Utilities** | | | | | | | | | | | | | | | | | | | | | |
| Hold | ACO.X | Atco | Dec.31 | 46.00 | 54.00 | 38.00 | 1,366 | 26.43 | 1.74 | 3.79 | 4.10 | 4.37 | 4.63 | 6.9 | 11.2 | 10.5 | 9.9 | 1.04 | 2.3 | 16.4 | 52.50 |
| | BCG | BC Gas | Dec.31 | 35.00 | 36.88 | 29.00 | 1,341 | 17.86 | 1.96 | 2.06 | – | – | – | – | – | – | — | 1.32 | 3.8 | – | N/A |
| Hold | CU | Canadian Utilities | Dec.31 | 52.00 | 56.05 | 43.10 | 3,297 | 23.29 | 2.23 | 3.59 | 3.76 | 3.92 | 4.22 | 5.5 | 13.8 | 13.3 | 12.3 | 1.88 | 3.6 | 11.3 | 56.00 |
| Hold | CUP.U | Caribbean Utilities ($US) | Apr.30 | 12.05 | 13.50 | 11.00 | 289 | 3.70 | 3.26 | 0.78 | 0.78 | 0.87 | 1.00 | 8.6 | 15.4 | 13.9 | 12.1 | 0.62 | 5.1 | 11.0 | 12.75 |
| Hold | EMA | Emera | Dec.31 | 17.75 | 18.20 | 15.55 | 1,737 | 11.85 | 1.50 | 1.20 | 1.16 | 1.18 | 1.18 | (0.6) | 15.3 | 15.0 | 15.0 | 0.85 | 4.8 | 0.6 | 17.00 |
| Hold | FTS | Fortis | Dec.31 | 42.09 | 44.83 | 33.55 | 626 | 27.50 | 1.53 | 2.36 | 3.20 | 3.36 | 3.53 | 14.4 | 13.2 | 12.5 | 11.9 | 1.88 | 4.5 | 17.3 | 47.50 |
| Buy | TA | TransAlta Corp. | Dec.31 | 22.00 | 30.13 | 19.15 | 3,714 | 11.69 | 1.88 | 1.29 | 1.27 | 1.55 | 1.84 | 12.6 | 17.3 | 14.2 | 12.0 | 1.00 | 4.5 | 22.7 | 26.00 |
| | | **Average Utilities** | | | | | | | | | | | | | **15.0** | **13.8** | **12.7** | | **4.4%** | | |

[1] EPS estimates for Caribbean Utilities are for the period ending April 30 the following year.
[2] Averages exclude data for ATCO.

Source: CIBC World Markets, Starquote.

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Briefing March 2004

# Electricity Restructuring
# Opening Power Markets

**About the Electricity Restructuring Series**
This briefing is the fifth in a series that highlights key learnings from the experience of North American and U.K. electricity restructuring initiatives over the past decade. The briefings focus on the impacts of public policies in the areas of economic regulation, air quality and climate change on investment in electricity generation and transmission, and on trade across regions.

Investment is needed in transmission capacity. Electricity in Canada and the United States has become a North American phenomenon, with growing volumes of exports and imports between the two countries. The result is a highly interconnected, complex continental network—one that is flexible in responding to fluctuations in demand and supply, but is more vulnerable in the event of a major failure.

Yet challenges exist to getting investment. North America's evolving electricity sector must find ways to raise the level of investment in order to strengthen the transmission infrastructure. This briefing suggests possibilities, while outlining why investment is needed and identifying some of the obstacles.

## INVESTMENT IS NEEDED

Under-investment in critical infrastructure cannot be sustained. Witness the Aug. 14 blackout. Its cascading nature underscored the need not only for a more resilient electricity infrastructure, but also for a less brittle system overall.

New demands due to trade, combined with an aging system, have created congestion on transmission lines. This congestion has given rise to an untenable situation with respect to reliability, and constitutes a barrier to electricity trade. In fact, the lack of adequate transmission has become a bottleneck to the development of generation in several areas. An inadequate infrastructure not only threatens electricity reliability; it also contributes to volatility in electricity prices and higher prices for consumers in constrained zones.

Transmission lines are strained and overtaxed, largely because investment in continental transmission capacity has stagnated while network congestion has increased. The North American Electric Reliability Council (NERC)

reported in 2002 that the number of power deals that could not be fulfilled due to transmission constraints quintupled, from 300 in 1998 to 1,500 in 2002.[1] This has created local market power problems and has complicated the operation of wholesale power markets. The grid, in its grim condition, requires upgrading that is estimated to be in the order of $50 billion US.

And money isn't the only issue. Arguably, there are imperfections in transmission governance arrangements that further erode the effectiveness of the transmission infrastructure. The transmission system remains fragmented, with too many system operators relying on incompatible scheduling, transmission pricing and emergency management mechanisms.[2]

Making transmission improvements comprises only one element among many in moving towards the objective of meeting future power needs. Nevertheless, facilitating transmission investment is an important objective, since transmission is currently the factor that most limits the supply of electricity in North America.

Given the deficiencies of the current infrastructure, investment is clearly required to accommodate cross-border exchanges and to ensure the reliability and security of electricity.

**Improving transmission is vital—but we must do more to meet North America's power needs, including removing obstacles to investment.**

However, investors who are considering the transmission sector in North America face increased risks. Why? In a nutshell, the sector lacks sufficient commercial incentives and potential rewards to balance new risks. We need to remove barriers and address disincentives to transmission investment either through regulatory mechanisms or market signals, particularly as markets continue to integrate.

## CHALLENGES FOR INVESTMENT

A number of regulatory issues and uncertainties are limiting investment in new transmission capacity.

### PLANNING

A lack of integrated and co-ordinated planning for transmission between jurisdictions exists. The focus on regional supply has limited the expansion of the transmission system; in general, the main problem lies in insufficient regional integrated planning. Moreover, the cumbersome procedures for finding sites and obtaining permission for new facilities deter investors. Multiple authorities are responsible for planning and building new facilities, and investors must endure long lead times before obtaining regulatory approval.[3] For example, three years' lead time is the current estimate to attain the necessary approval for transmission line work in the Pacific Northwest Economic Region. The "not in my back yard" factor is a particular challenge for investors in planning for, and obtaining, suitable new corridors.

**The electricity sector suffers from a lack of integrated and co-ordinated planning for transmission.**

### REGULATED RATES

Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies.[4] These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid.[5]

### FINANCING

Obtaining desired levels of financing is also problematic. Following the Enron bankruptcy and the ensuing loss of market credibility, it has become more difficult for energy companies to get credit for working capital and to finance their investments. And the upshot is that companies have been curtailing or exiting energy trading and marketing, and energy trading activity is down more than 70 per cent in the United States.[6] In turn, there is a lack of financing to pursue projects,[7] which has reduced the incentive to pursue new infrastructure projects or new transmission connection technologies.

### REGULATORY UNCERTAINTY

Several regulatory factors combine to create an unfavourable investment climate in the electricity sector:

- Changes in market restructuring policies in both Canada and the United States are ongoing.
- In light of the continuing attempts to create an even playing field in the wholesale power supply market through non-discriminatory access, there is indecision as to how transmission systems should be operated.[8]
- With increased regionalization, it is unclear who will own and operate the grid in the future. Despite regionalization, the authority to improve the grid remains with individual states and provinces. And, as the blackout demonstrated, key industry decision-makers are unsure of their regulatory options during emergencies or market events.[9]

## ENCOURAGING INVESTMENT

Encouraging investment increasingly preoccupies the industry as a whole. The Canadian Electricity Association (CEA) has estimated that about $150 billion in investment will be required in the electricity sector over the next 20 years, either to replace aging capacity and infrastructure or to add to what already exists. And the industry will be relying on private capital for much of this future investment.[10]

**To secure the substantial sums that will be required by the electricity sector over the next 20 years, several investment challenges must be overcome.**

Key players have been pushing politicians for regulatory reform to encourage investment in transmission. For example, the Edison Electric Institute has urged the U.S. Congress to update federal laws that restrict critically needed investment in the power transmission system. The CEA, along with the Canadian Gas Association, is urging multi-jurisdictional efforts to improve the investment climate in Canada.

Ideally, a multifaceted approach should be designed to overcome investment challenges. This section presents five key elements that such an approach should encompass.

### RATES OF RETURN AND DEPRECIATION

As the CEA has pointed out, investors must see reasonable rates of return on their capital.[11] Specifically, the CEA contends that rates of return should recognize the value that the transmission grid plays in the economy. Rates should include clear signals on congestion and losses to transmission users, and should encourage technological innovation.

Increases in regulated rates of return on infrastructure projects would provide better incentives for building transmission. Rate improvements could assist in enhancing the security and reliability of the overall electricity system by attracting new investment to reduce congestion, increase import/export capability, add capacity and support competitive markets. A more secure and reliable system would engender greater competition for infrastructure contracts and could lead to lower costs for such work and lower consumer prices.

The CEA has issued a call for substantially higher capital cost allowance (CCA) rates to reflect the economic life of depreciating assets and to permit expansion. “Given steadily growing demand and long lead times to plan and bring new supply and infrastructure on-line, a decision on CCA rates is urgently needed to allow utilities to build out infrastructure equivalent to approximately 35 per cent of existing capacity over the next two decades.”[12]

It is important that Canada’s rates be competitive with those of the United States so that both countries can maintain a solid pace of transmission infrastructure improvement.

Furthermore, the risk profile of new transmission facilities is generally greater than that for existing facilities. These greater risks—and the lack of regulatory recognition of these risks—may make utilities reluctant to pursue investment. Regulators should therefore recognize these additional risks when setting rates.[13]

Maintaining competitive rates is a necessary, but not a sufficient, condition for investment, however. It is important to improve rates in Canada, but, given that U.S. transmission companies are not investing adequately either, there are clearly other issues that must be addressed in order to get the investment that is so evidently needed.

## PLANNING

The blackout prompted serious thought about planning, and the merits of regionalization. The U.S. Federal Energy Regulatory Commission (FERC) has argued that the blackout demonstrated the need for regional co-ordination and planning, and for national standards. FERC's regional transmission organization (RTO) system aims to formalize the regional planning process and efficiently manage the growth of the transmission system.[14] Standard Market Design (SMD), an attempt at standardization and regionalization, may boost infrastructure investment. SMD is a federal plan to standardize all U.S. wholesale power markets. The FERC proposal calls for a single set of market rules that would eliminate the differences between regional electricity markets. FERC views these differences as barriers that limit the ability of energy users to get access to lower-cost power resources.[15] The current energy bill delays SMD until 2007.

**The Aug. 14 blackout underscored the need for planning, although differences of opinion exist as to how best to proceed.**

Some states and provinces have chosen a different interpretation of the blackout, regarding it as an indication that they should isolate themselves on the grid to avoid problems. However some experts, such as Connie Hughes, Chair of the Ad Hoc Committee on Critical Infrastructure for the U.S. National Association of Regulatory Utility Commissioners, argues that there is no reason for breaking down power and energy trade between countries.[16] Although critics of regionalization view it as an infringement on state and provincial rights, integrated planning will likely work more effectively under a regionalized RTO system.

## LOCATIONAL MARGINAL PRICING

Locational marginal pricing (LMP) is a market-pricing approach used to manage the efficient use of the transmission system. LMP sets prices specific to location. It aims to manage congestion by pricing electricity higher in locations where congestion exists, thus providing a precise market-based method for pricing electricity that includes the cost of congestion. By doing so, LMP also indicates where investment in new transmission facilities is most needed. LMP has been recognized as a significant improvement on flawed congestion management and uniform pricing systems.[17]

Some electricity markets have adopted or are adopting LMP: Pennsylvania New Jersey Maryland (PJM ISO) implemented LMP in 1998; New York (NY ISO) in 1999; New England (ISO-NE) in 2003.[18] And it appears to be advantageous; transmission investments are now being proposed in congested zones in these three jurisdictions.[19] Furthermore, FERC is promoting LMP as a means of managing electric transmission congestion. It is the proposed pricing model for many of the RTOs.[20]

LMP could help dissolve "load pockets"[21] and allocate scarce transmission resources more efficiently. Specifically, LMP provides better information for investment decisions by:

- identifying congested areas;
- producing transparent prices that assist investment analysis;
- helping to account for the value of upgrades to the system; and
- assisting in comparing the value of "competing" investment options.

LMP also supports efficient regional planning.

Despite the potential advantages of LMP, it is a complex approach that is not without its own challenges. Using pricing to provide incentives for expansion creates an inherent conflict—it lessens the motivation for transmission companies to deal with congestion, as they may be able to collect more revenues when it exists. To address this concern, New York State auctions the rights to recover congestion revenues to entities that do not control the grid.[22]

Realistically, LMP must be regarded as a necessary feature of a successful system, but not as a solution in itself. Ideally, LMP should be a complementary part of a larger suite of mutually reinforcing tools, both market and regulatory, that, acting together, improve the reliability and efficiency of a power system.[23]

## MERCHANT TRANSMISSION

Another option to improve transmission capacity is to permit "merchant" transmission lines. These are projects, usually involving direct current lines, financed by private sector interests to export power over long distances and across borders on a fee-for-service basis. AltaLink is advocating merchant transmission lines, as is its American parent, Trans-Elect, Inc. Merchant

transmission lines have the potential to alleviate transmission congestion issues. Moreover, several merchant transmission projects and long-distance transmission line projects have been proposed as means of connecting more "environmentally friendly" forms of power, such as hydro and wind, to their markets.

However, as a new industry, merchant transmission is unproven.[24] Investment in it is therefore more likely to play a significant role in addressing transmission constraints over the longer, rather than the shorter, term.

**RELIABILITY STANDARDS**

Electricity reliability, which had long rested on the back burner of political priorities, was quickly marched to the forefront this summer. The blackout, was, of course, the catalyst. It exposed the fact that the current system for maintaining reliability—which is based on standards with which utilities voluntarily comply—is no longer effective. The introduction of competition in wholesale electric markets has eroded the incentive for voluntary action. Now, more than ever, the electricity market needs mandatory standards, along with financial consequences for non-compliance.

NERC is developing a single set of reliability standards to replace its existing operating policies and planning standards. The new standards will address planning and operations, and will include compliance measures for each standard.[25] Legislation on this issue is being considered as part of the national energy bill before the U.S. Congress. Among the bill's measures is a plan to make reliability standards mandatory.[26] The bill has been on hold, but the Senate will conduct a second vote in January 2004. FERC Chairman Pat Wood recently announced that while federal legislation setting electric reliability requirements is the best fix for grid problems, FERC can act to boost reliability if Congress fails to pass a bill.[27]

Canada is in favour of the creation of a self-regulating organization tasked with ensuring reliability. With members from both Canada and the United States, this entity would develop, implement and enforce consistent reliability standards for the interconnected North American electricity grid, while respecting the jurisdiction of sovereign regulatory bodies.[28] The former Natural Resources Minister, Herb Dhaliwal, stated that Ottawa would consider bringing in mandatory reliability standards for power grid operators that could discipline those that do not toe the line.[29]

## CANADIAN CHOICES IN A NORTH AMERICAN MARKET

The transmission system across Canada is not as strained as in the United States. Therefore, the urgency to improve transmission capacity in Canada is not as strong. However, considerable concern exists over the lack of interprovincial trade. North–south transmission capacity exceeds east–west capacity since infrastructure has developed on the basis of historical market demand.

**Exhibit 1**
North American Electricity Trade Is Bright

The single most significant energy trading relationship in the world is between Canada and the United States. Cross-border trade in electricity has been growing dramatically largely due to legislation in the United States, which, over the past 25 years, has encouraged the trading of electricity between and within jurisdictions. Over the last few years, it has also been bolstered by the North American Free Trade Agreement. A more integrated North American electricity market has meant increased integration of regional markets through regional transmission organizations (RTOs) and contractual arrangements.

In 1996, the U.S. Federal Energy Regulatory Commission (FERC) mandated open access for non-discriminatory electricity transmission that led to state and provincial reforms, such as the creation of wholesale trading. FERC imposed some reciprocity conditions upon foreign applicants that required them to open their transmission power grid along the lines adopted for the U.S. wholesale market. Then, in 1999, FERC ordered the creation of Regional Transmission Organizations (RTOs) by December 2001 to better co-ordinate planning; this invited Canadian utilities that buy from or sell electricity to the United States to participate.

Canada dominates U.S. electricity imports—in fact, we actually dominate U.S. *energy* imports. And the United States is increasingly relying upon Canadian energy supplies; almost 100 per cent of American electricity imports come from Canada.[1] Notably, for example, imports of power from BC Hydro arguably prevented California from experiencing widespread blackouts during the 2001 power crisis.[2] However, transmission investment has not kept pace with electricity demand or with generation investment over the past 15 years.

North–south transmission capacity continues to exceed east–west, and there are no strong signs of growth in inter-regional trade in North America. Baseline projections from the Energy Modeling Forum in the United States validate this trend.

American-owned companies continue to be active in Canada, especially in the deregulated provinces of Alberta and Ontario. Canadian companies, such as TransEnergie, Fortis, TransAlta and NS Power, are increasingly active in the U.S. market.

Given its integrated nature, a continental electricity sector appears to be here to stay.

1 This is according to Canada's most recent trade statistics (2001). Lawrence Martin, "Elbowing aside Brian's legacy," *The Globe and Mail*, June 4, 2003, p. A17.

2 Michael Den Tandt, "Energy-hogging U.S. can't stay sore at us forever," *The Globe and Mail*, April 3, 2003, p. B2.

3 Prices and Emissions in a Restructured Electricity Market, Energy Modeling Forum, Stanford University, May 2001.

The north–south trading of electricity supplies (particularly exports to the United States from Quebec, Manitoba and British Columbia) has been more prevalent, economical and effective than east–west transmission. While cross-border electricity trade is growing, inter-regional trade is not necessarily increasing. Trade is hindered by the fact that Canadian provinces tend to function as silos, with little interprovincial co-operation and extensive interprovincial barriers.

**Strengthening east–west electricity trade could bring many advantages to Canada.**

In light of the desire in Canada for better flow of electricity among provinces, it is incumbent upon us to explore the viability of strengthened east–west electricity trade in Canada.[30] Additional transmission infrastructure is needed to allow sources of generation, some of which are distant from major demand centres, to be brought to market. While most provinces are interconnected with their immediate neighbours, possible further development of east–west lines, notably those between Ontario and Manitoba, and Ontario and Quebec, must be further examined. A major study about transmission expansion in Canada is underway.[31] There may be significant costs to expanding east–west transmission in Canada, but there might also be environmental benefits. For example, if an Ontario–Manitoba line could supply some capacity to replace coal-fired generation in Ontario (consistent with Canada's climate change and Ontario's energy policies), then it may make good sense as a policy objective.[32]

Strengthening interprovincial links may assist in securing the long-term provincial supply needs, such as in the case of the Ontario–Manitoba link. Additionally, developing an east–west grid could be considered to be an investment in the future and an exercise in nation building.

Canada's priorities must be addressed within the context of the North American electricity market. The U.S. regulatory framework exerts strong influence over Canadian decisions regarding cross-border commercial activity in electricity. Within each country, measures can be taken to bolster integration, but regulatory policy must be co-ordinated across North America.

In moving forward with competitive electricity markets, there are sound reasons to enhance Canada–U.S. and interprovincial transmission transfer capability. But, in making decisions on how to proceed, Canada needs to carefully evaluate the merits and drawbacks of the U.S.-driven initiatives. If, as FERC proposes, membership in RTOs becomes essential for power trading in North America, then there will be significantly stronger reasons for Canadian membership in them. Canada is already facing decisions about joining RTOs, and it should pay particular attention to analyzing the advantages and disadvantages of joining with states in regional relationships.

Canada should also be aware that any decision to adopt SMD would affect not only the functioning of RTO markets, but also the roles of the independent market operators and system operators. The standardization of markets and the introduction of independent transmission providers would change the nature of the market, along with the players themselves. SMD could provide market safeguards and facilitate continental trade. But Canadian companies must carefully balance the potential competitiveness benefits that they could derive from SMD against the loss of independence that it would bring.

Canadians should also bear in mind that policy and regulation designed for the American situation may have unintended impacts on us and on our bilateral relationship. For instance, both the augmented continental movement of electricity and decisions regarding transmission capacity could have implications for competitiveness.[33] Thus, there is a need for ongoing Canada–U.S. dialogue and for building stronger relations, with the objective of minimizing cross-border discrepancies. Ergo, now might be an opportune time for Canada to examine the extent of its involvement with NERC. Moreover, in setting harmonized market rules, regulators should aim to accommodate jurisdictional realities.

## MOVING AHEAD WITH OPEN ELECTRICITY MARKETS

Adequate transmission capacity is vital to an efficient electricity market. To strengthen the North American transmission grid, players in the Canadian electricity

sector—regulators, investors, politicians and policy-makers—must make a number of decisions on key issues. In particular:

- In supporting transmission investment, the Canadian electricity sector must consider how best to prepare for an increasingly regionalized electricity system in North America.
- Utilities, transmission companies and system operators should consider the extent of their involvement and their roles in integrated planning.
- Canadian regulators should decide whether improved rates of return on invested capital and CCA rates would result in desired investment activity.
- Regulators should resolve whether LMP could provide additional incentives for new transmission investment and, at the same time, also support regional planning.
- In light of the pending U.S. energy legislation regarding mandatory reliability standards, governments must decide on the possible benefits of forming a new self-regulating reliability organization for North America.

In moving ahead on these issues, we cannot forget to encourage new technologies. They will increase the capacity and efficiency of existing networks and reduce line losses,[34] and will be vital in making grid capacity improvements sustainable.

**Exhibit 2**
Current Initiatives

- A report for the Federal-Provincial-Territorial Electricity Transmission Working Group was recently completed. The "Regional Electricity Transmission Grid Study" discusses current transmission constraints and barriers to transmission and generation development.
- The Canadian Electricity Association (CEA) has recently published recommendations for an integrated North American electricity market, specifically aimed at enhancing cross-border electricity trade. Interestingly, these proposals are similar to those put forth by the U.S. Federal Energy Regulatory Commission (FERC). The CEA measures include:
  - increased participation in RTOs (regional integration);
  - increased focus on harmonizing market rules;
  - enhancement of cross-border and interprovincial transmission transfer capability; and
  - co-ordination of critical infrastructure protection.[1]
- Ontario has recently formed the Electricity Conservation and Supply Tax Force.
- The May 2002 U.S. National Transmission Grid Study (NTGS), published by the U.S. Department of Energy, highlights many of the legacy transmission issues in the country and proposes 50 specific recommendations.[1]
- The North American Energy Working Group (NAEWG) report—*North America—Regulation of International Electricity Trade* is an overview of federal regulations in Canada, the United States and Mexico with respect to the authorization of the construction and operation of international power lines, and the authorization of electricity exports and imports.

[1] Canadian Electricity Association, *Canadian electricity and the economy—The Integrated North American Electricity Market: Enhancing Opportunities for Cross Border Trading and Environmental Performance* (Toronto: Canadian Electricity Association, 2003).

Finally, to effectively address the current challenges preventing required investment in transmission infrastructure, a strategic and forward-looking Canadian plan must form part of a focused North American approach.

1 ICF Consulting, *The Cascading Blackout: Why Wasn't the Power Outage Contained?* Issue Paper, Fairfax, VA.

2 Paul L. Joskow, "The Difficult Transition to Competitive Electricity Markets in the U.S." (AEI-Brookings Joint Center for Regulatory Studies, July 2003).

3 Nickle's Energy Analects, July 21, 2003. According to Scott Thon, President and Chief Executive Officer of AltaLink.

4 Ibid.

5 New Concepts for the Transmission Grid [on-line]. Department of the Environment Workshop, August 2001. [cited November 2003] Available from <www.ornl.gov/HTSC/pdf/roadmap080301/dale.pdf>.

6 According to Russell J. Tucker, Edison Electric Institute. Presentation [on-line]—March 18, 2003. [cited December 2003] Available from <www.eia.doe.gov/oiaf/aeo/conf/tucker/tucker.ppt>.

7 Nickle's Energy Analects, July 21, 2003.

8 Opinion-editorial, August 15, 2003: "The Power Grid Needs Mandatory Reliability Standards and Infrastructure Investment." [on-line] Steve Wright, Bonneville Power Administrator. [cited December 2003] Available from <www.bpa.gov/corporate/kc/home/docs/2003/testimony_of_%20steve_wright_june_0604_2003%20.pdf>.

9 U.S. General Accounting Office, *Electricity Restructuring: 2003 Blackout Identifies Crisis and Opportunity for the Electricity Sector*, [on-line] November 2003. [cited December 2003] Available from <www.gao.gov/new.items/d04204.pdf>.

10 Hans Konow, CEA President, Nickle's Energy Analects, Oct. 3, 2003.

11 Canadian Electricity Association, *Canadian electricity and the economy—The Integrated North American Electricity Market: Enhancing Opportunities for Cross Border Trading and Environmental Performance* (Toronto: Canadian Electricity Association, 2003).

12 Nickle's Energy Analects, Oct. 3, 2003. Hans Konow, CEA President. CEA wants CCA rates to rise from 8 per cent to 20 per cent on new generation assets and from 4 per cent to 12 per cent on transmission and distribution assets.

13 These risks include cost disallowances, cost overages, equipment problems and revenue risk. See Navigant Consulting, *Regional Electricity Transmission Grid Study* (Toronto: Navigant Consulting, 2003), p. 63.

14 Department of Energy National Transmission Grid Study [on line]. [cited January 2004] Available from <www.eh.doe.gov/index.html>.

15 Energy User News, Jan. 31, 2003. [cited December 2003] Available from <www.energyusernews.com/>.

16 "Grid reliability essential: Hughes," *Financial Post*, Sept. 3, 2003.

17 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

18 LMP has also operated in the New Zealand market since 1996, and in some South American countries. LMP is being considered in Australia and Ontario, and is planned in California (CAISO), Texas (ERCOT), Midwest (MISO) and Southeast (SeTRANS).

19 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

20 "LMP and Financial Transmission Rights." Presentation by John D. Chandley, LECG Economics Finance, Nov. 11, 2003.

21 Load pockets are geographical areas in which the demand for electricity can exceed the capacity of local generating facilities and/or in which there is an electricity import limitation as a result of transmission line constraints.

22 Auction revenues are allocated to transmission owners and applied to embedded costs of transmission system (to reduce the transmission service charge paid by loads). From Pietrewicz.

23 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

24 Constraints to the development of merchant transmission include market imperfections, immaturity of the merchant transmission industry, significant market risks, and the free rider problem. See Navigant Consulting, *Regional Electricity Transmission Grid Study* (Toronto: Navigant Consulting, 2003), p. 91.

25 NERC Web site. [cited December 2003] Available from <www.nerc.com/>.

26 Barrie McKenna, "Senators block proposed energy bill," *The Globe and Mail*, Nov. 22, 2003, p. B3.

27 *Restructuring Today* [newsletter@restructuringtoday.com], Dec. 3, 2003.

28 Notes for an Address by the Honourable Herb Dhaliwal, PC, MP, (Former) Minister of Natural Resources Canada to the Canadian Electricity Association Washington Forum, Washington, D.C., March 19, 2002. [cited December 2003] Available from <www.nrcan.gc.ca/media/speeches/2002/200232_e.htm>.

29 Simon Tuck, "U.S. firm faces blackout blame," *The Globe and Mail*, Nov. 19, 2003.

30 Alternative options for improving transmission capacity include improving north–south links or boosting generation capacity in centres that require it.

31 The Regional Electrical Transmission Grid Study in Canada.

32 Given the cost of natural gas, expanding gas-based generation stations may be more expensive than getting hydro (e.g., from Manitoba), even with high transmission charges.

33 In the cases of some U.S. regions undergoing restructuring, a key motivation has been a desire to obtain lower-cost power for consumers. One source has been hydro power from Canada.

34 Transmission line losses—power lost due to wire resistance—are a function of distance transported from generator to demand.

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# Allowed Return on Equity in Canada and the United States

## An Economic, Financial and Institutional Analysis

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# I. INTRODUCTION[1]

Canada and the United States have almost hundred-year histories of regulating investor-owned utilities. This shared experience is different from almost all of the rest of the world, where the appearance of investor-owned (i.e., private) utilities came only with the privatization wave of the late 20th century. The regulatory laws, mechanisms and institutions in those other countries are new—and in many cases untested. But longstanding regulatory institutions in Canada and the US have for decades been helping to provide safe and adequate services to the public at reasonable prices while ensuring that the companies involved remain "going concerns" with sufficient credit worthiness to attract the capital needed to maintain and expand their facilities.

Over the past decade, however, a significant difference has appeared in the regulatory practices between Canada and the US. In an effort to improve regulatory efficiency, Canadian regulators—first in British Columbia, then more widely—moved away from the case-by-case approach to determining the fair return on equity (ROE) for utility rate making purposes. Canadian regulators adopted generic, formula-based approaches to deriving the admittedly elusive fair ROE. US regulators in the 1980s and 1990s made two tries at generic, formula-based approaches to setting the ROE (one at the federal level and one in the State of New York), but, in the end, did not abandon their longstanding, case-by-case methods that rested on two existing and long-accepted financial theories.

The apparent efficiency of bypassing case-by-case evidentiary proceedings with a generic formula may have foretold a new and more efficient method of deriving regulated rates generally—except for one thing. The current Canadian generic ROE formula appears to have created a persistent divergence between allowed gas utility returns in Canada and the US. Since 1998, ROEs used to make regulated tariffs have been, on average, 100 to 150 basis points lower than in the US. That is, in dozens of evidentiary proceedings since 1998, US regulators have allowed their companies to set tariffs reflecting ROEs that were on average substantially higher than for their Canadian formula-driven ROE counterparts.

The purpose of this report is to analyze the root causes of this disparity between Canadian and US ROEs that has apparently been propelled—either directly or indirectly—by the Canadian ROE adjustment formula. Since the "appropriate" level of ROE is driven by the risk/return requirements of those utility investor-owners, the obvious question is whether Canadian utilities face sufficiently less risk than their US counterparts. Conversely, we investigate whether the difference in allowed returns for ratemaking is merely a symptom of a structurally inflexible formula rather than an indicator of underlying risk differences. If it is the latter, then Canadian regulators have indeed streamlined rate cases for the better. If the former, then perhaps the formula has had unintended consequences and is in need of updating better to reflect the market's judgment on the cost of equity of regulated Canadian utilities.

---

[1] This report was written by NERA's Kenneth Gordon, Special Consultant and former Chairman of the Department of Public Utilities Massachusetts and the Public Utility Commission in Maine and Jeff D. Makholm, Senior Vice President. They were supported by Ryan Knight at NERA.

It is important to state at the outset how we approach examining this divergence We cannot automatically presume that the burden falls on Canadian regulators to justify the persistently lower average ROEs than those granted by their US counterparts. Nevertheless, it is the group of Canadian regulators that changed course in the last decade, led by those regulators using the generic formula for streamlined regulatory procedures. Those regulators in the US who failed to find a suitable way to streamline their ROE procedures continued on the former path common to both Canadian and the US regulation—to examine anew, in every tariff case, expert evidence on ROE for the company in question for the relevant period of time. We do not believe that either Canadian or US regulators would consider the results of those case-by-case evidentiary procedures to be biased on a large scale. They are perhaps expensive, time consuming or overwrought—but not biased. Therefore, it is natural—and again to us justifiable—to subject the new Canadian generic formula to the test of bias. If we find that Canadian and US utilities face comparable operating environments and risk to investors, then it is natural to question the efficacy of the new Canadian formula approach to the ROE, not the traditional path US regulators still hold. It is therefore not prejudgment that prompts us to examine underlying justifications for the new and lower Canadian ROEs, but practicality. We do not question whether US regulators (or Canadian regulators up to the adoption of the new formula) were incapable of deriving "just and reasonable" tariffs. What we do question is whether, based on underlying risk factors, the new Canadian generic ROE formula can do likewise.

Canadian regulators have acknowledged in rate cases that a disparity exists between Canadian and US allowed ROEs, but have not concluded whether or not the disparity warrants action.[2] For example, the regulator in Quebec, the Regie de l'Energie, stated in 2007, "[i]n the Regie's view, even though rates of return allowed in the United States are clearly higher on average than those allowed in Canada, the evidence does not make it possible to conclude that there is any prejudice to or unfair treatment of the distributor.... The evidence does not make it possible to compare the overall differences that may exist in the institutional, economic and financial contexts of the two countries and their impact on the opportunities they provide for investors." [3]

Unfortunately, nothing surrounding the required ROE for the purpose of making regulated tariffs is an easy discussion. Unlike the other elements of tariff setting (operating costs, maintenance costs, administrative expenses or the interest rates on utility bonds) the ROE is not directly observable. The required ROE is a function of investor *expectations*. Those expectations remain complex functions of how investors believe that price regulation, along with the utility's other circumstances, will work to allow them a return on the capital that they devote to serving the public. Given the complexity associated with discussion of the fair ROE, this report will examine the root of the post-1998 differences in permitted ROEs. Those differences stem either from corresponding differences in risk in Canada versus the US or from more banal causes relating to the operation of the generic ROE formula itself vis-à-vis investors' genuine risk-driven expectations.

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2 *See*: Ontario Energy Board (OEB) *A Review of the Board's Guidelines for Establishing Return on Equity* RP-2002-0158 (2004) ¶ 122. *See* also: Alberta Energy Board (EUB) *Generic Cost of Capital* Decision 2004-052 (2004) pgs 25-27.

3 Regie de l'Energie, *Decision: Application to Modify the Tariffs of Gaz Metro Ltd*. D-2007-116 (2007) §4.1.10.

The report concludes that the regulatory environments in Canada and the US are highly similar and directly comparable. Since the world's first utility commission regulatory statute was written in the US in 1907 in Wisconsin, that general form has been widely copied in all states and provinces in Canada and the US.[4] These two national jurisdictions thus share a common heritage that is quite different, for example, from the newly-privatized regulatory jurisdictions in the rest of the world. Those jurisdictions overseas regulate their investor-owned utilities on an institutional basis quite different than in Canada and the US—two countries that share the longest, largest and most unencumbered trade border in the world. It is thus a fair question to compare and contrast Canadian and US utilities with each other to examine how their regulators deal with them and, in particular, derive the ROEs used to set their regulated tariffs.

**Section II** contains our Executive Summary. In **Section III**, we examine the evident divergence between allowed returns in Canada and the US that propels this study. In **Section IV**, we compare the methods used for setting base ROEs in Canada to the case-by-case methods still used by US utility regulators, despite two highly visible attempts to create generic formulas there. In **Section V**, we examine the sources of risk for regulated utilities and any apparent differences between investor-owned utilities in Canada and the US that might, in principle, explain the wedge in ROEs that has appeared since 1998.

[4] That statute was drafted by John R. Commons, a professor of economics at the University of Wisconsin and 10 years later the President of the American Economic Association.

# II. EXECUTIVE SUMMARY

In the introduction to this report, we stated that we do not automatically presume that the burden falls on Canadian regulators to justify the persistently lower ROEs allowed relative to their US counterparts. First, those numbers may not fairly gauge the treatment of Canadian gas distributors on the part of regulators. Second, those ROEs may combine with other aspects of Canadian financial markets or regulatory procedures that do not generalize to the US. Third, the relative ROEs may reflect business, regulatory, or financial risk differences for Canadian gas distributors versus their US counterparts.

Taking these elements into account, however, it is our opinion that the generic Canadian formula itself should be the subject of scrutiny. The formula works like an "autopilot" for setting new Canadian ROEs that uses long bonds as the only contemporary gauge of financial markets—instead of directly targeting equity costs. If the new autopilot has been setting a different course than the case-by-case "human" pilots that previously characterized Canadian ROE, and still characterize US ROE setting, then the autopilot should bear the burden of showing that it is not biased. We cannot conclude going in that the group of independent regulators setting their own ROEs on a case-by-case basis are the ones to be exhibiting a bias.

**Figure 1** in our report, showing a marked split in the allowed ROEs in Canada and the US, demands the examination of three issues regarding the meaning and comparability of the relative ROEs before the question of whether the Canadian formula has exhibited a bias in recent years can be addressed:

- We explain that under both Canadian and US regulatory methods, the ROE is the measure of cost of capital that enters the formula to make "just and reasonable" rates. It is the measure of compensation allowed for the capital that investors devote to the service of the public *at the time rates are set*. What happens afterward—in other words, what the utilities actually achieve in profitability—is a different matter. The actual returns reflect many things including management effectiveness, sales growth, the weather, macroeconomic considerations, changes in capital costs, etc. But regulatory treatment of investor-owners is tightly bound to the ROE. We conclude that allowed ROE is the proper metric for comparison.

- We find that the regulatory institutions and customs for setting regulated prices for investor-owned Canadian and US utilities are very alike. That is, in accounting, administrative procedures, regulatory legislation, and basic constitutional protections of private property, little or nothing separates the average Canadian from the average US regulatory jurisdictions, unlike newly-privatized utilities in new regulatory jurisdictions overseas, where regulatory institutions are young (and largely untested),. There are of course differences in regulatory treatment from province to province and from state to state. But we find generally that there is no persistent difference in regulatory legislation or rule making between Canada and the

US.[5] As such, the cost of equity capital is comparable between the two countries as long as the risk of gas distributors is the same or similar on both sides of the border.

- We examine the definition of risk to investors of placing their capital at the use of the public, for which the ROE provides compensatory payment. We look at how those risks could be different in Canada versus the US. What we find is that the basic sources of risk—regulatory, business and financial—are comparable with respect to both jurisdictions. Objective and disinterested analyses of the relative risks between Canadian and US utilities are rare, but what we have found points to no smaller risks in Canada. As such, we conclude that there is no objective evidence showing that business or regulatory risks are sufficiently lower in Canada to account for the divergences shown in **Figure 1**.

With this analysis, our conclusion is inescapable. The Canadian ROEs produced by the generic Canadian ROE formula are biased downward. The formula has, since its inception, ridden on autopilot the declining Canadian long-bond interest rates (the cost of a kind of debt) with no independent check on the cost of equity. The generic Canadian formula might not always be biased, and indeed in an era of stable interest rates and equity markets it may have held a true course for many years. But is has been overtaxed by the relatively unprecedented decline in interest rates since the late 1990s. The uncorrected, un-calibrated formula—not risk differences or inherent Canadian regulatory differences—has driven the divergence between observed Canadian and US ROEs.

The manifest remedies are either to return to "human" pilots (representing case-by-case ROE determinations) or re-calibrate the Canadian generic formula by re-examining the current relationship between the contemporaneous cost of debt and gas utility equity. Given the similarity in the jurisdictions, the institutions of regulation and capital markets, it would be useful in our opinion to employ both Canadian and US gas utility equities in such an analysis, along with both of the main cost of equity models (DCF and CAPM). Without a new calibration, it is likely that as long as the interest rates in Canada and the US remain low, the generic ROE formula will continue to fly off course—essentially treating Canadian utility investors unfairly and slowly taxing their financial health in this era of low interest rates.

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[5] If one threw all 63 federal and provincial/state regulatory statutes (13 for Canada, 51 from the US) into one pile with all the names blacked out, we would challenge anyone to sort them into a Canadian or US pile based on their content alone.

# III. AN EVIDENT DISPARITY IN CANADIAN AND US ALLOWED RETURNS

This report is propelled by the need to examine the persistent gap between the allowed returns on equity for ratemaking purposes between Canadian and US regulators.[6] This section examines what the divergence is and where it comes from. It examines whether the ROE figures in Canada and the US are both a reasonable and comparable metric for determining effective regulatory control over profitability in both countries, and also describes how the Canadian ROE formula works.

There are two key questions. First, does the divergence mean anything? Is the ROE (as opposed to earned returns) the right metric for comparison? Second, are the economies comparable enough (given differences in taxes, etc.—everything but regulatory risk) to permit ROE comparisons.

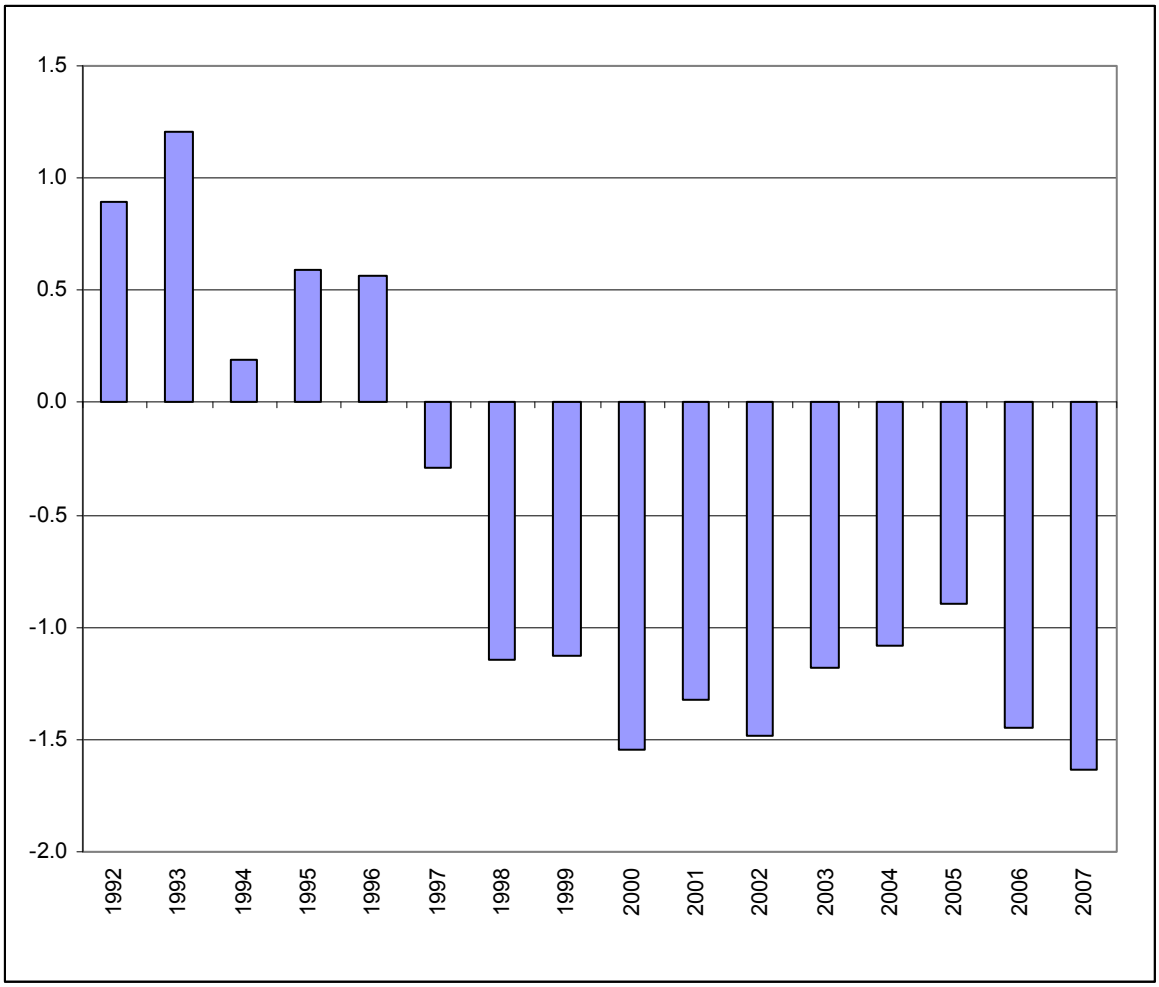
## A. The Divergence between Canadian and US Allowed Returns for Ratemaking

**Figure 1** shows that Canadian allowed returns were, at one time, higher than those allowed in the US, but that this changed during 1997. Since then, Canadian allowed returns have been markedly lower than those in the US.

**Figure 1** was compiled using data submitted by members of the Canadian Gas Association (CGA) for Canada and data gathered from Regulatory Research Associates for the US. The CGA submitted data for 8 Canadian LDCs, although data were not available for every LDC for every year. The number of rate case decisions for US LDCs for which Regulatory Research Associates data were available varies from 10 in 1999 to 42 in 1993. The data used to construct Figure 1 is presented in **Table 1** below.

[6] It is important to keep in mind that "allowed returns" (i.e., ROE) means the rate of return equity, permitted in a rate case proceeding, to form a component of regulated prices. It does not refer to an attempt by regulators to control the return on capital actually earned by utilities once those rates are set. Ratemaking in Canadian and US jurisdictions is generally a *prospective* exercise.

**Figure 1: Allowed Return Average Differential (Canada-US) for Gas Distribution Utilities, 1992-2007**




Source: Canadian Gas Association, Regulatory Research Associates.

- **Figure 1** was generated by subtracting the average allowed US ROE from the average allowed Canadian ROE for each year. This differential for Canada ranges from 121 basis points above US ROEs in 1993 to 164 basis points below in 2007. Starting in 1997, the differential has been consistently negative; indicating that, over the past decade, average allowed US ROEs are higher on average than those in Canada. These average allowed ROEs for both countries are presented on **Table** 1.

**Table 1: Canada-US Average Allowed Return Differential, 1992-2007**

| | Canada | US | Difference |
|---|---|---|---|
| 1992 | 12.88 | 11.98 | 0.89 |
| 1993 | 12.58 | 11.37 | 1.21 |
| 1994 | 11.44 | 11.24 | 0.19 |
| 1995 | 12.03 | 11.44 | 0.59 |
| 1996 | 11.68 | 11.12 | 0.56 |
| 1997 | 11.01 | 11.31 | -0.29 |
| 1998 | 10.38 | 11.52 | -1.15 |
| 1999 | 9.52 | 10.64 | -1.12 |
| 2000 | 9.80 | 11.35 | -1.55 |
| 2001 | 9.64 | 10.96 | -1.32 |
| 2002 | 9.61 | 11.10 | -1.48 |
| 2003 | 9.79 | 10.97 | -1.18 |
| 2004 | 9.55 | 10.63 | -1.08 |
| 2005 | 9.52 | 10.41 | -0.89 |
| 2006 | 8.99 | 10.43 | -1.45 |
| 2007 | 8.71 | 10.35 | -1.64 |

By the simple metric of average ROEs in Canada and the US, a clear disparity has emerged. This disparity was the subject of a recent report by Concentric Energy Advisors, which examined the disparity between Ontario LDCs and US LDCs in particular. The Concentric Report concludes that Canadian ROEs were more sensitive to the drop in bond yields over this period than were US ROEs.[7] Further, the Concentric Report suggests that this sensitivity arose through the adoption of an automatic adjustment mechanism that explicitly ties Canadian ROEs to long-bond prices.[8]

## B. Is Allowed ROE the Proper Metrics for the Comparison of the Treatment of Utilities by their Regulators?

A threshold question is whether the figures in Table 1 mean anything in terms of assessing regulatory treatment in Canada versus the US. That is, given the unique economic and financial contexts of each country, are ROEs structurally different such that an allowed return in the Canada does not mean the same thing as an allowed return in the US?

Three issues arise in answering this question. First, is the ROE the proper metric, as opposed to the return that the utilities in question have actually achieved during the period of time the rates were in effect? It is a question that arises often in comparison of ROEs. Second, does capital flow freely between countries? If capital does not flow between countries, allowed returns are

[7] Concentric Energy Advisors, "A Comparative Analysis of Return on Equity of Natural Gas Utilities," prepared for Ontario Energy Board (2007). p. 2.

[8] *Id.*, p. 56.

likely to not be comparable as capital costs would reflect strictly national macroeconomic considerations. Third, given the distinct tax and financial environments, such as differences in country-specific interest rates, are allowed returns similar indicators in both Canada and the US? This section examines these issues in turn.

## 1. Allowed ROEs versus Achieved Returns

Is the allowed ROE the proper metric, or are the returns that the utilities in question have actually achieved during the period of time the rates were in effect the relevant indicator? We readily conclude that the answer is yes: allowed ROEs are the proper metric. Both in Canada and the US, the general manner of regulatory control is for regulators to set *reasonable rates* and then allow utilities to do the best they can to make a business and earn a reasonable return against those rates. That is to say, utilities in Canada and the US are not cost-plus businesses that can appeal to cover costs after the fact. Utilities are not confined to any particular return. There are admittedly exceptions (which we consider idiosyncrasies) to this general statement—but the character of ratemaking control in both countries is prospective.

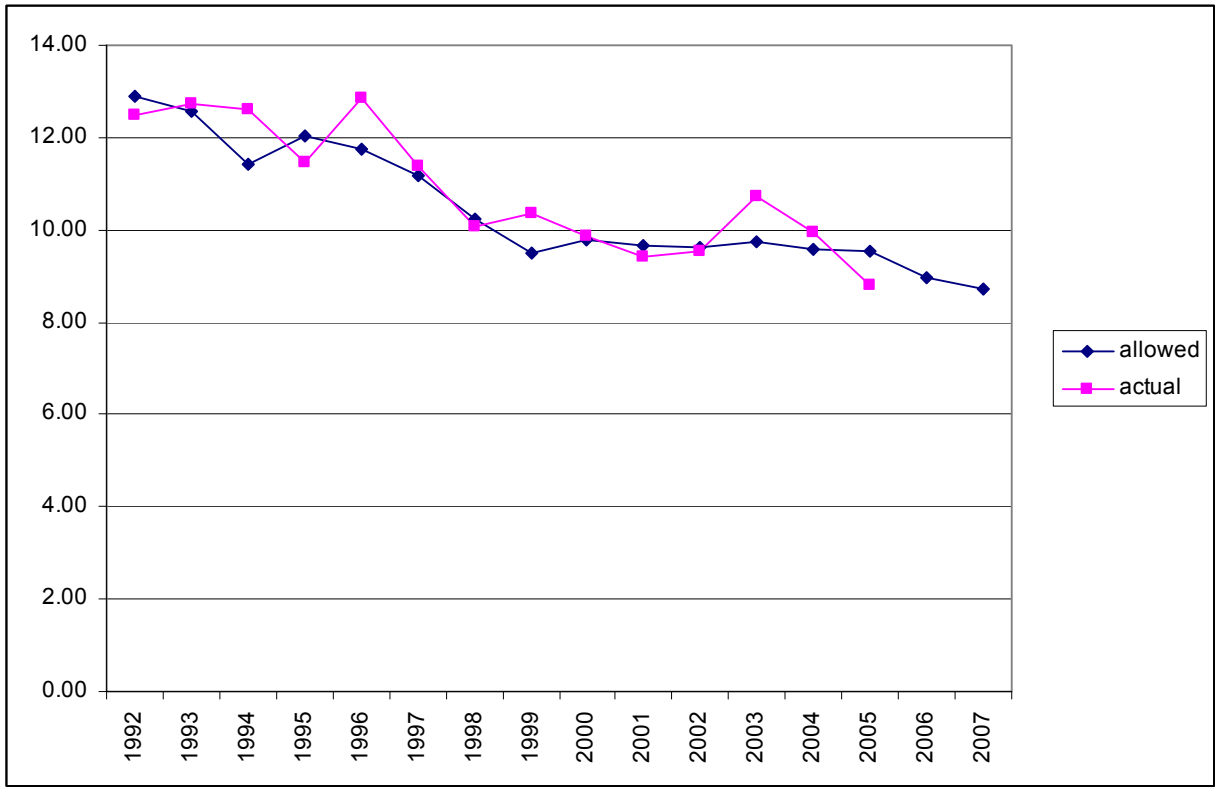
For over a century, both in Canada and the US, the pull between private enterprise and the public welfare has been settled just this way: regulators deem the return to be considered "just and reasonable" and the private utility subsequently does its best to profit—until such time as the regulator or the utility request that the question of the forward-looking just and reasonable rates should be adjudicated again.

It follows that if the ratemaking mechanisms defined by regulatory legislation and rulemaking (*i.e.*, how costs are added together and then divided by measured sales to form the rate) are the same in Canada and the US, then the allowed ROEs are directly comparable. After the fact, some utilities may profit more than others (*e.g.*, those in fast-growing service territories versus slow-growing ones).[9] Or there may be some times when it is easier than others for utilities to profit (*i.e.*, when capital costs are generally falling rather than rising against a fixed set of just and reasonable rates). But with the commonality of ratemaking mechanisms in Canada and the US, the role of the allowed ROE is the same. Hence, its comparability across jurisdictions is proper.
If ratemaking procedures and operating conditions are comparable in Canada and the US, there would be no reason to expect utilities in either country would regularly earn more than the allowed ROE. **Figure 2** shows that, as we would expect, given our review of the mechanisms of rate regulation in Canada, earned returns have been both above and below allowed returns in

[9] There is a comparison between returns for Canadian and US regulated pipelines, offered in NEB RH-2-2004 by CAPP (the Canadian Associate of Petroleum Producers) that might seem to suggest a persistent success in achieved returns for Canadian companies versus their US counterparts (although we have not looked closely into the sources or particular reasons for those results reported by CAPP). We note, however, that these are returns obtained by federally-regulated interstate pipeline companies, not local gas utilities. Those pipeline companies do not have the public service obligations or stable customer base of distribution companies, and they are not informative to the comparison of the Canadian versus US *utility* ROEs. *See:* NEB, *Reasons for Decision* RH-2-2004 Phase II (2005), Figure 5-1.

Canada since the inception of the formula. In our experience, this pattern of allowed versus actual ROEs, reflecting occasional average divergences, is characteristic of utilities in the US as well.

**Figure 2: Allowed versus Earned Returns For Gas Distributors in Canada, 1992-2007**




Source: Canadian Gas Association

We show **Figure 2** merely as a way of dealing again with the statement that earned returns—an *ex post* measure of utility performance against a fixed set of "just and reasonable rates"—is not exceptional in Canada. There is nothing, to us, in **Figure 2** that removes the reasonable use of **Figure 1** as a reason to question whether Canadian ROE methods lately have been causing a divergence in the fair return between Canada and the US.

## 2. Capital Flows

There is no doubt that Canada and the US can experience unique macroeconomic conditions (interest rates, inflation, GDP growth, etc.). That said, Canada and the US share the longest, largest and most open trade border in the world. There has not been a shot fired in anger across this border since 1812. Canada-US trade is open, with few import or export taxes or tariffs.

Energy trade in North America is governed by the North American Free Trade Agreement (NAFTA), the Canada-US Free Trade Agreement (FTA), and the General Agreement on Tariffs and Trade (GATT). Among other things, NAFTA has "provided the building block for the emergence of a cooperative North American market for energy goods."[10]

Today, there are:

- 35 cross-border natural gas pipelines between the US, Canada, and Mexico.
- 22 cross-border oil and petroleum product pipelines.
- 51 cross-border electric transmission lines.

These facilities physically bind Canada and the US together.[11] This physical integration is matched by capital market integration as well. Since deregulation of the wellhead price of natural gas (1985 in Canada, 1981 in US), trade in this "increasingly significant sector" would be based on "internationally-recognized, non-discriminatory market access principles."[12] With competitive markets for the gas commodity and for transport capacity, shippers can negotiate for gas supplies and pipeline space on transmission systems in both Canada and the US, searching for the most economical mix of commodity and transport costs. The situation between Canada and the US is remarkable—unlike many parts of the world, where pipelines are not built if it means passing through other countries.

There does appear to be a preference for domestic investment, especially by pension funds and other "trustee investments," which could result in segmented capital markets. However, many Canadian firms are cross-listed on US exchanges—including Enbridge. As identified by the Concentric report, US investors do play a significant, albeit less prominent, role in the capitalization of Canadian utilities.[13] To the extent that the trustee investments in Canadian utilities represent a structural barrier to investing outside the country, then the cross-border equity investments from the US are a marginal source of funds.[14] Furthermore, some Canadian utilities and their parent companies engage in business in the US and abroad, indicating that utility companies are not regionalized.

One test of the comparability of allowed utility returns is the cost of capital for non-utility firms in Canada and the US. It may be that there are structural differences in the cost of capital

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[10] *See:* North American Energy Working Group, "North American Natural Gas Vision," Experts Group on Natural Gas Trade and Interconnections, January 2005: http://www2.nrcan.gc.ca/es/es/naewg/NANaturalGasVision_e.cfm (Accessed on October 28, 2007).

[11] *Id.*, p. 34.

[12] *Id.*, p. 10.

[13] Concentric, s*upra* note 4 p. 50.

[14] Under the efficient markets hypothesis, the marginal investor sets the price for a security. To the extent that this hypothesis holds, it may be that US investors are leading the valuation of Canadian firms. *See:* Ibbotson, R.G. and G.P. Brinson, *Global Investing: The Professional's Guide to the World Capital Markets*, McGraw-Hill: New York (1993), p. 37-41.

between Canada and the US that would result in a categorically lower cost of capital for Canadian firms, reflecting a lower opportunity cost of investment for Canadian utilities.

In an attempt to address this question, a 2007 study by researchers at the Bank of Canada estimated a cost of capital 30-50 basis points *higher* for Canadian firms than US firms, all else equal. The study estimated cost of capital based on a forward-looking, discounted cash flow (DCF) analysis of Canadian and US firms from 1988 to 2006.[15] This study takes into account forward-looking investor expectations, and is evidence that the cost of capital does not appear to be categorically lower in Canada.

## 3. Tax Differences

Differences in tax laws have been proposed in some previous discussions about the differences in recent Canadian and US allowed returns as a potentially confounding factor in Canada-US comparisons. Tax rates facing Canadian and US investors are indeed different, both for domestic and cross-border investments. However, it is the practice of Canadian and US regulators to set allowed ROEs on a pre-tax basis, permitting income taxes for the utility, as such, to enter the ratemaking formula as a pass through expense in permitted rates.[16] In other words, income taxes are treated in both jurisdictions as a measurable expense when grossing up the pre-income-tax ROE to calculate a post-income-tax figure for use in setting consumers charges. Therefore, as the income tax treatment is similar, if the institutional, financial and economic risk environments are comparable, ROEs are comparable as well, regardless of differences in taxation.

## 4. Macroeconomic Interest Rates

If interest rates forecasts are substantially lower in Canada, the apparent disparity in allowed returns may simply be a byproduct of lower underlying capital cost rates, and there may be no difference in the relevant fair ROE awarded by Canadian and US regulators.

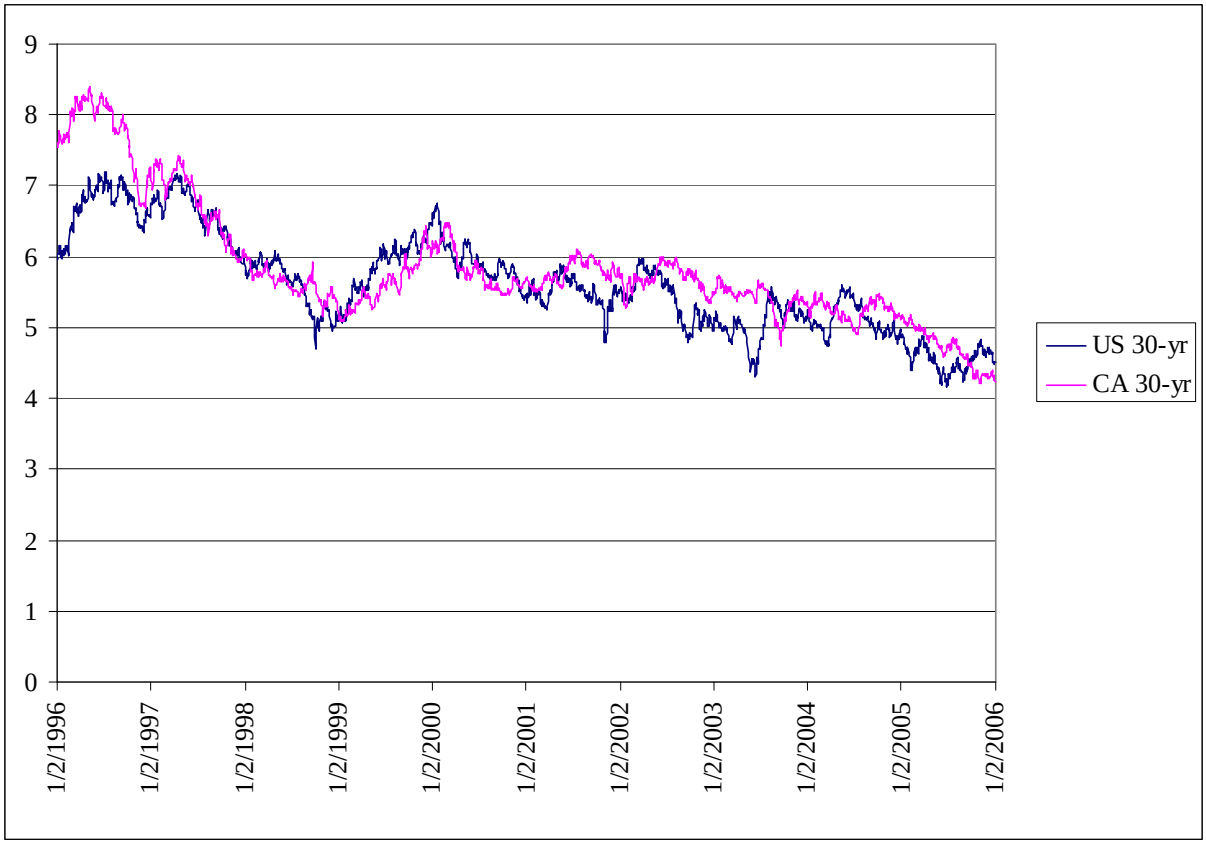
As **Figure 3** shows, interest rates have been in rough parity since the beginning of the divergence, and US long-bond yields were even below Canada's for much of the time. This would indicate that macroeconomic interest rates are not driving the divergence since 1998 (although they may account for some of the positive divergence before that time), given that US interest rates have been both above and below Canada's rates during the period of interest.

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[15] Witmer, J. and Zorn, L. "Estimating and Comparing the Implied Cost of Equity for Canadian and U.S. Firms" Bank of Canada Working Paper 2007-48 (2007). Available at: http://www.bank-banque-canada.ca/en/res/wp/2007/wp07-48.pdf (Accessed on 11/15/07).

[16] The income taxes on dividends or capital gains for individual investors are not a subject of concern to Canadian or US regulators—only the income taxes that form a part of compensatory rates for the utility.

**Figure 3: Long-Term Bond Yields in Canada and the United States (1996-2006)**




Source: US Treasury Department and Bloomberg

## C. The Source and Form of the New Canadian ROE Methods

Beginning in 1994, Canadian regulators—first some, then others—have adopted automatic adjustment mechanisms for setting the ROE in utility rates based on a fixed spread with observed movements in Canadian interest rates on long bonds. In these jurisdictions, the ROE is automatically adjusted annually based on movements in long-term bond forecasts.

The approach used by the NEB, Ontario, Quebec and Alberta is to establish a "benchmark" ROE that is applied to all utilities, with individual business risks taken into account when the capital structure is "deemed."[17] The generic ROE is then adjusted annually as follows:

[17] Capital structures are "deemed" in Canada based on relative business risk. An LDC with more business risk will be deemed a higher equity ratio in its capital structure to raise the overall weighted average cost of capital. This contrasts with the US, where LDCs are predominantly allowed to choose their capital structure within a band of reasonableness.]

1. The forecast yields on 3 and 12 month out 10-year Canadian bonds are obtained from the most recent forecast by Consensus Economics.

2. These two forecasts are then averaged.

3. To get an estimate for a 30-year forecast, the result is adjusted to reflect the actual spread between 10-year and 30-year bonds in the previous month as reported in *The Financial Post*.

4. This estimated 30-year forecast is subtracted from the previous years' forecast.

5. The difference is multiplied by 0.75.

6. The new ROE is previous years' ROE plus (minus) the result.

Some provinces may use a slightly different adjustment, but the process is largely similar. The ROE adjustment is shown in Equation 1.

$$ROE_t = ROE_{t-1} + .75(Forecast_t - Forecast_{t-1}) \quad \textbf{(1)}$$

Using this formula, the following rates would result from a benchmark ROE of 12 percent based on interest rates of 8 percent if interest rates were to fall.

**Table 2: Hypothetical Formula-Based ROEs**

| Bond forecast | Allowed ROE |
|---|---|
| 8.00 | 12.00 |
| 7.00 | 11.25 |
| 6.00 | 10.50 |
| 5.00 | 9.75 |
| 4.00 | 9.00 |
| 3.00 | 8.25 |

The formula approach was first introduced in British Columbia in 1994 before being adopted by Manitoba and the NEB in 1995. Ontario adopted the NEB approach for 1997, and was followed by Quebec in 1999. Finally, Alberta adopted formula adjustments in 2004.

**Table 3: Major Jurisdictions Implementing Formula-Based ROEs**

| Regulator | Jurisdiction | Case ID | Year |
|---|---|---|---|
| British Columbia Utility Commission (BCUC) | British Columbia | Decision in the Matter of Return on Common Equity, June 10, 1994 | 1994 |
| National Energy Board (NEB) | Federal | Reasons for Decision re: RH2-94 Cost of Capital, March 1995 | 1995 |
| Public Utilities Board of Manitoba (PUBM) | Manitoba | PUB Order 49/95 | 1995 |
| Ontario Energy Board (OEB) | Ontario | Draft Guidelines on a Forumla-Based Retun on Common Equity for Regulated Companies | 1997 |
| Regie de l'Energie | Quebec | D-99-11 | 1999 |
| Alberta Energy Utilities Board (EUB) | Alberta | 2004-052 | 2004 |

The 0.75 adjustment factor arose out of the 1995 NEB formula decision. The formula is based on the historical observation that allowed returns tend to move in the same direction as long-term bond yields. There was a desire to protect utility customers from high bond yields and shareholders from low bond yields, so the NEB decided to weight the ROE movement by 0.75 times the change in bond prices. Previously, Manitoba had used a 0.8 adjustment, while British Columbia made one-to-one adjustments if bond prices moved outside of a certain band.

Before the formula can be applied, a base ROE must be calculated. The benchmark ROE may be arrived at in a variety of ways, and is set in a manner similar to the setting of ROEs in the US. Equity risk premium (ERP) analysis, capital asset pricing model (CAPM) analysis and, less often, comparable earning analysis are all taken into consideration. Notably, the DCF method is given little to no weight, for a variety of reasons. For example, the NEB has acknowledged that the DCF test is theoretically sound, but raised concerns about practical difficulties.[18]

Not all major Canadian jurisdictions had implemented formula-based ROEs when US and Canadian returns began to diverge. However, the jurisdictions retaining case-by-case analyses seemed to set ROEs in a manner that was highly sensitive to changes in the bond markets.[19] One could therefore view the "formula" jurisdictions as price leaders who set the standard for following the decline in bond prices in the setting of returns.

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[18] NEB, Reasons for Decision RH-2-94 (1994) §2.5.

[19] See, Alberta Energy and Utilities Board (EUB), *Canadian Western Natural Gas Co. Ltd. 1997 Return on Common Equity and Capital Strucutre and 1998 General Rate Application*, Decision 2000-9 (2000). On page 65, the EUB states, "[t]he Board notes that interest rates and bond yields have significantly declined during the time frame… Consequently, this significant reduction in interest rates will have a major impact on the determination of a fair return for a utility."

The unique feature of the Canadian ROE formula is that is sets a gap between Canadian long bonds and the fair ROE, as shown in **Figure** 3. The only reason that the ROE does not move in lock step with the long bond is the *notion* that the spread grows/shrinks with the move in the bond, by a quarter of the bond's movement. We say "notion" purposely, because the formula's tie between long bonds and ROE is not based on financial evidence on the contemporaneous spread between what the market requires as a return on bonds as opposed to a return on equity investments in Canadian utilities.

This last point bears emphasis. For those jurisdictions that have adopted the formula shown in Equation 1, or those jurisdictions led by those who do, the only new evidence determining ROE in utility rate cases is the movement in long-bond interest rates. Nothing in the application of the formula, as a factual matter, attempts to gauge contemporaneous equity cost rates. Rather, the formula adjusts ROEs based on the historical observation that allowed ROEs move in the same direction as bond yields.

In this fashion, the Canadian formula diverges from attempts in the US to streamline cost of capital proceedings by implementing a generic formula for the cost of capital. There have been two highly visible attempts to do such a thing in the US, by the Federal Energy Regulatory Commission (FERC) in the late 1980s and by the New York Public Service Commission (NYPSC) in the early 1990s.[20] In both of those cases, the target of the generic formulae was the cost of equity, using contemporaneous market information with theoretical models designed specifically to gauge equity costs.

Neither the FERC nor the NYPSC methods ultimately resulted in an abandonment of a case-by-case examination of the cost of equity. The FERC methods have streamlined somewhat the construction of the "proxy groups" for gathering market information on similarly-situated regulated firms and have basically set the form of the theoretical formula for combining stock yields plus analyst growth rates (in the "yield plus growth" or DCF formula). Those streamlines aside, the FERC generally dropped its pursuit of a generic formula by about 1992 over legal concerns that a company-specific record must support the finding of a fair return. The FERC since has not departed from a case-by-case examination of the cost of equity. The NYPSC formula, for its part, was created after a multi-month process costing some millions of dollars. It, too, centered on a formula for deriving the cost of equity (rather than the long bond rates plus a pre-determined spread), but it was never adopted formally by the NYPSC.

## IV. THE TRADITIONAL CASE-BY-CASE METHODS OF CANADIAN AND US REGULATORS

Rate cases in the US are relatively standardized affairs. This is not to say that US commissions never err in their decisions, that all commission decisions are objective or that rate cases are

[20] FERC Order 442 *Generic Determination of Rate of Return for Public Utilities*, Docket No. RM85-19-000; New York Public Service Commission, *Generic Financing Proceeding*, *Case* No. 91-M-0509.

never protracted battles. Property rights and US regulation are continually evolving and have only reached their current state through experimentation and judicial rebuke.

In an attempt to relieve the regulatory burden the FERC intended to move to a generic ROE approach in the 1980s with Orders 420, 442 and 461, and similar efforts were made by the NYPSC and the Federal Communications Commission (FCC) in telecommunications. However, the generic ROE pursued in these cases was never applied extensively and fell into disuse. US ROEs are now determined the same way they have always been determined: through discounted cash flow (DFC) analysis that examines a comparable group similar to the utility in question.

US gas utilities generally do not generally undergo annual rate cases.[21] Rather, the ROE stands until either the utility requests a rate case or the commission judges that conditions have changed enough to warrant a re-examination of rates. To streamline rate cases, commissions have objectivity standards that include the need for a theoretical justification of the methods used and all subjective decisions are justified in the public record. These standards help to ease contention in rate cases and limit the discussion to manageable issues.

In this section we will explore the methods used for rate setting in a case-by-case environment. We begin with the most popular method in the US, the DCF, before examining the CAPM and other ERP methods. Finally, we discuss the role of capital structures in case-by-case ratemaking.

## A. Discounted Cash Flow (DCF) or Yield Plus Growth

The most popular method used to determine the ROE among US regulatory commissions is to determine what future stream of common dividends investors expect on a case-by-case basis using discounted cash-flow (DCF) analysis. Its popularity is a function of its ease of use and comprehension by finders of fact not necessarily particularly versed in financial theories. At its most fundamental level, the DCF method endeavors to compute the cost of equity capital by summing the two sources of equity investor returns—the "yield" portion (meaning the dividend yield with respect to the stock price) and the "growth" portions—the rise in the stock price that investors expect to see. In a world of complicated ratemaking formulae and financial theories, it is no surprise that "yield plus growth" has an intrinsic appeal, particularly when there are many sorts of similar utilities by which to gauge the sum of these two common-sense factors that make up the ROE. The formal statement of the DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962.[22]

Part of the DCF formula that may not appeal to analysts and regulators is the growth rate expected by investors. That growth rate is inherently inscrutable, and in small capital markets

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[21] California has annual adjustments to rates, but that is a unique US jurisdiction and not in any way an indicator of what happens in the rest of the country. The tortured experience associated with the lead up and aftermath of the California energy crisis of 2000-2001 continues to cast regulatory procedures there in a unique light.

[22] *See* Gordon, M.J. *The Investment, Financing and Valuation of the Corporation* (Homewood, IL: Richard D. Irwin Inc., 1962; reprint, Westport, CT: Greenwood Press, Publishers, 1982).

(such as many utility jurisdictions overseas), it is very hard to gauge investor expectations and thus to apply the DCF model. But in the US, where the model retains its great popularity, a robust industry of independent stock market analysts helps greatly. Both in print and on the web, disinterested estimates of utility growth rates are readily available to assist in the calculation of DCF-derived ROE figures. Combining these publicly-available growth rate estimates with the availability of a number of similar-risk companies, in "proxy groups," allows regulators to enjoy the stabilizing influence of the law of large numbers in setting the ROE.[23] For practical-minded regulators looking for stable, understandable and objective evidence, its popularity is no surprise.

DCF analysis involves making selections at two key stages: first, the analyst selects a specific "proxy group" of utilities facing similar risks and then selects the various of inputs such as the growth rate. Many of the practical concerns of Canadian regulators over these selections have been addressed in US jurisdictions, and the regulatory burden of case-by-case ratemaking has been lightened by establishing consistent selection criteria at each stage. One concern unique to Canadian jurisdictions, however, is the applicability of proxy groups that contain US utilities.

Given the degree of capital market integration, the degree of cross-border gas trade, and the international presence of several Canadian LDCs, we believe that a proxy group that includes US utilities facing similar risks would be appropriate for Canadian utilities. We will examine in Section IV whether the risks facing Canadian utilities are, in fact, comparable to those facing US utilities but, so long as Canadian regulators are attentive to potential macroeconomic divergence, we see no economic or financial factor that would confound the use of proxy groups that include US utilities.

## B. Equity Risk Premium (ERP) and the Capital Asset Pricing Model (CAPM)

Equity risk premium (ERP) analysis is based on the observation that it is more risky to hold equity than bonds. Assuming that investors are risk adverse, they will require a higher return to hold assets with higher risk. Equity returns therefore carry a premium over bond returns. If risk-free bond yields could be identified and the equity premium could be estimated, the cost of capital will result.

There are a wide variety of methods for estimating the cost of capital along these lines, the most popular of which is the capital asset pricing model (CAPM). The CAPM formula itself is rather straightforward. Its components are: (1) the risk free rate of return; (2) the market rate of return; and (3) the beta. These inputs are combined to estimate the ROE.

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[23] In practical terms, the "law" describes the stability of a random variable, with repeated sampling. That is, given a sample of independent and identically distributed random variables, the sample average will approach and stay close to the true population average as the size of the sample increases. This is a long way of saying that the ROE results from a "proxy group" sample of similar utilities are more representative of the actual ROE than the ROE for a single company alone.

$$ROE = Risk\text{-}Free\ Rate + \beta(Market\ Return) \quad \textbf{(2)}$$

Despite this algebraic simplicity, there are different methods to obtain each of these components and to compute the required rate of return. The effects of choosing one method over another can substantially change the required cost of capital. Because CAPM, with the exception of the beta term, does not have the "law of large numbers" properties in a comparable group that the DCF has, there is less reason to focus primarily on a comparable group rather than the utility in question, especially when the beta is significantly different from that of the proxy group.

The practical elements of the CAPM formula are full of contention. For example, the beta term relates the movement in an individual company stock price compared with that of the entire market for stocks. Greater relative movement vis-à-vis the market means a higher beta. Those betas published by investment analyst houses (such as *Value Line*, Merrill Lynch or others) make use of an adjustment procedure that moves "raw" betas toward 1.0. The "adjusted" published betas are generally the ones used by US regulators when they make reference to the CAPM.

The other area of contention is the market return—defined as the premium that the market for equities demands as a spread on the risk free rate. Market risk premiums are not published, but have to be derived. Some are based on historical achieved returns and others try to gauge investor expectations on future equity returns not unlike those who perform a DCF analysis. In rate case application of the CAPM, there is always dissension among interested parties regarding the size of the market risk premium, as its choice directly affects the level of "just and reasonable" rates. Practical-minded regulators wrestle with this issue.

- Despite these areas of contention, one benefit of the use of the CAPM is that the theory upon which it rests provides a relatively clear method for gauging the effect of increased leverage, or "gearing," on the cost of equity. It is well known in both financial theory and in practical investment circles that a high proportion of debt in the capital structure adds financial risk to the business risk facing a company—and raises both the cost of debt and equity. The CAPM model provides a theoretical method to compute the effect of different gearing on the ROE.[24] Indeed, in some prominent cases in the US, the this method has been used as the basis for regulators to grant higher equity costs to adjust for the use of greater gearing levels as deemed prudent by the regulator.[25]

[24] For the theoretical formula regarding the relationship between betas (and hence equity costs) and gearing, see: Copeland, T.E., and Weston, J.F., *Financial Theory and Corporate Policy, Third Edition*, Addison-Wesley, Reading, Massachusetts (1988), p. 457.

[25] For example, in the aftermath of the electricity utility restructuring in Texas, the Public Utility Commission there approved a 50 basis point "financial risk" premium to the cost of equity for all electricity distributors in the state to reflect its desire that the utilities all move toward a higher amount of debt in their capital structures (60 percent) reflecting the spin-off of their generating function. *See* Public Utility Commission of Texas, *Order No. 42: Intermin Order Establishing Return on Equity and Capital Structure*, Docket No. 22344 (2000).

CAPM is often used in US rate cases, but it is almost never used as the sole determinant of the cost of equity capital.[26] The judgment required in selecting parameters for the CAPM is no less significant than the judgment required for judicial use of the DCF, and the CAPM lacks the "central tendency" properties of DCF that smooth the results to yield a more reliable estimate.

## C. Capital Structure

Modern financial theory suggests that there is a relatively wide zone of reasonableness for capital structures, with capital structures within that zone producing about the same cost of capital.[27] In the US, a utility's management is therefore granted a measure of discretion as to the type of capital raised. Having a solid level of financial integrity can provide rate stability and other benefits to customers, and commissions are reluctant to interfere with a utility's capital structure unless it is pushing the bounds of reasonableness.

In the US, the projected actual capital structure ratios of the utility at the time that new rates would go into effect are used to calculate a pre-tax weighted-average cost of capital. Because the rate proceeding will set rates to be charged for service in future periods, it is appropriate to base the capital structure components on the best available estimates for the period of time in which the rates will be in effect. Furthermore, the actual degree of leverage has important implications for ratemaking, as higher leverage raises financial risk and therefore the cost of capital.

Financial risk is the portion of total corporate risk over and above basic business risk that results from using debt.[28] Because equity investors are the residual claimants after the payment of debt, the cost of equity increases with higher debt ratios (*i.e.* with higher leverage). As a company increases the portion of debt in its capital structure, investors perceive a greater chance that there will not be sufficient returns available after the payment of fixed charges. Both the Modigliani-Miller theory, a the basis for the field of finance, and empirical tests of the theory confirm this inextricable link between capital structure and the cost of equity.[29]

The total cost of capital is therefore U-shaped with respect to capital structure. High equity percentages raise the WACC, but the WACC also increases at high debt percentages as investors seek higher returns on equity due to the increased financial risk.

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[26] One jurisdiction in our experience, Oregon, for some time in the 1990s and into the mid 2000s appeared to use the CAPM as the sole method for finding the ROE. It stopped that seemingly sole reliance in 2001. *See* Public Utilities Commission of Oregon, Order No. 01-777 (2001).

[27] *See* Morin, R., *Utilities' Cost of Capital*, PUR, Arlington, VA 1984, p. 268.

[28] Brigham, E.E., *Financial Management, Theory and Practice, Third Edition*., The Dryden Press, Chicago (1982), p. 861.

[29] *See* Copeland, T.E. and Weston, J.F., *Financial Theory and Corporate Policy, Third Edition*., Addison-Wesley, Reading MA (1988), Chapters 13 (theory) and 14 (empirical evidence and applications).

Hypothetical capital structures have been used in the US when it was judged that utilities were deviating from reasonable capital structures by either employing too much debt or equity in an effort to raise overall returns. Hypothetical capital structures may also be used if the utility is owned by a parent company that faces markedly difference risks from those faced by utilities and therefore carries a capital structure that would be inappropriate for a utility.

In such cases, the capital structure of a comparable group of utilities is used, on the basis that comparable groups' capital structures reflect the opportunity costs facing investors, satisfying the comparable investment standard. Very rarely would a capital structure be "deemed" in the US without consulting a comparable group and addressing why the actual capital structure chosen by the management is inappropriate.

# V. RELATIVE RISK FOR CANADIAN AND US GAS UTILITIES

The previous two sections of this paper described how Canadian and US regulators have derived the ROE. This section investigates whether there is any justification for concluding that lower (higher) risks for utilities in Canada (the US) justify ten years of divergent returns.

In this section, then, we first examine more carefully which risks matter to utility investors. We then examine the practical boundaries to those risks for regulated utilities in Canada and the US and upon what legal and procedural foundations those risks rest. Finally, we examine whether there is any evidence available that allows us to conclude that the divergence in Table 1 stems from any persistently lower risk in Canada for gas distributors than that level we observe in the US.

## A. What Risk Matters to Utility Equity Investors?

Any discussion of risk in the context of utilities invites controversy. Much of this, in our opinion, comes from a *colloquial* as opposed to a *technical* definition of risk in the context of ROE. In setting a fair compensation for investors in the ROE, the risks that matter are the ones for which those investors require compensation. Colloquially, all would agree that predicting the weather is *risky*, but to the extent that over time weather conforms tightly to averages, the rates set on average weather patterns carry no particular risk to investors' ability to recoup their cost of capital. That is to say, *weather risk* is not the same as *ROE risk*. For a natural monopoly gas utility whose costs are geared to serving customers with whatever local weather conditions exist, the weather does not stand between them and recouping their funds—and is not properly a part of the ROE.

Weather is merely one example of the need to focus on technical risk definitions in gauging the fairness of the ROE. While the cost of service may differ between US and Canadian utilities based on their distinct geographies and other factors, both can expect the opportunity to earn a fair rate of return that is based on the returns to an investment of comparable risk.

### 1. Regulatory Risk

The risk that a gas LDC faces is inherently intertwined with regulation. Gas LDCs are a natural monopoly—the only thing standing between an LDC and monopoly profits is regulation. The greatest risk to an LDC is the risk that the regulator will not allow the utility to recover prudent costs—including the cost of capital—in a timely manner.

## 2. Business Risk

The business risk faced by LDCs in Canada does not significantly differ from those in the US. There are forward-looking risks facing investors that are somewhat independent from regulatory risk. These risks are limited, however, as a utility has the right to call for a rate case if significant events (such as a recession) damage its ability to earn a reasonable return on its invested capital without an increase in prices—a recourse obviously not available to unregulated firms. Business risk is therefore an interaction between regulatory risk and the business environment and many business risks can be lessened, modified or even eliminated through various regulatory practices.

Forward-looking business risks include:

- *Long-Lived Assets*. Gas LDCs in Canada and the US connect to a multitude of consumers. Therefore, distributors are the ones charged with the planning of upgrades to networks that in many cases are decades old. The need for major expenditures to provide safe local service do not always follow rate case schedules, so there is often a lag between investments in long-lived assets and recovery of those costs in rates. Such risks in the cost of planning and engaging in ongoing local network maintenance are the same in both Canada and the US, and both utilize deferral accounts to mitigate this risk.

- *Risks of service interruptions*. Major or minor service interruptions are generally the responsibility of the distributor—as are the costs of remedying outages. Cracked gas mains, storm damage to electricity wires and sub-stations, are all the responsibility of the distributor, which can try to plan for—but cannot guarantee—the collection of all costs that are incurred.

- *Adequacy of depreciation*. The depreciation allowance included in distribution company rates is an estimate based on historic experience. Depreciation allowances may not consider economic obsolescence resulting from unanticipated technological change or potential large capital additions. As such, there is a risk that utility plant will be under-depreciated, and changes in technology or regulation may cause shareholders to bear the result of inadequate depreciation.

- *Risk of technological bypass*. Gas LDCs in Canada and the US are at risk of customers bypassing the network by switching fuels or adopting alternate technologies. If bypass is significant there is no guarantee that the remaining rates will be adjusted to recover the cost of abandoned or excess capacity.

- *Risk of the competitiveness of rates*. While LDCs are entitled to recover their actual, prudently-incurred cost of doing business, gas LDCs in Canada and the US are at risk for the continued viability of the overall business. Competitive pressures from distributed generation or alternate fuels could create a situation in which allowed revenues are not competitively viable.

- *Risk of timeliness and adequacy of allowed revenue levels*. Gas LDCs in Canada and the US face the need to increase distribution rates as costs increase. It is expensive and difficult to file for a small rate increase. Utilities would absorb such costs until they become large enough to justify the cost of a rate filing.

### 3. Financial Risk

Apart from the regulatory and business environments facing an LDC, investors face financial risk as well. Financial risk is the risk associated with carrying debt in the capital structure. Debt return (i.e., interest payments) are contractual obligations. Up to a point, raising utility funds with debt provides for a less expensive way to provide the capital needed to provide services to customers. But with greater proportions of debt, the risk that those interest payments will not be "covered" increases, and with it both the interest rate demanded by lenders and the return required by equity investors. This effect on required rates of return is well established and widely known.

Financial risk is generally taken into account in setting ROEs in US rate cases. To the extent that a regulated firm's capital structure mimics those of a group of its regulated peers, no adjustment is necessary for financial risk. One the other hand, if there is a difference between the firms in question and their peers, then an adjustment to reflect the differential financial risk may be necessary (as happened in a noteworthy case for all of the regulated electric distributors in Texas—where a 50 basis point premium for the ROE was permitted to reflect the regulator's desire for the distribution-only utilities to take on more debt).[30]

The question of financial risk appears to often be obscured in Canada, where the generic ROE is provided for all utilities in a jurisdiction, leaving the issues of financial risk to be deal with in a specific deemed capital structure to address the risks of a particular distributor.

## B. What are the Practical Boundaries to Regulatory Risk?

With any investor-owned utility, the regulator and the utility have reciprocal obligations that are generally well recognized. That is, the utility operates the service and provides the capital needed to maintain and expand the facilities that allow the public to be adequately served. For its part, the regulator provides a stable regulatory environment, oversees the adequacy of services, and offers the utility a reasonable opportunity to earn a return on its investments.

[30] See Texas PUC, *Generic Issues Associated with Applications for Approval of Unbundled cost of Service Rates Pursuant to PURA §39.21 and PUC Subst. Rule §25.34*4, Docket No. 22344.

Among its various duties, a key role for regulators is to signal, credibly, to investor-owned utilities' investors how their investments will be recovered in regulated charges.[31]

Such regulation is described in the economic literature as a "form of long-term contracting."[32] Canada and the US have proven over 100 years of natural gas regulatory history that they are able to honor the "long-term contract." The exact form of this long-term contracting has evolved throughout this history as regulators pushed against the regulatory boundaries, were reprimanded by courts, were given new direction through legislative action, and were chaired by individuals of various political inclinations as new executives were elected.

In mature regulatory jurisdictions with strong legal and administrative histories, such as Canada and the US, the regulatory compact represents a concatenation of: (1) strong primary legislation; (2) credible, comprehensive and transparent administrative procedures for making regulatory decisions and adjudicating disputes; (3) accounting regulation specifically designed for utility ratemaking; and (4) clear pathways for reliable judicial review of regulatory decisions. Newer regulatory jurisdictions around the world that do not have comparable bodies of regulatory precedent routinely use explicit contracts to express such principles.

## 1. Strong Primary Legislation

Canadian regulatory legislation is effectively very similar to that in the US, although Canada does not have all of the judicial precedent regarding the constitutional protection of private property that characterizes the US. Canada's regulatory compact is based instead on common law and "fundamental justice" but nevertheless does appear to be comparable the US in practice.[33] The US Constitution, especially the fifth and fourteenth amendments, provides the foundation that supports those protections in the US.

In Canada and the US, Supreme Court interpretations of this primary legislation define the legal limitations on regulators' ability to take action on charges that may damage the value of utility investors' property. The best known case is that of *Federal Power Commission v. Hope Natural*

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[31] This mutuality of obligations is sometimes called the "regulatory bargain" or "regulatory compact," but those are merely convenient labels for how governments and investors have traditionally worked out how the public will be adequately served by private companies.

[32] Professor Oliver E. Williamson, an authority on the economics of transactions and regulation, noted that "[a]t the risk of oversimplification, regulation may be described contractually as a highly incomplete form of long-term contracting in which (1) the regulatee is assured an overall fair rate of return, in exchange for which (2) adaptations to changing circumstances are successively introduced without the costly haggling that attends such changes when parties to the contract enjoy greater autonomy." Williamson, O.E., *The Economic Institutions of Capitalism*, Free Press, New York (1985), p. 347. See also Victor Goldberg, Regulation and Administered Contracts, *Bell Journal Of Economics*, Vol. 7 (Autumn 1976): p. 426-448.

[33] Canada's equivalent to the US 14th Amendment, Section 7 of the Charter of Rights and Freedoms, states: "[e]veryone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice." As a relatively recent act, it remains to be seen exactly how "fundamental justice" will be interpreted but it has thus far been interpreted as more than simple procedural rights.

*Gas*, in which the Supreme Court set a standard for determining "just and reasonable" returns, a standard that has stood the test of time.[34] Canada and the US share a remarkably similar regulatory mandate and their "fair and reasonable" standards for utilities returns are almost identical. Indeed, Canada's *Northwestern Utilities v. City of Edmonton* anticipated the landmark US *Hope* case by fifteen years. Both established the opportunity cost of capital as the relevant standard by which utilities' returns should be judged.

The Supreme Court of Canada stated in *Northwestern Utilities*:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise…[35]

In the *Hope* decision, the US Supreme Court, by a vote of five to three, set a new standard for determining "just and reasonable" returns for investor-owned utilities.

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[36]

In *Bluefield*, an earlier case leading up to the *Hope* decision, the US Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties...[37]

In setting required revenues, a utility's returns would henceforth be measured by investors' possible earnings on alternative enterprises of similar risk. The Supreme Courts thus ruled that a utility's investments were safe from seizure (*i.e.*, a "taking") if regulators set charges to award returns consistent with investors' opportunity cost of

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[34] *Federal Power Commission v. Hope Natural Gas*, 320 US 591 (1944).

[35] *Northwest Utilities v. City of Edmonton*, S.C.R. 186 (NUL 1929).

[36] *Hope,* 320 US 591, 603 (1944).

[37] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 US 679, 693 (1923). The *Hope* and *Bluefield* decisions refer to two Constitutional Amendments. The Fifth Amendment, as interpreted by the Court, gave the Court jurisdiction over Congress in such matters. The Fourteenth Amendment, under the Court's interpretation, gave it similar jurisdiction over the States.

capital. These limitations on the discretion of regulators were not academic exercises. For the purposes of the future gas market, the *Hope* and *Northwest Utilities* decisions were critical. They sharply limited investor or shipper uncertainty regarding the ability of regulators to act in a manner that would damage the value of the assets that investors would devote to regulated enterprises.

## 2. Credible, Comprehensive and Transparent Administrative Procedures

Predictable regulatory or tariff-making practices are unlikely without a clear set of administrative procedures that bind the way that the independent regulators conduct their business. Canada and the US both provide stability to their utility investors through strong administrative procedures.

An important tenet of Canadian administrative practices is the common law right to procedural fairness. The Supreme Court of Canada has held that judicial and quasi-judicial bodies, but also other administrative decision makers, must follow common law principles of procedural fairness that include the right to be heard and the right to be judged impartially. [38]

The 1946 Administrative Procedures Act guides regulatory procedures in the US. Similar to Canada, it requires regulators to hold hearings, warn participants of impending rule changes, to allow participation in regulatory proceedings from the affected parties and to accept evidence (subject to cross-examination in those hearings). The late US Senator Daniel Patrick Moynihan explained that:

> The APA rests on a constellation of ideas: government agencies should be required to keep the public informed of their organization, procedures, and rules; the public should be able to participate in the rule-making process; uniform standards should apply to all formal rule-making and adjudicatory proceedings; and judicial review should be available in certain circumstances. Taken together with the Freedom of Information Act, an amendment to the APA that was enacted in 1966 and added to in 1974, 1986, and 1996, the APA was intended to foster more open government through various procedural requirements and thus to promote greater accountability in decision making.[39]

These are precisely the elements of "due process" in the administration of regulation. Indeed, the legal inquiries that resulted in the Administrative Procedures Act arose out of the general judicial concern (arising in the US in the 1930s) that regulating prices of investor-owned companies *at any level* represented a potentially unconstitutional taking of private property. That

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[38] An important decision with regard to procedural fairness was *Nicholson v. Haldimand-Norfolk Reg. Police Commrs.*, where the Supreme Court of Canada significantly extended the rights to procedural fairness to non-judicial administrative decision makers and solidified the right to justification for a decision. *Nicholson v. Haldimand-Norfolk Reg. Police Commrs*., [1979] 1 S.C.R. 311.

[39] Daniel Patrick Moynihan, *Secrecy: The American Experience* New Haven, Conn: Yale University Press, 1998, p. 157.

potential unconstitutionality, it was rightly thought, could only be prevented if a specific framework was applied for assuring the due process of regulatory decisions.

While Canada does not have an exact equivalent to the U.S. Administrative Practices Act of 1946, it does have an umbrella of provincial statutes, the charter(s) of the administrative decision maker(s), and the protection of common law, which includes previous interpretations as well as foundational justice and the founding principles of the constitution.[40] Through these channels, Canadian administrative procedures are equally well-established and effective as US procedures.

## 3. Accounting for Utility Ratemaking

The goals of effective and efficient regulation can be frustrated without a consistent, credible, and sustainable set of regulatory accounts. Strict accounting standards (*i.e.*, the Uniform System of Accounts) rarely leave US or Canadian energy utilities and their regulators in major dispute over basic financial issues (like profitability, depreciation expenses or the admissibility of particular costs).

Strong and transparent accounting standards were established over half a century ago in Canada and the US, but such is not the case in other, supposedly "mature" jurisdictions. For example, a major component of the reviews of British Gas conducted in recent years by both Ofgas (the gas regulatory body before Ofgem was created) and the Monopolies and Mergers Commission concerned basic accounting and finance items in an environment with no regulatory accounting standards.[41] This confusion in the UK over British Gas's rate of profits on its capital stock and the depreciation allowed on billions of pounds sterling of transportation assets represents a major risk to utility investors that is absent in Canada and the US. Canadian and US accounting standards would never leave major assets in question, as was the case in the UK and elsewhere following privatization.

## 4. Reliable Judicial Review

Effective limits on regulatory authority in systems with well functioning regimes come from the judiciary and other paths of appeal. In both Canada and the US, the fundamental legal limitations on the ability of regulators to take actions that damage the holdings of utility investors (in some way or another) come from well-known Supreme Court decisions. The Courts in both countries have found that the property rights of investors in regulated companies,

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[40] The provincial administrative practices acts include: *Statutory Powers Procedure Act*, R.S.O. 1990, c. S.22 (Ont.); *Administrative Procedures Act*, R.S.A. 2000, c. A-3 (Alta.); *Administrative justice, An Act respecting*, R.S.Q. c. J-3 (QC).

[41] *The Economist* has referred to UK regulatory accounting as a "fiddly bit of guesswork." (See: "Don't you just love being in control?" *The Economist*, May 18th, 1996.)

as well as the rights of the customers they serve, require strict regulatory attention to invested capital.

## C. What are the Elements of Canadian vs. US Regulatory Risk?

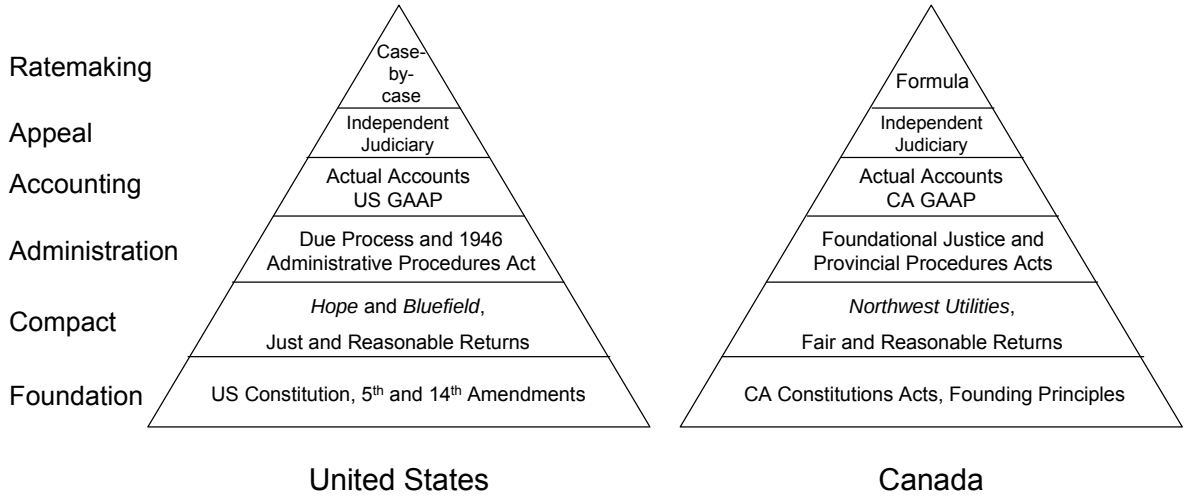
While Canada and the US share a credible regulatory environment, the exact regulatory foundations are admittedly not identical. However, the differences that do exist are more procedural than fundamental. The two jurisdictions engage in roughly the same practices, although they may go by slightly different names or receive more or less attention. The differing levels of attention does not imply that some practices are superior to others; rather, these differences arise from the dates the practices were implemented, the procedures used to handle the practices, and the emphasis placed on various practices in regulatory proceedings.

These principles are generally true of all regulatory jurisdictions in the US and Canada. Both equity investors and lenders generally give funds to utilities with the reasonable expectation the principles of obligations to be provided with a fair return will be honored. Even though the particular utility statutes may vary from jurisdiction to jurisdiction, and even though regulatory commissions may have different policies and precedents in different jurisdictions, investors anticipate the basic bargain between them and their regulator (who represents the public) will apply to their investments.

From the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the US have virtually indistinguishable regulatory environments—so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases.[42] **Figure 4** illustrates the regulatory pyramid in Canada and the United states.

[42] See, for example, Alberta's *Generic Cost of Capital* decision, where the EUB stated, "[t]he Board concurs that the above decisions [*Northwestern*, *Hope*, and *Bluefield*] are the most relevant judicial authorities with respect to the establishment of a fair return for regulated utilities." Alberta Energy and Utilities Board, *Generic Cost of Capital* Decision 2004-052 (2005), p. 13.

**Figure 4: Elements of Recent ROE Regulation in the US and Canada**




Regulation in Canada and the US is founded on strong primary legislation that protects the rights of citizens. The constitution of Canada is an amalgam of codified acts and uncodified traditions and conventions.[43] The Constitutions Act, 1982 established a Charter of Rights and Freedoms, the Canadian equivalent to the US Bill of Rights. While the Charter extends many protections to Canadian citizens, including the right to "foundational justice," this Charter does not explicitly include the protection of property rights. A significant difference in the regulatory foundations is the strong constitutional protection of property rights in the United States afforded by the 5th and 14th amendments.

The regulatory compact in both countries is shaped by judicial decisions and includes the right to earn a "fair return" on investment, as determined by the opportunity cost of capital, which is termed the "comparable investment" standard. While the phrase, "regulatory compact," is not used as often in Canada as in the US, the concept is there. Indeed, the decisions that shape the US compact are cited in Canadian rate cases, and the Canadian decisions are widely recognized as establishing an effective compact that is very nearly identical to that of the US.[44]

While Canada does not have a single, federal administrative practices statue, administrative practices are highly refined in Canada and afford at least as much protection to investors as does the United States. The Canadian common law protection—enhanced by the introduction of foundation justice in the Charter of Rights and Freedoms and provincial administrative

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[43] The Preamble to the Constitution Act, 1867 states that the provinces shall have, "a Constitution similar in Principle to that of the United Kingdom."[43] This has been interpreted as stating that the practices of the United Kingdom that were common before the creation of the constitution form part of the Canadian constitution—for example, the practice of an independent judiciary has been constitutionally guaranteed under this argument. See *Provincial Judges Reference* [1997] 3 S.C.R. 3.

[44] Morin, R.A. *New Regulatory Finance*, Vienna, Virginia: Public Utilities Reports (2006), p. 12.

procedures acts—equals the US standard of due process and the Administrative Procedures Act of 1946 in its protection of investors' rights.

In both Canada and the US, regulatory accounting is sufficiently refined that actual accounts are used for ratemaking without contention, avoiding the regulatory conflicts that surround benchmarked costs or replacement value accounting. The right to use actual costs for intraprovincial/intrastate regulation comes from provincial and state statutes. While some provinces have "fair value" mandates and are not required to use book values, they do so nonetheless.[45] This is similar to the US, where five states have "fair value" statues but have defined fair value to be the book value, so it is a difference without a distinction.

There is a perception that Canadian judiciaries are reluctant to interfere with the decisions of utility regulators. However, US judiciaries also do not overturn regulatory decisions without a clear reason to do so, and judicial rebuke is the exception rather than the rule in the US. Most important is that clear pathways for appeal exist in both countries and appeals are conducted in a manner such that, should major grievances be raised, the judiciaries are capable of reaching a reasonable decision.

Canada and the US share similarly mature regulatory compacts, supported by well-established accounting, administrative and appellate procedures. They are unique in their advanced regulatory environment based on credible, actual accounts. The greatest risk-determinant for utilities, regulatory risk, is comparable in Canada and the US.

## D. Does the Continued Ability to Raise Capital for Canadian Utilities Indicate that All is Well?

**Figure 1** drove this examination of the foundations of the regulatory procedures and risk. It shows that the allowed ROE was persistently lower in Canada that in the US over the previous decade. To the extent that this divergence is found not to be the result of different Canadian regulatory practices or lower regulatory risk vis-à-vis the US, but the result of the use of Canada's formula, an obvious question arises: would this cause investors to withhold funds from Canadian utilities?

In other words, is there any evidence that the Canadian utilities whose returns make up **Figure 1** have been unable to raise funds? If the generic Canadian ROE formula rests too heavily on long bonds and ignores genuine equity capital costs, the most manifest evidence that this is detrimental would show up in a difficulty for those companies in raising new capital. Conversely, does the continued ability of these Canadian utilities to provide adequate services in and of itself refute any possibility that the formula-based ROE is biased or inadequate?

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[45] The use of actual accounts in Canada was upheld in *B.C. Electric Co.*, where the court established that the book value of prudently incurred costs could be used to provide a fair return, despite a statute requiring that appraisal value be used. *B.C. Electric Co. Ltd. v. Public Utilities Commission et al.* (1957) 13 D.L.R. (2d) 589 (BCCA).

We conclude that as a practical matter the answers to these questions are no. Absence of evidence that Canadian utilities subject to the formula are barred from the market for funds does not constitute evidence that those ROEs are adequate in the market.

There are times in the not-so-recent past when persistently inadequate returns have appeared for utilities in general. During two periods of high inflation in the 1970s and 1980s, US utilities faced wholly inadequate returns. Inflation, coupled with the need to construct new generation and transmission capacity, ruined the ability of traditional regulatory procedures to provide utilities with a reasonable prospect of earning an adequate ROE. In short, the traditional methods of regulating rates, using a test year, created a lag in the ability to recoup ongoing, inflated, costs that visibly affected the financial health of utilities.

Evidence that the utilities were suffering was clear in the stock markets, as utility stocks slid in relation to their book values. During both periods, it was common for utility stocks to be trading below the equity book value of utility investments (roughly the equity "rate base"). When this happened, any new equity raised by these utilities would "dilute" the equity of existing shareholders—basically providing a subsidy to new equity investors from old ones.[46] Such a subsidy could not continue forever, as it would doom an investor enterprise. As it happened, however, the problem—as highly visible as it was—was only relatively temporary.

No equity investors would willingly sell proportional rights to the future returns on the equity rate base for a discount—but they did so during this period anyway. Why? Given their overriding obligations to provide safe, adequate and reliable service to customers, they had effectively no choice in the matter. Inflation pushed up the cost of new funds to the extent that it reflected a subsidy from existing shareholders, but nothing during the years of high inflation left utilities off the hook regarding their own responsibilities to serve the public.

Fixing the problem required either a change in regulatory procedures to deal with high inflation (for example, using inflation accounting like in European or Latin American countries), or an end to high inflation itself. When inflation dropped in the US, utilities returned to business-as-usual. The prospect of high inflation is still a risk to which utilities have generally no defense except a strong belief that the central bank will work to prevent its recurrence.[47] But in no fashion was the continued investment in US utility infrastructures in the 1970s and 1980s evidence that the ratemaking formula wasn't damaging investor interests in periods of high inflation.

Similarly, the evidence that Canadian investors continue to provide safe, adequate and reliable service to their consumers cannot be taken as evidence, in and of itself, that the formula-based returns reflected in **Figure 1** are fair. The utilities in Canada are a mixture of closely-held subsidiaries (without traded stocks of their own) and publicly-traded firms. If the ROEs based

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[46] See: Morin, R.A., *New Regulatory Finance*, Public Utilities Reports, Inc., Vienna, Virginia (2006), p. 364; and Hymay, L.S., *Americas Electric Utilities: Past, Present and Future*, Public Utilities Reports, Arlington, Virginia (1985), p. 262.

[47] Of course, bankruptcy is a defense against persistent confiscatory regulatory treatment, but that has only appeared rarely in the US, and then only in conjunction with other idiosyncratic events.

on the formula are unfair, it would be, in our opinion, beyond practical measures to try to discern objectively, as a separate matter, how it damaged the interest of investors. By its very nature the market's cost of equity is not easily and objectively measurable—which is precisely why regulators and analysis use indirect formulae like the DCF and CAPM. Reverse-engineering the effect of the Canadian generic formula is not a practical and objective possibility to measure the effect it has had on utility equity investments in Canada since around 1998.

# The Fair Return Standard for Return on Investment by Canadian Gas Utilities:

# Meaning, Application, Results, Implications

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## Acronyms and Abbreviations

| | |
|---|---|
| AAM | Automatic adjustment mechanism |
| Alberta Board | Alberta Energy and Utilities Board |
| ATWACC | After-tax weighted average cost of capital |
| AUC | Alberta Utilities Commission |
| BC Commission | British Columbia Public Utilities Commission |
| BCUC | British Columbia Utilities Commission |
| California Commission | California Public Utilities Commission |
| CAPM | Capital asset pricing model |
| CE | Comparable earnings |
| CPUC | California Public Utilities Commission |
| DCF | Discounted cash flow |
| ERP | Equity risk premium |
| EUB | (Alberta) Energy and Utilities Board |
| FCA | Federal Court of Appeal |
| FRS | Fair return standard |
| LDC | Local distribution companies |
| Manitoba Commission | Manitoba Public Utilities Commission |
| MPUB | Manitoba Public Utilities Commission |
| MRP | Market risk premium |
| NGTL | NOVA Gas Transmission Ltd. |
| NEB | National Energy Board |
| NERA | National Economic Research Associates |
| Northwestern | *Northwestern Utilities Ltd v. Edmonton* [1929] S.C.R. 186 |
| OEB, Ontario Board | Ontario Energy Board |
| Régie | Régie de l'énergie (du Québec) |
| RfD | Reasons for Decision |
| ROE | Rate of return on equity |
| SCC | Supreme Court of Canada |
| TCPL, TransCanada | TransCanada PipeLines Ltd |
| TQM | Gazoduc TransQuébec & Maritimes |

## Executive Summary

**The meaning of the Fair Return Standard (FRS)** Canadian governments responded to the growth of the gas business and the potential for abuse of dominant position in it by placing utilities under the jurisdiction of administrative tribunals. In theory, the extent of this regulation is unlimited. In practice it is constrained by the Constitution Act and by Common Law.

The Supreme Court in *Northwestern Utilities Ltd v. Edmonton* [1929] S.C.R. 186 (Northwestern) defined the scope of the utilities' right to price their product and their right as a result to a fair return. The Court stated "By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise". This definition remains in full legal effect today.

A fair rate of return to the corporation is paramount and is all that can be considered in arriving at a fair rate. In the unrealistic situation that a fair return worked a hardship on the consumer, the choices before government to provide relief are unlimited but they should not lower the fair rate of return. Indeed the Federal Court of Appeal (FCA) in *TransCanada PipeLines v. Canada National Energy Board* 2004 F.C.A. 149 confirmed that a fair return need not be modified out of deference to its impact upon customers.

As the operations of regulated utilities have become larger and more complicated, the courts have developed the view that a selected board of experts could deal more effectively with the rules of rate making than could the courts on appeal. Therefore, as long as the board in question acted within their jurisdiction, a successful appeal was unlikely. Notwithstanding the breadth of discretion afforded a regulator in establishing just and reasonable rates, the mutuality of interest between utilities and their customers nevertheless requires that a fair return be provided for the services rendered. The legal framework governing the determination of that fair return is the "Comparable Return Standard". It does not mandate any particular approach to that fair return.

**The application of the FRS** The current generic approach by Canadian regulators to gas utility rates of return on equity (ROE) awards pursuant to the FRS evolved after a long period in which regulators applied informed judgment to extensive evidence about a variety of tests. During that period, differing weights were given to the results but, with the exception of one jurisdiction and one test[1], none was ever permanently discarded. Over the years however, greatest reliance came to be placed on the equity risk premium (ERP) model.

With the passage of time, the phenomenon of successive protracted proceedings, eliciting similar evidence, stimulated the search for a generic approach. From the mid-1990's Canadian regulators accreted around the concept of an ROE for a benchmark utility based on an ERP over a risk-free rate, the resulting base-year award then being adjusted

annually by a predetermined automatic mechanism. This is the essence of the generic ROE, now adopted for the regulation of that component of all major gas pipeline and distribution utilities' revenue requirements.

**The results of regulators' current application of the FRS** The number and duration of rate proceedings has been significantly reduced and in certain jurisdictions the way has been paved for long-term settlements, some of which have made provision for sharing of efficiency gains between customers and owners.

The Canadian approach to return matters stands in strong contrast to that in the USA, with which Canada shares the long tradition of cost of service utility regulation. There, in accordance with essentially similar jurisprudence, the fairness of return on investment is evaluated against the opportunity cost of capital.

While settlements are also common in the USA, American regulators have not pursued the generic ROE approach but instead maintain case by case reviews, emphasize the important role of informed judgment, entertain a variety of evidence, but tend to the discounted cash flow method (DCF) as the default mechanism for their fair return findings.

In the NEB generic ROE era, no new pipelines have applied for tolls based on that determination of ROE. Instead, new projects such as Alliance, Emera Brunswick, Maritimes and Northeast, and Mackenzie Valley have all come before the Board with negotiated tolls based on significantly higher ROEs. This suggests that the NEB's generic ROE is insufficient to attract capital to greenfield gas pipeline projects.

**The implications of this application of the FRS** The now-universal generic ROE approach by Canadian regulators of major gas utilities has created some regulatory economies. But unfortunately its mechanistic character suspends for lengthy periods the previously-valued application of informed judgment to the results of alternative methods of achieving the FRS required by Canadian jurisprudence in ROE awards.

A wide and unprecedented gap has developed between Canadian gas utility ROEs and those of USA utilities and of North American low risk industrials. This is factual ground for concluding that the FRS, essentially the opportunity cost of capital needed to ensure financial integrity and capital attraction, is no longer being achieved by the generic ROE approach.

Canadian regulatory convergence on the generic ROE may however inhibit its necessary reappraisal because particular regulators may be reluctant to break ranks with the group and because the consensus around an approved generic ROE is widely supported by stakeholders[2], for reasons of regulatory efficiency and short term economic self-interest.

It would be helpful if, at the same time as specific cases occasionally come before individual regulators[3], some further studies of general relevance were to be carried out. For example, examination is recommended of the results, *ex post*, of the generic approach

in terms of the comparability of the resulting returns with non-utility and utility comparators and of the fundamentals of the present design including the choice of the risk-free rate; the appropriate measurement of the risk-premium; the adjustment mechanism; and the place of the DCF model which is accepted by the great majority of North American regulators.

## Introduction

The Canadian Gas Association (CGA) Discussion Paper "Return on Equity: Allowed Returns for Canadian Gas Utilities"[4], highlighted the importance of a "fair return" in supporting investments for the long term strength of the nation's natural gas grid. The paper went on to summarize the origins and evolution of Canada's "fair return standard". The paper noted that Canadian gas utilities are not now receiving allowed returns comparable with those of U.S. gas utilities or low-risk unregulated companies. As a result, Canadian utilities, it stated, are treated unfairly and may be inhibited from offering a robust optimal system that would provide the highest quality of service today and would be properly oriented towards a sustainable energy future.

Against that background, the Association asked the present authors, who had provided advice in the drafting of the Discussion Paper, to expand on some of the issues raised in it, particularly the identified need for the policy community and regulators to ensure that allowed returns remain fair and appropriately reflect the significant changes in their foundational elements such as comparable earnings.

In response, the authors provide here an examination of the meaning of the FRS in jurisprudential terms, discuss its application by Canadian regulators over the decades, review the results of the convergence since the mid-1990s on a generic approach to returns on equity and consider the implications of that approach for the future health of Canada's gas utility businesses. As to the application of the FRS, regulators have received thousands of pages of evidence and written hundreds summarizing it, providing their views and setting out their reasons for decision. Our discussion is necessarily a selective and summary one. However, we hope not to have omitted any point of fundamental significance.

## 1. The Jurisprudential Meaning of the Fair Return Standard

**The inception of utility regulation in Canada** The introduction of utility regulation by governments was grounded in the view that the activity had evolved into a number of sufficiently large corporations operating in a business characterized by natural monopoly and therefore capable of exerting market power to the detriment of consumers.

History demonstrated a number of methods of control available to the authorities. In response to concerns about the monopoly power wielded by Standard Oil, the United States introduced anti-trust legislation which led to its massive restructuring into a number of smaller corporations, forcing increased competition. The result was re-organization of their position from virtual dominance of the sector to competition among the newly formed corporations. Similar experience occurred in diminishing the dominant areas in steel and railroads.

Canada, because of its size in terms of population and domestic product, chose to remove the actual or feared problem of monopolies in the utility field either by use of legislative regulation or by Crown ownership.

In the context of regulation, some economists express the view that a regulator serves as a surrogate for competition in terms of the regulated company's potential dominance of a particular activity. While this may not be a complete explanation of the public purpose, it is a useful analogy. The pertinent and difficult question is what should these regulated companies be entitled to charge their retail, commercial and industrial customers so as to ensure safe and modern service in exchange for a fair return on shareholders' capital?

**Regulatory responsibility conferred on administrative tribunals** The history of the natural gas industry is a relatively short one: it is only in the early part of the 20$^{th}$ century that independent commercial use started to visibly develop.

As privately-owned utilities started to evolve into fewer but larger companies capable of exerting market power, the response of Canadian governments was utility regulation under which administrative tribunals were given the jurisdiction to regulate private utility companies falling under their mandate. By and large, however, Crown-owned utilities were not regulated in the conventional way since their corporate governance was taken to be enlightened by the government's perception of the pubic interest of the day.

The recognition of the value of natural gas as a legitimate alternative to electricity and fuel oils as an energy source, and the need for such control, raised a number of regulatory and constitutional issues.

As a preliminary point, it is obvious that the constitutional division of powers dictated by sections 91 and 92 of the *British North America Act* divided the regulatory responsibility between the Federal and Provincial governments. This is a separate subject, capable of

extensive comment, but it is sufficient for this paper to say intra-provincial activity fell to the Provincial Legislatures and extra-provincial activity to the Federal Parliament.

**Constraints on the extent of regulation** In Canada, the extent to which governments choose to regulate is theoretically unlimited. The absence of property rights for corporations makes them vulnerable to draconian legislation, if our governments so choose. However, the courts have recognized Common Law rights that co-exist with the Canadian Charter of Rights and Freedoms. Expropriation without compensation offends the Common Law rights of persons and corporations and is unknown to have occurred in Canada except for some unusual circumstances during war time.

The full reach and restraint by the Constitution Act or Common Law as they affect persons and corporations is beyond the narrower scope of this paper. It is sufficient to state that the rights are real, recognizable and enforceable.

**Jurisprudence concerning utility rates—the fair return standard** The important test of the prices or rates to be paid by consumers of natural gas supplied by a public utility has been established by our highest court, the Supreme Court of Canada (SCC). The Court confirmed the right of the companies to price the product within the confines of a fair rate of return on investments for the shareholder.

The SCC defined the scope of that right in 1929 and it remains in full legal effect today. It is consistently referred to and followed. The right to a fair return, and what it is, was defined by the SCC in *Northwestern Utilities Ltd. V. Edmonton,* [1929] S.C.R. 186 where Mr. Justice Lamont stated:

> "The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise".

The importance of maintaining safe and reliable service requires a fair return as defined by Mr. Justice Lamont. The consumer has grown accustomed to a high standard in the delivery of gas services. Humanly, they are used to both the high quality of product and service. Equally human, they balk at rate increases while knowing that to avoid deterioration in service, timely increases are necessary.

**"Fair return" vs. fairness to the consumer** While it has not yet happened, if providing a fair return to utilities as defined by the courts results in hardship for the consumer, how should it be resolved? The greater good is served by the application of Mr. Justice Lamont's definition. The language found in most legislation refers to words such as rate fair to the corporation and consumer. Fairness to the consumer in that sense is redundant. A fair rate of return to the corporation is paramount and is all that can be

considered in arriving at a fair rate. The fair rate by logic alone should be deemed of necessity fair to the consumer.

That a fair rate of return would be a hardship on the consumer is practically unrealistic. It is academic and an unlikely result. An increase in rates is always unwelcome. If the rate rose to a hardship, some government intervention should be expected or the regulator may adjust the rate design while still ensuring the provision of a "fair return" to the utility. The point is that there are choices for relief, such as subsidies or a rate design short of lowering the fair rate of return. If hardship is the consequence of a fair return, nonetheless, the fair return must be set. Failure to do so over time will, as we have collectively seen, lead inevitably to the deterioration of, and in the extreme case, the failure of service and supply.

The Federal Court of Appeal (FCA) recently restated the principles of a fair return in *TransCanada PipeLines v. Canada National Energy Board* 2004 F.C.A. 149, where it confirmed the logic of Mr. Justice Lamont's definition by confirming that the fair return need not be modified out of deference to its impact upon customers. A fair return assures the opportunity to earn a level of profit equal to a comparable return from business of similar risk, although flexibility by which the ultimate tolls are designed may mitigate clear hardship or unfairness to consumers. However, by definition, a fair return should not result in these consequences.

Consumers and those outside the industry frequently forget or never considered that while utilities are by law always entitled to a fair return, it is a limited blessing in that higher earnings in buoyant times are not available to the utilities. There are no windfall profits such as may arise in other parts of the energy sector. It is only logical that the other side of that equation applies and a fair rate of return must also be allowed in less prosperous economic times.

**Judicial review of regulatory awards** The right to a fair return is one foundation of utility jurisprudence. Of concern is the growing development of the law that demonstrates a reluctance of the courts to review regulatory awards.

Until the 1930s, judicial review was more common as the courts viewed it their role to protect the public's interest. However, as Canada's industrial base grew and the operation of regulated utilities became both larger and more complicated, the view developed that a selected board of experts could deal more effectively with the rules of rate-making than the courts so long as the board in question acted within their jurisdiction, a successful appeal was unlikely.

The concept of judicial review was more elaborately defined by the SCC in *Pushpanathan v. Canada (Minister of Citizenship and Immigration),* [1998] 1 S.C.R. 982, where in summary it held that judicial review was identified by three tests. First, was the decision reasonable, second was the decision patently unreasonable and finally was the decision correct in law. It was only the latter, correct in law test, which receives a judicial welcome. It is the present law that a decision by the board must, if a question of

law be correct any other finding or decision of the board must be patently unreasonable before judicial review is available.

The human concern by applicants of regulatory boards is the question of bias and fairness. A board that is neither can mouth the established fair return definition but not accept the applicant's facts. It is obvious that a fair return is dependant on the facts accepted by the Board and, except in extreme circumstances, the courts will not interfere. For fairness to occur dictates good faith by all participants.

Notwithstanding the breadth of the discretion afforded a regulator in establishing just and reasonable rates, the mutuality of interest between utilities and their customers nevertheless requires that a fair return be provided for the services rendered. The term just and reasonable does not displace the common law standard, rather it supports it (NWL 1929; TCPL 2004; see also *Ottawa Electric Railway Co. v. Nepean Township* (1920), 605 S.C.R. 216 at QL5, 11-12; *Chastain v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 (C.C.S.C.) McIntyre J. at p. 454-456; *Re City of Dartmouth* [1976], N.S.J. No.457, 17 N.S.R. (2d) 425, MacKegan C.J. at QL para 11). As the Federal Court of Appeal most recently expressed it, failure to observe the fair return standard would result in tolls that are not just and reasonable. In some cases, the courts confirmed that the fair return need not be modified out of deference to its impact upon customers.

**Conclusion** Accordingly, it can be seen that the legal framework governing the determination of a fair return is the "Comparable Return Standard". It does not mandate any particular approach to the determination of a fair return. The courts have recognized the regulators' expertise in this area as superior to their own. What pervades the courts' approach to the determination of a fair return, however, is the mutuality of interest as amongst utilities and their customers in tying the availability of a fair return to the long term viability of the utility in providing the essential monopoly services our society requires.

The latitude given boards to set rates includes the ability to rely on a formula. It is unlikely that any one formula can fit all rates. A decision by a board that distorts fair return by the application of a formula that achieves that result poses the obvious risk of being incorrect at law and subject to judicial revision on that ground, a result any board would seek to avoid.

## 2. Application

**The place given to the Lamont decision** In their decisions on ROE[5], Canadian gas utility regulators[6] have seldom made explicit reference to the Lamont decision (Lamont). There have been important exceptions. Thus, in its seminal first decision on TransCanada's rates, the National Energy Board (NEB) in 1971 stated that it had been guided by relevant jurisprudence, as well as by its understanding of the [NEB] Act and then cited the "fair return" portion of the Lamont decision[7], followed by other now familiar cases, Canadian and American. Then, some 30 years later, in dealing with an application for review and variance of its 1995 decision on Cost of Capital[8], the Board noted that the applicant had cited Lamont and it went on to summarize the key elements of that decision, stating that in considering the legal framework associated with the determination of a fair return, the Board had looked at both prior judicial and Board consideration of the issue[9]. That 2002 decision was the subject of an application for review and variance and, in addressing the fair return standard, the Board in 2003 examined its legal obligations and again cited Lamont along with other Canadian and American jurisprudence[10]. Finally, in dealing in 2005 with an application for new tolls, the Board summarized the evidence and provided its views on the legal framework for determining a fair return, giving attention to Lamont and other cases[11]. The Alberta Energy and Utilities Board[12] (EUB, Alberta Board) in its landmark July 2004 decision on the Generic Cost of Capital, as part of its consideration of the legislative and judicial framework, examined relevant decisions, Canadian and American, starting with Lamont[13].

**Lamont is present, whether explicitly so or not** Despite the scarcity of specific references, it is nevertheless reasonable to assume that, while acting in accordance with their respective legislative mandates, all Canadian regulators in making ROE awards to gas utilities have recognized the jurisprudence relating to fair return, and specifically the Lamont decision, whether they have said so or not. In addition to the Lamont test of "comparable investment" or opportunity cost of capital, drawing on American jurisprudence[14], regulators have concluded that, in order for a return to be fair, it must also meet the tests of "capital attraction" and "financial integrity"[15]. In this connection, the Régie de l'Énergie du Québec (Régie) has in several decisions accepted the view that the cost of capital must be evaluated on the basis of the fundamental principle of the market opportunity cost of capital and that the rate of return must allow the regulated entity to assure and maintain its capacity to attract funds under reasonable conditions[16]. In other cases, intervenors have drawn regulators' attention to the Lamont text[17]. In still others, the regulator has referred obliquely to the objectives of fairness and capital attraction[18].

**The traditional approach to ROE determinations** Prior to the mid-1990's, the practice of Canadian gas utilities was to make rate applications, often every one or two years[19], generally requiring re-determination of their ROEs as one component of the total revenue requirement that could be recovered in rates. In these proceedings, as the Ontario Energy Board (OEB) has noted, four main approaches were traditionally used by experts

to establish a fair ROE. The Comparable Earnings Test (CE), Discounted Cash Flow (DCF) test, Capital Asset Pricing Model (CAPM) and Equity Risk Premium (ERP) test [20], are all used in varying degrees to formulate an opinion regarding a fair return to investors for the test year. Parties, the OEB observed, have generally relied on a combination of these models to establish a utility's ROE. In a combined approach, the OEB and experts before it have assigned different weights to the results of the various tests in order to give more significance to those models which they consider to be the most relevant[21].

Within the compass of what must be a relatively short paper, it is impossible to trace the outworking of this approach by each of the Canadian gas utility regulators. However, successive NEB Reasons for Decision respecting TransCanada PipeLines' rates illustrate how this approach was followed by one regulator over the quarter century to 1994.

That Board, like others, was careful from the start to point out that "The final conclusion as to what is enough but not too much in the way of return is not precisely supportable on a mathematical basis."[22] "Many tests and techniques for assisting the process of reaching a just decision have been used" the Board said "but no single test is conclusive, nor is any group of them definitive: whatever tests may be used, in the last analysis the adjudicating body can not escape the responsibility of exercising judgment as to what, in a stated set of circumstances, is a just and reasonable return or rate of return, or what is a range of justness and reasonableness of return or rate of return."[23] Such reference to the necessity of the exercise of judgment in making return awards is a recurring theme in Canadian regulatory decisions over the years.[24]

**Diversity of tests applied in the traditional approach** Reverting to the NEB's practice, in the early years of the Board's "active" regulation of TransCanada's tolls, comparable earnings appear to have been at the centre of its attention. Thus: "The Board concludes, based primarily on the comparable earnings analysis of Canadian industrials which are reasonable alternative investment opportunities for the applicant's shareholders, that a return of…is appropriate for the test year…"[25] In an oil pipeline rate case about this time, there was applicant evidence "…that statistics relating to US utilities and industrials deserve perhaps a greater weight in the assessment of the current cost of equity capital than similar Canadian statistics." The Board however disagreed and expressed the belief that "…far greater weight should have been given to Canadian data…Accordingly the Board was particularly interested in the statistics presented relating to Canadian industrials…"[26] and concluded "…that the cost of equity should be equal to or slightly less than the opportunity cost of investment in such companies."[27]

By 1978, the evidence put before the Board included CE and DCF tests, the latter to measure "capital attraction", but additionally the beginnings of the ERP approach appeared. The applicant, TransCanada, was cited to the effect that "…a reasonable ROE could also be inferred from an examination of the yield differentials maintained in the past between long term bonds and those of an equity nature in the regulated industry".[28]

However, in that particular case, the Board again stated that it paid particular consideration to "…the CE of Canadian industrials which it believes to be representative of reasonable alternative investment opportunities for the applicant's shareholders."[29]

**Over time, the ERP becomes the focus** By 1981, intervenor evidence was being filed before the NEB and it related to the DCF method while the applicant relied primarily on the CE test[30]. However, within a couple of years something of a pattern had been established that was to last until the mid-1990s with the applicant and one intervenor filing CE, DCF and ERP evidence while gas-producer intervenors were focussing their efforts on the DCF approach.[31] In assessing this spectrum of evidence, the NEB tended over time to place at first "slightly more" reliance on ERP, to find inherent distortions in the CE data that it received and to be concerned about the results of the DCF test. By the time of the last rate hearing prior to the generic cost of capital proceeding, the Board found that "…in the light of recent and prevailing financial market conditions, neither the DCF test nor the CE test currently yield reliable results…" Accordingly these tests were given little or no weight in the Board's decision" and instead the Board was of the view that "…the ERP was the primary measure of investors' required returns in the circumstances of this case." However, the Board was careful to state its view that these tests (CE, DCF) may prove useful under different economic conditions.[32]

This era during which Canadian regulators determined ROE awards by reviewing evidence from multiple tests and applying their own judgment was summarized for the British Columbia Utilities Commission (BCUC, the BC Commission) in evidence and referred to by the Commission in a 2006 decision[33] as follows:

> "The evidence is that up to the 1960s the principal methodology to determine fair rates of return was CE, as, according to Dr. Booth, the DCF method and the ERP method which was derived from the CAPM, were developed in the 1960s. By the 1980s all three methodologies were in use in Canada. In the early 1990s capital markets in Canada fell into considerable turmoil, causing DCF and CE to give unreliable results, which resulted
> in the ERP becoming the main, if not the sole, methodology used by regulatory bodies in Canada to establish fair rates of return…The DCF and CE methods have never managed to restore themselves to favour in regulatory bodies' eyes...In the United States the DCF and CAPM methods got their start in the 1970s and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions."[34]

**Search for a generic approach to ROE** The context for the search by Canadian regulators for a generic approach to ROE was characterized by: frequent rate applications; repetitive evidence, often provided by the same expert witnesses, on the three principal tests; growing disenchantment with the CE and DCF tests; and increasing reliance on the ERP approach. That search was led by the BC Commission which "…was the first regulatory agency in Canada to examine the applicability of a generic, formula-based approach to setting a natural gas or electric utility ROE as a means of improving the efficiency and effectiveness of the regulatory process."[35]

**British Columbia** In its June 1994 decision resulting from that search,[36] the BC Commission expressed the view that the DCF test was of little use in the present economic climate, that CE raised a circularity problem when it was based on utilities data and that primary reliance should be placed on risk premium tests, with CE and DCF as checks. The Commission's view was that generic hearings produce cost savings and better quality of evidence because a variety of experts are gathered at a single point in time. This view has been borne out by the subsequent experiences of, for example, the Alberta Board and the NEB.

**National Energy Board** When the NEB reported its generic return decision nine months later in March 1995, it found that CE was only useful as a check, that there were practical limitations on the DCF method and that most experts gave primary weight to the ERP, which the Board also did. Annual adjustments in the resulting ROE were to be in a ratio of 0.75 of the forecasted change in the yields of Government of Canada long-term bonds (long Canadas).[37] The NEB later referred to this as "the RH-2-94 formula".

**Manitoba** Two months after that, the Manitoba Board Public Utilities Board (Manitoba Board, MPUB) decided a gas distributor rate case, prior to which the applicant had proposed a mechanical formula to adjust the Board's then-currently allowed ROE. The Board approved a spread, effectively an ERP, between long Canadas and the ROE for the distributor and an adjustment factor of 0.80 of the change in the underlying long Canada bond yields.[38]

**Ontario** The OEB has since 1997 followed its own guidelines on a formula-based return on common equity for utilities under its regulation.[39] The initial setup involved establishing a just and reasonable return applicable to each of the Ontario local distribution companies. This base comprised a forecasted yield on long Canadas for the test year to which was added an appropriate premium. The primary methodological approach to be used in evaluating the appropriate risk premium was the ERP. The annual adjustment factor proposed was 0.75 of the difference between the forecasted long Canadas yield and the corresponding forecasted yield for the immediately preceding year. The OEB gave three reasons for adopting the formula approach to ROE. The first was regulatory efficiency, already mentioned. The second was the weight of experience of other Canadian jurisdictions which had reviewed the issue and adopted a formula-based ERP. The third was that it may provide a first step towards formulaic rate making such as incentive rates.[40]

**Alberta** Alberta was the fifth jurisdiction to adopt a generic approach, which was done by a decision of July 2, 2004. The award for 2004 was based on the CAPM estimate, which the Alberta Energy and Utilities Board (Alberta Board, EUB) found was supported by no less than seven other methods examined in evidence while the Board did not put any weight on four other methods, including DCF and CE.[41] In this connection it is worth noting that the Board took the position that the CE test is not equivalent to the (Lamont) comparable investment test. The Board observed that the CE test measures actual earnings on actual book value of comparable companies, however it does not

measure the return "…it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise."[42] This conceptual concern was one of the reasons the Board gave to place no weight on the CE test. Nevertheless, the Board did consider that there may be other measures of comparable investments that should be considered in establishing an appropriate ROE. It went on to examine eight possible ones.[43] [44] As to the adjustment mechanism, the Alberta Board concluded that an adjustment to the generic ROE based on 0.75 of the change in forecasted long-Canada bond yield would be appropriate, beginning in 2005.[45]

**Québec** The Régie has since its decision D-99-11 of 10 February 1999 respecting a rates application by Gas Métropolitain, applied a *de facto* generic ROE based on the CAPM model with an annual adjustment equal to 0.75 of the forecasted change in the risk-free return.[46] This approach was reconsidered in 2007: the ERP was adjusted marginally upwards on the assessment that Gaz Métropolitan's risk had increased compared to that of the benchmark distribution utility. The adjustment mechanism was to be left unchanged through 2009. In the 2007 proceeding, the applicant introduced as an alternative to CAPM, for the first time in Canada, the Fama-French model, which is used in the financial industry, but so far used only once in the United States in the regulatory context and never before in Canada.[47] Even though the two models differ, the objective of both is to estimate the return an investor expects to earn on an investment in securities having a certain risk. The main difference between the two approaches is in the method used to express that risk which, the applicant contended, Fama-French does better than CAPM for utility-type businesses. The Régie however did not retain the Fama-French model for establishing the rate of return in this decision: the Régie considered that the application of that model to regulated enterprises has not been sufficiently examined to date to be used as a basis for fixing the rate of return of a distributor.[48]

**The generic approach reviewed and reconfirmed** Two of the regulators who pioneered the generic ROE with automatic adjustment mechanism (AAM)—the BC Commission[49] and the NEB[50]—subsequently reviewed their decisions of the mid-1990s. After again receiving and reviewing much expert testimony, in the NEB case on two separate occasions (2002, 2005), the established methodology was reconfirmed by both. Indeed, one considered that "It is clear the ERP methodology is the "gold standard" for Canadian regulators..." and stated that "…the Commission Panel will give primary weight to its application and results…"[51]

**A new test rejected** TransCanada recommended in the RH-4-2001 NEB proceeding that the Board adopt an After Tax Weighted Average Cost of Capital (ATWACC) methodology to establish a fair return for its mainline. This was a new methodology as far as the NEB was concerned and it rejected it, just as the Régie was in 2007 to reject the Fama-French test, and it reaffirmed the ERP.[52] [53]

**Legal obligation to apply the FRS?** In its consideration of the application for review of its 2002 decision (RH-R-1-2002), the NEB refuted the assertion of TransCanada that the Board "is required by law to apply the comparable investment, financial integrity and capital attraction standards to determine a fair return for the Mainline" as an overstatement of the law on this issue. The Board went on to note that in its decision which was under review (RH-1-2002), it had agreed that the three components of the FRS, along with the balancing of customer and investor interests should be attributes of a fair return. The Board further noted the statement it had made in RH-1-2002 that these principles are reflected in the various accepted methodologies to establish cost of equity capital, such as the ERP approach, which is the basis of the RH-2-94 Formula and that no one took issue with this statement. In the Board's view, it was implicit that the application of a test that reflects these standards would result in a return that meets these standards. Therefore, the Board did not have to state explicitly that the resulting return would meet the comparable investment, financial integrity and capital attraction standards. The Board stated that an express finding, such as was sought by TransCanada, which discharges the fundamental legal obligation of the regulator is not necessary when the standards that must be met are imbedded in the methodology used to determine the return. The Board also considered that there is no legal obligation to use an FRS, comprised of the comparable investment, financial integrity and capital attraction standards to determine tolls. Rather, in normal circumstances, a fair return established by the Board should meet those three elements. This, the Board stated, was accomplished through the methodology that was used to determine the return.[54] This issue was revisited in depth by the NEB in RH-2-2004, Phase II, which followed the decision of the FCA in TCPL v. NEB. The Board stated that it "…also agrees with TransCanada that the case law establishes that it is the overall return on capital to the company which ought to meet the comparable investment, financial integrity and capital attraction requirements of the fair return standard."[55] The Board went on to say that it is not required to meet the FRS by subscribing to any particular methodology or solely by examining evidence on overall return (TCPL had suggested neither). It concluded that it would ensure that each element going into the traditional methodology is "reasonable", then "…uses its judgment to ensure that the resulting return is a fair return in accordance with the legal requirements." [56] In summary, the NEB in RH-2-2004 Phase II accepted that the law requires application of the FRS, including the comparable investment, capital attraction and financial integrity standards, in determining the overall return, but does not stipulate any particular methodology for doing so.

**Risk-free rate critiqued** The applicant before the BC Commission in 2006 stated, in the words of the Decision, that "the theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. However, the application of the model typically assumes that the return on the market is highly correlated with the risk free rate, that is, that the equity market return and the risk-free rate move in tandem. Similarly, an ROE formula that is predicated on a close tracking between the allowed return and the risk-free rate assumes the risk-free rate and the return on the market are highly correlated. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long term government bond yield as a

proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

> the yield on long-term government bonds reflects the impact of monetary and fiscal policy;
> yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; and
> long-term government bond yields are not risk-free; they are subject to interest rate risk."[57]

This critique of the risk-free rate and the relationship of market returns to that rate, although recorded by the Commission, was not responded to in the Commission's decision.

**Convergence among Canadian gas utility regulators** Recent years have seen a rapid and complete convergence among the five Canadian utility regulators who have major gas distribution and transmission entities under their jurisdictions. All now base their ROE awards essentially on judgments as to an appropriate base year ROE for a benchmark utility. In every case, this base year award uses a risk free rate plus an ERP with, in some cases, an allowance for flotation costs. Subsequent annual adjustments are made mechanically on the basis of 0.75 of the changes in the forecasted long Canadas yields.[58]

**Insofar as incumbent utilities are affected, the generic ROE plus AAM is entrenched in Canadian regulatory practice—**Canadian regulators have in the last dozen years affirmed and reaffirmed the generic ROE based essentially on the ERP methodology as the sole method of awarding and, through the associated AAM, varying the returns on equity for gas utility investors. This position has withstood several review applications and one appeal to the courts. In one important case, as a result of a negotiated settlement, it cannot be reopened before 2012.[59]

**Contrast with American practice** This Canadian situation stands in sharp contrast with that in the USA with which Canada shares the tradition of cost of service utility regulation where the fairness of return on investment is evaluated against the opportunity cost of capital.[60] There, only two commissions undertook what turned out to be lengthy, expensive and ultimately unsuccessful searches for a generic solution. There is a longstanding seeming disinterest on the part of the American regulatory community in pursuing this search. Instead, where rate cases are not settled, U.S. regulators continue to rely on the application of judgment to multiple test results[61] with DCF as the default mechanism[62].

### 3. Results from the mid-1990s

**The number and duration of rate proceedings involving ROE evidence significantly reduced** In the period 1971-1994 inclusive, the NEB in respect of only one company, TransCanada, averaged one rate proceeding every 18 months. It is likely that, with TransCanada having now settled its tolls for the period 1 January 2007 through 31 December 2011, the similar hearings in the period 1995-2011 will turn out to have averaged one per eight years. Similar regulatory efficiencies affecting a large number of utilities, electric as well as gas, are being found by the principal provincial jurisdictions.

**In some jurisdictions, the way paved for long-term settlements of rate matters** The NEB's experience again furnishes an example. The Board's decision on a generic rate of return may have been a factor enabling TransCanada[63] and Westcoast Energy[64] to achieve their first multi-year negotiated settlements of remaining toll and tariff matters. Note that one of the objectives of both settlements was "to maintain ("or improve", in the case of TransCanada) the financial integrity…" of the pipeline company.[65] [66]

Regarding the Alberta Board, on the one hand a month after bringing down its Generic Cost of Capital decision in July 2004 approved NOVA Gas Transmission Ltd's (NGTL) application to commence negotiated settlement discussions. These eventuated in a settlement of all revenue requirement issues, return on equity being treated as a flow-through item, for the three-year maximum period allowed by the Board, commencing 1 January 2005.[67] On the other hand, prior to the implementation of the ROE formula, Northwestern Utilities and ATCO Electric both negotiated settlements. Since the introduction of the formula there have been no long term settlements other than NGTL.

The BC Commission has approved a Settlement Agreement for Terasen Gas for 2004-2007, incorporating a Performance-Based Rate Plan,[68] and subsequently approved its extension for 2008-2009.[69]

As to pipelines under the NEB's jurisdiction, two points are notable. First, settlements of toll issues have been the norm for oil pipelines since the mid-1990's. Second, all new oil and gas pipelines have applied for tolls, based on settlements, where the ROE exceeds that generated by the Board's generic formula, often by a generous amount.

**Transmission utilities' incentive agreements have provided for efficiency gains and sharing of those gains between customers and utility owners** Annual or biennial adversarial proceedings relating to ROE are for transmission businesses now a thing of the past. This may have encouraged and enabled parties to settlement negotiations to build-in to the resulting agreements features that encourage these pipelines to search for efficiencies with the prospect of retaining for the investor a share of those efficiencies. All of the negotiated settlements mentioned in the previous paragraph incorporate such features in one form or another. In a degree, these shared savings mechanisms have cushioned the impact of declining ROEs resulting from the application of the generic ROE decisions in an environment of declining bond yields. For example, in the letter to

shareholders accompanying TransCanada's 1996 Annual Report, the management commented that there had been a one per cent decline in the rate of return on common equity allowed by the NEB in 1996. The letter went on to say "That one per cent represented a reduction in 1995 earnings of about $21 million that had to be made up. A substantial part of it came from discretionary revenue earned under an incentive agreement reached late in 1995 between TransCanada and its customers. Incentive regulation allows TransCanada to share in discretionary revenues and cost savings."[70] This cushioning effect may be available to some pipelines on a continuing basis, but in a regulatory context its results must not be seen as an element of a fair return. Fair return relates to the opportunity cost of capital. Earnings from incentive agreements are rewards for extraordinary cost-savings and for entrepreneurship in devising service offerings that create value for which shippers are willing to pay. As the Federal Court of Appeal reminded in the 2004 TransCanada decision,[71] the fair return must be determined independently of its impact upon resulting customer rates.

**But Canadian and U.S. regulators' ROE practices are now widely divergent after decades of essentially parallel approaches** Canadians have converged on the generic approach using essentially anticipated risk-free rates plus ERP and adjusting by a ratio to anticipated changes in risk-free rates. In the U.S., the federal and one state commission attempted to regularize the ROE component of rate cases, but failed to do so. One commentator has stated that "Efforts to make the process objective and mechanical are futile as an administrative and practical matter."[72] Instead, where cases are litigated, commissions continue to refer to the legal standards set by the landmark U.S. Supreme Court decisions in Bluefield and Hope. The regulators receive and access data from quantitative financial models and apply informed judgment in order, as the California Pubic Utilities Commission (CPUC, California Commission) has put it, to arrive at "An ROE set at a level commensurate with market returns on investments having comparable risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility obligations."[73] Moreover, U.S. regulators: have continued to accept evidence that depends in large part on data about other U.S. gas and electric companies' returns; have had at least some regard to short term bond rates; and in some cases have stated a consistent practice to moderate changes in the ROE relative to changes in interest rates in order to increase the stability of ROE over time.[74]

**And Canadian gas utility ROEs have fallen significantly below those of American ones and below those of low risk North American industrials** Historically, the ROEs of Canadian gas local distribution companies (LDCs) have approximately matched those in the U.S. industry. Since the inception of the generic ROE approach by Canadian regulators, the returns enjoyed by Canadians have fallen increasingly and significantly (up to 150 bp) below those of these comparables. This result arises despite the fact that independent analysis shows that business risks faced by LDCs in Canada do not significantly differ from those in the U.S.; that the greatest risk-determinant for utilities, regulatory risk, is comparable in Canada and the U.S.; and that tax differences do not matter to the comparison of Canadian and U.S.[75] [76]

**ROEs for greenfield interprovincial and international pipelines** In the "generic ROE era" it has become the practice for new pipelines subject to NEB jurisdiction to apply for tolls that have been the subject of prior negotiation with shippers. Typically, these tolls reflect ROEs about 300 or more basis points higher than incumbent pipelines, such as Foothills, TCPL, TQM and Westcoast, receive under the generic ROE.[77] Two points arise. First, this practice suggests that the NEB's generic ROE is insufficient to attract capital needed for greenfield projects. Second, one wonders whether this *de facto* vintaging of ROEs in the Canadian interprovincial and international pipeline sector breaches a fundamental principle of fairness.

## 4. Implications

**On the one hand, the generic ROE has created regulatory economies and encouraged the search for other efficiencies in the sector** The frequency of adversarial proceedings leading to ROE awards has been greatly reduced with consequent public and private savings. The generic ROE may have encouraged negotiated settlements of remaining rate issues, which typically incorporate elements of incentive rate-making encouraging efficiencies in investment and operations. Some utilities may have been able in this way to partially compensate for the low ROEs resulting from the application of the generic formula. However where that may have happened, it has been at the expense of greater risks by the utilities. Even with the presence of incentive features, there is no assurance that settlements will result in a "fair return" being earned each year of the settlement and over its lifetime, which could be as much as five years. The scope to achieve efficiencies while ensuring high quality of service may be exhausted and the overall return may fail to meet the fairness standard.

**On the other hand, the generic ROE approach is mechanistic and necessarily suspends the further application of regulatory judgment for extended periods, marking a sharp break with past practice**

- It was not uncommon in the past for regulators to expressly reject mechanistic approaches to ROE awards and stress the importance of judgment.[78] The initial generic decisions and any subsequent reviews, like the annual or biennial rate cases that preceded them, were based on careful assessment of much evidence and the application of informed regulatory judgments.

- However, once decisions are taken on a generic process, including the now universal AAM, the further application of judgment as to whether the FRS is being attained is suspended.[79] In principle, as the Alberta Board has observed, parties are free at any time to petition the regulator to consider a review of the adjustment formula in which, in Alberta, the petitioning party would bear the onus of demonstrating a material change in facts or circumstances from the evidence filed in its generic proceeding to merit a review of the formula.[80] In practice, the party's freedom to petition can be circumscribed for periods as long as five years as a result, for example, of a settlement agreement, a term which can therefore cover one or more economic cycles.

**It would appear from work done prior to [81] and parallel with [82] this review that the FRS may not have been achieved on an ex-post basis** This important conclusion is suggested by the comparison of Canadian gas LDCs' ROEs and the ROEs of U.S. gas utilities and North American low risk industrials, already referred to. It seems reasonable as an aspect of the industry oversight expected of regulators that, especially after a change as fundamental as the generic ROE, they would assess that change in terms of

whether the results required *ex ante* by the FRS have in fact been achieved *ex post*, with particular regard to the opportunity cost of capital. Such an examination by regulators is particularly warranted because the generic ROE plus AAM effectively prevents regulated entities from routinely presenting evidence and argument as to whether *ex post* the resulting ROEs have indeed reflected opportunity pricing of the cost of capital and achieved other objectives of the FRS which the generic regime is intended prospectively to do.[83]

**Two fundamental features driving ROE changes and arguably driving the "wedge" between Canadian LDC returns and others, namely the risk free rate and the AAM ratio appear to deserve critical examination**

- On the first point, as noted in Section 2 above, while one applicant has critiqued the risk-free rate, the regulator involved (the BC Commission), although summarizing the applicant's concerns, did not respond to them. It is not difficult, for instance by reading the Bank of Canada's periodic comments on factors influencing rates to find reasons to question why LDC ROE's should be directly linked to bond rates.[84]

- On the second point, the AAM ratio of 0.75 (and the 0.80 chosen initially by one regulator) had some empirical support in the proceedings leading to the respective initial generic decisions. Also it received principled support by the applicants in a number of proceedings. However it appears not subsequently to have been critically evaluated in terms of the behaviours of equity returns of comparable unregulated sectors in relation to changing bond yields in the dozen years since the earliest Canadian generic ROE decisions.

- Regarding U.S. LDC returns, the work of Concentric Energy Advisers for the OEB has shown a much lower coefficient of regression (0.46) between U.S. ROEs and long bonds compared to Ontario ROEs (0.86): in other words, that is for every one percentage point change in interest rates, the Ontario ROEs change by 86 basis points while U.S. ROEs change by 46 basis points.[85]

**The generic, mechanistic ROE including the AAM may require some reconsideration, if the FRS is to be achieved on a going forward basis**

The work carried out by Concentric for the OEB and by National Economic Research Associates (NERA) for the CGA identifies concerns that sow a doubt as to the ability of the present design of the generic ROE to continuously meet the fair return standard. It is indisputable that this bold and widely-welcomed initiative of Canadian regulators has entrained and encouraged valuable public and private efficiencies. However, in exchange, the generic ROE has reduced the opportunities, present in previous practice, to periodically exercise oversight of this critical element in the revenue requirement, review the results of a variety of tests, apply informed judgments to them, and recalibrate their ROE awards in conformity with their understanding of the FRS. Even though regulators are willing to entertain applications for review of the generic approach, it remains that

there are necessarily fewer examinations of the relevant data to ensure the generic formula plus the AAM continues to produce end results which meet the FRS.

Examination of the results of the generic approach, ex-post, suggests that, in an environment where interest rates have been, first, falling and then stabilizing at low levels, the generic ROE plus an AAM that tracks changes in expected bond yields in a ratio of 0.75 may have pulled ROEs down excessively in relation to the FRS and that, in the judgement of Concentric, "This may require consideration of additional qualitative and financial metrics in making the ROE determination."[86] In other words, what was found to be "fair and reasonable" or "just and reasonable" by careful examination of multiple tests and the appropriate exercise of informed judgment, may no longer be so after successive adjustments by admittedly-simple AAMs taking place in continuously changing economic and business conditions.

**The remarkable convergence among Canadian gas utility regulators may be an obstacle to reappraisal of the ERP plus AAM approach to the generic ROE**

The NEB in dealing with TransCanada's Fair Return Application dated 6 June 2001, centred on a novel After Tax Weighted Average Cost of Capital (ATWACC) approach, stated: "In summary, in the Board's view, the lack of regulatory precedent is not a barrier to the adoption of a new approach to regulation. However, in the absence of such precedent and in the absence of any support from stakeholders for the proposed change (meaning to the ATWACC approach—authors), the Board's analysis of the proposal should show a clear benefit to be derived from the new approach when compared with previous acceptable approaches."[87] As already noted, the Régie in 2007 was similarly faced with a novel approach proposed by Gaz Métroplitan, the Fama-French model which, according to the evidence, had never before been used in Canada and only once in the USA. The Régie decided not to retain Fama-French as a method of fixing the ROE because it had not been sufficiently examined to date to be used as a basis for fixing the rate of return of a distributor.[88]

In view of the foregoing, it is reasonable to pose the questions "Is there likely to be regulatory precedent and stakeholder support for initiatives by the gas utility industry for review of and change in the generic ROE?"

As to "regulatory precedent", it may not be easy for any Canadian regulator to "break ranks" with the rest, particularly after several have relatively recently reviewed their generic ROE practices and decided against major changes to them. Having taken place, regulatory convergence may be a powerful disincentive even for needed changes.

As to "stakeholder support", it appears that Canadian gas utility stakeholders are continuing in their virtually unanimous support of the respective regulators' established approaches. In the environment of generally-declining bond yields, the present design of the generic ROE has worked to the short-term economic advantage of industrial users, residential consumers, producers and shippers. This has generated an attitude, common in the regulatory world, of "what we have we hold". As long as the provision of safe and adequate service does not seem to be immediately at risk, this attitude is likely to

continue. Broad stakeholder support for major revisions favourable to the utilities seems unlikely to materialize so long as utilities seem able to attract capital and avoid impairing their financial integrity. It appears doubtful, however, that the FRS is satisfied by these considerations alone if the end result is unfair relative to returns available from investments in companies of similar risk.

**Desirable next steps** It would be helpful if, at the same time as specific cases occasionally come before individual regulators,[89] some further studies of general application were to be carried out. It is not the purpose of this paper to propose an alternative framework for ROE determination. However, any reconsideration should clearly take place against the background of an *ex post* examination of the results of the generic approach in terms of the comparability of the resulting returns with non-utility and utility comparators. It must include the fundamentals of the present design, namely the choice of the risk-free rate, the appropriate measurement of the risk premium and the adjustment mechanism. And it cannot exclude consideration of the place of the DCF model, given its acceptability to a majority of North American regulators. Finally, in an era of North American economic and business integration, the question must be asked "Can Canadian gas utilities successfully compete for capital if their regulators continue to award lower returns on generally thinner equity shares than those enjoyed by the American industry?"

Absent such a reconsideration and consequent adjustment, in an environment of continuing very low interest rates and bond yields, the present generic ROE formula alone may not be protecting the public interest in the provision by incumbent utilities of a robust, flexible natural gas delivery structure financially strong to support future sustainability of our energy economy.

## ENDNOTES

[1] The jurisdiction is Alberta. The test is the traditional comparable earnings one. See under heading 2 "Application", subheading "Alberta" on page 16.
[2] The word "stakeholder" has become an undefined term of art, particularly in NEB decisions on applications reflecting negotiated settlements, where it may be used as a synonym for parties to those settlements. In this paper, by "stakeholders" are meant parties, other than utility managements and shareholders, who have an economic interest in gas utility rates or tolls and who routinely take part in related regulatory proceedings and in settlement discussions. In this definition, depending on the nature of the utility, "stakeholder" can mean gas producer; shipper; exporter; industrial, commercial or residential consumer; or provincial government.
[3] An example may be the application to the NEB by Gazoduc TransQuébec & Maritimes (TQM) for Cost of Capital for 2007 and 2008, revised filing December 18, 2007, the first such application by that company since 1994. However, because of the complexity of the issues involved in this application and because of language considerations, a longer than normal hearing process is required. The hearing is presently scheduled to commence 23 September 2008, which means that a decision on this hearing would not be released until early 2009. See National Energy Board letter to TQM of 22 January 2008, file OF-Tolls-Group1-T201-2007-03 01.
[4] *Return on Equity: Allowed Returns for Canadian Gas Utilities*. A Discussion Paper Developed by the Canadian Gas Association. Summer 2007. 20 pages in bilingual format.
[5] The Lamont decision relates to "…a fair return…on the capital invested in its enterprise…" (S.C.R., 1929, page 193). However, the costs of debt and any preferred shares, assuming they are prudently incurred, are usually taken as a cost to be flowed directly through to rates via the cost of service. The ROE is therefore the salient variable in the fair return on the (total) capital invested in the enterprise. The discussion in this paper relates entirely to regulators' awards for the return on the owners' equity investment. It does not extend to consideration of what those awards mean in terms of return on the total capital invested by the utility in question even though, and the authors acknowledge this, the entire focus of the Lamont decision is on return on the total capital.
[6] By "Canadian gas utility regulators" is meant the relevant regulatory boards and commissions of Alberta, British Columbia, Canada, Manitoba, Ontario and Quebec.
[7] National Energy Board (NEB). Reasons for Decision (RfD). In the Matter of the Application under Part IV of the National Energy Board Act of Trans-Canada Pipelines Limited, RH-1-70, December 1971, pages 6 – 6 to 6 – 9.
[8] NEB, RfD, TransCanada et al. Cost of Capital. RH-2-94, March 1995.
[9] NEB, RfD, TransCanada PipeLines Limited. Cost of Capital (Fair Return Application of 6 June 2001). RH-4-2001, June 2002, pages 8-12.
[10] NEB, RfD, TransCanada PipeLines Limited. Review of RH-4-2001 Cost of Capital Decision. RH-R-1-2002, February 2003, Chapter 3: Fair Return Standard, pages 6-12.
[11] NEB, RfD, TransCanada PipeLines Limited. Cost of Capital. RH-2-2004 Phase II, April 2005, Chapter 2 Legal Framework for Determining a Fair Return, pages 8-20. In this context, the NEB noted the finding of the Federal Court of Appeal in TransCanada's unsuccessful appeal of the Board's 2002 decision. The Court, the Board stated, found that the impact of any resulting toll increases on customers is not a relevant consideration in the determination of the required rate of return on equity.
[12] Since January 1, 2008 the economic regulatory functions of the former EUB in respect of investor-owned and certain municipally-owned utilities are being exercised by the Alberta Utilities Commission (AUC).
[13] Energy and Utilities Board (EUB), Decision 2004-052, Generic Cost of Capital, July 2, 2004, Section 3.2 Relevant Judicial Decisions, pages 12-13.
[14] The principal American Supreme Court decisions are *Bluefield Water Works & Improvement Company vs. Public Service Commission of The State of West Virginia et al 262 U.S. 679 [1923]* (Bluefield) and *Federal Power Commission et al vs. Hope Natural Gas Co., 320 U.S.591* [1944] (Hope). They are cited by the NEB in RH-1-70 (op.cit.) at 6 – 8 and 6 – 9, RH-4-2001 (op.cit.) at page 8 and RH-2-2004 (op.cit.) at pages 14-16.

[15] This is borne out by the Alberta Board in EUB Decision 2004-052 (op.cit.) where after quoting from Northwestern, Hope and Bluefield, it stated at page 13 that "The Board notes that no party took issue with the general consensus that in order for a return to be fair, it must meet the tests of "comparable investment", "capital attraction" and "financial integrity" described in the above decisions.

[16] « La Régie accepte…que l'évaluation du coût des capitaux propres sur base présumée doit reposer sur le principe fondamental du coût d'opportunité de marché des capitaux propres…La Régie est d'avis que le taux de rendement accordé au Distributeur doit lui permettre d'assurer et de maintenir sa capacité d'attirer les fonds à des conditions raisonnables » Source : Régie de l'Énergie du Québec. Hydro-Québec. D-2003-93. 2 mars 2003, à la page 70. The same principles had earlier been expressed in Régie de l'Énergie du Québec. Hydro-Québec. D-2002-95. 30 avril 2002, à la page 163. These were admittedly electric utility cases, however since the Régie uses essentially the same methodology to determine its ROE awards for Québec gas utilities, it is reasonable to suppose that it does so in pursuit of the same principles of opportunity cost of capital and capital attraction as it applies to the electrical sector.

[17] Manitoba Public Utilities Board Act. Centra Gas Manitoba Inc. General Rate Application. Order No. 99/07, July 27, 2007, page 65.

[18] Ontario Energy Board (OEB) Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities (OEB Compendium). Chapter 2: Current OEB Approach, page 2, which reads in part "The Board's objective in setting the rate of return on rate base is to ensure that the utility is provided with a fair return which enables it to meet its obligations and maintain its capability of attracting capital".

[19] By way of example, TransCanada PipeLines averaged one such application to the NEB per 18 months in the period 1971-1994 inclusive.

[20] The NEB in RH-4-2001 (op.cit.) at page ix (Glossary of Terms) characterizes the ERP method as a family of models that includes CAPM and ECAPM (Empirical Capital Assets Pricing Model). See also RH-4-2001 page 48, second paragraph.

[21] OEB, op.cit.

[22] NEB, RH-1-70 op cit, page 6 – 6.

[23] NEB, op cit, pages 6 – 2 and 6 – 3.

[24] The application of informed judgement is similarly a constant in American regulators' decisions in utility rate cases. Consider the following from the California Commission's December 15, 2005 Decision 05-12-043 on the Test Year 2006 Return on Equity for the Major Utilities (Pacific Gas and Electric [PG&E], Southern California Edison [SCE] and San Diego Gas and Electric [SDG&E]). At page 23, the Commission stated "In the final analysis, it is the application of informed judgment, not the precision of financial models, which is the key to selecting a specific ROE estimate. We affirmed this view in D.89-10-031, which established ROEs for GTE California, Inc. and Pacific Bell, noting that we continue to view the financial models with considerable skepticism." The Commission then uses the term "informed judgment" eight times in respect of its own decision-taking. As a matter of interest the resulting ROE awards for 2006 were, for PG&E 11.35%; for SCE 11.60%; and for SDG&E 10.70%.

[25] NEB, RfD, TransCanada PipeLines Limited, RH-3-76, December 1976 page 4 – 13.

[26] NEB, RfD, Interprovincial Pipeline Limited, RH-2-76, December 1977, page 6 – 23.

[27] NEB, RH-2-76, op cit, page 6 – 26.

[28] NEB, RfD, TransCanada PipeLines Limited, RH-1-78, July 1978, page 5 – 9.

[29] Ibid.

[30] NEB, RfD, TransCanada PipeLines Limited, RH-4-81, Phase I, August 1981, pages 4 – 5 and 4 – 6.

[31] NEB, RfD, TransCanada PipeLines Limited, RH-3-1982, July 1982, pages 3 – 10 to 3 – 12.

[32] NEB, RfD, TransCanada PipeLines Limited RH-4-93, June 1994, page 27.

[33] BC Utilities Commission, Decision in the matter of Terasen et al, March 2, 2006, page 45.

[34] This statement is from an article by Dr. Jeff D. Makholm in Public Utilities Fortnightly, May 15, 2003, pages 12-18, "In Defense of the 'Gold Standard'". The fuller context is as follows: "The fair rate of return became a hotly contested issue in the early 1970s…The DCF and CAPM methods got their start at this time and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions." (Makholm, page 14, column 1).

[35] OEB, op cit, page 8.

[36] BC Utilities Commission, Decision in the matter of Return on Common Equity, BC Gas Utility et al, June 10, 1994, see especially pages 17-18.

[37] NEB, RfD, RH-2-94, TransCanada et al, Cost of Capital, March 1995.
[38] Manitoba Public Utilities Board Act, Order No.49/95, May 5, 1995 in an application by Centra Gas Manitoba Inc. The Manitoba Board in that decision reserved the right to require a full ROE hearing prior to the 1997 test year as a result of unusual or significant changes in the economy. However such a hearing did not take place. Centra Gas Manitoba was acquired by Manitoba Hydro, a provincial crown corporation, in 1999 and the ROE was subsequently replaced by a provision for a net income as part of Centra's costs, the allowed net income would not exceed the allowed return on equity under the Rate Base/Rate of Return methodology—see Manitoba Public Utilities Board Act, Order No. 103/05, July 12, 2005 in an Application by Centra Gas Manitoba Inc, page 40.
[39] OEB, Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997 (not page numbered).
[40] OEB, Compendium, op cit, page 24, Section 5.1 Rationale for Draft Guidelines, Rationale for Adopting Formula ROE.
[41] EUB, Decision 2004-052, op cit, pages 15-31, Section 4.2 ROE Methodology and 2004 ROE.
[42] EUB, op cit, page 23.
[43] EUB, op.cit, Section 4.2.7 Other Measures of Comparable Investment, pages 24-30.
[44] The CE test was not the only one with which the EUB had difficulties. Thus, it is noted that the Alberta Board in Decision 2004-052, concluded "…that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM." EUB op.cit. page 23.
[45] EUB, op cit, pages 31-32, Section 4.3 Annual Adjustment Mechanism.
[46] The Régie had previously applied the ERP approach but without an automatic adjustment feature, see for example Régie du Gaz Naturel, Décision D-96-31, 9 octobre 1996, Gaz Métropolitain, pages 69-70, La prime de risque du marché.
[47] Régie de l'énergie, Décision D-2007-116, Gaz Métropolitan, page 23.
[48] Ibid, pages 23-24.
[49] BC Utilities Commission, Decision in the matter of Terasen et al, March 2, 2006, op cit.
[50] NEB RfDs in TransCanada PipeLines Limited: Cost of Capital. RH-4-2001, June 2002; RH-R-1-2002, Review of RH-4-2001 February 2003; Cost of Capital. RH-2-2004 Phase II, April 2005. The RH-R-1-2002 decision was unsuccessfully appealed to the Federal Court of Appeal by TransCanada PipeLines (2004 FCA 149).
[51] BC Utilities Commission, op cit, page 52. Note that, while intending to give primary weight to the application and results of the ERP method, the Commission stated that it would need to apply judgment to the evidence before it.
[52] NEB RfD, TransCanada PipeLines Limited, RH-4-2001, pages 45-56.
[53] It may be noted that the EUB in Decision E99099, 1999/2000 Electric Tariff Applications, 25 November 1999 decided to "use both the traditional method and a modified ATWACC as tools to arrive at the fair return for (a number of electric utilities) with primary weight placed on the traditional method." (see page 328). The ATWACC evidence, which was accepted by the EUB with some modifications to its results, was submitted by the same witness (Dr.Vilbert) whose methodology and results were rejected by the NEB in RH-4-2001.
[54] NEB RfD, RH-R-1-2002, op cit, pages 11-12 Legal Obligation to use the FRS.
[55] NEB RfD, RH-2-2004, op.cit., page 19.
[56] Ibid.
[57] BCUC, Decision in Terasen et al, March 2, 2006, page 46.
[58] The degree of convergence as reflected in the annual ROE awards is remarkable. Thus, for year 2008 the range of ROEs is only about 50 basis points (bp) with La Régie at 8.91% (Gaz Métro) and the OEB at 8.39% and the EUB, NEB and the BCUC in the middle of the range with 8.75%, 8.71% and 8.62% respectively. Contrast this with the spread of 65 bp in the awards by one American regulator to three utilities for one year (footnote 25).
[59] The case is TransCanada's Canadian mainline. The negotiated settlement of March 2007 relates to the period 2007-2011 inclusive and provides that, during the Term, TransCanada will not pursue litigation of the NEB RH-2-94 ROE formula on behalf of… its Mainline System—see TransCanada PipeLines,

Application to the NEB, March 14, 2007: Application for Approval of a Negotiated Mainline Tolls Settlement and 2007 Mainline Tolls. Page 5 of 13, item 19. This Negotiated Settlement was approved by the NEB on 31 May 2007 by Order TG-06-2007.

[60] American regulators routinely cite their legal standard for fair return, essentially the Bluefield and Hope cases which are sometimes referred to also by Canadian regulators (examples: Alberta Board, NEB, see pages 11-12 above). The California Commission does so in the following terms in case D-05-12-043 (Test Year 2006 Return on Equity for the Major Energy Utilities) "The legal standard for setting the fair rate of return has been established by the United States Supreme Court in the Bluefield and Hope cases. The Bluefield decision states that a public utility is entitled to earn a return upon the value of its property employed for the convenience of the public and sets forth parameters to assess a reasonable return. Such return should be equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties. That return should also be reasonably sufficient to assure confidence in the financial soundness of the utility, and adequate, under efficient management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties. The Hope decision reinforces the Bluefield decision and emphasizes that such returns should be sufficient to cover operating expenses and capital costs of the business. The capital cost of business includes debt service and stock dividends. The return should also be commensurate with returns available on alternative investments of comparable risks.

[61] A sampling of relatively recent cases finds that the California Commission received and used DCF, CAPM and MRP evidence in case D-05-12-043 (see footnote 24), the Illinois Commerce Commission accepted DCF and CAPM evidence in a September 2005, once-in-a-decade decision on Northern Illinois Gas Company's rates; the New York Public Service Commission (NYPSC) received CAPM, CE, DCF and ERP evidence, found CE and ERP not to be particularly useful, and gave a 50/50 weighting to CAPM and DCF in a 2007 National Fuel Gas rate case (Case 07-G-0141).

[62] See above, text page 15 and footnote 34.

[63] NEB, Letter Decision, RH-2-95, December 1995. The TransCanada settlement covered the period 1 January 1996 through 31 December 1999.

[64] NEB, RfD, Westcoast Energy Inc., RH-2-97, Part II, August 1997. The Westcoast settlement covered the period 1 January 1997 through December 31, 2001.

[65] NEB, Compilation of Key Documents Related to the Board's RH-2-95 Decisions, TransCanada, June 1996, page 19, sub Article 1, item 1.2, v).

[66] NEB, RH-2-97, op cit, page 1, sub Article 1, item 1.2, (f).

[67] EUB, Decision 2005-057, NOVA Gas Transmission Ltd., 2005-2007 Revenue Requirement Settlement, July 7, 2005, see page 2 thereof.

[68] BCUC Order G-51-03 of 29 July 2003 for the initial term.

[69] BCUC Order G-33-07 of 23 March 2007 for the extension.

[70] "TransCanada PipeLines. Annual Report, 1996. Letter to Shareholders, page 4, final paragraph.

[71] Supra, page 9.

[72] Makholm, Jeff D., op cit, page 18, column 1.

[73] CPUC, D-05-12-043 on Test Year 2006 Return on Equity for the major energy utilities, Findings of Fact, paragraph 16.

[74] It is acknowledged that the Canadian "0.75 ratio" to forecasted changes in long Canadas has this effect.

[75] National Economic Research Associates (NERA). Allowed Return on (Gas Utility) Equity in Canada and the United States: An Economic, Financial and Institutional Analysis. Ken Gordon, Jeff Makholm, Wayne Olsen, November 2007. Tax differences are dealt with on page 13, business risk on pages 24-25 and regulatory risk on pages 25-32.

[76] Concentric Energy Advisors concluded for the OEB that "(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing U.S. companies or other provinces' utilities that would explain the difference in ROEs." See Concentric op. cit., Section VII Conclusions and Summary of Findings, paragraph (6) on page 57.

[77] *Alliance Pipeline Ltd* (Alliance) filed on 31 October 2007 its normal annual toll revisions to become effective 1 January 2008 The NEB filing ID is A16816. Alliance noted that the filed-for tolls reflect a base return on equity of 12%, subject to an incentive adjustment, on a deemed capital structure that provides for 30% equity. These are the same numbers as appeared in Alliance's original certificate application to the

NEB which was approved in November 1998 in GH-3-97. At the time of writing, Alliance's 2008 tolls are still interim.
*Emera Brunswick Pipeline Company Ltd*. reached a negotiated agreement for a monthly fixed toll that would cover all fixed charges including an equity return typically in the 11 to 14 percent range. NEB RfD Emera Brunswick Pipeline Company Ltd., GH-1-2006, May 2007, Section 7.1 Tolls and Tariffs, page 76
*Mackenzie Valley Gas Pipeline*, Section 3.1 of the August 2004 application in GH-1-2004 which is still under consideration presents toll principles that include a deemed capital structure based on 30% equity and an ROE equal to the NEB multi-pipeline ROE plus 2.21% for the initial 10 years, see page 3-4
*Maritimes and Northeast Pipeline* filed on 28 December 2007 a negotiated toll settlement for the calendar year 2008 which embodies an allowed ROE of 11.66 per cent on a deemed equity of 31.18%. NEB filing ID A17299.

[78] The seminal NEB decision in TransCanada's first rate application, RH-1-70 of December 1971 contains some important language relating to both points.
First, as to mechanistic approaches, the Board stated at page 6 – 6 "The final conclusion as to what is enough but not too much in the way of return, and rate of return, is not precisely supportable on a mathematical basis. If it were, one computer and a few programmers could replace all the regulatory boards in North America and dispense undeniable justice instantaneously."
Second, as to the exercise of judgment, the Board said at pages 6 – 2 and 6 – 3 that "Many tests and techniques for assisting the process of reaching a just decision have been used, but no single test is conclusive nor is any group of them definitive: whatever tests may be used, in the last analysis the adjudicating body can not escape the responsibility of exercising judgment as to what, in a stated set of circumstances, is a just and reasonable return or rate of return, or what is a range of justness and reasonableness of return or rate of return." These early comments by the NEB in a sense echo the view expressed by the SCC in Lamont where, in 1929 S.C.R., at page 199, the Court stated "The question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be on one of the things entrusted by the statute to the judgment of the Board."

[79] Note that, in applying its automatic mechanism to adjust the rate of return on common equity, the BCUC initially advised the affected companies that it had "…reviewed the performance of the automatic mechanism to adjust the rate of return…and has determined that the mechanism has performed favourably." (Letters L-61-96, December 2, 1996; L-73-97 of December 2, 1997; L-89-98 of December 4, 1998). After 1998, however, the references to review and to favourable performance were dropped and the annual notification letters now simply state that "…the Commission has determined that the current ROE automatic adjustment mechanism results in an allowed return of…" (example: Letter L-93-07 of November 22, 2007). Essentially the same approach is followed by the EUB (Example: Order U2007-347 of 30 November 2007) and NEB (Example: Letter of 29 November 2007, File OF-TollsGen-RRCE 02).

[80] EUB Decision 2004-052, July 2, 2004, page 34.

[81] CGA op cit, Section 3: Maintaining a Fair Return, pages 14-17.

[82] NERA, op cit, particularly pages 7 – 11.

[83] Note that the EUB, in giving its reasons for establishing a standardized approach for setting an ROE, stated "An applicant is also free to apply to the Board to review the ROE formula in the manner provided for in this Decision. Even without an application by a particular party, the ROE formula will be subject to review in certain circumstances and in any event will be considered for review after five years." See EUB, Decision 2004-052, op.cit., page 8.

[84] A scan of Bank of Canada published comments for the past few years points to the following as rate-affecting monetary policy factors: economic growth; utilization of economic capacity; demand on the economy, domestic and export; inflation rates and inflation risks; U.S. economy and major sectors; global economy and major components EU, Japan, China; global markets, including commodity markets (e.g. energy), and their balances; Canada/USA exchange rates and the influence on the Canadian economy; cost of credit to firms and households; state of financial markets, Canada and abroad. These notes are based mainly on reading the Bank of Canada's semi-annual Monetary Report and Update available online at http://www.bank-banque-canada.ca/en/mpr/mpr_previous.html.

[85] Concentric Energy Advisors. A Comparative Analysis of Return on Equity of Natural Gas Utilities. Prepared for the OEB. June 14, 2007, pages 18-19. Concentric correctly point out that, "…as interest rates

have declined dramatically in Canada in the past ten years, one would expect the OEB formula to yield accordingly lower authorized ROEs. The formula, however, is symmetrical, and ROEs will most likely recover at a faster rate in Ontario than in the U.S., when interest rates begin to rise. In fact, if interest rates continue to steadily rise, the OEB adjustment formula could surpass and yield higher results than historical data suggest U.S. authorized returns would reach under the same circumstances."

[86] Ibid, page 57, last sentence in item 5.

[87] NEB, Rfd, RH-4-2001, heading Regulatory Precedent, at page 43.

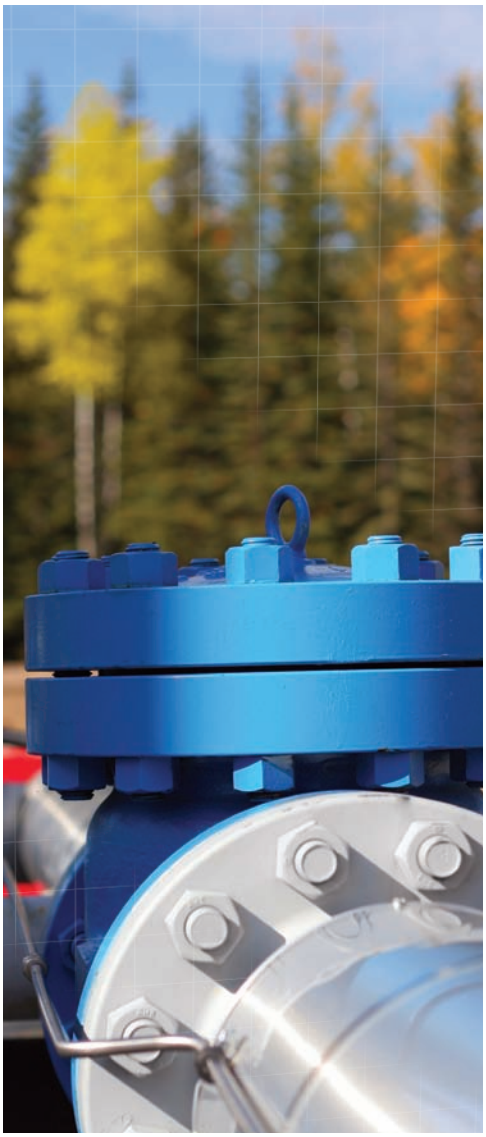
[88] Régie de l'énergie. Décision D-2007-116., pages 23-24.

[89] The example has already been given of the 17 December 2007 application to the NEB by Gazoduc Trans-Québec et Maritimes for cost of capital determination for the years 2007 and 2008. See footnote 3, which also notes the lengthy hearing process which this application may involve, extending over about a 13-month period.

National Energy Board
Office national de l'énergie

# CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

## TRANSPORTATION ASSESSMENT







JULY 2007

Canada

National Energy Board

Office national de l'énergie

# CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

## TRANSPORTATION ASSESSMENT

**JULY 2007**

Canada

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# ACRONYMS AND ABREVIATIONS

| | |
|---|---|
| AOS | Authorized Overrun Service |
| Alliance | Alliance Pipeline Ltd. |
| Altex | Altex Energy Ltd. |
| CAPP | Canadian Association of Petroleum Producers |
| CEPA | Canadian Energy Pipeline Association |
| Cochin | Cochin Pipe Lines Ltd. |
| Coral | Coral Energy Canada Inc. |
| DBRS | Dominion Bond Rating Service |
| EBIT | Earnings Before Interest and Taxes |
| Enbridge | Enbridge Pipelines Inc. |
| Express | Express Pipeline Limited Partnership |
| Foothills | Foothills Pipe Lines Ltd. |
| FT | Firm Transportation |
| FT-RAM | Firm Transportation Risk Alleviation Mechanism |
| GDP | Gross Domestic Product |
| Gateway | Gateway Pipeline Inc. |
| IGUA | Industrial Gas Users Association |
| Irving/Repsol | Irving Oil Company Limited and Repsol YPF |
| Kinder Morgan | Kinder Morgan Canada Inc. |
| LNG | Liquefied Natural Gas |
| M&NP | Maritimes & Northeast Pipeline Management Ltd. |

| | |
|---|---|
| Mackenzie | Mackenzie Gas Project |
| Moody's | Moody's Canada Inc. |
| NEB or Board | National Energy Board |
| NGL | Natural Gas Liquid |
| OEB | Ontario Energy Board |
| PADD | Petroleum Administration for Defense Districts |
| Petro-Canada | Petro-Canada Oil and Gas |
| PNGTS | Portland Natural Gas Transmission System |
| ROE | Return on Common Equity |
| S&P | Standard & Poor's |
| Terasen | Terasen Pipelines Inc. |
| T-South | Westcoast's Southern Mainline (Zone 4) |
| TNPI or Trans-Northern | Trans-Northern Pipeline Inc. |
| TPTM | Terasen Pipelines (Trans Mountain) Inc. |
| TQM | Trans Québec & Maritimes Pipeline Inc. |
| TransCanada or TCPL | TransCanada PipeLines Limited |
| U.S. | United States |
| Union Gas | Union Gas Limited |
| WCSB | Western Canada Sedimentary Basin |
| Westcoast | Westcoast Energy Inc. |

# UNITS

| | |
|---|---|
| b/d | Barrels per day |
| Mb/d | Thousand barrels per day |
| MMb/d | Million barrels per day |
| Bcf | Billion cubic feet |
| MMcf/d | Million cubic feet per day |
| GJ | Gigajoule |
| $m^3/d$ | Cubic metres per day |
| $10^3m^3/d$ | Thousand cubic metres per day |

# FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency whose purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest[1] within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians.

The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines, as well as tolls and tariffs. Another key role is to regulate international and designated interprovincial power lines. The Board also regulates the imports of natural gas and the exports of natural gas, oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements. In its advisory function, the Board provides energy information and advice by analyzing information about Canadian energy markets obtained through regulatory processes and monitoring.

This report marks the third year that the Board has provided an assessment of the Canadian hydrocarbon transportation system. This report utilizes data from various publicly available sources which are collected and monitored by Board staff in addition to throughput data supplied by the pipeline companies. The Board also benefited from discussion with members of the investment community with respect to capital markets. Prior to the release of this report, a draft was sent to the Canadian Energy Pipeline Association (CEPA), the Canadian Association of Petroleum Producers (CAPP), and the Canadian Gas Association (CGA) for comment. Other parties such as the Industrial Gas Users Association (IGUA) also expressed interest and provided comment on the issues and aspects of information in this report. A listing of all organizations that provided comment or information in the production of this report is shown in Appendix 1. Comments by all parties were taken into consideration in the preparation of this report.

Any comments on the report or suggestions for further analysis can be directed to:

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If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as can be done with any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

Information about the NEB, including its publications, can be found by accessing the Board's website: http://www.neb-one.gc.ca.

1 The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that changes as society's values and preferences evolve over time.

# INTRODUCTION

Energy is essential to our daily lives. The ability of the pipeline transportation system to deliver energy, in the form of natural gas, natural gas liquids (NGLs), crude oil, and petroleum products is critical to Canada's economic well-being. In 2006, approximately $110 billion worth of products was moved through Canadian pipelines to markets at home and in the U.S. The cost in 2006 of providing these transportation services is estimated to be around $4.7 billion, not including the fuel costs paid by shippers on natural gas pipelines. This was accomplished by infrastructure that is mostly invisible to consumers and that operates safely with minimal environmental impact.

Canadians depend on this infrastructure for a safe, reliable, and efficient energy supply. The 45 000 kilometres (km) of natural gas and oil pipelines regulated by the NEB are a crucial element in Canada's hydrocarbon transportation system (Figures 1 and 2). These include large-diameter, cross-country, high-pressure natural gas pipelines, low pressure crude oil and oil products pipelines, and small-diameter pipelines.

In line with its mandate to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest, the Board has identified five goals which articulate its purpose and core directives[2]:

1. NEB-regulated pipelines and activities are safe and secure, and are perceived to be so.
2. NEB-regulated facilities are built in a manner that protects the environment and respects the rights of those affected.
3. Canadians benefit from efficient energy infrastructure and markets.
4. The NEB fulfills its mandate with the benefit of effective public engagement.
5. The NEB delivers quality outcomes through innovative leadership and effective support processes.

To determine whether the goals are being achieved, the Board has established various measures and a system of monitoring for each goal. Each year, the Board also issues various reports that discuss these different aspects of Canadian energy infrastructure and activities. This report focuses largely on aspects of Goal 3, and provides an update on the Board's assessment on how well the Canadian hydrocarbon transportation system is working. This report marks the third consecutive year for this assessment and utilizes the system of monitoring and measurements for the performance of the transportation system that was established in previous years. For the hydrocarbon transportation system to function efficiently and effectively, it must operate in a safe and environmentally acceptable manner, which relates to Goals 1 and 2. The Board also reports annually on safety, integrity, and environmental performance of NEB-regulated pipelines in a companion report that was published in March 2007, which may be found at http://www.neb-one.gc.ca/safety/SafetyPerformanceIndicators/index_e.htm.

2 NEB Strategic Plan 2007-2010

**FIGURE 1**

***Gas Pipelines Regulated by the NEB***

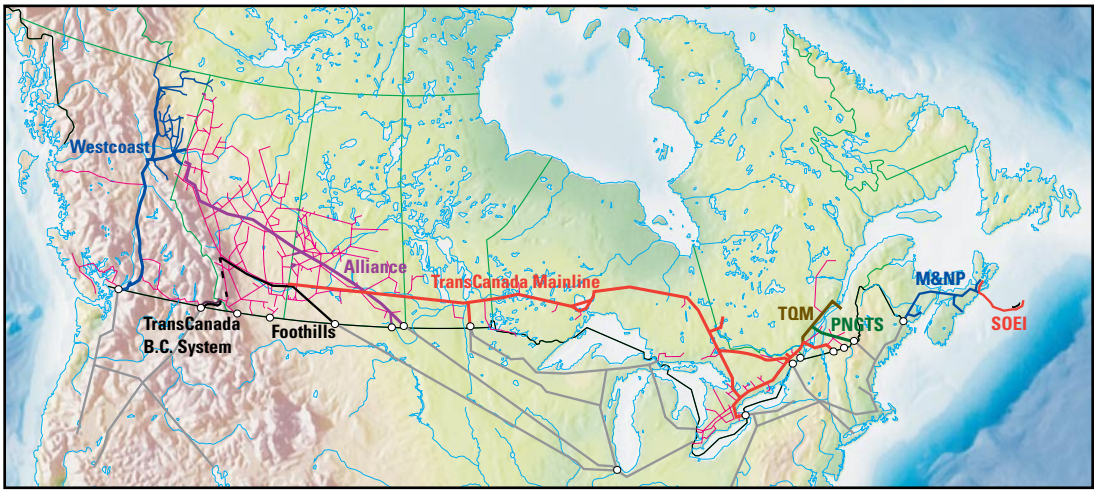
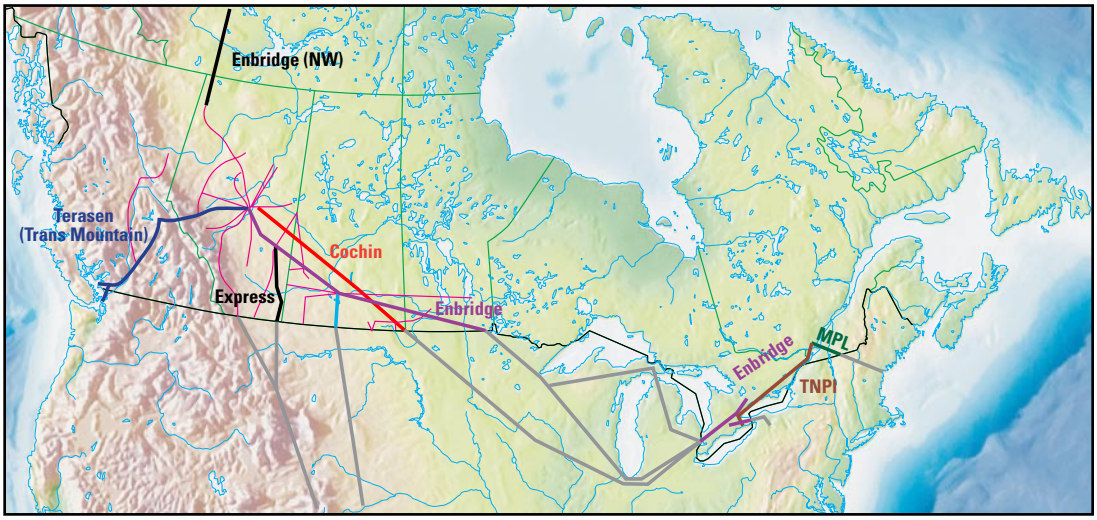



**FIGURE 2**

***Oil Pipelines Regulated by the NEB***




The Board believes that the following outcomes are important characteristics of a well functioning hydrocarbon transportation system:

- There is adequate pipeline capacity in place to move products to consumers who need them;
- Pipeline companies provide services that meet the needs of shippers at just and reasonable prices; and,
- Pipeline companies have adequate financial strength to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

In general, an efficient hydrocarbon transportation system will have an ability to respond on a timely basis to changing market conditions. This may entail adjustments to pipeline capacity or enhancement of pipeline services.

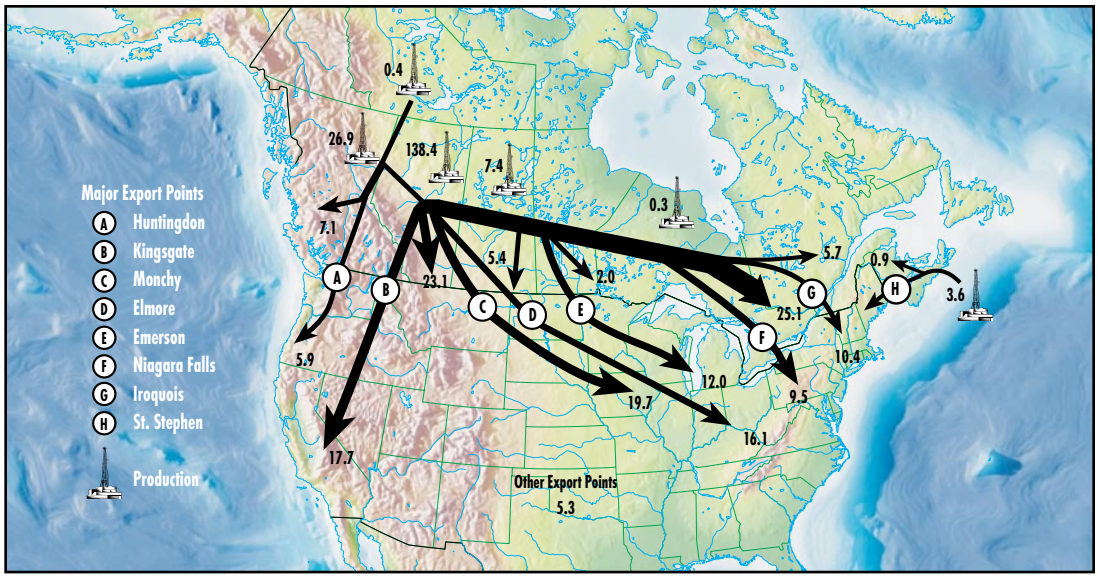
To assess the extent to which these outcomes are achieved, the Board uses publicly available data for Group 1 regulated companies and Express Pipeline Limited Partnership (Express), the largest Group 2 company.[3] These companies represent the major NEB-regulated pipelines and provide a good view of the overall functioning of the hydrocarbon transportation system. In addition, the Board used throughput and capacity information received from the pipelines; discussions with members of the investment community; and input from the users of NEB-regulated pipelines. Although the majority of information presented in this report is an update and assessment for 2006; where available, 2007 information is also provided. A listing of the companies regulated by the NEB, as of December 31, 2006, can be found in Appendix 2.

This report should not be viewed as a regulatory decision. In this report the Board is not making a determination on regulatory matters such as the appropriate rate of return on equity that should be earned by pipeline companies. The factors used to assess the functioning of the transportation system are not necessarily the same as those which are applied in a regulatory proceeding.

Figures 3 and 4 provide an overview of the supply and disposition of natural gas and crude oil in Canada. More information on the supply and disposition of energy in Canada can be found in the Board's Energy Overview report, published in May 2007, which may be found at http://www.neb-one.gc.ca/energy/EnergyReports/index_e.htm#energy_overview.

**FIGURE 3**

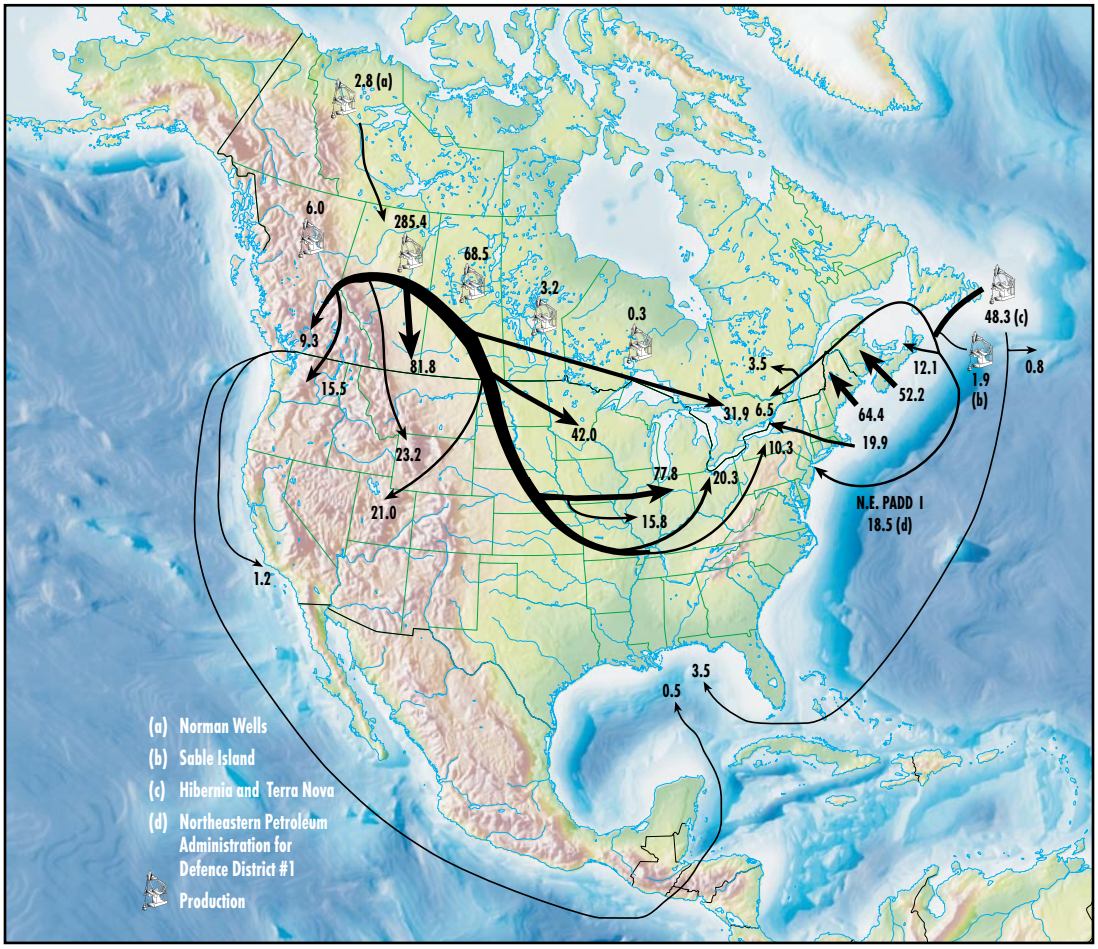
***2006 Supply and Disposition of Natural Gas (Billion Cubic Metres)***




3 For the purpose of the Board's financial regulation, pipeline companies are divided into two groups, Group 1 and Group 2. Major oil and gas pipeline companies are designated as Group 1 and are generally actively regulated by the NEB. All other NEB-regulated pipelines are designated as Group 2 and are subject to a lighter degree of regulation.

**FIGURE 4**

***2006 Supply and Disposition of Oil***
***(Thousand cubic Metres per Day)***



C H A P T E R T W O

# ADEQUACY OF PIPELINE CAPACITY

A key measure of an energy market's operational efficiency is the ability of its pipeline system to adequately transport crude oil, refined products, natural gas and natural gas liquids (NGLs) from producing to consuming regions.

This section will examine the following factors to assess the current adequacy of pipeline capacity:

1. price differentials compared with firm service tolls for major transportation paths;
2. capacity utilization on pipelines; and
3. the degree of apportionment on major oil pipelines.

The Board has generally taken the view that some excess capacity on a pipeline is desirable. This may result in higher tolls for shippers; however, the costs associated with inadequate pipeline capacity can be far greater. Substantial revenue loss for producers and governments can result when producers are unable to move their oil and gas to market. In addition, excess capacity allows shippers the flexibility to access the appropriate markets with the right product, thereby maximizing their revenues.

For example, in the case of oil transportation, if there is inadequate pipeline capacity to transport crude oil to the West Coast (PADD V), producers have the option of transporting crude oil to Ontario, PADD II (Midwest), southern PADD II (Cushing, Oklahoma), PADD III (U.S. Gulf Coast) or PADD IV (Rockies). As well, during periods when refineries are in turnaround (maintenance) in any of these locations, producers can deliver crude oil volumes to other markets, providing there is adequate pipeline capacity.

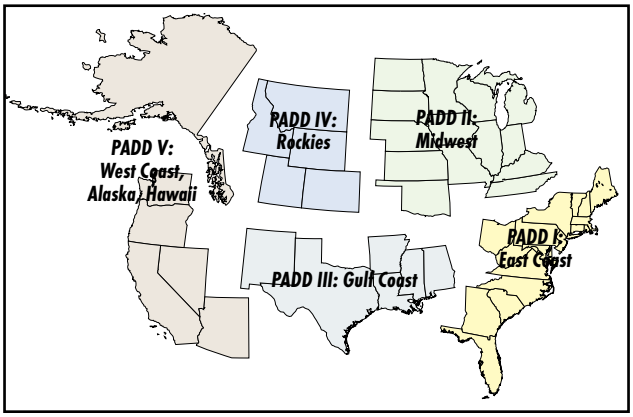
## 2.1 Price Differentials

### *Price Differentials and Natural Gas Firm Service Tolls*

When there is adequate pipeline capacity between two market hubs, commodity prices will be connected and the price differential will be equal to, or less than, the transportation costs between the two points. As long as the price differential is less than the toll plus fuel, the market is indicating that there is adequate pipeline capacity between the two pricing points. In a market with adequate capacity, suppliers would generally direct their product to the

**FIGURE 5**

***Petroleum Administration for Defense Districts***



market that nets the highest revenue back to the seller, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market, resulting in higher prices for downstream consumers or lower prices to producers, creating a higher differential in price between the two end points.

In order to use price differentials as an indicator on the adequacy of pipeline capacity, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below – one for transportation on TransCanada PipeLines Limited Mainline (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc. (Westcoast).

Figure 6 shows the basis differential between Alberta and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The price differential between Alberta and the Dawn delivery point is generally below the total cost of transportation (firm transportation plus fuel) via the TransCanada pipeline connecting these two markets. This indicates that pipeline capacity is adequate between these locations. As indicated by the variation in the price difference between the two locations, natural gas pricing is very responsive to relatively small changes in flow or demand. Times of exceptional natural gas demand in eastern markets, such as the summer heat waves of 2005 and 2006 that produced a strong demand for natural gas-fired power generation for air conditioning in eastern markets, or reduced supplies from the Gulf of Mexico in the months following hurricanes Katrina and Rita (August 2005 to January 2006), have resulted in short term increases in the price differential. Conversely, mild weather and ample gas in storage can moderate the price differential and the demand for gas and transportation services such as occurred in the autumn of 2006 and the early part of the 2006/2007 winter heating season.

Figure 7 shows the price differential between Compressor Station 2 on the Westcoast system and the export point at Huntingdon/Sumas compared with the firm service toll for transportation between the two locations (T-South or Southern Mainline), including fuel costs. Since January 2003, except for the peak winter months in recent years, the price differential has been lower than the cost of transportation, indicating that there has been adequate capacity in place. Overall, the comparison of price differential and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. However, natural gas pricing is volatile. Short-term increases in the price differential have been observed in recent years as a result of changes to market conditions such as,

**FIGURE 6**

***Dawn – Alberta Price Differential vs. TransCanada Toll and Fuel***

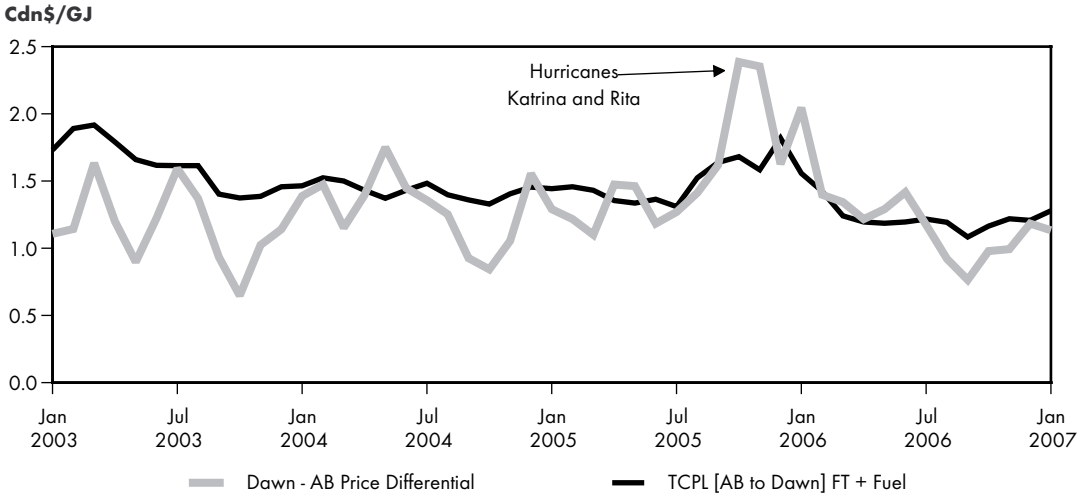
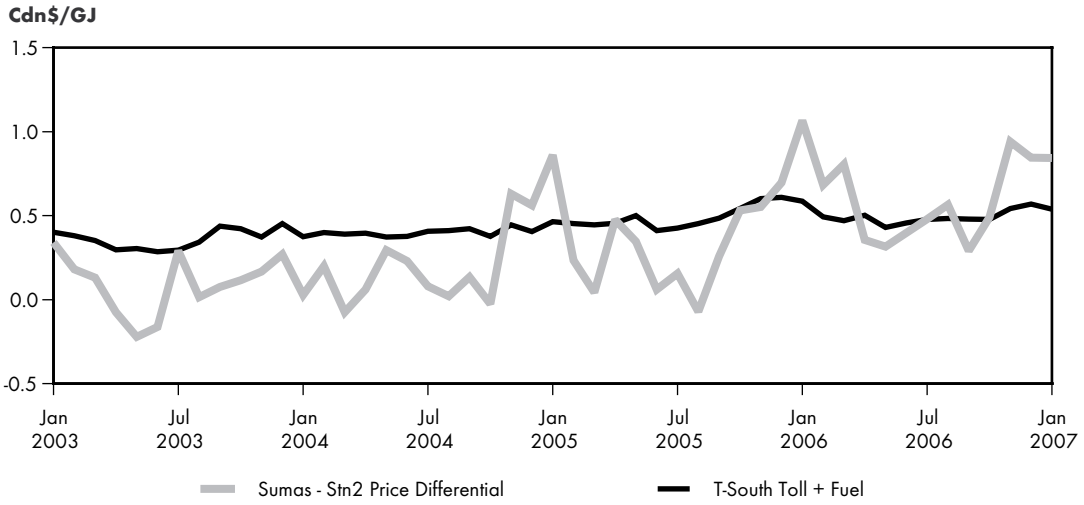


**FIGURE 7**

***Sumas – Station 2 Price Differential vs. Westcoast T-South Toll and Fuel***




hurricane-induced supply disruptions in the United States, unpredictable weather-related demand, and availability of other transportation options during such periods.

Overall, the comparison of price differentials and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. In general, the price differential between pricing points has been slightly lower than the cost of pipeline transportation (tolls) and fuel. However, natural gas prices can fluctuate in response to weather and can impact both price differential and pipeline fuel costs. Pipeline tolls tend to be more constant. Figures 6 and 7 both indicate occasions where the price differential exceeded transportation (toll) and fuel costs. These events proved to be temporary, and gas flows and prices moderated.

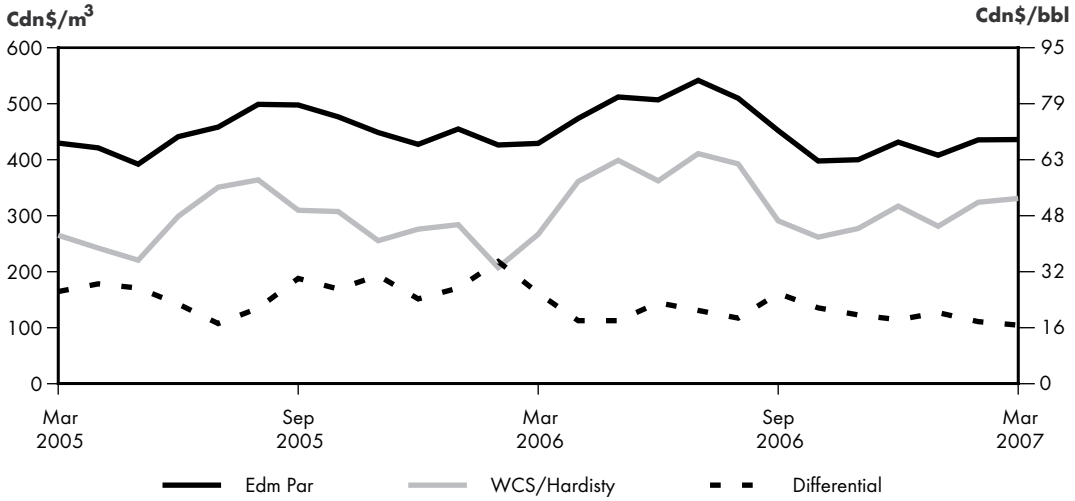
### *Price Differentials and Tolls on Oil Pipelines*

The price differentials for crude oil are determined by a number of factors, including availability of pipeline capacity, supply and demand fundamentals, seasonality and the grade (quality) of crude oil. Price differentials are increasingly becoming an issue on oil pipelines because of increasing production from the oil sands. Oil sands crude oil is a heavier bitumen blend and has limited market access because it requires specially equipped refineries to process it into useable refined products. This limited access exerts downward pressure on heavy crude oil prices and widens the light-heavy differential during certain times of the year. Historically the discussion on price differentials have been exclusive to heavy crude oil; however, with increased production of upgraded bitumen or light synthetic crude oil - the price differential between synthetic crude oil, Canadian light crude oil, and other crude oil supplied to U.S. refineries is becoming an increasingly important issue. Largely as a result of increased synthetic crude oil production and limited pipeline capacity to downstream markets, price discounts have also been observed for Canadian synthetic and light crude oil.

Figure 8 illustrates the light-heavy differential as indicated by the difference in the price of Edmonton Par light crude oil and Western Canadian Select (WCS), a heavy crude oil blend that is priced at Hardisty, Alberta. As illustrated, the differential between them has been wide and volatile during the time period shown; however, there has been a narrowing trend since September 2006. In the first quarter 2007, the light-heavy differential was 27 percent. In particular, in the month of March, the light-heavy differential narrowed to its lowest level since August 2004. There are two main reasons

**FIGURE 8**

***Canadian Crude Oil Prices and Differential***




for this narrowing; one is the Syncrude upgrader expansion, which is processing more bitumen, up to 350 Mb/d per day from 240 Mb/d in 2006; the second is the Spearhead and Mobil pipeline reversals which are transporting almost 200 Mb/d of crude oil south of Chicago to as far as the U.S. Gulf Coast. Typically, during the summer months, the differential narrows because of an increase in seasonal demand for heavier crudes for the production of asphalt.

## 2.2 Capacity Utilization on Major Routes

Where adequate pricing data is not available at major receipt and delivery locations on pipeline systems, another measure of adequate capacity comes from directly comparing the throughput or flow on the pipeline with its capacity. The Board monitors capacity utilization for most of the large pipelines it regulates.

The following figures show pipeline average monthly throughput compared with capacity for some of the largest NEB-regulated pipeline systems, including the TransCanada Mainline, Foothills Pipe Lines Ltd. (Foothills), TransCanada B.C. System, Westcoast, Alliance Pipeline Ltd. (Alliance), Trans Québec & Maritimes Pipeline (TQM), Maritimes & Northeast Pipeline (M&NP), Enbridge Pipelines Inc. (Enbridge), Kinder Morgan Canada's Terasen Pipelines (Trans Mountain) Inc. (TPTM), Express and Trans-Northern Pipeline Inc. (TNPI).

### *Natural Gas*

Figure 9 compares the average monthly throughput on the TransCanada Mainline (which is approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan) to the capacity of TransCanada's prairie line. This comparison illustrates that there has consistently been capacity in excess of throughput volumes over the time period shown. The excess capacity even persisted through the period of July 2005 to July 2006, which included two hotter-than-normal summers that produced strong demand for natural gas for power generation in eastern markets, and greater demand for Canadian gas due to production losses in the U.S. stemming from the late summer hurricanes of 2005.

On the eastern part of the TransCanada system, a number of expansions occurred in 2006 or are proposed for 2007 which are directed towards reducing bottlenecks to connect additional supply from Dawn and to access growing markets in Eastern Canada and the U.S. Northeast.

Overall, the indicator shows that there has been adequate pipeline capacity to move volumes to eastern markets. Excess capacity, which averaged 1.4 Bcf/d over the past four years, provided the impetus for the TransCanada Keystone Pipeline project. In this initiative, TransCanada proposes to transfer Line 100-1 of the Mainline to TransCanada Keystone Pipeline GP Ltd. for conversion to oil service. This transfer and conversion, if approved, could result in an annual average capacity reduction on the Mainline of approximately 0.5 Bcf/d. The Board approved the facilities transfer on 9 February 2007, however the TransCanada Keystone application for the construction of the requested oil facilities is still before the Board.

The volumes shown in Figure 10 are the average monthly throughput on TransCanada's Foothills Pipeline (Sask.) compared with capacity. This pipeline transports western Canadian gas supply to

**FIGURE 9**

***TransCanada Mainline Throughput vs. Capacity***

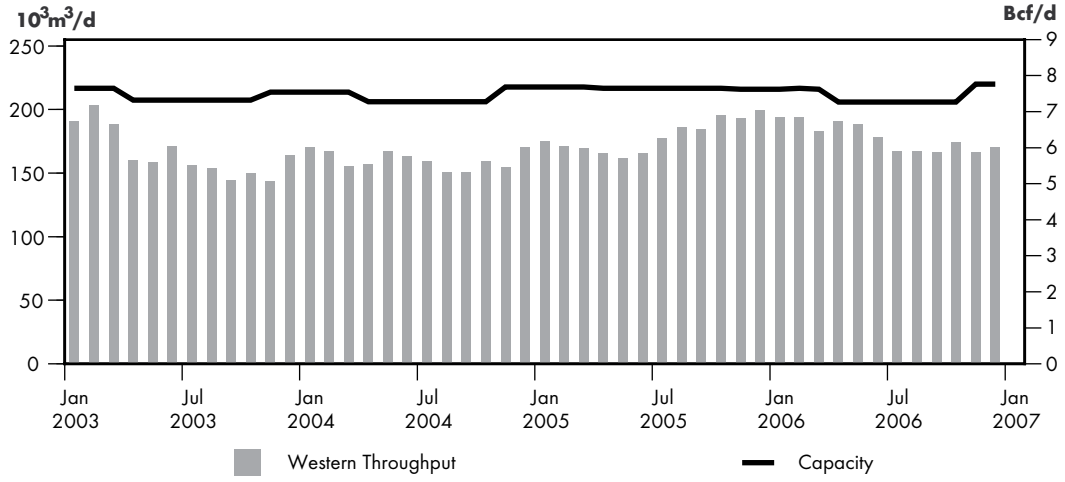
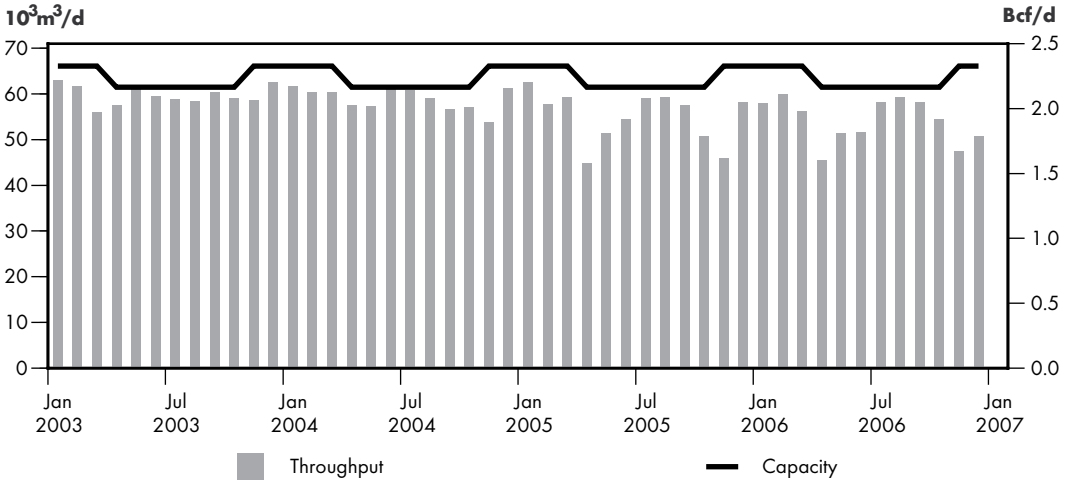



**FIGURE 10**

***Foothills Pipeline (Sask.) Throughput vs. Capacity at Monchy***



markets in the U.S. Midwest through a connection with the Northern Border Pipeline Ltd. (Northern Border) at Monchy, Saskatchewan. The Foothills (Sask.) throughput has displayed distinct seasonal patterns in recent years, with annual average capacity utilization running at 88 percent in 2006, down from an average of 94 percent in 2003. Throughput on the Foothills Pipeline (Sask.) runs fairly close to capacity in both the winter and the summer months to meet winter heating demand and to meet summer demand for power generation and storage injection. Throughput subsequently declines in the low-consumption spring and autumn months.

Figure 11 compares the average monthly throughput on Westcoast's Southern Mainline with the capacity on this system between Station 2 and the export point at Huntingdon/Sumas. This figure shows the seasonal nature of throughput on the Southern Mainline with higher volumes being transported during the peak winter months and less during the summer. Contributing factors to the low flows on Westcoast during 2006 and recent years include greater competition with production from the U.S. Rockies region for markets in the U.S. Pacific Northwest, mild winter weather, and increased hydro power generation in B.C. and the U.S. Pacific Northwest.

Figure 12 shows the average monthly capacity and throughput on the TransCanada B.C. System, which primarily serves California. The annual average capacity utilization in 2006 was 64 percent, slightly higher than in previous years. There exists spare capacity on this pipeline to export gas through Kingsgate, B.C. California market players have transportation options enabling them to access supply from the Rocky Mountains, San Juan and Permian basins, in addition to the Western Canada Sedimentary Basin (WCSB). This supply competition has reduced imports from the WCSB at Kingsgate.

Figure 13 shows the average monthly throughput on the Alliance system relative to physically available capacity. Alliance offers approximately 1.325 Bcf/d of firm service capacity, and makes any additional capacity available to its contracted shippers pro rata as Authorized Overrun Service (AOS). Available AOS levels are determined on a daily basis and may be used at the cost of fuel only. The total available capacity is variable, depending on such factors as ambient temperature and compressor unit availability (as influenced by maintenance schedules). Alliance's total available capacity has essentially been fully utilized since the commencement of service, with all available firm service contracted on a long-term basis.

**FIGURE 11**

***Westcoast Mainline Throughput vs. Capacity***

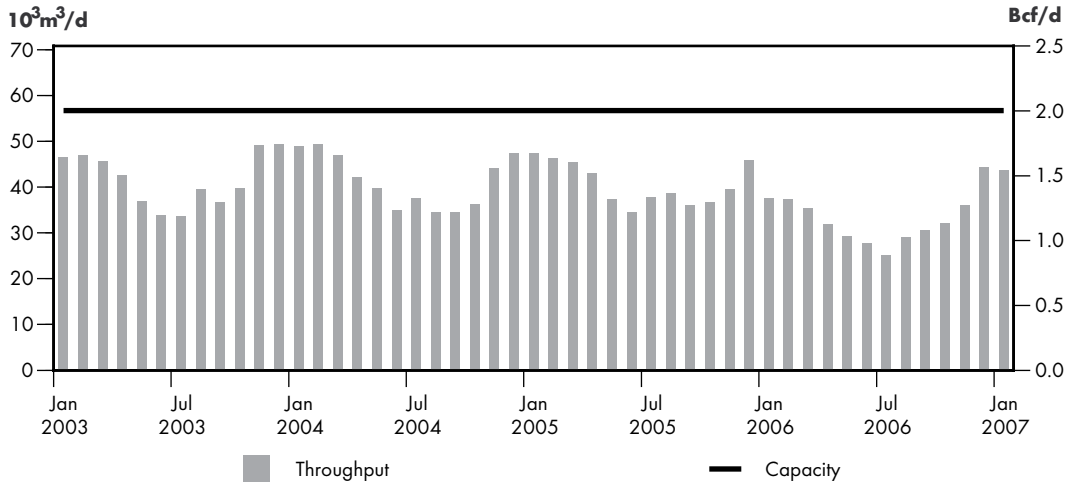


Figure 14 compares the average monthly throughput and capacity on the TransQuébec & Maritimes system (TQM) which delivers gas from the TransCanada Mainline at Saint-Lazare, Quebec to Québec City and the East Hereford export point in Quebec (New Hampshire state border). More volumes are transported during winter months, highlighting the use of natural gas for heating in this region and the seasonal nature of the throughput on this pipeline. With average annual capacity utilization of around 60 percent, there has historically been spare capacity on this pipeline, particularly in summer months. However, with the limited compression on the system needed to meet TQM's delivery pressure at the East Hereford export point, the available spare capacity is very sensitive to the actual load distribution on the pipeline. In 2006, TQM undertook a system expansion to serve an incremental demand arising from the construction of a new gas-fired power plant in Quebec.

Figure 15 compares the average monthly capacity and throughput on the M&NP pipeline. The annual average capacity utilization has declined from about 92 percent in 2002 to an average of about 68 percent in 2006. The reduction in this pipeline's capacity utilization stems from declining natural

**FIGURE 12**

***TransCanada B.C. system Throughput vs. Capacity at Kingsgate***

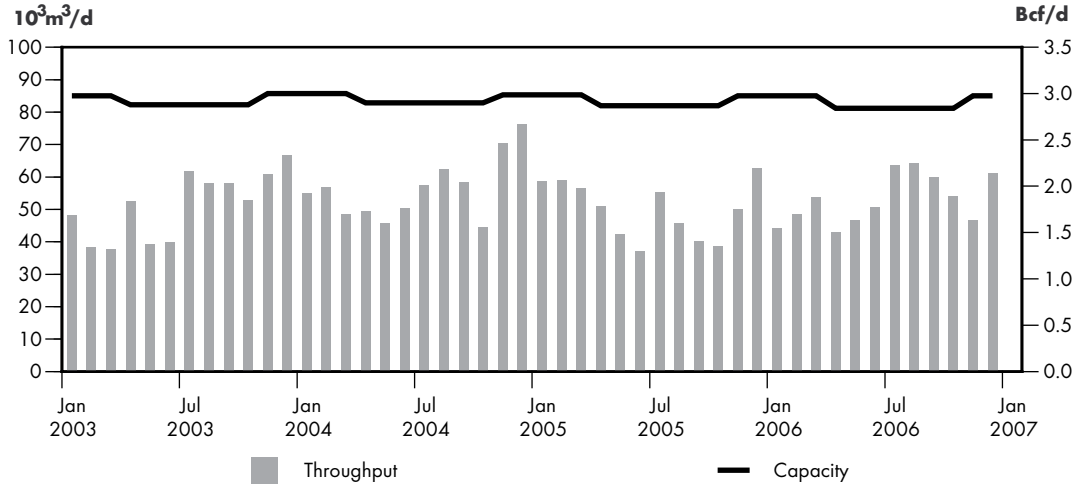



**FIGURE 13**

***Alliance Throughput vs. Capacity***

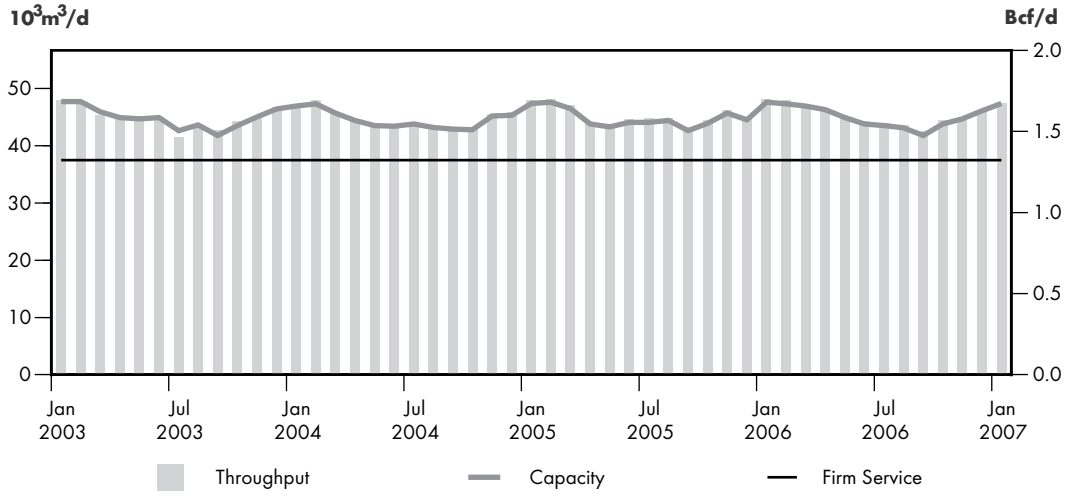


**FIGURE 14**

***Trans Québec and Maritimes Throughput vs. Capacity***

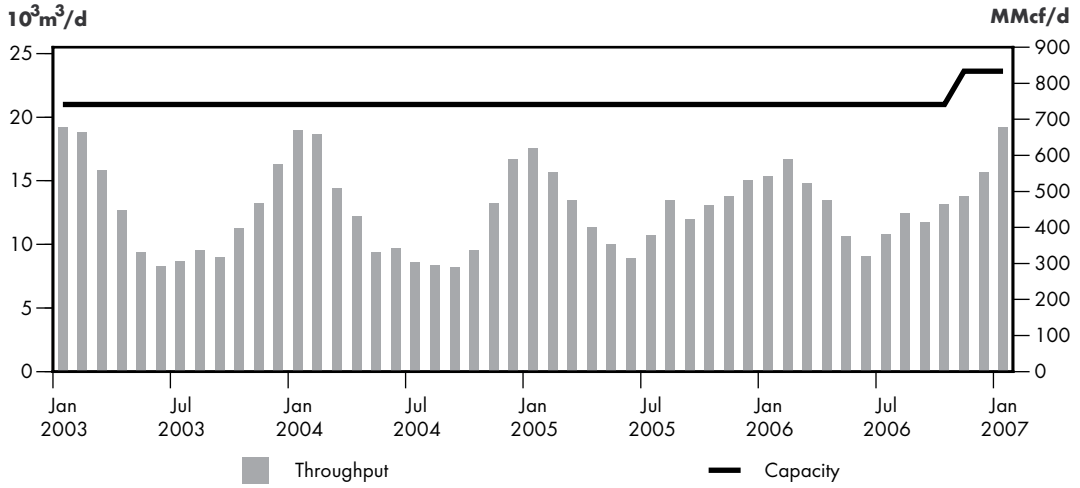
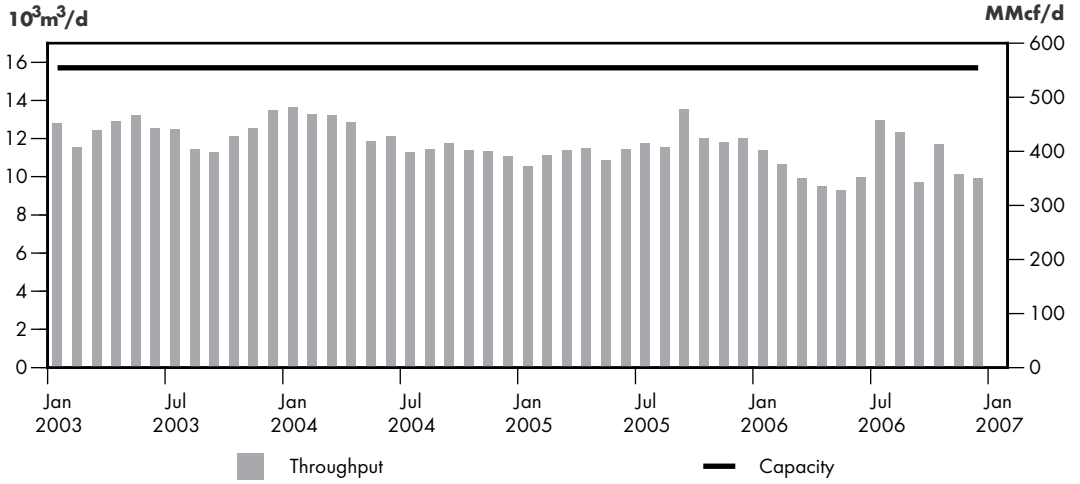



**FIGURE 15**

***Maritimes and Northeast Pipeline Throughput vs. Capacity***




gas production from offshore Nova Scotia. Variations in throughput are primarily related to changes in gas supply as the export demand for gas destined to northeastern U.S. markets is consistently strong. In late 2006, additional compression at the offshore platform was installed to boost deliverability. In addition, a couple of gas supply projects are being considered in the region with the potential to supplement supply.

### *Oil*

Determining the capacity and throughput on an oil pipeline can be complex as there are many factors to be considered: the type of product, product mix, type of batching and pipeline configurations.

The Enbridge system originates in Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba where it joins with the Lakehead system in the U.S. It is the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The Enbridge system also connects

with pipelines that deliver crude oil to Cushing, Oklahoma and the U.S. Gulf Coast. The system consists of many lines transporting crude oil, NGLs and refined petroleum products. Figure 16 illustrates Enbridge throughput versus capacity. In 2006, Enbridge transported roughly 247 000 $m^3/d$ (1.6 MMb/d) of crude oil, petroleum products and NGLs. In the first quarter 2007, Enbridge operated at about 85 percent of capacity. Since the third quarter of 2006, many of its lines have been operating at or near full capacity with some lines in apportionment (see Section 2.3).

Terasen Pipelines (Trans Mountain) Inc., owned by Kinder Morgan, transports crude oil and refined petroleum products from Edmonton, Alberta west to locations in British Columbia, Washington State and offshore. TPTM's current capacity, assuming some heavy crude oil, is 35 700 $m^3/d$ (225 Mb/d). The pipeline has been operating at or near capacity for several years and on many occasions has been under apportionment (See Section 2.3). Figure 17 shows two capacities for the TPTM pipeline; one assumes no shipments of heavy crude oil and the other assumes 15 percent heavy crude oil. When heavy crude oil is shipped, it reduces the capacity of the pipeline. On average, in 2006, 15 percent of TPTM's crude oil receipts at Edmonton were heavy crude oil. In the second quarter of 2007, the TPTM Pump Station Expansion is expected to be in-service. It will add an additional 5 600 $m^3/d$ (35 Mb/d) of capacity.

In February 2006, TPTM applied to the NEB to loop a 158 km segment of its pipeline, extending from Hinton, Alberta to a location near Rearguard, British Columbia. The Project would increase capacity by 6 360 $m^3/d$ (40 Mb/d). An oral public hearing was held in August 2006 and the Board approved the application in October. The targeted in-service date is the fourth quarter 2008.

In the first quarter of 2007, TPTM operated at approximately 77 percent of capacity (see Figure 17). Despite operating at below its nameplate capacity of 285 Mb/d, TPTM was under apportionment in January and February of 2007. Growing oil sands production, strong demand from refiners in Washington State and continuing growth in crude oil shipments off the Westridge Dock are contributing to apportionment on the TPTM system. As well, in the summer of 2006, a temporary shutdown of the Prudhoe Bay field in Alaska, because of pipeline corrosion, resulted in increased throughput on the TPTM pipeline.

During the past several years, Express has been operating at capacity. Despite a major expansion in 2005 that added 16 000 $m^3/d$ (100 Mb/d), bringing the capacity to 44 900 $m^3/d$ (280 Mb/d) there has

**FIGURE 16**

***Enbridge Pipeline Throughput vs. Capacity***

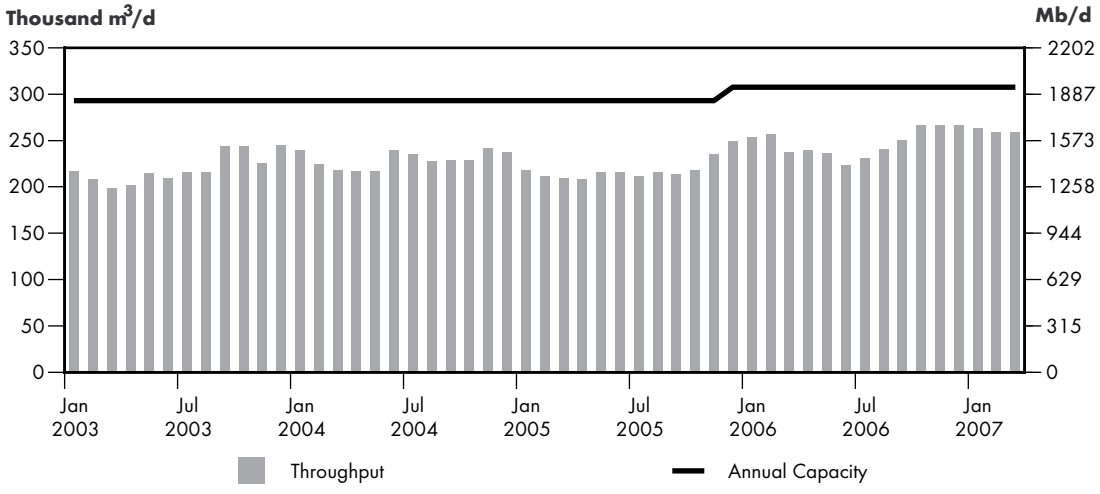


**FIGURE 17**

***Teresen Pipelines Trans Mountain (TPTM) Throughput vs. Capacity***

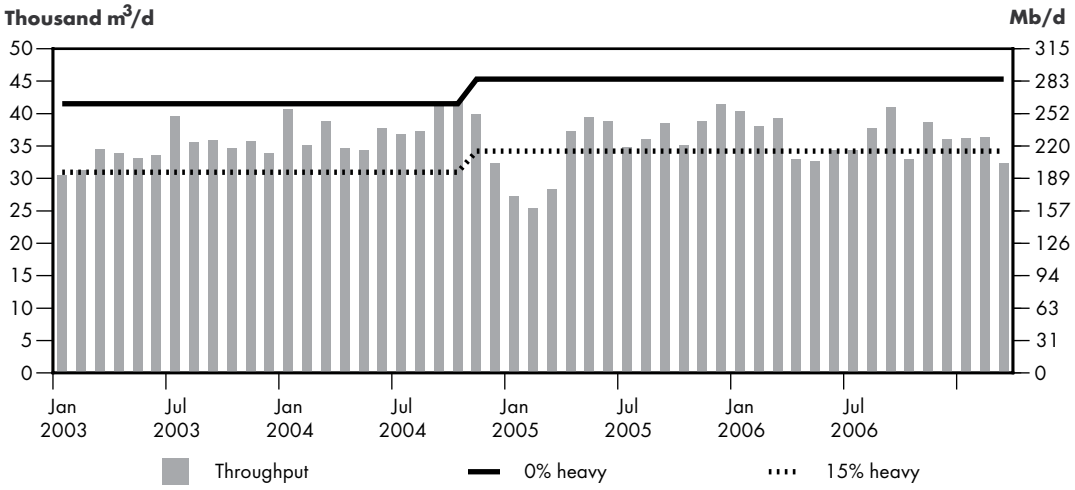
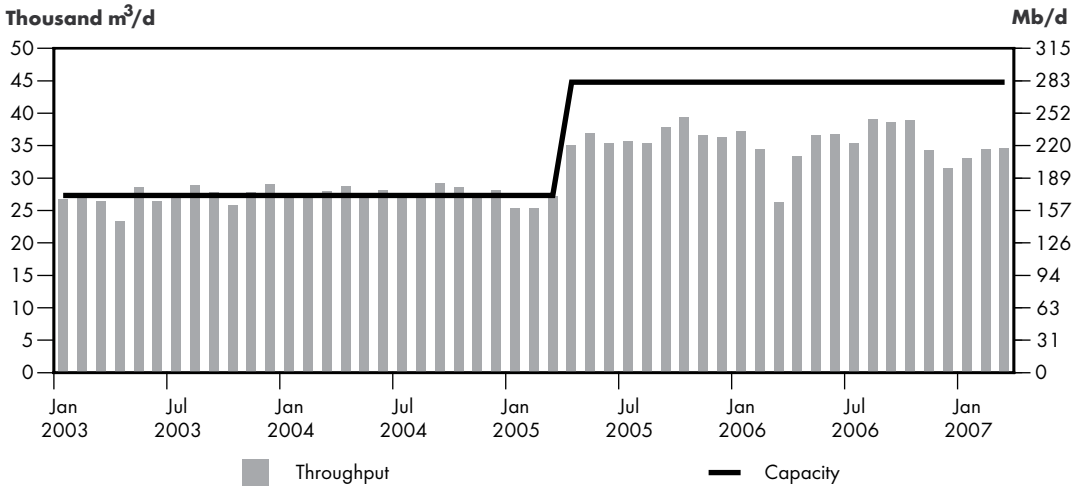



**FIGURE 18**

***Express Throughput vs. Capacity***



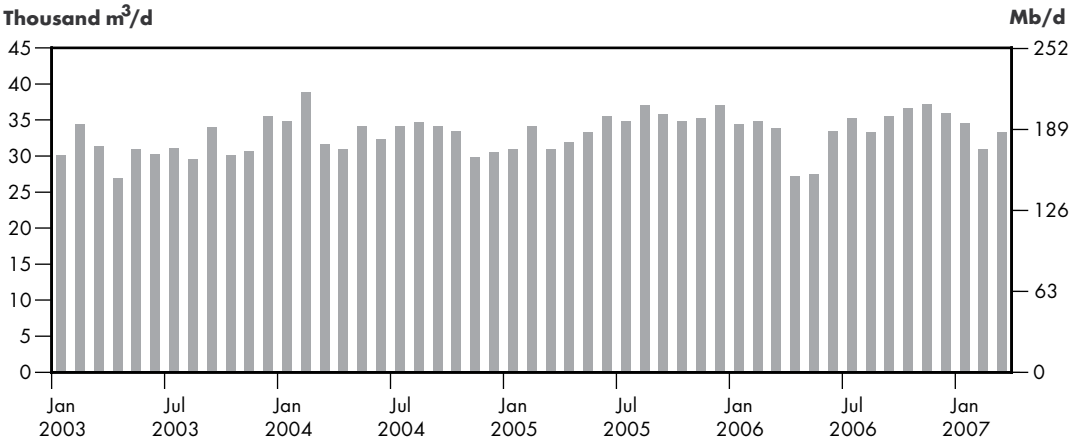

been apportionment on the pipeline in 2006. Express is the only crude oil pipeline in western Canada that operates under long-term take-or-pay agreements with its shippers for a majority of its capacity.

In the first quarter 2007, Express operated at approximately 76 percent of capacity (Figure 18). Crude oil shipments have been reduced at Hardisty on the Express pipeline because of continuing apportionment downstream on the Platte Pipeline in the U.S.

Trans-Northern Pipelines Inc. is a refined petroleum products pipeline. The pipeline transports refined petroleum products west from Montreal to north Toronto and operates bi-directionally between Toronto and Oakville, Ontario. TNPI also transports refined products from Imperial Oil Limited's (Imperial) refinery in Nanticoke, Ontario west to Toronto. In the first quarter of 2007, TNPI throughput averaged 33 000 $m^3/d$ (208 Mb/d) of petroleum products. The pipeline is generally operating at capacity.

**FIGURE 19**

***Trans-Northern Pipelines Inc. Throughput***




During the first quarter 2007, there was a fire at Imperial's refinery located in Nanticoke. This resulted in the refinery ceasing operations and a subsequent gasoline and diesel shortage in southern Ontario and Quebec. TNPI throughput was reduced during this period.

Calculating TNPI's capacity is difficult due to multiple delivery locations and the different capacities on each line segment.

## 2.3 Apportionment

Oil pipelines typically operate as common carriers. Common carriers require shippers to nominate their volumes for delivery into a pipeline on a monthly basis without a contract for pipeline capacity. When shippers nominate more oil or oil products in a given month than the pipeline can transport, shippers' volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations and refinery maintenance. There are a few pipelines in Canada that operate all or part of the pipeline with long-term shipper take-or-pay agreements, including Express, Enbridge Line 9 and TNPI.

Some recent apportionment levels for Enbridge, TPTM and Cochin are discussed below.

### *Enbridge*

Enbridge's Lines 3 and 4 are dedicated to transporting heavy crude oil and Line 2 transports light crude oil. Historically, Lines 2 and 4 were heavy crude oil lines; however, following the Line 2/3 line swap in the fourth quarter 2005, Line 2 transitioned from a heavy crude oil line originating at Hardisty, Alberta to a light crude oil pipeline originating in Edmonton. In addition, Line 3 made the transition from a light crude oil pipeline originating at Edmonton to a heavy crude oil pipeline originating at Hardisty. This swap resulted in a net heavy capacity increase of 39 000 $m^3/d$ (246 Mb/d) and a corresponding decrease of light capacity of 18 400 $m^3/d$ (116 Mb/d). This added some much needed capacity to accommodate growing heavy crude oil output from the oil sands.

Table 1 indicates apportionment and throughput from August 2006 to March 2007. In the fourth quarter 2006, throughputs were very high on the Enbridge system and there was apportionment on Lines 5, 6 and 14. There has not been apportionment on the Enbridge system in the first quarter 2007; however, many of the Lines have been either fully subscribed or operating at maximum capacity.

**TABLE 1**

***Enbridge Apportionment***

| | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 |
|---|---|---|---|---|---|---|---|---|
| Apportionment | 0% | 0% | 0% | 0% | 8%* | 0% | 0% | 0% |
| Throughput ($10^3m^3$/d) | 240.7 | 251.0 | 266.3 | 266.8 | 266.7 | 263.6 | 258.9 | 259.7 |

* Lines 5, 6 and 14

Capacity is also constrained due to a downstream bottleneck at Superior, Wisconsin because the capacity out of Superior is 230 000 $m^3$/d (1.4 MMb/d), less than the up to 300 000 $m^3$/d (1.9 MMb/d) that Enbridge can deliver to that destination.

Enbridge throughput fell slightly in the second quarter 2006 as a result of outages at two oil sands plants. In the third quarter 2006, throughput increased reflecting capacity expansions and increases in oil sands production. In addition, competitively priced western Canadian crude oil displaced some import volumes that would typically be delivered to the Sarnia area on Enbridge's Line 9. It is expected that increasing production from the oil sands in 2007 could contribute to further apportionment on Enbridge.

Enbridge's Line 9 has a capacity of 38 150 $m^3$/d (240 Mb/d) and transports crude oil from Montreal, Quebec to refineries located at Nanticoke and Sarnia, Ontario. There was no apportionment on Line 9 between August 2006 and February 2007. Shipments on Line 9 have been trending downward, particularly since the closure of Petro-Canada's refinery in Oakville in the second quarter of 2005. In 2006, the reduction in throughput was a result of maintenance activity at Imperial's Sarnia refinery in the second quarter and an increase in deliveries of more competitively priced western Canadian crude oil.

In January 2007, Enbridge Pipelines (Westspur) Inc. applied to the National Energy Board pursuant to section 52 of the *National Energy Board Act* (NEB Act), for the Alida, Saskatchewan to Cromer, Manitoba Capacity Expansion Project. The Enbridge Westspur pipeline was built in 1956 as an oil trunkline to transport crude oil. The pipeline also transports NGL from a gas processing plant in Steelman, Saskatchewan. Westspur interconnects with the Enbridge export lines at Cromer where the crude oil accesses the downstream markets.

The project proposes to construct a new 60 km, 168.3 mm (6 inch) pipeline to transport NGL from Alida to Cromer and convert the existing pipeline from its current NGL service to crude oil. Capacity on the existing line would increase from 25 000 $m^3$/d (157 Mb/d) to 34 600 $m^3$/d (218 Mb/d)

***Terasen Pipelines (Trans Mountain) Inc.***

Apportionment on TPTM is calculated separately for domestic destinations, export destinations and Westridge Dock destinations (as shown in Table 2 as Domestic, Export and Dock). Apportionment between August 2006 and March 2007 reflects continuing increases in oil sands supply and strong demand for Canadian crude oil in the Washington State area. In addition, increases in heavy crude oil shipments, result in a decrease in the capacity on the TPTM system. With weakness in the price of West Texas Intermediate (WTI) and discounting of Canadian crude oil because of over-supply in the Cushing area, coupled with a lack of take away capacity in that region, producers may increasingly look to the higher priced west coast and offshore markets for improved netbacks.

**TABLE 2**

***TPTM Apportionment***

| | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 |
|---|---|---|---|---|---|---|---|---|
| Apportionment | | | | | | | | |
| Domestic | 0% | 8% | 0% | 14% | 35% | 22% | 10% | 0% |
| Export | 0% | 0% | 0% | 0% | 12% | 0% | 0% | 0% |
| Dock | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Throughput ($10^3m^3$/d) | 37.6 | 41.0 | 32.9 | 38.6 | 35.9 | 36.2 | 36.3 | 32.4 |

In April 2006, the NEB approved a request from Kinder Morgan Inc. to include a Westridge Dock Premium in the TPTM tariff to allocate capacity to the Westridge Dock. In the Board's decision, it directed Kinder Morgan to set up a deferral account for any premiums received and refund the money to toll payers in the following calendar year. The Board directed Kinder Morgan to publish the aggregate bid premium information on a quarterly basis; and, it approved the extension of the bid premium process until the start-up of the pump station expansion (PSE).

### *Cochin*

In January 2007, Kinder Morgan Energy Partners purchased the remaining approximately 50 percent of Cochin Pipeline that they did not already own from BP Canada Energy Company (BP). Prior to the purchase, BP operated the pipeline and owned a slight majority stake.

The Cochin pipeline is the largest and longest NGL pipeline in Canada. In the past, it has transported propane, ethane, ethylene and butane, although no butane has been shipped since 2002. Ongoing maintenance work on the pipeline has affected the available capacity; however, (Table 3) there has not been apportionment on Cochin since summer 2005 when the pipeline was forced to unexpectedly shutdown for immediate repairs.

Since March 2006, Cochin has operated at a voluntary pressure reduction due to a defect found in the U.S. portion of the pipeline. This pressure restriction, not to exceed 900 psi, applies to the entire line from Fort Saskatchewan, Alberta to Windsor, Ontario and is in effect through at least to the fall of 2007. Ethylene shipments, because of its high vapour pressure, have been suspended until further notice.

Cochin also announced on 8 February 2007 that it would be suspending delivery of ethane effective 31 March 2007, while the company evaluates its pipeline integrity issues and the related capital expenditures. Cochin will continue to ship propane to all destinations on its system. Shippers were also informed that the pipeline would operate at reduced pressure through at least Fall 2007. With only propane in the line, the average capacity is expected to be around 9 500 to 11 100 $m^3$/d (60 Mb/d to 75 Mb/d). Once the pressure restrictions are lifted, capacity is likely to return to 16 700 $m^3$/d (105 Mb/d).

**TABLE 3**

***Cochin Apportionment***

| | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 |
|---|---|---|---|---|---|---|---|---|
| Apportionment | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Throughput ($10^3m^3$/d) | 7.6 | 5.6 | 9.5 | 7.6 | 10.9 | 7.7 | 7.4 | 6.5 |

## 2.4 Chapter Summary

Overall, the examination of throughput and capacity on NEB-regulated natural gas pipelines in section 2.2 shows that pipeline capacity is adequate across the country although there may be occasions of short-term limitation at some points depending upon markets, storage and seasonal shifts. The demand for natural gas varies seasonally and, as a result, the flow of natural gas and utilization of some Canadian pipelines can be variable. Where available, the use of storage helps to reduce the variation in flows and allows pipeline capacity to be used more efficiently and at more stable utilization levels.

Although natural gas supply from new sources continue to be added to supplement declining conventional supply from the WCSB, growing demand within Western Canada has resulted in some excess capacity on pipelines transporting gas from the region. The existence of some excess capacity has provided suppliers with the flexibility to access markets of their choice at most times. Natural gas pipeline projects in 2006 were mainly directed towards providing connection to new supplies and addressing bottlenecks in the market area.

While capacity utilization indicators show that there was spare capacity on some oil and petroleum products pipelines in 2006, this was partially due to facility outages reducing the amount of crude oil or products to be transported. Despite operational challenges in the oil sands industry in early 2006, bitumen production levels have increased over the previous year as problems were rectified and new expansions were brought on-line. The production growth in the oil sands and continued strong demand in the U.S. has resulted in very high utilization of capacity on Canadian oil pipelines. In addition, a slight recovery in conventional crude oil production in western Canada, North Dakota and PADD IV are challenging pipeline systems that operate at close to capacity and are in apportionment at times. Overall, growing oil sands production has kept the utilization and demand for oil pipeline capacity very high.

In the past, the lack of excess pipeline capacity and available markets to process heavier crude oil has resulted in the light-heavy price differential widening as illustrated in Figure 8. In the first quarter 2006, the differential widened to 42 percent. However, this has not been the case in 2007, where the differential has narrowed to a two and a half year low reflecting the effect of additional markets accessed through the Syncrude upgrader expansion and the Spearhead and Mobil pipeline reversals which deliver western Canadian crude oil to Cushing and the U.S. Gulf Coast, respectively. This should provide continuing strength to heavy crude oil prices through the summer as demand will increase in response to the upcoming asphalt season.

# LOOKING AHEAD – PROPOSED PIPELINES

## 3.1 Natural Gas

In the coming years, it is expected that demand for natural gas in North America will continue to outpace the growth in North American domestic supplies. In Canada, natural gas supply from new sources such as frontier regions, LNG, and coalbed methane will be increasingly required to supplement declining supply from conventional sources from the WCSB and Sable Island to meet growing demand. In addition, increased consumption for oil sands development in Alberta, and electricity generation in Ontario, are expected to drive significant incremental Canadian requirements for natural gas. The Canadian oil sands projects are a large and growing market for natural gas in both the generation of electricity and steam. Steam is used for in situ oil production and to upgrade bitumen into synthetic blends. In addition, new gas-fired electrical generation will likely be needed to help displace the use of existing coal-fired electricity generation in Ontario.

Although there were few newly announced natural gas pipeline projects in 2006, there was notable progress in several of the natural gas pipeline projects reported last year. Table 4 below, summarizes the announced proposals on NEB-regulated pipelines. These projects reflect the industry's expectations regarding changes in natural gas supply and demand in coming years, and the industry's outlook on the potential adjustments in Canadian pipeline infrastructure in order to:

- connect incremental gas supply from new sources in the north or from new terminals for receiving liquefied natural gas;
- expand pipeline capacity to growing markets in eastern Canada and the U.S. Northeast; and
- transfer pipeline assets from gas service where adequate capacity may exist, to oil transportation service where demand and value for new capacity is higher.

### *Liquefied Natural Gas*

A key supply source for North America is expected to be the rapidly developing global LNG market. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. While economies of scale advances in liquefaction and transportation have enabled the use of LNG as a cost competitive source of gas supply in North America, those cost efficiencies are starting to be lost to higher input and construction costs. In anticipation of growing natural gas requirements in North America, there are numerous proposals to expand existing U.S. terminals and construct new LNG receiving facilities, including several proposed projects in Canada as summarized in Figure 20.

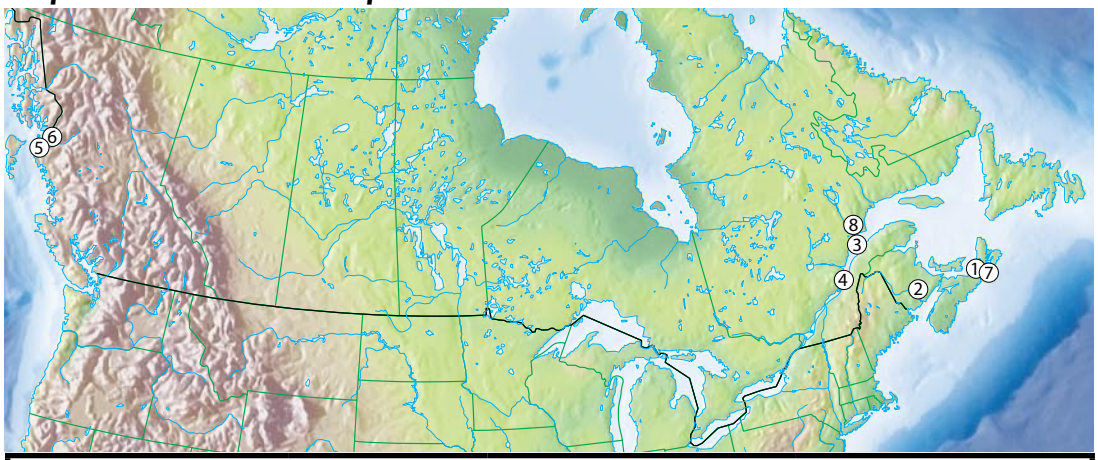
## TABLE 4

### *Canadian Natural Gas Pipeline Proposals — 2006*

| Pipeline | Location | Capacity Increase (Bcf/d) | Proponents' Estimated Completion Date | Market Impacted |
|---|---|---|---|---|
| TransCanada PipeLines Limited – 2007 Eastern Mainline Expansion | Ontario, Québec | 0.377 | Late 2007 | Central Canada Northeastern U.S. |
| TransCanada Pipelines Limited and TransCanada Keystone GP Ltd. | Saskatchewan, Manitoba | -0.5 | 2009/10 | Transfer and conversion of gas pipeline assets to oil transportation service |
| Mackenzie Gas Pipeline | Mackenzie Delta, Northwest Territories to Alberta | 1.2 | 2014 | North America |
| Emera Brunswick Pipeline | New Brunswick | 0 .75 | 2008 | Atlantic Canada, Northeastern U.S. |
| EnCana – Deep Panuke Pipeline | Nova Scotia | 0 .3 | 2010 | Atlantic Canada, Northeastern U.S. |
| TransCanada PipeLines Limited / Trans Québec & Maritimes Pipeline Inc. – Gros Cacouna and Rabaska | Québec | 0.5<br>0.5 | 2009/10 | Central Canada Northeastern U.S. |

## FIGURE 20

### *Proposed Canadian LNG Projects*




| Location | Terminal | Company | Capacity (Bcf/d) | Proposed on Stream Date |
|---|---|---|---|---|
| 1. Goldboro, Nova Scotia | Maple LNG | 4 Gas BV and Suntera Canada Ltd. | 1.0 | 2009 |
| 2. Saint John, New Brunswick | Canaport LNG | Repsol YPF and Irving Oil | 0.8 | 2008 |
| 3. Rivière-du-Loup, Quebec | Gros Cacouna LNG | Petro-Canada and TransCanada Pipelines Ltd. | 0.5 | 2009 |
| 4. Québec City, Quebec | Rabaska | Gaz Métro, Enbridge and Gaz de France | 0.5 | 2009 |
| 5. Ridley Island, British Columbia | WestPac LNG | WestPac Terminals Inc. | 0.3 | 2009 |
| 6. Emsley Cove, British Columbia | Kitimat LNG | Gavelston Energy | 0.6 | 2010/11 |
| 7. Point Tupper, Nova Scotia | Statia LNG | Statia Terminals Canada Partnership | 0.5 | n/a |
| 8. Saguenay, Quebec | Énergie Grande-Anse | Saguenay Port Authority and Énergie Grande-Anse Inc. | 1.0 | n/a |

However, there is uncertainty around the number of LNG terminals that will be built in Canada as well as the potential effects that imported LNG will have on gas markets and the pattern of natural gas flow. The Canaport LNG facility in Saint John, New Brunswick is currently under construction and is scheduled to start service in 2008. Additional pipeline connections will also be required in most cases to connect the proposed LNG receiving terminals to existing natural gas pipeline infrastructure and natural gas markets.

These potential changes in Canada's natural gas supply and demand have important implications to both existing pipeline transportation systems and proposed new pipeline and LNG projects. Facilities which connect significant new supply from new sources such as the North and LNG or significant changes in regional demand (e.g. oil sands in Alberta and electricity generation in Ontario) will have the potential to influence markets and alter the utilization and gas flow on existing pipelines. In turn, these changes may impact the tolls and associated costs in using those pipelines. For example, introduction of new gas supply in Eastern Canada could result in greater utilization or flow reversals in regional pipelines and may also affect the flow of supply from traditional sources and pipelines. Similarly, greater demand in Alberta or Ontario can also alter the flow and availability of natural gas to adjacent regions.

In addition, the expected introduction of LNG close to Canadian markets has heightened the awareness of potential issues related to gas quality. Consequently, pipelines will need to work closely with their customers to establish gas quality standards and monitoring processes to ensure compatibility with existing equipment and end-use operation.

## 3.2 Oil

The expected growth in oil sands production is an increasingly important consideration to the pipeline industry as it determines which incremental markets to serve and how to expand the pipeline system efficiently since not all refineries are able to process a full range of crude oil types. Proposed refinery expansions and new construction in eastern Canadian are located close to the major petroleum product markets in the U.S. Northeast and have access to foreign crude oil supplies in addition to east coast offshore production. Other refineries in central Canada and the United States are proposing modifications which will enable them to process the heavier crude oil from oil sands production.

Looking to the future, the NEB expects that Canadian crude oil production will continue to increase, placing greater demands for transportation capacity to connect new supply and markets. Consequently, there are a number of proposals to provide additional pipeline capacity to transport crude oil and to provide additional supplies of diluent required to support growing oil sands operations. This additional pipeline capacity could enhance access to markets and increase market penetration. The North American demand for oil and refined products is also expected to increase, triggering a number of proposals for refinery expansions and the construction of new refineries in Canada and in the United States.

Table 5 provides a summary of the numerous proposals to expand or construct new oil pipeline capacity in Canada. These reflect the industry's outlook on growing oil sands production and the need for additional pipeline capacity to enhance market access. These proposals include pipelines to transport western Canadian crude oil to the west coast for delivery to Washington State and offshore markets, to the U.S. Midwest and southern PADD II and to the U.S. Gulf Coast (PADD III), and to provide new sources of diluent required for growing oilsands production. It is estimated that these pipeline projects comprise over $23 billion in spending.

**TABLE 5**

***Announced and Proposed Canadian Oil Pipelines and Expansions***

| Pipeline | Potential Filing Date | Capacity Increase (Mb/d) | Proponents' Estimated Completion Date | Market |
|---|---|---|---|---|
| Terasen (TPTM) | | | | |
| Pump Station Expansion | Filed Feb 2006; Approved in Oct 2006 | 35 | April 2007 | PADD V |
| Anchor Loop – TMX1 | Approved in Oct 2006 | 40 | Nov. 2008 | Offshore/Far East |
| Southern Option | | | | |
| TMPL TMX2 | N/A – Open Season unsuccessful | 100 | Mid 2010 | PADD V |
| TMPL TMX3 | N/A | 300 | 2012 | Offshore/Far East |
| Northern Option (TMX North) | N/A | 400 | 2012 (uncertain) | PADD V Offshore/Far East |
| Enbridge Gateway (oil/diluent) | N/A | 400/150 | Between 2012 and 2014 | PADD V Offshore/Far East Alberta (diluent line) |
| Pembina Spirit (diluent) | N/A | 100 | April 2009 | Alberta |
| Enbridge Southern Lights | Filed 9 March 2007 | | 2010 | Alberta |
| Diluent return line | | 186 | | PADD II |
| Line 2 Expansion (oil) | | | | PADD II |
| Edmonton to Cromer | | 47 | | PADD II |
| Cromer to Clearbrook | | | | PADD II |
| TCPL (Keystone) | Filed Section 52 – Dec 2006 | 435 | 4Q2009 | Southern PADD II and PADD III |
| Expansion / Extension to Cushing, OK | | 155 | 4Q2010 | |
| Alberta Clipper | Filed May 30 2007 | 450 | July 2010 | Southern PADD II |
| Expansion | N/A | 350 | N/A | |
| Altex Energy | 2008 | 250 | 2012 | PADD III |
| Enbridge Spearhead | Open Season (2 Mar -2 April 2007) | 65 | 2009 | Southern PADD II |
| Expansion | | 100 | 2011 | |
| Spearhead Looping | FERC only | | | |
| Enbridge (Southern Access) | FERC only | 315 | | Midwest/Southern PADD II |
| Phase I | | 120 | 2008 | |
| Phase II | | 148 | 2009 | |
| Phase III Extension | | 47 | N/A | |

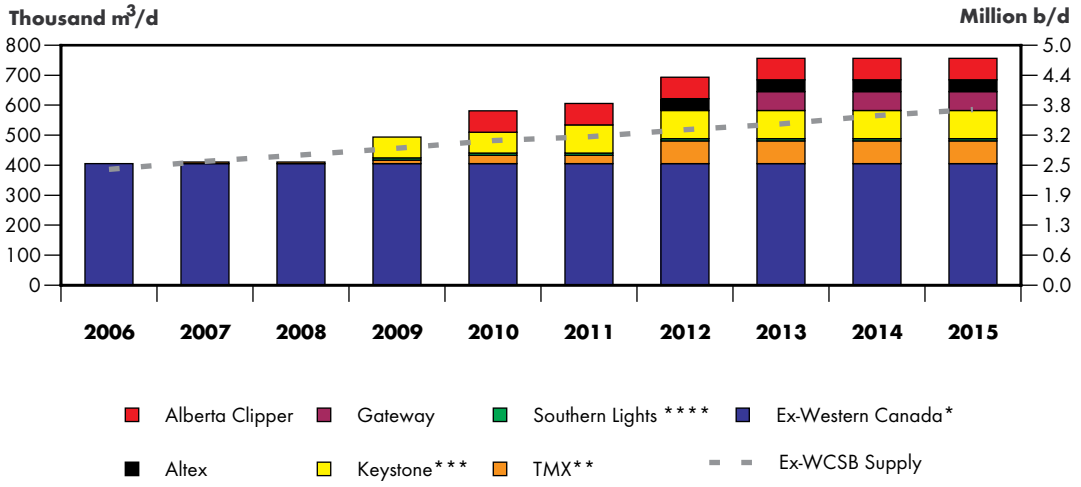
In the past year, the Board has also approved two crude oil pipeline related applications. In October 2006, the Board approved an application filed by TPTM to loop a portion of its pipeline between Hinton, Alberta and Rearguard, British Columbia. The project will increase capacity by 6 360 $m^3/d$ (40 Mb/d). It is expected to be in service by third quarter 2008.

In June 2006, the Board received an application by TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd. to transfer a portion of TransCanada's natural gas pipeline and associated facilities to crude oil service. The Keystone Project is a proposal to convert existing natural gas facilities in Canada and to construct a new crude oil pipeline in the U.S. to transport crude oil from Hardisty, Alberta to Patoka, Illinois. It would have a capacity of 69 000 $m^3/d$ (435 Mb/d) and is expected to be in-service in 2009 if approved. The Board approved the facilities transfer on 9 February 2007; however the TransCanada Keystone application for the construction of new oil facilities is still before the Board.

Looking beyond 2006, Figure 21 illustrates the NEB's forecast of crude oil production and the anticipated pipeline capacity available to transport crude oil and products from Western Canada on existing and proposed new facilities. This chart highlights that oil pipeline capacity is expected to be very tight in the next few years. It is expected that apportionment will occur in the fourth quarter 2007 and that this may be an issue for the next 18 months. As indicated by the figure, between now and 2009 crude oil pipelines out of Western Canada are expected to operate at capacity. The upstream industry is working together with pipeline companies to develop initiatives to reduce the impacts and/or eliminate apportionment. In 2009, TPTM would have an additional 12 000 $m^3/d$ (75 Mb/d) of capacity with its pumping station expansion and the looping; Southern Lights could add an additional 7 500 $m^3/d$ (47 Mb/d) to the Enbridge system from Cromer, Manitoba; and Keystone could be in-service if its application were approved by the Board.

**FIGURE 21**

***Proposed Oil Pipeline Projects & NEB Forecast of Crude Oil Production***




* Total current crude oil pipeline capacity out of the WCSB assuming maximum heavy oil volumes.

** Pump Station expansion of 35 Mb/d by 2007 and looping 40 Mb/d by 3Q2008. TMX North would expand capacity by an additional 400 Mb/d but is not shown here.

*** Keystone could be expanded by 155 Mb/d and extended to Cushing, Oklahoma by 4Q2010

**** Net crude oil capacity increase of 47 Mb/d by 4Q2008

# PIPELINE TOLLS & SHIPPER SATISFACTION

The Board utilizes a number of indicators to assess whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). This includes monitoring the stability of pipeline tolls as indicated through year-to-year variations in a benchmark toll for each of the major NEB-regulated pipelines; and direct shipper feedback received through response to the NEB's annual survey on pipeline services and via formal complaints. In addition, the frequency and acceptance of negotiated toll settlements, and the development of new or enhanced pipelines services are important indicators that there is alignment between the interest of pipeline companies and their shippers.

Historically, revenue requirements have been established using cost of service methodology, with some components for the return on and of invested capital. The revenue was then assigned to various rate categories and cost drivers for conversion into unit rates, or tolls. The revenue requirement and the toll setting methodology were matters for adjudication before the Board.

## 4.1 Negotiated Settlements

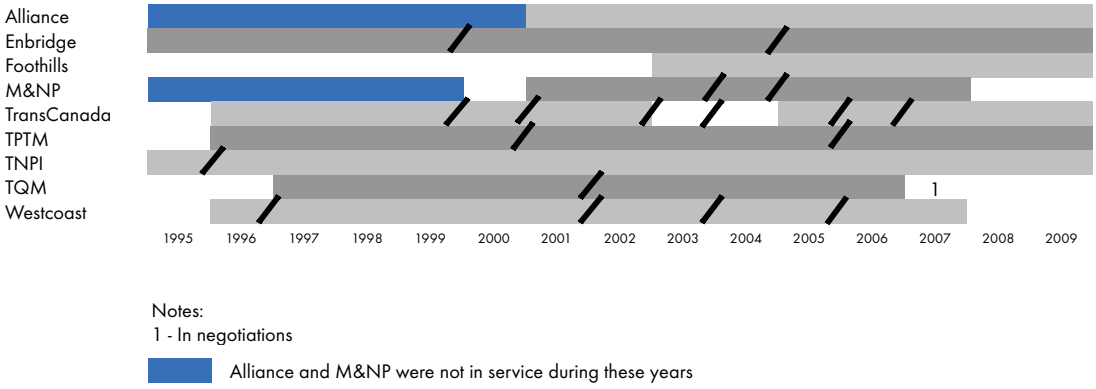
To improve the effectiveness of the regulatory process, the Board has supported the use of negotiated settlements since the mid-1980s as an alternative to toll hearings. In September 1988, the Board issued its first Guidelines for Negotiated Settlements. These guidelines were subsequently updated in August 1994 and revised again in June 2002 to provide flexibility when addressing contested settlements. With increasing use of negotiated settlements, adversarial hearings before the Board on tolls are becoming less frequent. Most of the pipeline companies still rely on cost of service methodology as a framework for the negotiated settlements.

As shown in Figure 22, all of the major pipelines regulated by the Board were operating under negotiated settlements during 2006. In late 2006, M&NP and its shippers successfully negotiated a one-year toll settlement for 2007. TransCanada has also recently negotiated a five-year settlement for 2007 to 2011 that was approved by the Board in May 2007. TPTM negotiated another five-year deal with its shippers for the years 2006 to 2010. TQM is currently operating under interim tolls which are based on a five-year settlement which expired on 31 December 2006. TQM is in discussion with its shippers regarding tolls for 2007 and future years. Westcoast Transmission and its shippers are currently in the second year of a two-year settlement for 2006 and 2007.

These negotiated settlements have resulted in a reduction in the regulatory burden for parties, both in terms of the time spent in hearings and the associated costs. They have also contributed to a better alignment of interests between pipeline companies and their shippers.

**FIGURE 22**

***Negotiated Settlements Timeline***




Notes:
1 - In negotiations

Alliance and M&NP were not in service during these years

## 4.2 Pipeline Tolls Index

Stable and reasonable tolls are a key area of concern for users of the transportation and an indicator of the system's efficiency. The Board tracks year-to-year variations in tolls; the section below describes movements in the benchmark toll for each of the major pipelines it regulates (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South Export toll). Under cost of service regulation, pipeline tolls can vary from year-to-year for various reasons. For example, a significant expenditure to modify or expand a system to meet shippers' needs could increase or decrease toll levels depending on the specific circumstances. Falling throughput or contract demand leading to lower capacity utilization could lead to a significant toll increase.

### *Natural Gas Pipeline Tolls*

Figure 23 shows indexes of benchmark tolls[4] for TransCanada's Mainline, Westcoast Transmission, Foothills, the TransCanada B.C. System (B.C. System), TQM, M&NP, Alliance, and the GDP deflator[5] all normalized to the year 2006.[6]

The increase in TransCanada's benchmark toll between 1997 and 2004 is mainly attributed to a large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. This toll tracked the GDP deflator fairly closely from 2001 to 2004. However, in 2005 and 2006 the toll fell, primarily due to increased contract demand: it remains below the level that it was in 2000.

Westcoast's tolls were relatively flat until 2004, when this toll increased by over 15 percent due to decontracting of firm services. Further reductions in volumes in 2006 caused a further 32 percent increase in 2006 tolls.

4 The benchmark tolls are: TransCanada Eastern Zone; Westcoast T-South Export; Foothills Zone 9; B.C. System Postage Stamp; TQM Saint Lazare to Trois-Rivières; M&NP Postage Stamp; and Alliance monthly demand toll.

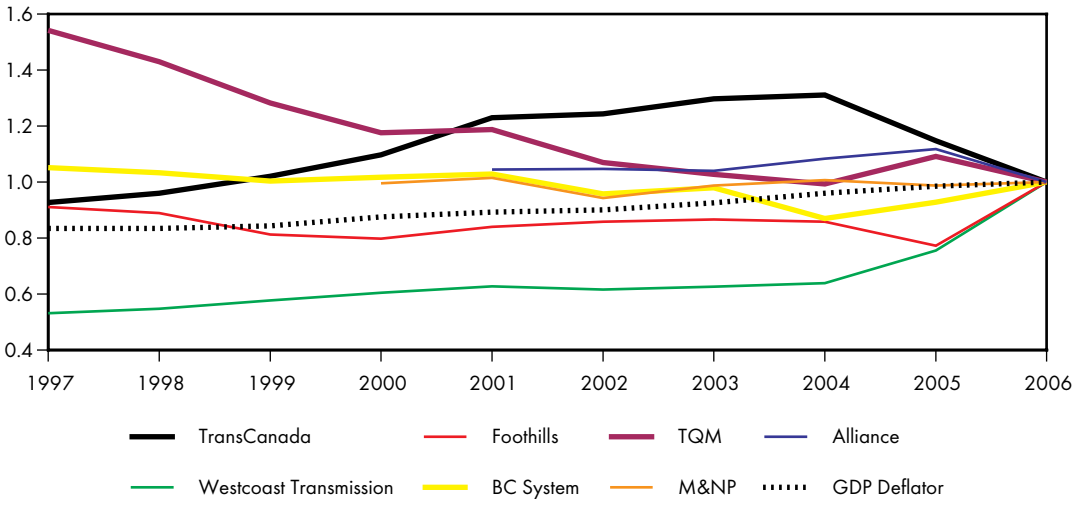
5 The implicit GDP deflator for 2006 is an estimate using actual data for the first half of the year and data estimated by Informetrica for the second half of the year.

6 Differing pipeline distances add to the challenges in comparing tolls between individual pipelines. Some normalization is required. Here the tolls are normalized only with respect to their own changes over time. The year of normalization is arbitrary; the most recent was selected as some tolls are only available for more recent years.

**FIGURE 23**

***NEB-Regulated Natural Gas Pipeline Benchmark Tolls***

**Normalized to 2006 = 1.00**




TQM's benchmark toll is below the 1997-1999 levels. This lower level is partly due to the Portland Natural Gas Transmission System (PNGTS) extension in 1999, which increased throughput over 30 percent from 1998. Foothills benchmark toll dropped in 1999 as a result of a cost-effective expansion of its system, but has increased in 2006 due to lower volumes and the end of the ten year period in 2005 for the deferred tax payback.

The B.C. System benchmark tolls in 2006 were close to the 1997 level. An (over 10 percent) increase in throughput volumes from 2003 reduced the 2004 benchmark toll on the B.C. System. M&NP and Alliance's benchmark tolls have been relatively constant since beginning operations at the end of 1999 and 2000 respectively.

### *Oil Pipeline Tolls*

Figure 24 presents indexed values for the benchmark tolls of Enbridge, TPTM, TNPI, Express and the GDP deflator, normalized to the year 2006.[7]

Enbridge's benchmark toll has risen fairly steadily over the period, growing at a faster pace than the GDP deflator, except for a drop in 2003. The tolls increased the most in 2000, 2004 and 2006. Under its negotiated settlement, Enbridge was able in the following year to recapture the revenue shortfall attributable to the lower throughput. The 2004 increase was primarily due to operating at lower capacity utilization with throughput not filling a recent capacity expansion. Higher fixed costs were spread across relatively lower volumes resulting in higher tolls.

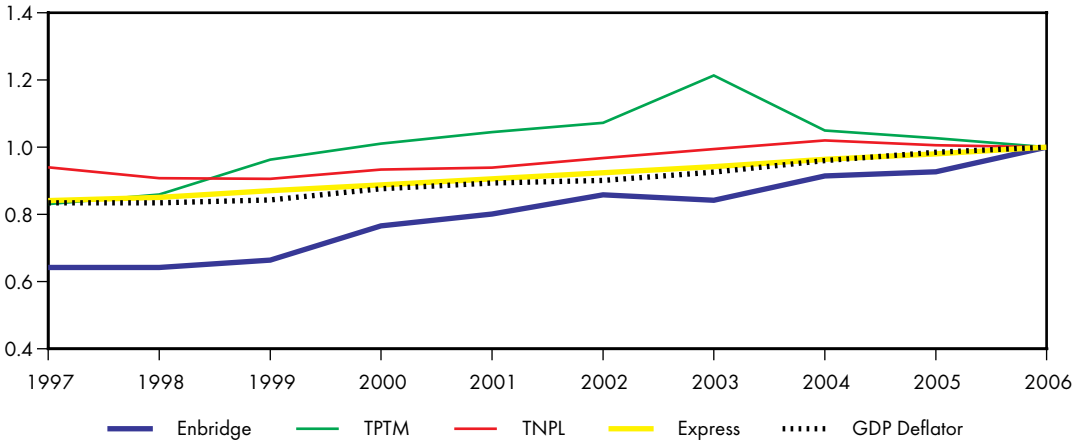
TPTM's benchmark toll rose steadily from 1997 to 2003 but fell in the last three years. The large 1999 increase was due to throughput forecasts. During TPTM's first incentive toll settlement, tolls were calculated on forecast volumes. In 1999 the throughput forecast was 17.9 percent lower than the 1998 forecast, which lead to a corresponding increase in the benchmark toll. In 2004, the benchmark toll dropped, primarily due to the disposition of deferrals for 2003 higher revenue. TNPI and Express's benchmark tolls moved roughly in line with the GDP deflator from 1997 to 2006.

7 The benchmark tolls are: Enbridge Edmonton to International Border near Chippewa; TPTM Edmonton to Burnaby; TNPI Oakville to Montreal; and Express 15-year.

**FIGURE 24**

***NEB-Regulated Oil Pipeline Benchmark Tolls***

**Normalized to 2006 = 1.00**

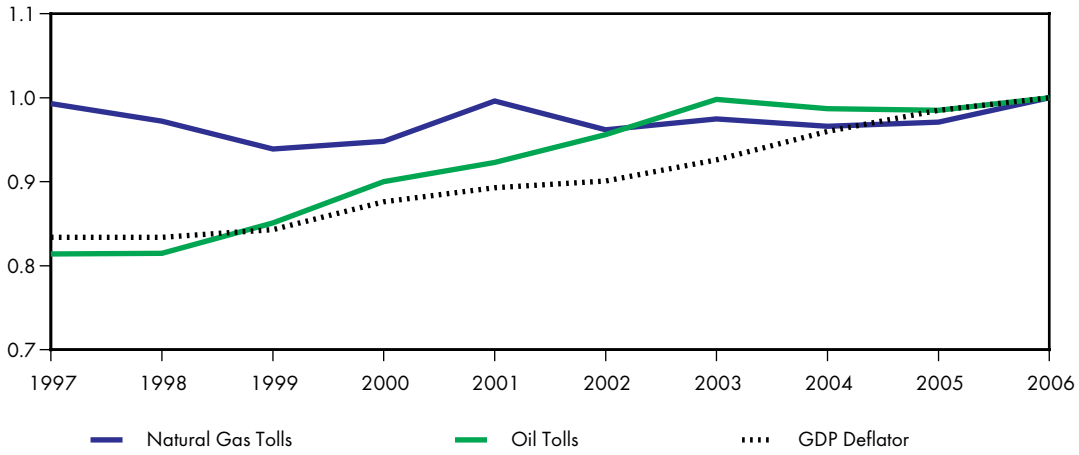



* Enbridge Toll does not include terminal and tankage fees.

**FIGURE 25**

***Oil and Natural Gas Pipeline Benchmark Tolls***

**Normalized to 2006 = 1.00**




### *Comparison of Gas and Oil Pipeline Tolls*

Figure 25 presents the GDP deflator with simple averages of the gas and oil benchmark pipeline tolls indices (reported in Figures 23 and 24).[8] From 1997 to 2006, average natural gas pipeline tolls have been relatively flat despite the rise in the GDP deflator. Over the same period, oil pipeline tolls increased but the net increase over the period has matched the GDP deflator. Throughput volumes have been the primary driving factor in variations during the period.

8 No adjustments are made for the relative volume, capacity or length of the individual pipelines.

## 4.3 Shipper Satisfaction

### *4.3.1 NEB Pipeline Services Survey*

The Board conducted its third annual Pipeline Services Survey in early 2007 to obtain direct feedback from the shippers of major NEB-regulated pipeline and midstream companies on the quality of service provided by those pipelines. The Board also used this survey to obtain feedback from shippers on the Board's regulatory performance with respect to tolls and tariffs.

To conduct this year's survey, the Board used a web-based survey tool, called Inquisite, which was sent to shippers directly via e-mail. For each survey received, shippers completed one response which reflects their company's corporate views on the services provided by the pipeline and midstream company being surveyed and on the services provided by the Board. The overall response rate for the survey was 27.0 percent, which was lower than last year's rate of 33.5 percent. The number of surveys sent out this year was 523, approximately 100 more than last year.

After analyzing the survey responses, the Board published a summary of the aggregate results on its website. They included the industry average and distribution of responses for each question and a summary of major themes. In addition, the Board provided each company and its shippers with detailed company-specific results including the average rating and distribution of responses for each question as well as the verbatim comments received from shippers, with the names of the respondents excluded.

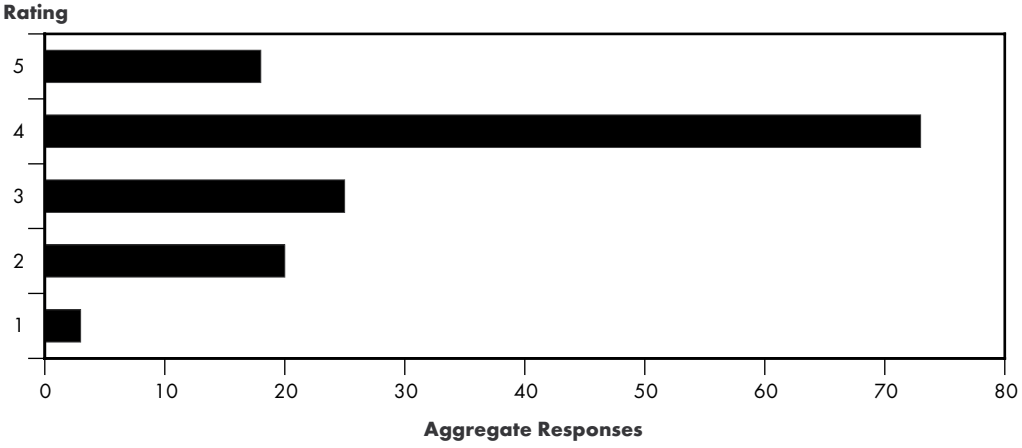
Appendix 3 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, refer to www.neb-one.gc.ca/Publications/Survey Results.

*Pipeline Services*

Figure 26 shows the aggregate results for the survey question that asked shippers to rate their satisfaction with the overall quality of service provided by their pipeline/midstream companies over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). The industry average score of 3.60 was slightly higher than the score of 3.57 in last year's survey. Sixty-five percent (65%) of the respondents gave their company a rating of satisfied or very satisfied on overall quality

**FIGURE 26**

***Shipper Satisfaction on Pipeline Quality of Service***



of service, compared to 58 percent last year. Based on these results, the Board is able to conclude that shippers again appear reasonably satisfied with the services provided by pipeline/midstream companies.

The three areas where shippers indicate that pipeline and midstream companies are doing very well are:

- Timeliness and accuracy of invoices and statements;
- Physical reliability of pipeline operations; and
- Satisfaction with transactional systems.

The three areas where shippers believe that companies could improve the most are:

- Reducing the level of transportation tolls or midstream charges;
- Exhibiting an attitude of continuous improvement and innovation; and
- Ensuring that settlements or tariff arrangements work well.

***Feedback on the Board***

The 2007 survey indicated that approximately 59 percent of shippers are either satisfied or very satisfied with the Board's performance with creating an appropriate regulatory framework and 55 percent of shippers are either satisfied or very satisfied with the Board's processes to resolve disputes. Both of these results were lower than in the 2006 survey. Two areas for improvement noted by shippers were for the Board to build its internal capacity to serve Canadians better and to provide effective regulatory processes that are more accessible to stakeholders and yield more timely decisions. Both of these areas are addressed in the Board's 2007-2010 Strategic Plan, which can be found at www.neb-one.gc.ca/AboutUs/strtgcpln2007_2010_e.htm.

### 4.3.2 Formal Complaints

If shippers are unable to resolve concerns with the pipeline, they can bring a formal complaint to the Board. The complaint would then be dealt with through appropriate dispute resolution, a formal complaint process or, in some cases, the parties may be able to negotiate a solution to the concern. There was only one formal shipper complaint during the past year which involved the Board.

***Several shippers on Cochin Pipe Lines Ltd. (Cochin)***

In December 2006, Cochin filed for new rates to become effective 1 January 2007. The new rates reflected increases ranging from 91 to 580 percent across both Regular Volume Rates and Incentive Volume Rates and included a new toll segment from Detroit, Michigan to Windsor, Ontario. The Board received 11 letters from Cochin's shippers and interested parties indicating concern with the magnitude and timing of the rate increases. Shortly thereafter, Cochin initiated settlement discussions with its shippers and, in February 2007, filed a negotiated settlement and letters of support from many of its shippers. Following further negotiations with one opposing shipper, Cochin advised that it and the shipper had reached a resolution of the outstanding issue. Cochin's toll settlement was subsequently approved by the Board in May 2007.

### 4.3.3 *Service Enhancements*

On an ongoing basis pipelines may propose modifications to their services as circumstances and needs of their customers change or innovative ideas are brought forward. Normally, the pipeline and its shippers will discuss and agree upon proposed service enhancements in their tolls task force prior to submission to the Board and ultimate adoption. However, if the task force is unable to agree on the service, a party may still bring the issue directly to the Board.

*Coral Energy Canada Inc. (Coral)*

Coral applied to the Board to modify the Firm Transportation Risk Alleviation Mechanism (FT-RAM) pilot, a service enhancement proposed by TransCanada for its long haul contracts on the Mainline. In February 2006, The Board approved Coral's application which sought to extend FT-RAM credits to short-haul contracts held by the same shipper, which when combined with a long-haul contract forms a continuous long-haul on the TransCanada Mainline. The Board subsequently also approved amendments supported by an unopposed tolls task force resolution to extend the FT-RAM pilot project for an additional year.

*TransCanada*

In May 2006, TransCanada applied to the Board for approval of two new services on its Mainline, designed to meet the fluctuating demands of new gas-fired electric generation in Ontario. The Board has approved the implementation of these services; Firm Transportation - Short Notice (FT-SN) and Short Notice Balancing (SNB) and the proposed tolling method for FT-SN. However, the Board directed TransCanada to develop an alternate tolling method for SNB service.

*Westcoast*

After lengthy discussions with the Toll and Tariff Task Force on the possible decontracting on transmission facilities, Westcoast and its customers agreed to the following firm service enhancements, which were subsequently approved by the Board in RHW-1-2005 and implemented in 2006:

- Term differentiated rates (offering lower rates for longer term commitment) were taken up by about 25% of eligible volumes starting in January 2006.
- Authorized Over Run service which provides firm service customers with access to additional capacity at a higher priority than interruptible service was successfully utilized during a scheduling constraint in late 2006.
- Cross-corridor crediting was implemented on the various corridors on Westcoast's T-North system in 2006.

Moreover, to address periodic imbalance management issues, Westcoast, in collaboration with its shipper community, proposed a Supply Imbalance Management Strategy that was unanimously supported by its Toll and Tariff Task Force, and is expected to be implemented in 2007.

## 4.4 Chapter Summary

The following observations are made in this chapter:

- Shippers are able to resolve the majority of their tolling issues of interest with pipelines through the negotiated settlement process;

- Pipeline tolls have been relatively stable on average, although particular regional situations may cause greater variability in some areas;
- Based on responses to the NEB Pipeline Services survey; shippers again appear reasonably satisfied with the services provided by pipeline/midstream companies.
- There are few formal service complaints; and
- Development of pipeline service enhancement continues.

The Board concludes that pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). Shippers are also reasonably satisfied with the role played by the Board itself, with some suggestions incorporated into the Board's own planning.

# PIPELINE FINANCIAL INTEGRITY AND ABILITY TO ATTRACT CAPITAL

Pipeline companies must have adequate financial integrity to attract capital on reasonable terms and conditions to effectively maintain their systems and build new infrastructure to meet the market's evolving needs. The following sections review and discuss a number of the factors relevant to these areas, starting with the area over which the Board has the most direct influence.

## 5.1 Common Equity

A common equity ratio is defined as the percentage of common equity in a company's capital structure. This ratio is often used to evaluate a company's financial risk. Higher common equity ratios increase the likelihood of a company being able to meet its obligations.

### *Deemed Common Equity Ratios*

The Board approves a deemed common equity ratio for the Group 1 pipeline companies that it regulates.[9] When the Board approves a Group 1 pipeline company's tolls for a specified time period, it typically also approves a return on equity (ROE) and deems a common equity ratio for the regulated entity. Alternatively, some Group 1 pipeline companies successfully negotiate a comprehensive tolls settlement with their shippers, which may include capital structure and return on equity. In this instance, the Board still considers the overall settlement. Given the extent of negotiated settlements, many of the equity ratios have been determined by negotiation among the parties involved. Through this mechanism, the Board has influence over the operating profitability and financial risk of some Group 1 pipeline companies.

**TABLE 6**

***Deemed Common Equity Ratios (Percent)***

| | 2002 | 2006 | 2007 |
|---|---|---|---|
| Alliance | 30 | 30 | 30 |
| Foothills | 30 | 36 | 36 |
| M&NP | 25 | 25 | 29.27 |
| TQM* | 30 | 30 | 30 |
| TransCanada B.C. System | 30 | 36 | 36 |
| TransCanada Mainline | 33 | 36 | 40 |
| Westcoast Transmission | 30 | 35 | 36 |

* TQM's common equity ratio was specified in its negotiated settlement that expired on 31 December 2006.

Table 6 shows the deemed common equity ratio for some NEB Group 1 pipeline companies through adjudication or negotiation. TransCanada, Westcoast Transmission, B.C. System, and Foothills have increased their deemed common equity ratios between 2002 and 2006. The market considers these increases to be credit positive, lowering the financial risk of the pipeline companies.

9 A deemed common equity ratio is a notional capital structure used for rate-making purposes that may differ from a company's actual capital structure.

*Return on Common Equity*

Return on equity is commonly used to assess the operating profitability of a company. Financial markets define ROE as net income divided by common equity.

For NEB-regulated pipeline companies, ROE is the return on the equity portion of the rate base that is approved by the Board and is determined either through adjudication or negotiation. A higher ROE is typically preferred by investors.

Annually, the Board establishes an approved-ROE following the method outlined in RH-2-94. It is applicable to pipelines that the Board regulates, except those that have Board approved alternative rates. Achieved ROEs can vary from NEB-approved levels for various reasons, such as incentives, profit-sharing mechanisms and cost reductions.

Table 7 shows the achieved ROE for several NEB-regulated pipeline companies from 2002 to 2006 along with the ROE approved by the NEB in accordance with the RH-2-94 Formula[10]. As per their respective negotiated settlements, Enbridge, TPTM and Trans-Northern are not required to submit their Financial Surveillance Reports to the NEB, which would include achieved ROEs. Therefore, these pipeline companies are not included in Table 7. Other companies are included in Table 8, but are not subject to the RH-2-94 Formula ROE: Alliance and M&NP have negotiated ROEs with their shippers,[11] and Westcoast's Field Services Division is financially regulated on a complaint basis as described in the Framework for Light-handed Regulation (RHW-1-98). Fees for gathering and processing services are negotiated individually with shippers. TransCanada and TQM have negotiated settlements which use the RH-2-94 Formula as a basis and allow incentives causing some variations from the Formula rate.

The RH-2-94 Formula produced an ROE of 8.88 percent for 2006, falling each year since 2003 because of low interest rates. From 2002 to 2006, for pipeline companies subject to the RH-2-94

**TABLE 7**

***Achieved ROEs and the RH-2-94 Formula ROE (Percent)***

| | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Alliance | 11.25 | 11.25 | 11.25 | 11.25 | 11.25 |
| Foothills | 9.53 | 9.79 | 9.56 | 9.46 | 8.88 |
| M&NP | 12.95 | 12.31 | 13.75 | 14.31 | 14.68 |
| TQM | 9.80 | 10.21 | 9.84 | 9.92 | 8.99 |
| TransCanada B.C. System | 9.53 | 8.21 | 8.51 | 9.46 | 8.47 |
| TransCanada Mainline | 9.95 | 10.18 | 9.83 | 9.66 | 8.92 |
| Westcoast Transmission* | 13.44 | 12.93 | 10.28 | 10.82 | 9.16 |
| **NEB RH-2-94 Formula** | **9.53** | **9.79** | **9.56** | **9.46** | **8.88** |
| **Midstream** | | | | | |
| Westcoast Field Services* | 14.87 | 6.76 | 11.63 | 12.48 | 10.46 |

Source: NEB Surveillance and Annual Reports

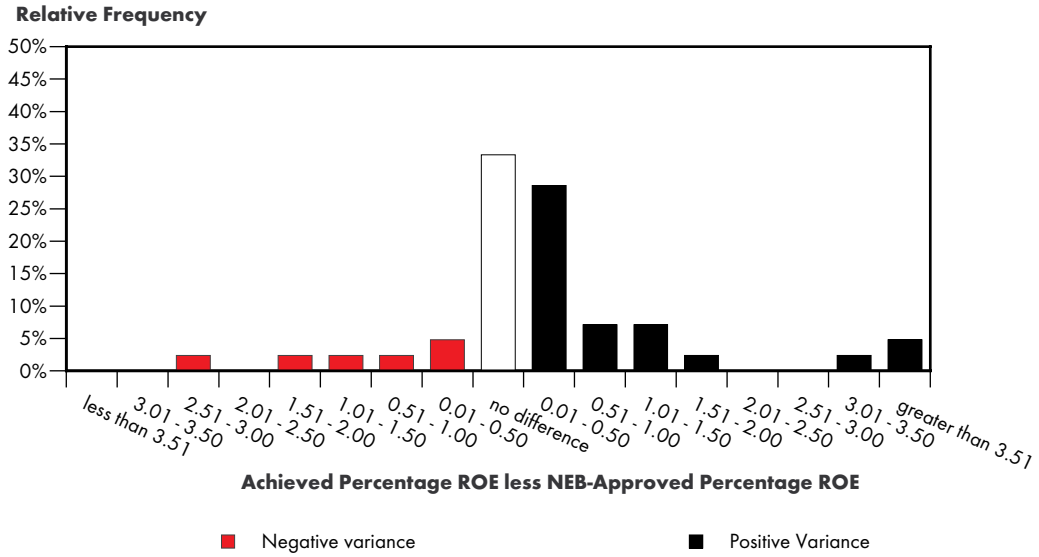
* excluding CWIP (construction work in progress) and, in the case of Transmission, deferrals.

10 The formula used to determine the ROE for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, and later amended to eliminate rounding.

11 The settlements were subsequently approved by the Board. Alliance's settlement sets its ROE at 11.25 percent over this period. M&NP has a base return on equity of 12 percent for 2007; up to and including 2006 their base rate was 13 percent, with incentive potential.

**FIGURE 27**

***Variance from NEB-Approved ROE for the Years 2001 to 2006***




Source: NEB Surveillance Quarterly and Annual Reports. Includes TransCanada Mainline and B.C. System, TQM, Westcoast Transmission system, and M&NP, as well as Foothills and Alliance which earn precisely their allowed ROE.

Formula ROE, only the TransCanada B.C. System has failed to earn an ROE at or above the Formula return in each year.

Most pipelines have, or have proposed, negotiated settlements. Three settlements have allowed ROEs that are different than the Formula ROE: Alliance, M&NP, and Trans-Northern. In the case of Alliance and M&NP, the ROE was fixed for an extended period. Other settlements use the RH-2-94 Formula as the allowed ROE and many of these settlements provide varying degrees of incentives to enable pipelines to earn more than the Formula ROE. As a result of the various incentives, most Group 1 pipelines have achieved actual ROEs that are greater than allowed ROEs. With the low interest rate environment, the RH-2-94 Formula produces an ROE of 8.46 percent for 2007.

Figure 27 charts the difference between achieved ROEs and NEB-approved ROEs for the TransCanada Mainline, the B.C. System, TQM, the Westcoast Transmission system, and M&NP. Also Foothills and Alliance are included; by their settlement their achieved ROEs equal their approved ROEs. From 2001 to 2006, pipeline companies (included in Figure 27) have met or exceeded their NEB-approved ROEs 86 percent of the time. The stability and predictability of returns is positive for both bondholders and equity investors. It also highlights that these pipeline companies, in many cases, have been able to meet or outperform approved levels through cost reductions, incentives and profit sharing mechanisms.

## 5.2 Financial Ratios

Financial ratios, based on financial statement information, can be useful in describing a company's performance and financial integrity. A financial ratio is most meaningful when the ratio of a particular company is compared with a benchmark or industry standard over time. A variety of ratios can be used to evaluate a company's liquidity, operating performance, growth potential, and risk. However, care must be exercised in the collection and interpretation of financial ratios. Reported financial information often pertains to a parent company, and includes non-regulated assets and/or assets from different industries.

The following sections specifically outline and discuss some ratios relating to the financial risk of certain companies with NEB-regulated pipelines.

Financial risk is the risk inherent in a company's use of debt and other obligations that have fixed payments. It differs from business risk which is the risk attributed to the nature of a particular business activity and for pipelines typically includes supply, market, regulatory, competitive and operating risks. Financial risk increases as the proportion of debt increases in relation to shareholders equity. An increase in debt may obligate a company to make more and larger fixed payments in the future. From a bondholder's perspective, a company with above average financial risk could have problems making interest payments. From an equity holder's perspective, a company's level of debt coverage gives some indication of the sustainability and value of the equity, and possible ability to pay dividends.

A company's financial risk can be described by ratios such as interest and fixed-charges coverage and cash flow-to-total debt and equivalents.

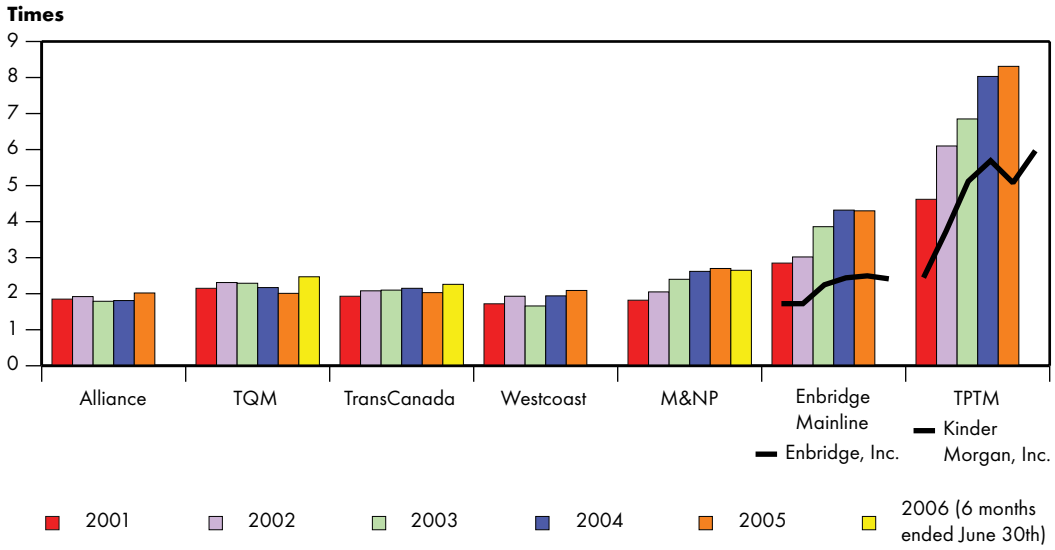
### *Interest and Fixed-Charges Coverage Ratios*

An *interest coverage ratio* describes a company's ability to make interest payments and repay its debt obligations. It is defined as Earnings Before Interest and Taxes (EBIT) divided by interest charges. The metric presented below is similar: the *fixed-charges coverage ratio* describes the ability to make interest payments as well as other types of fixed payments a company is obligated to make. It is defined as earnings before interest, fixed charges and taxes divided by fixed-charges, including interest. Higher ratios indicate a higher likelihood that the company will be able to meet its obligations and, if all other things are equal, could indicate that it has unused borrowing capacity.

The fixed-charges coverage ratios for some NEB-regulated pipeline companies, as calculated by the Dominion Bond Rating Service (DBRS), are shown in Figure 28. Complete data are not available consistently for all companies: the Enbridge Mainline is shown in the block data, the consolidated company Enbridge Inc. is shown as the line. TPTM information was not available on a stand-alone

**FIGURE 28**

***Fixed-Charges Coverage Ratios***




Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge (Mainline) in 2006.

basis for 2006: the overlay line shown is its new owner, Kinder Morgan Inc. The average fixed-charges coverage ratio for the companies for which data is available is 2.42, which is a 6 percent increase year-over-year for those companies.[12]

No company saw its 2006 fixed-charges coverage ratio lower than its 2001 levels. From 2001 to 30 June 2006, the fixed-charges coverage ratio for the five natural gas pipeline companies shown increased modestly from a little under 2 times to around 2.2 by 2006. The two oil pipelines (Enbridge (Mainline) and TPTM, in each case representing the oil pipelines business unit) had higher ratios, which increased more rapidly. TPTM's fixed-charges coverage ratio has been higher, primarily due to a deemed common equity ratio of 45 percent (larger than its peers), which means it carried less debt, and had lower fixed payments. The continuing increases in fixed-charges coverage ratios for all companies is one metric signaling a decrease in the pipeline companies' financial risk, when considered as a group.

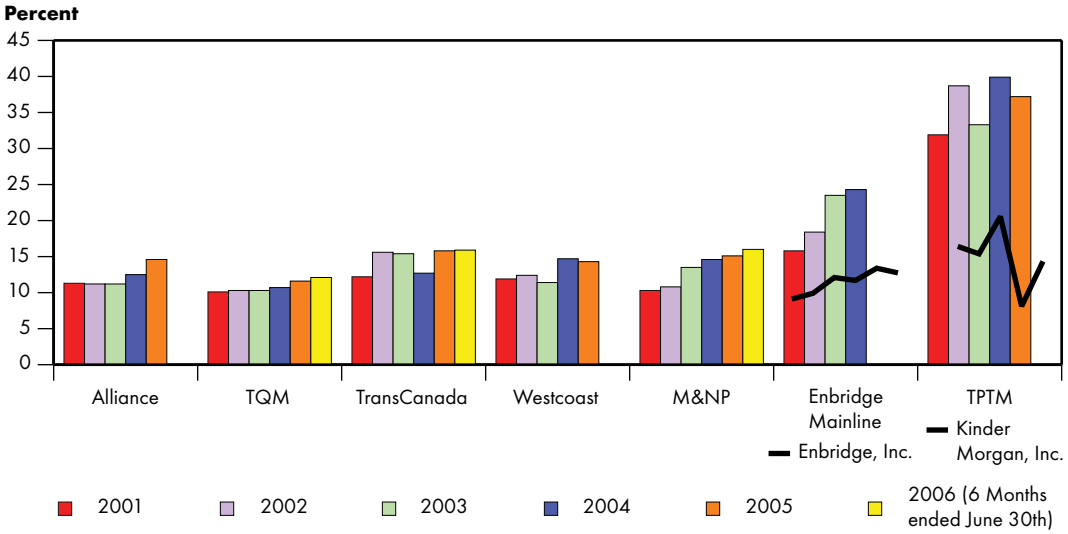
### *Cash Flow-to-Total Debt and Equivalents Ratio*

The cash flow-to-total debt and equivalents ratio is another way of describing a company's ability to meet its debt obligations and fixed payments. It is defined as operating cash flow divided by total debt and debt equivalents. Again, higher ratios indicate an increased likelihood of a company being able to meet its obligations and indicate that it has greater borrowing capacity.

The cash flow-to-total debt and equivalents ratio for some NEB-regulated pipeline companies, as calculated by DBRS, are shown in Figure 29. As earlier noted, this ratio is not available for the pipeline units. The average cash flow-to-total debt and equivalents ratio for these companies was 14.2 percent for the partial year ending June 2006, a slight increase from the year before.[13] TPTM's cash

**FIGURE 29**

***Cash Flow-to-Total Debt and Equivalents Ratios***




Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge (Mainline) in 2005 and 2006.

12 This average includes only Alliance, M&NP, TransCanada and Enbridge Inc.; this group had a simple average of 2.28 in 2005 and 1.93 in 2001. In last year's report, the average of 3.22 cited included other pipelines, such as TPTM.

13 The ratio is heavily influenced by the availability of TPTM data. In the 2006 report, the average ratio was 17 percent including data available for TPTM. Without TPTM the ratio was much more modest. Using only the companies which have data available this year, the average is 14.2 for 2006, slightly up from 14.0 for 2005 and up notably from 10.0 in 2000.

flow-to-total debt and equivalents ratio was higher than its peers for the same reason that its fixed-charges coverage ratio was higher.

On average, the cash flow-to-debt and equivalents ratio for these pipeline companies has grown by more than 20 percent from 2000 to 2006. The increase has been steady without any noteworthy periods of deterioration. The increase in this coverage ratio, and the consistent increase in cash flow-to-total debt and equivalents support the observation from the fixed-charges coverage that, on average, these pipeline companies' financial risk has been decreasing.

## 5.3 Credit Ratings

In Canada, pipeline credit ratings are determined by three independent credit rating agencies, Dominion Bond Rating Service (DBRS), Standard & Poor's (S&P), and Moody's. In general, credit ratings provide an assessment of the probability that a debt issuer will live up to its obligations and as such are an indication of the financial integrity of the rated company. Credit ratings assigned to a company generally reflect the consolidated operations of the entire company and not solely the regulated portion. Consequently, the credit rating for companies such as Enbridge, TransCanada and Westcoast that have both regulated and non-regulated operations may be influenced by its non-regulated operations. In addition, the credit ratings may be influenced to some extent by a parent company. Credit ratings are somewhat subjective in that a company's ratings are the expert opinion of the credit rating agency, which may result in different ratings by different agencies. See Appendix 4 for a comparison of the rating scales for DBRS, S&P, and Moody's.

*DBRS*

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. The key credit considerations will vary industry by industry; however, some of the common factors that are considered for most ratings are: core profitability, asset quality, strategy and management strength, and the financial and business risk profile.

For pipelines, the following specific factors are also considered in deriving the credit ratings: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities. The credit ratings for most Group 1 pipeline companies shown in Table 8

**TABLE 8**

***DBRS Credit Rating History***

| Pipeline | 2002 | 2003 | 2004 | 2005 | 2006 | Current |
|---|---|---|---|---|---|---|
| Alliance | A(low) | A(low) | A(low) | A(low) | A(low) | A(low)/Stb |
| Enbridge Pipelines | A(high) | A(high) | A(high) | A(high) | A(high) | A(high)/Stb |
| Express[1] | A(low) | A(low) | A(low) | A(low) | A(low) | A(low)/Stb |
| M&NP | A | A | A | A | A | A/Stb |
| TQM | A(low) | A(low) | A(low) | A(low) | A(low) | A(low)/Stb |
| TransCanada | A | A | A | A | A | A/Stb |
| Trans Mountain | A(low) | A(low) | A(low) | A(low) | repaid | repaid |
| Trans-Northern | NR | NR | NR | A(low) | A(low) | A(low)/Stb |
| Westcoast[2] | A(low) | A(low) | A(low) | A(low) | A(low) | A(low)/Stb |

1 Senior secured
2 Unsecured debentures
NR Not rated

indicates that the ratings have remained stable from 2002 to the present, varying from A(low) to A(high), and there have been no recent rating changes.

***Standard & Poor's***

An S&P credit rating reflects a borrower's capacity and willingness to meets its financial commitments on a timely basis. S&P bases its ratings on the overall creditworthiness of a consolidated company. Therefore, the rating of a wholly-owned subsidiary, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent.

In S&P's rating methodology, a company rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and

economic conditions than companies in higher-rated categories. A company rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the company to meet its financial commitments.

The rating histories for several Group 1 pipeline companies are provided in Table 9. The table illustrates that the ratings have remained stable from 2002 to the present, varying from 'BBB+' to 'A-'. There have been two recent rating changes. First, the credit rating on the long-term debt of Westcoast Energy Inc. was upgraded to 'BBB+' in January 2007 from 'BBB', which had been in place since February 2004. The rating change was based on the ownership change at the parent company level that occurred effective 2 January 2007 when Duke Energy Corporation completed the spin-off of its natural gas business (including Westcoast) to Spectra Energy Corporation, a new publicly traded company. Second, in April 2007, S&P revised its outlook on TranCanada from 'negative' to 'stable'. The negative outlook on TransCanada's credit rating had been in place since December 2002, and was initially associated with TransCanada's acquisition of a significant interest Bruce Power in February 2002. S&P noted that TransCanada's recent acquisition of ANR and its investment in the Keystone oil pipeline project provide a stabilizing offset to the declining rate base and lower return on equity from its traditional business.

Both DBRS and S&P have expressed an opinion at various times that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Nonetheless, the ratings assigned by these credit rating companies indicate that NEB-regulated companies are all rated investment grade.

**TABLEAU 9**

***S&P Credit Rating History***

| Pipeline | 2002 | 2003 | 2004 | 2005 | 2006 | Cote actuelle |
|---|---|---|---|---|---|---|
| Pipelines Enbridge | A-/Neg | A-/Stb | A-/Stb | A-/Stb | A-/Stb | A-/Stb |
| M&NP[1] | A/Stb | A/Stb | A/Stb | A/Stb | A/Stb | A/Stb |
| TQM | BBB+/Stb | BBB+/Stb | BBB+/Stb | BBB+/Stb | BBB+/Stb | BBB+/Stb |
| TransCanada | A-/Watch/Neg | A-/Watch/Neg | A-/Watch/Neg | A-/Neg | A-/Neg | A-/Stb |
| Trans Mountain | BBB+/Neg | BBB/Stb | BBB/Stb | BBB/Stb | debt repaid | debt repaid |
| Westcoast[2] | A/Stb | BBB+/Stb | BBB+/Stb | BBB/Watch/Neg | BBB/Stb | BBB+/Stb |

1 Senior secured
2 Unsecured debentures

*Moody's*

Moody's credit analysis focuses on the fundamental factors and key business drivers relevant to an issuer's long-term and short-term risk profile. The foundation of Moody's methodology rests on two basic considerations:

- The risk to the debt holder of not receiving timely payment of principal and interest on the specific debt security.
- A comparison of the level of risk with that of all other debt securities.

Like S&P, Moody's focuses its ratings on the overall creditworthiness of the consolidated entity. In so doing, Moody's measures the ability of an issuer to generate cash in the future, thus its primary focus is on the predictability of future cash generation. This determination is built on an analysis of the individual issuer and of its strengths and weaknesses compared to those of its peers worldwide. An examination of factors external to the issuer is also conducted, including industry- or country-level trends that could impact the entity's ability to meet its debt obligations. Of particular concern is the ability of management to sustain cash generation in the face of adverse changes in the business environment.

The rating histories for several Group 1 pipeline companies are provided in Table 10. All of Moody's ratings placed the pipelines in the investment grade category, specifically rated 'medium grade' to 'upper-medium grade'.

There has been one recent rating change by Moody's. In March 2007 Moody's downgraded the ratings on the senior unsecured debt of Enbridge Inc. one notch to Baa1 from A3.[14] Moody's stated that the one notch downgrade was based on concerns relating to the company's weak financial profile, the complexity of its organizational and capital structure, and the scope and financial impact of the company's substantial organic growth plans.

## 5.4 Comments by the Investment Community

Access to capital market is necessary for pipeline companies to maintain and, potentially, expand their systems as the needs of the transportation market changes. Board staff met with credit rating analysts, equity analysts, and suppliers of capital such as insurance and pension funds to discuss their views on the ability of NEB-regulated pipeline companies to access capital markets as well as their views on transportation markets and the current regulatory environment in Canada.

**TABLE 10**

***Moody's Credit Rating History***

| Pipeline | 2002 | 2003 | 2004 | 2005 | 2006 | Current |
|---|---|---|---|---|---|---|
| Alliance[1] | A3 | A3 | A3 | A3 | A3 | A3 |
| Embridge Inc. | A2 | A3 | A3 | A3 | A3 | Baa1 |
| Express[2] | Baa1 | Baa1 | Baa1 | Baa1 | Baa1 | Baa1 |
| M&NP[2] | A1 | A1 | A1 | A2 | A2 | A2 |
| TransCanada[1] | A2 | A2 | A2 | A2 | A2 | A2 |

1 Unsecured debentures
2 Senior secured

14 Enbridge Inc. is the parent company of Enbridge Pipelines Inc., which owns the Enbridge Mainline. Unlike DBRS and S&P, Moody's does not rate the debt issued by Enbridge Pipelines Inc.

There was a consensus among parties that there is substantial liquidity in both domestic and export global capital markets. Solid economic growth in recent years, low interest rates, the accumulation of capital in pension funds and the ability of private equity funds to borrow large sums at low rates from finance companies were among the reasons cited for the current situation, which was characterized as 'a lot of money chasing too few assets'. Regulated businesses, along with infrastructure and real estate, were seen as particularly attractive investments. It was noted that the federal tax changes made in October 2006 with respect to income trusts and increases in the dividend tax credit also increased demand for shares of dividend paying companies like financials, utilities and pipelines, at least temporarily.

Given this environment, there was agreement that NEB-regulated pipelines have not had difficulty accessing equity or debt markets. The parent companies of TransCanada PipeLines Limited and Enbridge Pipelines Inc. recently went to the equity market and collectively raised more than $2 billion. Both companies have also had substantial debt issues recently. However, some parties expressed concern that on a stand-alone basis the regulated entities themselves might have difficulty attracting capital given low ROEs. Others felt that the regulated entities would be able to attract capital but that the terms under which they did so may be more costly than for the consolidated entity.

Again this year the investment community noted that price-to-earnings ratios of utilities in Canada have been higher than those in the U.S. because of large energy infrastructure investment opportunities, a more stable regulatory environment and global interest in Canadian stocks. While there is currently substantial liquidity, it was noted that capital markets could change and this could happen very quickly and result in considerable volatility.

Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

## 5.5 Chapter Summary

The observations made in this chapter may be summarized as follows:

- Fixed-charges and cash flow-to-total debt and equivalents coverage ratios have increased since 2001;
- Deemed common equity ratios have increased since 2001;
- Achieved ROEs have in most cases been greater than or equal to their NEB-approved levels since 2001;
- Approved ROEs have been predictable, but declining and may now be too low;
- Credit ratings continue to be investment grade; and
- The investment community views NEB-regulated companies as having access to capital markets at this time of significant liquidity, but noted that market conditions can change rapidly and that on a stand-alone basis the regulated entities themselves may have difficulty attracting capital given current ROEs.

In general, these observations signal that, currently pipelines companies have adequate financial strength to attract capital on reasonable terms and conditions.

# CONCLUSIONS

Based on the criteria identified in the Introduction to this report, the Board believes that the Canadian hydrocarbon transportation system continues to work effectively.

1. **There is adequate capacity in place on existing natural gas pipelines.** The price differentials and capacity utilization charts indicate that most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. The existence of some excess capacity out of the WCSB has provided suppliers with the flexibility to access markets of their choice at most times. Proposed pipeline projects are mainly directed towards providing connection to new supplies or addressing bottlenecks in the market area.

   **Capacity remains very tight on oil pipeline systems.** While the capacity utilization indicators show that there was spare capacity on some of the pipelines in 2006, this was partially due to facility outages reducing the amount of crude oil or products to be transported. It is likely that export crude oil pipelines out of Western Canada may experience periods of apportionment by the fourth quarter 2007, and this may continue for the next 18 months. As indicated by Figure 21, no significant pipeline capacity is expected to be added between now and 2009. The industry and the pipeline companies are working together to develop a number of initiatives to reduce and/or eliminate the impacts of apportionment.

   The number of announced and proposed pipeline and expansions, and the transfer of under-utilized gas pipeline facilities on the TransCanada Mainline to transportation of crude oil, illustrates that the hydrocarbon transportation systems are responding and have the ability to make adjustments to pipeline capacity as market conditions change.

2. **Shippers continue to indicate that they are reasonably satisfied with the services provided by pipelines.** Once again, shippers rate the physical reliability of pipeline operations highly and express the most concern around the level of pipeline tolls.

3. **NEB-regulated pipeline companies are financially sound and have been able to attract capital on reasonable terms and conditions.** While it is recognized that some of the data and indicators reviewed are for the consolidated operations of pipeline companies, the investment community views NEB-regulated companies as having access to capital markets at this time of significant liquidity. However, the investment community also noted that market conditions can change rapidly and that on a stand-alone basis the regulated entities themselves may have difficulty attracting capital given current ROEs.

As identified in Chapter 3, there are a significant number of pipelines proposed to ensure that the Canadian transportation system has sufficient capacity to deliver the additional volumes of oil and natural gas to serve new and growing markets. The challenge for the pipeline transportation industry is to put appropriate capacity in service corresponding with changes in production and market requirements. For this to happen there must be adequate and predictable lead times to achieve

sufficient market support from amongst competing proposals, obtain regulatory approvals, arrange financing, mobilize labour and materials, and construct facilities.

A key component and ongoing challenge from the NEB's perspective is to provide, in a timely manner, a fair and effective process that does not distort the market place investment decisions. This may involve ongoing efforts to coordinate regulatory activities with other jurisdictions and to provide clear regulatory processes with predictable timelines. New investment can be frustrated when unexpected regulatory hurdles create delays or unpredictable timelines which may introduce uncertainty from changing supply and market conditions and business risk. Further, unnecessary construction delays, for both expansions and new pipelines, can be costly to both energy consumers and producers as the development of new supplies is constrained. Given the large capital outlay and the long-term nature of these investments, market participants seek to ensure that the optimal decisions are made.

The Board recognizes that this report represents only a snapshot in time and does not include a comparison with or to pipeline transportation systems in other jurisdictions. As part of its mandate, the Board will continue to monitor the effectiveness of the transportation system and will continue to meet with parties to gain an understanding of all perspectives on this issue. The Board welcomes feedback on the measures and conclusions in this report and also welcomes suggestions for improvements to future reports.

The Board thanks those companies and organizations that directly or indirectly provided the information found in this report, including those that actively participated in the Pipeline Services Survey.

# STAKEHOLDER CONSULTATION

Alliance Pipeline Ltd.
BMO Nesbitt Burns
Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association
Canadian Gas Association
Canaccord Adams
Caisse de dépôt et placement du Québec
CIBC World Markets
Cochin Pipe Lines Ltd.
Dominion Bond Rating Service
Enbridge Pipelines Inc.
Express Pipeline Limited Partnership
Foothills Pipe Lines Ltd.
Industrial Gas Users Association
Kinder Morgan Canada Inc.
Maritimes and Northeast Pipeline
Moody's Investor Services
Ontario Teachers' Pension Plan
RBC Capital Markets
Scotia Capital
Standard & Poor's
Sun Life Financial
Terasen Pipelines Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipeline Inc.
Trans Québec & Maritimes Pipeline Inc.
TransCanada PipeLines Limited
Union Gas Limited
Westcoast Energy Inc.

# GROUP 1 AND GROUP 2 PIPELINES

## Regulated by the NEB As of 31 December 2006

### *Group 1 Gas Pipelines*

Alliance Pipeline Ltd.
Foothills Pipe Lines Ltd.
Gazoduc Trans Québec & Maritimes Inc.
Maritimes & Northeast Pipeline Management Ltd.
TransCanada PipeLines Limited
TransCanada PipeLines Limited, B.C. System
Westcoast Energy Inc.

### *Group 1 Oil and Products Pipelines*

Cochin Pipe Lines Ltd.
Enbridge Pipelines Inc.
Enbridge Pipelines (NW) Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipelines Inc.

### *Group 2 Natural Gas and Natural Gas Liquids Pipelines*

AltaGas Pipeline Partnership
Apache Canada Ltd.
ARC Resources Ltd.
Bear Paw Processing Company (Canada) Ltd.
BP Canada Energy Company
Burlington Resources Canada (Hunter) Ltd.
Canada Customs and Revenue Agency
Canadian Natural Resources Limited
Canadian-Montana Pipe Line Corporation
Centra Transmission Holdings Inc.
Champion Pipeline Corporation Limited
Chief Mountain Gas Co-op Ltd.
DEFS Canada L.P.
Delphi Energy Corporation
Devon Canada Corporation
Devon Energy Canada Corporation

DR Four Beat Energy Corp.
Echoex Energy Inc.
EnCana Border Pipelines Limited
EnCana Ekwan Pipeline Inc.
EnCana Oil & Gas Co. Ltd.
EnCana Oil & Gas Partnership
Enermark Inc.
ExxonMobil Canada Properties
Forty Mile Gas Co-op Ltd.
Huntingdon International Pipeline Corporation
Husky Oil Operations Ltd.
Kaiser Exploration Ltd.
KEYERA Energy Ltd.
Many Islands Pipe Lines (Canada) Limited
Marauder Resources West Coast Inc.
Mid-Continent Pipelines Limited
Minell Pipeline Limited
Murphy Canada Exploration Company
Murphy Oil Company Ltd.
Nexen Inc.
Niagara Gas Transmission Limited
Northstar Energy Corporation
NuVista Energy Ltd.
Omimex Canada, Ltd.
Paramount Transmission Ltd.
Peace River Transmission Company Limited
Pengrowth Corporation
Penn West Petroleum Ltd.
Petrovera Resources Ltd.
Pioneer Natural Resources Canada Inc.
Portal Municipal Gas Company Canada Inc.
Prairie Schooner Limited Partnership
Profico Energy Management Ltd.
Renaissance Energy Ltd.
St. Clair Pipelines Management Inc.
Shiha Energy Transmission Ltd.
Suncor Energy Inc.
Sword Energy Limited
Talisman Energy Inc.
Taurus Exploration Canada Ltd.
Union Gas Limited
Vault Energy Inc.
Vector Pipeline Limited Partnership
County of Vermillion River No. 24 Gas Utility
2193914 Canada Limited
806026 Alberta Ltd.
1057533 Alberta Ltd.

### *Group 2 Oil and Products Pipelines*

Amoco Canada Petroleum Company Ltd.
Aurora Pipe Line Company
Berens Energy Ltd.
BP Canada Energy Company
Dome Kerrobert Pipeline Ltd.
Dome NGL Pipeline Ltd.
Duke Energy Empress L.P.
Enbridge Pipelines (Westspur) Inc.
Ethane Shippers Joint Venture
Express Pipeline Limited Partnership
Genesis Pipeline Canada Ltd.
Glencoe Resources Ltd.
Husky Oil Limited
Imperial Oil Resources Limited
ISH Energy Ltd.
Montreal Pipe Line Limited
Murphy Oil Company Ltd.
NOVA Chemicals (Canada) Ltd.
PanCanadian Kerrobert Pipeline Ltd.
Paramount Transmission Ltd.
Penn West Petroleum Ltd.
Plains Marketing Canada, L.P.
PMC (Nova Scotia) Company
Pouce Coupé Pipe Line Ltd. (as agent and general partner of the Pembina North Limited Partnership)
Provident Energy Pipeline Inc.
Renaissance Energy Ltd.
SCL Pipeline Inc.
Shell Canada Products Limited
Sun-Canadian Pipe Line Company
Taurus Exploration Canada Ltd.
Yukon Pipelines Limited
1057533 Alberta Ltd.

# PIPELINE SERVICES SURVEY

## Aggregate Results

Below are the aggregate responses for each question in the survey. Respondents were asked to rate their satisfaction with the services they receive on a scale of 1 to 5, where 1 indicates "Very dissatisfied" and 5 indicates "Very satisfied". See the Board's website for the complete details

1. How satisfied are you with the physical reliability of the pipeline company's operations?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 4 | 18 | 12 | 74 | 31 | 3.79 |

2. How satisfied are you with the quality, flexibility and reliability of the pipeline company's transactional systems (nominations, bulletin boards, reporting, contracting, etc)?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 0 | 24 | 16 | 75 | 22 | 3.69 |

3. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 7 | 7 | 14 | 75 | 31 | 3.87 |

4. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc) provided by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 3 | 17 | 21 | 79 | 19 | 3.68 |

5. How satisfied are you with the timeliness and usefulness of commercial information (tolls, service changes, new services, contract information, etc) provided by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 7 | 13 | 34 | 70 | 15 | 3.53 |

6. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 10 | 30 | 36 | 51 | 11 | 3.17 |

7. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 9 | 22 | 32 | 54 | 21 | 3.41 |

8. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 6 | 20 | 37 | 54 | 19 | 3.44 |

9. How satisfied are you with the suite of services offered by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 4 | 13 | 40 | 67 | 10 | 3.49 |

10. How satisfied are you with the level of this pipeline company's tolls in relation to the transportation services your company receives?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 7 | 26 | 42 | 53 | 4 | 3.16 |

11. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 11 | 16 | 38 | 45 | 14 | 3.28 |

12. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 11 | 8 | 47 | 52 | 5 | 3.26 |

13. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 3 | 20 | 25 | 73 | 18 | 3.60 |

14. On an overall basis, has the pipeline company's quality of service in the last year:

| | | |
|---|---|---|
| Improved | 18 | 13% |
| Remained the Same | 100 | 72% |
| Decreased | 20 | 15% |
| **Total** | **138** | **100%** |

15. What are the things that this pipeline company does well?

16. What are the things that this pipeline company could do better?

17. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 4 | 10 | 39 | 67 | 9 | 3.52 |

18. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 4 | 6 | 39 | 53 | 7 | 3.49 |

19. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

# DEBT RATING COMPARISON CHART

This chart provides a comparison of the rating scales used by Dominion Bond Rating Service (DBRS), Standard and Poor's (S&P), and Moody's when rating long-term debt.

Standard & Poor's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A 'Positive' outlook means that a rating may be raised; a 'Negative' outlook means that a rating may be lowered; and a 'Stable' outlook means that a rating is not likely to change.

| Credit Quality | DBRS | S&P | Moody's |
|---|---|---|---|
| **Investment Grade** | | | |
| Superior / High grade | AAA | AAA | Aaa |
| | AA (high) | AA+ | Aa1 |
| | AA | AA | Aa2 |
| | AA (low) | AA- | Aa3 |
| Good / Upper Medium | A (high) | A+ | A1 |
| | A | A | A2 |
| | A (low) | A- | A3 |
| Adequate / Medium | BBB (high) | BBB+ | Baa1 |
| | BBB | BBB | Baa2 |
| | BBB (low) | BBB- | Baa3 |
| **Non-Investment Grade** | | | |
| Speculative | BB (high) | BB+ | Ba1 |
| | BB | BB | Ba2 |
| | BB (low) | BB- | Ba3 |
| Highly Speculative | B (high) | B+ | B1 |
| | B | B | B2 |
| | B (low) | B- | B3 |
| Very Highly Speculative | CCC | CCC | Caa1 |
| | CC | CC | Caa2 |
| | C | C | Caa3 |
| | D | D | Ca |
| | | | C |

Note: DBRS and S&P ratings in the CCC category and lower also have subcategories "high/+" and "low/-" and the absence of "high/+" and "low/-" designation indicates the rating is in the "middle" of the category.







# GOAL 3

## Canadians benefit from efficient energy infrastructure and markets.

National Energy Board | Office national de l'énergie

# CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

## TRANSPORTATION ASSESSMENT







JUNE 2006

Canada



National Energy Board

Office national de l'énergie

# CANADIAN HYDROCARBON

## TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT

**JUNE 2006**

Canada

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# ACRONYMS AND ABREVIATIONS

| | |
|---|---|
| AOS | Authorized Overrun Service |
| Alliance | Alliance Pipeline Ltd. |
| Altex | Altex Energy Ltd. |
| CAPP | Canadian Association of Petroleum Producers |
| CEPA | Canadian Energy Pipeline Association |
| Cochin | Cochin Pipe Lines Ltd. |
| Coral | Coral Energy Canada Inc. |
| DBRS | Dominion Bond Rating Service |
| EBIT | Earnings Before Interest and Taxes |
| Enbridge | Enbridge Pipelines Inc. |
| Express | Express Pipeline Limited Partnership |
| Foothills | Foothills Pipe Lines Ltd. |
| FT | Firm Transportation |
| FT-RAM | Firm Transportation Risk Alleviation Mechanism |
| GDP | Gross Domestic Product |
| Gateway | Gateway Pipeline Inc. |
| IGUA | Industrial Gas Users Association |
| Irving/Repsol | Irving Oil Company Limited and Repsol YPF |
| Kinder Morgan | Kinder Morgan Canada Inc. |
| LNG | Liquefied natural gas |
| M&NP | Maritimes & Northeast Pipeline Management Ltd. |
| Mackenzie | Mackenzie Gas Project |

| | |
|---|---|
| Moody's | Moody's Canada Inc. |
| NEB or Board | National Energy Board |
| OEB | Ontario Energy Board |
| PADD | Petroleum Administration Defense Districts |
| PCOG | Petro-Canada Oil and Gas |
| PNGTS | Portland Natural Gas Transmission System |
| ROE | Return on Common Equity |
| S&P | Standard & Poor's |
| Terasen | Terasen Pipelines Inc. |
| T-South | Westcoast's Southern Mainline (Zone 4) |
| TNPI or Trans-Northern | Trans-Northern Pipeline Inc. |
| TPTM | Terasen Pipelines (Trans Mountain) Inc. |
| TQM | Trans Québec & Maritimes Pipeline Inc. |
| TransCanada or TCPL | TransCanada PipeLines Limited |
| U.S. | United States |
| Union Gas | Union Gas Limited |
| WCSB | Western Canada Sedimentary Basin |
| Westcoast | Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission |

# UNITS

| | |
|---|---|
| Bcf | Billion cubic feet |
| MMcf/d | Million cubic feet per day |
| GJ | Gigajoule |
| $m^3/d$ | Cubic metres per day |
| $10^3m^3/d$ | Thousand cubic metres per day |
| MW | Megawatt |

# FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency whose purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest[1] within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians.

The main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids (NGLs) and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas. In addition, the Board provides energy information and advice by collecting and analyzing information about Canadian energy markets through regulatory processes and monitoring.

This report, the second of its kind, provides an assessment of the Canadian hydrocarbon transportation system. To do so, it brings together data from various publicly available sources that was collected and monitored by NEB staff as well as throughput data supplied by the pipeline companies. The Board also benefited from discussion with members of the investment community with respect to capital markets and emerging issues. Prior to the release of this report, a draft was sent to the Canadian Energy Pipeline Association (CEPA) and the Canadian Association of Petroleum Producers (CAPP) for comment. Comments provided by CAPP and CEPA were taken into consideration in the preparation of this report.

Any comments on the report or suggestions for further analysis can be directed to:

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Applications Business Unit
National Energy Board
Telephone: (403) 299-3661
Email: koverli@neb-one.gc.ca

If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as can be done with any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

Information about the NEB, including its publications, can be found by accessing the Board's website: http://www.neb-one.gc.ca.

[1] The Canadian public interest is all Canadians and refers to a balance of economic, environmental and social interests that change as society's values and preferences change.

# INTRODUCTION

Energy is essential to our daily lives. The ability of the pipeline transportation system to deliver this energy in the form of natural gas, natural gas liquids (NGLs), crude oil and petroleum products is critical to Canada's economic well-being.

Canadians depend on a safe, reliable and efficient energy supply. The 45 000 kilometres (km) of interprovincial and international pipelines regulated by the NEB are a crucial element in Canada's transportation and distribution system (Figures 1 and 2). These systems include large-diameter, cross-country, high-pressure natural gas pipelines, low-pressure crude oil and oil products pipelines, and small-diameter pipelines.

Pipelines have a well-deserved reputation as the safest and most energy-efficient method of moving vast amounts of fuel from producers to consumers. In 2005, approximately $120 billion worth of products flowed through Canadian pipelines to markets at home and in the U.S. The cost in 2005 of providing these transportation services is estimated to be around $5 billion, not including fuel costs paid by shippers on natural gas pipelines. This was accomplished by infrastructure that is mostly invisible to consumers and that operates with a low rate of failure and minimal environmental impact.

To assist in the delivery of its mandate and to ensure that the Board's regulatory oversight provides value to Canadians, the Board developed five goals:

1. NEB-regulated facilities and activities are safe and secure, and are perceived to be so.
2. NEB-regulated facilities are built and operated in a manner that protects the environment and respects the rights of those affected.
3. Canadians benefit from efficient energy infrastructure and markets.
4. The NEB fulfills its mandate with the benefit of effective public engagement.
5. The NEB delivers quality outcomes through innovative leadership and effective processes.

Each year, the Board issues various reports that focus on different aspects of Canadian energy markets. This report, which assesses how well the Canadian hydrocarbon transportation system is working, pertains largely to Goal 3. However, for the system to function efficiently and effectively, it must operate in a safe and environmentally acceptable manner, which relates to Goals 1 and 2. Outcomes related to safety and the environment are discussed in a companion document, the Board's report, *Focus on Safety and Environment, a Comparative Analysis of Pipeline Performance.*

This report should not be read as a regulatory document. In this report, the Board is not making a determination on regulatory matters because the factors on which the functioning of the transportation system is assessed are not necessarily the same as those considered in a regulatory proceeding.

For the hydrocarbon transportation system to work well, the Board believes the following three outcomes should be achieved:

1. there is adequate pipeline capacity in place to move energy products from producers to consumers;
2. pipeline companies are providing services that meet the needs of shippers at reasonable prices; and
3. pipeline companies have adequate financial integrity to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

An efficient hydrocarbon transportation system needs to have the ability to be expanded on a timely basis when changing market conditions require new pipeline capacity. In order for expansion to occur in the time frame required, two things should occur. First, pipeline companies must have ready access to financial markets on reasonable terms and conditions. In addition, the regulatory process must be timely and predictable, while allowing a fair opportunity for all affected parties to provide input prior to a decision on an application being made.

In this report, the Board provides an assessment of the ability of pipeline companies to access capital on reasonable terms and conditions. The Board does not, however, provide an assessment of the efficiency and effectiveness of its regulatory processes. The Board reports on a number of regulatory efficiency measures in its *Annual Report to Parliament* and in the annual *Departmental Performance Report* that are submitted to the Treasury Board, both of which are public documents. This report, in the discussion of the Pipeline Services Survey (see Section 2.3.1), does provide information on shippers' perceptions of the Board's regulatory process. The Board recognizes that there is the potential to improve the means by which regulatory effectiveness and efficiency is measured and will be consulting with stakeholders on this topic.

For the Board's financial regulatory purposes, pipeline companies have been divided into two groups, Group 1 and Group 2. Major oil and gas pipeline companies are designated as Group 1 and are actively regulated by the NEB. All other NEB-regulated pipeline companies are classified as Group 2 companies and are subject to a lighter degree of regulation. A listing of companies regulated by the Board, as of 31 December 2005, can be found in Appendix 4.

**FIGURE 1**

***Gas Pipelines Regulated by the NEB***

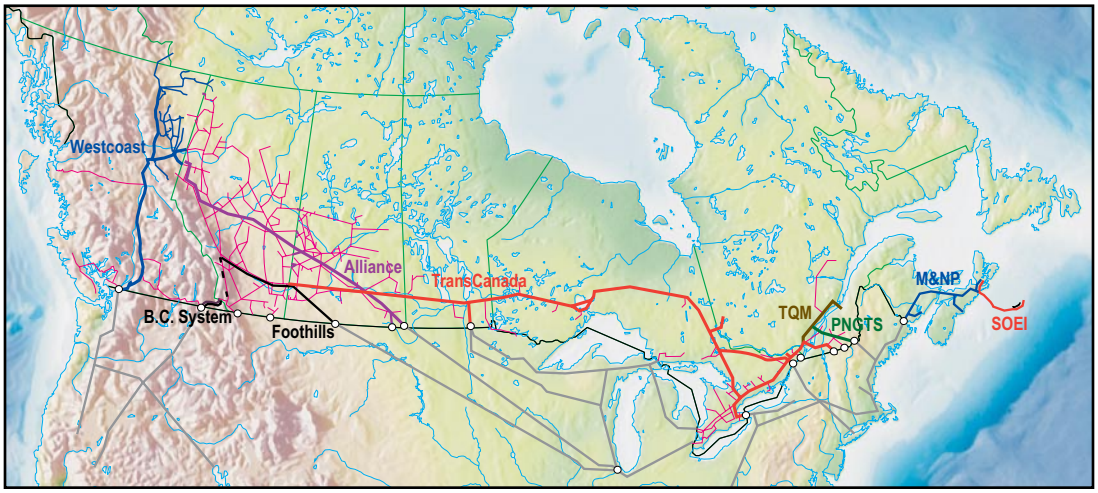


FIGURE 2

***Oil Pipelines Regulated by the NEB***

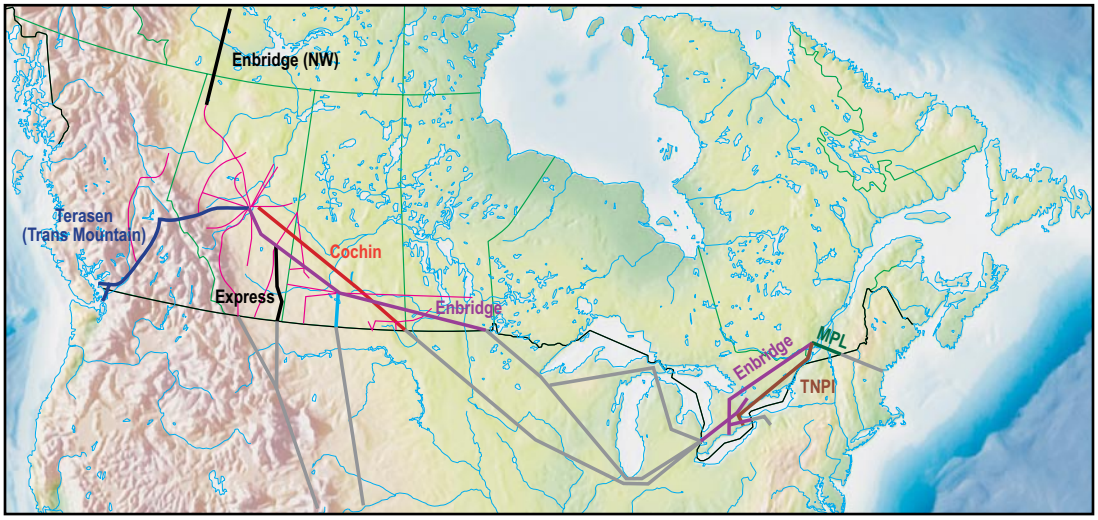
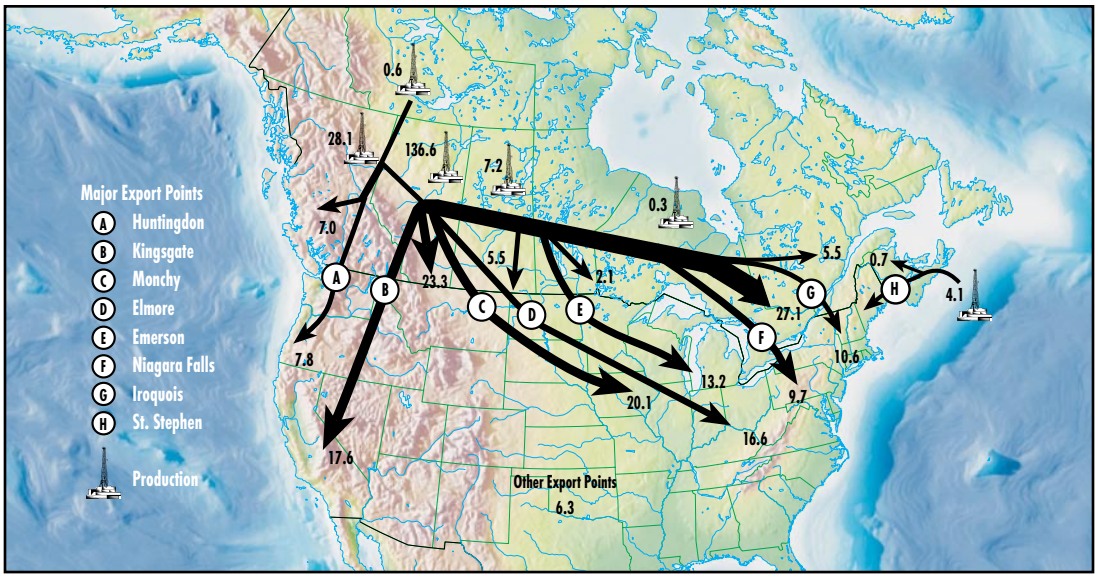



FIGURE 3

***2005 Supply and Disposition of Natural Gas***

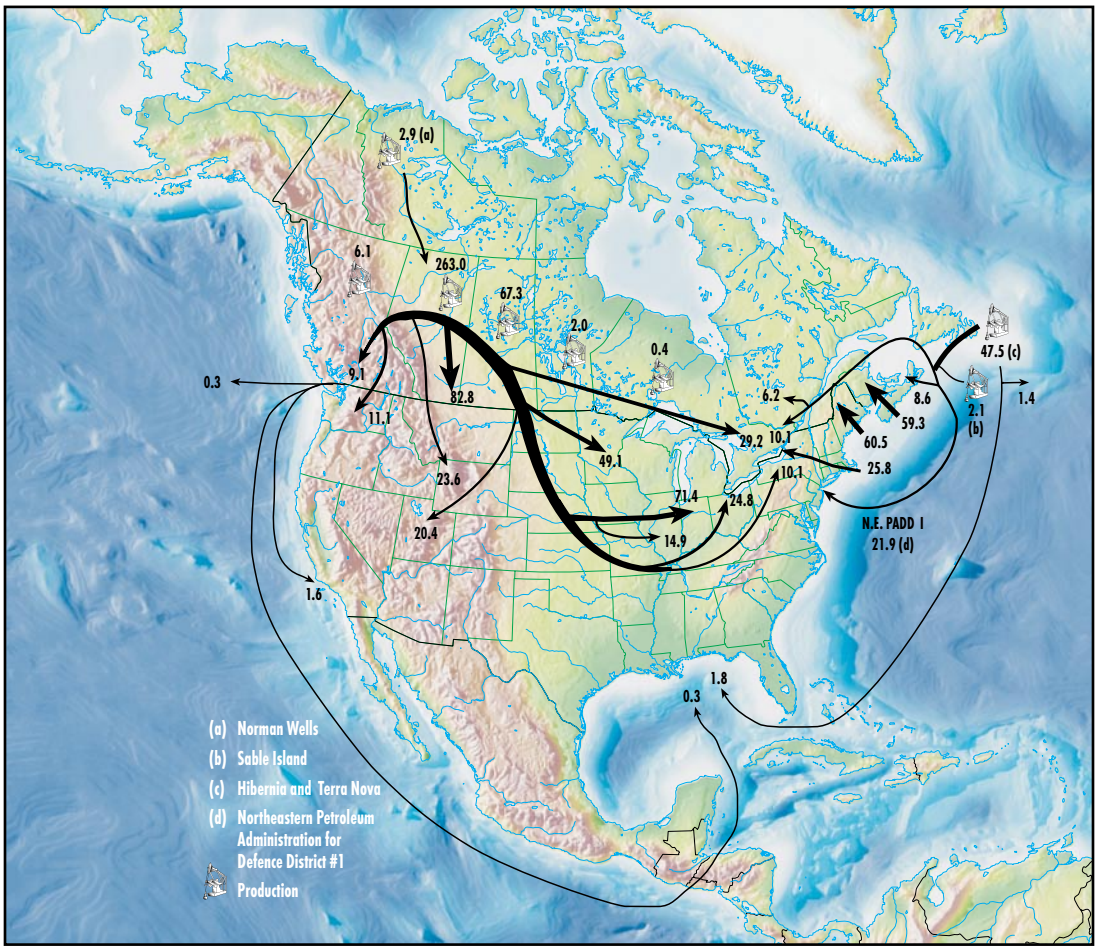



Publicly available data for Group 1 companies and Express Pipeline Limited Partnership (Express), the largest Group 2 company, was used to assess the extent to which the three outcomes identified by the Board are being achieved. These companies represent ownership of the majority of the Canadian hydrocarbon transportation system regulated by the NEB and the data from these companies provides a good view of the overall functioning of the hydrocarbon transportation system.

More detailed information can be found in the Board's 2005 Annual Report.

**FIGURE 4**

***2005 Supply and Disposition of Oil***



# THE CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

## 2.1 Adequacy of Pipeline Capacity

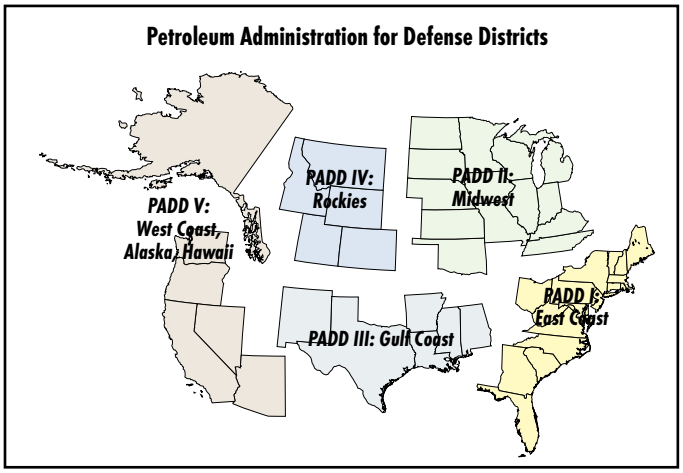
A key measure of an energy market's operational efficiency is the ability of its pipeline system to adequately transport crude oil, refined products, natural gas and NGLs from producing to consuming regions.

This section examines the following factors to assess the current adequacy of pipeline capacity:

1. price differentials compared with firm service tolls for major transportation paths;
2. capacity utilization on pipelines; and
3. the degree of apportionment on major oil pipelines.

The Board has generally taken the view that some excess capacity on a pipeline is better than not having enough. Higher tolls for shippers are a cost of having excess pipeline capacity; however, the costs associated with not having enough pipeline capacity are generally greater. Substantial revenue is lost when producers are unable to move their oil or gas to market. Not only is it important to have some excess capacity, but flexibility with sufficient access to the right markets or for the right type of product is also important.

When there is inadequate pipeline capacity to transport crude oil to the West Coast and PADD V (West Coast) producers have the option of transporting crude oil to Ontario and PADD II (Midwest) or PADD IV(Rockies). In addition, when refineries are in turnaround (maintenance) in Ontario and PADD II, crude oil volumes can be delivered to the West Coast and PADD V or PADD IV providing there is pipeline capacity.




The importance of having adequate pipeline capacity in place is highlighted by the fact that the value of natural gas and oil transported in NEB-regulated pipelines far exceeds the cost of service on those pipelines.

### 2.1.1 Price Differentials and Natural Gas Firm Service Tolls

When there is adequate pipeline capacity between two market hubs, commodity prices will be connected and the price differential will be equal to, or less than, the transportation costs between the two points. As long as the price differential is less than the toll plus fuel, the market is indicating that there is adequate pipeline capacity between the two pricing points. Conversely, when there is inadequate pipeline capacity between two market points, the basis, that is the differential in price between the two end points, will exceed the cost of transportation. In a market with adequate capacity, sellers would generally direct their product to the market that nets the highest revenue back to the producer, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market and the price differential persists, resulting in higher prices for consumers and lost revenues for producers.

In order to use price differentials as a measure of the adequacy of pipeline capacity, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below – one for transportation on TransCanada PipeLines Limited (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission (Westcoast).

Figure 5 shows the basis differential between the Alberta border and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The basis between the Alberta border and the Dawn delivery point is generally below the total cost of transportation (firm transportation plus fuel) via the TransCanada pipeline connecting these two markets. This indicates that pipeline capacity is adequate between these locations. As indicated by the variation in basis between the two locations, natural gas pricing is very responsive to relatively small changes in flow or demand. The short-term increase in the basis differential between September 2005 and January 2006 was a result of increased demand for supply from other basins when gas supplies from the Gulf of Mexico were reduced due to hurricanes Katrina and Rita. Cold weather early in the winter also affected demand. In addition, after the hurricane-induced gas price increase, the cost of fuel for use in the pipeline compressors also increased temporarily. Very mild weather and reduced demand in response to higher prices has since moderated flows and the demand for gas and transportation.

**FIGURE 5**

***Dawn – Alberta Basis vs. TransCanada Toll and Fuel***

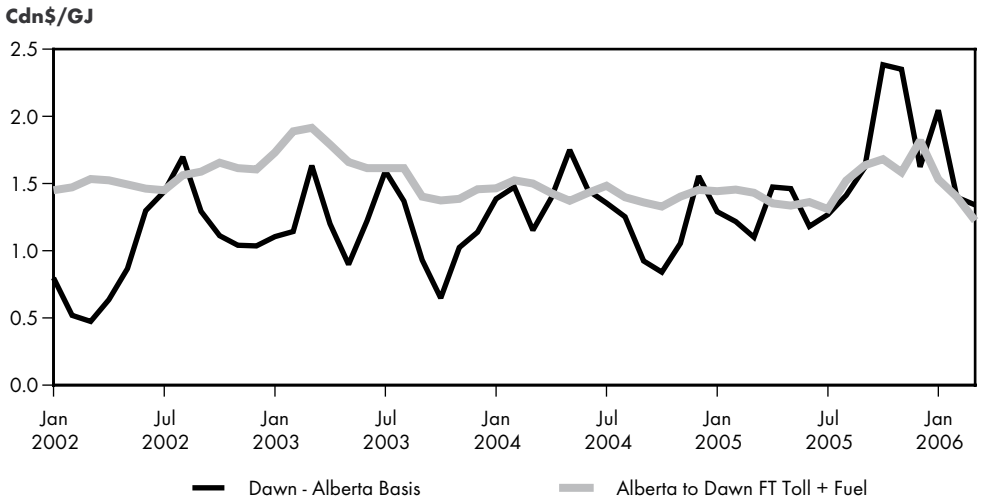
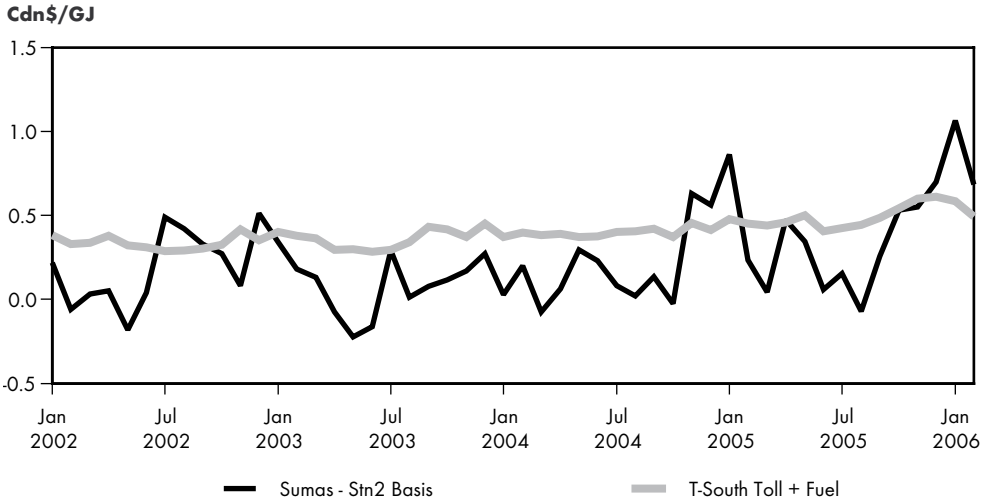


Figure 6 shows the basis between Compressor Station 2 on the Westcoast system and the Sumas export point compared with the Westcoast firm service toll between the two points (T-South or Southern Mainline), including fuel costs. Since January 2002, except for a few months, the basis has been lower than the transportation costs indicating that there has been adequate capacity in place since that time.

**FIGURE 6**

***Sumas – Station 2 Basis vs. Westcoast T-South Toll and Fuel***




Note: 2006 - interim term-differentiated toll (5 or more years service).

Overall, the comparison of price differentials and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. In general, the basis between pricing points has been slightly lower than pipeline transportation and fuel costs. However, natural gas pricing is volatile. Hurricane-induced supply disruptions in the Gulf of Mexico and erratic weather impact both basis and pipeline fuel costs. Figures 5 and 6 both indicate times where the basis exceeded transportation and fuel costs. These events proved to be temporary, and gas flows and prices moderated.

### *Price Differentials and Tolls on Oil Pipelines*

The major drivers of price differentials, amongst other things, are availability of pipeline capacity, competition, supply and demand, seasonality and the grade (quality) of crude oil. Price differentials are increasingly becoming an issue on oil pipelines because of the increase in bitumen blend crude oil supply from the oil sands. Limited access to markets, particularly those with refineries that process heavy crude oil, exerts downward pressure on heavy oil prices and widens the light-heavy differential.

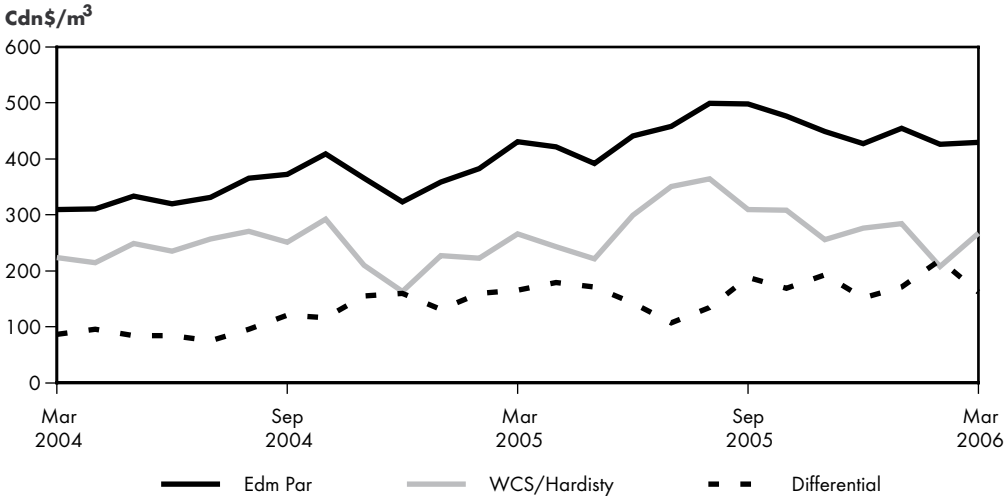
Figure 7 illustrates the wide light-heavy differential as indicated by the difference in price of Edmonton Par light crude oil and Western Canadian Select (WCS), a heavy crude oil. As shown, the average differential has been increasing during the time period shown and in recent years has averaged about 30 percent over the course of a year. Notably, in the first quarter of 2006, the price of heavy crude was, on average, 42 percent less than the price for light crude oil (the light-heavy differential).

Typically, the differential is narrower during the summer months due to the additional demand for heavier crude oil for use in the production of asphalt for paving.

Differentials have also widened as a result of supply growth from the oil sands, pipeline constraints and a lack of refinery capacity to process heavier crude oil. Wide light-heavy differentials reduce heavy oil producers' netbacks and at extreme levels could possibly result in some oil sands projects being uneconomic. Recently, the differential has narrowed because of increased market access with the delivery of western Canadian crude oil to Cushing, Oklahoma through the Spearhead Pipeline and into the U.S. Gulf Coast through the reversed Mobil Pipeline.

**FIGURE 7**

***Canadian Crude Oil Prices and Differential***




### 2.1.2 Capacity Utilization on Major Routes

Pricing data is available for a number of injection and delivery points on pipeline systems. Even where this data is not available, another measure of adequate capacity is obtained by comparing throughput with capacity. The Board monitors capacity utilization for most of the large pipelines it regulates.

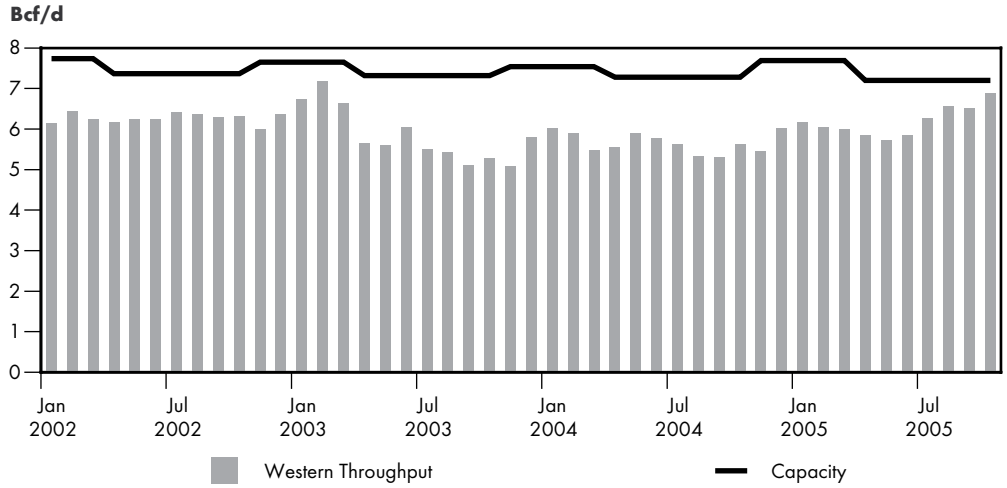
The following figures show pipeline average monthly throughput compared with capacity for some of the largest NEB-regulated pipeline systems, including the TransCanada Mainline, Foothills Pipe Lines Ltd. (Foothills), TransCanada B.C. System, Westcoast, Alliance Pipeline Ltd. (Alliance), Trans Québec & Maritimes Pipeline (TQM), Maritimes & Northeast Pipeline (M&NP), Enbridge Pipelines Inc. (Enbridge), Kinder Morgan Canada's Terasen Pipelines (Trans Mountain) Inc. (TPTM), Express and Trans-Northern Pipeline Inc. (TNPI).

*Natural Gas*

Figure 8 compares the average monthly throughput on the TransCanada Mainline (which is approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan) to the capacity of TransCanada's prairie line. It demonstrates that while the prairie line has been operating at between 70 to 80 percent of capacity since April 2003, the volumes have increased in recent months. These higher volumes reflect increased eastern demand for Canadian gas due to last year's hot summer weather and reduced gas supplies (since September) from the Gulf of Mexico following the late summer hurricanes. Overall, the indicator shows that there has been adequate pipeline capacity to move volumes to eastern markets.

**FIGURE 8**

***TransCanada Mainline Throughput vs. Capacity***




The volumes shown in Figure 9 are the average monthly throughput on TransCanada's Foothills Pipeline (Sask.) compared with capacity. This pipeline connects with Northern Border Pipeline Ltd. (Northern Border) and Monchy, Saskatchewan to flow gas to the U.S. Midwest. While the Foothills (Sask.) capacity utilization has been running at an annual average of about 94 percent since 2002, there was some decline in the spring of 2005. The lower volumes were due to a period of unsold firm capacity on the connecting Northern Border pipeline, stemming from low seasonal demand and high storage levels.

**FIGURE 9**

***Foothills Pipeline (Sask.) Throughput vs. Capacity at Monchy***

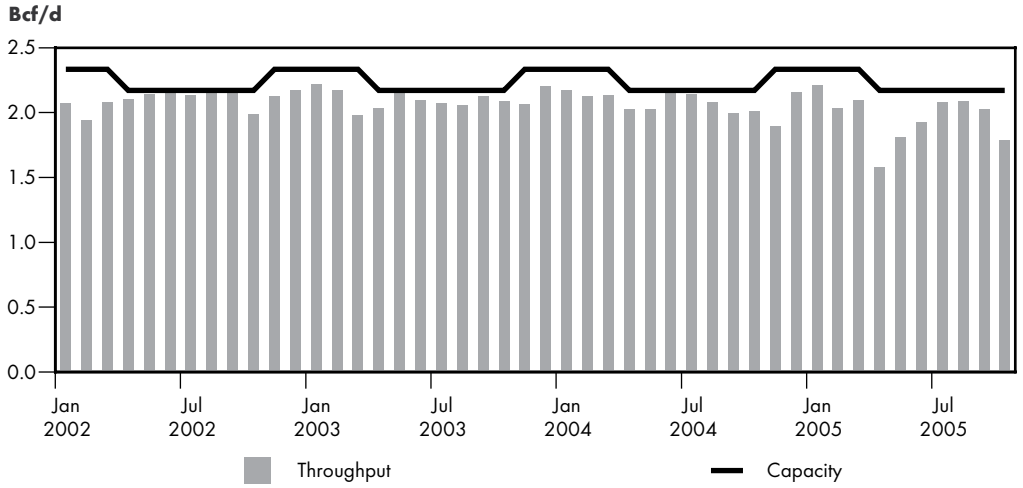



Figure 10 compares the average monthly throughput on Westcoast's Southern Mainline with the capacity on this system between Station 2 and the Sumas export point. This figure shows the seasonal nature of throughput on the Southern Mainline with higher volumes being transported during the peak winter months and less during the summer. One of the major contributors to low flows on Westcoast is the competition with production from the U.S. Rockies region which also has access to the U.S. Pacific Northwest market via Williams' Northwest Pipeline system. A warm winter and increased hydro power generation in British Columbia and the U.S. Pacific Northwest reduced gas flows on this pipeline in early 2006. In fact, the peak flow levels were lower than normal, as was the duration of the winter peak.

FIGURE 10

***Westcoast Mainline Throughput vs. Capacity***

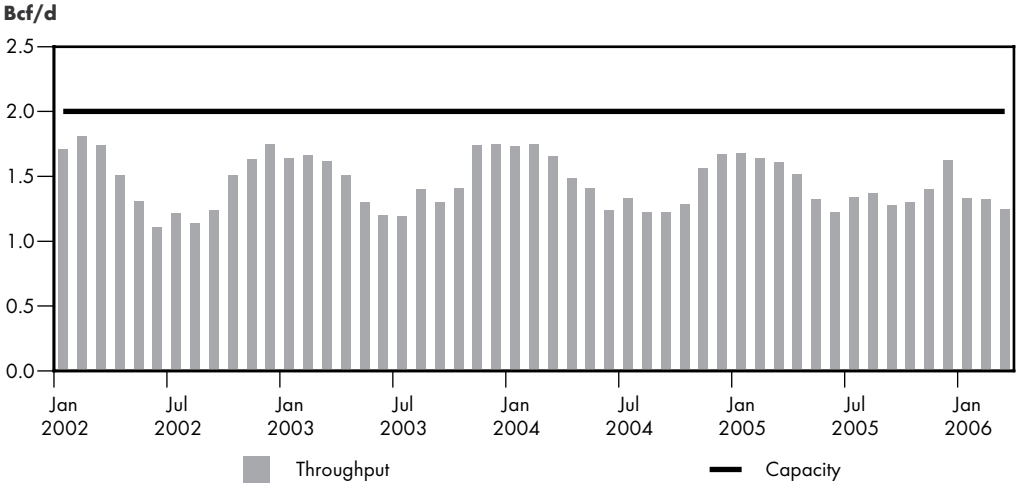



Figure 11 shows the average monthly throughput and capacity on the TransCanada B.C. System. The annual average capacity utilization dropped from about 77 percent in February 2002 to about 60 percent in March 2006, and there is spare capacity on this pipeline to export gas through Kingsgate. In California, which is the B.C. System's primary market region, market players have transportation options enabling them to access supply from the Rocky Mountains, San Juan and Permian basins, in addition to the Western Canada Sedimentary Basin (WCSB).

FIGURE 11

***TransCanada B.C. System Throughput vs. Capacity at Kingsgate***

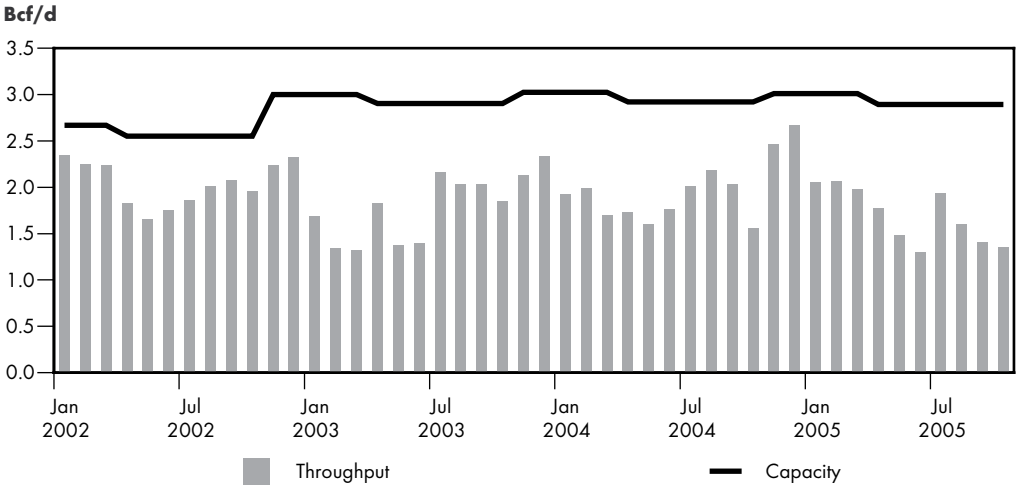



Figure 12 shows the average monthly throughput on the Alliance system relative to physically available capacity levels. Alliance offers approximately 37 534 $10^3m^3/d$ (1.325 Bcf/d) of firm service capacity, and makes any additional capacity available to its contracted shippers pro rata as Authorized Overrun Service (AOS). Available AOS levels are determined on a daily basis and may be used at the cost of fuel only. The total available capacity is variable, depending on such factors as ambient temperature and compressor unit availability (as influenced by maintenance schedules). Alliance's total available capacity has essentially been fully utilized since the commencement of service, with all available firm service contracted on a long-term basis.

FIGURE 12

***Alliance Throughput vs. Capacity***

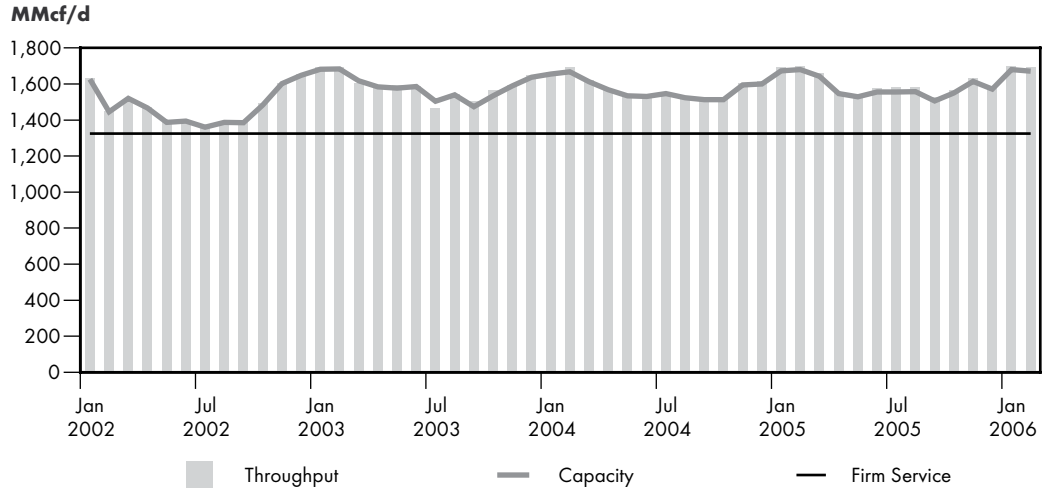



Figure 13 compares the average monthly throughput and capacity on TQM. This figure shows the seasonal nature of the throughput on this pipeline, with more volumes being transported during the peak winter months. With the annual average capacity utilization of around 60 percent, there is spare capacity on this pipeline which delivers gas between the TransCanada Mainline, connecting TQM at Saint-Lazare on the Ontario and Québec border, and TQM's endpoints at Saint-Nicolas (south shore of Québec City) and East Hereford (New Hampshire state border). However, with the limited compression on the system needed to meet TQM's delivery pressure at the East Hereford export point, the available spare capacity is very sensitive to the actual load distribution along the pipeline. Higher system utilization in 2005 reflects increased exports at East Hereford due to reduced gas supplies from the Gulf of Mexico following the late summer hurricanes.

FIGURE 13

***Trans Québec & Maritimes Throughput vs. Capacity***

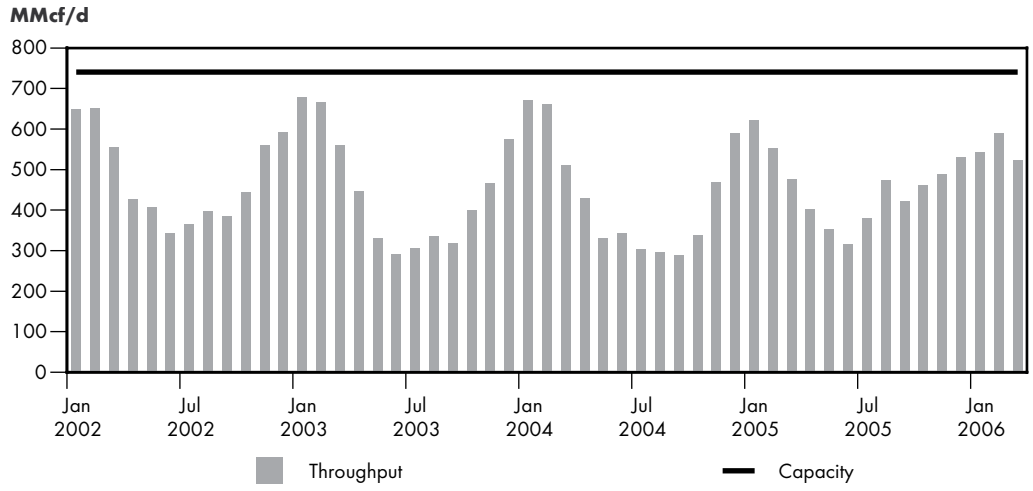
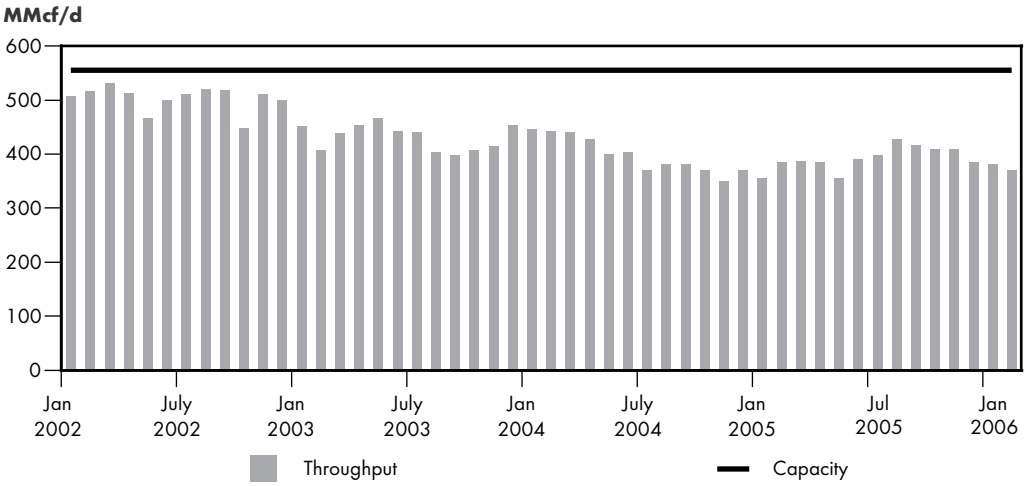



Figure 14 compares the average monthly throughput on the M&NP pipeline with its capacity. The annual average capacity utilization has been declining from about 92 percent in 2002 to an average of about 70 percent in 2005. The drop in this pipeline's utilization stems from declining natural gas production from Nova Scotia's Sable Offshore Energy Project. The variations in throughput are primarily related to changes in gas supply.

FIGURE 14

***Maritimes & Northeast Pipeline Throughput vs. Capacity***




Although the Dawn-Parkway corridor is not regulated by the NEB, it is a key link between the Dawn hub and growing markets in eastern Canada and the U.S. Northwest. Last year the Ontario Energy Board (OEB) approved Union Gas' Phase 1 Expansion, expected to be in service by November 2006. This year, Union filed an application with the OEB for its Phase 2 Expansion. If approved, the expansion is expected to be in service by 1 November 2007. Market demand for capacity in this corridor is expected to remain robust due to the liquidity of Dawn as a transactional trading point given its market reach.

### *Oil*

Determining the capacity and throughputs on an oil pipeline can be complex as there are a number of factors to be considered: the type of product, product mix, type of batching, pipeline configurations and bottlenecks.

The Enbridge system originates in Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba to join the Lakehead system in the U.S. It is the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The system consists of several lines transporting crude oil, NGLs and refined petroleum products. Figure 15 illustrates Enbridge Mainline throughput versus capacity for all lines. In 2005, Enbridge transported roughly 224 600 $m^3/d$ (1.4 million barrels per day) of crude oil, petroleum products and NGLs. In the first quarter of 2006, Enbridge operated at around 80 percent of capacity (Figure 15). Certain lines, particularly Lines 3 and 4, which transport heavy oil, have been operating at or close to full capacity, with some apportionment (see Section 2.1.3).

In November 2005, Kinder Morgan purchased Terasen Inc., owner of the Trans Mountain pipeline system. This purchase made Kinder Morgan a major oil pipeline player in Canada. TPTM's current capacity, assuming some shipments of heavy oil, is 35 700 $m^3/d$ (225 Mb/d). The pipeline has been operating at or near capacity for several years and on many occasions has been under apportionment (see Section 2.1.3). However, the capacity indicated in Figure 16 is 45 300 $m^3/d$ (285 Mb/d). This higher capacity assumes no heavy crude oil shipments. On average, particularly in the last two years, 20 percent of TPTM's crude oil receipts at Edmonton are heavy and because of the increased viscosity, pipeline capacity was reduced to 35 700 $m^3/d$ (225 Mb/d).

FIGURE 15

***Enbridge Pipeline Throughput vs. Capacity***

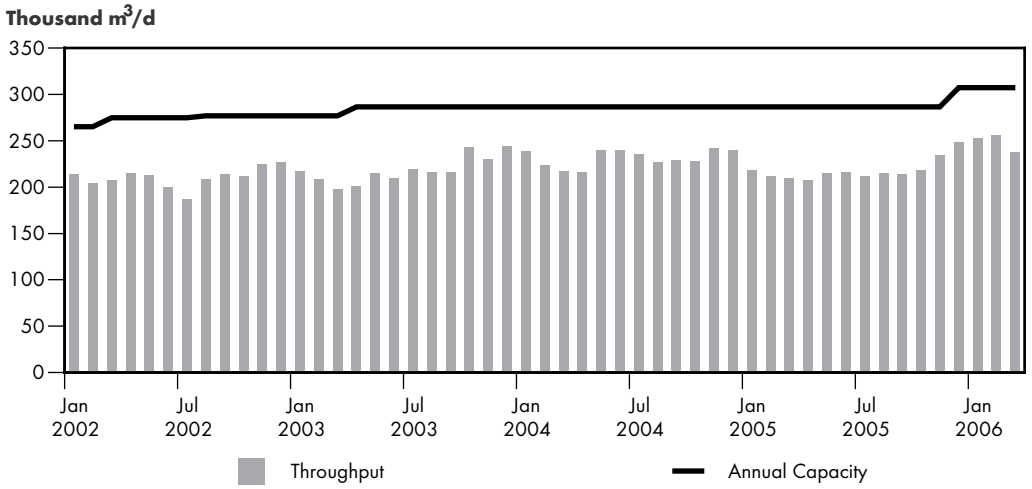
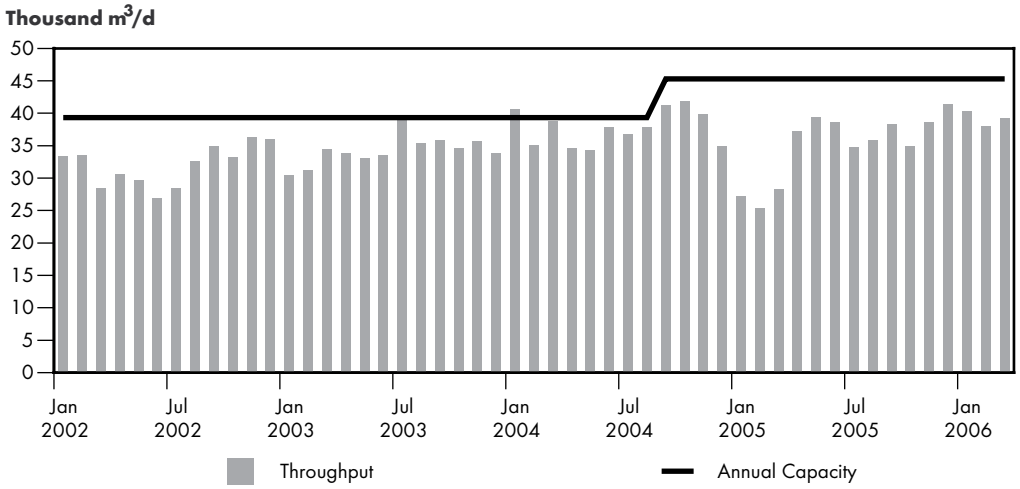



FIGURE 16

***TPTM Throughput vs. Capacity[2]***




On 5 July 2005, Terasen applied to the NEB for a capacity increase of 5 600 $m^3/d$ (35 Mb/d). It was approved on 10 November 2005 and the in-service date is April 2007.

In the first quarter of 2006, TPTM operated at approximately 86 percent of capacity (see Figure 16). Though the system did not operate at capacity, TPTM was under apportionment in January, February and March of 2006. Many factors contributed to this apportionment, including growing oil sands supply coupled with increased demand from Washington State refiners and crude oil shipments off the Westridge Dock.

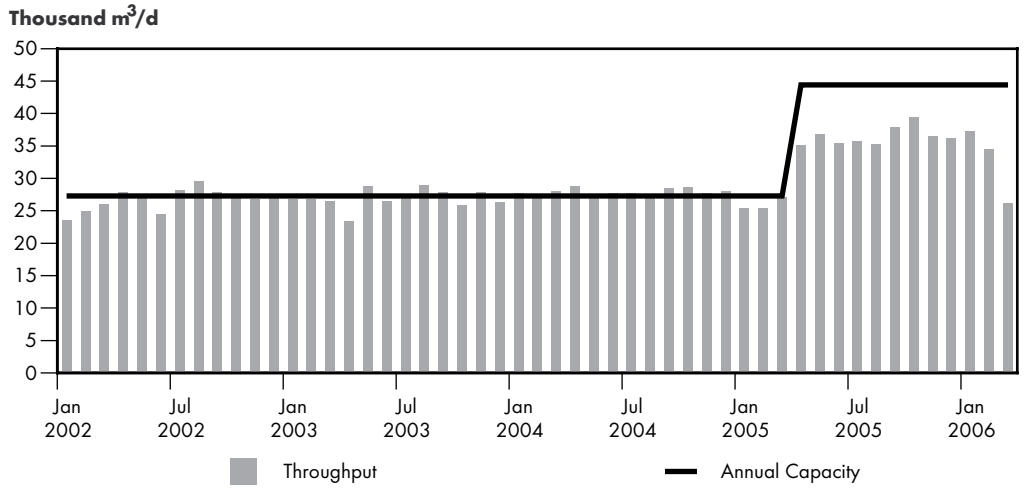
During the past several years, Express has been operating at capacity. In April 2005, Express completed its 17 600 $m^3/d$ (100 Mb/d) expansion, bringing the total capacity to 44 900 $m^3/d$ (280 Mb/d). Express is the only crude oil pipeline in western Canada that operates under long-term take-or-pay agreements with its shippers for the majority of its capacity.

2 Capacity shown is light crude oil only (0% heavy).

In the first quarter of 2006, Express operated at approximately 73 percent of capacity (Figure 17). Throughputs were reduced in March 2006 due to apportionment on the Platte Pipeline system in the U.S.

FIGURE 17

***Express Throughput vs. Capacity***



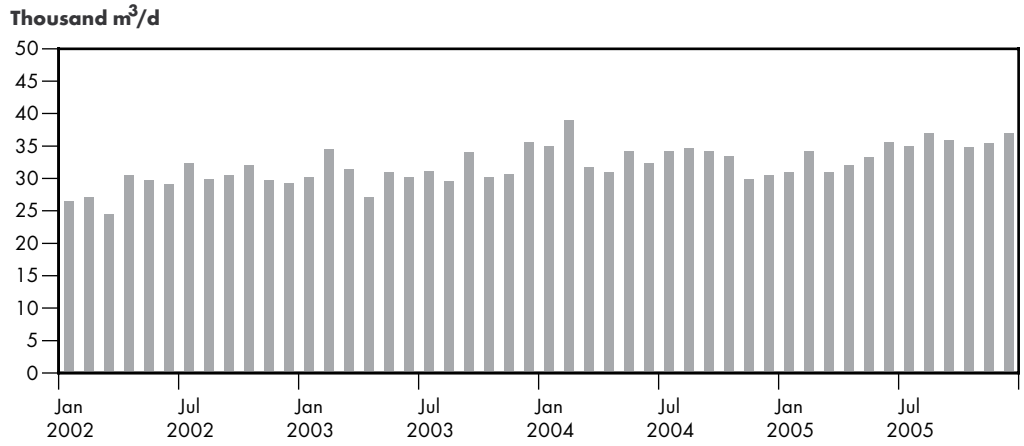

TNPI is a refined petroleum products pipeline. Historically, the pipeline system extended from Nanticoke, Ontario to Montreal, Quebec serving petroleum industry terminals along the route. In 2003, TNPI applied to the Board to increase the line capacity between Montreal and Farran's Point, Ontario from 10 500 $m^3/d$ (66 150 Mb/d) to 21 000 $m^3/d$ (132 300 Mb/d) and to reverse the direction of flow between Farran's Point and Metropolitan Toronto from a west-to-east direction to an east-to-west direction.

The Board approved TNPI's application to reverse the line and to accept take-or-pay obligations from Petro-Canada and Ultramar for 91 percent of the capacity. The remaining 900 $m^3/d$ or nine percent of the capacity from Farran's Point to Toronto is available for spot shipments.

The expansion and the reversal, which took place in November 2004, were a response to declining shipments on the TNPI system and the closure of Petro-Canada's refinery in Oakville, Ontario. Increased deliveries from Montreal on TNPI serve markets in Ontario formerly served by Petro-Canada's Oakville refinery and by Ultramar by rail from Quebec (Figure 18).

FIGURE 18

***Trans-Northern Pipelines Inc. Throughputs***



Calculating TNPI's capacity is difficult due to multiple delivery locations and the different capacities on each line segment.

### 2.1.3 Apportionment

Oil pipelines normally operate as common carriers, although pipelines such as Express, Enbridge Line 9 and TNPI operate with long-term shipper take-or-pay agreements. Common carriers require shippers to nominate their volumes for delivery into a pipeline on a monthly basis without a contract for the pipeline's capacity. When shippers nominate more oil or oil products in a given month than the pipeline can transport, shippers' volumes are apportioned (reduced) based on the tariff set out by the pipelines. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations and refinery maintenance. Some recent apportionment data for Enbridge, TPTM and Cochin is shown below.

*Enbridge*

Historically, Lines 2 and 4 were dedicated to the transportation of heavy crude oil and Line 3 was dedicated to the transportation of light and medium crude oils. In the third quarter of 2005, Enbridge completed the Terrace Phase III expansion project to facilitate the growth in heavy crude oil. By converting Line 2 from heavy to light service and Line 3 from light to heavy service, it increased its heavy capacity by 39 000 $m^3$/d (245 700 b/d and reduced its light capacity by 18 400 $m^3$/d (115 920 b/d).

As illustrated in Table 1, Line 4 was under apportionment once between August 2005 and February 2006. In February, each shipper was required to reduce its volume, resulting in a three percent reduction. There are a number of factors that caused the apportionment: increased throughput from the oil sands, apportionment on the Platte system in the U.S., increases in conventional production in North Dakota for injection at Cromer, Manitoba and Clearbrook, Minnesota; pipeline reconfiguration; and refinery maintenance.

Enbridge's Line 9 has a capacity of 38 150 $m^3$/d (240 000 b/d) and transports oil from Montreal, Quebec to Sarnia, Ontario. In contrast to last year, there was no apportionment on the line between August 2005 and February 2006. This was partly due to increased volumes of western Canadian light conventional crude oil being processed in Ontario refineries.

**TABLE 1**

***Enbridge Appointment*[3]**

| | Aug-05 | Sept-05 | Oct-05 | Nov-05 | Dec-05 | Jan-06 | Feb-06 |
|---|---|---|---|---|---|---|---|
| Line 4 Apportionment | 0% | 0% | 0% | 0% | 0% | 0% | 3% |
| Throughput ($10^3m^3$/d) | 104.3 | 103.4 | 102.4 | 113.0 | 90.4 | 113.9 | 111.0 |

*Terasen Pipelines (TransMountain) Inc.*

Apportionment on TPTM is calculated separately for domestic destinations, export destinations and Westridge Dock destinations (as shown in Table 2 as Domestic, Export and Dock). Apportionment in November 2005 through to March 2006 reflects increased volumes associated with expansion in the oil sands and the higher market demand for Canadian crude. In addition, heavy crude oil volumes also increased during this time limiting capacity on the TPTM system. With improving market economics TPTM is delivering increasing volumes of western Canadian crude oil into Washington

State refineries as well as for export over the Westridge Dock which contributed to apportionment at both of these locations.

Following three notices of motion and an oral argument heard on 11 April 2006, the Board released its Decision approving the inclusion of a premium in the Tariff as a means of allocating capacity to the Westridge Dock. Further information can be found in the Board's letter decision dated 12 April 2006 and MH-2-2005.

**TABLE 2**

***TPTM Apportionment***

| | Aug-05 | Sept-05 | Oct-05 | Nov-05 | Dec-05 | Jan-06 | Feb-06 | Mar-06 |
|---|---|---|---|---|---|---|---|---|
| Apportionment | | | | | | | | |
| Domestic | 0% | 0% | 0% | 12% | 0% | 16% | 32% | 34% |
| Export | 0% | 0% | 0% | 18% | 15% | 18% | 33% | 43% |
| Dock | 0% | 0% | 0% | 74% | 0% | 30% | 87% | 93% |
| Throughput ($10^3m^3/d$) | 35.9 | 38.4 | 34.9 | 38.7 | 41.4 | 40.3 | 38.0 | 39.2 |

*Cochin*

The Cochin pipeline is the largest and longest NGL pipeline in Canada. It transports propane, ethane, ethylene and butane, although no butane has been transported since 2002. Ongoing maintenance work on the pipeline has affected the available capacity. The lower throughput volumes and apportionment in September 2005 was caused by unexpected downtime required for immediate repairs. Because ethylene was already in the pipeline, there was no flexibility to transport larger volumes of other products (ethylene has a higher vapour pressure than propane and ethane and reduces the capacity of the pipeline).

Effective 7 March 2006, Cochin suspended the transportation of ethylene until at least the fall of 2007 due to a defect found in the U.S. portion of the pipeline and went on a voluntary pressure restriction. The pressure is not to exceed 900 psi and applies to the whole line from Fort Saskatchewan, Alberta to Windsor, Ontario. Without ethylene in the pipeline, propane and ethane shippers are not expected to face apportionment. The average capacity will be around 10.3 to 11.9 $10^3m^3/d$ (64 890 b/d to 79 970 b/d). Once the pressure restrictions are lifted, capacity is expected to return to 17.5 $10^3m^3/d$ (110 250 b/d).

**TABLE 3**

***Cochin Apportionment***

| | Aug-05 | Sep-05 | Oct-05 | Nov-05 | Dec-05 | Jan-06 | Feb-06 | Mar-06 |
|---|---|---|---|---|---|---|---|---|
| Apportionment | 0% | 18% | 0% | 0% | 0% | 0% | 0% | 0% |
| Throughput ($10^3m^3/d$) | 8.6 | 5.6 | 9.9 | 6.0 | 9.7 | 9.2 | 9.8 | 7.7 |

### 2.1.4 Summary of the Adequacy of Pipeline Capacity

Overall, the examination of throughput and capacity on NEB-regulated natural gas pipelines shows that pipeline capacity is adequate across the country although there may be limitations at some points depending upon markets, storage and seasonal shifts. The demand for natural gas varies seasonally and, as a result, the flow of natural gas through some Canadian pipelines can be variable as well.

[3] Line 4 was the only line on the Enbridge system out of western Canada that was apportioned during this period.

Where possible, the use of storage helps to reduce the variation in flows and allows pipeline capacity to be used more efficiently with higher annual capacity utilization.

Oil pipeline capacity, however, is tight and is expected to remain tight through 2008, even with the current expansions underway (Figure 28). This is being driven by increases in crude oil supply from the oil sands and in conventional production in North Dakota and PADD IV. In the first quarter of 2006, the price of heavy crude oil was, on average, 42 percent less than the price of light crude oil. This compares to a more typical light/heavy differential of around 30 percent. The light/heavy differential is typically wider during the winter months, reflecting reduced demand for asphalt and lower gasoline demand. However, the size of the differential in the first quarter reflects pressures building from an increase in supply, in this case from the oil sands, pipeline constraints and lack of refinery capacity to process heavier crude oil. Recently, the differential has narrowed as a result of market extension into Cushing, Oklahoma and the U.S. Gulf Coast through the Spearhead Pipeline and the Mobil Pipeline, respectively.

## 2.2 Pipeline Tolls

### *2.2.1 Pipeline Tolls Index*

Another indicator of a hydrocarbon transportation system's efficiency is whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). One of the factors the Board uses to analyze this is year-to-year variations in a benchmark toll for each of the major pipelines it regulates (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South Export toll). Under cost-of-service regulation, pipeline tolls can vary from year-to-year for various reasons. For example, a significant expenditure to modify or expand a system to meet shippers' needs could increase or decrease toll levels depending on the specific circumstances. Falling throughput or contract demand leading to lower capacity utilization could lead to a significant toll increase. The following sections review variations and trends of some NEB-regulated pipeline tolls since 1997.

*Natural Gas Pipeline Tolls*

The benchmark tolls[4] for TransCanada's Mainline, Westcoast, Foothills, the TransCanada B.C. System (B.C. System), TQM, M&NP, Alliance, and the GDP deflator[5] normalized to the year 2001 are shown in Figure 19.

The increase in TransCanada's benchmark toll between 1997 and 2004 is mainly attributed to a large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. This toll tracked the GDP deflator fairly closely from 2001 to 2004. However, in 2005 the toll fell, primarily due to increased contract demand and is below the level that it was in 2000.

Westcoast's tolls have increased moderately except for two years, 2000 and 2005. In 2000, Westcoast's benchmark toll increased more than 10 percent from the previous year primarily due to a large amount of non-routine pipeline integrity costs and in 2005, this toll increased by over 15 percent due to decontracting of firm services.

[4] The benchmark tolls are: TransCanada Eastern Zone; Westcoast T-South Export; Foothills Zone 9; B.C. System Postage Stamp; TQM Saint Lazare to Trois-Rivières; M&NP Postage Stamp; and Alliance monthly demand toll.

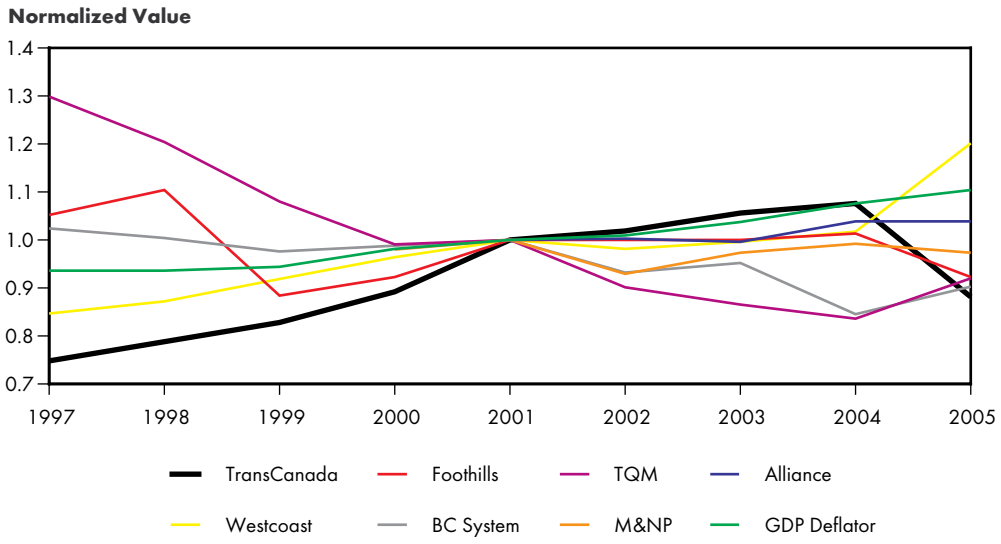
[5] The GDP deflator for 2005 is an estimate using actual data for the first half or the year and data estimated by Infometrica for the second half of the year.

The B.C. System, Foothills and TQM's benchmark tolls were lower in 2005 than in 1997. The B.C. System's benchmark toll decreased in 2004 primarily because of an increase in throughput volumes (over 10 percent) from 2003. Foothills benchmark toll dropped in 1999 as a result of a cost-effective expansion of its system. TQM's benchmark toll has decreased since 1997, although it increased somewhat in 2005. The decline was due, in part, to the Portland Natural Gas Transmission System (PNGTS) extension in 1999, which increased throughput over 30 percent from 1998.

M&NP and Alliance's benchmark tolls have been relatively constant since beginning operations at the end of 1999 and 2000 respectively.

FIGURE 19

***NEB-Regulated Gas Pipeline Benchmark Tolls***




### *Oil Pipeline Tolls*

The benchmark tolls for Enbridge, TPTM, TNPI, Express and the GDP deflator, normalized to the year 2001[6], are shown in Figure 20.

Enbridge's benchmark toll has risen fairly steadily over the period, growing at a faster pace than the GDP deflator, except for a drop in 2002. The tolls increased the most in 2000 and 2004. The increase in 2000 was due to unforeseen lower throughput levels in the previous year. Under its negotiated settlement, Enbridge was able, in the following year, to recapture the revenue shortfall due to the lower throughput. The 2004 increase was primarily due to operating at lower capacity utilization as a result of throughput not filling a recent capacity expansion. Higher fixed costs were spread across relatively lower volumes resulting in higher tolls.

TPTM's benchmark toll rose steadily from 1997 to 2003 but fell in the last two years. There was a large increase in 1999 due to low forecast throughput. During TPTM's first incentive toll settlement, tolls were calculated on forecast volumes. In 1999 the throughput forecast was 17.9 percent lower than the 1998 forecast, which lead to a corresponding increase in the benchmark toll. In 2004, the benchmark toll dropped primarily due to the disposition of 2003 deferrals for higher revenue. TNPI and Express's benchmark tolls moved in line with the GDP deflator from 1997 to 2005.

6 The benchmark tolls are: Enbridge Edmonton to International Border near Chippewa; TPTM Edmonton to Burnaby; TNPI Oakville to Montreal; and Express 15-year.

FIGURE 20

***NEB-Regulated Oil Pipeline Benchmark Tolls***

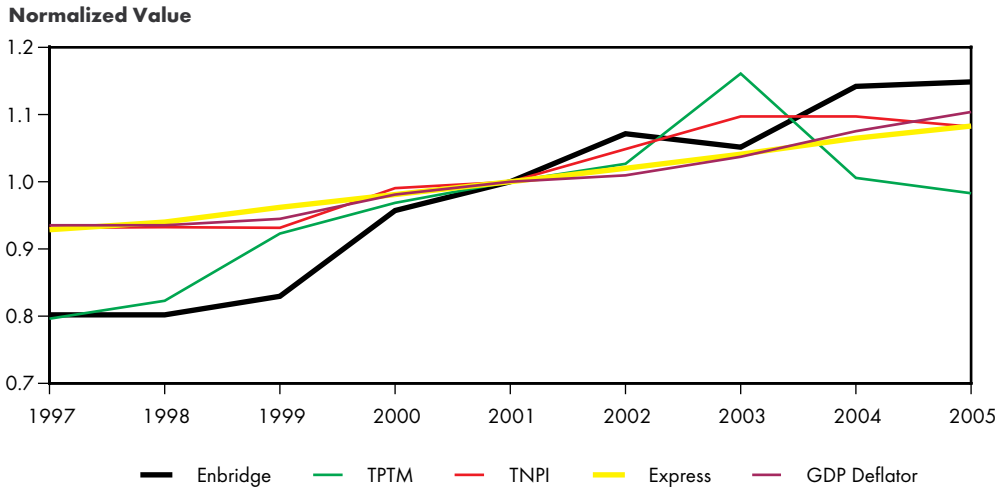
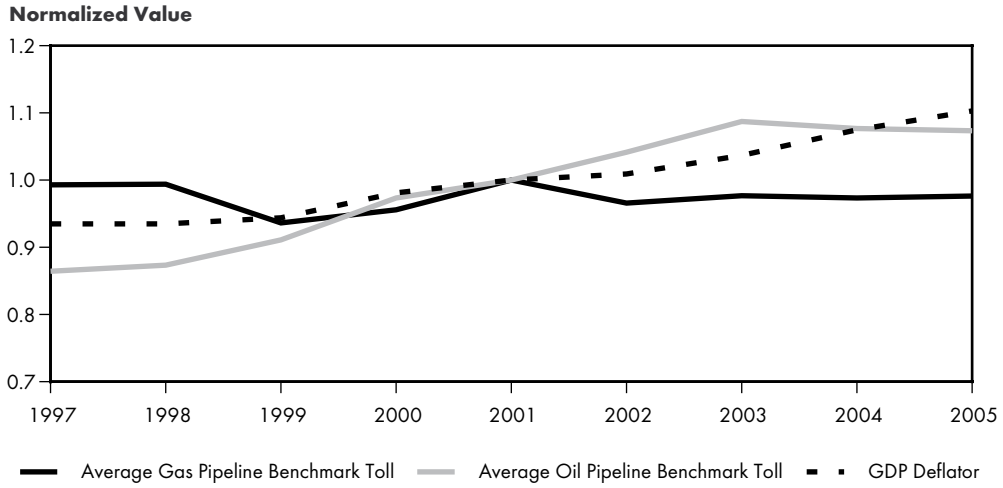



FIGURE 21

***Oil and Gas Pipeline Benchmark Tolls***




### *Comparison of Gas and Oil Pipeline Tolls*

The average gas and oil benchmark pipeline tolls (reported in Figures 19 and 20) and the GDP deflator are graphed in Figure 21. From 1997 to 2005, oil pipeline tolls increased on average more than gas pipeline tolls, whereas gas pipeline tolls experienced more variation than oil pipeline tolls.

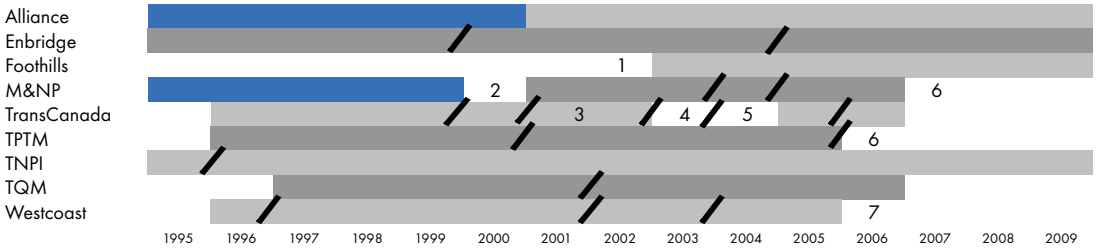
## 2.2.2 Negotiated Settlements

To improve the effectiveness of the regulatory process, the Board has supported the use of negotiated settlements as an alternative to toll hearings since the mid-1980s. In September 1988, the Board issued its first *Guidelines for Negotiated Settlements*. These guidelines were subsequently updated in August 1994 and revised again in June 2002 to provide flexibility when addressing contested settlements.

Most of the major Group 1 companies have successfully negotiated multi-year settlements with their shippers. Beginning in 1995, the Board approved a succession of multi-year settlements. These agreements generally included incentives to reduce costs and provisions to share savings between the pipeline company and its shippers. Several of these multi-year settlements have been renegotiated upon their expiry. For example, Enbridge Pipelines has negotiated three consecutive five-year settlements covering the period 1995 to 2009. Similarly, TPTM and TQM have had two successive five-year settlements and are in the process of renegotiating new ones. Refer to Figure 22 which shows, for each pipeline company, the years that were covered by negotiated settlements.

**FIGURE 22**

***Negotiated Settlements Timeline***




Notes:
1 - Foothills is regulated under an actual cost of service methodology
2 - RH-1-2000 Hearing for tolls from 1 December 1999 to 30 September 2000
3 - RH-1-2001 Hearing to consider contested settlement for 2001 and 2002 tolls
4 - RH-1-2002 Hearing for 2003 tolls
5 - RH-2-2004 Hearing for 2004 tolls
6 - In negotiations
7 - Westcoast and its shippers have negotiated a 2-year settlement
Alliance and M&NP were not in service during these years

Negotiated settlements have contributed to a significant reduction in the regulatory burden for all parties with less time spent participating in hearings and a corresponding reduction in costs associated with the hearing process. This may be somewhat offset by the increased time spent by pipeline companies and their shippers in task force meetings. Parties note that the greater use of task forces and settlements has increased the collaboration between pipeline companies and shippers and resulted in a better alignment of interests.

Some settlements have included various innovative performance mechanisms such as incentives for cost control and performance improvement standards. Examples of the latter include the service standards in Westcoast's 1997–2001 settlement and the service and reliability metrics in Enbridge's 2005–2009 incentive agreement.

Negotiated settlements have also increased the length of period for which tolls are set. Rather than annual toll proceedings, a number of agreements have terms of five years or longer, which provides greater predictability and stability.

## 2.3 Shipper Satisfaction

### 2.3.1 *NEB Pipeline Services Survey*

The Board conducted its second Pipeline Services Survey in early 2006 to obtain direct feedback from the shippers on the level of service provided by major NEB-regulated pipeline companies. The Board also uses this survey to obtain feedback from shippers on the Board's regulatory performance with respect to tolls and tariffs.

This year, the Board used a web-based survey tool to send the survey directly to shippers via e-mail. Shippers were sent one survey for each pipeline the shipper utilized during the past year. Each survey asked the shippers to provide their company's corporate views on the services provided by the pipeline being surveyed and on the services provided by the Board. The overall response rate of 33.5 percent was a significant improvement over last year's rate of 23 percent.

After analyzing the survey responses, the Board published a summary of the aggregate results on its website. They included the industry average and distribution of responses for each question and a summary of major themes. In addition, the Board provided each pipeline company and its shippers with detailed company-specific results. These results include the pipeline company's average rating, distribution of responses for each question as well as the verbatim comments received from shippers, excluding the names of the respondents.

The Board follows up on the survey results, including feedback on the Board, by meeting with pipeline companies and shippers.

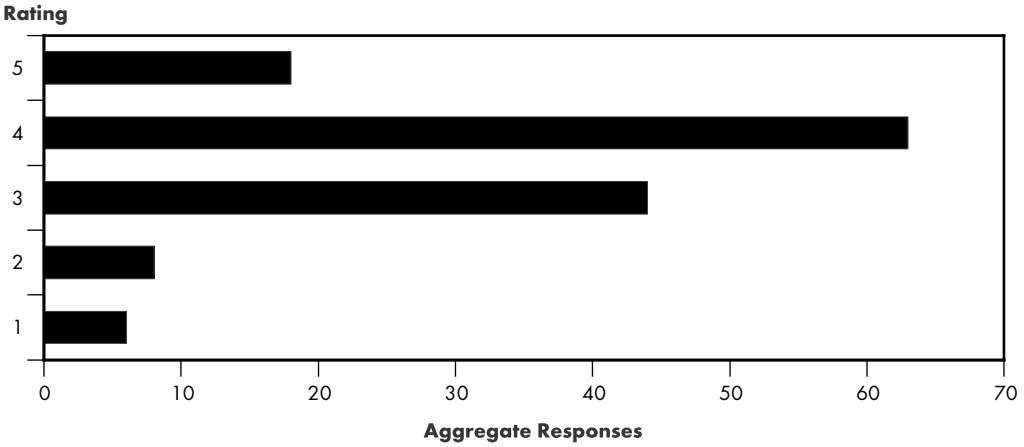
Appendix 2 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, refer to www.neb-one.gc.ca/Publications/SurveyResults.

*Pipeline Services*

Figure 23 shows the aggregate results for the survey question that asked shippers to rate their satisfaction with the overall quality of service provided by their pipeline companies over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). While the average score of 3.57 was lower than the score of 3.78 in last year's survey, shippers still appear reasonably satisfied with the services provided.

FIGURE 23

**Overall Quality of Service**



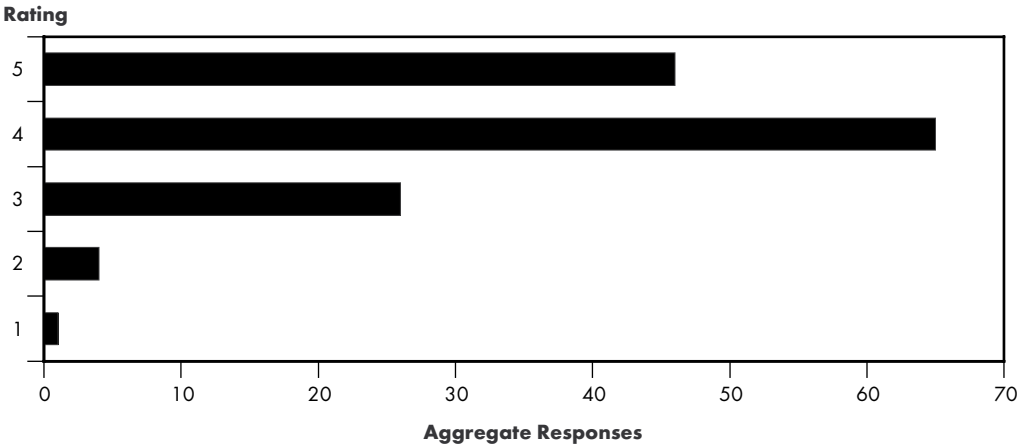
The three areas where the pipeline companies rated the highest were the same areas as in last year's survey, as demonstrated by the scores on the following questions:

1. How satisfied are you with the physical reliability of the pipeline company's operations?
2. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?
3. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the company?

The high level of satisfaction with the physical reliability of pipeline operations indicates that energy products are reliably being delivered to markets (see Figure 24).

**FIGURE 24**

***Physical Reliability of Operations***




The three areas where shippers believe that pipeline companies could improve the most are very similar to the areas in last year's survey. The questions where the pipeline companies rated lower were:

1. How satisfied are you that this pipeline company's tolls are competitive?
2. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?
3. How satisfied are you with the collaborative process (negotiations or task force meetings) utilized by this pipeline company?

*Performance of the Board*

The survey also indicated that approximately two-thirds of shippers are either satisfied or very satisfied with the Board's performance in creating an appropriate regulatory framework and with the Board's processes to resolve disputes. While this was a slight improvement over the previous year's survey, shippers did identify areas where the Board could improve its processes and performance.

### 2.3.2 Formal Complaints

If shippers are unable to resolve concerns with the pipeline, they can bring a complaint to the NEB. It can then be dealt with through appropriate dispute resolution (ADR), through a formal complaint process or the parties may continue to negotiate towards resolution. There were two shipper complaints this past year requiring a formal process before the Board:

*Abitibi Consolidated Company (Abitibi) and Boise White Paper, L.L.C. (Boise)*

Centra Transmission Holdings Inc., a Group 2 company, applied to the Board to increase its tolls. Subsequently two shippers, Abitibi and Boise wrote to the Board requesting additional time to examine Centra's application. The Board subsequently initiated a written process to deal with the matter. The Board approved Centra's application for increased tolls, subject to certain amendments. Additional information can be found in the Board's Reasons for Decision RHW-3-2005.

*Petro-Canada Oil and Gas (PCOG)*

PCOG applied to the Board requesting the issuance of an order requiring Westcoast to grant the permanent firm service relocation of PCOG's Transportation North Long Haul firm service without the requirement to extend its existing service agreement by two years. On 4 May 2006, the Board issued its decision on PCOG's application. The Board found that the practice of requiring a term extension does not constitute unjust discrimination and that permanent relocation may be considered a service. The Board was also of the view that not enough information concerning the appropriate level of consideration was included in the submissions. The Board directed Westcoast to bring the matter of permanent firm service relocation and the appropriate level of consideration back to the Board after discussion with the Tolls and Tariff Task Force. Further, the Board advised that PCOG's term extension, if any, will reflect the final Board decision in this matter. Additional information can be found in the Board's file, 4775-W005-1-17.

### 2.3.3 Service Enhancements

Pipeline companies modify their services on an ongoing basis as circumstances change or innovative ideas are brought forward. Normally, the pipeline or its shippers bring these proposed service enhancements to their tolls task force for discussion and review prior to submission to the Board and ultimate adoption. This past year, for example, Westcoast applied to the Board to introduce firm service enhancements of term differentiated rates and authorized over run service in Zones 3 and 4 and cross corridor crediting in Zone 3. The Board approved Westcoast's application. More information can be found in the Board's Reasons for Decision RHW-1-2005.

If the task force is unable to resolve the issue, a party may bring the issue directly to the Board. This past year, one such enhancement was brought to the Board and subsequently approved.

*Coral Energy Canada Inc. (Coral)*

Coral applied to the Board to modify the Firm Transportation Risk Alleviation Mechanism (FT-RAM) pilot, a service enhancement proposed by TransCanada for its Mainline. The Board approved Coral's application and directed TransCanada to modify its Mainline Transportation Tariff to reflect this decision. Additional information can be found in the Board's Reasons for Decision RHW-2-2005.

### 2.3.4 Summary of Shipper Satisfaction

This past year, it was found that shippers are reasonably satisfied with the services provided by the pipeline companies and the Board's performance in creating an appropriate regulatory framework and the Board's processes to resolve disputes. For both the pipeline companies and the Board, shippers identified areas for improvement in service. Areas of improvement for the pipeline companies are outlined in the previous section. Shippers also noted that the Board could improve its processes through which tolls and tariffs are determined by streamlining those processes and actively engaging stakeholders so that it better understands

the market context in which it makes decisions. The Board is taking this feedback into consideration. For example, in its Strategic Plan for 2006 – 2009 the Board identified the objective for its regulatory processes to be efficient, seamless and responsive to all stakeholders.

## 2.4 Pipeline Financial Integrity and Ability to Attract Capital

In order for a hydrocarbon transportation system to be efficient, pipeline companies must have adequate financial integrity to attract capital on reasonable terms and conditions. This enables them to effectively maintain their systems and build new infrastructure to meet the market's evolving needs. The following sections review and discuss a number of the factors used to assess these areas.

### 2.4.1 *Financial Ratios*

Financial statement information can be used to create financial ratios that are used for assessing a company's performance and financial integrity. Evaluating a financial ratio is most meaningful when the ratio of a particular company is compared with a benchmark or industry standard over time. These ratios can be used to evaluate a company's liquidity, operating performance, growth potential, and risk. However, care must be exercised in the collection and interpretation of financial ratios. Some reported financial information may pertain to a parent company, which may include non-regulated assets and/or assets from different industries.

The following sections specifically outline and discuss some of the ratios used to assess the financial risk and operating profitability of certain NEB-regulated pipeline companies. The final section outlines and discusses some NEB-approved financial ratios.

*Financial Risk*

Financial risk is the risk inherent in a company's use of debt and other obligations that have fixed payments. It differs from business risk which is the risk attributed to the nature of a particular business activity and, for pipelines, typically includes supply, market, regulatory, competitive and operating risks. Financial risk increases as the proportion of debt increases in relation to shareholders equity. An increase in debt may obligate a company to make more and larger fixed payments in the future. From a bondholder's perspective, a company with above average financial risk could have problems making interest payments. From an equity holder's perspective, a company's level of financial risk gives some indication of its financial viability.

Ratios used to evaluate a company's level of financial risk include interest coverage, fixed-charges coverage, and cash flow-to-total debt and equivalents.

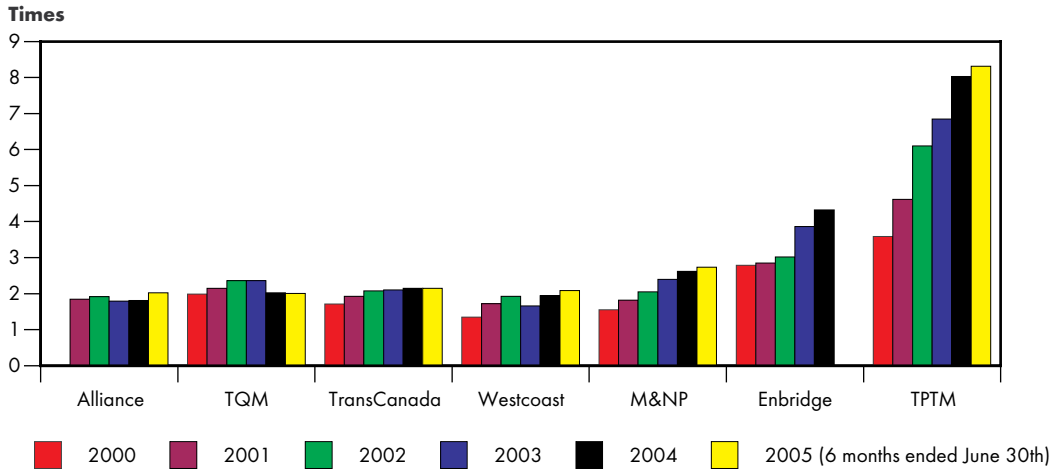
*Interest and Fixed-Charges Coverage Ratios*

An interest coverage ratio assesses a company's ability to make interest payments and repay its debt obligations. It is defined as Earnings Before Interest and Taxes (EBIT) divided by interest charges. A fixed-charges coverage ratio also assesses the ability to make interest payments and repay debt obligation; however, it also takes into consideration other types of fixed payments a company is obligated to make. It is defined as EBIT less other fixed-charges divided by interest and other fixed-charges. Higher ratios indicate an increased likelihood that the company will be able to meet its obligations and may indicate that it has unused borrowing capacity.

The fixed-charges coverage ratios for some NEB-regulated pipeline companies, as calculated by the Dominion Bond Rating Service (DBRS), are shown in Figure 25. The average fixed-charges coverage

FIGURE 25

***Fixed-Charges Coverage Ratios***




Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge in 2005.

ratio for these companies for the six months ending June 2005 is 3.22 times. TPTM's fixed-charges coverage ratio is higher, primarily due to a deemed common equity ratio of 45 percent (larger than its peers), which means it carries less debt and, therefore, has lower fixed payments.

From 2000 to 30 June 2005, the fixed-charges coverage ratio for these pipeline companies increased on average by 49 percent[7]. This growth was primarily driven by M&NP, Enbridge and TPTM. No company saw its fixed-charges coverage ratio decline from its 2000 level. The consistent increases in fixed-charges coverage ratios is one metric signaling a decrease in these pipeline companies' financial risk, when considered as a group.

### *Cash Flow-to-Total Debt and Equivalents Ratio*

The cash flow-to-total debt and equivalents ratio is another way of assessing a company's ability to meet its debt obligations and fixed payments. It is defined as operating cash flow divided by total debt and equivalents. Again, higher ratios indicate an increased likelihood of a company being able to meet its obligations and indicate that it has greater borrowing capacity.

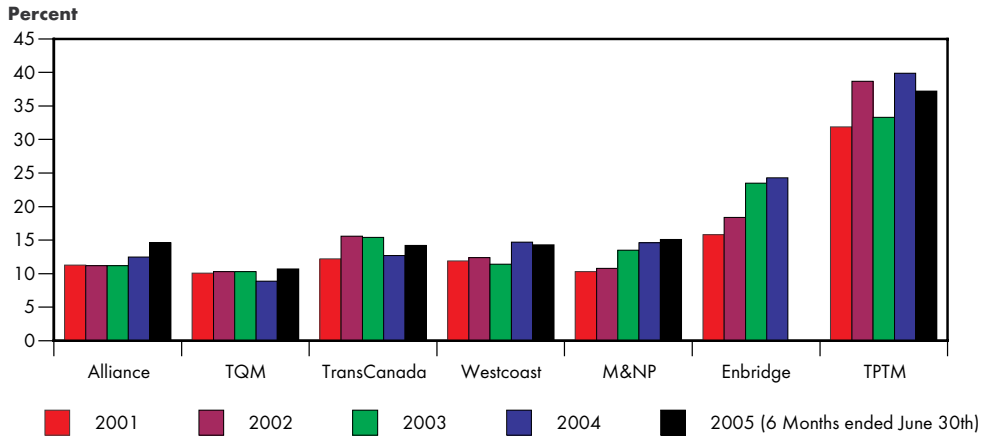
The cash flow-to-total debt and equivalents ratios for some NEB-regulated pipeline companies, as calculated by DBRS, are shown in Figure 26. The average cash flow-to-total debt and equivalents ratio for these companies was 17.68 percent for the 6 months ending June 2005. TPTM's cash flow-to-total debt and equivalents ratio was higher than its peers for the same reason that its fixed-charges coverage ratio was higher.

On average, the cash flow-to-debt and equivalents ratio for these pipeline companies has grown by 20 percent from 2000 to 2005. The increase has been steady without any noteworthy periods of deterioration. Similar to the fixed-charges coverage ratio, the consistent increase in cash flow-to-total debt and equivalents ratios is another metric which signals that, on average, these pipeline companies' financial risk has been decreasing.

[7] Historically, Enbridge's fixed-charges and cash flow-to-debt and equivalents ratios were much higher than the average of the other pipeline companies in Figures 20 and 21. Since these ratios were not provided for Enbridge in 2005, the pipeline company average for 2005 and the percentage increase since 2000 and 2001 respectively, may be biased downward.

FIGURE 26

***Cash Flow-to-Total Debt and Equivalents Ratios***




Source: DBRS

N.B. There was no cash flow-to-total debt and equivalents ratio reported for Enbridge in 2005.

## *Operating Profitability*

### *Return on Common Equity*

ROE is commonly used to assess the operating profitability of a company. ROE is defined as net income divided by common equity. For NEB-regulated pipeline companies, this is the return on the equity portion of the rate base that is approved by the Board. A higher ROE is typically preferred by both bondholders and, even more so, by equity investors.

Table 4 shows the achieved ROE for several NEB-regulated pipeline companies from 2000 to 2005 along with the NEB-approved ROE in accordance with the RH-2-94 Formula[8] (RH-2-94 Formula ROE). Alliance, Enbridge, M&NP and TPTM are not subject to the RH-2-94 Formula ROE as they have all negotiated an ROE with their shippers[9]. As per their respective negotiated settlements, Enbridge and TPTM are not required to submit their achieved ROE to the NEB. Therefore, neither of these pipeline companies are included in Table 4. Westcoast's Field Services Division is also not subject to the ROE formula as it is under light-handed regulation[10]. Its tolls for gathering and processing services are negotiated individually with shippers.

From 2000 to 2005, most pipeline companies subject to the RH-2-94 Formula ROE have consistently had ROEs in the mid-to-high nine percent range (except for Westcoast Transmission which has achieved higher ROEs). The RH-2-94 Formula ROE for 2006 is 8.88 percent.

### *NEB-Approved Ratios*

When the Board approves a Group 1 pipeline company's tolls for a specified time period, it typically also approves a ROE and deems a common equity ratio for the regulated entity. Therefore, the Board has influence over the operating profitability and financial risk of some Group 1 pipeline companies.

8 Formula used to determine the ROE for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, and later amended to eliminate rounding.

9 These pipelines settlements are subsequently approved by the Board.

10 Light-handed regulation is essentially regulation on a complaint basis with rules. Additional information can be found in RHW-1-98.

TABLE 4

***Achieved ROEs and the RH-2-94 Formula ROE (Percent)***

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|---|
| Alliance | 11.21 | 11.25 | 11.25 | 11.25 | – | – |
| Foothills | 9.90 | 9.61 | 9.53 | 9.79 | 9.56 | 9.46 |
| M&NP | 13.80 | 14.20 | 12.95 | 12.31 | 13.75 | 14.31 |
| TQM | 9.96 | 10.21 | 9.80 | 10.21 | 9.84 | 9.92 |
| TransCanada | 9.99 | 9.72 | 9.95 | 10.18 | 9.83 | 9.66 |
| B.C. System | 9.90 | 6.86 | 9.53 | 8.21 | 8.51 | 9.46 |
| Westcoast Field Services | – | 13.62 | 14.87 | 6.76 | 11.63 | 12.48 |
| Westcoast Transmission | 12.68 | 15.84 | 13.44 | 12.93 | 10.28 | 10.82 |
| **NEB RH-2-94 Formula** | **9.90** | **9.61** | **9.53** | **9.79** | **9.56** | **9.46** |

Source: NEB Surveillance and Annual Reports; dash indicates not available

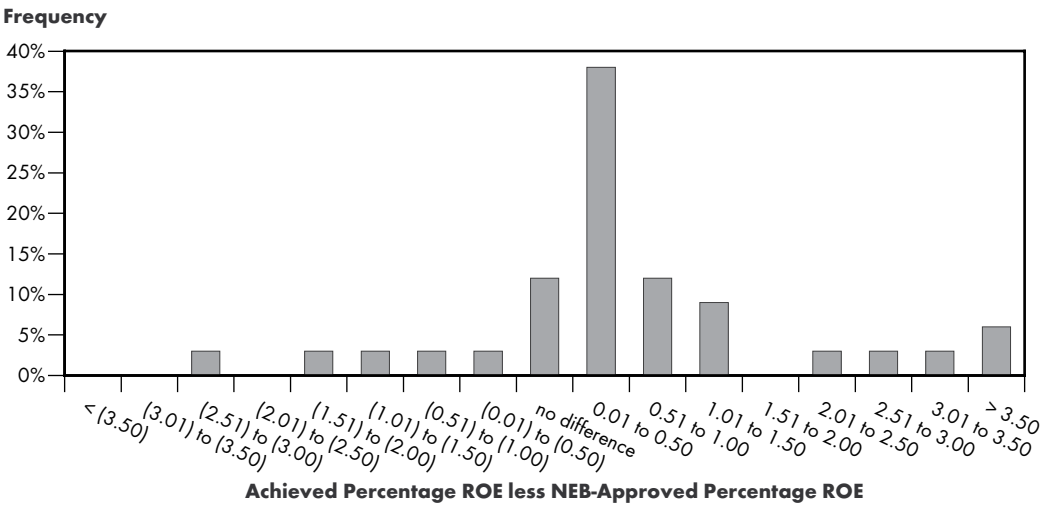
## *NEB-Approved Return on Common Equity*

NEB-approved ROEs have great influence over the ROEs that are actually achieved. Achieved ROEs can vary from NEB-approved levels for various reasons, such as incentive and profit sharing mechanisms and cost reductions over the year.

Figure 27 charts the difference between achieved ROEs and NEB-approved ROEs for TransCanada, B.C. System, TQM, Westcoast Transmission system, and M&NP[11]. Enbridge and TPTM are not required to submit their achieved ROEs to the Board as per their negotiated settlements. Westcoast Field Services is not included as it is subject to light-handed regulation. Foothills and Alliance are not included in Figure 27 as neither is able to over- or under-perform on ROE in accordance with their respective cost-of-service methodologies.

FIGURE 27

***Achieved and NEB-Approved ROE for the Years 1999 to 2005***




11 TransCanada, B.C. System, TQM and Westcoast Transmission system have NEB-approved ROEs subject to the RH-2-94 Formula ROE, whereas M&NP has a NEB-approved ROE of 13 percent.

From 1999 to 2005, pipeline companies (included in Figure 27) have met or exceeded their NEB-approved ROEs 85 percent of the time. This stability and predictability of their operating profitability is positive for both bondholders and equity investors. It also highlights that these pipeline companies, in many cases, have been able to meet and outperform approved levels through cost reductions, incentive and profit sharing mechanisms.

*NEB-Approved Deemed Common Equity Ratios*

A common equity ratio is defined as the percentage of common equity in a company's capital structure. This ratio is often used to evaluate a company's financial risk. Higher common equity ratios increase the likelihood of a company being able to meet its obligations. The Board approves a deemed common equity ratio[12] for most of the Group 1 pipeline companies that it regulates.

**TABLE 5**

***Deemed Common Equity Ratios (Percent)***

| | 2000 | 2006 |
|---|---|---|
| Alliance | 30 | 30 |
| Foothills | 30 | 36 |
| M&NP | 25 | 25 |
| TQM | 30 | 30* |
| TransCanada | 30 | 36 |
| B.C. System | 30 | 36 |
| Westcoast Transmission | 30 | 31* |

* TQM and Westcoast Transmission's 2006 deemed common equity ratios are interim.

Table 5 shows the deemed common equity ratio for some NEB Group 1 pipeline companies. TransCanada, Westcoast Transmission, B.C. System and Foothills have had their deemed common equity ratios increased between 2000 and 2006. These increases are credit positive and lower the financial risk of the pipeline companies.

### 2.4.2 Credit Ratings

In Canada, pipeline credit ratings are determined by three independent credit rating agencies: DBRS, Standard & Poor's (S&P), and Moody's Canada Inc. (Moody's). A comparison of the rating scales for DBRS, S&P and Moody's can be found in Appendix 1. Credit ratings, like stock prices, generally reflect the consolidated operations of the entire company and not solely the regulated portion. Thus, using these ratings as an accurate measure of the creditworthiness of a NEB-regulated pipeline owned by a company with both regulated and non-regulated operations, such as TransCanada and Enbridge, must be interpreted with some care. In addition, credit ratings are somewhat subjective in that a company's ratings are the expert opinion of the credit rating agency, which may result in different ratings by different agencies.

*Dominion Bond Rating Service*

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. While key considerations will vary from industry to industry, some of the common factors considered for most ratings are: core profitability, asset quality, strategy and management strength, and financial and business risk.

The following factors are also important considerations in deriving the credit ratings for pipelines and electric and gas utilities: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities. DBRS credit ratings for several NEB-regulated pipeline companies are shown in Table 6. As indicated, these ratings have remained stable from 2000 to the present, varying from BBB (high) to A (high).

[12] A deemed common equity ratio is a notional capital structure used for rate-making purposes that may differ from a company's actual capital structure.

***Standard & Poor's***

A credit rating from S&P reflects its current opinion of a company's overall capacity to pay its financial obligations. S&P bases its ratings on the overall creditworthiness of a consolidated company. Therefore, the rating of a wholly-owned subsidiary, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent. S&P's opinion may also apply to specific financial obligations.

In S&P's rating methodology, a company rated "A" has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than companies in higher-rated categories. A company rated "BBB" has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to weaken the company's capacity to meet its financial commitments.

S&P credit ratings for several NEB-regulated pipeline companies are shown in Table 7. This table indicates that these ratings have been relatively stable from 2000 to the present, ranging from BBB (stable) to A (negative).

Both DBRS and S&P have, at various times, expressed an opinion that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Notwithstanding these comments, the ratings assigned by both of these agencies for the NEB-regulated companies are all investment grade.

***Moody's***

Moody's credit analysis focuses on the fundamental factors and key business drivers relevant to an issuer's long-term and short-term risk profile. The foundation of Moody's methodology rests on two basic questions:

1. What is the risk to the debt holder of not receiving timely payment of principal and interest on this specific debt security?
2. How does the level of risk compare with that of all other debt securities?

Like S&P, Moody's credit rating is its current opinion of a company's overall capacity to pay its financial obligations and focuses its ratings on the overall creditworthiness of a consolidated entity. In so doing, Moody's measures the ability of an issuer to generate cash in the future. This determination is built on an analysis of the strengths and weaknesses of the individual issuer compared with those of its peers worldwide. Moody's also takes into consideration factors external to the issuer, including industry or nation-wide trends that could impact the entity's ability to meet its debt obligations. Of particular concern is the ability of company management to sustain cash generation in the face of adverse changes in the business environment.

The rating histories for several NEB-regulated pipeline companies are provided in Table 8. All of Moody's ratings place these pipelines in the investment grade category, ranging from "medium grade" to "upper-medium grade".

**TABLE 6**

***DBRS Credit Rating History***

| Pipeline | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | Current |
|---|---|---|---|---|---|---|---|
| Alliance | BBB(high) | A(low) | A(low) | A(low) | A(low) | A(low) | A(low) |
| M&NP | A | A | A | A | A | A | A |
| TQM | A(low) | A(low) | A(low) | A(low) | A(low) | A(low) | A(low) |
| TransCanada | A | A | A | A | A | A | A |
| Westcoast[1] | A(low) | A(low) | A(low) | A(low) | A(low) | A(low) | A(low) |
| Enbridge | A(high) | A(high) | A(high) | A(high) | A(high) | A(high) | A(high) |
| Express[2] | NR | A(low) | A(low) | A(low) | A(low) | A(low) | A(low) |
| TPTM | A(low) | A(low) | A(low) | A(low) | A(low) | A(low) | discontinued /debt repaid |
| TNPI | NR | NR | NR | NR | NR | A(low) | A(low) |

Notes: (1) Unsecured debentures; (2) Senior secured

NR Not reported

**TABLE 7**

***S&P Credit Rating History***

| Pipeline | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | Current |
|---|---|---|---|---|---|---|---|
| TQM | BBB+/Stable | BBB+/Stable | BBB+/Stable | BBB+/Stable | BBB+/Stable | BBB+/Stable | BBB+/Stable |
| TransCanada | A-/Stable | A-/Stable | A-/Watch Negative | A-/Watch Negative | A-/Watch Negative | A-/Negative | A-/Negative |
| Westcoast | A-/Negative | A-/Stable | A/Negative | BBB/Stable | BBB/Positive | BBB/Watch Negative | BBB/Stable |
| Enbridge | A-/Stable | A-/Negative | A-/Negative | A-/Stable | A-/Stable | A-/Stable | A-/Stable |
| TPTM | BBB+/Stable | BBB+/Stable | BBB+/Watch Negative | BBB/Stable | BBB/Stable | BBB+/Stable | discontinued / debt repaid |

**TABLE 8**

***Moody's Credit Rating History***

| Pipeline | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | Current |
|---|---|---|---|---|---|---|---|
| Alliance[1] | Baa1 | A3 | A3 | A3 | A3 | A3 | A3 |
| M&NP[2] | A1 | A1 | A1 | A1 | A1 | A2 | A2 |
| TransCanada[1] | A2 | A2 | A2 | A2 | A2 | A2 | A2 |
| Enbridge | NR | NR | NR | NR | NR | NR | NR |
| Express[2] | A3 | Baa1 | Baa1 | Baa1 | Baa1 | Baa1 | Baa1 |

Notes: (1) Senior unsecured; (2) Senior secured

### 2.4.3 Comments by Investment Community

As noted previously, pipeline companies must be able to access capital markets to maintain and, potentially, expand their systems as the needs of the transportation market change. Board staff met with credit rating analysts, equity analysts (sell-side analysts), and suppliers of capital such as insurance and pension funds (buy-side analysts) to discuss their views on the ability of NEB-regulated pipeline companies to access capital markets, as well as their views on transportation markets and the current regulatory environment in Canada. This section reflects the views expressed in those meetings.

All parties expressed the view that there was no problem accessing debt markets at this time. In fact, utilities frequently enter the market to refinance their debt and, given the current liquidity in the markets, they have been able to do so at favourable spreads relative to government bonds.

Several analysts noted that Canadian regulation, including the ROE formula approach, provides transparency, predictability and stability, which are seen as highly beneficial. However, a number of analysts felt that the ROE generated by the NEB ROE formula and the formulas of other Canadian regulators were "a little too low" and not supportive of dividend growth or credit metrics. Although most analysts felt that utilities have good access to equity markets, the current level of ROEs was seen by some as impeding this access. As there has been, in most cases, adequate pipeline capacity from the WCSB in recent years, the ability of pipeline companies to access equity markets has not been significantly tested.

Many equity analysts publish their assessments of various companies for investors. Most of the analysts currently rate major NEB-regulated pipeline companies in the "Hold" or "Buy" categories. A number of equity analysts commented that where they have "Buy" ratings on Canadian utility stocks, they tend to reflect the prospects of the companies' non-regulated businesses. A number of analysts also noted that companies have reduced costs and taken other steps to support corporate profit and dividend growth for several years, and they questioned how long this can continue.

It was noted that pipeline stocks are part of the interest-sensitive segment of the equity market and as such, low interest rates have been positive for valuations and the price-to-earnings ratio. The price-to-earnings ratios of Canadian utilities have been higher than their U.S. and European counterparts. The reasons given for this difference included greater growth opportunities in Canada given oil sands, northern gas, power infrastructure development, a more stable regulatory environment, as well as strong foreign interest in Canadian stocks in general.

### *2.4.4 Summary of Pipeline Financial Integrity and Ability to Attract Capital*

The financial information and observations by the investment community are summarized as follows:

- Fixed-charges and cash flow-to-total debt and equivalents coverage ratios have increased since 2000.
- Deemed common equity ratios have increased since 2000.
- Achieved ROEs have, in most cases, been greater than or equal to their NEB-approved levels between 1999 and 2005.
- Achieved ROEs have been stable and predictable.
- Credit ratings continue to be strong.
- The investment community is of the view that NEB-regulated companies should have no problems accessing the capital markets at this time.

These observations signal that, currently, NEB-regulated pipelines have adequate financial integrity to attract capital on reasonable terms and conditions.

## 2.5 Proposed Pipelines

Many proposals to expand pipeline capacity or build new pipeline systems have been announced, applied for or recently approved. These include gas pipelines to growing markets in Canada and the U.S. and pipelines to ship western Canadian crude oil to the West Coast for delivery to Washington State and offshore markets, the U.S. Midwest and southern PADD II and the U.S. Gulf Coast (PADD III). More specifically, these project proposals include:

- new pipelines connecting northern gas supplies to existing gas infrastructure;
- natural gas expansions in the east to facilitate market development in eastern Canada and the U.S. Northeast; and
- pipeline laterals connecting existing infrastructure to proposed LNG receiving terminals in Nova Scotia and New Brunswick; and
- oil pipeline expansions and new pipeline proposals to facilitate the expected growth in the next decade in oil sands production.

*Natural Gas*

In the coming decade, demand for natural gas in North America is expected to exceed the growth in North American domestic supplies. In Canada, there are two sectors of growth that bear noting: oil sands projects in Alberta and electricity generation in Ontario.

The Canadian oil sands projects are a large and growing market for natural gas. Today, these projects consume about 0.7 Bcf/d. Natural gas is used to generate power, generate steam for in situ oil production and upgrade bitumen into synthetic blends. Gas demand for oil sands is expected to more than double to perhaps 2 Bcf/d over the next decade depending on the number of oil sands projects that proceed and the technology used.

In addition, Ontario's policy to remove 7 500 MW of coal-fired electrical generation by 2009 may require significant supplies of natural gas for power generation While refurbishment of existing nuclear generation and the addition of renewable power sources may meet part of the requirement, it is possible that new electrical generation will primarily be fired by natural gas.

Table 9 summarizes currently announced Canadian natural gas pipelines and expansion proposals.

**TABLE 9**

***Announced Canadian Natural Gas Pipelines and Expansions***

| Pipeline | Location | Capacity Increase (Bcf/d) | Proponents' Estimated Completion Date | Market to be Served |
|---|---|---|---|---|
| TransCanada PipeLines Limited – 2006 Eastern Mainline Expansion | Ontario, Québec | .310[13] | Late 2006 | Central Canada, Northeastern U.S. |
| TransCanada PipeLines Limited– 2007 Eastern Mainline Expansion | Ontario, Québec | .377[14] | 2007 | Central Canada, Northeastern U.S. |
| Mackenzie Gas Pipeline | Mackenzie Delta, Northwest Territories to Alberta | 1.2 | 2011 | North America |
| Maritimes & Northeast Pipeline – Brunswick Pipeline | New Brunswick | 0.75 | 2008 | Atlantic Canada, Northeastern U.S. |
| Maritimes & Northeast Pipeline – Bear Head Pipeline | Nova Scotia | .813 | N/A | Atlantic Canada, Northeastern U.S. |

N/A Not Available

13 TCPL Eastern Mainline Expansion: Montreal/North Bay Shortcut to Iroquois delivery point.

14 TCPL Eastern Mainline Expansion: Montreal/North Bay Shortcut to Les Cèdres (148 MMcf/d), Philipsburg Extension to Philipsburg (12 MMcf/d) and Kirkwall/Niagara Line to Chippawa (217 MMcf/d).

### *Liquefied Natural Gas*

A key supply source for North America is expected to be the rapidly developing global LNG market. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. Furthermore, advances in liquefaction and transportation technologies have lowered the unit cost of LNG by 30 percent over the past decade, enabling the use of LNG as a cost competitive source of gas supply in North America. In anticipation of growing natural gas requirements, expansions of some existing U.S. terminals and numerous new receiving facilities have been proposed, including sites in Canada as shown in Table 10.

However, there is uncertainty around the number of LNG terminals that will be built in Canada as well as the potential effects that imported LNG will have on gas markets and the pattern of natural gas flow. As discussed above, pipeline laterals will be required to connect LNG receiving terminals to existing natural gas pipeline infrastructure in order to deliver the gas to market.

**TABLE 10**

***Proposed Canadian LNG Terminals***

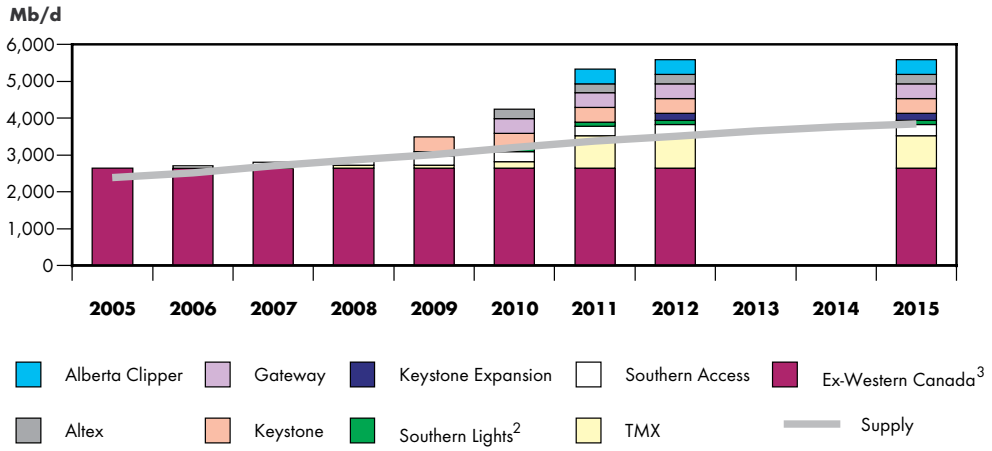



| Terminal | Company | Location | Capacity (Bcf/d) | Proponents' Estimated Completion Date | Market to be Served |
|---|---|---|---|---|---|
| **1** Bear Head | Anadarko Petroleum Company | Point Tupper, Nova Scotia | 0.750 to 1.00 | N/A | Atlantic Canada, Northeast U.S. |
| **2** Keltic Goldboro | Keltic Petrochemicals Inc. | Goldboro, Nova Scotia | 1.00 | Late 2009 | Atlantic Canada, Northeast U.S. |
| **3** Cacouna Energy | TransCanada PipeLines Limited and Petro-Canada | Gros Cacouna, Québec | 0.50 | 2010 | Québec, Ontario, Northeast U.S. |
| **4** Rabaska | Gaz Metro Limited Partnership, Gaz de France and Enbridge Inc. | Beaumont, Québec | 0.50 | 2010 | Québec, Ontario |
| **5** Canaport | Irving Oil Limited and Repsol YPF | Saint John, New Brunswick | 1.0 | Late 2008 | Atlantic Canada, Northeast U.S. |
| **6** WestPac Prince Rupert | WestPac Terminals Inc. | Ridley Island, British Columbia | 0.15 to 0.50 | 2009 | Westcoast North America |
| **7** Kitimat | Galveston Energy | Port of Kitimat, British Columbia | 0.61 | 2009 | Westcoast North America |
| **8** Statia | Statia Terminals Canada Partnership | Canso Strait, Nova Scotia | 0.50 | N/A | Atlantic Canada, Northeast U.S. |

N/A Not Available

## FIGURE 28

### *NEB Supply Forecast and Proposed Pipeline Projects and Timing*




1 The pipeline projects are listed alphabetically. In-service dates are proposed by the project sponsors

2 Edmonton to Cromer

3 Total pipeline capacity out of the WCSB

## TABLE 11

### *Announced and Proposed Canadian Oil Pipelines and Expansions*

| Pipeline | Potential Filing Date | Capacity Increase (Mb/d) | Proponents' Estimated Completion Date | Market |
|---|---|---|---|---|
| **Terasen (TPTM)** | | **75** | | PADD V |
| Phase One TMX1 | Filed July 2005 | 35 | April 2007 | Offshore/Far East |
| Phase Two TMX1 | Filed February 2006 | 40 | Nov. 2008 | |
| **Southern Option** | | **700**[1] | | PADD V |
| TMPL TMX2 | 01Q2007 | 100 | Jan. 2010 | Offshore/Far East |
| TMPL TMX3 | N/A | 300 | Jan. 2011 | |
| **Northern Option** (TMX) | N/A | **450** | 2011 | PADD V<br>Offshore/Far East |
| **Enbridge Gateway**<br>(oil/diluent) | Fall 2006 | **400/150** | Mid-2010 | PADD V<br>Offshore/Far East<br>Alberta (diluent line) |
| **Pembina Spirit** (diluent) | N/A | 100 | April 2009 | Alberta |
| **Enbridge Southern Lights** | N/A | | | |
| Southern Lights (diluent) | | **180** | | |
| **Line 2 Expansion** (oil) | | **169** | 2009 | Alberta |
| Edmonton to Cromer | | 103 | | PADD II |
| Cromer to Clearbrook | | 33 | | PADD II |
| Clearbrook to Superior | | 33 | | PADD II |
| **TCPL Keystone** | June 2006 | 435 | 2009 | Southern PADD II/<br>PADD III |
| **Alberta Clipper** | N/A | **400** | 2010/11 | Southern PADD II |
| Altex Energy | N/A | 250 | 4Q2010 | PADD III |
| **Enbridge (Southern Access)** | | **315** | | Midwest/Southern |
| Phase I | May 2006 | 120 | Oct. 2006 and Feb. 2007 | PADD II |
| Phase II | N/A | 148 | 2008/09 | |
| Phase III | N/A | 47 | N/A | |

N/A Not Available

1 The 700 mb/d includes the existing capacity of 300 mb/d and the capacity additions from TMX2 and TMX3.

*Oil*

High crude oil prices and strong global demand are key drivers in the expansion of the oil sands. In this regard, many proposals to expand existing pipelines or build new facilities have been announced. Figure 28 shows that pipeline capacity out of western Canada could be tight in 2008.

Table 11 illustrates announced and potential expansions by Canadian pipelines. Additional details about these proposals are found in the EMA entitled *Canada's Oil Sands Opportunities and Challenges to 2015: An Update*, released in June 2006.

The proposals for pipeline expansion and construction of new pipelines indicate that the market is responding to increases in supply and demand.

## 2.6 Emerging Issues

While the transportation system is currently working well, there are a number of challenges facing the industry.

The demand for natural gas in North America is expected to increase by about two percent per year over the next decade. Conventional sources of supply for natural gas in North America are not likely to meet the increased demand. LNG is the fastest growing fuel source worldwide, and LNG's market share in North America is estimated to grow to about 15 percent within the decade. Although there is uncertainty around the number of LNG terminals that will be built in North America and the potential effects that imported LNG will have on the supply, demand and pattern of natural gas flow, LNG could become an important component of gas supply in Canada.

The construction of LNG terminals could have implications for existing pipeline transportation systems. For some pipelines, such as the TransCanada Mainline, this could result in volumes from the WCSB being displaced. For others, such as PNGTS and M&NP on the east coast, there is the possibility of higher capacity utilization on their systems. Direction of flow and toll design may also be affected. The PNGTS pipeline system has the potential for backhauls or reversal to import gas into Canada. There are also possibilities for expansion, reversals or backhauls in Quebec on TQM. Northern gas projects such as the Mackenzie Valley Pipeline or a pipeline from Alaska, if approved, and constructed, would also affect flows on existing systems.

If the expected increase in natural gas demand for power generation in Ontario materializes, it will impact the balance of supply and demand and consequent gas flows. The impact of this power generation on pipeline infrastructure will depend on the total amount of generation built and its location. New pipeline services may also be required to satisfy the needs of the power generation customers.

The expected growth in oil sands production is forcing industry to address questions such as which incremental markets to serve and how to expand the pipeline system to access them efficiently. Options include expanding existing systems and constructing new systems to access new markets in the U.S. and/or Asia. Given the large capital outlay and the relative irreversibility of the investment, market participants want to ensure that the optimal decisions are made.

There is concern in industry and in the financial community about the potential for insufficient pipeline capacity, particularly oil capacity, and conversely, the potential for excess capacity if too many projects go ahead. Other issues include the financial implications of increasing levels of competition among oil pipelines and the manner in which the regulatory process would unfold if numerous competing applications come before the NEB.

The challenge for the pipeline transportation industry is to have appropriate pipeline capacity in service to correspond to increases in production and growing market needs. For this to happen, there must be recognition of adequate lead times to achieve sufficient market support from amongst competing proposals, obtain regulatory approvals, arrange financing, mobilize labour and materials, and construct. A key component is that the regulatory process continues to be fair and effective with clear timelines and clear requirements.

Some of the above-noted issues will be settled among market participants; others may be examined in formal proceedings before the Board. The Board will continue to consult with stakeholders and seek input if and when any regulatory initiatives are pursued.

# CONCLUSIONS

In the Introduction to this report, the Board identified its assessment criteria. Based on these criteria the Board continues to believe that, at the present time, the Canadian hydrocarbon transportation system is working effectively.

1. **There is adequate capacity in place on existing natural gas pipelines.** The basis differentials and capacity utilization charts show that most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. Some excess capacity out of the WCSB and the unprecedented high prices for energy has provided producers with the flexibility to access markets of their choice at most times. However, there are constraints at the market end of some pipelines as indicted by expansions currently underway.

   **Capacity is tight on oil pipeline transportation systems.** While the capacity utilization charts show that there is spare capacity on some of the pipelines, additional capacity is required to meet the growing demand, provide flexibility and enhance market penetration. The need for additional capacity is best shown by the number of announced and proposed pipelines and expansions.

2. **Shippers continue to indicate that they are reasonably satisfied with the services provided by pipeline companies.** The results of the NEB Pipeline Services Survey again rate the physical reliability of pipeline operations very highly, while satisfaction with toll competitiveness was again identified as the area where shippers most had concerns.

3. **NEB-regulated pipeline companies are financially sound** and able to attract capital on reasonable terms and conditions. While it is recognized that some of the data and indicators reviewed is for the consolidated operations of pipeline companies, discussion with the investment community indicated that, at this time, NEB-regulated pipeline companies should have no difficulty raising capital. Extensive investment will be required in the future to provide needed infrastructure and the financing for those facilities will depend upon the characteristics of the projects and the financial markets at that time.

As identified in Section 2.5 there are a significant number of proposals to build or expand Canadian pipelines to deliver additional volumes of oil and natural gas to growing markets. Some of these proposals may be competing for the same sources of supply and perhaps the same markets.

The challenge from the NEB's perspective is to provide, in a timely manner, a fair and effective process that does not distort the market place investment decisions. This may involve coordinating with other jurisdictions. Investors desire clear regulatory processes with predictable timelines. New investment can be frustrated when timelines stretch out and unexpected regulatory hurdles materialize during the process. Further, unnecessary construction delays, for both expansions and new pipelines, can be costly to both energy consumers and producers as the development of new supplies is constrained.

The Board recognizes that this report is only a snapshot in time and does not include a comparison with or to pipeline transportation systems in other jurisdictions. As part of its mandate, the Board will continue to monitor the effectiveness of the transportation system and will continue to meet with parties to gain an understanding of all perspectives on this issue. The Board welcomes feedback on the measures and conclusions in this report and also welcomes suggestions for improvements to future reports.

The Board thanks those companies and organizations that directly or indirectly provided the information found in this report, including those that actively participated in the Pipeline Services Survey.

## Debt Rating Comparison Chart

This chart provides a comparison of the rating scales used by DBRS, S&P and Moody's when rating long-term debt.

| Credit Quality | DBRS | S&P | Moody's |
|---|---|---|---|
| **Investment Grade** | | | |
| Superior/High grade | AAA | AAA | Aaa |
| | AA (high) | AA+ | Aa1 |
| | AA | AA | Aa2 |
| | AA (low) | AA- | Aa3 |
| Good/Upper Medium | A (high) | A+ | A1 |
| | A | A | A2 |
| | A (low) | A- | A3 |
| Adequate/Medium | BBB (high) | BBB+ | Baa1 |
| | BBB | BBB | Baa2 |
| | BBB (low) | BBB- | Baa3 |
| **Non-Investment Grade** | | | |
| Speculative | BB (high) | BB+ | Ba1 |
| | BB | BB | Ba2 |
| | BB (low) | BB- | Ba3 |
| Highly speculative | B (high) | B+ | B1 |
| | B | B | B2 |
| | B (low) | B- | B3 |
| Very highly speculative | CCC | CCC | Caa1 |
| | CC | CC | Caa2 |
| | C | C | Caa3 |
| | D | D | Ca |
| | | | C |

Note: DBRS and S&P ratings in the CCC category and lower also have subcategories "high/+" and "low/-," and the absence of "high/+" and "low/-" designation indicates the rating is in the "middle" of the category.

S&P's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A "Positive" outlook means that a rating may be raised; a "Negative" outlook means that a rating may be lowered and a "Stable" outlook means that a rating is not likely to change.

## Pipeline Services Survey Aggregate Results

Below are the aggregate responses for each question in the survey. Respondents were asked to rate their satisfaction with the services they receive on a scale of 1 to 5, where 1 indicates "Very dissatisfied" and 5 indicates "Very satisfied". See the Board's website for the complete details.

1. How satisfied are you with the physical reliability of the pipeline company's operations?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 1 | 4 | 26 | 65 | 46 | 4.06 |

2. How satisfied are you with the quality, flexibility and reliability of the pipeline company's transactional systems (nominations, bulletin boards, reporting, contracting, etc.)?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 1 | 4 | 26 | 65 | 46 | 4.06 |

3. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 9 | 10 | 24 | 60 | 36 | 3.75 |

4. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 4 | 12 | 37 | 73 | 16 | 3.60 |

5. How satisfied are you with the timeliness and usefulness of commercial information (tolls, service changes, new services, contract information, etc.) provided by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 6 | 7 | 43 | 69 | 17 | 3.59 |

6. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 8 | 29 | 62 | 31 | 10 | 3.04 |

7. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 14 | 19 | 39 | 49 | 17 | 3.26 |

8. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 6 | 19 | 47 | 49 | 11 | 3.30 |

9. How satisfied are you with the suite of services offered by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 4 | 17 | 51 | 55 | 10 | 3.37 |

10. How satisfied are you that this pipeline company's transportation tolls are competitive?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 14 | 29 | 45 | 38 | 11 | 3.02 |

11. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 8 | 12 | 51 | 42 | 8 | 3.25 |

12. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 7 | 11 | 48 | 47 | 6 | 3.29 |

13. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 6 | 8 | 44 | 63 | 18 | 3.57 |

14. On an overall basis, has the pipeline company's quality of service in the last year:

| | | |
|---|---|---|
| Improved | 19 | 13% |
| Remained the Same | 110 | 78% |
| Decreased | 13 | 9% |
| **Total** | **142** | **100%** |

15. What are the things that this pipeline company does well?

16. What are the things that this pipeline company could do better?

17. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 7 | 7 | 30 | 72 | 8 | 3.54 |

18. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 3 | 7 | 23 | 54 | 4 | 3.54 |

19. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

## Stakeholder Consultation

Alliance Pipeline Ltd.
BMO Nesbitt Burns
Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association
CIBC World Markets
Cochin Pipe Lines Ltd.
CPP Investment Board
Credit Suisse First Boston
Dominion Bond Rating Service
Enbridge Pipelines Inc.
Express Pipeline Limited Partnership
First Energy Capital
Foothills Pipe Lines Ltd.
Kinder Morgan Canada Inc.
Maritimes and Northeast Pipeline
Moody's Canada Inc.
Ontario Teachers' Pension Plan
RBC Capital Markets
Standard & Poor's
Sun Life Financial
TD Newcrest
Terasen Pipelines Inc.
Trans Mountain Pipe Line
Trans-Northern Pipeline Inc.
Trans Québec & Maritimes Pipeline Inc.
TransCanada PipeLines Limited
Union Gas Limited
Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

## Group 1 and Group 2 Pipeline Companies Regulated by the NEB

*As of 31 December 2005*

**Group 1 Gas Pipelines**
Alliance Pipeline Ltd.
Foothills Pipe Lines Ltd.
Gazoduc Trans Québec & Maritimes Inc.
Maritimes & Northeast Pipeline Management Ltd.
TransCanada PipeLines Limited
TransCanada PipeLines Limited B.C. System
Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

**Group 1 Oil and Products Pipelines**
Cochin Pipe Lines Ltd.
Enbridge Pipelines Inc.
Enbridge Pipelines (NW) Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipelines Inc.

**Group 2 Natural Gas and Natural Gas Liquids Pipelines**
AltaGas Pipeline Partnership
AltaGas Suffield Pipeline Inc.
AltaGas Transmission Ltd.
Apache Canada Ltd.
ARC Resources Ltd.
Bear Paw Processing Company (Canada) Ltd.
BP Canada Energy Company
Canadian Hunter Exploration Ltd.
Canadian Natural Resources Limited
Canadian-Montana Pipe Line Corporation
Centra Transmission Holdings Inc.
Champion Pipeline Corporation Limited
Chief Mountain Gas Co-op Ltd.
DEFS Canada L.P.
Devon Energy Canada Corporation
Echoex Energy Inc.
EnCana Border Pipelines Limited
EnCana Ekwan Pipeline Inc.
EnCana Oil & Gas Co. Ltd.
EnCana Oil & Gas Partnership
EnCana West Ltd.
ExxonMobil Canada Properties
Forty Mile Gas Co-op Ltd.

Huntingdon International Pipeline Corporation
Husky Oil Operations Ltd.
KEYERA Energy Ltd.
Many Islands Pipe Lines (Canada) Limited
Mid-Continent Pipelines Limited
Minell Pipeline Limited
Murphy Canada Exploration Company
Murphy Oil Company Ltd.
Nexen Inc.
Niagara Gas Transmission Limited
Northstar Energy Corporation
Omimex Canada, Ltd.
Paramount Transmission Ltd.
Peace River Transmission Company Limited
Pengrowth Corporation
Penn West Petroleum Ltd.
Petrovera Resources Ltd.
Pioneer Natural Resources Canada Inc.
Portal Municipal Gas Company Canada Inc.
Prairie Schooner Limited Partnership
Profico Energy Management Ltd.
Regent Resources Ltd.
Renaissance Energy Ltd.
St. Clair Pipelines Management Inc.
Samson Canada, Ltd.
Shiha Energy Transmission Ltd.
Sierra Production Company
Suncor Energy Inc.
Taurus Exploration Canada Ltd.
Union Gas Limited
Vector Pipeline Limited Partnership
County of Vermilion River No. 24 Gas Utility
2193914 Canada Limited
806026 Alberta Ltd.
1057533 Alberta Ltd.

**Group 2 Oil and Products Pipelines**
Amoco Canada Petroleum Company Ltd.
Aurora Pipe Line Company
Berens Energy Ltd.
BP Canada Energy Company
Dome Kerrobert Pipeline Ltd.
Dome NGL Pipeline Ltd.
Duke Energy Empress L.P.
Enbridge Pipelines (Westspur) Inc.
Ethane Shippers Joint Venture
Express Pipeline Limited Partnership
Genesis Pipeline Canada Ltd.
Glencoe Resources Ltd.
Husky Oil Limited
Imperial Oil Resources Limited

ISH Energy Ltd.
Montreal Pipe Line Limited
Murphy Oil Company Ltd.
NOVA Chemicals (Canada) Ltd.
PanCanadian Kerrobert Pipeline Ltd.
Paramount Transmission Ltd.
Penn West Petroleum Ltd.
Plains Marketing Canada, L.P.
PMC (Nova Scotia) Company
Pouce Coupé Pipe Line Ltd., as agent and general partner of the Pembina North Limited Partnership
PrimeWest Energy Inc.
Provident Energy Pipeline Inc.
Renaissance Energy Ltd.
SCL Pipeline Inc.
Shell Canada Products
Shell Canada Products Limited
Sun-Canadian Pipe Line Company
Taurus Exploration Canada Ltd.
Yukon Pipelines Limited
1057533 Alberta Ltd.







# GOAL 3

## Canadians benefit from efficient energy infrastructure and markets.

National Energy Board

Office national de l'énergie

# Canadian Hydrocarbon **Transportation** System

transportation

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transportation

**TRANSPORTATION ASSESSMENT** • August 2005

Canada

National Energy Board | Office national de l'énergie

# Canadian Hydrocarbon **Transportation** System

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**TRANSPORTATION ASSESSMENT** • AUGUST 2005

Canada

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# Acronyms and Abbreviations

| | |
|---|---|
| AOS | Authorized Overrun Service |
| Alliance | Alliance Pipeline Ltd. |
| B.C. System | TCPL B.C. System |
| Chevron | Chevron Canada Limited |
| Cochin | Cochin Pipe Lines Ltd. |
| DBRS | Dominion Bond Rating Service |
| EBIT | Earnings Before Interest and Taxes |
| Enbridge | Enbridge Pipelines Inc. |
| Express | Express Pipeline Limited Partnership |
| FFO | Funds from Operations |
| Foothills | Foothills Pipe Lines Ltd. |
| FT | Firm transportation |
| IPI | Implicit Price Index |
| IT | Interruptible transportation |
| LNG | Liquefied natural gas |
| M&NP | Maritimes and Northeast Pipeline |
| MPL | Montreal Pipe Line |
| NEB or Board | National Energy Board |
| PNGTS | Portland Natural Gas Transmission System |
| ROE | Return on Equity |
| S&P | Standard & Poor's |
| SOEI | Sable Offshore Energy Inc. |
| T-South | Transportation South Zone on Westcoast |
| Terasen (TMPL) | Terasen Pipelines (Trans Mountain) Inc. |
| TNPI | Trans-Northern Pipeline Inc. |
| TQM | Trans Québec & Maritimes Pipeline Inc. |
| TransCanada or TCPL | TransCanada PipeLines Limited |
| U.S. | United States |
| WCSB | Western Canada Sedimentary Basin |
| Westcoast | Westcoast Energy Inc. |

# Units

| | |
|---|---|
| Bcf | Billion cubic feet |
| Bcf/d | Billion cubic feet per day |
| MMcfd | Million cubic feet per day |
| GJ | Gigajoule |
| $m^3/d$ | Cubic metres per day |
| $10^3m^3/d$ | Thousand cubic metres per day |
| MW | Megawatt |

# FOREWORD

As part of its regulatory mandate, the National Energy Board (the Board or NEB) continually monitors energy and transportation markets to ensure that Canadians derive the benefits of economic efficiency. To further assist in its monitoring efforts, the Board identified a need in its *2004-2005 Report on Plans and Priorities* to implement a performance measurement system for pipeline tolls and tariffs, including the financial health of the pipeline industry.

This report provides an assessment of how the Canadian hydrocarbon transportation system is currently functioning and sets out the framework the Board will use for future assessments.

The data contained within this report is based on publicly available information collected and monitored by NEB staff. In identifying some of the emerging issues around the transportation system, the Board also benefited from discussions with members of the investment community. A draft of the report was sent to the Canadian Energy Pipeline Association and the Canadian Association of Petroleum Producers for comment prior to its release.

Any comments on the report or suggestions for further analysis can be directed to:

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National Energy Board

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Email: bbranston@neb-one.gc.ca

If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as it can submit any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

# INTRODUCTION

The Canadian hydrocarbon transportation system moves over $100 billion in petroleum products and natural gas to Canadians and export markets each year. In 2004, energy export revenue was almost $59 billion, accounting for about 15 percent of total Canadian exports. Energy is essential to our daily lives and the ability of the pipeline transportation system to reliably and efficiently deliver this energy is critical to our country's economic well-being. The Board regulates the physical and financial operations of pipelines that cross interprovincial boundaries and the international boundary.

The Board has developed five corporate goals to ensure that its regulatory program provides value to Canadians. The third goal is that "Canadians derive the benefits of economic efficiency". To determine whether this goal is being achieved, the Board monitors energy and transportation markets for evidence that they are working well.

Each year the Board issues various Energy Market Assessment reports that focus on different aspects of Canadian energy markets. This is the first time that the Board has issued a report that focuses on the functioning of the Canadian hydrocarbon transportation system.

This report is similar to the Board's other market monitoring reports and its intent is to assess how well the Canadian hydrocarbon transportation system is working and to outline a system to monitor and measure the performance of the transportation system from year to year. This report should not be read as a regulatory document, like a Reasons for Decision. In this report, the Board is not making a determination on regulatory matters such as the appropriate rate of return on equity that should be earned by pipeline companies. Thus, the factors on which the functioning of the transportation system is assessed are not the same as those which are applied in a regulatory proceeding.

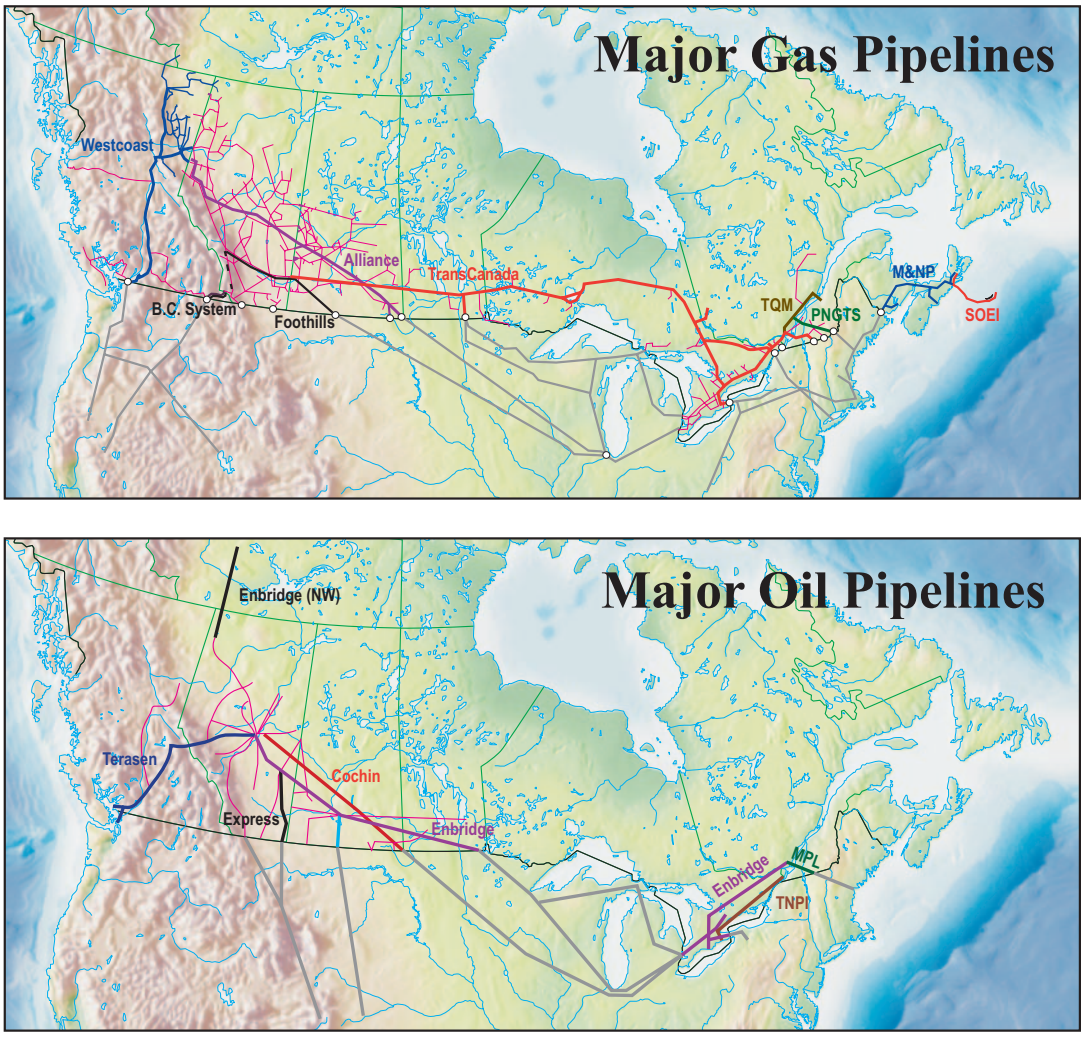
For the transportation system to work well, the Board believes that the following three outcomes should be achieved:

1. there is adequate pipeline capacity in place to move products to consumers who need them;
2. pipeline companies are providing services that meet the needs of shippers at reasonable prices; and
3. pipeline companies have adequate financial strength to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

To assess the extent to which these outcomes are being achieved, the Board used publicly available data for Group 1 regulated companies (see Figure 1). This group comprises the major pipeline companies that are subject to ongoing regulatory oversight by the Board. As these companies represent a major part of the Canadian transportation system, the data from these companies provides a good view into the overall functioning of the transportation system.

**FIGURE 1**

***Gas and Oil Pipelines Regulated by the National Energy Board***



# THE CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

## 2.1 Adequacy of Pipeline Capacity

A key measure of the efficient operation of energy markets is that there is adequate pipeline capacity to transport crude oil, refined products, natural gas and natural gas liquids from producing regions to market areas.

This section examines the following factors to assess the current adequacy of the pipeline capacity:

- price differentials compared with firm service tolls for major transportation paths
- capacity utilization on pipelines; and
- the degree of apportionment on major oil pipelines.

The Board has generally taken the view that it is better to have some excess pipeline capacity than to have inadequate capacity. While there are costs associated with having excess capacity in terms of higher tolls for shippers, the costs associated with insufficient pipeline capacity are generally greater. When there is inadequate take-away capacity, natural gas or oil production is shut-in or shipped to less attractive markets, resulting in foregone revenues for producers, foregone royalty revenue for governments, higher commodity prices for downstream consumers, an inefficient allocation of supply and a negative signal to investors in the upstream sector. The assurance that adequate capacity is available to serve various market regions provides a strong incentive to invest in exploration and development.

Further, some excess capacity in the system provides flexibility in the market. For example, when gas demand and prices are high in California because of poor hydro-electric conditions, Canadian producers would like to move gas to that market. When cold weather strikes the U.S. Northeast and prices in that market increase, the existence of some spare capacity allows producers to swing supply to that market, meeting consumers' needs and helping prices to stabilize.

The importance of having adequate pipeline capacity in place is highlighted by the fact that the value of natural gas and oil transported in NEB-regulated pipelines far exceeds the cost of service on those pipelines (e.g., in 2004 the value of products transported was approximately $100 billion compared with $4.5 billion for the cost of providing transportation service).

### *2.1.1 Price Differentials and Firm Service Tolls*

One measure of adequacy is based on the principle that, if adequate capacity exists, the price differential (or basis) between two points on a pipeline should be equal to or less than the cost of

transportation. As long as the price differential is less than the firm service toll plus fuel, the market is demonstrating that there is adequate pipeline capacity between the two pricing points. When there is inadequate pipeline capacity between two market points, the basis will exceed the cost of transportation. In a market with adequate capacity, sellers would generally redirect their product to the higher price market, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market and the price differential persists, resulting in higher prices for consumers and lost revenues for producers.

In order to use this measure, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below; one for transportation on TransCanada PipeLines Limited (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc. (Westcoast).

Figure 2 shows the basis between the Alberta border and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The fact that the basis is consistently lower than the firm service toll demonstrates that there generally has been excess capacity available on TransCanada since at least January 2001, although it appears that capacity between these two points has firmed up during the summer months since July 2002.

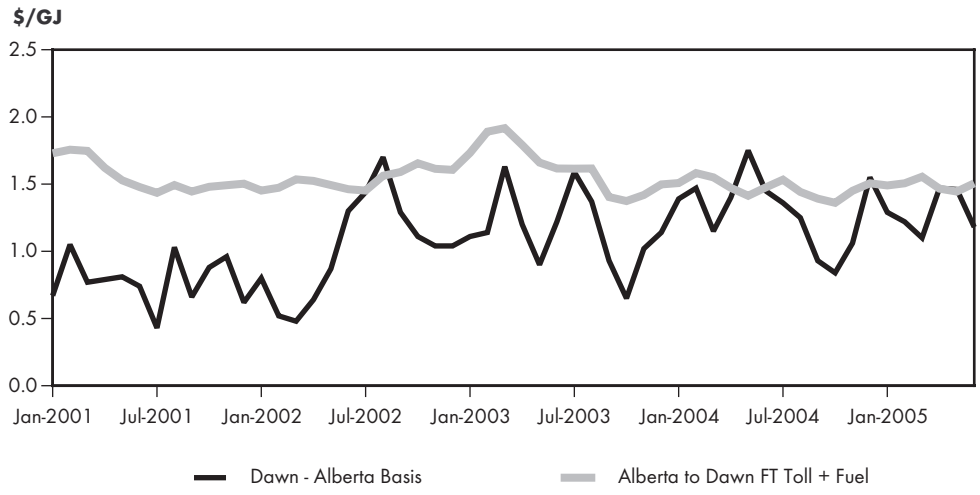
Figure 3 shows the basis between Compressor Station 2 on the Westcoast system and the Sumas export point compared with the Westcoast firm service toll between the two points (T-South or Southern Mainline), including fuel costs. Except for a few months, the basis has been lower than the transportation costs since February 2001, which indicates that there has been adequate capacity in place since that time[1].

*Dawn-Parkway Corridor*

Although there is inadequate pricing data available, there is evidence that capacity is tight on the Dawn-Parkway corridor of the Union Gas system. After the close of a binding open season in December 2004, Union signed contracts with 22 parties for an expansion of its system between Dawn and Parkway. Following the consideration of Union's facilities application, the Ontario Energy Board

**FIGURE 2**

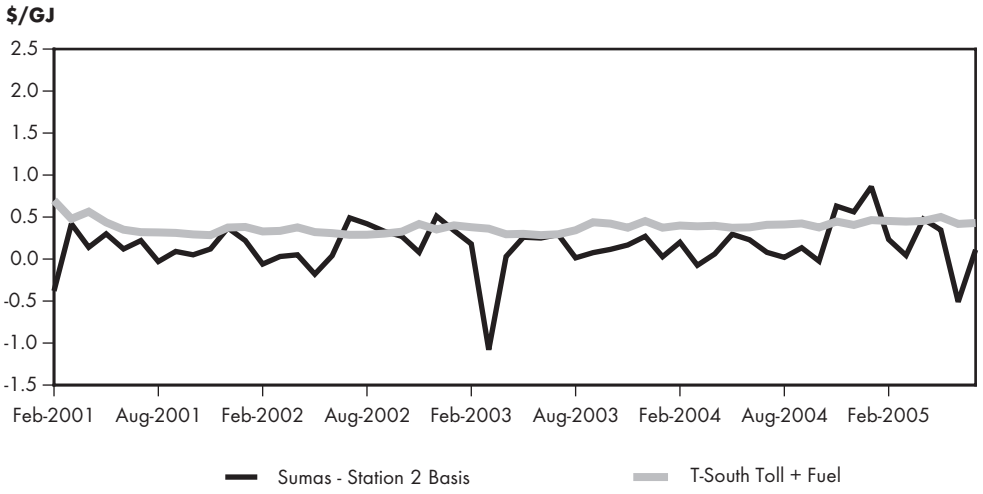
***Dawn - Alberta Basis vs. TransCanada Toll and Fuel***




1 The negative price differential at March 2003 may be a data anomaly.

FIGURE 3

***Sumas - Station 2 Basis vs. Westcoast T-South Toll and Fuel***




approved the expansion which is expected to be in service by November 2006. While not regulated by the NEB, this corridor is a key link between the Dawn hub and markets in eastern Canada and the U.S. Northeast.

### 2.1.2 *Capacity Utilization on Major Routes*

Where good pricing data is not available at major injection and delivery points on a pipeline system, another measure of adequate capacity is to monitor pipeline throughput compared with capacity. Capacity utilization is monitored for most large pipelines regulated by the Board.

The following figures show pipeline average monthly throughput compared with capacity on some of the largest pipeline systems regulated by the NEB, including TransCanada, Westcoast, Alliance Pipeline Ltd. (Alliance), Enbridge Pipelines Inc. (Enbridge), Terasen Pipelines (Trans Mountain) Inc. (Terasen (TMPL)) and Express Pipeline Limited Partnership (Express).

The volumes shown on Figure 4 are average monthly throughput[2] on the TransCanada Mainline and are approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan. These volumes are compared with the design capacity of TransCanada's prairie line. Figure 4 shows that since April 2003, the prairie line has been operating at between 70 to 80 percent of capacity.

Figure 5 shows the average monthly throughput on Westcoast's Southern Mainline compared with capacity between Station 2 and the Sumas export point. This figure shows the seasonal nature of throughput on the Southern Mainline with more volumes being transported during the peak winter months and less volumes being transported during the summer months.

In Figure 6, throughput on Alliance's system is compared with the firm service contracted capacity of 37,534 $10^3m^3/d$ (1,325 MMcfd) and physical capacity, which has been calculated as the sum of the contracted capacity and capacity made available for Authorized Overrun Service (AOS). As shown, Alliance's capacity has been virtually 100 percent utilized since the commencement of its operations because of the high contract level and the offering of AOS, priced at only the cost of fuel, which has filled any additional capacity.

2 Daily fluctuations in throughput are not shown on the figure.

**FIGURE 4**

***TransCanada Mainline Throughput vs. Capacity***

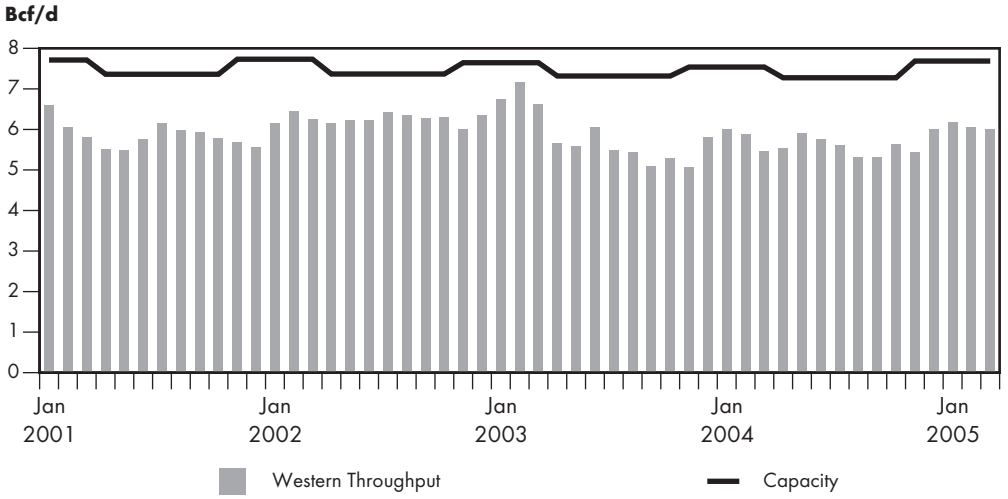
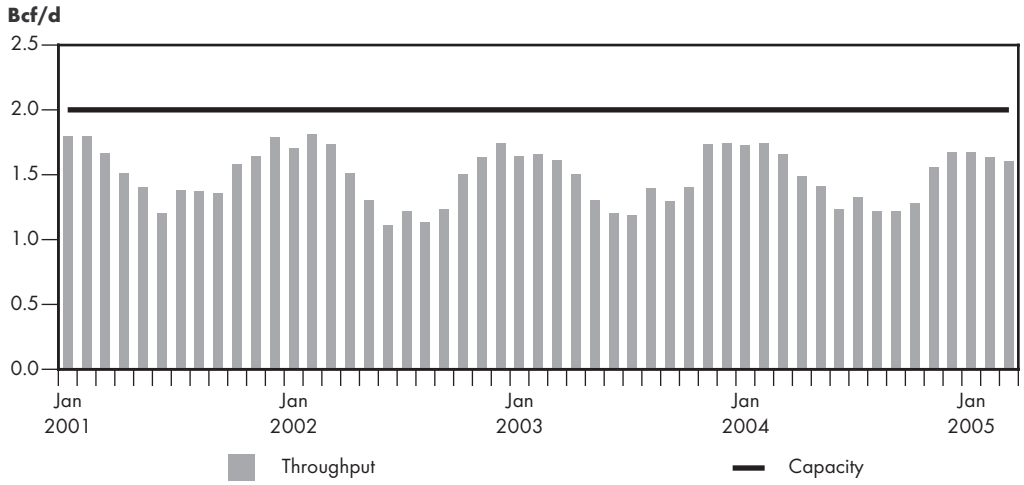



**FIGURE 5**

***Westcoast Mainline Throughput vs. Capacity***




It is somewhat difficult to assess utilization of the Enbridge system because it consists of several lines, most of which are dedicated to carrying specific grades of crude oil or natural gas liquids. As shown in Figure 7, since January 2001 Enbridge's mainline has been operating, on an overall average, at levels as low as 68 percent of capacity and as high as 86 percent of capacity. In the first quarter of 2005, Enbridge's mainline was operating at around 74 percent of capacity. Certain lines, particularly Lines 4 and 9 have been operating at or close to full capacity, with some apportionment (see section 2.1.3).

Terasen (TMPL) was operating at near capacity in 2003-04, with apportionment in January and March 2004. Given the high utilization rate, expected rising demand for pipeline space related to expected production growth in the oil sands, and increased shipments of heavy crude oil, Terasen (TMPL) applied in December 2003 for a 4 300 $m^3/d$ expansion. The Board approved this expansion and it went into service in September 2004. In the first quarter of 2005, Terasen (TMPL) operated at approximately 60 percent of capacity, mainly because of refinery turnarounds on the west coast (see Figure 8).

**FIGURE 6**

***Alliance Throughput vs. Capacity***

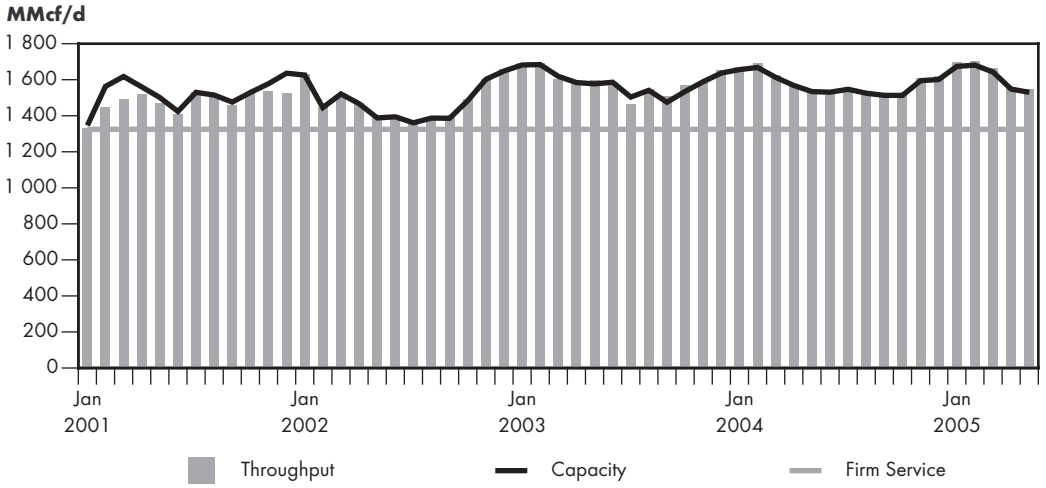
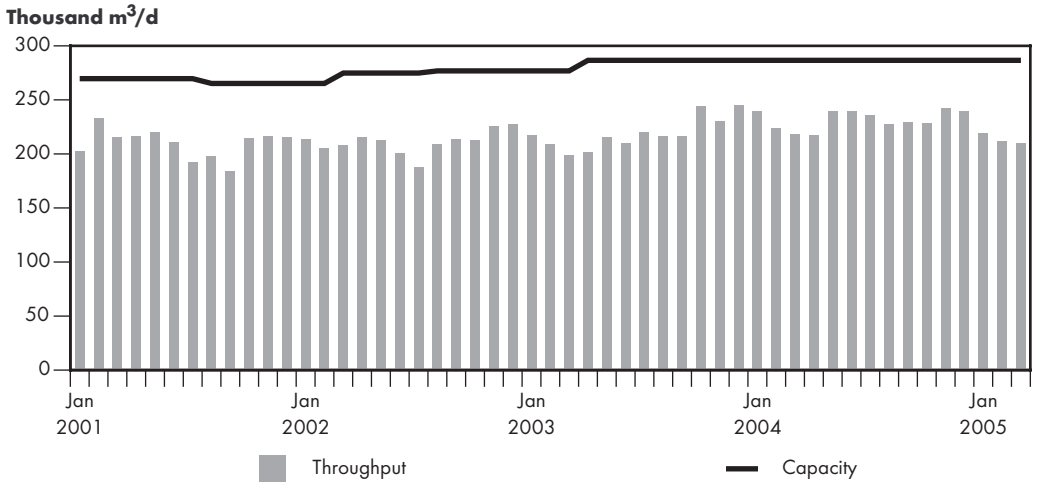



**FIGURE 7**

***Enbridge Pipeline Throughput vs. Capacity***




Express Pipeline Limited Partnership has been operating at full capacity for several years; at times exceeding 100 percent of its rated capacity (see Figure 9). On 1 April 2005, an expansion of 17 100 $m^3/d$ was completed. Unlike Enbridge or Terasen (TMPL), Express primarily operates with long-term financial commitments with its shippers. Given that shippers have financially committed to the system, they will tend to use their available space on Express before shipping on other systems.

### 2.1.3 Apportionment

Oil pipelines operate for the most part as common carriers. On common carriers, shippers nominate their desired volumes for delivery into the pipeline on a monthly basis and have no contractual rights to the pipeline's capacity. Lack of adequate pipeline capacity occurs when shippers nominate more oil or oil products for transport than the pipeline can carry that month. When this happens, each of the shippers that nominate volumes is allotted or "apportioned" a share of the available capacity based on the capacity allotment agreement for each pipeline. Some recent apportionment data for Enbridge, Terasen (TMPL) and Cochin Pipe Lines Ltd. (Cochin) are shown below.

**FIGURE 8**

***Terasen (TMPL) Throughput vs. Capacity***

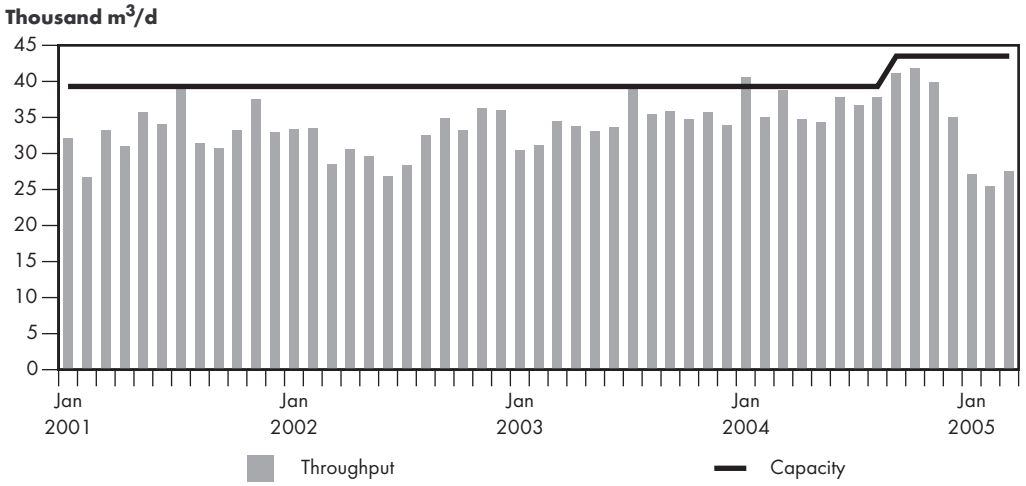
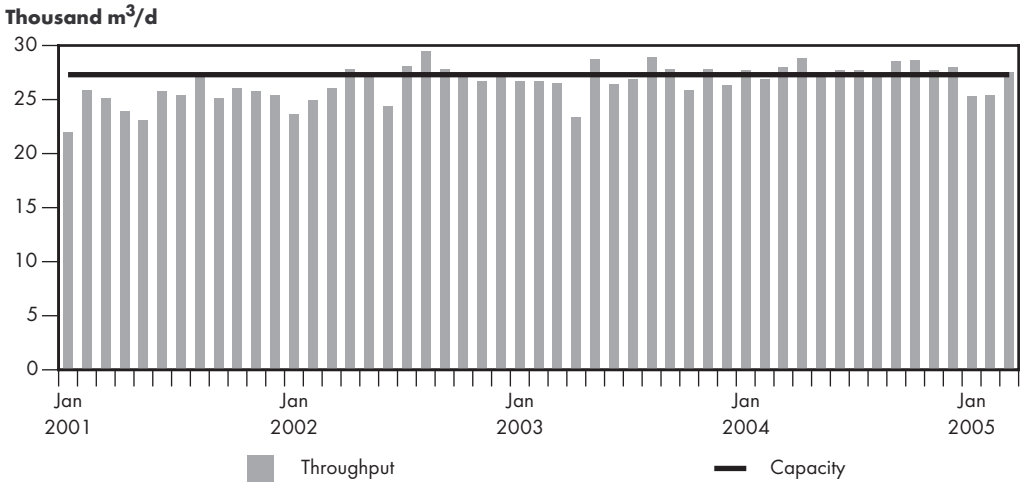



**FIGURE 9**

***Express Throughput vs. Capacity***




## *Enbridge*

Enbridge's Line 2 and 4 are dedicated to the transportation of heavy crude oil, while Line 3 is dedicated to light and medium crude oils. In the first quarter of 2005, Line 4 was either marginally over subscribed or fully subscribed. In the third quarter of 2005, Enbridge is planning to switch service in Lines 2 and 3, thereby increasing heavy capacity by 39 000 $m^3/d$.

Enbridge's Line 9 has a capacity of 38 150 $m^3/d$ and transports oil from Montreal to Sarnia. As shown in Table 1, apportionment has occurred fairly frequently on this line. One reason for this apportionment is increased shipments of crude oil produced from the Hibernia and Terra Nova fields which have high wax content and decreases operating capacity. Another reason is that foreign crude oil has been attractively priced and imports have been high in several months.

**TABLE 1**

***Enbridge Apportionment***

| | Sep-04 | Oct-04 | Nov-04 | Dec-04 | Jan-05 | Feb-05 | Mar-05 | Apr-05 |
|---|---|---|---|---|---|---|---|---|
| Line 4 Apportionment | 0% | 0% | 0% | 6% | 0% | 0% | 1% | 0% |
| Throughput ($10^3m^3/d$) | 98.1 | 100.5 | 101.4 | 119.3 | 113 | 114.2 | 114.8 | 104.7 |
| Line 9 Apportionment | 21% | 18% | 0% | 0% | 4% | 10% | 0% | 0% |

**TABLE 2**

***Terasen (TMPL) Apportionment***

| | Sep-04 | Oct-04 | Nov-04 | Dec-04 | Jan-05 | Feb-05 | Mar-05 | Apr-05 |
|---|---|---|---|---|---|---|---|---|
| Apportionment | 24% | 14% | 14% | 0% | 0% | 0% | 0% | 13% L<br>62% D |
| Throughput ($10^3m^3/d$) | 41.2 | 41.8 | 39.8 | 34.9 | 27.2 | 25.4 | 28.3 | 37.2 |

### *Terasen (TMPL)*

On Terasen (TMPL), apportionment is calculated separately for volumes delivered to land-based and Westridge Dock destinations (shown as L and D respectively in Table 2). Apportionment in September through November 2004 was attributed to land-based nominations that were due to increased demand as well as maintenance on the system that reduced available capacity. Even with the capacity expansion that was completed in September 2004, there was apportionment in November due partly to greater demand by Washington State refiners. From December 2004 to March 2005, throughput fell and there was no apportionment for those months. The April 2005 apportionment of 13 percent for land-based volumes likely reflects increased nominations from the Washington refineries following plant turnarounds. The 62 percent apportionment for the Westridge Dock could reflect increased test shipments of heavier type crude oils.

As a result of periods of apportionment on Terasen (TMPL) since 2003, two applications have been filed with the Board. One is from Chevron Canada Limited (Chevron) for an order designating Chevron's refinery at Burnaby, B.C. as a priority destination for unapportioned delivery of crude oil from Edmonton. The second application was filed by Chevron Standard Limited, Neste Canada Inc. and Chevron for an order designating Chevron's refinery at Burnaby, B.C. as a priority destination for the unapportioned delivery of iso-octane from Edmonton.

### *Cochin*

The capacity on Cochin is dependent on the type of product that is transported in the line and the time of year. Propane, ethane, ethylene and field-grade butane can all be transported on the line but the amount of ethylene nominated in a month affects the capacity. When there is a large amount of ethylene in the line, the capacity is reduced significantly. Cochin is still on pipeline restrictions since a rupture on the U.S. portion of the pipeline and a subsequent fire in 2003.

There was no apportionment in the first quarter of 2005, but pressure restrictions continue to limit capacity on Cochin. Apportionment is anticipated to occur between June and September 2005 due to a scheduled line shut-down for hydro-testing.

**TABLE 3**

***Cochin Apportionment***

| | Sep-04 | Oct-04 | Nov-04 | Dec-04 | Jan-05 | Feb-05 | Mar-05 | Apr-05 |
|---|---|---|---|---|---|---|---|---|
| Apportionment | 32% | 0% | 0% | 5% | 0% | 0% | 5% | 0% |
| Throughput ($10^3m^3$/d) | 7.4 | 11.4 | 11.0 | 10.3 | 12.3 | 8.7 | 7.6 | 9.4 |

*Wascana Pipeline*

As operator of the Wascana Pipeline, PMC (Nova Scotia) Company received notice that the Bridger Pipeline would not be able to accept deliveries of crude oil from Wascana south of the first Bridger Pipeline pump station at Poplar, Montana because of integrity concerns. As a result of this constraint on the U.S. side, Wascana has been operating at greatly reduced rates. The Bridger Pipeline is currently investigating and repairing a large number of anomalies that were identified on its system. While it is still too early to determine with any certainty when the Bridger Pipeline will return to normal operation, the company's target is the end of August 2005.

## 2.2 Index of Pipeline Tolls

Another indicator of the efficiency of the transportation system is whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices. The Board assesses this by analyzing the change over time in a benchmark toll for each major pipeline (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South export toll). Given the nature of cost of service regulation, pipeline tolls may increase simply because a major capital project was undertaken to meet shippers' needs. Nonetheless, if a benchmark toll increases sharply, it could indicate an issue in transportation markets (e.g., falling throughput or contract demand).

*Gas Pipelines*

Figure 10 compares the tolls for TransCanada, Westcoast and Foothills Pipe Lines Ltd. (Foothills) with the Implicit Price Index (IPI), Non-residential structures[3], normalized to the year 1997.

The increase in TransCanada's Eastern Zone toll between 1997 and 2001 is mainly attributed to the large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. The toll has been tracking the IPI fairly closely since 2001.

In 2000, Westcoast's T-South export toll increased over 10 percent from the previous year primarily because of non-routine pipeline integrity costs. The export toll began moving more closely to the IPI in 2001.

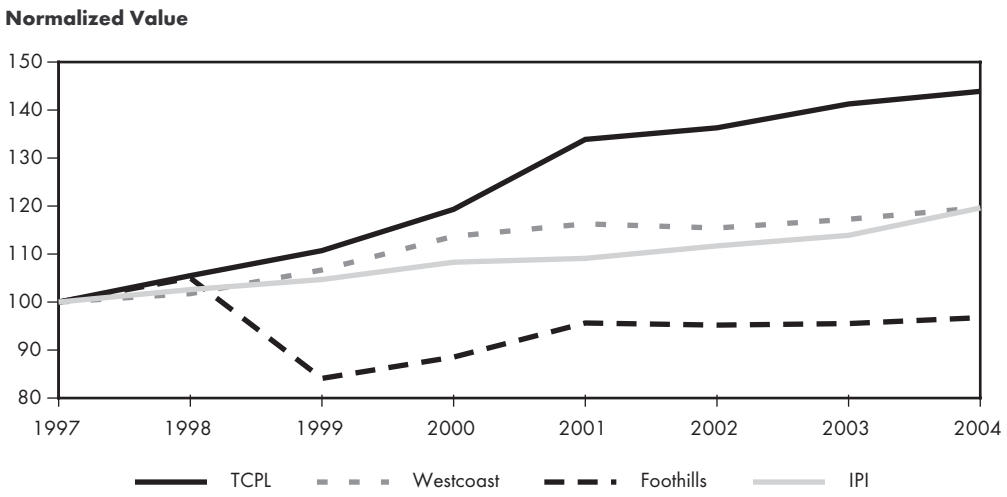
After declining in 1999 as a result of a cost-effective expansion of its system, Foothills' Zone 9 tolls have remained fairly stable. In addition, Maritimes & Northeast Pipeline's (M&NP) tolls have been relatively constant at around $0.66-68/GJ since it began operations in 2000 and Alliance's tolls have remained flat at $0.77/GJ since it began operations in 2001.

3 Statistics Canada suggested this index as being a suitable index for pipeline services.

Statistics Canada - CANSIM Series v3840577 - Table 384-0036: Implicit price indexes, Gross Domestic Product (GDP), PEA; Canada; Business gross fixed capital formation, non-residential structures (Index, 1997=100)

**FIGURE 10**

***Gas Pipeline Tolls and the Implicit Price Index (Normalized to the Year 1997)***




## *Oil Pipelines*

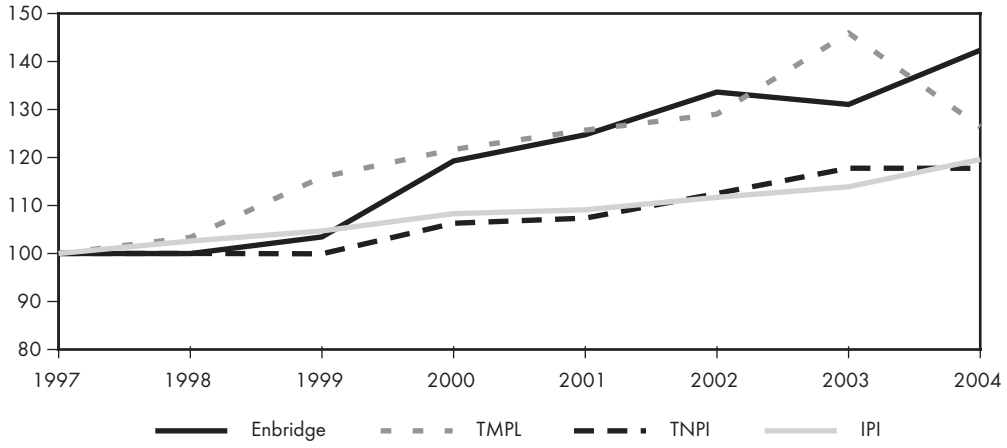
Figure 11 below shows benchmark tolls for Enbridge, Terasen (TMPL) and Trans-Northern Pipelines Inc. (TNPI) compared with the IPI, Non-residential structures, normalized to the year 1997.

In 2000, Enbridge's tolls (Edmonton to International border) increased because throughput levels were unexpectedly low in 1999. Under its negotiated settlement, Enbridge was able to recapture the shortfall in the ensuing years. The increase in 2004 tolls was mainly because Enbridge was operating at approximately 80 percent capacity utilization, as throughput has not filled recent capacity expansions. The full fixed costs are spread across lower volumes, resulting in higher tolls.

In 1999, Terasen (TMPL)'s tolls (Edmonton to Burnaby) increased because of low forecasted throughput (the 1999 forecast was 17.9 percent lower than the 1998 forecast and the toll is calculated based on forecast throughput). In 2004, Terasen (TMPL)'s tolls decreased, mainly because of the

**FIGURE 11**

***Oil Pipeline Tolls and the Implicit Price Index (Normalized to the Year 1997)***



disposition of 2003 deferrals for higher revenue and lower costs and slightly higher throughput starting in October 2004.

TNPI's tolls (Oakville to Montreal) have generally moved in tandem with the IPI since 1997.

## 2.3 Shipper Satisfaction

Shipper satisfaction is also another key measure of the efficiency of the transportation system. The Board uses the following tools to measure shipper satisfaction with the services they receive from pipeline companies:

- an annual survey;
- feedback through informal discussions with shippers and other stakeholders; and
- formal complaints filed with the Board.

### *2.3.1 NEB Pipeline Services Survey*

In June 2004, the Board established an annual Pipeline Services Survey to obtain direct feedback from the shippers of ten major NEB-regulated pipeline companies on the level of service provided by those companies. The survey was also used to obtain feedback on the Board's performance in implementing its regulatory role with respect to tolls and tariffs.

In January 2005, the first Pipeline Services Survey was administered. Companies sent the survey to each of their active shippers, who then returned their responses directly to the Board. The overall response rate to the survey was 23 percent.

After analyzing the survey responses, the Board published a summary of the results in aggregate. The aggregate results include the industry average and distribution of responses for each question and a summary of any major themes or trends. In addition, the Board provided each pipeline and those shippers that participated in the survey with detailed company-specific results. Those results included the pipeline company's average rating and distribution of responses for each question and the verbatim comments received from shippers, with the source of those comments removed.

Figure 12 shows the aggregate results for the first survey question, which asked shippers to rate the overall quality of service provided over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). The figure shows that shippers, on average, are reasonably satisfied with the services provided by pipeline companies[4].

The survey results indicated that shippers believe the pipeline companies are doing well in the following areas:

- physical reliability of operations;
- timeliness and accuracy of invoices and statements; and
- timeliness and usefulness of operations information.

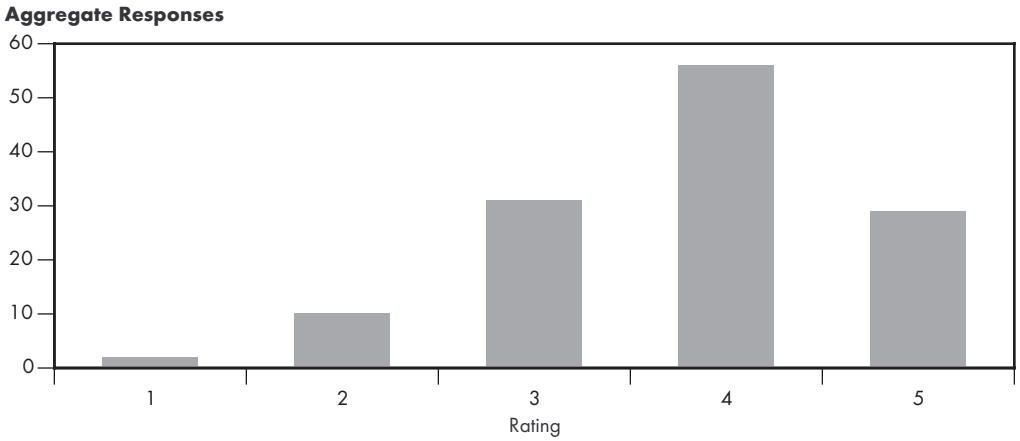
The areas where shippers believe that pipeline companies could improve the most are:

- make tolls more competitive;

4 The industry average is the average of all responses across all pipelines.

FIGURE 12

***Overall Quality of Service (Industry Average, 3.78)***




- exhibit an attitude of continuous improvement and innovation; and
- work towards fair and reasonable solutions when resolving issues.

Appendix 2 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, go to www.neb-one.gc.ca/Publications/ and look under Survey Results.

### 2.3.2 *Informal Monitoring*

Informal monitoring involves face-to-face discussions between NEB staff and pipeline companies, shippers, provincial regulators and other stakeholders, such as members of the investment community. It enables NEB staff to seek views on industry issues and concerns, including pipeline performance and perceptions about regulatory processes. These discussions also provide the Board with an opportunity to gauge the efficiency of transportation systems and can provide an early signal of the need for leadership in some areas of economic regulation[5].

Some examples of comments received from stakeholders during informal monitoring meetings included:

- Where possible, tolls should be set for multiple years (e.g., three to five years) at a time. This practice would provide cost savings, more toll certainty and avoid re-examining the same material over and over. Some shippers stated that an NEB policy statement would encourage this outcome (similar to what the Federal Energy Regulatory Commission does with its *Notice of Proposed Rulemakings*). This suggestion was supported by a number of members of the investment community.
- A mechanism is needed for the Board to hear shipper concerns on a regular basis. With negotiated settlements, shippers feel that the Board gets little information on their concerns.

5 The Board is, of course, bound by its Code of conduct not to discuss any matter with outside parties that is currently a matter before the Board in a regulatory proceeding. See the Board's Web site for a copy of the Code of conduct.

### 2.3.3 *Formal Complaints*

The number and nature of formal shipper complaints to the Board is another indicator of how satisfied shippers are with pipeline services. A sizeable number of complaints could indicate that a problem needs to be addressed. There have only been a few complaints filed in the last two years that have required a formal process before the Board.

## 2.4 Pipeline Financial Viability and Ability to Raise Capital

The final measure of the efficiency of the transportation system is the financial strength of the pipeline companies. This section looks at the financial viability of several NEB-regulated pipeline companies and their ability to raise capital on reasonable terms and conditions to invest in infrastructure. To undertake this assessment, the following factors are examined: financial ratios, credit rating reports and equity analyst assessments.

As noted in the Introduction, it is not the intention of this report to assess factors that would be examined in a regulatory proceeding on cost of capital such as the comparable earnings standard or the capital attraction standard. Rather, the purpose of this report is to provide a broad assessment as to whether the Canadian transportation system is working and one factor in that regard is whether it is able to efficiently expand to meet the needs of producers and end-use customers.

### 2.4.1 *Financial Ratios*

Financial ratios are useful indicators of a company's performance and financial situation. They can be used to evaluate a company's liquidity, operating performance, growth potential and risk. Evaluating financial ratios is most meaningful when the ratios for a particular company are tracked over time or compared with industry benchmarks. Care must always be exercised in collecting and interpreting financial ratios for pipeline companies given that some financial information pertains to their larger parent companies which may include non-regulated assets.

Some key ratios used to assess the financial viability of pipeline companies include interest coverage ratios, funds from operations to total debt, return on equity (ROE) and total debt to equity. A few of these ratios are discussed below.

*Interest Coverage Ratios*

Interest coverage ratios measure how many times interest payments could be made with a company's earnings before interest expenses and income taxes are paid. From a bondholder's perspective, interest coverage is an indicator of whether a company could have problems making its interest payments. From an equity holder's perspective, this ratio helps to give some indication of the short-term financial viability of the company.

One formula used to determine the coverage of interest is Earnings Before Interest and Taxes (EBIT) divided by Annual Interest Expense. Another coverage ratio that focuses on cash flows rather than accounting income is funds from operations (FFO) interest coverage. FFO interest coverage data are not included in this report.

A higher coverage ratio is typically better for both bondholders and equity investors. From a bondholder's perspective, a high coverage ratio indicates a low probability that the firm will fail to

meet its interest obligations in the near term. For stock investors, a high ratio indicates that a company is relatively solvent.

Table 4 shows the EBIT interest coverage ratios for Group 1 pipeline companies as calculated by the Dominion Bond Rating Service (DBRS). Most interest coverage ratios are in the 2-3 times range, except for Terasen (TMPL) which has a coverage ratio many times higher than its peers. The reason for this higher ratio is primarily because of Terasen (TMPL)'s common equity ratio of 45 percent, which means it carries less debt. Table 4 also shows that the coverage ratios for most companies are stable or improving over time.

DBRS notes that interest coverage ratios for Canadian pipelines are often lower by 1.0 to 1.25 times than those for U.S. pipelines. It cites the following factors as contributing to these lower coverage ratios:

- lower allowed returns on equity (typically 200 basis points);
- lower allowed deemed common equity ratios of 30 percent to 35 percent in Canada; and
- flow-through tax accounting in Canada versus the normalized method in the U.S. (which allows for the recovery of deferred income taxes in tolls).

Despite the lower coverage ratios as noted by DBRS, none of the major NEB-regulated companies has had a problem servicing their debt obligations.

### *Return on Equity*

Return on Equity (ROE) is a common measure of financial performance and is frequently used when evaluating and comparing companies. The ROE a company earns can be expressed financially as net income divided by common equity. However, for NEB-regulated pipeline companies, this ratio is expressed as the return on the equity portion of the rate base that is approved by the Board.

Table 5 shows the actual ROE for several Group 1 pipeline companies from 1999 to 2004 along with the NEB-approved ROE in accordance with the RH-2-94 Formula[6]. Alliance, Enbridge, M&NP and Terasen (TMPL) are not subject to the NEB-approved ROE as they all have negotiated a different

**TABLE 4**

***EBIT Interest Coverage Ratios***

| | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|
| Alliance | - | 1.85 | 1.92 | 1.85 |
| Enbridge | 2.80 | 2.84 | 3.02 | - |
| Foothills | 2.16 | 2.16 | 2.39 | 2.41 |
| M&NP | 1.55 | 1.82 | 2.05 | - |
| Terasen (TMPL) | 3.62 | 4.69 | 6.12 | 7.03 |
| TQM | 1.99 | 2.15 | 2.36 | 2.36 |
| TransCanada | 1.97 | 2.16 | 2.32 | 2.36 |
| Westcoast | 1.58 | 1.99 | 2.14 | 1.85 |

6 Formula used to determine the rate of return on common equity for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, as amended to eliminate rounding.

**TABLE 5**

***Return on Equity for the Period 1999 to 2004***

| | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|---|
| Alliance | - | 11.21 | 11.25 | 11.25 | 11.25 | - |
| Enbridge | 11.70 | 11.20 | 12.20 | 13.00 | - | - |
| Foothills | 9.58 | 9.90 | 9.61 | 9.53 | 9.79 | 9.56 |
| M&NP | - | 13.80 | 14.20 | 12.95 | 12.31 | 13.75 |
| Terasen (TMPL) | 18.50 | 17.50 | 19.60 | 20.40 | 20.40 | - |
| TQM | 9.94 | 9.96 | 10.21 | 9.80 | 10.21 | 9.84 |
| TransCanada | 9.64 | 9.99 | 9.72 | 9.95 | 10.18 | 10.18 |
| TCPL B.C. System | 9.58 | 9.90 | 6.86 | 9.53 | 8.21 | 8.51 |
| Westcoast Field Services | - | - | 13.62 | 14.87 | 6.76 | 11.63 |
| Westcoast Transmission | 11.68 | 12.68 | 15.84 | 13.44 | 12.93 | 10.28 |
| NEB RH-2-94 Formula | 9.58 | 9.90 | 9.61 | 9.53 | 9.79 | 9.56 |

Source: DBRS (Enbridge, Terasen); NEB Surveillance and Annual Reports (all others); dash indicates not available

ROE with their shippers[7]. Also, Westcoast's Field Services Division is not subject to the formula as its tolls for gathering and processing services are negotiated individually with shippers.

The ROE numbers for Enbridge and Terasen (TMPL) have been taken from their DBRS Credit Rating reports as those companies currently do not file NEB surveillance reports. As such, the numbers are somewhat higher than one would normally expect and might include some non-regulated income in the calculations (e.g., Terasen (TMPL)'s income includes $6 to $7 million annually of dividend income from its parent, Terasen Inc.). The complete details of these credit rating reports should be read before comparing the ROE for Enbridge and Terasen to the other companies listed in Table 5.

### 2.4.2 Credit Ratings

In Canada, credit ratings are determined by three independent credit rating agencies, DBRS, Moody's and Standard & Poor's (S&P). See Appendix 1 for a comparison of the rating scales for DBRS and S&P. Credit ratings, like stock prices, generally reflect the consolidated operations of the entire company and not solely the regulated portion. Thus, the use of credit ratings as an accurate measure of the performance for a regulated pipeline owned by a company that has both regulated and non-regulated operations, such as TransCanada and Enbridge, has to be interpreted with some care. In addition, credit ratings are somewhat subjective in that the rating imposed on a company is the expert opinion of an investment analyst, which may result in different ratings by different firms.

*DBRS*

In assigning a credit rating to a particular company, DBRS attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. While the key considerations will vary industry by industry, some of the common factors that are considered for most ratings are: core profitability; asset quality; strategy and management strength; and financial and business risk profile.

7 Negotiated ROE for Alliance is 11.25 percent and for M&NP is 13.0 percent.

For pipelines, electric and gas utilities, the following factors are also important considerations in deriving the credit ratings: regulatory factors, competitive environment, supply and demand considerations, and regulated vs. non-regulated activities.

The credit ratings for the Group 1 pipeline companies shown in Table 6 indicate that the ratings have remained stable from 1999 to the present. Alliance has improved from BBB(high) to A(low).

*Standard & Poor's*

An S&P credit rating is a current opinion of a company's overall financial capacity to pay its financial obligations. S&P bases its ratings on the overall creditworthiness of the corporation. Therefore, the rating of a wholly-owned subsidiary company, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent. This opinion focuses on the company's capacity and willingness to meet its financial commitments as they come due and may also apply to specific financial obligations. The rating histories for several Group 1 pipeline companies are provided in Table 7.

In S&P's rating methodology, a company rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than companies in higher-rated categories. A company rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the company to meet its financial commitments.

**TABLE 6**

***DBRS Credit Rating History – Senior and Subordinated Debt***

| | 1999 | 2000 | 2001 | 2002 | Current |
|---|---|---|---|---|---|
| Alliance | BBB(high) | BBB(high) | A(low) | A(low) | A(low) |
| Enbridge | A(high) | A(high) | A(high) | A(high) | A(high) |
| M&NP | A | A | A | A | A |
| Terasen (TMPL) | A(low) | A(low) | A(low) | A(low) | A(low) |
| TQM | A(low) | A(low) | A(low) | A(low) | A(low) |
| TransCanada | A | A | A | A | A |
| Westcoast | A(low) | A(low) | A(low) | A(low) | A(low) |

**TABLE 7**

***S&P Credit Rating History***

| | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| Enbridge | A/Stable | A-/Negative | A-/Negative | A-/Stable | A-/Stable |
| Terasen (TMPL) | BBB+/Stable | BBB+/Stable | BBB+/Watch Neg | BBB/Stable | BBB/Stable |
| TQM | BBB+/Stable | BBB+/Stable | BBB+/Stable | BBB+/Stable | BBB+/Stable |
| TransCanada | A-/Stable | A-/Stable | A-/ Watch Neg | A-/Negative | A-/Negative |
| Westcoast | A-/Negative | A-/Stable | A/Negative | BBB/Stable | BBB/Positive |

Each of these agencies has expressed an opinion at various times that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Nonetheless, the ratings assigned by the credit rating agencies indicate that NEB-regulated companies are all within investment grade.

### 2.4.3 *Access to Capital Markets*

As mentioned in the Introduction, pipeline companies must be able to access capital to expand and maintain their systems to adequately meet the evolving needs of the marketplace.

The most straightforward test of a pipeline company's ability to finance new capacity is market evidence of their ability or inability to finance major new construction. However, there has not been much pipeline construction in the last few years because natural gas production from the Western Canada Sedimentary Basin (WCSB) has hit a plateau and adequate pipeline capacity is in place. While there has been some recent expansion of oil pipeline capacity, no really large investments have been made. Thus, the question to ask is whether or not pipeline companies would have any difficulty in financing new projects when they arise.

To answer this question, the Board met with credit rating agencies, suppliers of capital and equity analysts in the investment community to discuss their views on the ability of Canadian pipelines to access capital markets, their general criteria for assessing NEB-regulated pipelines, and their views on the current regulatory environment in Canada.

On the primary question of access to capital, all of the organizations consulted indicated that Canadian pipelines should have no difficulty raising capital at reasonable cost at this time. For example, they believed that there should be no major challenges in financing a pipeline such as the Mackenzie Valley natural gas pipeline or additional oil pipelines to carry growing production from the oil sands. It was noted by some that debt issues for Canadian pipelines have traditionally been very attractive, in part because of the secure regulatory environment. The organizations consulted were generally of the view that a debt issue would be favourably received by the market.

With respect to attracting equity, some investment analysts noted that a major equity issue at the current ROE awarded by the NEB could be more problematic. They noted that recent projects, such as Alliance and M&NP, have been based on a higher equity return. It was noted by some that incumbent pipelines are at a disadvantage if they have to raise capital at the existing ROE. Others were of the view that greenfield projects are riskier and simply require a higher ROE to attract the equity investment. It was recognized that the Board has approved the higher ROEs that have been necessary to support greenfield pipelines such as Alliance and M&NP.

### 2.4.4 *Other Comments by the Investment Community*

Credit rating agencies and pension funds are primarily concerned about the predictability of cash flows to support debt and dividend payments. In this regard, the Board's RH-2-94 Formula is viewed positively because it improves predictability. Most of the companies with whom the Board met stated that they would like to see arrangements that provide certainty over multi-year periods because annual toll hearings introduce uncertainty and can distract pipeline management from focusing on other important aspects of their business. They also would like to see tolls and tariffs in place at the start of a fiscal year because interim toll situations increase uncertainty.

Pension fund administrators expressed the view that the Board should 'protect' credit ratings because downgrades could be very costly to bondholders. They noted that Canadian bonds are an important revenue source for Canadian pension funds and that a downgrade could require them to sell a large percentage of their bonds at discounted prices. On the other hand, some groups were of the view that the Board should not be overly concerned about maintaining a 'target' credit rating for a pipeline; investment grade ratings should be adequate.

It was noted by some that the business environment for the traditional Canadian gas pipelines has become somewhat riskier since the construction of the Alliance pipeline and the slowdown in the growth of gas production. Accordingly, they believe that basic financial parameters in the Board's regulatory scheme should be improved[8]. Finally, a number of parties expressed concern that the Board does not have adequate rules to ensure financial protection ('ring-fencing') of a regulated utility and concern was expressed that cash could be drained from a pipeline company if its parent were to experience severe financial difficulties.

### *2.4.5 Assessments by Equity Analysts*

Several equity analysts regularly publish their assessments of various companies for investors. The Board reviews these assessments for the consolidated operations of pipeline companies as they provide some useful information on their financial viability and outlook for the future. As with credit ratings, equity analysts generally focus on companies that have stand-alone share offerings and, in many cases, these offerings include non-regulated as well as regulated businesses. While observations vary from analyst to analyst and from company to company, most NEB-regulated pipelines have been rated in the 'hold' or 'buy' categories over the last year, indicating that this sector of the investment community does not have any significant concerns about their short-term prospects.

8 In its RH-2-2004 Phase II Reasons for Decision dated April 2005, the Board approved an increase in TransCanada's deemed common equity ratio from 33 percent to 36 percent.

# Conclusions and Emerging Issues

## Conclusions

Based on the chosen measures, the Board believes that the Canadian hydrocarbon transportation system is working very well at the present time.

Currently, **there appears to be adequate natural gas pipeline capacity in place on existing systems**, especially since production from the WCSB has levelled off over the last few years. The existence of some excess capacity out of the WCSB has provided producers with the flexibility to access their market of choice and the value of natural gas exports hit a record high of $26.5 billion in 2004. There are some constraints in the system east of Dawn, Ontario but this has not to date caused any prolonged problems in delivering adequate volumes to the marketplace to meet the needs of consumers.

**Overall, there is adequate capacity on the oil pipeline transportation system** and all types of oil produced in the WCSB are being delivered to markets within and outside Canada. However, capacity on some systems has been tight, notably on Terasen (TMPL). This has been illustrated by the need for Terasen (TMPL) to apportion shippers in recent months and by Chevron's request for priority destination status for its Burnaby refinery. Canadian oil producers also appear to believe that there is a need to improve access to heavy crude oil markets in the U.S. Inadequate access to refineries designed to run heavier crudes appears to have been a contributing factor to the recent high heavy/light price differentials for Canadian crudes. This need for improved access has been illustrated by the Canadian industry's support for the reversal of two U.S. pipelines to Cushing, Oklahoma and the U.S. Gulf Coast to allow growing oil sands production to penetrate new markets.

Based on the results from the NEB Pipeline Services Survey, **shippers are reasonably satisfied with the services provided by pipelines** (overall rating of 3.78 out of 5). In particular, physical reliability of pipeline operations was rated very highly by shippers, indicating that products are reliably delivered to markets. There are, however, a few areas where some work is required on the part of the pipeline companies to improve service, including:

- making tolls more competitive;
- exhibiting an attitude of continuous improvement and innovation; and
- working collaboratively towards fair and reasonable solutions to resolve issues.

The financial assessment indicates that **NEB-regulated pipeline companies are financially sound**. However, it is recognized that some of the data and indicators reviewed are for the consolidated operations of pipeline companies. While pipeline companies have not had to raise large amounts of capital in recent years, the Board's survey of the investment community revealed that it believes that

pipeline companies should have no difficulty in raising capital to finance most major new projects at this time.

The Board recognizes that this report is a snapshot in time and does not include a comparison, for example, with pipelines in other jurisdictions. The Board considers this report as a first step in assessing the effectiveness of the hydrocarbon transportation system in Canada. The Board will continue to monitor the effectiveness of the system and will continue to meet with parties to gain an understanding of all perspectives on the transportation system. The Board welcomes feedback at any time on the measures and conclusions in this report and welcomes suggestions for improvements to future reports.

## Emerging Issues

While the transportation system is currently working well, there are a number of emerging challenges facing the industry.

To meet the needs of producers and users, the transportation system must be able to adapt to the changing needs of the market over time and expand to attach new sources of supply. This can be particularly challenging for the pipeline sector because investments tend to be "lumpy" and, given the long life of the assets, investors have to be reasonably assured of the existence of supply and markets over a long time period. Clearly, the longer the time period over which an investment is recovered, the greater the possibility that market circumstances will change.

The potential for market change over time is highlighted by the uncertainties around the number of liquefied natural gas (LNG) terminals that will be built in North America and the potential effects that imported LNG will have on the supply and demand balance and on the pattern of natural gas flows. For example, the construction of LNG terminals in Quebec could have important implications for the flow pattern on TransCanada and TQM and could impact the toll design of the system.

Another event that could impact the supply and demand balance and consequent gas flows is the significant potential gas requirement for power generation that will be driven by Ontario's policy to remove 7 500 MW of coal-fired capacity from its system. Although the refurbishment of existing nuclear generation might meet part of the requirement for the displaced coal, there will likely be a significant volume of new natural gas-fired generation to enter the system. The exact impact of this incremental generation on natural gas pipelines will depend on the total amount of generation awarded and the location.

On the oil side of the market, the expected growth in production from the oil sands is posing tough choices for the industry regarding which incremental markets to access and how to expand the pipeline system. Options include expansion of existing systems and construction of new systems to access new markets in either or both the U.S. and Asia. Given the large capital outlay and the relative irreversibility of the investment decision, market participants want to ensure that the optimal decisions will be made.

From a regulatory perspective, the challenge is to provide a fair and effective process that does not distort the investment decisions that should optimally be made in the marketplace. Investors in new pipelines desire clear regulatory processes with predictable timelines. New investment can be frustrated when timelines stretch out and unexpected regulatory hurdles materialize during the process. Unnecessary delays in construction of new systems that are in the public interest can result in increased costs to energy users as development of new supplies are constrained.

The flattening of natural gas production from the WCSB and construction of the Alliance pipeline has created challenges for a number of the older systems that are experiencing a sharp decline in the long-term contracts on their systems. Natural gas is still being moved on these systems, but many shippers prefer to rely on short-term services to maximize their flexibility. Under the traditional cost of service approach, the remaining firm shippers have to bear the load of recovering the fixed costs in the form of rising tolls. While the erosion of long-term contracts has not yet vitiated the cost of service framework, new toll design structures may need to be considered to effect a fair sharing of costs and to maintain the competitiveness of these systems.

Lastly, having regard to the financial viability of the pipeline companies, there is interest in the investment community and amongst shippers in working towards multi-year frameworks for the establishment of tolls on more pipeline systems. A multi-year framework would provide more certainty for all parties and reduce the burden associated with continual negotiations and regulatory proceedings. While the Board is committed to working towards a framework which reduces regulatory uncertainty, it recognizes that it may be difficult to structure a multi-year framework that will meet the needs of all parties when the market context is expected to change considerably in the next few years. The investment community would also like to see tighter regulatory rules regarding parent-affiliate dealings in order to protect the cash flows of the regulated entities.

Some of these issues will be settled amongst parties, others may be examined in formal proceedings before the Board, and others may be amenable to potential regulatory actions outside of the hearing process. The Board will continue to consult with stakeholders on these issues and seek input if and when any regulatory initiatives are pursued.

# DEBT RATING COMPARISON CHART

This chart provides a comparison of the rating scales used by DBRS and S&P when rating long-term debt.

| Credit Quality | DBRS | S&P |
|---|---|---|
| Superior | AAA | AAA |
| | AA high | AA+ |
| | AA | AA |
| | AA low | AA- |
| Good | A high | A+ |
| | A | A |
| | A low | A- |
| Adequate | BBB high | BBB+ |
| | BBB | BBB |
| | BBB low | BBB- |
| Speculative | BB high | BB+ |
| | BB | BB |
| | BB low | BB- |
| Highly Speculative | B high | B+ |
| | B | B |
| | B low | B- |
| | CCC | CCC |
| | CC | CC |

Ratings in the Adequate category and above are considered Investment Grade.

Standard & Poor's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A 'Positive' outlook means that a rating may be raised; a 'Negative' outlook means that a rating may be lowered; and a 'Stable' outlook means that a rating is not likely to change.

# Pipeline Services Survey Aggregate Results

The results below are the aggregate responses from shippers on several major NEB-regulated pipeline companies. See the Board's Web site for the complete details.

1. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 2 | 10 | 31 | 56 | 29 | 3.78 |

2. What are the things that this pipeline company does well?
3. What are the things that this pipeline company could do better?
4. How satisfied are you with the physical reliability of the pipeline company's operations?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 2 | 9 | 12 | 53 | 52 | 4.13 |

5. How satisfied are you with the quality, flexibility and reliability of the pipeline company's transactional systems (nominations, bulletin boards, reporting, contracting, etc.)?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 5 | 9 | 32 | 51 | 27 | 3.69 |

6. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 3 | 9 | 19 | 49 | 38 | 3.93 |

7. How satisfied are you with the timeliness and usefulness of *operations* information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 5 | 9 | 24 | 61 | 26 | 3.75 |

8. How satisfied are you with the timeliness and usefulness of *commercial* information (tolls, service changes, new services, contract information, etc) provided by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 1 | 11 | 34 | 65 | 16 | 3.66 |

9. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 8 | 21 | 46 | 38 | 11 | 3.19 |

10. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 6 | 19 | 28 | 51 | 18 | 3.46 |

11. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 6 | 24 | 32 | 42 | 12 | 3.26 |

12. How satisfied are you with the suite of service options (FT, IT, backhaul, etc.) offered by the pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 3 | 6 | 33 | 47 | 15 | 3.63 |

13. How satisfied are you that this pipeline company's transportation tolls are competitive?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 9 | 14 | 55 | 39 | 4 | 3.12 |

14. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 6 | 8 | 47 | 45 | 7 | 3.35 |

15. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 7 | 9 | 43 | 49 | 9 | 3.38 |

16. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 5 | 7 | 35 | 51 | 16 | 3.58 |

17. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

| 1 | 2 | 3 | 4 | 5 | Average |
|---|---|---|---|---|---|
| 4 | 11 | 33 | 38 | 13 | 3.46 |

18. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

19. Additional comments

**YUB-YECL-36**

**Reference:** Prepared Testimony of Foster Associates Inc., page 15

**Issue:** Maintenance of Creditworthiness Financial Integrity

**Quote:** While NRG is somewhat smaller (assets of approximately 9 million) than Yukon Electrical, it would be of reasonably similar business risk to Yukon Electrical. (Line No. 413-414.)

**Request:**

Compare and contrast the business risks between YECL and NRG.

**Response:**

NRG is a very small gas distribution utility (2007 rate base of approximately 10 million) serving approximately 6,500 customers in a rural area southeast of London, Ontario. Its largest community served has a population of approximately 7,000. Union Gas, the neighboring gas distributor, has a rate base of more than 4 billion and over 1 million customers. While YECL is larger than NRG in both customers and rate base, comparatively both are very small relative to their Canadian peers.

From an economic diversity perspective, both economies are characterized by relatively low diversity. NRG's service area is dominated by the agricultural sector, while the economy in and surrounding Yukon Electrical's service area is characterized by mining and public administration. Approximately 85 of NRG's gross margin is from the residential and commercial sectors, compared to 100 of Yukon Electrical's gross margin.

NRG receives gas supply through Union Gas, which in turn has access to gas supplies from diversified suppliers in Western Canada and the U.S. through two major pipeline systems. Yukon Electrical's power supply is largely from Yukon Energy.

With respect to the regulatory environment generally, the Ontario Energy Board, which regulates NRG, is considered to be even-handed and reasonable in its approach. There is no specific element of the regulatory environment that would distinguish the OEB's

regulation of NRG from the YUB's regulation of Yukon Electrical. Both NRG and Yukon Electrical are regulated on the basis of forward test years and have access to deferral and variance accounts. For example, NRG has a purchased gas variance account which provides for pass-through of differences between forecast and actual gas costs; Yukon Electrical has similar protection for variances between forecast and actual purchased power costs.

**YUB-YECL-37**

**Reference:** Prepared Testimony of Foster Associates Inc., page 16

**Issue:** Business Risk

**Quote**: Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future. (Line No. 437-439.)

**Request:**

(a) Is it common for utilities such as YECL to request deferral accounts to mitigate some of the business risks faced by the utility?

(b) In the event of future risk, does anything prevent a utility from making an application before its regulator to cover those risks?

(c) If such risks are just and prudent, would a utility include compensation for those risks in its revenue requirement?

**Response:**

(a) Yes, for costs that are beyond the control of management.

(b) No, however, there is no guarantee that the regulator will approve the requested deferral account or the recovery of the costs in the deferral account. As well, there is no assurance that the regulatory process could be completed and a related decision rendered in a fashion that would cover the full risk involved.

(c) Yes, the required return would include compensation for risks that are just and prudent and that are borne by shareholders.

**YUB-YECL-38**

**Reference:** Prepared Testimony of Foster Associates Inc., pages 16 to 22

**Issue:** Regulatory Risk

**Quote:** The regulatory framework in which a utility operates is, next to the basic demand risks, the most significant aspect of risk to which shareholders in a regulated firm are exposed. The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts. (Line No. 456-459.)

**Request:**

(a) Does YECL face a higher regulatory risk than the typical electricity distribution utility in Canada?

(b) From a regulatory perspective, is an integrated utility considered more risky than one that is not integrated?

(c) In general, does an integrated utility face more business risk than one that is not integrated? If so, provide third party references.

(d) What was the last capital structure, return on debt and return on equity approved for Northland Utilities (Yellowknife) Limited?

(e) What was the last capital structure, return on debt and return on equity approved for Northland Utilities (NWT) Limited?

(f) Do FortisBC, FortisAlberta, or ATCO Electric serve any communities with populations that range from 10 to 300?

(g) Do EPCOR Utilities and ENMAX in Alberta only serve one community?

**Response:**

(a) No.

(b) In principle, one would expect vertically integrated and wires utilities to be provided a similar ability to recover a fair return on and of their investment. However, there are two distinguishing factors: (1) vertically-integrated utilities in the aggregate, particularly those with relatively high costs of generation, continue to face some possibility that the industry will be restructured and their existing generation will face competition; (2) vertically-integrated utilities which are required to construct significant new generation face higher risks of cost disallowances than pure wires utilities.

(c) Yes. As stated in its September 2006 report on vertically integrated utilities, S&P states On Standard & Poor's business profile scale (where '1' is excellent and '10' is vulnerable), vertically integrated utilities generally have satisfactory business profiles of '5' or '6' ..We view a company that owns regulated generation, transmission, and distribution operations, as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management. The document is attached in response to YEC-YECL-40(g) as YEC-YECL-40(g) Attachment 1.

(d) Decision 12-2005 (August 2005) reflected an overall negotiated settlement including the issues of capital structure and return on equity. The parties agreed to an equity ratio of 39.60 for 2005 and 39.57 for 2006 and an equity return of 10 for both years. The agreed-to cost of debt, which was not specified in the settlement, was 6.12 for both years. NUY has applied for a common equity ratio of 47.5 and an ROE of 9.6 for the 2008-2010 test years.

(e) Decision 9-2006 (March 2006) established an equity ratio of 39-40 and an equity return of 9.5 for test years 2005 and 2006. The costs of debt for each of the two test years, not specified in the decision, were, respectively, 6.47 and 6.51 . NWT has applied for a common equity ratio of 50 and an ROE of 9.6 for the 2008-2010 test years.

(f) Ms. McShane does not have the specific information requested for FortisAlberta and FortisBC, but given the location of the two utilities, it is likely that both serve some communities of that size. However, FortisAlberta serves 175 total communities and a total of over 450,000 customers; the largest 10 communities have a combined population of over 250,000. FortisBC serves a total of 155,000 customers (109,000 direct and 46,000 indirect customers). The largest two communities served have a total population in excess of 200,000. ATCO Electric serves approximately 200,000 customers in Alberta and 245 communities; the largest three of those communities have a total metro area population in excess of 150,000.

(g) EPCOR Utilities and ENMAX serve the communities of Edmonton (population approximately 750,000) and Calgary (population approximately 1 million), respectively.

**YUB-YECL-39**

**Reference:** Prepared Testimony of Foster Associates Inc., page 23

**Issue:** Common Equity Ratio

**Preamble:** Table 3 shows common equity ratios for Canadian electric utilities. The evidence shows that for those utilities (transmission and distribution) with rated debt (2006) common equity ratio of between 43.4 and 44.5 was evident. The same table showed for utilities with rated debt that were integrated, the common equity ratio was 40.5 .

**Request:**

(a) Does this table indicate that integrated utilities present less business risk than non-integrated utilities?

(b) Would the fact that YECL is an integrated utility offset or mitigate some of the business risk?

**Response:**

(a) No, one cannot draw that conclusion. The actual capital structures of individual companies are not necessarily consistent with the level of business risk. It is necessary to look at other factors, including debt rating and the impact of diversification of the consolidated operations. For example, Nova Scotia Power, an integrated electric utility, has an actual common equity ratio of 40 , but is only rated BBB by S&P. Toronto Hydro, which is a distribution only utility, has a higher common equity ratio of 42.5 , and had an S&P debt rating of A- when the testimony was prepared. Toronto Hydro was subsequently upgraded to A rating in June 2008.

(b) No, as indicated in response to YUB-YECL-38(c) integrated electric utilities are considered to be riskier than utilities that are purely wires (distribution and or transmission) utilities.

## YUB-YECL-40

**Reference:** Prepared Testimony of Foster Associates Inc., page 24

**Issue:** Business Risk of NTPC

**Request:**

(a) Quantify the higher business risks faced by NTPC versus those of YECL?

(b) Please reconcile the approved equity ratio of NTPC of 48.86 with the opinion that the equity ratio should be approximately 56-57

**Response:**

(a) The analysis of business risk is largely qualitative; there are no formulas which permit the quantification of differences in business risk for companies with no equity market data. In Ms. McShane's judgment, NTPC's higher business risks warrant a common equity ratio approximately five percentage points higher than that of Yukon Electrical.

(b) In her November 2006 testimony on behalf of NTPC, Ms. McShane concluded that, at the forecast capital structures, the incremental risk premium for NTPC relative to a benchmark utility would be no less than 50 basis points, based on differences in costs of debt between A and BBB rated utilities. The PUB adopted Ms. McShane's minimum 50 basis point incremental equity risk premium at the forecast 2007 08 common equity ratio of 48.86 . The 56-57 equity represents the increase in the actual common equity ratio that would be required to eliminate the 50 basis point incremental risk premium adopted by the PUB. Since the 50 basis point incremental risk premium adopted by the PUB represented the minimum required, it follows that the estimated 56-57 equity ratio represents the minimum ratio required to equate NTPC to a benchmark utility..

**YUB-YECL-41**

**Reference:** Prepared Testimony of Foster Associates Inc., page 25

**Issue:** Business Risk

**Quote:** Yukon Electrical would be viewed as facing higher business risks than the typical Canadian utility. (Line No. 658-659.)

**Request:**

How would the business environment faced by YECL compare with that of the maritime utilities? Please compare and contrast the business risks.

**Response:**

As noted at lines 626-631, Two of the smaller investor-owned primarily electric distribution utilities that would be considered the closest comparators to Yukon Electrical of the Canadian electric utilities with rated debt (Maritime Electric and Newfoundland Power) both have target actual common equity ratios of 45 . While they are the closest comparators, both are significantly larger and face lower business risk than Yukon Electrical. The business risk factors are set out below.

Newfoundland Power:

Newfoundland Power is a much larger utility than Yukon Electrical (refer to Table 1 of Ms. McShane's evidence), and serves over 85 of customers in the province. Its customer base is largely residential (Newfoundland and Labrador Hydro serves the large industrial customers) and the customer base is stable, exhibiting relatively slow but steady growth. The franchise area is divided into eight separate (but connected) areas on the Avalon Peninsula Highway, including St. John's, a city of over 100,000, and three other areas with populations in excess of 20,000. The economy is relatively undiversified and growth in the economy exhibits volatility; the three major industries are resource-based: the fishery, pulp and paper and oil and gas. The utility competes with fuel oil, but electricity has both a price and regulatory advantage. Newfoundland Power attaches approximately 90 of new home construction for heating load. Its power supply comes largely from Newfoundland and Labrador Hydro (90 ); while it owns

some of its own generating capacity, the dispatch of that capacity is coordinated with that of Newfoundland and Labrador Hydro. Supply from Newfoundland and Labrador Hydro is approximately 80 hydro-electric and the remainder thermal. Newfoundland Power has a weather normalization clause that protects its revenues from variability arising from weather volatility. It also has a revenue stabilization mechanism that allows for the pass through of purchased power and fuel costs. The regulatory framework is supportive and provides a relatively high degree of assurance that Newfoundland Power will recover the allowed return.

Maritime Electric:

Maritime Electric serves the entire province of Prince Edward Island. It has over four times as many customers as Yukon Electrical and over three times the sales (in KwH). Close to 80 of its sales are to residential and small commercial customers. Its service area includes two major population areas, Charlottetown and Summerside. The Conference Board of Canada expects Prince Edward Island to experience the highest population growth in the Atlantic Provinces, due to in-migration, which will underpin strong growth in the consumption of services. Of all the Atlantic Provinces, the demographic trends are the most positive for Prince Edward Island. The economy is characterized by agriculture, food processing, tourism, aerospace, and transportation equipment industries. Competitive pressures are minimal; fuel oil is used for heating and there is no natural gas available to the island. The utility purchases most of its energy under contracts with New Brunswick Power (86 ) and on island wind facilities (13 ). The island location exposes it to the risk of supply interruption; however, the utility owns some on-island facilities as back-up. The utility operates with an Energy Cost Adjustment Mechanism that provides for pass-through of actual energy costs. The operating environment (weather) is less extreme than either the Avalon Peninsula of Newfoundland or the Yukon. The regulatory framework in Prince Edward Island is supportive.

With respect to Nova Scotia Power, Yukon Electrical would face less risk. Nova Scotia Power is a much larger utility than Yukon Electrical (460,000 customers, including the cities of Halifax with a metro area population of 370 thousand, and a rate base of close to 3 billion). It has a higher direct exposure to industrial customers (in the pulp and paper industry) than Yukon Electrical. Nova Scotia Power has limited competitive threats given its location. It faces environmental risks due to the nature of its generation portfolio (coal and oil) and, at present, risks related to recovery of variances between

actual and forecast fuel costs as it has no fuel cost adjustment mechanism, although the regulator has approved the implementation of such a mechanism in principle.

## YUB-YECL-42

**Reference:** Prepared Testimony of Foster Associates Inc., page 26

**Issue:** Incremental Equity Risk Premiums

**Quote:** If the capital structure for each of the utilities in Table 4 above were adjusted to eliminate the incremental equity risk premiums, the allowed equity ratios would be approximately 46-47 . (Line No. 687-689.)

**Request:**

(a) In the case of FortisBC, does this imply that the 0.40 risk premium would equate to a 6-7 incremental equity thickness?

(b) In the case of Newfoundland Power, does this imply that the 0.15 risk premium would equate to a 1.5-2.5 incremental equity thickness?

(c) With respect to U.S. utilities and the rates charged to their customers, is the higher equity thickness somewhat mitigated by the lower income tax rates?

**Response:**

(a&b) Yes. The range of 46-47 is an approximation of the average equity ratio of the electric utilities listed in Table 4 that would be consistent with elimination of the incremental equity risk premium relative to a benchmark utility. The estimations were made assuming (1) each utility is taxable, and under two theories: (a) the before and after tax costs of capital remain unchanged as the capital structure changes; and (b) the after-tax cost of capital declines as the debt ratio rises; and, (2) income taxability has no impact on the cost of capital. Some of the utilities are not taxable, and for those that are, the benefit of the tax deductibility of interest in the case of utilities flows to ratepayers, not shareholders. In the second scenario, there is no impact of the deductibility of income tax on the cost of capital. In all cases, the cost of equity declines as the equity ratio rises, but at different rates of decline. The table below summarizes the results.

| | **Taxable: Average of Theory 1 and 2** | **Non-taxable** |
|---|---|---|
| Alberta Taxable Distributors | 37 | 37 |
| FortisBC | 45 | 47 |
| Maritime Electric | 58 | 61 |
| Newfoundland Power | 46 | 47 |
| Northwest Territories Power | 56 | 58 |
| Nova Scotia Power | 46 | 49 |
| Ontario Electric Distributors | 40 | 40 |
| Yukon Energy | 47 | 49 |
| **Average** | **47** | **48** |
| **Median** | **46** | **46** |

The calculations are provided in YUB-YECL-42(a&b) Attachment 1.

(c) No. A recent report by the US Tax Foundation (March 2008) indicates that the combined US federal and state corporate income tax rate is higher than the equivalent Canadian tax rate in all but 4 states.

## Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0.295 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **60.00** | **40.00** | **54.5** | **45.5** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 60.00 | 2.60 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.77 | | 40.00 | 3.51 |
| Weighted Average Cost of Capital | | | | 6.11 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 54.50 | 2.36 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.23 | | 45.50 | 3.75 |
| Weighted Average Cost of Capital | | | | 6.11 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **60.00** | **40.00** | **54.5** | **45.5** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 60.00 | 2.60 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.77 | | 40.00 | 3.51 |
| Weighted Average Cost of Capital | | | | 6.11 |

| | | | |
|---|---|---|---|
| t new debt | | 16.0775 | |
| T old debt | | 17.7000 | |
| 1-t new debt | | 83.9225 | |
| 1-t old debt | | 82.3000 | |
| ratio | | 1.02 | |
| WACC ratio | | 6.230 | |
| New WACC | 6.230 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) | |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 54.50 | 2.36 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.50 | | 45.50 | 3.87 |
| Weighted Average Cost of Capital | | | | 6.23 |

**Average Change in ROE:** -0.40

## Non-Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **60.00** | **40.00** | **52.7** | **47.3** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 60.00 | 3.69 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.77 | | 40.00 | 3.51 |
| Weighted Average Cost of Capital | | | | 7.20 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 52.70 | 3.24 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.37 | | 47.30 | 3.96 |
| Weighted Average Cost of Capital | | | | 7.20 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **60.00** | **40.00** | **52.7** | **47.3** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 60.00 | 3.69 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.77 | | 40.00 | 3.51 |
| Weighted Average Cost of Capital | | | | 7.20 |

| | | |
|---|---|---|
| t new debt | 0.0000 | |
| T old debt | 0.0000 | |
| 1-t new debt | 100.0000 | |
| 1-t old debt | 100.0000 | |
| ratio | 1.00 | |
| WACC ratio | 7.198 | |
| New WACC | 7.198 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 52.70 | 3.24 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.37 | | 47.30 | 3.96 |
| Weighted Average Cost of Capital | | | | 7.20 |

**Average Change in ROE:** -0.40

## Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0.295 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **57.30** | **42.70** | **41.8** | **58.2** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 57.30 | 2.48 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 10.25 | | 42.70 | 4.38 |
| Weighted Average Cost of Capital | | | | 6.86 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 41.80 | 1.81 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.67 | | 58.20 | 5.05 |
| Weighted Average Cost of Capital | | | | 6.86 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **57.30** | **42.70** | **41.8** | **58.2** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 57.30 | 2.48 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 10.25 | | 42.70 | 4.38 |
| Weighted Average Cost of Capital | | | | 6.86 |

| | | | |
|---|---|---|---|
| t new debt | | 12.3310 | |
| T old debt | | 16.9035 | |
| 1-t new debt | | 87.6690 | |
| 1-t old debt | | 83.0965 | |
| ratio | | 1.06 | |
| WACC ratio | | 7.239 | |
| New WACC | 7.239 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) | |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 41.80 | 1.81 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.32 | | 58.20 | 5.43 |
| Weighted Average Cost of Capital | | | | 7.24 |

**Average Change in ROE:** -1.25

## Non-Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **57.30** | **42.70** | **38.6** | **61.4** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 57.30 | 3.52 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 10.25 | | 42.70 | 4.38 |
| Weighted Average Cost of Capital | | | | 7.90 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 38.60 | 2.37 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.00 | | 61.40 | 5.53 |
| Weighted Average Cost of Capital | | | | 7.90 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **57.30** | **42.70** | **38.6** | **61.4** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 57.30 | 3.52 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 10.25 | | 42.70 | 4.38 |
| Weighted Average Cost of Capital | | | | 7.90 |

| | | | |
|---|---|---|---|
| t new debt | | 0.0000 | |
| T old debt | | 0.0000 | |
| 1-t new debt | | 100.0000 | |
| 1-t old debt | | 100.0000 | |
| ratio | | 1.00 | |
| WACC ratio | | 7.901 | |
| New WACC | 7.901 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) | |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 38.60 | 2.37 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.00 | | 61.40 | 5.53 |
| Weighted Average Cost of Capital | | | | 7.90 |

**Average Change in ROE:** -1.25

## Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0.295 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **55.50** | **44.50** | **53.5** | **46.5** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 55.50 | 2.41 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.95 | | 44.50 | 3.98 |
| Weighted Average Cost of Capital | | | | 6.39 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 53.50 | 2.32 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.75 | | 46.50 | 4.07 |
| Weighted Average Cost of Capital | | | | 6.39 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **55.50** | **44.50** | **53.5** | **46.5** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 55.50 | 2.41 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.95 | | 44.50 | 3.98 |
| Weighted Average Cost of Capital | | | | 6.39 |

| | | | |
|---|---|---|---|
| t new debt | | 15.7825 | |
| T old debt | | 16.3725 | |
| 1-t new debt | | 84.2175 | |
| 1-t old debt | | 83.6275 | |
| ratio | | 1.01 | |
| WACC ratio | | 6.434 | |
| New WACC | 6.434 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) | |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 53.50 | 2.32 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.85 | | 46.50 | 4.11 |
| Weighted Average Cost of Capital | | | | 6.43 |

**Average Change in ROE:** -0.15

## Non-Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **55.50** | **44.50** | **52.9** | **47.1** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 55.50 | 3.41 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.95 | | 44.50 | 3.98 |
| Weighted Average Cost of Capital | | | | 7.40 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 52.90 | 3.25 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.80 | | 47.10 | 4.14 |
| Weighted Average Cost of Capital | | | | 7.40 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **55.50** | **44.50** | **52.9** | **47.1** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 55.50 | 3.41 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.95 | | 44.50 | 3.98 |
| Weighted Average Cost of Capital | | | | 7.40 |

| | | |
|---|---|---|
| t new debt | 0.0000 | |
| T old debt | 0.0000 | |
| 1-t new debt | 100.0000 | |
| 1-t old debt | 100.0000 | |
| ratio | 1.00 | |
| WACC ratio | 7.396 | |
| New WACC | 7.396 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 52.90 | 3.25 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.80 | | 47.10 | 4.14 |
| Weighted Average Cost of Capital | | | | 7.40 |

**Average Change in ROE:** -0.15

## Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0.295 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **51.41** | **48.59** | **44.0** | **56.0** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 51.41 | 2.23 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.25 | | 48.59 | 4.49 |
| Weighted Average Cost of Capital | | | | 6.72 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 44.00 | 1.91 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.60 | | 56.00 | 4.82 |
| Weighted Average Cost of Capital | | | | 6.72 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **51.41** | **48.59** | **44.0** | **56.0** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 51.41 | 2.23 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.25 | | 48.59 | 4.49 |
| Weighted Average Cost of Capital | | | | 6.72 |

| | | | |
|---|---|---|---|
| t new debt | | 12.9800 | |
| T old debt | | 15.1660 | |
| 1-t new debt | | 87.0200 | |
| 1-t old debt | | 84.8341 | |
| ratio | | 1.03 | |
| WACC ratio | | 6.897 | |
| New WACC | 6.897 | WACC | (1-T (NEW DEBT)) (1-T (OLD DEBT)) |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 44.00 | 1.91 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.91 | | 56.00 | 4.99 |
| Weighted Average Cost of Capital | | | | 6.90 |

**Average Change in ROE:** -0.50

| | |
|---|---|
| COST OF DEBT | |
| Tax Rate | |

| Current Debt Ratio | Current Equity Ratio |
|---|---|
| **51.41** | **48.59** |

# Theory1

| | Cost |
|---|---|
| Debt | 6.15 |
| | 0.00 |
| Common Equity | 9.25 |
| Weighted Average Cost of Capital | |

Solve for Cost of Equity

| | Cost |
|---|---|
| Debt | 6.15 |
| Preferred | 0.00 |
| Common Equity | 8.75 |
| Weighted Average Cost of Capital | |

# Theory 2

| Current Debt Ratio | Current Equity Ratio |
|---|---|
| **51.41** | **48.59** |

| | Cost |
|---|---|
| Debt | 6.15 |
| | 0.00 |
| Common Equity | 9.25 |
| Weighted Average Cost of Capital | |

| | |
|---|---|
| t new debt | |
| T old debt | |
| 1-t new debt | |
| 1-t old debt | |
| ratio | |
| WACC ratio | |
| New WACC | 7.656 |

Solve for Cost of Equity

| | Cost |
|---|---|
| Debt | 6.15 |
| Preferred | 0.00 |
| Common Equity | 8.75 |
| Weighted Average Cost of Capital | |

**Average Change in ROE:**

## Non-Taxable

0.0615
0

| Moving to Debt | Moving to Equity |
|---|---|
| **42.0** | **58.0** |

| Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|
| 0.00 | 51.41 | 3.16 |
| | 0.00 | 0.00 |
| | 48.59 | 4.49 |
| | | 7.66 |

| Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|
| 0.00 | 42.00 | 2.58 |
| | 0.00 | 0.00 |
| | 58.00 | 5.07 |
| | | 7.66 |

| Debt | Equity |
|---|---|
| **42.0** | **58.0** |

| Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|
| 0.00 | 51.41 | 3.16 |
| | 0.00 | 0.00 |
| | 48.59 | 4.49 |
| | | 7.66 |

0.0000
0.0000
100.0000
100.0000
1.00
7.656
WACC (1-T (NEW DEBT)) (1-T (OLD DEBT))

| Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|
| 0.00 | 42.00 | 2.58 |
| | 0.00 | 0.00 |
| | 58.00 | 5.07 |
| | | 7.66 |

-0.50

## Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0.295 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **62.50** | **37.50** | **53.5** | **46.5** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 62.50 | 2.71 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.35 | | 37.50 | 3.51 |
| Weighted Average Cost of Capital | | | | 6.22 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 53.50 | 2.32 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.38 | | 46.50 | 3.90 |
| Weighted Average Cost of Capital | | | | 6.22 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **62.50** | **37.50** | **53.5** | **46.5** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 62.50 | 2.71 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.35 | | 37.50 | 3.51 |
| Weighted Average Cost of Capital | | | | 6.22 |

| | | | |
|---|---|---|---|
| t new debt | | 15.7825 | |
| T old debt | | 18.4375 | |
| 1-t new debt | | 84.2175 | |
| 1-t old debt | | 81.5625 | |
| ratio | | 1.03 | |
| WACC ratio | | 6.418 | |
| New WACC | 6.418 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) | |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 53.50 | 2.32 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.81 | | 46.50 | 4.10 |
| Weighted Average Cost of Capital | | | | 6.42 |

**Average Change in ROE:** -0.75

## Non-Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **62.50** | **37.50** | **51.0** | **49.0** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 62.50 | 3.84 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.35 | | 37.50 | 3.51 |
| Weighted Average Cost of Capital | | | | 7.35 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 51.00 | 3.14 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.60 | | 49.00 | 4.21 |
| Weighted Average Cost of Capital | | | | 7.35 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **62.50** | **37.50** | **51.0** | **49.0** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 62.50 | 3.84 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 9.35 | | 37.50 | 3.51 |
| Weighted Average Cost of Capital | | | | 7.35 |

| | | | |
|---|---|---|---|
| t new debt | | 0.0000 | |
| T old debt | | 0.0000 | |
| 1-t new debt | | 100.0000 | |
| 1-t old debt | | 100.0000 | |
| ratio | | 1.00 | |
| WACC ratio | | 7.350 | |
| New WACC | 7.350 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) | |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 51.00 | 3.14 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.60 | | 49.00 | 4.21 |
| Weighted Average Cost of Capital | | | | 7.35 |

**Average Change in ROE:** -0.75

## Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0.295 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **60.00** | **40.00** | **53.0** | **47.0** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 60.00 | 2.60 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.90 | | 40.00 | 3.56 |
| Weighted Average Cost of Capital | | | | 6.16 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 53.00 | 2.30 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.22 | | 47.00 | 3.86 |
| Weighted Average Cost of Capital | | | | 6.16 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **60.00** | **40.00** | **53.0** | **47.0** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 60.00 | 2.60 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.90 | | 40.00 | 3.56 |
| Weighted Average Cost of Capital | | | | 6.16 |

| | | | |
|---|---|---|---|
| t new debt | | 15.6350 | |
| T old debt | | 17.7000 | |
| 1-t new debt | | 84.3650 | |
| 1-t old debt | | 82.3000 | |
| ratio | | 1.03 | |
| WACC ratio | | 6.316 | |
| New WACC | 6.316 | WACC (1-T (NEW DEBT)) (1-T (OLD DEBT)) | |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 29.50 | 53.00 | 2.30 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.55 | | 47.00 | 4.02 |
| Weighted Average Cost of Capital | | | | 6.32 |

**Average Change in ROE:** -0.52

## Non-Taxable

| | |
|---|---|
| COST OF DEBT | 0.0615 |
| Tax Rate | 0 |

| Current Debt Ratio | Current Equity Ratio | Moving to Debt | Moving to Equity |
|---|---|---|---|
| **60.00** | **40.00** | **50.7** | **49.3** |

# Theory1

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 60.00 | 3.69 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.90 | | 40.00 | 3.56 |
| Weighted Average Cost of Capital | | | | 7.25 |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 50.70 | 3.12 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.38 | | 49.30 | 4.13 |
| Weighted Average Cost of Capital | | | | 7.25 |

# Theory 2

| Current Debt Ratio | Current Equity Ratio | Debt | Equity |
|---|---|---|---|
| **60.00** | **40.00** | **50.7** | **49.3** |

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 60.00 | 3.69 |
| | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.90 | | 40.00 | 3.56 |
| Weighted Average Cost of Capital | | | | 7.25 |

| | | | |
|---|---|---|---|
| t new debt | | 0.0000 | |
| T old debt | | 0.0000 | |
| 1-t new debt | | 100.0000 | |
| 1-t old debt | | 100.0000 | |
| ratio | | 1.00 | |
| WACC ratio | | 7.250 | |
| New WACC | 7.250 | WACC (1-T (NEW DEBT)) | (1-T (OLD DEBT)) |

Solve for Cost of Equity

| | Cost | Tax Rate | Proportion | After Tax Weighted Component |
|---|---|---|---|---|
| Debt | 6.15 | 0.00 | 50.70 | 3.12 |
| Preferred | 0.00 | | 0.00 | 0.00 |
| Common Equity | 8.38 | | 49.30 | 4.13 |
| Weighted Average Cost of Capital | | | | 7.25 |

**Average Change in ROE:** -0.52

**YUB-YECL-43**

**Reference:** Prepared Testimony of Foster Associates Inc., page 29-32

**Issue:** Coverage Ratios

**Request:**

Please confirm that the FFO Interest Coverage, the FFO Total Debt and the EBIT interest coverage ratios for YECL (at a common equity ratio of 47.5 ) is higher that those for Canadian utilities as indicated in Table 8 and higher than those compared in Table 4. If confirmation cannot be made, explain and indicate those Canadian utilities which have higher ratios based on the most recent decisions affecting those utilities.

**Response:**

Please note that the numbers on Table 10 (which summarizes the average EBIT Coverage Ratios) should be re-ordered to match the source schedule, Schedule 2. The coverage ratios cited from this table in lines 836-837 of Ms. McShane's testimony should be corrected to match the revised Table 10.

Table 10 should be as follows:

**Table 1**

| Electric Utilities with Rated Debt | Ratings DBRS Moody s S P | EBIT Interest Coverage (2004-2006) |
|---|---|---|
| Canadian Electric Utilities: | | |
| All | A Baa1 A- | 2.6X |
| Transmission & Distribution | A Baa1 A- | 2.7X |
| Integrated | A(low) Baa2 BBB | 2.5X |
| U.S. A-rated Electric | na A2 A | 3.6X |

It is confirmed that the indicated ratios for Yukon Electrical are higher than the averages that would be calculated for the utilities in Table 4 and the averages that were presented

for Canadian utilities in Table 8 (FFO Interest Coverage and FFO Debt) and Table 10 (EBIT Coverage).

However, as stated at page 30, lines 797-802, with respect to FFO Interest Coverage, an FFO Interest Coverage ratio for Yukon Electrical in the range of 4.2X to 4.7X would be higher than the achieved ratios of other Canadian transmission and distribution utilities (3.8X), which would be reasonable given Yukon Electrical's higher business risk. However, at a 52.5 equity ratio, the ratio would be similar to, but still lower than, the average FFO coverage ratios achieved by the low risk (A rated) U.S. electric utilities (4.9X).

There are a number of individual utilities which have ratios similar to or higher than those indicated for Yukon Electrical at 47.5 equity. These companies and their ratios are found on Schedule 2, page 1 of 2, which was the source schedule for Tables 8 and 10. The actual ratios reflect the experienced performance of those companies, not the specific outcomes of regulatory decisions. It is the actual financial performance which is important in assessing the reasonableness of the ratios for Yukon Electrical, as it is actual performance which determines debt ratings.

**YUB-YECL-44**

**Reference:** Prepared Testimony of Foster Associates Inc., page 33-35

**Issue:** Debt Rating Agency Commentary

**Request:**

Comments were submitted regarding the lower return and thinner equities experienced by Canadian utilities in contrast to U.S .and global peers. Is this a reflection of the higher business risk of the U.S. electric utilities?

**Response:**

No. It is unlikely that the debt rating agencies would have referenced the lower equity ratios and ROEs relative to their U.S. peers had they concluded the differences were justified by differences in risk. A relatively recent study commissioned by the Ontario Energy Board, Concentric Energy Advisors, A Comparative Analysis of Return on Equity of Natural Gas Utilities , June 14, 2007, compared the risks of Canadian and U.S. gas distributors as well as the capital markets in the two countries.

The study concluded,

> . Taken as a whole, U.S. gas utilities are not demonstrably riskier than Canadian gas utilities.

and,

> As a result of the interplay between the Canadian and U.S. markets, Canadian utilities compete for capital essentially on the same basis as utilities in the U.S. In the current market environment, no fundamental differences were identified that would indicate a significant difference in investor required returns between the two markets.

At the May 2008 CAMPUT Conference, Concentric Advisors reported in its presentation that they had prepared a similar study on behalf of Hydro One Inc. and the Coalition of Large Distributors, completed March 2008, comparing Canadian and U.S. electric utilities, and that their conclusions corroborated the results of the earlier study.

**YUB-YECL-45**

**Reference:** Capital Additions; Application, page 9-1, 9-2

**Issue Sub-Issue:** Expenditures

**Quote**: System Performance Projects (Line No. 17.)

Life Extension Projects (Line No. 1.)

System Replacement Projects (Line No. 4.)

Forced Projects (Line No. 8.)

**Preamble**: The Board wishes to better understand the basic principles underlying YECL's distribution improvement project categorization.

**Request:**

(a) How are the acceptable levels determined in respect of System Performance Projects?

(b) Please offer a detailed explanation as to how new feeder increase the life cycle of the distribution system.

**Response:**

(a) Yukon Electrical's operations group meets on a weekly basis with engineering staff to discuss the past weeks system performance. Of priority at these weekly meetings are all unplanned distribution outages or events which cause supply disruptions to customers. Events are recorded and trends are identified, ie reoccurring failures of specific feeders, transformers or services. Trends are then investigated by researching the causes; supporting information may be available by reviewing Service Interruption Report. Depending on the cause of the outages a determination is made to either immediately make corrections to the equipment or if the asset upgrades can be put into the capital budget cycle.

In addition Yukon Electrical compares the characteristics of its system to those identified by CEA, the Canadian Electrical Code, Territorial codes, AEUC's and feedback from Electrical Protection agencies to ensure that things such as voltage standards are in compliance. Yukon Electrical also reviews safety bulletins and feedback from its standards group to implement recommended or mandated changes required on the electrical system.

Line Patrols, planned programs and customer feedback also provide guidance as to whether the power system is operating in the way that it should and in a way that meets customer's service requirements.

(b) A new feeder from a specific substation or point of delivery has the potential to extend the life of an existing feeder by eliminating the need to perform potential upgrades. The new circuit can potentially off load the existing circuit thus reducing the need to upgrade and increase conductor size. This off loading and reduction in current also has a positive impact on line losses. It may also have the potential to create an alternate source or feed for a specific area by creating a loop feed, elimination of a radial feed or only one source of supply. A balanced system will extend the life of equipment and reduce the number of equipment failures.

**YUB-YECL-46**

**Reference:** Capital Additions; Application, page 9-5

**Issue Sub-Issue:** 2006 Capital Expenditures

**Request:**

(a) When were the current Canadian mandatory standards and codes, that are referred to in the 2006 Capital Expenditures related to Generation plants, and upon which the work is justified, last updated? (page 9-5)

(b) Please provide a more in-depth explanation in regard to the greater than 1.2 million that was spent in Distribution New Extensions category of 2006 capital expenditures. What types of projects are in this amount, which makes up more than half of the 2,433,000 dollars that are shown? (page 9-6)

(c) In respect of the older YECL underground system (30 years) that is in place, i.e. Tummel Road to Vanier Rebuild (Phase I), is this system still a radial feed type of system? If so, why has YECL not taken steps to construct an alternate feed? Over the intervening 30 years and in consideration of current standards, has YECL considered replacement of the live-front transformers, considering the risk to linemen working on the apparatus? (page 9-8)

(d) Considering the make up the Whitehorse O H system (Justice Centre to Whitehorse Star), i.e. the pre-1969 vintage of certain poles, and the fact that the system was in violation of current electric codes, what were the key driver to correct the failings when installing u g versus correcting an already deficient O H system? Why was this not corrected sooner? (page 9-9)

**Response:**

(a) Attached are a number of the generation standards relating to generation plants referenced by Yukon Electrical (YUB-YECL-46(a) Attachment 1). Typically the last set of digits of the document number (in the attachment) indicate the year of the most recent update of that code.

(b) Please refer to YUB-YECL-46(b) Attachment 1 for a listing of the 2006 New Extensions.

(c) The system is now a loop feed, providing an alternate feed in the event of a cable failure. The live front transformer and other hazards in this area have been eliminated with new construction that meets current operating and safety standards. Other potential operational hazards have been identified and will be eliminated in future capital projects as Yukon Electrical continues to reinvest in the distribution infrastructure. In the meantime, Yukon Electrical operations personnel are trained to continue to identify and address all risks as part of their job plans.

(d) Yukon Electrical has and continues to rebuild infrastructure based on the criteria detailed on page 9-2 of the Application. While structures met code clearances years ago at the time of their construction, clearance code requirements have changed resulting in existing structures not meeting today's standards. Prior to reconstruction to today's standards, Yukon Electrical's journeymen lineman manage operations and maintenance risk through the company's job planning process. In the particular case of Justice Centre to the Whitehorse Star, this work was planned in conjunction with the First Avenue conversion to minimize overall costs and minimize complexity of operation.

**Summary**
**Fuel Storage and Handling Documents**

| Issuing Agency | Document Number | Title of Document | Regulation | Referenced in Regulations | Reference Document (Guidelines/Protocols) | Design Standard | Explanatory Document | Explanation |
|---|---|---|---|---|---|---|---|---|
| American Petroleum Institute: | | | | | | | | |
| | API RP 651-97 | Cathodic Protection of Aboveground Petroleum Storage Tanks | | | x | | | |
| | API RP 652-97 | Lining of Aboveground Petroleum Storage Tank Bottoms | | | x | | | |
| | API 620 and 650 | Seismic Loads on Large Tanks | | | | x | | |
| | API Std 653-01 | Tank Inspection, Repair, Alteration, and Reconstruction | | | | x | | |
| | API RP 1632-96 | Cathodic Protection of Underground Storage Tank and Piping Systems | | | x | | | |
| | API Std 2610-94 | Design, Construction, Operation, Maintenance and Inspection of Terminal and Tank Facilities | | | | x | | |
| Canadian Council of Ministers of the | | | | | | | | |
| | CCME PN 1180 | Environmental Guideline for Controlling Emissions of Volatile - Organic Compounds from Aboveground Storage Tanks (1995) | | | x | | | for emmisions |
| | CCME PN 1299 | Canadian Environmental Quality Guidelines (1999) | | | x | | | soils remediation |
| | CCME | CWS for PHC Canada-wide Standards for Petroleum Hydrocarbons in Soil (2001) | | | x | | | soils remediation |
| Canadian General Standards Board: | | | | | | | | |
| | CAN/CGSB-3.2-99 | Fuel Oil, Heating | | | | | x | Canadian general Standards - fuel classification |
| Canadian Petroleum Products Institute: | | | | | | | | |
| | CPPI/PACE Report 87-1 | Impressed Current Method of Cathodic Protection of Underground Petroleum Storage Tanks | | | | | | |
| | CPPI (1995) | Using the CPPI Colour-Symbol System to Mark Equipment and Vehicles January 1990 for Product Identification | | x | | | | |
| | CPPI (2000) | Recommended Practices: Operation of Shop-Fabricated Aboveground Petroleum Storage Tank Systems | | | x | | | |
| Canadian Standards Association: | | | | | | | | |
| | CAN/CSA-B139-00 | Installation Code for Oil Burning Equipment | x | x | | | | |
| Environmental Protection Agency: | | | | | | | | |
| | EPA/530/UST-90/007 | Standard Test Procedures for Evaluating Leak Detection Methods: Statistical Inventory Reconciliation Methods | | | x | | | |
| | EPA 510-B-95-009 | Introduction to Statistical Inventory Reconciliation | | | x | | | |
| NACE International: | | | | | | | | |
| | NACE RP0169-2002 | Control of External Corrosion on Underground or Submerged Metallic Piping Systems | | x | x | | | |
| | NACE RP0285-2002 | Corrosion Control of Underground Storage Tank Systems by Cathodic Protection. | | x | x | | | |
| | NACE RP0193-2001 | External Cathodic Protection of On-Grade Carbon Steel Storage Tank Bottoms | | x | | | | |
| | NACE TM0101-2001 | Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Tank Systems | | x | x | | | |
| | NACE No. 10/SSPC- | PA6 Fiberglass-Reinforced Plastic (FRP) Linings Applied to Bottoms of Carbon Steel Aboveground Storage Tanks | | x | | | | |
| National Research Council: | | | | | | | | |
| | NRCC 38727 | National Fire Code of Canada (NFCC) - 1995 | x | | | | | establishes standards of fire safety |
| Steel Tank Institute: | | | | | | | | |
| | STI SP001-00 | Standard for Inspection of In-service Shop Fabricated Aboveground Tanks for the Storage of Flammable and Combustible Liquids. | | | x | | | |
| | STI R831-98 | Optional Recommended Practice for Control of Localized Corrosion Within Underground Steel Petroleum Storage Tanks. | | | x | | | |
| | STI R893-89 | Recommended Practice for External Corrosion Protection of Shop Fabricated Aboveground Tank Floors. | | | x | | | |
| | STI RP011-01 | Recommended Practice for Anchoring of Steel Underground Storage Tanks. | | | x | | | |
| Underwriters' Laboratories of | | | | | | | | standards - ULC certification seal |
| | ULC-S601-2000 | Aboveground Horizontal Shop Fabricated Steel Tanks | | x | | | | |
| | ULC-S601(A)-2001 | Shop Refurbishing of Aboveground Horizontal Shop Fabricated Steel Tanks | | x | | | | |
| | CAN/ULC-S602-1992 | Above ground Steel Tanks for Fuel Oil and Lubricating Oil | | x | | | | |
| | CAN/ULC-S603-1992 | Underground Steel Tanks | | x | | | | |
| | CAN/ULC-S603.1-1992 | Galvanic Corrosion Protection Systems for Underground Steel Tanks | | x | | | | |
| | ULC-S603(A)-2001 | Refurbishing of Underground Steel Tanks | | x | | | | |
| | ULC-S615-1998 | Underground Reinforced Plastic Tanks | | x | | | | |

**Summary**
**Fuel Storage and Handling Documents**

| Issuing Agency | Document Number | Title of Document | Regulation | Referenced in Regulations | Reference Document (Guidelines/Protocols) | Design Standard | Explanatory Document | Explanation |
|---|---|---|---|---|---|---|---|---|
| | ULC-S615(A)-1987 | Refurbishing of Underground Reinforced Plastic Tanks | | x | | | | |
| | ULC-S618-2000 | Magnesium and Zinc Anodes and Zinc and Copper/Copper Sulphate Reference Electrodes | | | x | x | | |
| | ULC-S630-2000 | Above ground Vertical Shop Fabricated Steel Tanks | | x | | | | |
| | ULC-S630(A)-2001 | Shop refurbishing of Aboveground Vertical Shop Fabricated Steel Tanks | | x | | | | |
| | CAN/ULC-S633-1999 | Flexible Underground Hose Connectors | | | | x | | |
| | CAN/ULC-S643-2000 | Above ground Shop Fabricated Steel Utility Tanks | | x | | | | |
| | CAN/ULC-S651-2000 | Emergency Valves | | | | x | | |
| | ULC-S653-1994 | Contained Above ground Steel Tank Assembles | | | | x | | |
| | ULC-S655-1998 | Above ground Protected Tank Assemblies | | | | x | | |
| | ULC-S656-2000 | Oil-Water Separators | | | x | | | |
| | ORD-C58.9-1997 | Secondary Containment Liners for Underground and Above ground Tanks | | | x | | | |
| | ORD-C58.10-1992 | Underground Jacketed Steel Tanks | | x | | | | |
| | ORD-C58.12-1992 | Leak Detection Devices (Volumetric Type) for Underground Storage Tanks | | | x | x | | |
| | ORD-C58.14-1992 | Leak Detection Devices (Nonvolumetric Type) for Underground Storage Tanks | | | x | x | | |
| | ORD-C58.15-1992 | Overfill Protection Devices for Flammable Liquid Storage Tanks | | | | x | | |
| | ORD-C58.19-1992 | Spill Containment Devices for Underground Tanks | | | | x | | |
| | ORD-C58.20-1996 | Special Corrosion Protection Underground Tanks | | | x | x | | |
| | ORD-C80.1-2000 | Aboveground Non-Metallic Tanks for Fuel Oil | | | | x | | |
| | ORD-C107.4-1992 | Ducted Flexible Underground Piping Systems | | | | x | | |
| | ORD-C107.7-1993 | Glass-Fibre Reinforced Plastic Pipe and Fittings | | | | x | | |
| | ORD-C107.12-1992 | Line Leak Detection Devices for Flammable Liquid Piping | | | | x | | |
| | ORD-107.14-1992 | Non Metallic Pipe and Fittings | | | | x | | |
| | ORD-C107.19-1992 | Secondary Containment of Underground Piping | | | | x | | |
| | ORD-C107.21-1992 | Under-Dispenser Sumps | | | | x | | |
| | ORD-C142.5-1992 | Above ground Concrete Encased Steel Tank Assemblies | | x | | | | |
| | ORD-C142.6-2000 | Storage Vaults | | | | x | | |
| | ORD-C142.13-1997 | Mobile Refueling Tanks | | | | x | | |
| | ORD-C142.15-2000 | Precast Concrete Tanks | | | | x | | |
| | ORD-C142.17-1998 | Above ground Special Purpose Relocatable Vertical Tanks | | | | x | | |
| | ORD-C142.18-1995 | Above ground Rectangular Steel Tanks | | | | x | | |
| | ORD-C142.19-1994 | Spill Containment Devices for Aboveground Tanks | | | | x | | |
| | ORD-C142.20-1995 | Above ground Secondary Containment Tanks | | | | x | | |
| | ORD-C142.22-1995 | Contained Above ground Vertical Steel Tank Assemblies | | | | x | | |
| | ORD-C536-1998 | Flexible Metallic Hose | | | | x | | |

## DISTRIBUTION

**70001** **NEW EXTENSIONS 2006**

| | |
|---|---|
| Miscellaneous Jobs 10,000 | 304,870 |
| Miscellaneous Jobs 10,000 - 30,000 | 497,662 |
| New OH Services | 76,171 |
| New UG Services | 174,622 |
| Whitehorse Copper Subdivision (YTG) | 230,687 |
| Retail on Black Street | 73,672 |
| YTG Copper Ridge Stege 11 2006 (Part 2)(YTG) | 267,269 |
| Hotsprings Rd Subdivision (YTG) | 42,026 |
| Canadian Tire New Building | 92,222 |
| Condos Whitehorse | 57,443 |
| Retail North Downtown Whitehorse | 32,844 |
| KFN Copper Joe Subdivision | 145,025 |
| C of W Black Street Reroute | 43,115 |
| C of W Service New Motorways Lots | 221,252 |
| Hawkins Alley Development | 74,722 |
| Hanson Street Development | 50,002 |
| Canyon Creek Development | 49,396 |
| **TOTAL - NEW EXTENSIONS** | **2,433,000** |

Detailed on page 9-6 of Application

**YUB-YECL-47**

**Reference:** Capital Additions; Application, page 9-11

**Issue Sub-Issue:** 2007 Capital Expenditures

**Request:**

(a) Please provide more detail respecting Other Projects that totaled almost 360 thousand or greater than 75 of the monies spent on 2007 capital expenditures related to generation plant. (page 9-11)

(b) Please provide the detailed search and evaluation YECL undertook relating to various billing solutions that led to the decision to proceed with ATCO-CIS. Provide the cost-benefit analysis that was done prior to YECL's decision to proceed with ATCO-CIS. Please provide details including costs of alternatives considered. (page 9-11)

(c) Please provide more detail concerning the Other Projects totaling 1.6 million or greater than half of the Distribution New Extension total for 2007. (page 9-12)

**Response:**

(a) Please refer to YUB-YECL-47(a) Attachment 1 for details on the 2007 Generation Projects.

(b) Please refer to the business case included with YUB-YECL-16(b) Attachment 1.

(c) Please refer to YUB-YECL-47(c) Attachment 1 for a listing of the 2007 New Extension projects.

## GENERATION

### 90100 GENERATION IMPROVEMENTS 2007

| | |
|---|---|
| Watson Lake Fuel System Upgrade | 49,303 |
| Watson Lake Generation Protection Upgrades | 45,377 |
| Haines Junction Fuel System Upgrade | 66,838 |
| Haines Junction Generation Upgrade | 116,600 |
| Teslin Unit Breaker Replacement | 68,373 |
| Other generation projects under 40k | 129,345 |
| **GENERATION IMPROVEMENTS TOTAL** | **475,836** |

Please refer to page 9-11 of the Application

## DISTRIBUTION

| | | | |
|---|---|---|---|
| **70001** | **Project** | **NEW EXTENSIONS 2007** | |
| | | Miscellaneous Jobs 10,000 | 468,642 |
| | | Miscellaneous Jobs 10,000 - 35,000 | 531,686 |
| | **Y05005** | New OH Services | 116,582 |
| | **Y05015** | New UG Services | 146,877 |
| | **Y05085** | Land Rights | 66,691 |
| | **Y10599** | NVDLP Lot 16 Marwell Division | 582,581 |
| | **Y10642** | Seine Square Condos | 65,277 |
| | **Y10658** | Raven's Ridge Subdivision | 90,584 |
| | **Y10718** | Marshel Creek Subdivision | 90,300 |
| | **Y10725** | Cook Street Seniors Complex | 47,660 |
| | **Y10732** | Fox Haven Estates | 82,085 |
| | **Y10747** | KFN Youth Elders Centre | 41,208 |
| | **Y10763** | C of W Service New Motorways Lots Stg 2 | 150,468 |
| | **Y10801** | Whitehorse Copper 2007 | 160,454 |
| | **Y10802** | CoW Marwell Sewer Lift | 69,147 |
| | **Y10859** | YTG Airport Parking Plugins | 44,353 |
| | **Y10872** | 2nd and Hawkins Suites | 95,763 |
| | **Y10877** | Copper Joe service | 53,620 |
| | **Y10893** | Gully Rd | 52,598 |
| | **Y10956** | Selkirk First Nation John Ra Subdivision | 46,181 |
| | **Y10964** | LSCFN C45 Subdivision Nordinskiold | 54,902 |
| | **Y10983** | VGFN Service to 6 new Houses | 48,000 |
| | | **TOTAL - NEW EXTENSIONS** | 3,105,660 |

Please refer to listing on pages 9-11 and 9-12 of the Application.

**YUB-YECL-48**

**Reference:** Capital Additions; Application, page 9-16

**Issue Sub-Issue:** 2008 Capital Expenditures

**Request:**

(a) Please provide a description of the projects that make up other projects valued at 677.5 thousand, or greater than half of the 1-million forecast total. (page 9-16)

(b) Please provide greater detail in how the other project total of almost 1 million was arrived at in respect of Distribution New Extensions. (page 9-17)

(c) In respect of the Distribution Improvements for 2008, is the work to be completed by YECL or is the work to be contracted out? Please provide a detailed explanation and delineation on a project-by-project basis. (page 9-18)

(d) With respect to the work that is necessary to connect Pelly Crossing with the WAF, was the engineering and design work completed by YECL? If not, please describe the process to undertake bids for engineering, design and handover of the completed intertie project. (page 9-18)

(e) Please provide details regarding how energized line poles become anchored to trees as an accepted practice. Please provide a copy of YECL's heavy loading standards and compare these standards with those of northern Alberta and British Columbia. Is the heavy loading in relation to customer load or northern snow loads, or a combination of both? (page 9-18)

(f) When were the Yukon Electrical heavy loading standards, referred in the Marsh Lake 9L Reliability Fix Phase 1 Squanga Distribution Improvement, last updated? (page 9-19)

(g) Do the lines contained in the Yukon Electrical Tie between First Avenue and Sixth Avenue present a risk to YECL personnel or contradictions to current electrical codes? (page 9-19)

(h) Please provide further detail into the other projects (distribution Improvements) that total 1 million. (page 9-20)

(i) Is the Pine Street Whitehorse Street and Sentinel Lighting project to be done in conjunction with other city public works projects? Has the City of Whitehorse asked that the lighting be undertaken and built to the newer standards? (page 9-20)

(j) Please provide details in regard to the operational efficiencies attendant with the implementation of AMR. What are the other features and benefits of this AMR technology referred to in Meters? Please provide a cost-benefit analysis that was done prior to YECL's decision to proceed with the implementation of AMR. Quantify the operational efficiencies in terms of reduced costs to YECL customers. (page 9-21)

(k) Please provide the details for the North 60 New Billing System, the business case and cost benefit analysis. (page 9-17)

**Response:**

(a) Please refer to YUB-YECL-48(a) Attachment 1 for a listing of the 2008 Generation projects.

(b) Please refer to YUB-YECL-48(b) Attachment 1 for a listing of the 2008 Distribution New Extension projects.

(c) 2008 Distribution Improvements work will be completed by a combination of Yukon Electrical and contractor crews. Yukon Electrical has the capacity for one line construction crew that will be supplemented by three line contractor crews during the peak summer fall construction season.

Yukon Electrical has a good understanding of the projects that it will be undertaking in the upcoming year. Yukon Electrical reviews the type of projects it is required to construct, the number of projects it has to construct and at the complexity of the work. Yukon Electrical will then allocate the work to its own line crew or its contractor crews. During our peak construction season, generally from May 15$^{th}$ to November 15$^{th}$, depending on ground conditions, Yukon Electrical will engage up to 3 contract line crews. Our practice is to award the projects based on one of 3 criteria if practical, tender or firm price, unit rate, or hourly rate. Ultimately our objective is to obtain fair and reasonable value for the

work at hand; the benchmark for this is how the labor and equipment price compares to the estimated project cost. Yukon Electrical will undertake projects with its own crew that are deemed complex, provide development opportunities for apprentices and new journeymen as well as customer sensitive work. This promotes a better understanding for employees of how the system is configured and operates not only in Whitehorse but throughout Yukon Electrical's service area. Completion of this more challenging work also prepares and develops our staff for future stand by and power restoration responsibilities as well as the roll of Operators in Charge of the high voltage electrical system as specified in; Yukon OH&S Safety Regulations Part 9, Electrical Protection Act & Electrical Utilities Code.

(d) The interconnection has been designed by Yukon Electrical's Professional Engineer and has been designed in accordance with Yukon Electrical's construction standards. Please note interconnection line is approximately 1 km long.

(e) Anchoring Guying to a tree is not an acceptable standard or Yukon Electrical's practice in normal operating and power restoration situations. However, in extreme circumstances and in an effort to avoid greater consequential damages, such as an extended after hours power outage or ultimately conductor sagging to unsafe ground clearances, it is a reasonable short term solution. The current practice requires that a permanent repair be completed as soon as it is reasonably practicable.

The heavy loading design referred to on (9-18) is a standard recently adopted by Yukon Electrical from the ATCO Electric construction standards. In summary, it is a type of power line construction utilized where conductors and structures are frequently subjected to excessive icing, frost or snow loading build up. Some of the basic enhancements of this construction are larger wire with more internal steel reinforcement, longer laminated or possibly steel cross arms and shorter spacing between structures. Ultimately the design is engineered to withstand more weight and react more effectively when snow and ice build up starts to clear from the lines or when it is being manually forced off by linemen.

(f) The heavy loading standards in use were created in Alberta in about 2000 and were first applied in Yukon in about 2002. These standards are reviewed on an

on going basis by ATCO Electric's standards group as well as Yukon Electrical's Supervising Engineer.

(g) The existing lines were constructed to acceptable standards and the electrical codes of the early and mid 1960. By today's standards, deficiencies exist in both standards. Risks to our staff when working on these facilities are identified as part of Yukon Electrical's job planning process and barriers deployed to eliminate the hazards.

(h) Please refer to YUB-YECL-48(h) Attachment 1 for details on 2008 System Improvement Projects.

(i) The replacement of this portion of lighting was initiated by Yukon Electrical's annual infrastructure patrols. The lighting on Pine Street is pre 1975 and is not up to present day standards. This reinvestment in infrastructure will have painted standards replaced with the current galvanized standard deployed at TAC lighting levels (Transportation Association of Canada) http: www.tac-atc.ca english pdf roadlight.pdf , it will also include underground cabling for these constructed to the new ducted standard rather than direct buried.

(j) Please refer to the business case in YUB-YECL-15(c) Attachment 1.

(k) Please refer to the business case in YUB-YECL-16(b) Attachment 1.

## GENERATION

| | | |
|---|---|---|
| **90100** | **GENERATION IMPROVEMENTS 2008** | |
| | Fish Lake dyke widening | 25,000 |
| | Fish Lake dyke brushing and surfacing upgrade | 50,000 |
| | Jackson Lake and Fish Lake Studies | 25,000 |
| | Fish Lake Riparian Flow Study | 20,000 |
| | Ditch 3 waterflow gate | 45,000 |
| | Fish Lake Unit 1 Generator Rebuild | 125,000 |
| | Fish Lake Unit 2 new wheel, shaft and bearing pedistal | 60,000 |
| | Waton Lake protection upgrades, cooling fans and fresh air intake upgrades | 60,000 |
| | Destruction Bay compton protection replacement, junction box battery charger fuel delivery metering upgrades | 54,000 |
| | Beaver Creek fuel delivery metering, crompton relay replacement, junction box oil pressure and temperature alarm upgrades | 30,000 |
| | Old Crow fuel delivery metering, heat exchanger unit 1, oil pressure, temperature alarm and battery upgrades | 30,000 |
| | Pelly Crossing tie to Grid Source | 150,000 |
| | Pelly Crossing heating for standby unit and interchange metering | 30,000 |
| | Haines Junction Fuel System Upgrade | 45,000 |
| | Haines Junction move unit breaker, plant and transformer | 91,500 |
| | Other generation projects | 173,500 |
| **GENERATION TOTAL** | | **1,014,000** |

Please refer to page 9-16 of the Application.

**70001** **DISTRIBUTION NEW EXTENSIONS 2008**

| | |
|---|---|
| Miscellaneous Jobs 10,000 | 370,000 |
| Miscellaneous Jobs 10,000 - 25,000 | 275,000 |
| New OH Services | 160,000 |
| Miscellaneous UG Services | 165,000 |
| Land Rights - Dist | 90,000 |
| Drafting Mapping | 30,000 |
| Cadet camp 3 phase service | 58,186 |
| Mountain Air Subdivision | 382,160 |
| Reeder tap (Little Atlin RETP) | 150,000 |
| Sid McKeown | 39,107 |
| Narrow Gauge condo 4th and strickland | 98,850 |
| Hamilton Blvd main infrasture extension | 300,000 |
| YTG Whitehorse Copper Phase II 2008 | 225,000 |
| CoW Stan McCowan Subd | 214,925 |
| TA'AN sudiv Klondike Hwy North and Alaska Hwy | 168,590 |
| Selkirk FN - Minto Crossing | 350,000 |
| other new extension jobs | 64,182 |
| **TOTAL - NEW EXTENSIONS** | **3,141,000** |

Please refer to pages 9-17 of the Application.

**70004 DISTRIBUTION IMPROVEMENTS 2008**

| | |
|---|---|
| Miscellaneous Pole Replacement Total | 146,500 |
| Watson Sawmill site to Junc. 37 lower post | 20,000 |
| Porter Creek Crestview | 50,000 |
| ROW widening Marsh Lake | 110,000 |
| 9L Whitehorse Area | 50,000 |
| substation platform bank and riser breaker | 30,000 |
| YECL Campbell Hwy Relocation | 50,000 |
| Carcross km 129- 131.5 hwy 2 (south of annie lake rd) | 150,000 |
| convert Spirit to 14.4kv 19.9kv | 35,000 |
| Morley Bay line rebuild | 40,000 |
| YECL Beaver Cr Pole Change | 69,000 |
| Pelly Crossing Tie to YEC Grid | 140,000 |
| Tagish Rd Rebuild in front of Tagish Estates | 180,000 |
| Tagish Bridge Conduit Rep | 51,000 |
| Marsh Lake 9L reliability fix - phase 1 - Squanga | 180,000 |
| YECL power quality protection of Deep Creek | 28,000 |
| Cadet camp convert to 3 phase | 85,000 |
| YECL Sy Upgrade Lot 1378 79 Range Rd (with Y10766) | 101,983 |
| YECL Tie between 1st & 6th Ave | 400,000 |
| Porter creek secondary ped replacement | 50,000 |
| Crestview - Squanga rebuild hybred | 140,000 |
| Pelly Crescent to Grey Mountain H frames | 200,000 |
| Ketza Court replace live front transformers | 175,000 |
| McIntryre 34kv U G Bypass | 50,000 |
| YECL Paddlewheel Line Relocate | 45,000 |
| Other system improvement projects | 390,517 |
| **TOTAL - DISTRIBUTION IMPROVEMENTS** | 2,967,000 |

Please refer to pages 9-18 to 9-20 of the Application.

**YUB-YECL-49**

**Reference:** Capital Additions; Application, page 9-22

**Issue Sub-Issue:** 2009 Capital Expenditures

**Request:**

(a) When did the YUB approve the Yukon Energy 20-Year Resource Plan? With respect to the community of Carcross, please provide a table illustrating electrical load for the period 2003 through 2007. Please provide evidence that YECL either agreed to or endorsed the YEC 20-Year Resource Plan. (page 9-23)

(b) How many YECL communities remain to be converted or upgraded to GE Fanuc standard? (page 9-23)

(c) How long has the standard been in place whereby an isolated community requires a 110 back-up if the largest unit is out of service? Please provide detail regarding total project costs that would see a 500 kW modular unit installed and when would the total project be completed. (page 9-23)

(d) Please confirm that the dollars spent on upgrading Old Crow's PLC would incorporate future generator expansion alluded to in (c). (page 9-24)

(e) Please provide detail regarding the 1.7 million of other projects forecast for 2009. (page 9-24)

(f) Please provide a detailed explanation regarding the process that YECL uses in order to determine the magnitude of its miscellaneous pole replacement forecast? (page 9-25)

(g) What is meant by miscellaneous pole replacements? (page 9-25)

(h) Approximately what percentage, using numbers of street lights as a reference point, use wire in conduit in lieu of direct buried U G cabling? (page 9-26)

(i) Please describe the difference between miscellaneous street light projects and other projects. (page 9-26)

(j) Please describe the logistics and the time that it will take to convert 13,200 conventional meters to AMR, considering that it took YECL's sister company (ATCO Electric) 12 years to convert approximately 178,000 meters to AMR in Alberta. How much of the 3.9 million is forecast to be spent in 2009? (page 9-27)

(k) Please provide greater detail in respect of the 150 thousand that is projected to be spent on the new Old Crow Bunkhouse. Please provide detail in respect of the upgrading to meet current legislation. Please show a cost-benefit analysis reflecting the difference between replacement and repair. (page 9-28)

**Response:**

(a) It is Yukon Electrical's understanding that the YUB provided recommendations to the Justice Minister regarding the 20 Year Resource Plan put forward by Yukon Energy (YEC). The report of the YUB was submitted to the Minister January 15, 2007.

In YEC's 2007 annual report in the President's message it states Yukon Energy's primary focus this year was to proceed with some of the major initiatives laid out in our 20- year resource plan. The plan addresses our major electrical generation and transmission needs from 2006 until 2025 and was **approved last year by the Yukon Utilities Board (YUB).**

In the report filed with the Minister by the YUB on page 11 of 55 and page 12 of 55, it states:

> *"YEC's criterion respecting communities to the WAF or MD grids, which states that any location with a load large enough to justify a diesel of about 1MW or more should be considered as a preferred location for new diesel units, is a criterion for deciding where to locate new units rather than a planning criterion to decide if new units are needed or not. Therefore, the Board has no concerns with YEC adopting this criterion."*

Carcross Taigish is the only community of Yukon Electrical that meets the above mentioned criterion and Yukon Electrical believes that adding the generator will enhance reliability for customers in the Carcross and Tagish area.

Below is the information showing the peak demand on the Carcross Tagish system since 2003:

Carcross Substation

| | |
|---|---|
| 2003 | 748 KW |
| 2004 | 835 KW |
| 2005 | 864 KW |
| 2006 | 921 KW |
| 2007 | 864 KW |
| 2008 | 1025 KW |

Loads having increased such that they are expected to peak consistently over 1MW on a go forward basis.

(b) To date, 5 communities remain to be upgraded to the GE Fanuc standard. They are: Beaver Creek, Destruction Bay, Old Crow, Teslin and Stewart Crossing.

(c) It is Yukon Electrical's understanding that the guideline of 110 back up with the largest unit unavailable was obtained from Northern Canada Power Commission prior to 1987. Northland Utilities also uses this criteria and it has been previously approved by its regulator.

The costs for Old Crow new generator are forecasted at 100k for pad, 50k for switch mod and tie to grid-generators, 600k for generator, and 200k transportation to retrofit the existing plant. The additional costs forecast in 2010 are approximately 800k.

(d) An upgraded PLC will have increased memory allowing for more inputs and outputs.

(e) Please refer to YUB-YECL-49(e) Attachment 1 for details on 2009 System Improvement Projects.

(f&g) On an annual basis, service personal identify structures (poles) throughout the service areas which warrant replacement. Structures identified vary in type and location as well as cost to replace. Generally replacement is justified by the age and condition of the structure. Replacement can however also be justified for other reasons: i.e. poles are damaged by vehicles, equipment, rodents, erosions and lighting. Structures may be working poles, poles that are climbed by service personal often and are damaged by the climbing spurs. On occasion, poles are replaced due to a change in the surrounding terrain such as a driveway that has been added or upgraded creating a ground clearance violation.

The pole replacement budget is determined through line patrols and pole testing. The reference to miscellaneous is that replacement can be as a result of many causes and occur in a variety of locations.

(h) All new sub surface construction and rebuilds since 2002 have been designed and constructed with ducted feeds vs. direct bury. Yukon Electrical has not conducted a study to determine how much of its street light cable is in duct however we would estimate that it would be less than 20 in the Whitehorse area.

(i) Miscellaneous would refer to individual or smaller groups of lights being replaced due to damage or excessive deterioration. The scope of larger projects such as Pine and Mountainview are typically known projects that tend to involve a complete street or drive rebuild and is refurbished inclusive of all underground power supply, cable and ducting.

(j) Based on Yukon Electrical's multiple team installation plan, it anticipates approximately 120 days or approximately 6 months will be required to install the AMR meters. 3.9 million has been forecast to be spent in 2009.

(k) The existing building is a trailer unit. The building's bathroom facilities, windows and emergency exits do not conform to current national building codes. With the extensive deconstruction and reconstruction needed to more than 60 of the building as well as the fresh water and septic systems, consideration was given to the down time of the accommodations. It was also noted that on site refurbishing or stick build is challenging for a number of reason such as availability of qualified trades people, materials and services. A prefabricated building would have a considerably shorter turn around time and adequately

meet our employee's needs and comply with the national building codes. Yukon Electrical also consulted with the Vuntut Gwitchin First Nation Development Corporation in regard to the construction work. They stated they could not entertain our request for a construction crew. Consideration was also given to alternate accommodations, however, the availability of a bed and breakfast or a hotel was very limited. Furthermore, just by the nature of our work, 24 7 accommodations are very important as our employees are dispatched from Whitehorse to respond to trouble calls in the community. It is very important that responding staff have a muster location with the basic essentials when deployed. It should also be noted that this same accommodation is used for our regular scheduled service trips to Old Crow and to accommodate construction crews when projects warrant.

## DISTRIBUTION

**70001** **NEW EXTENSIONS 2009**

| | |
|---|---|
| Miscellaneous Jobs 10,000 | 423,500 |
| Miscellaneous Jobs 10,000 - 25,000 | 366,025 |
| New OH Services | 95,167 |
| New UG Services | 219,615 |
| Land Rights - Dist | 90,000 |
| Whistle Bend | 190,000 |
| Arkell Infill | 650,000 |
| Other new extentions based on historical trends | 927,693 |
| **TOTAL - NEW EXTENSIONS** | **2,962,000** |

Detailed on page 9-24 of Application

**YUB-YECL-50**

**Reference:** Income Tax; Application, page 10-1

**Request:**

(a) Please provide income tax expense for the years 2003-2005 inclusive.

(b) Does YECL have any knowledge that territorial or federal tax rates may change during the forecast period? If so, please provide such knowledge.

(c) How has YECL accounted for changes in tax rates (either federally or territorially) during the years 1997 to 2007?

**Response:**

(a) The income tax expense was:

2003 1,357,000

2004 1,240,000

2005 1,328,000

(b) As outlined on page 10-2 of the Application, Yukon Electrical is forecasting the Federal tax rate to drop during the test period from 19.5 in 2008 to 19.0 in 2009. There are no forecasted changes to the territorial rate of 15.0 .

(c) Yukon Electrical uses the enacted tax rates in place to calculate each year's tax expense.