

**IN THE MATTER OF YUKON
ENERGY CORPORATION
2012/2013 GENERAL RATE
APPLICATION TO THE YUKON
UTILITIES BOARD**

FINAL ARGUMENT

YUKON ENERGY CORPORATION

November 28, 2012

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**YUKON ENERGY 2012/2013 GENERAL RATE APPLICATION
("APPLICATION") TO THE YUKON UTILITIES BOARD
("YUB" OR "BOARD")**

YUKON ENERGY CORPORATION FINAL ARGUMENT

PREFACE

OVERVIEW OF YUKON ENERGY APPLICATION

The Application was submitted to the Board on April 27, 2012 (Exhibit B-1) for adjustments to Yukon Energy's ("YEC's") revenue requirements, rates and other related matters as required to recover YEC's forecast costs to supply customers in 2012 and 2013 and to plan for future requirements thereafter in a new era of depleted hydro surplus and sustained, strong Yukon growth. The Application provides for a complete and thorough review of all aspects of Yukon Energy's operations since the 2008/2009 GRA, as well for the continued development of Yukon's capability to meet ongoing growth with reliable, affordable and environmentally responsible power that is flexible to changing loads and conditions.

The Application requests approval for the first increase by the Board in Yukon Energy's firm retail rates for non-industrial customers since 1998/99.

Approval is sought as follows for rate adjustments through Rider J and Rider R to recover the forecast revenue shortfalls for 2012 and 2013 of approximately \$3.455 million and \$7.685 million respectively (revenue shortfalls as set out in Table 1 at page 4 of the Application):

- Rider J (2012): a 6.4% rider applicable for all YEC and YECL retail firm rates and 2.9% for industrial firm rates); and
- Rider R (2013): a 6.5% rider applicable for all YEC and YECL retail firm rates and all industrial firm rates (including Rider J).

In addition to forecast operating, maintenance and capital costs to provide cost effective power for ratepayer needs, the Application also includes the following proposals for enhanced rate stability:

- Update and re-activate the Diesel Contingency Fund ("DCF") as of January 1, 2012 so that customer rates and YEC's diesel generation expenses are based on forecast long term average ("LTA") diesel generation requirements related to actual grid loads rather

than on YEC diesel generation requirements that fluctuate in response to changes in annual YEC hydro or wind generation availability.

- Transition measure for LTA diesel generation costs to prevent rate increases in excess of those requested at this time, i.e., provision to include only approximately 66% of LTA diesel generation fuel costs in the requested revenue requirement for 2012 and approximately 59% for 2013.
- Updated Planning Cost Accounting Policy, and related transition measures for existing deferred cost projects in excess of \$1 million, to address unprecedented levels of feasibility planning study costs undertaken to assess potential options for meeting load growth and reducing future diesel generation, i.e., the updated accounting policy allows these costs to be addressed in a manner that moderates risks for options not yet reasonably assured of being advanced, and recognizes the need for near and longer term rate stability that avoids undue rate increase impacts.

The complete set of Orders sought from the Board are set out in the Application (Exhibit B-1, Application) at pages 5 to 8, and include (in addition to the above noted matters):

- Forecast 2012 and 2013 cost requirements by major cost component, i.e., fuel and purchased power, non-fuel operating and maintenance, depreciation and amortization, mid-year rate base, and return on rate base (including provision for an allowed return on equity ("ROE") of 8.77% for both 2012 and 2013);
- Wholesale rate adjustments for Rate Schedule 42; and
- Other related matters regarding the Reserve for Injuries and Damages (RFID), the use of Faro Dewatering Account Funds, credit to the DCF of any future funds from secondary sales (Rate Schedule 32), new Demand Side Management ("DSM") accounting policy, new depreciation rates (reduced for fixed assets to reflect changes in service lives identified in the depreciation study provided as Tab 10 of the Application), provision for costs of the current GRA, and amortization of earlier regulatory and related costs.

OUTLINE OF YUKON ENERGY FINAL ARGUMENT

Yukon Energy's Final Argument provides the support from the record for the requested Orders, focuses on the extensive evidence examined within the scope of the Board's review of the Application, and includes the following major sections:

- **Part 1 - Core Elements of Yukon Energy's Application** - Addresses core elements of the overall Application as submitted and reviewed during the hearing process to date, including matters addressed in the Application (pages 1 to 14) and Supporting Tab 1.

- **Part 2 - Response to Key Issues Raised** - Provides Yukon Energy's responses to key issues raised by the Board and intervenors in information requests (IRs) and the oral hearing, and provides transcript references containing more detailed information on these issues.

In response to the Chair's direction that Argument by each participant follow the outline of the Application, the following are noted regarding how components of the Application are addressed in this Final Argument:

- The Application (pages 1 to 14) provides the overall GRA, and as such is addressed as required in Part 1 of this Final Argument.
- Tab 1 (Introduction) of the Application provides background information for the GRA, and is addressed as required in Part 1 of this Final Argument.
- Tab 2 (Yukon Energy System Sales and Generation) of the Application is addressed as required in Part 1 of this Final Argument, and Yukon Energy's response to key issues raised by the Board and intervenors in relation to Tab 2 are addressed in Part 2 of this Application (Section 1 of Part 2).
- Tab 3 (Revenue Requirement) of the Application is addressed as required in Part 1 of this Final Argument, and Yukon Energy's response to key issues raised by the Board and intervenors in relation to Tab 3 are addressed in Part 2 of this Application (Section 2 of Part 2).
- Tab 4 (Rates) of the Application is addressed as required in Part 1 of this Final Argument, and Yukon Energy's response to issues raised in relation to ERA relating to Rate Schedule 39 is addressed in Part 2 of this Application under Diesel Generation Forecast and DCF (Section 2.1 of Part 2).
- Tab 5 (Capital Projects) of the Application is addressed as required in Part 1 of this Final Argument, and Yukon Energy's response to key issues raised by the Board and intervenors is addressed in Part 2 of this Application (Section 3 of Part 2).
- Tab 6 (Board Directives) of the Application reviews Board directives since the 2008/09 GRA and, where relevant, YEC's response. This section of YEC's Application does not receive separate attention in this Final Argument.
- Tab 7 (Financial Schedules) of the Application provides supporting financial details for the Application. This section of YEC's Application does not receive separate attention in this Final Argument.

- Tab 8 (Return on Equity) of the Application is addressed as required in Part 1 of this Final Argument.
- Tabs 9 (2010 Audited Financial Statements) provides background information. This section of YEC's Application does not receive separate attention in this Final Argument.
- Tab 10 (Depreciation Study) of the Application provides supporting details for the related new depreciation rates proposed in Part 1 of this Final Argument. This section of YEC's Application does not require separate attention in this Final Argument.

Total documentation and evidence in this hearing are substantial. There were two rounds of interrogatories with a total 1036 information requests, 32 undertakings and approximately 663 pages of transcript. To date, there have been over 100 exhibits, and 7 Board Orders flowing from the Application. There were 5 registered intervenors, all of whom actively participated. No intervenors, however, provided evidence in the proceeding.

To the extent that the Board and intervenors examined specific issues with respect to specific parts of Yukon Energy's Application through interrogatories or cross-examination, Yukon Energy has attempted in this argument to address the apparent concerns raised. However, in the view of Yukon Energy, its filing, the answers to the many interrogatories, and other evidence submitted (including undertakings) fully address all such concerns, and fully support the reasonableness and necessity of the proposed revenue requirement. Further, no evidence-based contrary position has been tendered by any party.

Accordingly, Yukon Energy submits that all evidence necessary for the Board to address the Orders requested is in the record.

PART 1: CORE ELEMENTS OF YUKON ENERGY'S APPLICATION

Part 1 addresses the following core elements of the overall Application as submitted and reviewed during the hearing process to date, including matters addressed in the Application (pages 1 to 14) and Supporting Tab 1:

- Ratepayer Savings Today from Successful Measures Over the Last 10 Years;
- New Era of Depleted Hydro Surplus and Increasing Diesel Generation;
- Growth in System Driving Increases in Other Yukon Energy Costs;
- Retain Simplified ROE Determination Based on Available Benchmarks;
- Dealing with Rate Stability Issues – DCF, Planning Cost Accounting Policy and Other Measures;
- Yukon System Planning Challenges;
- Reliance on Application Forecasts as Filed; and
- Conclusion.

Due to past legacy hydro and transmission developments to meet earlier growth, Yukon continues today to offer the lowest electrical rates in Northern Canada (Application, Appendix 4.2). Yukon Energy is working to keep this advantage while meeting current and future growth needs. The Application sets out the context for the current challenges and the specific measures that Yukon Energy proposes for Board approval at this time.

Yukon Energy has been experiencing cost pressures for some time. As indicated in Tab 1 of the Application (Table 1.1), since 2009 there have been significant shortfalls from the 8.49% YUB approved return on equity (ROE) approved in the 2008/2009 GRA¹. Absent a new rate increase, forecast ROE at existing rates without the Application falls to 4.38% in 2012 and -0.97% in 2013.

In short, ongoing cost pressures as reviewed in the Application have become simply too material to continue without a reasonable rate increase at this time.

Ratepayer Savings Today from Successful Measures Over the Past 10 Years

Yukon ratepayers today secure savings from initiatives undertaken by Yukon Energy over the past 10 years.

¹ As noted in table 1.1: 7.92% in 2009 (Actual); 7.45% in 2010 (Actual); and 6.59% in 2011 (FYF in GRA, subsequent Actual).

Despite continuing cost pressures from many sources over the last several years, Yukon Energy has successfully implemented various measures to avoid the need for rate increases and ensure that costly diesel generation is minimized as the load grows².

- Yukon Energy initiatives since the 2009 GRA have resulted in material reductions today in Yukon Energy's applied for GRA revenue requirements of \$6.8 million in 2012 and \$6.5 million in 2013, including:
 - Ratepayers savings of \$3.0 million in 2012 and \$2.6 million in 2013 arising from the reduction in diesel generation requirements following completion of 3 major legacy projects (CSTP 2, Mayo B and Aishihik 3rd Turbine);
 - Ratepayer savings of \$1.5 million annually in the test years from the refinancing of Yukon Energy's long term debt at the end of 2010; and
 - Ratepayer savings of \$2.3 million in 2012 and \$2.4 million in 2013 arising from reductions requested today in the depreciation rates of key generation and transmission assets.

- Additional savings flow from measures taken before the 2008/09 GRA which reduced the applied for revenue requirement at that time by more than \$6 million and which in many cases continue to provide ongoing cost savings to ratepayers - these successful earlier measures include completion of the Mayo Dawson transmission line in 2003, the 2008 completion of the Carmacks-Stewart Transmission Project Stage 1, material secondary sales revenues that help to reduce rates needed for firm sales, debt refinancing in 2003 that materially reduced ongoing interest costs, and depreciation rate changes in 2005 that materially reduced only depreciation expenses.

All of these measures demonstrate very clearly Yukon Energy's commitment to keep rates as low as possible while addressing significant challenges related to ongoing non-industrial and industrial load growth on the Yukon system and the need to ensure continued safe and reliable service.

New Era of Depleted Hydro Surplus and Increasing Diesel Generation

The 2008/2009 GRA indicated that the WAF system was reaching a point where the material surplus hydro generation available since the closure of the Faro mine was becoming greatly diminished. Further, with ongoing non-industrial load growth and increased interest from potential industrial customers, it was anticipated that the then existing hydro generation would likely be fully utilized within a few years – highlighting the need to look ahead to developing the next era of affordable and environmentally responsible projects to meet this forecast growth.

The current Application confirms that continued non-industrial and industrial load growth has outstripped the available surplus hydro generation, notwithstanding the additional hydro capability which new legacy projects have brought to the system since 2009, to the point that diesel generation is once again required to supply growth (Exhibit B-16, pages 4 and 5).

² See Tab 1, Pages 1-4 and 1-5 and Exhibit B-16, pages 3 and 4.

- Non-industrial grid load growth has been higher than the 2006 Resource Plan forecast of 1.85% per year and the 2011 Resource Plan forecast of 2.26% per year. By the end of 2013, non-industrial grid load growth as projected in the GRA is expected to grow by approximately 35 GWh over the 2009 approved forecast. More recent internal forecast updates indicate non-industrial grid load is expected to exceed GRA forecasts in 2013 by more than 7 GWh.
- Industrial growth by the end of 2013 as projected in the GRA is expected to increase by approximately 33 GWh over 2009 approved forecasts³.

A notable share of the added growth today must be met with diesel generation and, absent new initiatives, as the load continues to grow the share of growth served by diesel generation will continue to become more and more significant – increasing from 30% of growth exceeding the 2011 grid load, to 59% of growth exceeding the GRA load forecast for 2013⁴.

This fundamental change on the system that is forecast to occur during the test years means that absent bringing on new lower cost sources of generation, an increasing portion of new load on the system must be supplied using costly diesel generation.

To demonstrate the impact this reality is having on Yukon Energy's costs -- the GRA forecasts diesel fuel costs in 2013 (assuming long term average hydro generation) at over \$4.7 million more than the diesel cost approved for the 2009 Revenue Requirement.

The Application mitigates this cost increase by proposing, as a transition measure, to include only 66% of long term average diesel generation fuel costs in the requested revenue requirements for 2012 and 59% for 2013.

- As reviewed in response to YUB-YEC-12, the 2009 approved diesel fuel costs recovered only 32% of long term average diesel generation costs - accordingly, the current Application moves a good portion of the distance towards full recovery of long term average costs.
- As noted in response to YUB-YEC-1-3, without this transition measure an additional cumulative rate increase of 3.59% would be needed by 2013 to recover 100% of long term average diesel generation costs.

³ Even though YEC's experience in 2012 with the Minto mine in particular shows materially lower growth than expected and Minto's latest updated forecast show industrial grid load in 2013 at almost 16 GWh below the GRA forecast.

⁴ See Exhibit B-16, page 5.

- However, even with this transition proposal, diesel fuel costs in 2013 are still forecast to be more than \$2.6 million higher than the diesel fuel costs approved for 2009⁵.

The available evidence shows continuing and potentially major new grid load growth in the near term after 2013.

Updated grid load forecasts beyond the test years in the Application through to 2030 show sustained non-industrial load growth and potentially major new industrial grid load growth scenarios and related default diesel grid generation. During the hearing, Yukon Energy tabled its November 2012 Resource Plan load forecast update [Exhibit B-20] to reflect evolving conditions, confirming that the best available current evidence continues to highlight prospective major new grid load growth with related growth in default diesel generation by as soon as 2014-2016 unless cost effective options are developed within this time period to displace such new default diesel generation. [See Exhibit B-16 (YEC Opening Statement); Exhibit B-20 (YEC Overview of 20-year Resource Plan: 2011-2030 - Updated Appendix A (Nov. 2011, entered Nov. 14, 2012); YUB-YEC-1-1].

Growth in System Driving Increases in Other Yukon Energy Costs

Yukon Energy's results over the last several years demonstrate that wide ranging cost pressures have been experienced for some time. Since the 2008/09 GRA there have been significant shortfalls from the 8.49% YUB approved return on equity ("ROE"), with actual ROE at 7.92% in 2009, 7.45% in 2010 and 6.59% in 2011. Absent new rate increases, forecast ROE at existing rates without the Application falls to 4.38% in 2012 and -0.97% in 2013 (see Tab 1, and Exhibit B-16, page 8). In short, ongoing cost pressures as reviewed in the Application have become too material to continue without a reasonable rate increase at this time.

In addition to increasing costs of diesel generation, ongoing load growth is leading to substantial increases in capital expenditures, the size of Yukon Energy and planning costs.

- ***Increases in Capital Expenditures*** - Yukon Energy has been actively and continuously engaged since 2005 in identifying and assessing a range of new resource supply options to meet these challenges. Attention initially focused on enhancement of existing hydro and other infrastructure. Overall, by 2013 an approximate \$213 million increase is forecast to have occurred in gross assets since 2009. Capital additions include:
 - Completion of three major legacy asset investment opportunities;

⁵ Per YUB-YEC-1-3: For 2012, diesel fuel costs at 100% LTA would increase by approximately \$1.134 million above the Application amount of \$2.163 million (Table 3.2 of Application), resulting in an approximately 8.38% increase in average rates for 2012 (or 1.98 percentage points higher than 6.4% increase in application). For 2013, diesel fuel costs would increase by approximately \$2.4 million if diesel generation was at 100% of LTA rather than the proposed 59% (as shown in Table 3.2 of the Application). After including the 1.98% increase to proposed rates in 2012, a \$2.14 million added increase to 2013 rates would equal 7.87% of the approximately \$64.52 million consolidated retail revenue that would be forecast in 2013 at 2012 retail rates.

- Refurbishment of old assets and projects to enhance grid reliability including major investments in the Mayo Hydro Substation (\$10.1 million), and in the Aishihik Generation Station (Redundancy Project - \$6.4 million); and
- Overall mid-year net rate base growth over this period of \$93.7 million excludes approximately \$119.69 million in new net contributions.

The impact on ratepayers of these new capital assets has been greatly moderated by approximately \$120 million of no cost contributions – the overall impacts on revenue requirement forecast for 2013 compared to 2009 approved forecast costs are an increase in depreciation and amortization expense of \$3.1 million and, despite lower average cost of capital⁶, an increase in return on rate base expense of approximately \$3.6 million.

- ***Increase in Labor and O & M Costs*** - The significant overall forecast growth in assets since 2009 has required a material increase in the size of Yukon Energy, increasing both labour expense and non-labour expense. Forecast labour expense by the end of 2013 is \$2.5 million higher than in 2009 approved costs, reflecting a forecast increase in 12.26 FTE positions. Non-fuel and non labour O&M is forecast to increase by \$2.7 million over 2009 approved costs.
- ***Increase in Planning Costs*** - In recent years, the range of YEC's assessment of diesel generation displacement options has expanded as the time approaches when resource development must move beyond enhancement of what was previously developed. Today YEC is truly on the cusp of needing to move forward with major new measures to displace the need to otherwise rely on diesel generation as the default supply option to meet Yukon's growing grid generation requirements.

Yukon Energy's 2008/09 GRA reviewed the on-going need to undertake significant planning activities to ensure the next generation of low costs supply resources is available to meet continued growth on the integrated grid and to displace diesel requirements. In Board Order 2009-8 the Board addressed these activities and stated as follows: "it understands that YEC does not have the luxury of waiting for those loads to, with full certainty materialize before taking any action" and further that "YEC's obligation to serve does require it to plan the system to meet these expected loads and any other requirements that may arise".

As anticipated in the 2008/09 GRA, Yukon Energy has carried out extensive feasibility planning studies since 2009 to assess potential options for reducing diesel generation, and deferred costs for these planning studies have remained in work-in-progress (WIP) for consideration at this GRA. This includes forecast spending to the end of 2013 of \$4.8 million for planning related to Marsh Lake Storage, \$3.0 million for DSM, \$2.2 million for Atlin storage, \$4.4 million for Gladstone Diversion, \$1.7 million for LNG, \$2.6 million for

⁶ YEC's forecast average cost of capital (debt plus equity) in 2013 is 5.85%, which is well below the 7.09% forecast cost approved for 2009.

geothermal, \$2.1 million for Mayo Lake Storage Enhancement and \$1.6 million for waste to energy.

Given the unprecedented levels of planning costs incurred since 2009, an updated planning cost accounting policy is included in the Application to ensure that these costs are addressed in a manner that helps to moderate risks, that recognizes the need for near term and longer term rate stability, and that does not result in undue rate impacts.

Retain Simplified ROE Determination Based on Available Benchmarks

As reviewed in Tab 8 of the Application, YEC has updated its forecast Return on Equity (ROE) based on a review of ROE methods and results in other jurisdictions to determine a reasonable low risk utility benchmark to use for the purposes of the current GRA filing⁷. This review indicated that while the British Columbia Utilities Commission (BCUC) low risk utility benchmark has been used in proceedings since the 1996/97 GRA, the low risk utility benchmark in that jurisdiction has not been subject to review since 2009. By contrast, the Alberta Utilities Commission (AUC) has recently completed a Generic Cost of Capital proceeding (with a Decision dated December 2011).

The recent AUC proceeding has determined the benchmark ROE for a low risk utility to be 8.75% (by contrast, the more dated 2009 BCUC benchmark would provide for a low risk utility ROE of 9.5%). It is proposed in the Application that the more recent low risk utility benchmark of 8.75% be adopted for the purposes of setting rates for Yukon Energy in the test years with the previously accepted risk premium of 52% applied to this benchmark. This methodology would increase the ROE by 0.28% from the YUB's last approved ROE⁸.

Based on above Yukon Energy's forecast return on equity in the Application is 8.77% for both 2012 and 2013.

During the oral hearing Yukon Energy confirmed that the ROE proposed for the test years retained a simplified approach as described above to minimize the regulatory burden, and, consistent with past practice as approved by the YUB (and contrary to AUC practice), Yukon Energy under no circumstances seeks any adjustment to its long standing capital structure (40% equity, 60% long-term debt)⁹.

⁷ Since the late 1990s, Yukon Energy has relied upon a low risk utility benchmarking approach along with a reasonable risk premium of 52% (based on BCUC precedents for similar electric utilities) as a simplified approach that reduces overall cost to the ratepayer through eliminating the requirement of costly expert assessment and testimony.

⁸ The ROE for Yukon Energy for the test years is based on 8.75% low risk utility benchmark plus the 52% risk premium for Yukon Energy (approved in 2008/2009 GRA) and subtracting 50% pursuant to direction provided in OIC 1995/90. OIC 1995/90 requires that the Yukon Utilities Board include in rates for Yukon Energy provision to recover a fair return on the Corporation's equity, less one-half of one per cent (0.5%). See Tab 8 for more detailed review.

⁹ Morrison, T101, lines 4 to 20 confirm YEC's historic capital structure, and that YEC has not done any reassessment of this structure since 1990. Osler, T288, lines 3 to T292, line 22 reviews YEC's submission on the ROE as proposed in the Application with no adjustment to the capital structure.

Yukon Energy notes that the following are available to support the reasonableness of the proposed ROE for 2012 and 2013 in the Application:

- In response to Undertaking #32 (page 651, line 11) filed November 16, 2012, it was confirmed that based on the last available BCUC benchmark approved ROE for Terasen (9.5% as approved in 2009) the YEC ROE for the test years would be 9.52%. This 9.5% ROE is still being utilized in B.C. and is applicable for 2012. Further, the decision on the current BCUC generic cost of capital proceeding is not expected until sometime in 2013.
- As reviewed in CW-YEC-1-41: Decision 13-2011 of the NWT Public Utilities Board (August 13, 2011), approved a ROE of 9.3% for the 2011 to 2013 test years as negotiated for NUL(YK); Decision 17-2011 of the NWT Public Utilities Board (November 14, 2011), NUL(NWT) approved a revised negotiated ROE settlement of 9.3%. These ATCO-owned utilities negotiated equity ratios of 43.5% and 44%, respectively, for each of the 2011-2013 test years. An ROE for Yukon Energy at 8.77% is more than 0.5 percentage points lower than the 9.3% approved for 2012-2013 for these northern distribution utilities, and YEC's equity ratio is also lower (at 40%).
- Yukon Energy asserts that the simplified approach in the Application to determine ROE is a cost-effective methodology that generates an ROE that in comparison to the available metrics described above is reasonable and fair to both YEC and ratepayers.

Rate Stability Issues – DCF, Planning Cost Accounting Policy and Other Measures

The requirement for material non-peaking diesel generation in the revenue requirement, even at less than 100% of LTA, brings the Diesel Contingency Fund (DCF) back into play¹⁰. The Application's forecast diesel generation reinstates the need for DCF measures to enable rates to recover diesel fuel and O&M costs based on LTA hydro generation rather than forecast actual diesel generation. Customer rates and YEC's diesel generation expenses are therefore once again to be based on forecast long term average ("LTA") diesel generation requirements related to actual grid loads rather than on YEC diesel generation requirements that fluctuate in response to changes in annual YEC hydro or wind generation availability.

The transition measures proposed for moving to full long term average diesel generation cost recovery have capped the current rate increase at 6.40% in 2012 and 6.50% in 2013. As a result, diesel generation included in the proposed revenue requirement equals 65.6% of long term average (LTA) costs in 2012 and 59.0% in 2013. Responses to IRs have reviewed the rationale for these transition percentages of LTA (YUB-YEC-1-7(i)), an explanation regarding why a transition to LTA diesel generation levels is required in rates to address growing grid loads (YUB-YEC-1-12), and review of the factors in addition to rate impact mitigation (e.g., favourable current water conditions, potential transition to lower cost LNG) supporting the transition

¹⁰ The history of the DCF was reviewed with Board counsel by Osler (T 569, line 6 to T571, line 20); a continuity schedule for the DCF was provided in response to Undertaking #23 (page 572, line 16) filed November 19, 2012; basic operation of the DCF was reviewed at T573, line 10 to T574, line 22.

approach applied in the test years as well as confirmation that a specific year is not proposed for 100% LTA diesel generation costs in rates (LE-YEC-1-5; LE-YEC-2-2).

The Application also includes proposed measures to update and permanently trigger the DCF as of January 1, 2012, measures to have future secondary sales net revenues go to the benefit of ratepayers through funding of the DCF, and measures to adjust the Wholesale Rate Schedule 42 Energy Reconciliation Adjustment (ERA) to reflect the DCF updates¹¹.

DCF issues were addressed extensively in the IR and oral hearing processes, and are accordingly reviewed in more detail in Part 2 of this Argument.

Other rate stability measures proposed in the Application include the updated planning cost accounting policy (Appendix 5.1), a new Demand Side Management (DSM) accounting policy (Appendix 5.2), and the Mayo B Flexible Debt provisions (Appendix 5.3).

Updated planning cost accounting policy issues were addressed extensively in the IR and oral hearing processes, and are accordingly reviewed in more detail in Part 2 of this Argument. The updated planning cost accounting policy, including related transition measures for existing deferred cost projects in excess of \$1 million, addresses unprecedented levels of feasibility planning study costs undertaken to assess potential options for reducing future diesel generation, i.e., the updated accounting policy allows these costs to be addressed in a manner that moderates risks for options not yet reasonably assured of being advanced, and recognizes the need for near and longer term rate stability that avoids, where feasible, undue rate increase impacts.

Yukon System Planning Challenges

As in the past, major new loads on the Yukon system create opportunities to develop new non-diesel supply options. During 2011, YEC updated the 2006 20-year Resource Plan as part of an extensive public engagement process that commenced with YEC's March 2011 charrette. In June 2012 YEC updated the 2011 20-year Resource Plan grid load forecasts (see Overview, attachment to YECL-YEC-1-18) - and in November YEC once again updated these forecasts to reflect evolving conditions (Exhibit B-20).

The fundamental realities faced by the Yukon system make planning for future load growth a challenging exercise.

- The Yukon system is an isolated system with no outlet to external markets to secure or sell electricity in response to conditions on the Yukon grid.
- The Yukon system also has a relatively small customer base over which the cost of investments in new assets must be spread.

¹¹ The increased need for baseload diesel generation signals increased ratepayer risks related to low water or drought conditions when costly requirements for diesel generation can greatly exceed 100% of LTA diesel generation costs (see the discussion of these risks with Board counsel, Osler, T575, line 4 to T578, line 16).

- The Yukon system is also winter peaking hydro grid with limited water storage capability and considerable seasonal and annual variability in hydro generation supplies.

These challenges emphasize the importance of having affordable, flexible and reliable non-hydro power supply capability able to deal with these conditions.

Yukon Energy also faces substantial challenges in forecasting and planning for major loads (mines or new subdivisions) – these potential load changes have material impacts in Yukon compared to larger and non-isolated provincial grids. Investments in assets to serve new large loads are expensive on the Yukon System and can have material hangover effect if the load disappears.

These realities also emphasize the importance of having flexible supply capability ready to serve such loads while managing the rate impact risks related to the hangover effect.

Yukon Energy has been actively and continuously engaged since 2005 in identifying and assessing a range of new resource supply options to meet these challenges. Attention initially focused on enhancement of existing hydro and other infrastructure. In recent years, however, the range of assessment has expanded as the time approaches when resource development must move beyond enhancement of what was previously developed.

Today Yukon Energy is truly on the cusp of needing to move forward with major new measures to displace the need to otherwise rely on diesel generation as the default supply option to meet Yukon's growing grid generation requirements.

During the IR and oral hearing processes issues were raised regarding Yukon Energy's updated 20-Year Resource Plan, particularly as regards the anticipated near term relevance of supply options such as wind and liquefied natural gas (LNG) and the potential options in future to serve new mines that may be connected to the grid. These issues will be a matter of ongoing discussion and assessment beyond the current Application. Evidence during the current proceeding, however, has shown that without major new loads connected to the grid, opportunities for major new capital intensive renewable resource options such as wind remain constrained (see Osler T374, line 9 to T379, line 24). In contrast, ongoing assessments indicated that significant savings could occur with LNG as a fuel at YEC's Whitehorse plant, replacing diesel engines due for retirement with gas fired engines (see Morrison, T 608 line 21 to T609, line 1 which concludes that LNG meets the reasonable assurance test).

Reliance on Application Forecasts as Filed

In accordance with past practice for GRA's where the utility accepts forecast risks, Yukon Energy's Application has continued to rely on the test year forecasts as filed at the outset (April 2012).

During the course of the IR and oral hearing process, numerous updates were provided as requested for actual loads, costs and overall financial performance through the third quarter of 2012 and for various other updated forecasts beyond that date. By their nature, such updates tend to provide partial pictures of ever changing conditions and do not provide a sound or principled basis for adjustment of the overall Application.

In the event that the Board does consider new forecast information that has emerged since the Application was filed, Yukon Energy notes that the single largest adjustment that has been documented to occur since the Application was filed is the Minto mine corrected forecast load for 2012 and 2013. This single corrected forecast as provided by one industrial customer, which has been documented in undertakings provided during the oral hearing¹², materially reduces Yukon Energy's forecast sales and revenues during the test years and accordingly would need to be included in the event that any adjustments to Application forecasts are to be considered based on actual or other more recent information provided since the Application filing in April 2012.

Conclusion

The extensive material filed in the Application and in the IR and hearing process highlight the extent to which the last several years have been incredibly challenging for Yukon Energy and its staff.

Yukon Energy has successfully completed by far the largest capital expenditure program in YEC's history while at the same time undertaking an unprecedented level of planning activities to prepare for the major load growth that is forecast to occur in the next few years.

The Application's proposed 2012 and 2013 revenue requirements reflect the reasonable costs required for Yukon Energy to supply customers in 2012 and 2013 and to plan for future requirements thereafter in a new era of depleted hydro surplus and sustained, strong Yukon growth. The proposed rate adjustments are required to recover the forecast revenue shortfalls related to the proposed revenue requirements. The updated DCF and planning cost accounting policy as proposed are required to enhance customer rate stability in the face of rising diesel generation and feasibility study planning costs.

¹² Minto corrected sales forecast (reduction from GRA forecast) of 9.9 GW.h in 2012 [T300, lines 18-20] and 17 GW.h in 2013 [T300, line 24 to T301, line 1]. The response to Undertaking #2 at page 26, line 23, filed November 19, 2012, noted the impact of this correction in reducing YEC's actual revenues as at the third quarter of 2012, with a forecast revenue reduction of \$1.024 million in 2012 and \$1.806 million in 2013. The corrected Minto sales forecast is also reflected in the November Update to the Resource Plan Load Forecast (Exhibit B-20).

PART 2: RESPONSE TO KEY ISSUES RAISED

Part 2 provides Yukon Energy's responses to key issues raised by the Board and intervenors in IRs and the oral hearing, and provides IR or transcript references containing more detailed information on these issues.

As requested by the Chair and reviewed in the Preface to this Final Argument, this supporting evidence follows the outline of the Application's supporting information (tabs), focusing on Tabs 2, 3, and 5 that address the substantive elements of the requested revenue requirement Orders.

1.0 TAB 2 - SALES & GENERATION

Tab 2 reviews ongoing growth in Yukon Energy grid sales and generation since 2009 relative to sales and generation forecasts for 2009 as approved by the Board for the 2008/2009 GRA, as well as the Application's forecast growth in sales and generation for the test years 2012 and 2013.

For the purposes of key issues reviewed in this Tab 2 part of the Argument, Yukon Energy will focus on the test year forecasts for wholesales to the Yukon Electrical Company Limited (YECL), sales to Whitehorse Copper Tailings (WHCT), and sales to Other Industrial Customers (Minto and Alexco). Issues regarding diesel generation forecasts and costs for the Application (and related DCF and secondary sales revenue matters) are addressed under Tab 3. YEC will wait to respond to any other issues raised by intervenors relating to retail sales, secondary sales, hydro or diesel generation forecasts, diesel fuel price and average efficiency forecasts, and peak demand forecast and reliable capacity requirement.

1.1 WHOLESALE SALES FORECAST

Wholesale Sales to YECL are reviewed in the Application in Tab 2, Section 2.2.1, pages 2-3 to 2-4. Page 2-4 explains the methodology for forecasting wholesale sales in the test years. The forecast sales in the Application include provision for YECL retail sales requirements (net of Fish Lake hydro generation), YECL's currently established wholesales to YEC (where YEC wheels power over YECL's distribution system for sales at Johnsons Crossing and use at other locations), and losses on the YECL distribution system. The forecast sales in the Application exclude provision for wheeling power over YECL's distribution system to serve WHCT (see Exhibit B-15), and this will be corrected in the compliance filing (along with the related correction to provide for increased purchased power by YEC to recover the power required for YEC's sales to WHCT).

In summary, no substantive issues have been raised that call into question the reasonableness of the Application's forecast of YECL wholesales to supply YECL retail sales and established YEC wholesales during the test years. The wholesales sales forecast to YECL as it relates to YECL retail sales has been examined in detail by all parties, including evidence on YEC consultations carried out with YECL. As in the past, YEC's forecast of these sales has tended to equal or exceed forecasts provided by YECL, and such forecasts have also continued to be sensitive to expected Fish Lake hydro generation by YECL.

Although 2012 actual retail sales are somewhat higher than forecast in the GRA (unlike industrial sales which are materially lower than forecast), as noted in Part 1 Yukon Energy has not adjusted its Application based on the principle that GRA cost and sales forecasts are not to be adjusted to reflect subsequent events.

More detailed information on specific wholesales sales forecast issues is provided in response to interrogatories and cross examination from the Board and intervenors as summarized below:

- **Forecast Methodology and Consultation with YECL:**
 - Detail regarding the development of the 2011 Resource Plan forecast and how the 2.26% long term growth rate developed in this plan was applied (YUB-YEC-1-1 and YUB-YEC-2-1¹³; YECL-YEC-1-4¹⁴).
 - Detail regarding adjustments applied to YECL's forecast to develop the wholesale sales forecast contained in the Application and documentary support (YECL-YEC-1-3 & YECL-YEC-1-5; YECL-YEC-1-15¹⁵; YECL-YEC-2-2¹⁶).
 - Detail regarding how the utilities collaborate on an ongoing basis to forecast Primary and Secondary energy sales (CW-YEC-1-6¹⁷; UCG-YEC-1-19¹⁸; YUB-YEC-2-2¹⁹).

¹³ YUB-YEC-2-1 explains the difference between the near term wholesale forecasts and the longer term resource plan forecasts and how each is used.

¹⁴ Explains how the average annual increase of 2.26% was calculated and explains how this calculation reflects Whitehorse's share of usage on the Yukon grid; provides the detailed calculations for grid growth in excel format; explains why the period 2001 to 2010 was used instead of 2002 to 2011.

¹⁵ Provides a monthly breakdown of Wholesale sales forecast in 2012 and 2013 in Table 2.1 of the Application, as well as the details of derivation of that forecast. The response explains the process YEC uses to derive this forecast.

¹⁶ YECL-YEC-2-2 provides documentation provided by YECL in 2011 that supports YECL's load forecast for 2012 and 2013 and summarizes the process and interactions that occurred between YEC and YECL.

¹⁷ YEC consulted with YECL concerning adjustments to its retail sales forecast "in general terms"; YEC is not aware of methods used by YECL to prepare its load forecast for 2012 and 2013 as YEC is only provided with the end result of the forecast.

¹⁸ Part (c) describes process for discussion of load forecasts between the two utilities that typically occurs each year.

¹⁹ Details how YEC collaborates with YECL on an ongoing basis to best forecast Primary and Secondary energy sales as well as the process followed in developing the wholesale forecast for 2012 and 2013. This response also notes the interactions that occurred in the development of the 2011 Resource Plan forecast.

- **Specific Forecast Issues – Treatment of Fish Lake** (YECL-YEC-1-3(b)) – Specifically, how Fish Lake #1 impacts the Wholesales forecast and why the annual load growth rate applied to the 2011 wholesale load forecast is net of Fish Lake (supply).
- **Specific Forecast Issues – Weather Normalization and HDD Analysis** – As noted in UCG-YEC-1-19 when testing the reasonableness of its 2012 forecast YEC performed some basic heating degree days analysis of 2011 actual sales to align the forecast to the 10 year average heating degree days. IRs focused on need for YEC to explain the methodology used (YECL-YEC-1-3(a)²⁰); precedents for approach (CW-YEC-1-6(d)²¹); and information regarding analysis provided by YEC (UCG-YEC-1-19(a) and (b))²².
- **Other Information raised in IRs** – Comparative YEC and YECL load forecast, with actual sales for 2009 to 2011 for wholesale transactions (UCG-YEC-1-19(b)).
- **Cross exam during the oral hearing** – CW raised issues regarding Fish Lake forecasts and weather normalization regarding sales forecasts (T60 to T64), and UCG sought clarity as to forecasts provided by YECL (T189-191; also see response to Undertaking #14, page 191, line 7 regarding YECL wholesale forecast updates for 2012/2013 provided at pages 299-300 of the transcript).

1.2 WHITEHORSE COPPER TAILINGS (WHCT) INDUSTRIAL SALES

Tab 2, Section 2.2.2.3 of GRA Application outlines forecast Yukon Energy industrial sales to WHCT starting in 2013.

No material issues were raised during interrogatories or the oral hearing regarding forecasts of the power requirements for WHCT in the test years.

The key issue raised regarding WHCT in interrogatories (YECL-YEC-1-20 and LE-YEC-1-9²³), in Exhibits filed prior to the oral hearing (Exhibit B-15) and in cross examination at the oral hearing (YECL cross at T108 to T122) relates to which utility should serve this industrial load. Yukon Energy's response to YECL-YEC-1-20 and Exhibit B-15, as summarized below, confirm the basis for YEC's intention to supply WHCT and for the wheeling approach that will be used to supply this industrial customer.

²⁰ Explains and provides calculations (in excel format) for normalized values which result in the decrease of 1 GWH HDD for 2011 sales.

²¹ YEC is not aware of any YUB Order approving the use of 10 year average HDD as a method of normalizing temperature sensitive sales.

²² YEC does not typically have access to YECL forecasts by customer class and cannot speak as to whether or how YECL weather normalizes its data.

²³ Confirms intention for WHCT to be a Yukon Energy customer. Notes customer will be required to pay for service in accordance with the approved Rate Schedule 39, and any applicable rate riders.

The response to YECL-YEC-1-20 confirms that YECL has existing distribution facilities to the WHCT mine site, and YECL has historically provided service to a customer located at the WHCT, but disputes YECL's claim that WHCT as an industrial customer should be served by YECL.

Exhibit B-15 provides additional information regarding the WHCT Sales Forecast and addresses the outcome of WHCT-related discussions between YEC and YECL since the Application was filed April 27, 2012.

- This exhibit attaches a letter from YECL to YEC on October 12, 2012 stating that it intends to serve WHCT as one of its customers, noting, "WHCT is in YECL's service territory and would be served electrical power over YECL's distribution system", and requesting that YEC amend its Application to reflect WHCT being served as a customer of YECL.
- Exhibit B-15 provides Yukon Energy's response on November 1, 2012 to the YECL letter and sets out Yukon Energy's position that the current GRA Application provides for continued consistency regarding how industrial customers are served in Yukon²⁴ as well as benefits for ratepayers²⁵, and indicates Yukon Energy proposes to serve WHCT by wheeling power over YECL's distribution system, the same way power is currently wheeled over YECL's system for YEC's service to its retail customers at Johnson's Crossing. The letter notes that the rate arrangement for such wheeling has been established in past proceedings before the Board²⁶, and that the same rate (8.298 c/kWh) currently applies to all energy sold under both rate schedules 51 and 42, as proposed in the Companies' Application for the 2009 Phase II Rate Application. Further, it is noted that Rate Schedule 51 has the same rate of 8.298 cents/kWh for all purchases by YEC from YECL throughout Yukon²⁷.

In addition to confirming the basis for the proposed wheeling and the fact that YEC has consistently served all major industrial customers in Yukon since securing its franchise in 1987, the evidence also confirms that, under any YEC revenue requirement approved by the Board for

²⁴ WHCT will be a "major industrial customer" as defined in OIC 1995/90, and therefore an industrial customer under Rate Schedule 39. Based on this definition and Rate Schedule 39, Yukon Energy has supplied all major industrial customers in Yukon since the NCPC transfer in 1987.

²⁵ The letter indicates that YEC serving YECL will save ratepayers approximately \$130,000 in 2013 based on WHCT's current forecasts, and potentially higher amounts in years after 2013.

²⁶ In the 2009 Phase II Rate Application, the Companies sought approval of amendments to Rate Schedule 51 (YECL Wholesales to YEC) to provide for a single energy-only rate that applies to all firm Yukon Energy purchases from Yukon Electrical throughout Yukon. Board Order 2010-13 approved this change in rate application for YECL wholesales to YEC, noting: "The Board agrees that Rate Schedule 51 should be an energy-only rate, applicable throughout Yukon and that it should be at the same level as the base for Rate Schedule 42."

²⁷ RS 51 specifies the current service locations from YECL to YEC at Johnson's Crossing and Marsh Lake; on this basis, the rate schedule itself is to be amended as required from time to time to include any new service location, e.g., WHCT.

2013, the rates required in 2013 by YEC to recover that revenue requirement will need to be increased if YECL rather than YEC was to serve WHCT.

1.3 OTHER INDUSTRIAL CUSTOMERS (MINTO AND ALEXCO)

Minto Mine

Tab 2, Section 2.2.2.1 of GRA Application outlines the forecast industrial sales to Minto Mine in the test years. UCG-YEC-1-20 (a) provides Minto mine 2009 to 2011 actual, January to May 2012 year to date actual, 2012 and 2013 forecast sales, measured and billed demand.

As noted and discussed at the oral hearing, the large reduction in updated forecast revenues as compared to the Application forecast reflects Minto mine actual sales which are consistent with the corrected forecast provided by Minto (see Exhibit # B-16 [YEC's Opening Statement] and discussion at transcript pages 300 and 301). Undertaking #2 as filed on November 19, 2012 notes that the full annual impact of the Minto corrected forecast for 2012 and 2013 is as follows:

- \$1.024 million reduction in 2012 forecast revenues; and
- \$1.806 million reduction in 2013 forecast revenues.

As noted in Part 1, based on the principle that GRA cost and sales forecasts are not to be adjusted to reflect subsequent events, Yukon Energy has not sought to adjust its Application to address this material change to 2012 and 2013 Minto sales forecasts.

Alexco Mine

Section 2.2.2.2 of GRA Application outlines the forecast industrial sales to Alexco mine in the test years.

Table 2 in UCG-YEC-1-20(b) provided actual (2010-2011) and forecast (2012-2013) measured and billed demand for Alexco mine. The response noted that in the GRA filing Yukon Energy erroneously used a 2012 and 2013 peak billing demand for Alexco of 3500 kVA for the purposes of forecasting revenues at existing rates. The effect of this error is to over forecast revenues by approximately \$0.22 million (2012) and \$0.16 million (2013). Yukon Energy will address the correction of this error in its compliance filing. During cross examination (transcript page 300), updated Alexco sales forecasts for 2012 and 2013 indicated, relative to Application forecasts, a small decline (0.5 GW.h) in 2012 and a small increase (1.2 GW.h) in 2013. As noted in Part 1, based on the principle that GRA cost and sales forecasts are not to be adjusted to reflect

subsequent events, Yukon Energy has not sought to adjust its Application to address these changes to 2012 and 2013 Alexco sales forecasts²⁸.

2.0 TAB 3 – REVENUE REQUIREMENT

Tab 3 of the Application reviews Yukon Energy's revenue requirement for the test years, including an overview, followed by more detailed consideration of key components (fuel and purchased power; non-fuel operating and maintenance expenses; rate base, depreciation and amortization; return on rate base (interest and ROE); and stabilization mechanisms (Rider F and the Diesel Contingency Fund [DCF]).

For the purposes of the Tab 3 part of the Argument, Yukon Energy will focus on the following key issues: fuel and purchased power and the updated diesel stabilization mechanism (DCF); labour expense (related to new positions); transmission brushing costs; administration costs (communications and DSM Administration); and issues raised regarding the Reserve for Injuries and Damages (RFID). Issues regarding ROE as proposed in the Application are addressed in Part 1 of this Argument. Capital cost issues and planning cost policy changes are addressed as part of the Tab 5 Argument. YEC will wait to respond to any other issues raised by intervenors relating to other revenue requirement components.

2.1 FUEL AND PURCHASED POWER AND THE UPDATED DFC

Tab 3 of the Application reviews the forecast costs of Fuel and Purchased Power for the test years in Section 3.1 and Section 3.2 (pages 3-2 to 3-5), Table 3.1 (Yukon Energy Revenue Requirement) and Table 3.2 (Fuel and Purchased Power). The 526% increase in fuel and purchased power costs forecast in 2013 compared to 2009 approved (as described at page 3-3) reflects higher loads, adjusted fuel prices, reactivation of an updated DCF (summarized at Section 3.6.2 and described at Appendix 3.2) that provides for forecast diesel generation based on annual long term average hydro generation, and specific test year transition measures that include only 59% to 66% of diesel requirements based on long-term average annual hydro generation²⁹. The forecast purchased power in the Application excludes provision for re-purchase of power wheeled over YECL's distribution system to serve WHCT (see Exhibit B-15 and Section 1.1 of Part 2 of this Argument), and this will be corrected in the compliance filing.

²⁸ Issues raised regarding Alexco mine also considered the implementation of the DSM audit recommendations and whether there would be any expansion of the Alexco facilities in the test years (CW-YEC-1-8).

²⁹ Tab 2, Section 2.3.2 reviews the growth in forecast diesel generation since the 2008/09 GRA in response to higher loads, the depleted hydro surplus and reactivation of the updated DCF with special transition mitigation measures. As described at page 3-5, forecast diesel generation is 7.5 GW.h in 2012 (at 65.6% of diesel requirement assuming long term average annual hydro generation) and 10.7 GW.h in 2013 (at 59.0% of diesel requirement assuming long term average annual hydro generation).

In summary, excluding matters related to the DCF, no substantive issues have been raised in IRs or the oral hearing regarding forecast fuel and purchased power costs for the test years.

The update and re-activation of the DCF as a stabilization mechanism is one of the key issues in the Application and in IRs (as well as in cross examination at the hearing). Key issues raised and the responses provided by YEC are summarized as follows (see also Part 1 of this Argument):

- **Purpose of the Fund, past practice, and basic operation** – the purpose of the DCF, its past practice when active from 1996 through 1999 (including past application regarding YECL's Fish Lake hydro generation) and its basic operation to stabilize diesel generation costs included in rates and YEC diesel generation costs each year (when active) have all been extensively addressed and described by Yukon Energy³⁰.
- **Fund Re-activation & Changes to reflect current system configuration** – as noted in the Application, IRs and in cross examination at the oral hearing, YEC has previously noted that prior to re-activation, the DCF mechanics needed to be updated to reflect the current system configuration. Specifically, the 2008 Diesel Contingency Fund Filing attached to UCG-YEC-1-12(c) or to CW-YEC-1-25 noted "*DCF operating rules will require attention in future to address a number of circumstances, including updating long term average hydro generation values, "fund triggers" and potentially a means to address secondary sales*". Board Order 2011-15 required that YEC provide a specific definition of the term "diesel on the margin" at its next GRA,³¹ and this was addressed in the Application (Appendix 3.2, Attachment 3.2, page 3.2-4 which notes that the proposed updated approach the DCF would be permanently switched "on" as of January 1, 2012 through a formulaic approach, i.e., there will no longer be a "diesel on the margin" test for activating the DCF.
- **Explanation of new formulaic approach used in updated DCF** – Tab 3, Attachment 3.2 of Appendix 3.2 of the Application details the new formulaic approach proposed by YEC to determine the quantum of diesel generation in rates. This approach is discussed and described in further detail in the several interrogatory responses: YUB-

³⁰ The basis for the DCF was addressed extensively in the Application in Appendix 3.2 which reviews in detail the history and purpose of fund. Further discussion re: historic use of the fund is provided in UCG-YEC-1-12. CW-YEC-1-25 attaches a copy of the last report to the YUB (the 2008 report). The history of the DCF was also reviewed with Board counsel by Osler at transcript page 569, line 6 to transcript page 571, line 20; a continuity schedule for the DCF was provided in response to Undertaking #23 (page 572, line 16) filed November 19, 2012, and basic operation of the DCF was reviewed at transcript page 573, line 10 to transcript page 574, line 22.

³¹ Order 2011-15 noted "The Board accepts the commitment of YEC to address all DCF issues in the next GRA and directs YEC to address any changes necessary in the operating rules, administration and revised revenue requirements pertaining to the DCF in its next GRA. Also, the Board requires that YEC provide a specific definition of the term "diesel on the margin". The Board directs that YEC complete its review and bring the necessary changes before the Board at the earliest of its next GRA or July 1, 2012."

YEC-1-30(b)³², YECL-YEC-1-16 and YECL-YEC-2-1;³³ CW-YEC-1-24(a) and (b)³⁴; CW-YEC-2-2 (referencing CW-YEC-1-24)³⁵.

- **Transition to LTA Diesel Generation Cost Recovery** – The transition measures proposed in the Application for moving to full long term average diesel generation cost recovery have capped the current rate increase at 6.40% in 2012 and 6.50% in 2013. As a result, diesel generation included in the proposed revenue requirement equals 65.6% of long term average (LTA) annual costs in 2012 and 59.0% in 2013. Responses to IRs have reviewed the rationale for these transition percentages of LTA (YUB-YEC-1-7(i)), provided an explanation regarding why a transition to LTA diesel generation levels is required in rates to address growing grid loads (YUB-YEC-1-12), and reviewed the factors in addition to rate impact mitigation (e.g., favourable current water conditions, potential transition to lower cost LNG) supporting the transition approach applied in the test years as well as confirmation that a specific year is not proposed for 100% LTA diesel generation costs in rates (LE-YEC-1-5; LE-YEC-2-2).
- **Ratepayer Cost Risks related to Drought** – The increased need for baseload diesel generation signals increased ratepayer risks related to low water or drought conditions when costly requirements for diesel generation can greatly exceed 100% of LTA diesel generation costs (this matter is addressed in Appendix 3.2, and was extensively reviewed with Board counsel by Osler, T575, line 4 to T578, line 16). The evidence confirms that the DCF as currently funded would not be able to address the added diesel costs associated with a single extreme drought year, let alone a series of extreme low water years.
- **Secondary Sales Revenues now go to DCF** – The updated DCF will now have all secondary sales revenues go to the DCF rather than to YEC in order to help mitigate ongoing ratepayer risks. The implications of this change were reviewed during cross exam (see T45 and T294).

2.2 LABOUR EXPENSE

The increase in 2012 and 2013 forecast labour expense compared to 2009 approved costs reflects additional positions (12.26 increase FTEs in 2012 forecast compared to 2009 approved),

³² YUB-YEC-1-30(b), YECL-YEC-1-16 and YECL-YEC-2-1 provide numerical examples in excel format of the DCF operation for different grid hydro generation variations.

³³ Additional scenarios that show the impacts on the DCF and ERA based on increases and decreases in Wholesale and Retail & Industrial loads relative to the GRA Forecast.

³⁴ Attaches pro forma monthly report.

³⁵ Provides further numerical examples of DCF additions, withdrawals, opening and closing balances and secondary sales credits for varying existing grid hydro conditions and variations higher or lower than existing grid hydro conditions (by 10% and 20%).

as well as negotiated and step increases (average annual increase in salaries per FTE is 4.3% from 2009 approved to 2013 forecast). The justification for labour cost increases in the test years was extensively reviewed in interrogatories and in cross examination at the oral hearing.

Detailed information is provided in Tab 3, page 3-7 to 3-17, and in Tables 3.3, 3.4, 3.5, 3.6, 3.7, 3.8 and 3.9. Further, explanation and justification and explanation for increases in labour costs was provided in response to the interrogatories. The increase in labour costs is discussed in YUB-YEC-1-14³⁶; YUB-YEC-1-16 (a);³⁷ a breakdown of labour expense components is provided in UCG-YEC-1-26(a);³⁸ further detail regarding compensation levels and ranges for recruited employees is provided in UCG-YEC-1-33(f); and detail regarding union vs. non-union labour costs is provided in UCG-YEC-1-23 and UCG-YEC-2-3. Other issues are addressed in YUB-YEC-1-14(d) and (f)³⁹; and YUB-YEC-1-14(a)⁴⁰.

Employee Complement History

Table 3.4 (in Tab 3, page 3-7) reviews the Employee Complement History (net of allocation to YDC)⁴¹. Further detail and explanation regarding the employee complement history as set out in Table 3.4 is provided in the following IR responses: UCG-YEC-1-28⁴²; CW-YEC-1-16⁴³; YECL-YEC-1-46(b)⁴⁴; and UCG-YEC-1-26(c)⁴⁵.

The response to UCG-YEC-1-26 (c) (related to how YEC and YDC related costs are tracked and allocated within YEC's revenue requirement) was further clarified and a correction was provided at the oral hearing (November 14, 2012). It was noted (transcript pages 539-40) that there was an error in the Application with respect to Table 3.4. It was noted that 0.71 positions are allocated to YDC (0.5 President and 0.21 Finance). The allocation of labour dollars for determining the revenue requirement did not include the 0.21 for finance – it was noted that this was approximately a \$30,000 reduction in revenue requirement for each test year.

³⁶ Part (b) addresses 2009 actual compared to 2009 GRA compliance; part (c) provides a breakdown of increases in labour costs in Table 3.3 between step increases, negotiated settlements and new positions.

³⁷ Provides explanation for increase in actual production labour costs compared to approved labour costs in 2009; and an explanation for increase in forecast labour in 2012 over 2009.

³⁸ Production, Transmission, Distribution, General O&M and Administration.

³⁹ Confirms that YEC does not currently employ a variable pay program.

⁴⁰ Confirms that contractor and consultant costs are not included in labour expense category.

⁴¹ Issues related to vacancies and vacancy rates were addressed in the following IRs: CW-YEC-1-17(c) (current organizational chart for corporation and with current vacant positions noted); YECL-YEC-1-46 (complete organization chart from 2009 to 2011 actual and 2012 and 2013 forecast; part (c) of this response provides corporate vacancy rate); YUB-YEC-2-12 (explains how the vacancy rate for test years was forecast and also explains why the same vacancy rate is forecast for each department).

⁴² Updates Table 3.4 with 2011 Actuals.

⁴³ Provides the percentage salary increases by year by department. YUB-YEC-1-13(e) provides Yukon CPI by year.

⁴⁴ Expands Table 3.4 to identify the portion of the employee complement separately charged to O&M and Capital.

⁴⁵ Explains how YEC and YDC related costs are tracked and allocated within YEC's revenue requirement.

Additional FTE Positions

The Application at pages 2-11 to 3-17 provides a detailed justification for the added positions. This was also discussed at the oral hearing.

Generally, new positions were added to reflect increased workloads as the utility deals with increased growth, increased assets, increased regulatory requirements and need to perform detailed and multi-year planning⁴⁶. In the absence of these additional staff positions this work would have had to be conducted at higher cost by consultants.

In sum, it has been demonstrated that added positions are required for continued efficient, safe and reliable operation of the utility, that each added position was carefully reviewed prior to being added to ensure that the costs are reasonable and prudently incurred, specifically, new positions must be thoroughly justified in part to ensure the work required is recurring and permanent⁴⁷ (otherwise it would be more cost efficient to hire consultants for the period of time that increased work load is required)⁴⁸.

Additional justification for specific positions has been provided in the following interrogatory responses or at the following transcript references:

- YUB-YEC-1-21 (a) details difference in roles and responsibilities of Manager of IT and the Network Administrator. This was also discussed in cross examination (Transcript 541, lines 14-25 to Transcript page 544) where it was noted that the manager of HR had previously been responsible for the IT department prior to the network administrator being promoted to manager of IT. This change was based on considerations related to total workload (see page 542, lines 2-19), and technical expertise. Mr. Mollard noted "the ability to have a manager who had sort of day to day responsibility for dealing with technical issue as they came up, we found that to be just more efficient in getting their job done." (page 542, lines 20-25). It was further noted that this promotion did not increase the number of IT personnel (page 544, line 5)
- YUB-YEC-1-22 provides rationale and support for adding SLQ/ Sharepoint administrator. This was further addressed in cross examination at transcript pages 544 to 545. It was noted the position was created in 2009 and staffed in 2010 (lines 12-14); discussion also noted that the approximate outsourcing costs were the work to be performed by a third party. Mr. Mollard notes at page 545, lines 1-9 that the person hired is fully engaged, "on

⁴⁶ YUB-YEC-1-20(h) added positions are required to address continued and growing requirements related to growth on the integrated system.

⁴⁷ LE-YEC-1-16(b) notes that six of the new positions have been added on a term basis and are scheduled to end within the next four years.

⁴⁸ See YUB-YEC-1-16(c).

rough numbers, a 2,000 hour work year, less a couple of hundred hours for leave and training and that sort of thing, you'd be looking at –and \$100 an hour I would argue is a bit light on the rate, but it's probably \$150,000 in consulting fees at least. Plus you'd have to travel because there's that - - that particular skill does not exist in Yukon that I'm aware of."

- YUB-YEC-1-20(h) notes the manager, resource planning and resource planning engineer are both required to boost the capacity of YEC's planning group given the unprecedented levels of planning being undertaken to meet load growth on the system. This was addressed in cross examination at transcript pages 545 to 550. Mr. Morrison noted the need to recruit this position, noting the director of resource planning is still sitting vacant, and the job is being done partly by the president, the director of special major projects and the vice president.
- YUB-YEC-1-20(h) explains how the resource planning engineer hire has reduced consultant costs and also notes that the modeling and analytical skills the Resource Planning engineer provides enhance Yukon Energy's ability to oversee and coordinate planning project work including ongoing system forecasting related analysis. This was addressed in transcript at page 548 where it was noted that YEC was "repatriating modeling" and "bringing that back in house so it wasn't being outsourced in terms of the water or power benefits model and our water management model, and the ability to manager contractors and conduct and give advice to senior management on environmental and resource planning issues, we were constantly outsourcing all of that work. So we looked at the numbers and felt that there was some real benefit in us brining those positions in house. These were positions that were recruited locally and our ability to do that also helped us kind of make that decision."
- YUB-YEC-1-20(i) explains the expected return to YEC due to the hire of the Manager, Energy Conservation (in terms of MW.h of energy and MW of capacity saved through energy conservation programs). The energy conservation office was discussed in cross examination at transcript pages 555 to 557.
- YUB-YEC-1-20(i) explains the expected return to YEC due to the hire of the Energy Conservation Administrator (in terms of MW.h of energy and MW of capacity saved through energy conservation programs). The energy conservation office was discussed in cross examination at transcript pages 555 to 557.
- YUB-YEC-1-23 (re Backfill Controller) explains that YEC considered it would be more cost effective to move the Controller to manage the implementation of the new financial system (and hire a backfill controller) rather than hire a new employee or hire a

consultant. The backfill controller and financial administrator positions were discussed in cross examination at transcript pages 556-560.

- At transcript page 560, lines 8-10 it was confirmed that the communications and protection control technologist has now been staffed.
- At transcript page 560 to 561 the permanent part time plant operator - Faro position was discussed.
- At transcript page 561, lines 18-25 and page 562 the capital mechanic position and capital electrician positions were discussed.

In sum, it has been demonstrated that added positions are required for continued efficient, safe and reliable operation of the utility, that each added position was carefully reviewed prior to being added to ensure that the costs are reasonable and prudently incurred, and specifically, new positions must be thoroughly justified in part to ensure the work required is recurring and permanent⁴⁹ (otherwise it would be more cost efficient to hire consultants for the period of time that increased work load is required)⁵⁰. Added positions are also required to address transition planning within the utility (i.e., to address planned retirements within the test years). See transcript page 550, lines 14-18 where Mr. Morrison notes "we're also experiencing over the next few years, some fairly significant potential retirements, me, maybe some others, and we are trying to make sure that we've got the right structure in place and the right people in place so when that happens, there's a pretty smooth transition."

2.3 TRANSMISSION BRUSHING COST

Tab 3, Section 3.3.2 and Table 3.6 provide summary of transmission costs and explanation regarding variances in labour and non-labour costs in the test years compared to 2009 Approved costs. Further detail on transmission expense and explanations regarding variances in transmission expense was provided in the following interrogatories: UCG-YEC-1-30;⁵¹ CW-YEC-1-18;⁵² and YECL-YEC-1-45⁵³.

⁴⁹ LE-YEC-1-16(b) notes that six of the new positions have been added on a term basis and are scheduled to end within the next four years.

⁵⁰ See YUB-YEC-1-16(c).

⁵¹ Updates Table 3.6 with 2011 Actual results and provides explanation for any variances);

⁵² Provides a detailed explanation of the increase/decreases year by year for Transmission Labour, Brushing and Other Non-Labour expenses in Table 3.6; also provides Table 3.6 showing each category of annual transmission cost on a \$/km transmission line basis);

⁵³ Details costs for 2009 to 2013 broken out as follows: supervision and engineering; overhead line maintenance; underground line maintenance; substation maintenance; brushing; meter and meter testing; service to outside parties; transformer repair and maintenance and street light maintenance.

Yukon Energy was directed in Order 2009-8 to undertake a study into brushing activities of similar utilities and report its findings to the Board, and also to include a written brushing policy to outline YEC's approach and explain the manner in which the budget for any year was derived. Tab 3, Pages 3-8 to 3-9 discusses each of the studies undertaken and the recommendations. The ECI study recommendations and YEC's response were also discussed in the following key IRs: LE-YEC-1-32⁵⁴; LE-YEC-1-36⁵⁵; and LE-YEC-1-35⁵⁶. The studies and recommendations were also addressed in the transcript at page 529 to 538. In particular the discussion at page 533 lines 15 to 20), corrected an error in the response to LE-YEC-1-32(b) and confirmed that YEC has completed work on all of the critical priority areas.

Yukon Energy was also requested to provide specific explanations regarding increases in brushing costs. These were provided in YUB-YEC-1-17; YUB-YEC-1-18; YUB-YEC-2-9 and UCG-YEC-2-7.

- **YUB-YEC-1-17** explains the comment in Tab 3 of Application that completion of CSTP will result in higher transmission costs and notes first time brushing costs are capitalized as part of the related capital project; explains the increased costs for brushing activities and how these relate to the annual brushing plan; provides the cost of each of the brushing studies undertaken by YEC⁵⁷;
- **YUB-YEC-1-18** reviews third party costs involved in brushing studies and field testing in 2012; explains that third party costs involved with the brushing studies and field testing were included in the transmission line brushing forecast; explains that no costs related to the brushing studies and field testing were allocated to distribution costs in table 3.7; explains how use of IVM methods will reduce transmission brushing costs⁵⁸;
- **YUB-YEC-2-9** provides explanation regarding impact or consequences of loss of 2 powerline technicians in 2010 on quantity or quality of transmission line brushing program or activities in 2010; provides explanation regarding why brushing expenses cannot be maintained at 2010 spending levels in future⁵⁹.

⁵⁴ Describes the recommendations being field tested; details whether there are any recommendations YEC disagrees with or considers impractical and provides rationale.

⁵⁵ Explanation regarding why YEC did not complete brushing on all the recommended priority spans in 2011.

⁵⁶ Clarifies the Mayo-Keno City line is a single pole structure with H-Frame dead-ends and identifies the line being listed as of H-frame construction as a typographical error.

⁵⁷ Specifically, work completed by ECI to assess current conditions and review and recommend improvements to the existing brushing program; and YEC participation in jointly funded multi-utility survey of best practices in brushing conducted by CEATI.

⁵⁸ This IR notes the expected savings from IVM were calculated by the consultant in the report (Appendix 12.2 pages 12.2-33 and 34).

⁵⁹ The IR references pages 12.2.-22 of Attachment 12.2 (page 21 of the Yukon Energy Corporation transmission vegetation conditions assessment prepared by ECI) which notes This notes that the cyclic brushing plan and integrated

- **UCG-YEC-2-7** provides explanation regarding why any transmission and distribution costs increased above annual inflation rate between 2011 and 2012 and between 2012 and 2013 and cross references and attaches responses to YUB-YEC-1-17 and YECL-YEC-1-18.

2.4 ADMINISTRATION COSTS

Section 3.3.5 and Table 3.9 provide summary of administration costs and explanation regarding increases in labour and non-labour costs in the test years compared to 2009 Approved costs. UCG-YEC-1-33(a) updates table 3.9 with 2011 Actuals; UCG-YEC-1-33(c) explain variances between 2011 actual, 2012 forecast and 2013 forecast administration cost level compared to 2009. For the purposes of this part of the Argument YEC is focusing on cost items that received more attention in interrogatories and cross examination at the hearing. YEC will wait to respond to any issues raised by intervenors relating to any other administration cost items.

DSM Administration

This is a new administrative expense category in the test years, with forecast expense of \$0.049 million in each of 2012 and 2013). Expenditures included in DSM Administration costs may include administration and other general overhead expenditures, staff training and specific expenditures related to information programs and advertising that are not directly attributed to a specific DSM program.

The DSM Accounting Policy is reviewed in Tab 3, page 3-12, Tab 5, Page 5-41 and in Appendix 5.2 of Tab 5 (where the proposed policy is appended), as well as the following interrogatory responses: YUB-YEC-1-38⁶⁰; CW-YEC-1-34; YUB-YEC-2-11⁶¹, and YUB-YEC-1-20 (e) to (g)⁶².

- YUB-YEC-1-20(b) notes there is no overlap with 'information programs and advertising' costs accounted for under the DSM department.
- Transcript page 27 and 28 and Undertaking #3⁶³ and Undertaking #4⁶⁴ provided further detail regarding DSM expense charged to this category; at page 28 Mr. Mollard notes:

vegetation management plans (created by ECI under its Transmission Vegetation Conditions Assessment have identified a need for a substantial increase of funds to the transmission brushing program in order to deal with a backlog of brushing that is urgently required.

⁶⁰ Notes the impetus for and rationale underlying the proposed DSM accounting policy provided as Appendix 5.2.

⁶¹ Addresses treatment of utility improvement and corporate costs in DSM in other jurisdictions.

⁶² YUB-YEC-1-20(e) reviews the legislative authorities for the inclusion of YEC's DSM policy in this Application and how YEC's DSM policy provides service to the public; YUB-YEC-1-20(g) notes the administrative expenses related to DSM would still be included in YEC's 2012/13 revenues requirement forecasts if the Board were to deny DSM costs.

“the account would be picking up items such as rent expense on the DSM office, for example, and costs associated with the running of that office - supplies, general office supplies, phone bills, that sort of thing that wouldn't be directly attributable to the programs”.

YUB-YEC-1-20(g) (the administrative expenses related to DSM would still be included in YEC's 2012/13 revenues requirement forecasts if the Board were to deny DSM costs).

Communications

Communications costs show a forecast increase of \$0.201 million by 2012 over 2009 approved expense and a decrease by \$0.011 million in 2013 from 2012 forecast. Increased costs relate to implementation of an on-going public information campaign which accounts for approximately \$0.2 million of the total budget and \$0.05 million for upgrading YEC's web site.

YUB-YEC-1-20 (a) and (b) provides further detail regarding the public information campaign, a justification for the level of expense; and program benefits for ratepayers. YUB-YEC-1-20 and YUB-YEC-2-13 justify the current level of expense noting:

- Yukon Energy is a publicly owned utility operated for and by Yukoners.
- Surveys undertaken by Yukon Energy in 2011 identified that Yukoners want to remain engaged in discussion around the territory's energy issues and the Corporation's objectives.
- Public input helps Yukon Energy make decisions regarding energy investments and strategic planning and also provides valuable input towards project planning.
- Ratepayers and the public also benefit through the ability to ensure stakeholder and other perspectives are incorporated into utility decision-making processes. For meaningful, two-way communication ratepayers need to be aware of what Yukon Energy's goals, plans and challenges are.
- In this regard, information needs to be widely and effectively communicated.

YUB-YEC-2-13⁶⁵ provides detailed information and support regarding the success of the public information campaign, noting that it has resulted in a significant amount of people accessing

⁶³ See November 16 Filing of Undertakings – this undertaking notes Actual 2012 Expenditures of \$54,000 related to labour, training, membership dues, office materials/services, rent and phone/internet.

⁶⁴ See Transcript page 82 and 83 and Exhibit B-19 – Exhibit B-19 notes forecast expenditures of \$49,368 related to rent and lease payments; travel; materials, supplies and services; contractors and consultants; utilities; and communications.

⁶⁵ YUB-YEC-2-13 provides additional information regarding YEC's public information campaign; breakdown of each cost and further information regarding the success of the campaign, how this is tracked; explanation regarding how this

Yukon Energy's public information and resources – the increased number of individuals accessing YEC's communication tools indicates that ratepayers are receiving significant information related to the activities of the Corporation and in this regard the program has proven very successful.

2.5 RESERVE FOR INJURIES AND DAMAGES (RFID)

RFID allows for an appropriate balance to be maintained between self-insurance, deductibles, commercial insurance and sudden and accidental losses; and allows such costs to be smoothed over a number of years to avoid rate instability for ratepayers. Section 3.3.6 and Table 3.10 provide a summary of Insurance and Reserve for Injuries and Damages costs.

YECL-YEC-1-51 reviews claims charged to the reserve and provides a justification for these costs to be charged to the reserve.

In Order 2009-8, following the 2008/2009 GRA, the Board ordered Yukon Energy to undertake a risk management study of other utilities and to provide a written policy outlining the criteria for charging items to the RFID. The studies were undertaken, as directed, in order to support the development of an RFID policy for Yukon Energy and to respond to concerns raised by the Board and intervenors in the last GRA (See Tab 6, Pages 6-9 to 6-12).

- The proposed RFID policy is provided as Appendix 3.1 to Tab 3; and
- The directed studies are provided in Tab 12 Appendix 12.3 and Appendix 12.4.

The policy was developed after YEC had AON undertake a survey of other utilities [provided in Appendix 12.3], as well as a general liability and commercial property retention analysis [provided as Appendix 12.4 of Application). The policy outlines clear criteria for charging items to the reserve as detailed in the following interrogatory responses: YECL-YEC-1-51; CW-YEC-1-23; YUB-YEC-1-28(c) and (d). In particular, CW-YEC-1-23(g) addresses the criteria for charging items to the reserve; and YECL-YEC-1-51(a) reviews the process for review and approve of charges to the reserve.

In response to concerns raised by the Board and intervenors during the 2008/2009 General Rate Application Yukon Energy also had an actuarial consultant prepare an actuarial valuation of YEC's RFID as at December 31, 2009 – which demonstrates \$195,000 to be appropriate for the annual

campaign has benefits ratepayers; why the communications budget did not decrease by \$0.05 million in 2013 (if the website upgrade cost is \$0.50 million).

appropriation to the RFID [Appendix 12.5]. Table 3.11 (Tab 3) further demonstrates the justification to increase annual appropriations to the RFID to at least \$195,000⁶⁶.

Further questions were raised regarding the rationale for applying the remaining funds in the Faro Dewatering Account against the outstanding balance in the reserve. The rationale for this approach was addressed in the Application (page 12) and in YUB-YEC-1-6 and YUB-YEC-2-5. The funds available in the Faro Dewatering Account have in proceedings since the 2005 Required Revenues and Related Matters proceeding been applied against outstanding balances in the RFID Account (as in the 2008/2009 GRA) or to address revenue deficiencies (for example following Order 2009-8). An alternative would be for the full outstanding balance of the Reserve for Injuries and Damages to be included in rate base. Absent application of the remaining funds in the Faro Dewatering Account the GRA would include costs of approximately \$0.116 million per year to amortize a remaining balance of \$0.578 million (an additional \$0.080 million in annual amortization costs would be added to the revenue requirement) [see, YUB-YEC-2-5].

⁶⁶ As noted in Table 3-11, the 10-year average of actual expenses is \$0.229 million; and actual expenses were \$0.133 million in 2009, \$0.421 million in 2010 and \$0.246 million in 2011.

3.0 TAB 5 - CAPITAL PROJECTS

For the purposes of this part of the argument YEC will focus on the major capital projects and major deferred costs affecting the test years as set out in Section 5.2.1 and Section 5.3.1 of the Application, the planning approach adopted when incurring deferred costs to assess new projects, and the updated planning cost accounting policy as set out in Appendix 5.1 of the Application.

A summary of the rationale and justification for each major project is provided in Tab 5 of the Application; referenced IRs provide further detailed supporting information.

YEC will wait to respond to any issues raised by intervenors relating to any capital or deferred projects under the \$1 million threshold used in the Application, as well as any issues relating to DSM accounting policy (Appendix 5.2) or the Mayo B Flexible Note (Appendix 5.3).

3.1 MAJOR CAPITAL PROJECTS SUBJECT TO PRIOR YUB REVIEW PROCESSES

Carmacks-Stewart Transmission Project – Stage 2; Mayo Hydro Enhancement Project and Aishihik Third Turbine Project have each been subject to prior detailed YUB review where the business case for proceeding with these projects was subject to rigorous public review and testing. The current Application has demonstrated the clear benefits to ratepayers from proceeding with and completing these projects in the test years.

The prudence of costs incurred by YEC on these projects has been examined in detail and confirmed in the Application and subsequent IRs.

Overall, the net rate base increase from these projects approximates \$43.8 million related to approximately \$172.3 million capital costs (less approximately \$128.5 million of government/YDC contributions) for projects in-service prior to December 31, 2011.

- 1. Carmacks-Stewart Transmission Project Stage 2** – As reviewed in Application section 5.2.1.1, the business case for this project was reviewed by the YUB in the 2006 Resource Plan, in the 2007 Part 3 review of CSTP, and in the 2008-09 GRA (response to YECL-YEC-1-8 REVISED [provided as Attachment 1 to CW-YEC-1-27]). As proposed in the Application, the \$41.9 million forecast contributions will fully offset the \$41.9 million final estimated costs and there is no impact on requested rates. Please also see response to CW-YEC-1-26 and UCG-YEC-1-49.
- 2. Mayo Hydro Enhancement Project (Mayo B)** – As reviewed in Application section 5.2.1.2, the business case for this project was reviewed by the YUB in the 2008-09 GRA

(response to YECL-YEC-1-5 REVISED provided as Attachment 1 to this response) and in the subsequent Part 3 review.

- a) The budget cost for the Mayo B project was \$120 million (including \$1.5 million for the Mayo Lake project licensing), with a forecast net rate base cost of \$36.5 million after Yukon and federal government contributions. As proposed in the Application, the net rate base cost forecast at \$35 million reflects forecast project costs of approximately \$116.6 million that are forecast to be offset by federal and Yukon Government/YDC contributions of approximately \$81.6 million⁶⁷.
- b) The project is designed to increase hydro generation capacity installed on the Mayo River from approximately 5 MW to approximately 15 MW⁶⁸.
- c) The project will reduce forecast diesel generation (at long term average hydro generation) by 20.7 GW.h in 2012 and 22.3 GW.h in 2013⁶⁹.
 - i. This will result in forecast savings in diesel generation fuel costs of approximately \$5.9 million in 2012 and \$6.4 million in 2013, and forecast savings in diesel O&M costs (at 3c/kW.h per 2009 GRA) of approximately \$0.6 million in 2012 and \$0.7 million in 2013.
 - ii. Based on the GRA's proposed percent of long term average (LTA) diesel generation to be included in the revenue requirement, these cost savings impacts on the revenue requirement would be approximately \$4.3 million for 2012 (66% LTA) and \$4.2 million for 2013 (59% LTA).
 - iii. The overall net revenue requirement impacts of Mayo B result in savings of \$2.9 million in 2012 and \$2.5 million for 2013. (See UCG-YEC-1-49).

3. Aishihik Third Turbine Project – As reviewed in Application Section 5.2.1.3, the business case for this project was reviewed by the YUB in the 2006 Resource Plan review, in the 2007 Part 3 review of CSTP, and in the 2008-09 GRA. As proposed in the Application, the net rate base cost is forecast at \$8.8 million, after \$5 million Yukon Government contributions.

The Application and numerous IRs addressed in detail the issues and circumstances related to AECOM materially underestimating the costs to undertake the project and

⁶⁷ **CW-YEC-1-27** provides a side-by-side comparison of the cost breakdown provided as CW-YEC-1-5 Table 1 in the Mayo B Facilities hearing (attached) and the \$116.6 million actual costs and an explanation of any variance greater than ±5%. **YUB-YEC-1-33** and **YECL-YEC-1-33** address issues related to the Project scope and confirm any explain why other projects at the Mayo plant were not included as part of the Project costs, i.e., Mayo Heat gate is considered an improvement to the existing plant and only \$0.750 million of Mayo Substation costs were allocated to the Mayo B Budget.

⁶⁸ **YUB-YEC-1-4** provides Mayo A and Mayo B rated capacity and operating output. See also YUB-YEC-2-3.

⁶⁹ **CW-YEC-1-27(e)** also provides an analysis of the costs and benefits of the Mayo B project based on actual costs, contributions and forecast sales in the same format as YUB-YEC-25 Attachment 1 in the Mayo B hearing.

Yukon Energy's response (see YUB-YEC-1-34⁷⁰). In sum, the costs included in the GRA Application are materially higher than the 2008/09 GRA estimate of project costs⁷¹; however, this cost increase was not an imprudent cost overrun – bids received after tender both by AECOM and Yukon Energy determined that the more accurate estimates were approximately \$13 million, not \$8.8 million.

Yukon Energy made a decision to proceed with the project only after a full review of the project's feasibility was undertaken and it was determined that the project would still provide material benefits to ratepayers due to diesel displacement savings - - even at the higher estimated cost (see response to CW-YEC-1-28⁷²).

Notwithstanding final estimated costs were higher than the original engineering cost estimates, the Aishihik Third Turbine Project is very attractive relative to diesel generation and will help to materially reduce ratepayer costs in the test years and beyond the test years. At the revised forecast net capital cost and a wide range of grid loads (i.e., 450 GW.h/year and higher) the levelized cost of energy (LCOE) for the project approximates 9 to 11 cents/kW.h over an assumed 65 year economic life (Application, page 5-9)⁷³. Accordingly, this project is forecast to provide a net economic benefit to Yukon ratepayers over its economic life solely on the basis of its expected displacement of diesel generation.

Pursuant to generally accepted principles of rate regulation, if utility costs are determined to be reasonable and prudently incurred then the utility is entitled to recover such costs through rates. In the circumstances of Aishihik Third Turbine, the appropriate test is not whether the costs were materially higher than forecast based on earlier engineering cost estimates, but whether such costs were prudently incurred and necessary to complete the project. Based on this test, the costs as incurred for this project should all be included in the approved rate base.

⁷⁰ **YUB-YEC-1-34** discusses steps YEC has taken to avoid past issues relating to estimating and the recourse Yukon Energy has taken against AECOM for the underestimation of project costs.

⁷¹ **YUB-YEC-1-5** provides the original cost estimates for the project and scope and cost changes since the original cost estimates were provided. **LE-YEC-1-21** also notes completed scope did not change from project scope contemplated initially. This IR provides detailed cost listings of the projected final cost by component and by contractor (including YEC internal costs). **YUB-YEC-2-4** addresses scope changes between the 2006 Resource Plan and 2010].

⁷² **CW-YEC-1-28** provides peaking capacity and "long-term average hydro energy supply" added to the system by this project (page 5-6, lines 25-26); provides the NPV analysis of the benefits of this project mentioned in footnote 3, page 5-7 of Application (analysis from 2007 CSTP Part 3 hearing); provides the analysis that led YEC to conclude in August 2010 that this project was still beneficial (page 5-8, lines 16-19 of Application); provides the original costs of this project as of August 2010 by component and the actual costs in the same detail with explanations for variances greater than ±5% between estimated and actual.

⁷³ Response to Undertaking #25 (page 584, line 21) filed November 19, 2012, shows diesel displacement with this project and Mayo B at 3.4 GW.h/year at a grid load of 450 GW.h/yr load (versus 4.3 GWh/yr with no Mayo B) and 4.4 GW.h/yr at 500 GW.h/yr load (versus 4.8 GW.h/yr with no Mayo B).

3.2 MAJOR CAPITAL PROJECTS REQUIRED TO ENSURE SYSTEM SAFETY AND RELIABILITY

Four major capital projects (see below) were undertaken to address issues related to existing infrastructure that were required to be addressed to ensure safe and reliable operation of the Yukon grid. They were not new supply options or greenfield projects. The business cases for these projects consequently focused on addressing the need for the project and ensuring accurate and complete estimation of costs rather than on a traditional cost benefit assessment, and the evidence confirms that forecast costs on these four projects were prudently incurred. Overall, the net rate base increase from these four projects is forecast at approximately \$19.1 million:

- 1. Mayo Hydro - Substation Enhancement** – As reviewed in Application Section 5.2.1.4, the project was undertaken to ensure system reliability and safety and to accommodate forecast loads. The facility is 50 years old and in need of major refurbishment and upgrades to continue operating in a safe and reliable manner, and to address (among other matters) outstanding concerns documented in the June 2004 BC Hydro Engineering report No Es94 and the need to maintain appropriate service for the Mayo A generators, Dawson and Elsa transmission Lines, and the local Mayo town distribution. In addition, many ongoing changes on the Yukon grid require material investment in the Mayo substation to ensure that it is equipped and fully capable of addressing those changes including interconnection of WAF and MD grids, the addition of Mayo B, and the addition of industrial loads in 2010 and beyond. The project is not specifically driven by any of these factors alone, but is a needed system improvement to address the confluence of all of these factors at this point in time.

The Application reviews why the work was undertaken at this time, and how overall efficiencies were gained through coordination with other projects being undertaken (Mayo B and CSTP Stage 2)⁷⁴. The net rate base cost is forecast at approximately \$10.15 million⁷⁵ for completion in 2012⁷⁶.

⁷⁴ **UCG-YEC-1-51** notes the timing for this project was primarily driven by existing system requirements. The completion of the CSTP2 and Mayo Hydro Enhancement (Mayo B) Projects advanced the Mayo Substation Project by approximately one to two years. Advancing the project also allowed Yukon Energy to take advantage of the tendering process on CSTP2 to purchase the bulk of the substation equipment (i.e. switches, breakers) through that tendering process – saving the cost of that work. With regard to Mayo B, this allowed YEC to take advantage of, and gain efficiencies from, the contractors being on site (i.e. PKI, etc.) and to utilize the outages planned for the Mayo B work to complete some of the Mayo Substation work.

⁷⁵ Provides a component breakdown by year for the Mayo Hydro Substation Enhancements for 2010, 2011, 2012 and 2013.

⁷⁶ **YUB-YEC-1-33; CW-YEC-1-29; LE-YEC-1-22** explain why only a portion of this project's costs was allocated to Mayo B project and justification for the allocation.

- 2. Mayo Head Gate Repairs** – As reviewed in Application Section 5.2.1.5, the project was undertaken to ensure plant reliability and safety. The existing reinforced concrete intake was constructed in the 1950s. In order to ensure continued safe and reliable operation, it needed replacement and upgrading to address ongoing deterioration and to ensure the intake gate is brought into compliance with current dam safety standards. The Application reviews the outcomes of an outside third party expert inspection of the intake gate in 2009, and the steps initially taken in response to that inspection including the assessment of options and the reasons behind choosing the preferred alternative. It also describes why this work was required now, and why it was coordinated with Mayo B⁷⁷. As proposed in the Application, the net rate base cost is forecast at approximately \$1.3 million for completion in 2012.
- 3. Aishihik Generation Station Redundancy** – As reviewed in Application section 5.2.1.6, the project was undertaken to rectify a serious system reliability issue identified as a result of a major system outage on January 29, 2006. This outage identified serious security of supply issues to Whitehorse during peak winter times. Attachment 1 to LE-YEC-1-18 provides a copy of the April 11, 2006 letter to the YUB setting out Yukon Energy's Outage Response and Reliability Plans following the January 29, 2006 event. YEC was asked by the YUB to provide a response that outlined the circumstances of the outage, how YEC responded to the emergency, the likelihood for the event recurring, what emergency plans YEC had in place for such an event, and what other system vulnerabilities were present (and how they were being addressed). This letter provided the detailed information to the YUB and interested parties and was filed as part of the interrogatory responses in the 2008/2009 GRA (LE-YEC-1-5). It is also provided as Attachment 1 to LE-YEC-1-18 in the current proceeding. As proposed in the Application, the net rate base cost is forecast at approximately \$6.4 million for completion in 2011⁷⁸.
- 4. Whitehorse Spillway Improvement** – As reviewed in Application section 5.2.1.7, the project was undertaken to ensure plant reliability and safety. The dam, including the spillway and spill gates, are over 50 years old and absent refurbishment/upgrades, the gates were becoming less reliable and more prone to failure. In an outage or any other times that large quantities of water must be spilled, loss of control of the gates may cause overtopping of the dam. In May 2011, an external advisor was retained to prepare

⁷⁷ As noted in **YUB-YEC-1-33**, the Project was required to be undertaken to ensure continued safe and reliable operation of the existing Mayo plant infrastructure and was not planned to be undertaken as part of the original scope of the Mayo B project.

⁷⁸ Cost estimates and changes in cost estimates were reviewed in detail in the IR process. **CW-YEC-1-30** provides a breakdown of the original estimated cost; a detailed explanation of the changes in costs; and a detailed history of the estimated costs of this project showing how each factor in the quote above increased costs from \$2.9 million to \$6.356 million. **LE-YEC-1-23** also provides detailed listing of the projected final cost by component and by contractor (including YEC internal costs).

a condition assessment of the gates. He identified areas where the spill gates needed to be upgraded and their related budgetary costs (see the Application for more details on the process leading to the approved budget). As proposed in the Application, the net rate base cost is forecast at approximately \$1.25 million for completion in 2013⁷⁹.

In conclusion, each of these projects is appropriately justified, properly managed and the resultant costs should be included in approved rate base.

3.3 OTHER MAJOR CAPITAL PROJECTS

The business cases for the following two projects relate to specific Yukon Energy needs as noted in the Application, and the evidence supports a determination that these forecasts costs are prudent and appropriate to include in rate base when the project comes into service:

1. **Enterprise System (JDE)** – As reviewed in Application section 5.2.1.9, and previously reviewed in the 2008/09 GRA, the project was undertaken to replace the current JDE enterprise business system (on which YEC's financials, inventory management and procurement functions are operating) with an integrated system that includes a computerized maintenance management system module for operations that is currently operating manually. The Application reviews the business case for this project⁸⁰. This project was necessary to ensure management can properly track and report costs and safeguard assets. As proposed in the Application, the net rate base cost is forecast at approximately \$3.2 million for completion in 2013.
2. **Whistle Bend Subdivision Supply** – As reviewed in Application section 5.2.1.8, the project is being undertaken in collaboration with YECL to determine how and when Whistle Bend should be connected to the system to ensure adequate supply and overall system reliability and protection. This project will not be in service before 2014 and will not impact rates in the test years. Although the forecast total spending in the test years is \$5.23 million, this number is a preliminary number and the final estimate will depend on the discussions with YECL. See response to YECL-YEC-1-31 provided an update regarding the business case for this project.

⁷⁹ **UCG-YEC-1-54** provides a component breakdown of the Whitehorse Spillway Improvements project expenditures by year.

⁸⁰ Further detail supporting the business case is provided in **UCG-YEC-1-56(c)** (which provides savings and productivity gains from the installation of the system); and **YUB-YEC-1-36** which provides business cases provided in the 2008-09 GRA [provided as Attachment 1 to YUB-YEC-1-36] as well as the economic benefit of the enterprise system proposed by YEC versus continuing with or updating the previous system. This response extensively reviews the process followed to select the new financial system (including a review of evaluation criteria and scoring; criteria, evaluations process and scores from product demonstrations). This response also explains why cost estimates changed from the 2008/09 GRA and provides a cost breakdown of Roll-Out #1.

3.4 MAJOR DEFERRED COST PROJECTS

As set out in Section 5.3.1 of the Application, nine major deferred cost projects are identified that reflect the unprecedented level of recent planning study cost activity.

IRs and cross examination regarding forecast deferred costs have focused on the planning approach adopted by Yukon Energy when incurring deferred costs to assess the feasibility of potential new generation or transmission projects, and YEC's responses to issues relating to the planning approach are summarized below. Thereafter, a summary is provided, under three groups for the nine major deferred cost projects, of the additional information provided in response to IRs.

3.4.1 Deferred Costs - Planning Study Approach

The Application outlines the requirement in recent years to undertake unprecedented levels of planning studies to develop baseline information in order for Yukon Energy to make commitments to proceed (or determinations not to proceed) with specific new generation projects that will reduce reliance on diesel generation requirements in response to future load growth.

- The 2011 Resource Plan highlights expected challenges in this regard related to near and longer term growth in the coming years and the related default diesel generation requirements and costs (see YECL-YEC-1-18 Attachment 1).
- YUB-YEC-1-40(c) further outlines in detail the underlying changes in the Yukon environment that have led to the unprecedented levels of planning costs incurred since 2009, noting significant load growth and related impacts on expected long term average annual diesel requirement costs in the near term and the longer term combined with the costs and increasing complexity of project options examined to displace future diesel requirements. This response notes that projects reviewed as part of the 2006 Resource Plan⁸¹ (in 2006) as well as the hydro enhancements such as Atlin, Marsh Lake and Gladstone Diversion reviewed in greater detail after 2008/09 as options to meet load requirements after 2012 were relatively straight forward and well understood⁸².
- Yukon Energy has also realized going forward the need to engage in planning and studies work in order to develop the next generation of "shelf ready" supply options that can be developed on timelines sufficient to meet developing near term and longer term

⁸¹ For example, Carmacks Stewart Stage 1 (which had been previously studied and as a transmission project was assumed to have a relatively straight forward licencing process), Aishihik 3rd Turbine (which had licences in place) and the Mirrlees Life Extension project (which had small planning costs and no requirement for licences or permits).

⁸² As noted in YUB-YEC-1-40, these options dated back to the NCPC transfer of assets to YEC in 1987.

load requirements. In this regard, Yukon Energy cannot wait until loads develop with full certainty before commencing the required planning and studies work to develop new sources of supply.

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- Yukon Energy recognizes the risks inherent in pursuit of planning studies on projects to displace diesel, and this was reviewed by Mr. Osler at transcript pages 274-275, i.e., the safest option for an investor is simply to run diesel, and a utility's ability to invest in pursuit of diesel-displacing options would require radical revision of strategy if the utility was required to bear the full risk each time a project cannot go forward.

Deferred Cost Projects versus Normal Capital Projects

In response to IRs, Yukon Energy has described its approach to deferred cost projects and why this approach differs from that adopted for normal capital projects.

The response to YUB-YEC-1-25 (a) reviews YEC's planning process in detail and notes that business cases that may be provided for capital projects are not typically available for deferred cost projects (i.e., deferred costs are incurred with regard to possible future capital projects to develop the business case that would allow the Corporation to have reasonable assurance that it can proceed with a specified project). For deferred cost projects there is typically only limited ability to describe the project (rather than a concept), provide economic or engineering analysis, discuss outcomes regarding alternatives or risks, prior to undertaking the deferred project.

In summary, deferred cost projects are typically initiated to define an opportunity for a capital project, e.g., assess broad range of alternatives for a specific resource option in order to identify a preferred alternative. In some cases, deferred cost projects advance to the point of prefeasibility or feasibility work to define a specific project and its initial business case. However, in other cases deferred cost projects are not able to go this far, i.e., in some instances, the deferred costs confirm that there is no basis for further work on the project at this time.

During the hearing, Board counsel reviewed with YEC witnesses (starting at transcript page 614) the table in YUB-YEC-1-39(e) that describes pre-tendering project phases and engineering activities related to planning studies, and sought clarification in particular (T622, lines 18 to 21) according to this table as to what was being spent to achieve the first step of "project definition". The responses highlighted the work required in many instances to define a project to the point that its feasibility can be assessed and a specific proposal can be prepared for regulatory review, e.g., starting at transcript page 625, line 22, Mr. Osler reviewed the example of what was needed to define Mayo B in 2008 prior to the YESAB submission in early 2009, notwithstanding the extent to which this project related to the enhancement of an existing hydro generation facility and has also been extensively studied in prior years.

The following are also noted regarding the scope and purpose of deferred cost studies:

- Deferred studies work (often undertaken as part of the resource planning process) is required to define near term and longer requirements (i.e., existing system capability and future requirements); assess resource options available to meet near term and longer term requirements and to make determinations regarding the need for a project and its selection as a preferred alternative.
- As part of this process a particular supply option may be studied to determine technical and economic feasibility. To do this, sufficient pre-feasibility work (preliminary engineering, baseline environmental studies and economic analysis) is required to be undertaken to define the specific project and ensure there are no specific showstoppers to proceed with further development work.
- This initial planning work is required to develop the case for YEC to make a commitment to proceed with further work. Once a sufficient case is established, i.e., that there is a need for a project and a preferred option to address the need, Yukon Energy can make a decision to proceed to further pre-decision planning stages work, including consultation regarding project concept; preparation and filing of Project Proposal with YESAB and related licencing and permitting activities; arrangements with partners and financing arrangements; determine final costing, design and contract approach; tender process to obtain final costs⁸³. In this regard, tables describing project pre-tendering activities typically set out the steps to be followed after the planning studies have managed to define adequately a specific project description and potential business case for more detailed pre-tendering planning study work.

Based on the above, a "business case" in the context of deferred cost projects, as described in Board Order 2009-8, Appendix A, paragraph 248 has a different meaning than a "business case" to be provided for major capital cost projects (as required by Directive #14 of Board Order 2009-8, and as addressed in response to YUB-YEC-1-32(c)).

In summary, deferred costs are often incurred (at least with regard to possible future capital projects) to develop the "business case" that allows the Corporation to have reasonable assurance that it can proceed with a specific capital project. Accordingly, there is only limited capability to describe a project (rather than a concept), provide economic or engineering analysis, discuss outcomes regarding alternatives or risks, etc. prior to undertaking a deferred project.

⁸³ **YUB-YEC-1-40(b)** reviews the general development phases that YEC currently considers for a project prior to tendering or construction, and the general relation of such phases to engineering estimates. Other related interrogatories include: **YUB-YEC-1-24** (reviews prudence test); **YECL-YEC-1-54**; **UCG-YEC-1-40** and **UCG-YEC-1-60**.

3.4.2 Deferred Costs - Hydro Enhancements (identified in 2006 Resource Plan)

Yukon Energy has continued since 2006 to focus on cost effective projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and Mayo. During the 2008/2009 GRA Marsh Lake Storage was described as one of a number of potential hydro enhancements that could be developed at an attractive cost compared to developing new greenfield hydro (or other) supply options.

Gladstone Diversion, Atlin Storage and Mayo Lake Enhanced Storage have also all been previously identified as other potential hydro enhancements that could cost-effectively displace diesel generation at current and future forecast grid loads.

The key risk associated with development of these small hydro enhancement projects in Yukon Energy's inventory relates not to economic justification for the project but to the regulatory and schedule risk related to planning and licence requirements - accordingly, deferred cost planning work for these projects has focused on addressing project definition, baseline environmental studies and initial consultation, and feasibility/conceptual engineering as required to assess permitting issues and requirements. Identifying and addressing "show stopper" issues as soon as is feasible, and prior to spending all costs needed for environmental assessment submissions, is one of the key points of focus regarding these studies.

Overall, \$13.55 million in deferred cost is forecast to go into rate base by the end of 2013 for the following hydro enhancement deferred cost projects (all but the Atlin Lake Storage project continue at this time to be pursued for potential implementation):

- 1. Marsh Lake Storage** – The Marsh Lake Storage Project is a cost effective means of enhancing winter capacity and energy available to the Whitehorse Rapids Generation Station in order to displace higher cost diesel generation that would otherwise be required.

Section 5.3.1.1 of the Application reviews the project concept and changes since the 2006 Resource Plan review⁸⁴, project risks costs and benefits, planning work undertaken to date (including public consultation, extensive work on shoreline erosion and groundwater issues and hydraulic modeling) and next steps.

This project remains highly attractive from a cost viewpoint, i.e., an LCOE (2010\$) is estimated at 8.5 cents/kWh assuming a capital cost (2010\$) of \$10.5 million, full utilization of annual generation of 6.4 GWh on average over a 65 year life, focused in winter months at

⁸⁴ **YUB-YEC-2-7(a)** reconciles the 2006 20 Year Resource plan cost estimate of \$1 million and the \$10.5 million cost estimate included in the Application.

current Whitehorse plant, and annual operating cost (2010\$) of \$8/MWh⁸⁵. Marsh Lake is assumed to provide 1 MW of added reliable winter peak. The project remains at a prefeasibility stage and prior to a decision to prepare any regulatory filings to secure approvals⁸⁶.

The recent Overview of the 20-year Resource Plan: 2011-2030 recommends completion of the required environmental, engineering and remediation studies related to the project in order to make a determination whether it is feasible and cost-effective to proceed⁸⁷. The project remains economic and attractive compared to other near term and longer term options reviewed in the 2011 20-year Resource Plan: 2011-2025.⁸⁸

The Application forecasts \$4.8 million going into base for this project on or before the end of 2013⁸⁹.

- 2. Gladstone Diversion** – This hydro enhancement project is a cost effective means of increasing the amount of water available in winter months for hydroelectric generation at the Aishihik hydro facility in order to displace higher cost diesel generation that would otherwise be required.

Section 5.3.1.2 of the Application reviews the project concept, risks, costs and benefits, review work undertaken to date and provides a projected LCOE (2010\$) over the 65 year estimated project life of 5.7 cents/kWh (assuming an estimated cost of \$40 million and full utilization of added energy generation of up to 36.6 GWh/year)⁹⁰.

In summary, this project's potential very positive benefit has been confirmed by the feasibility and planning studies to date, i.e., this hydro enhancement opportunity continues to offer higher potential long-term diesel displacement (well over 30 GW.h/year) than any other

⁸⁵ **YUB-YEC-2-16** – provides in excel format the fully utilization LCOE analysis and underlying assumptions. This response also provides further detail and explanation regarding Table 1 included in response to YUB-YEC-1-42 (with reference to YCS-YEC-2-10(a) and the Resource Plan Overview provided as Attachment 1 to YECL-YEC-1-18). The response confirms that the \$10.5 million cost to complete the project is not over and above the \$4.38 million total project costs forecast by the end of 2013.

⁸⁶ **YUB-YEC-1-42** provides details relating to project status and stage of development.

⁸⁷ See YECL-YEC-1-18 Attachment 1.

⁸⁸ **YUB-YEC-2-7(b) and YUB-YEC-2-16(f)** – discuss the point at which YEC would consider the project uneconomic (or make a decision not to proceed with the project). Such a decision is based on an assessment of various cost and risk factors specific to the project being reviewed, the options then available and the grid load forecast to be supplied and accordingly it is not appropriate to specify a specific dollar level at which YECL would view a project as uneconomical. YUB-YEC-2-16(f) notes that there is not a fixed \$/MWh benchmark that guides decision making regarding whether or not to proceed with a project. Each project must be evaluated based on its own facts and circumstances.

⁸⁹ **YECL-YEC-1-38** provides details regarding capital cost expected and any additional generation upgrades needed.

⁹⁰ **YUB-YEC-2-19** provides the corrected LCOE of 5.7 c/kW.h and the fully utilization LCOE analysis in Excel format with underlying assumptions.

identified current enhancement option, with a projected LCOE at less than 10 cents per kW.h. The project remains at a prefeasibility stage and prior to a decision to prepare any regulatory filings to secure approvals⁹¹.

The Overview of the 20-year Resource Plan: 2011-2030 recommends that YEC plan within the next 6 to 12 months to reach a final determination regarding whether the project is feasible to pursue at this time, based on discussions with local First Nations and regulators (See YECL-YEC-1-8 Attachment 1). YEC is working with DFO and the Champagne and Aishihik and Kluane First Nations and commitment to continued expenditures is, in part, guided by these discussions⁹².

During the hearing, YEC witnesses reviewed with Mr. Janigan (at transcript pages 219-220, and again at pages 253-258) the history and status of this project, including the response to YUB-YEC-2-8 which addressed questions about concerns and status with respect to both the Department of Fisheries and Oceans and the local First Nations. In summary, the project looks very attractive if YEC can find a way to work with the First Nations and with the regulators to come up with an acceptable approach and YEC's current efforts are focused on trying to confirm an approach that would be acceptable.

The Application forecasts \$4.4 million going into rate base for this project on or before the end of 2013.

- 3. Atlin Lake Storage** – This hydro enhancement project was examined as a cost effective means of enhancing winter capacity and energy available to the Whitehorse Rapids Generation Station in order to displace higher cost diesel generation that would otherwise be required. Based on the planning study work carried out, potential benefits of 10.5 cents/kWh LCOE (2010\$) have been estimated over the 65 year project life with an estimated cost of \$30 million (2010\$).

Section 5.3.1.3 of the Application reviews the project concept, risks, costs and benefits and costs incurred to date and rationale for the decision not to proceed with further work at this time.

The inter-jurisdictional nature of this project (need for BC approvals) and challenges by local residents presented material challenges. With the material risk that this project would be delayed or not proceed in the near-term, progression through the planning process was carefully monitored and controlled by staged approvals for expenditure applied to each

⁹¹ **YUB-YEC-1-43** provides detail relating to the project status and current stage of development.

⁹² **YUB-YEC-2-8** discusses whether the project is supported by DFO and the Champagne and Aishihik First Nations and prudence of continued expenditures on this project absent such support.

project phase and costs were effectively terminated as soon as it became apparent in July 2011 that the new park designation would prevent this project from proceeding at this time⁹³.

During the hearing Yukon Energy reviewed with Mr. Janigan (starting at transcript page 261) the chronology of events related to the planning work on this project which confirm the prudence of YEC's ongoing costs in pursuit of this low-cost option to secure ongoing diesel displacement benefits from enhanced Whitehorse hydro generation, including the following (T263 and following):

- When YEC started the project, the Yukon premier received a letter from the premier of BC indicating the BC government's initial support for the project.
- Within the BC regulatory process, this project did not require a permit (due to its small scale) and was not in a park.
- In response to the initial letter from PALS, YEC obtained a legal opinion that the Parks Act permit question did not apply to the project and that YEC did not require a permit to proceed with the work as proposed.
- By the time YEC got the Minister's letter stating that a park permit was required, YEC had virtually finished spending on the project in a substantive way and was also participating with the land use planning group who indicated that there was nothing in their draft report which would encumber YEC's project going forward.
- YEC concluded a memorandum of understanding with the Taku River Tlingit First Nation to advance the work that YEC was doing, and YEC had no indication from this First Nation that they wanted YEC to stop work on the project.
- YEC's studies did not indicate any risk in terms of environmental baseline analysis that there were problems with this project on a technical basis, or that there were environmental issues that were beyond expected mitigation.

The Application forecasts \$2.2 million going into rate base on or before the end of 2013⁹⁴.

⁹³ **YUB-YEC-2-6** notes that a cancellation clause was included in the consultant's contracts for Atlin work. Yukon Energy was notified on July 15, 2011 of the park designation and consultants were directed in writing to stop work immediately the same day. After July 15, 2011, only approximately \$5,100 of further costs were incurred for consultant time and YEC labor to close out the project files.

⁹⁴ **YUB-YEC-1-44** provides a breakdown information on total costs to end of 2011.

- 4. Mayo Lake Enhanced Storage** – This project was originally included as a component of the Mayo Hydro Enhancement Project proposal. During the 2009 adequacy review process, YESAB informed Yukon Energy that the proposal was adequate with the exception of the Mayo Lake storage component. As a result, YEC made the decision to withdraw the Mayo Lake storage component from the original project proposal and file the Mayo Lake Enhanced Storage Project as a separate project at a later date. Following the Mayo B Part 3 hearing, the Yukon Utilities Board's (in its report to the Minister of Justice) recommended that YEC pursue the additional metre drawdown at Mayo Lake, noting positive effects that added draw down of Mayo Lake would have on the economics of Mayo B and associated positive impacts on rates.

Section 5.3.1.4 of the Application reviews the project concept, work completed to date (including environmental and socio-economic field work activities, analysis and assessment, project proposal preparation, engineering support, and public consultation), and project risks, costs and benefits. This project is included under Relicensing rather than Feasibility Study deferred cost projects, reflecting the central objective to modify the current water licence affecting water storage at Mayo Lake. The discussion in the Application notes forecast project costs over the life of the project of \$5.4 million (2012\$) (including mitigation and monitoring costs) with an LCOE (2010\$), or 6.3 cents/kWh for approximately 4 GWh/year of added average hydro grid energy with 1 metre of added storage at Mayo Lake⁹⁵.

Yukon Energy has completed a Project Agreement with the local First Nation (Nacho Nyak Dun First Nation) regarding the Mayo B and Mayo Lake projects⁹⁶. The project is in the final steps of preparing a submission to YESAB for regulatory review and the Application noted the earliest potential project in-service estimated to be during 2013⁹⁷. The Application forecasts \$2.1 million going into rate base on or before the end of 2013. However, the Overview of the 20-year Resource Plan: 2011-2030 provided updated grid load scenarios Appendix A (page A-4) indicating that this project's earliest in-service date is now winter 2014/15.

3.4.3 Deferred Costs - Other Near Term Generation Options

Yukon Energy has been examining other non-hydro potential near term opportunities as potential options to meet near term grid load diesel displacement. The four major deferred cost projects in this category each involve very different resource options. In each instance, the deferred cost work has initially focused on the preliminary studies needed to define an opportunity for a capital

⁹⁵ **YUB-YEC-1-45** provides various details relating to the project LCOE and costs. YUB-YEC-2-18 provides the full utilization LCOE analysis in excel format with underlying assumptions.

⁹⁶ **YECL-YEC-1-39** - sought a copy of the Project Agreement with NDNFN (which is confidential and cannot be provided).

⁹⁷ **YUB-YEC-1-45 (b)** notes the project is forecast in the GRA to come into service prior to 2013 and deferred costs related to the Project are forecast to close out in the end of 2012 and amortize over the remaining life of the current licence (13 years) starting from 2013.

project, e.g., assess the broad range of alternatives for the specific resource option in order to identify a preferred alternative or alternatives that may be optimal and feasible for near term development. For some of these resource options, deferred cost projects have advanced to the point of prefeasibility or feasibility work to define a specific project and its initial business case. In addition to the major deferred cost projects, feasibility studies also were conducted on wind resource options and on Atlin grid connection.

1. **Demand Side Management (DSM)** – (DSM) is widely recognized in utility resource planning (e.g., BC Hydro Power Smart program, similar programs by Manitoba Hydro and other major utilities) to be feasible at relatively low cost (Full Utilization LCOE on average likely less than 10 c/kW.h) for ongoing implementation with non-industrial and industrial customers. Section 5.3.1.5 of the Application reviews the context underlying proceeding with a robust DSM plan at this time, the project concept, work being undertaken to prepare a plan and project costs (actual to date and forecast for the test years).

With regard to the DSM expense in the test years the following key context setting factors are noted in the Application (Section 5.2.1.5 and Tab 6, Pages 6-3 to 6-7):

- a. The Energy Strategy for Yukon strongly supports conservation measures such as DSM as a means of addressing growing demand (and related diesel generation requirements) in Yukon.
- b. The Yukon Utilities Board (with encouragement and support from intervenors) has directed that Yukon Energy and Yukon Electrical (Order 2009-2 and Order 2009-8) consult with stakeholders and jointly develop a DSM policy paper (Plan) to be presented as part of the next generation rate application. A significant amount of DSM related planning and consultation work has been undertaken by Yukon Energy individually and by Yukon Energy in coordination with Yukon Government, Yukon Development Corporation and Yukon Electrical in order to implement a robust and aggressive DSM/SSE program, and to meet the Yukon Utilities Board directive⁹⁸. The Application and interrogatories update on the progress regarding filing a DSM plan, noting that the DSM working group is currently in the draft stage of the five year DSM plan which will be submitted to the YUB upon completion⁹⁹.
- c. There is widespread public acceptance and support for DSM programming and energy conservation.

⁹⁸ **YUB-YEC-1-46** reviews in detail costs incurred to date and to be incurred over the test years.

⁹⁹ **LE-YEC-1-24 (and CW-YEC-1-35(a))** - update and progress on filing a DSM plan (YEC and YECL).

CW-YEC-1-8; CW-YEC-1-35(b) provide details on YEC's audit study with Alexco mine facilities, and YEC's LED Streetlight project.

YUB-YEC-1-7(a) to (c), (g) reviews DSM potential re: secondary sales customers who converted to firm, subject of electric heating under purview of DSM, proposed audit pilot program.

The Application forecasts approximately \$3 million (net of contributions) going into rate base on or before the end of 2013¹⁰⁰. Over 90% of these expenditures are related to DSM planning for which program cost benefit assessments are not applicable, including the DSM Conservation Potential Review, pilot programs, community engagement, end use surveys, working groups, energy audit and management plan, and public education/communication (see UCG-YEC-2-5).

At this time a full utilization LCOE of 10 cents per kWh for this resource option would be compared to the existing marginal cost of supply being displaced (i.e., diesel generation at a cost of approximately 30 c/kWh). However, DSM is also a relatively low cost supply option compared to other available near term supply options being reviewed. Further detail regarding near term resource options is provided in the 2011 20-Year Resource Plan: 2011-2030 Overview provided as Attachment 1 to YECL-YEC-1-18.

The Application and interrogatories clarified that there are no reductions in forecast sales in the test years due to DSM as some lead time is required before energy savings can be translated into electrical energy available (with the amount of lead time required expected to vary by initiative), and there was no reasonable basis when the GRA was prepared to estimate any potential load reductions by customer class or overall during the test years¹⁰¹.

- 2. Waste to Energy/ Biomass** – In assessing potential future supply options Yukon Energy has looked beyond diesel and hydro resources that have formed a significant portion of its supply portfolio to date and has also considered thermal biomass generation options that could be locally developed (based on local sources of supply) and that would provide firm, reliable power. Thermal biomass resources can be developed with conventional technology but require development of relatively more capital intensive high pressure steam generation plants that would typically be intended for year round operation in order to secure cost efficient use of the facilities. In this respect it is an option that is potentially relevant under increased grid loads that provide sufficient opportunity for the biomass generation to displace default diesel generation.

Section 5.3.1.6 of the Application reviews the project concept (both Waste to Energy and Biomass), provides references to publically available reports and feasibility work to date on Yukon Energy's website, and reviews project risk, costs and benefits. The

¹⁰⁰ **YUB-YEC-1-46** and **YUB-YEC-1-52** provide further detail and information on project costs. **YUB-YEC-1-52** addresses details on YEC Energy Conservation office costs, consultations, objectives and deliverables. **UCG-YEC-1-18** and **UCG-YEC-1-61** also review details on YEC DSM efforts, audit processes, impacts, and expenditures and cost recovery from ratepayers.

¹⁰¹ **LE-YEC-1-12** (and **YCS-YEC-1-26**) note typical DSM programs are implemented over a three to five year period at which time they are usually evaluated and modified based on the results of that evaluation.

Overview of the 20-year Resource Plan: 2011-2030 recommends that YEC identify and pursue opportunities for small scale (e.g., 2 to 3 MW) wood biomass pilot project, potentially in association with existing wood operations at Haines Junction, and seek funding support for this pilot project (YECL-YEC-1-18 Attachment 1).

In contrast, Yukon Energy has stated that Waste to Energy will not be pursued further at this time. These projects have remained at a prefeasibility stage and prior to a decision to prepare any regulatory filings to secure approvals. The Application forecasts approximately \$1.6 million (net of contributions) going into rate base on or before the end of 2013¹⁰².

3. District Heating – Yukon Energy is currently exploring various thermal supply options that produce waste heat, including liquefied natural gas, biomass and waste to energy. For these projects, a developed district heating market in Whitehorse may provide added value through generation of additional revenues that may lower costs for thermal supply options and consequently reduce impacts on ratepayers. Section 5.3.1.7 of the Application reviews status of work on this project, which remains at a prefeasibility stage with feasibility work being planned. The Application forecasts approximately \$0.5 million (net of contributions) going into rate base on or before the end of 2013¹⁰³.

4. LNG – Feasibility of thermal generation using LNG is being considered by Yukon Energy for near-term development (i.e., before 2015) as it is expected to provide a reliable, abundant, low cost, and flexible source of supply with reduced greenhouse gas emissions and costs compared to using existing diesel generation. Work in 2011 was undertaken by Yukon Energy to assess the feasibility of LNG for power generation in

¹⁰² **YUB-YEC-1-47** provides additional details on the project cost-benefit assessments, and work being done or requested. Further detail is provided in the following IRs:

1. **YUB-YEC-2-17** provides the PV analysis provided in YUB-YEC-1-47 in Excel format, including underlying assumptions.
2. **YCS-YEC-1-16** provides detail on costs spent;

UCG-YEC-1-62 provides details on programs, expenditures, costs and benefits expected, and how costs will be recovered from ratepayers.

¹⁰³ **YCS-YEC-1-17** and **UCG-YEC-1-16** provide details on programs, expenditures, costs and benefits expected.

YUB-YEC-1-48 reviews additional details on study findings to date, non-utility/private sector implementation option, benefits, requested approvals, and expected basis for viability. Further, detail is provided in the following IRs:

1. **YECL-1-YEC-1-44** - details on plans for LNG use, net impact on fuel costs, and basis for projecting LNG and diesel prices.
2. **YCS-YEC-1-21** - explain why non-renewable LNG option taking precedence over other alternatives.
3. **YCS-YEC-1-22** - details of commitments, contracts and feasibility studies undertaken.
4. **LE-YEC-1-27** - details on studies and plans and contracts; LNG plant timing, location, capacity; plans for combined heat and power.
5. **UCG-YEC-1-64** - details on programs, expenditures, costs and benefits expected, and how costs recovered from ratepayers.

Yukon to determine if it is a viable near-term supply option to be included in near-term resource planning.

Section 5.3.1.8 of the Application reviews the status of work on this project, which remains at feasibility assessment stage with consideration for near term development. The Application forecasts approximately \$1.7 million spending during the test years with none of these amounts going into rate base before the end of 2013. The Overview of the 20-year Resource Plan: 2011-2030 recommends that, subject to completion of current assessments, YEC proceed to determine whether it is able to establish LNG generating capability in Whitehorse prior to 2015 with sufficient capacity to displace grid diesel generation under current Base Case grid load forecasts, and also determine the feasibility of utilizing LNG in the event that material additional near-term grid loads occur such as those assessed under Scenarios A and B (YECL-YEC-1-18 Attachment 1)¹⁰⁴.

During the hearing, Mr. Morrison indicated that the LNG project very much meets the reasonable assurance test (T608, line 25 to T609, line 1).

3.4.4 Deferred Costs - Long term Generation Options

Yukon Energy has worked on appropriate planning activities required over the near-term to protect the ability to proceed with potential longer term legacy resource development options when loads are sufficient to justify proceeding. Deferred cost projects in this category address preliminary studies needed to define an opportunity for a future capital project, e.g., assess the broad range of alternatives for the specific resource option in order to identify potential preferred alternatives that may be optimal and feasible for future development as grid loads continue to grow. Geothermal is the one major deferred cost project in this category - large hydro feasibility studies have also been conducted regarding potential greenfield hydro site alternatives.

- 1. Geothermal** – Geothermal opportunities offer future potential to provide significant low cost, clean, and reliable long-term electricity supply in Yukon if successful exploration can define appropriate opportunities close to the grid. Section 5.3.1.9 of the Application reviews the status of work on this project, which remains at prefeasibility stage. The Application forecasts approximately \$2.6 million going into rate base on or before the end of 2013. The Overview of the 20-year Resource Plan: 2011-2030 recommends that YEC carry out scaled down geothermal investigations and look for funding support for geothermal exploration and studies, and seek funding support for these activities (YECL-YEC-1-18 Attachment 1)¹⁰⁵.

¹⁰⁴ **YUB-YEC-1-49** provides additional details on feasibility studies to date, suggested role of LNG, basis for incurring additional costs to further feasibility work, fixed asset expenditure forecast and expectation to meet reasonable assurance before end of 2012 (and related implications for accounting treatment of costs).

¹⁰⁵ **YUB-YEC-1-50** provides additional details on work to date, tendering of work done by contractor; **YECL-YEC-1-40** provides details on study findings, LCOE, and sites; and **UCG-YEC-1-65** provides details on programs, expenditures, costs and benefits expected, and how costs recovered from ratepayers.

3.5 PLANNING COST ACCOUNTING POLICY

The updated planning cost accounting policy, which was developed to address unprecedented levels of deferred planning costs, is reviewed in the Application (page 6-8 and page 11), Tab 3 (page 3-21 to 3-23); Tab 5 (page 5-2 and page 5-27, 5-29 and 5-54) and Appendix 5.2 which provides a copy of the updated planning cost accounting policy. The planning cost accounting policy was reviewed extensively in both rounds of interrogatories and in cross examination at the oral hearing.

Update to Planning Cost Accounting Policy

The planning cost accounting policy is designed to balance the requirement for a utility to undertake planning and studies work critical to the Corporation's mandate and the need to ensure rate stability over time. Rate stability is provided through deferring and amortizing costs over a defined period instead of either expensing such costs in the year incurred, or deferring such costs until such time as a final decision is made on project feasibility.

The history of the earlier planning cost accounting policy was reviewed during the hearing. The response to Undertaking #26 (page 594, filed November 19, 2012) confirms that Board Order 1993-08 addressed matters arising from YEC's previous planning study costs accounting policy related to projects that had ended without proceeding to construction (similar to Atlin project today), including how such costs that were prudent were included in rate base and amortized over 5 years. This undertaking also confirmed that YEC's previous planning study costs accounting policy kept projects in WIP until a project's fate was determined.

The planning cost accounting policy (last reviewed in 1992/93) was updated as part of this Application to ensure it continues to reflect the current circumstances of the Corporation given the unprecedented levels of planning costs incurred since 2009¹⁰⁶, and to ensure these costs are addressed and included in rates in a manner that moderates near term rate impacts for ratepayers.

These updates are being implemented to enhance accountability, transparency and intergenerational equity by providing for a clear decision-making framework and public review of costs (to the extent that rates are affected) at earlier planning stages. The policy specifically addresses the concerns that arise when material deferred studies costs continue to accumulate over long periods (See YUB-YEC-1-39 and YUB-YEC-2-15)¹⁰⁷.

¹⁰⁶ **CW-YEC-1-33(a)** attaches copy of existing policy developed in 1992 and filed and reviewed during 1993/94 GRA. **CW-YEC-1-33(b)** notes that under existing policy WIP balances by end of 2013 would be \$15.6 million.

¹⁰⁷ Yukon Energy is also aware of similar issues faced by other utilities such as BC Hydro related to excessive reliance on deferral/regulatory accounts and risks posed to utility and ratepayers over the long term due to continued deferral of

Specific Updates

YECL-YEC-1-43 provides a comparison of the previous and proposed planning cost accounting policy. As this IR notes, in many respects, the framework and intent of the policy remains the same, and many of the changes provided in the proposed policy essentially provide greater additional clarity regarding how the policy is applied in practice. The rate impact mitigation functions of the current policy remain in place¹⁰⁸, with further transitional measures adopted to smooth impacts in the test years related to the material accumulated deferred costs.

- Updates to the policy have focused on clarifying principles that would address the above noted concerns.
- One key update to enhance rate stability is the specification of a “reasonable assurance test¹⁰⁹” and provision for deferred studies costs that do not reach “reasonable assurance” to be closed out each year and amortized over a 5 year period¹¹⁰. It is expected that this will tend to prevent planning costs from accumulating to levels in excess of \$ 1 million. [YUB-YEC-1-39(b)].
- Other measures included in the proposed policy to enhance rate stability are as follows:
 - One-time transition provision for deferred studies >\$1 million in the test years – this proposed transition measure will moderate rate impacts in the test years by allowing for a 10 year (rather than 5 year) amortization period for deferred cost projects that have not reached reasonable assurance. Major projects that are subject to transition provisions in the test years are noted in footnote 4 of the Planning Cost Accounting Policy provided in Appendix 5.1 of the Application. In the future, the new policy will tend to prevent such costs from accumulating to levels that would require such mitigation measures (see YUB-YEC-1-39(b) and (e) and YECL-YEC-1-54).

costs. See YUB-YEC-1-39 and UCG-YEC-1-40 for review concerns raised by reliance on deferral account mechanisms in other jurisdictions.

¹⁰⁸ **YUB-YEC-1-39(e)** notes the 5-year amortization period was to maintain consistency with other jurisdictions (e.g. NWT Power Corporation), retain continuity with past policies and to be sensitive to the existing challenges faced by YEC (i.e., the need to undertake planning studies to ensure resource options are shelf ready and can be developed to meet generation needs for a non-interconnected system).

¹⁰⁹ “Reasonable Assurance” is generally consistent with YEC’s commitment to proceed with a specific project [test is described in Appendix 5.1, footnote 2; YUB-YEC-1-39(c); CW-YEC-1-33(c); YCS-YEC-1-23] . CW-YEC-1-33(b) notes recent experience with CSTP and Mayo B had met the reasonable assurance test at time of decision to prepare a YESAB filing.

¹¹⁰ The 12 month carry over period was addressed in YUB-YEC-1-39(f) – Provides rationale underlying the short carry over period for 12 months and notes this period was deemed appropriate in order to formalize a process for systematic annual internal review of deferred costs. This is also reviewed in YUB-YEC-2-15 (d) and (e).

- Amortization period of 10 years for projects that have met the reasonable assurance test but are later abandoned in order to mitigate and smooth rate impacts when such prudent and reasonably incurred costs are included in ratebase. This reflects the reality that at any decision point in the project's planning phase up to the point of the "decision to construct" there may be a decision not to proceed with a project. This also reflects the reality that the further along in the planning stages a project process the greater likelihood that significant costs will be incurred related to assessment, licencing, engineering and tendering costs (see YUB-YEC-1-39(d)).

IR responses clarified that the planning cost accounting policy only addresses how cost will be accounted for in YEC's revenue requirement, and does not address how the prudence of individual cost items will be assessed. The prudence and value of each cost to be included in rates, whether research¹¹¹, ongoing operations or for a project that provides long term multi-year benefits must be assessed separately on its own merits during a GRA process. All costs proposed to be included in a utility revenue requirement, and rates, in a GRA Application are subject to review by the Board (see YUB-YEC-2-15(a)).

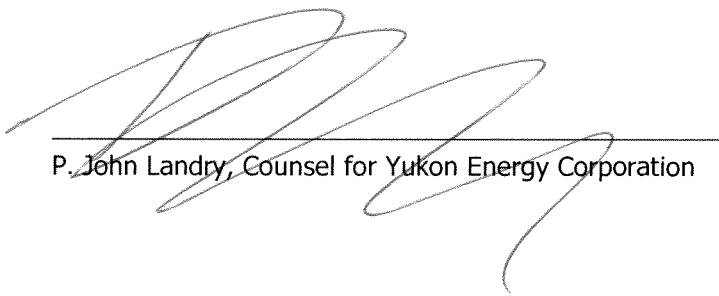
Deferred costs to date are provided for review in the current application and the Board may assess prudence of current costs and forecast test year costs for each deferred project. Future deferred costs will need to be reviewed by the Board in future GRAs, prior to being included in rates¹¹². At that time the Board and intervenors will have the opportunity to review the prudence of such expenditures. It is expected the YUB would apply the same prudency test for deferred costs included in current and future applications as considered for capital projects or other expenses prior to being included in rates, i.e., were the costs prudently incurred with a business case objective to provide some form of enduring benefit.

¹¹¹ YUB-YEC-2-15 (a) and (b) addressed the definition of "Pure research" noting such costs relate to negligible research or operations work that does not provide enduring or multi-year benefits. YEC has confirmed that no such costs are expensed in the test years (T36, lines 2 to 13).

¹¹² YECL-YEC-1-53.

As noted by the Board in Section 5.3.2.1 of Order 2009-8, there is considered to be enduring value for YEC and its ratepayers from planning and studies work or regulatory and licencing work undertaken. This value reflects the long planning times for certain projects, the range of ongoing benefits for feasibility work undertaken, and the need to have projects or research "shelf ready" to address future load requirements as they occur, even if a project does not proceed (see responses to YUB-YEC-1-39(g); YUB-YEC-1-39(i); YUB-YEC-1-24 and YUB-YEC-1-39(h)).

ALL OF WHICH IS RESPECTFULLY SUBMITTED



P. John Landry, Counsel for Yukon Energy Corporation