YUKON UTILITIES BOARD
(YUB)

REFERENCE: **Tab 3 Revenue Requirement**

ISSUE/SUB-ISSUE: **Consultants**

QUESTION:

a) Please provide a table showing the amount YEC has spent and forecast to spend on consultants for the years 2005 to 2009 inclusive. Within the table provide a breakdown for each year based on the categories of Capital, O&M, Admin and General, and Regulatory, listing the individual or organization that provided the service. Provide reference to specific schedules containing these costs.

b) For those individuals or organizations listed in part A, for those instances where the costs exceed $50,000 in a given year, provide the terms of reference of the consulting engagement, the related project, and what results were achieved.

ANSWER:

(a) and **(b)**

For consultant and contractor costs by function for O&M, please see YECL-YEC-1-39.

For regulatory costs since the 2005 proceeding, these were provided and reviewed in detail in the respective YEC cost claim filings leading to Board Order 2007-7, 2007-8, 2007-9 and 2008-1 (see Tab 6 page 6-7 to 6-8). As noted in YECL-YEC-1-28, regulatory forecasts for the test years were developed on a top-down basis and do not have specific amounts for consulting versus other services (such as travel or legal).

With respect to the remainder of the information requested, the information is not readily compiled in the way in which the question is asked and YEC cannot without a substantial amount of time and effort provide it in the format requested. Further, Yukon Energy does not release information relating to the amounts paid to specific individuals or companies.

REFERENCE: **Application, Page 3-17**

ISSUE/SUB-ISSUE: **Contributions**

QUESTION:

a) Please provide continuity schedules of contributions and amortization of contributions for the years 2005 to 2009 inclusive. Within the schedule provide a breakdown based on the following categories:

YTG Contributions
YDC Contributions
Minto Exploration Contributions Other Contributions

b) Please provide a table on the CSTP project showing capital costs, contributions by the parties listed above and any amortization of the capital costs and contributions for the period 2006 to 2009 inclusive.

ANSWER:

(a)

The continuity schedule of contributions and amortization of contributions is set out in Tab 7, Schedule 1, rows 22-26.

All contributions received from 2005 to 2007 were “Other Contributions” with the exception of:

- $4.450 million in 2007, which was from Yukon Government ($0.450 million) and YDC ($4 million).

Forecast 2008 contributions in the GRA are all “Other Contributions” with the exception of:

- $10.000 million from YTG for CSTP
- $3.000 million from YTG for CSTP
- $7.200 million from Minto for the CSTP main line

- $9.989 million from Minto for the Minto spur
- $1.500 million from YTG for Aishihik 3rd turbine, and
- $0.030 million from YTG for fish hatchery upgrades.

Forecast 2009 contributions in the GRA are all "Other Contributions" with the exception of:

- $3.500 million from YTG for the Aishihik 3rd turbine.

(b)

For spending on CSTP by year, please see Table 5.2. For contributions to CSTP by year, please see YUB-YEC-1-9(a). No amortization of capital costs or contributions occurred in 2007 or prior as the project was in 'work in progress'. For 2008 and 2009 CSTP in service values, please see the table below:

CSTP capital cost and contributions

$000s	2008	2009
Capital Cost		
Opening Balance	0	38174
Additions from WIP	38383	0
Depreciation	-209	-840
Closing Balance	38174	37334
Contribution		
Opening Balance	0	34449
Additions from WIP	34629	0
Depreciation	-180	-722
Closing Balance	34449	33727

REFERENCE: **Application, Page 3-19**

ISSUE/SUB-ISSUE: **Cost of Debt, Minto Mine Obligation re: Diesels**

QUESTION:

a) In Order 2007-5, what comments did the Board make regarding the purchase of the Minto diesels?

b) Has YEC provided a business case on the purchase of the Minto diesels? If not, Please provide the business case showing where this option fits according to YEC's 20 Year Resource Plan and what options in the Resource Plan are recommended to be deferred because of this option.

c) Has the Board approved the incorporation of the Minto diesels into rate base?

d) Could YEC obtain an unsecured advance from YDC to finance the Minto diesels?

ANSWER:

(a)

In Appendix A to Board Order 2007-5 the Board noted as follows (at page 19-20):

> The Board is of the view that section 10.2 of the PPA provides adequate protection for YEC and Yukon ratepayers as to the condition of the units. The Board accepts that the price for the units as determined in the PPA and as further noted in UCG-YEC-2-14 and YUB-YEC-1-8 is reasonable. The Board also accepts the terms as to the mobility of the units. However, the Board is not convinced the units are needed. Other than a parenthetic notation late in the Resource Plan process, YEC has not demonstrated a need for the units nor provided an adequate business case supporting this option. Given the new capacity criteria employed by YEC, YEC has not furnished evidence that these units are needed based on those criteria, nor where this capacity addition stacks with the other projects identified within the Resource Plan.

> Further, the new funding available for the third turbine at Aishihik from the Government of Yukon also brings into question the need for the units and whether they would be a least cost option. The Board agrees with YECL that no evidence has been offered to support the statement that line loss reductions will offset other incremental costs. The Board also agrees with Mr. Percival and UCG's argument that if YEC did not agree to finance the customer contribution from Minto, the use of the units as security would not be necessary. In the event that YEC had to use the units as security for collection from Minto, it is questionable that the units would be in the condition stated in section 10.2 as under those circumstances the units are more likely to be in a distressed condition. Based on the foregoing, the Board does not accept the purchase of the Diesel Units as part of the PPA.
>
> YEC is free to purchase the units; however, at this time the Board cannot provide any assurance to YEC that the units would be approved as an addition to rate base. However, it is open to YEC to develop an appropriate business case supporting the need for the Diesel Units and include it for consideration in its next GRA.

The Board provided as follows with regard to Directive 15:

> The Board does not accept the purchase of the Diesel Units as part of the PPA. YEC is free to purchase the units; however, at this time the Board cannot provide any assurance to YEC that the units would be approved as an addition to rate base. However, it is open to YEC to develop an appropriate business case supporting the need for the Diesel Units and include it for consideration in its next GRA.

(b)

Yukon Energy provides its case in support of the Minto Diesels in Tab 5 of the Application in Section 5.2.1.2, at pages 5-7 to 5-11.

In its Order the Board expressed concern that issues of price (i.e., the least cost option) and need had been insufficiently addressed during the Resource Plan process and the

PPA hearing – these issues are specifically addressed in the above-referenced pages of the Application.

As noted on pages 5-8 and 5-9 of the Application, the cost of the Minto diesels (estimated in the Application at $0.498 million/MW including work required to winterize the units) remains competitive with the estimated costs of the Mirrlees Life Extension Project ($0.457 million/MW as noted in supplementary filing Exhibit 16 of the Resource Plan proceeding). Further, it is noted that acquiring the units provides some flexibility with regard to long term planning. Once all PPA commitments have been met regarding the units YEC may elect to sell the units or move them from the mine site to an alternate location.

As noted at page 5-9 of the Application, the Faro Mirrlees re-commissioning project is nearing completion. The Whitehorse Mirrlees Refurbishment (3 units totally 14 MW) is budgeted and anticipated to occur as follows:

- In 2008: Unit #3, providing an additional 5 MW of capacity at a cost of $1.1 million, plus an additional $0.535 million generator rewind for 2010.

- In 2010: Unit #2, providing an additional 5 MW of capacity at a cost of $1.250 million, plus $0.435 million for the generator.

- In 2012: Unit #1, providing an additional 4 MW of capacity at a cost of $1.050 million, with no required generator rewind.

Upgrades to common systems were undertaken in 2007 (at a cost of $0.468 million) and 2008 (at a cost of $0.450 million), and are also anticipated to take place in 2010-12 (at an anticipated cost of $1.465 million).

As noted at page 5-9 of the Application, the purchase of the Minto diesels has not changed the planned refurbishment of Unit #3 and Unit #2 or any further planned upgrades to common systems. However, as noted, the timing for refurbishment of Unit #1 is flexible and the option exists to mothball the unit for pending optimum capacity for the unit to be brought back into service.

At page 5-11, three other benefits are noted from acquiring the Minto diesel units:

- Units are located near key major loads at the end of a long transmission line (reductions in line losses when diesel units needed to serve these loads).

- The units can be run without any emissions impacts in Whitehorse.

- Cost effective contingency protection in the near term.

(c)

In Order 2007-5, the Board did not approve the purchase of the Minto diesels noting (at page 20), “at this time the Board cannot provide any assurance to YEC that the units would be approved as an addition to rate base” and providing that “it is open to YEC to develop an appropriate business case supporting the need for the Diesel Units and include it for consideration in its next GRA”.

Yukon Energy has proceeded with the purchase of the Diesel units as a condition of the Power Purchase Agreement with Minto and has included an assessment of the additional issues the Board asked to be considered in Order 2007-5 at Tab 5 of its 2008/2009 General Rate Application.

(d)

The financing arrangement for the Minto Diesels is set out in detail in YEC's PPA with the Minto Mine. It does not involve YDC and there is no agreement between YEC and YDC to finance, or be involved in any way in, YEC's purchase of the diesels.

REFERENCE: **Application, Page 3-20**

ISSUE/SUB-ISSUE: **Cost of Debt, YDC Flexible Promissory Note**

The face interest rate on the note is 6.55% and, due to the present substantial benefits to ratepayers arising from the Mayo-Dawson line given current forecast diesel prices, the full 6.55% face-interest rate is forecast to be paid in 2008 and 2009.

QUESTION:

a) Are the “present substantial benefits to ratepayers” based on the forecast costs of the MD line or based on the actual costs of that line?

b) Please provide the calculations of the “substantial benefits to ratepayers” (include the electronic version in your response), based on the fuel prices in effect at the end of 2008.

c) Based on the reduced current fuel prices (December 31, 2008) what does YEC forecast the interest rate for 2009 to be on this note?

ANSWER:

(a)

The “present substantial benefits to ratepayers” are based on the actual costs of the line.

(b)

For 2008, the Mayo Dawson line resulted in benefits to ratepayers of $4.700 million in avoided diesel fuel (16.488 GW.h of baseload diesel saved, at 3.8 kW.h/litre efficiency and an average price of $1.0832 per litre) and a further $0.263 million in avoided diesel O&M costs (at 1.6 cents/kW.h for 16.488 GW.h of diesel saved) as well as $0.314 million in avoided diesel capital costs as set out in the Mayo-Dawson financing agreement. Total diesel savings were therefore $5.278 million. This does not include the benefits to YECL of being able to purchase wholesale power from YEC at Stewart Crossing and avoid the use of diesel gensets.

Total costs for the Mayo-Dawson line with an equity return at approved fair ROE levels of $0.913 million (project mid-year 2008 rate base at $25.923 million times 40% equity ratio at 9.05% rate of return as last approved by the YUB), interest on the flexible note of $1.052 million, plus depreciation of $0.724 million and O&M cost of $0.073 million. The resulting total costs of the project are $2.762 million.

The net benefits of the Mayo Dawson project in 2008 were $2.516 million.

(c)

YEC forecasts the actual rate of interest in 2009 to be 6.55%. Based on the calculation provided in the promissory note and described in (b) above, as long as the price of diesel remains above approximately 50 cents/litre, the interest on the note is expected to remain at the full 6.55%.

REFERENCE: Application, Page 4-2

ISSUE/SUB-ISSUE: Pelly Crossing Connection

The current level of existing firm rates (including Rider J and the fixed component of industrial Rider F, as reviewed in Section 4.3) provides $0.359 million excess revenue in 2008 and $1,334 million excess revenue in 2009 compared to revenue requirements set out in Tab 3.

QUESTION:

a) Based on the actual connection date for Pelly Crossing, please update the excess revenue forecast for 2008.

ANSWER:

(a)

The 2008 financial statements are in the process of being finalized but are not yet complete and therefore the requested information based on final 2008 results is not available at this time. However, the Yukon Public Utilities Act sets out a requirement at section 25(1) for each utility to file a statement showing various financial information for the preceding year by March 31. Yukon Energy is currently preparing (unaudited) financial statements for this purpose and expects to meet the requirements of the Act. Once that material has been prepared, it will be possible to update and confirm the 2008 unaudited results in the form of Tab 7 to the Application. As was done in 2005, these schedules will be updated as soon thereafter as possible prior to the May hearing. It is presently expected that these updates will be filed in late March or early April.

Following the same approach as footnote 2 at page 4-3 of the Application (which provided an example of a $197,000 reduction in the excess from a one month delay), an initial estimate of the updated excess revenues forecast for 2008 is approximately $43,300 (versus $359,000 as shown in Table 4.1 of Application). This estimate reflects an overall reduction in YEC 2008 net revenues by approximately $315,700 (estimated $431,500 loss of industrial sales plus an estimated $20,200 loss of Pelly Crossing wholesale revenues, less estimated savings of about $136,000 in depreciation and related cost (lower rate base and reduced Flexible Term Note)).

REFERENCE: **YEC Application, page 1-6**

ISSUE/SUB-ISSUE: **Reliability**

Winter peak-generation interruption related to a single major system-risk event (Aishihik transmission interruption) was underlined by the January 29, 2006, Whitehorse-Aishihik-Faro (WAF) grid outage.

PREAMBLE:

The YUB wishes to gain reliability information related to WAF.

QUESTION:

a) Please provide a table showing reliability performance measures on a calendar-year basis with respect to YEC's WAF and MD grids. The table should include such indices as:

- The System Average Interruption Duration Index (SAIDI)

- The System Average Interruption Frequency Index (SAIFI)

- The Customer Average Interruption Duration Index (CAIDI)

Annual averages for the above must be derived from raw data, not by averaging monthly averages.

b) Please identify any formalized evaluation process that YEC has in place in order to identify problem areas on the WAF or MD grids.

c) Please identify protection or reliability studies that have been undertaken over the period 2005 to 2007. If studies were undertaken, please provide details and results, and any work that has been undertaken or may need to be done in order to mitigate shortcomings that may have been identified.

ANSWER:

(a)

Please see table provided below.

YEC Reliability Performance Stats - by Grid

		SAIFI	SAIDI	CAIDI
Mayo Dawson Grid				
	2008	**3.76**	**4.28**	**1.14**
	2007	**9.99**	**5.06**	**0.51**
	2006	**4.99**	**7.39**	**1.48**
	2005	**4.93**	**2.37**	**0.48**
WAF Grid				
	2008	**10.90**	**12.47**	**1.14**
	2007	**6.95**	**9.45**	**1.36**
	2006	**5.34**	**6.45**	**1.21**
	2005	**4.32**	**0.81**	**0.19**

2005 WAF is Faro only
(data not kept on all YEC WAF communities)

(b)

Over the past 5 years YEC has contracted with BC Hydro Engineering for review of generation and substation assets, Acres International for review of Transmission lines, and Northwest Territories Power Corporation and Gygax Engineering Associates Ltd for review of the Whitehorse Diesel plants.

These third party assessments have been used along with staff evaluations to determine issues and problems with YEC assets.

(c)

The following asset assessments were undertaken on the system – these reports were available in 2004 (before the period specified in the IR), and assisted in the preparation of YEC's 20-Year Resource Plan; 2006-2025:

- *Condition assessment of Selected Yukon Energy Corporation Substation Assets* – BC Hydro June 2004.

- *Assessment of Transmission Line for Yukon Energy* Corporation – Acres Intl – Feb.2004 Generation Assets report – BC Hydro – May 2004.

- *Condition Assessment of Selected Yukon Energy Generating Assets* – B.C. Hydro: This assessment was completed in May 2004 and focused on Whitehorse hydro (Units WH1 through WH4), Whitehorse diesel (Units WD1 through WD7) and Aishihik hydro (Units AH1 and AH3). The condition assessment did not review the other diesel plants or the Mayo hydro facility.

- *Condition Assessment of Selected Yukon Energy Corporation Substation Assets* - BC Hydro: This report was completed in June of 2004. The focus of this assessment was on circuit breakers and transformers located at the substations at Aishihik, Takhini, MacIntyre, Whitehorse (all on WAF) plus Mayo.

- *Assessment of Transmission Lines for Yukon Energy Corporation* - Acres International: This report was completed in December 2003 and was commissioned to assess Yukon Energy's transmission assets. The condition assessment by Acres International of Yukon Energy's transmission lines was of a significantly different type than the Generation and Substation assessments. In the Acres assessment, the primary item to be addressed was the expected remaining life of the transmission assets, based on a sampling of the WAF transmission line.

Overall, BC Hydro and Acres International found Yukon Energy's assets to be in good to relatively good condition with a few exceptions. As a result of the Condition Assessment Reports, Yukon Energy developed short to medium term capital investment plans to address the bulk of the items identified by BC Hydro and Acres International. This Yukon Energy plan was submitted to the Yukon Utilities Board as part of the 2005 Required Revenues and Related Matters Application and was approved by the Board on October 18, 2005 (YUB Order 2005-12). Yukon Energy continues to carry out the work recommended by the Condition Assessment Reports.

The following chart provides an overview of the specific recommendations made by BC Hydro and Acres International and Yukon Energy's progress in responding to each recommendation.

Generation Assets Recommendations	**Yukon Energy Progress**
WH4 needs more maintenance and capital spending to deal with Equipment concerns.	Governor work is about 50% complete, will be completed in 2009. WH4 is a priority for 2009 capital spending.
Aishihik fire suppression system and egress system from the generator room.	Being addressed as part of 2009 work plan.
Rewind AH2	Complete.
WD1, 2 &3 at end of life. Evaluate and determine action[1].	WD3 rebuild currently in progress. WD 1&2 planned in future years.
WD 3,4,5,6 &7 should be run regularly to ensure availability.	Practice is in place.
Oil contamination of cooling water, sump oil and asbestos issues need to be addressed.	Asbestos identification is complete. Hydrocarbon separation and disposal system currently being designed for 2009 completion.
Governor testing, starting and synchronizing problems need to be dealt with.	Testing for all Whitehorse units (both diesel and hydro) is currently being done to determine plans. Aishihik will also be done. To be complete in 2009.

Substation Asset Recommendations	**Yukon Energy Progress**
Mayo transformers T1 and T2 need upgrading.	Complete.
Mayo transformer T1 to be replaced in 5 years.	Transformer has been upgraded and will be reassessed in 2009.
Inspect air core reactors.	To be completed in 2009.
34.5 kV HLC and SFE feeder circuit breakers need to be replaced within 20 years.	One complete. Addressing the others.

[1] Yukon Energy is aware that the Mirrlees units are approaching retirement, and earlier resource planning exercises (1992 and 1996) were based on these three units being retired prior to 2006. The units have been retained in-service due to the current system load, which has not required material running time. The units will also be retained in-service into the future at least until the current hydro surplus on the WAF system is consumed by firm load and additional generation resources are developed. On this basis, major refurbishment of the Mirrlees units was required to stave off the risk of a major failure or the inability of these units to supply reliable utility standard service when required.

Disconnect switches in various locations need replacement.	Some complete, continue to replace the remainder.
Surge arrestor protection needs some improvement in several substations.	To be completed in 2009-2010
Transmission Asset Recommendations	**Yukon Energy Progress**
Approx. 0.5% of all transmission line poles were in imminent risk of failure Approx. 5% needed increased maintenance to ensure that their condition didn't deteriorate significantly.	The remaining 94% of all transmission line poles were expected to be able to be maintained "as is" for the next 20 year period. Assessments are ongoing. YEC has spent between $300,000 and $500,000 per year on replacements and upgrades to maintain the condition of the poles.

Line assessments are also undertaken for each of the main transmission lines on the Whitehorse-Aishihik-Faro and the Mayo-Dawson grids. Each main line is assessed at least once every five years to determine the condition of poles, insulators, cross-arms and dead end structures. Reports are then used to prioritize repairs and make budget requests for the next fiscal year. The Mayo-Dawson line was assessed in 2007 and maintenance from that assessment is on-going. The Aishihik section of the WAF line was assessed in the spring of 2008 and as a result several dead end insulators were replaced. The Whitehorse to Faro segment of the WAF grid was assessed in October 2008. A report is currently being drafted and any recommended repairs will be prioritized based on that assessment.

REFERENCE: **YEC Application**

ISSUE/SUB-ISSUE: **Sales Forecast**

QUESTION:

a) Please provide tables 2.2 to 2.4 in an Excel spreadsheet complete with formulae intact.

b) With respect to YEC's firm retail sales forecast, please provide details, i.e. numbers of customers and usage per customer that forms the basis of YEC's proposed growth in general service sales.

c) Please provide the detail upon which YEC based its forecast respecting the modest growth in the number of residential customers and the consistent use per customer over the period.

d) Please provide metered load for the years 2005 to 2008.

e) Please provide corresponding generation for the same period.

f) Please provide losses on a system-by-system basis, i.e. WAF and MD.

g) Please provide capital and O&M initiatives undertaken by YEC to mitigate losses on the system. If those are not available or YEC has no DSM initiatives, please provide a detailed explanation.

h) Please provide actual sales for YEC's residential and general service customers for the period 1998 to 2008.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b) and **(c)**

Please see LE-YEC-1-7.

(d) and **(e)**

Please see the attachment to part (a) above and Tab 2, Table 2.5.

(f)

Please see YECL-YEC-1-24(a).

(g)

System losses (as shown in Table 2.5 of Tab 2 of the Application) are the sum of generation, transmission and distribution losses. These losses are considered during the planning, design and operating phases of the Corporation's generation, transmission and distribution assets.

During the planning and design stages of major projects, electrical and mechanical losses are key factors in selection of equipment, voltage and conductor sizing.

New generation projects are assessed using a computer-based model that includes assessment of line and hydraulic losses by calculating grid net energy benefits.

During the planning and design stages selection of voltage, conductor size and transformer efficiencies to reduce losses is undertaken on transmission projects. Voltage selection, conductor sizing and transformer selection is undertaken on new distribution projects. Voltage conversions and load re-distribution is undertaken on existing distribution to reduce losses.

(h)

Actual sales for YEC’s residential and general service customers for the period 1998 to 2004 are as provided below. Actuals for 2005 to 2007 are provided in Tables 2.2 to 2.4 from Tab 2 of the Application provided in CW-YEC-1-4(a) Attachment 1. Actuals for 2008 are discussed in response to CW-YEC-1-4(d).

Sales to YEC residential and general service customers (MW.h) 1998 to 2004

	1998	1999	2000	2001	2002	2003	2004
Residential	11,403	10,314	9,889	9,543	9,716	9,968	10,199
General Service	12,981	12,427	12,503	12,513	12,692	13,345	14,016

REFERENCE: **YEC Application**

ISSUE/SUB-ISSUE: **Peak Demand Forecast**

QUESTION:

a) Please detail and explain the long-term planning assumptions YEC used to develop its peak-demand forecast.

b) Please define what YEC perceives as being long-term.

c) Please provide winter load duration curves for the WAF hydro generating plant for the period 1998 to 2008.

d) With respect to adding generation capacity on the WAF system, please provide details underpinning YEC's determination that the N-1 criteria remains the key requirement when compared to the outcomes of the LOLE criteria.

e) Please provide the business case that led YEC to determine that 6.4 MW of diesel capacity can be added to the system in the best economical manner through purchase of diesel units at the Minto mine site.

f) Subsequent to the re-commissioning of the FD1 unit at Faro and purchase of the Minto diesel units, YEC determined that the most economical option of adding generation capacity to the WAF grid is through an orderly refurbishment of the Whitehorse Mirrlees units. Please provide the business case.

g) Respecting capacity additions on the WAF system, when would the LOLE criteria supplant the N-1 criteria?

h) With respect to Yukon River icing, please provide the study and accompanying results that led YEC to determine that the 24 MW winter peak output for the Whitehorse hydro plant remains valid for planning the system.

ANSWER:

(a)

Yukon Energy's long-term planning models focus on determining the energy requirements of the respective systems. Peak demand is determined based on the energy forecasts as the sum of (a) non-industrial peak demand, which is determined using an assumption of consistent on-peak load factor for these loads over time, and a 100% coincidence factor, plus (b) industrial peak demand, which is estimated for each industrial load as best as can be determined, also assuming a high coincidence factor.

(b)

As noted in the Resource Plan, Yukon Energy's long-term forecasts focus on determining potential supply requirements over 20 years, but extend forecasts to 40 years to ensure decisions that may be required late into the 20 year planning horizon incorporate consideration of how the projects would be used on the system for a reasonable period of time after they come into service.

(c)

Please see YECL-YEC-1-23(b) and YECL-YEC-1-50. In particular, note that Excel data in YECL-YEC-1-23(b) includes all readily available hourly load data since 1998, at the level of YEC generation (i.e., not including Fish Lake).

(d)

During the YEC Resource Plan hearing, Yukon Energy noted that the N-1 criteria was at that time the determining factor on WAF, and would remain the determining factor unless and until one of two things occurred:

a) The Aishihik transmission line was twinned, or a similar resolution to the non-redundancy of this line; or,
b) Addition of 6-7 MW of industrial load to the LOLE calculation (the N-1 calculation specifically excludes industrial load).

Neither of these two events has occurred.

(e)

The business case of the Minto Diesels is provided in the Application at Tab 5, pages 5-7 to 5-11. The business case was also addressed as a component of the Minto PPA hearing in 2007.

In sum, in order for YEC to meet its N-1 planning criteria, additional diesel generation was required (i.e., as noted a total of 30 MW of generation is needed in the case of loss of the Aishihik Generating Station or L172 from Whitehorse to Aishihik). The cost of the 4 units (1.6 MW each) is $2.24 million with an additional $0.95 million in upgrades required. This brings the price to $3.19 million or $0.498 million/MW.

The purchase of new diesels units is estimated at $1.05 million/MW, while the Whitehorse Mirrlees life extension is forecast to cost $0.482 million/MW.

Given the recognized need for Yukon Energy to ensure cost-effective capacity resources are made available (either through new additions, or life extension of generators otherwise scheduled for retirement), this source of capacity is competitive with the other lowest cost option also being pursued over the next few years, the Whitehorse Mirrlees life extension.

(f)

The Whitehorse Mirrlees life extension project was reviewed in the 20-Year Resource Plan (pages 4-28 to 4-33), the Supplemental Materials to the Resource Plan (filed May 2006 at pages 4-9), the Resource Plan Update filed November 2006 (pages 3-5) and is reviewed at pages 5-9 to 5-11 of 2008/2009 General Rate Application.

The Whitehorse Mirrlees project is a cost effective means to secure needed capacity for WAF. This was the basis for extensive review of the project at the 20 Year Resource Plan proceeding, and the basis for the Board's recommendation that "Based on the foregoing, the Board recommends that YEC proceed with the Mirrlees units WD1, WD2, and WD3, as planned." The business case today remains as provided in the Resource Plan proceeding; that is, the Mirrlees life extension project remains the most cost effective way to secure up to 14 MW of capacity in a flexible and staged manner, well below the cost of purchasing and installing new diesel generation.

Specifically, over the course of a number of years, likely to 2012 (perhaps later for WD1), the project will provide 14 MW of capacity (compared to retirement of these units) at a cost of $0.482 million/MW. The purchase of new diesels units is estimated at $1.05 million/MW.

(g)

Please see YUB-YEC-1-34(d).

(h)

The study noted was never finalized, and in any event was oriented at determining the potential for higher flows to be accommodated on the Yukon River. With respect to the firm capacity of the plant at its current configuration and downstream conditions, the attached memo reviews the conclusions arising as they relate to firm capacity planning, including a review of the matter with Dr. Billinton, which confirms the continued use of 24 MW as the appropriate firm winter capacity for the Whitehorse plant.

InterGroup CONSULTANTS

Suite 500-280 Smith Street
Winnipeg, Manitoba
R3C 1K2
tel: (204) 942-0654
fax: (204) 943-3922
e-mail: intergroup@intergroup.ca

Memorandum

DATE:	March 13, 2008	**PROJECT:**	P642.1
TO:	Hector Campbell, Rick Carson KGS		
FROM:	Patrick Bowman		
SUBJECT:	**WHITEHORSE HYDRO ICING STUDY – IMPLICATIONS FOR YEC**		

Summary of Implications

You have asked for a review of the draft KGS ice study dated April 2007, which identifies important considerations for the WAF system. The implications of the study's conclusions for YEC depend heavily on the operating philosophy YEC adopts to address the issues noted in the ice study. At a simple level, two major philosophies are noted:

- A **steady state philosophy**, based on maintaining the WH plant at no more than 21 MW during the early part of winter in order to ensure no cutbacks in output will be required due to adverse icing events. Were YEC to adopt this approach, it appears the requirement for firm capacity on the system would increase under both the N-1 and LOLE criteria, in the range of approximately 3 MW or slightly above, compared to Resource Plan assumptions. In addition, this approach would lead to greater requirements for peaking diesel each year during the 21 MW constraint period, which is roughly estimated as a $0.7 million impact over the 8 year period 2009-2016 (assuming Minto is in-service).
- An **adaptive philosophy**, which maintains output at the 24-25 MW level (within the range of current practice) in early winter, with full knowledge that in some years this may need to be cut back as far at 15 MW to avoid flooding. This philosophy will require some degree of monitoring to know when flooding events are developing. Under this approach, the requirements for added capacity on the system compared to Resource Plan assumptions are either very small (0.3 MW) or zero depending on whether N-1 or LOLE is the driving criteria at any given point in time. Also, the requirement for added peaking diesel compared to Resource Plan approaches is more limited than under the steady state philosophy, roughly calculated at less then $0.3 million over the 8 year period 2009-2016 (assuming Minto is in-service)[1].

[1] Note also that this is peaking diesel that will be required during actual ice events such as occurred in 2000/01. As such even though the Resource Plan did not consider this requirement, neither the ice study nor the choice of operating philosophy *create* this requirement, they simply serve to inform the calculation of a peaking diesel requirement that has existed all along whether it was modelled or not.

The adaptive philosophy also offers the advantage that it appears to drive very little to no changes to the YEC basic operational planning, with the exception of a requirement for ice event monitoring.

A further conclusion of the draft ice study that is relevant for planning purposes is the determination that the effective maximum output of Whitehorse Rapids that could be achieved on a planning basis, by way of enhanced upstream storage, is 30 MW. Were YEC to aggressively pursue upstream storage that would otherwise provide for more than 30 MW of firm flows, it would still not be prudent to dispatch such flows during early winter as, during a bad ice event, YEC would not be able to prevent flooding and still maintain its licenced minimum flows of 85 cms. As a result, such flows would not be firm for capacity planning purposes.

KGS Ice Study

Pursuant to issues raised in the Resource Planning process in 2006, YEC engaged KGS Group engineers to investigate the icing conditions on the Yukon River downstream of the Whitehorse plant, to determine the constraints if any posed by ice on the use of the plant at higher output levels than presently targeted.

The draft KGS study, dated April 2007 (and subsequent presentation dated June 2007), indicates a number of key findings with respect to ice. These conclusions drive implications for the Whitehorse system that require further consideration to understand the full impact on YEC's (a) plant operating philosophy, (b) diesel generation requirements (i.e., fuel) for peaking, and (c) capacity planning criteria. This memo focuses on the implications for capacity planning criteria.

The relevant points raised in the KGS work for the purposes of this review are as follows:

- The ice conditions on the Yukon River are variable from year to year and, not unlike other comparable northern rivers, it is difficult if not impossible to predict with any certainty which years will be 'bad ice' years in advance.
- The last bad ice year was 2000/01, which occurred since the last studies of icing on the river in about 1994. This means that substantially new data has contributed to the present models compared to past reviews.
- YEC can confirm the high water experience in 2000/01, and excellent data is available regarding the water levels and flows at Marwell (locations upstream and downstream of Marwell are not of the same level of completeness[2]). Although the 2000/01 year was the worst year recorded (out of a sample set of about 14 years of good data on ice and water levels), it is not anomalously bad compared to what would be expected on a river of this type (calculated ice roughness values consistent with 2000/01 are approximately equal to the normal top end of the range for roughness values on comparable rivers).
- The implications of bad ice are worst at the time the system is peaking – that is, very cold days in the early part or the middle of winter:
    - During a bad ice event in the worst ice conditions on record, the system output can be cut back by YEC to avoid flooding. However, the amount of cut back required depends on the level of output in advance of the icing event. For example, if the plant output was

[2] KGS has recommended further consideration be given to data monitoring to ensure, among other things, that future data collection focuses on more locations on the river.

25 MW before the icing event, it would need to be cut back to approximately 15 MW to avoid flooding. If the plant were operating at 30 MW in advance of the icing event, the level of cutback would have to be to approximately 10 MW (or approximately equal to the licenced minimum flows). The steady state operating level where no cutbacks would be required is approximately 21 MW. The duration of the cut back would not be for the entire winter, however the precise duration can not be predicted. It is expected that the duration would be for at least a period measured in weeks, and that the ultimate level achievable for that winter would never be as high as in a winter without bad ice (i.e., the effects to some extent linger the entire winter).

  - The second worst year on record does not have comparable detailed data, but based on inference from the data available, it would suggest no cut back is necessary at 25 MW output before the event, and cut back to 18 MW based on 30 MW before the event. This is summarized in the following table:

Level of output prior to icing event:	Level of cutback required during event comparable to worst icing event on record (2000/01)	Level of cutback required during event comparable to second worst icing event on record (1978/79)
21 MW	None	None
25 MW	15 MW	None
30 MW	Approx 10 MW (approx equal to licenced minimum flows)	Estimated at 18 MW

- The 2000/01 experience is sufficiently likely that future instances of bad ice similar to this year must be incorporated into system planning. However, the plant allows for a flow reduction response to ameliorate flooding, such that the key issue is not physical risks to property and persons, but to the economics related to the plant operating philosophy and firm plant rating.
  - ***Operating philosophy:*** The study effectively indicates that there are two operating philosophies for the plant that could be used. The first is to ensure that, during the key parts of the winter, the plant is operated such that no cutbacks would be required in firm plant output in the event a bad ice year arose. This is equivalent to an operating philosophy of maintaining an output that is no higher than about 21 MW during the first half or so of winter (i.e., a 'steady state' philosophy). The alternate operating philosophy is to maintain output at the levels otherwise indicated by system demand, and be prepared to cut back, potentially dramatically, if an icing event arises (i.e., an 'adaptive' philosophy). Clearly, the first philosophy provides less peaking capability from the Whitehorse plant than the second, which will consequently require more diesel generation (fuel consumption) to meet peak loads during these times [and consequently more frequent interruption of secondary sales].
  - ***Firm Plant Rating:*** Depending on the operating philosophy selected as noted above, concerns arise that the Whitehorse plant may not be as capable as it has previously been assumed (at 24 MW). This is because there are conditions where the plant could be cut

back below 24 MW in an icing event. One initial reaction is that perhaps the plant is only capable of 21 MW at best, which may serve to diminish the measured capability of the system by 3 MW. However, further concerns were noted in the event that the adaptive system operating philosophy were selected from the note above, in which case the plant may in fact risk being cut back to well below 24 MW (perhaps 15 MW) which might be a major adverse impact on measured system capability (loss of 9 MW of firm capacity).

Capacity Implications

In order to understand the appropriate way to address the ice study implications on capacity planning, Dr. Billinton was consulted. Briefly, the discussion noted the following key points:

- **N-1:** Although an icing event is one factor that could affect the availability of capacity on the system, it is not as large as the impact of losing the Aishihik transmission line (30 MW+), and as a result would not change the approach to determining system capability as measured under the N-1 criteria. [Note that the N-1 criteria is the driving factor for new capacity additions today]. So long as the Whitehorse plant retains its 24 MW rating in the N-1 formula (i.e., its capability during non-adverse events is at least 24 MW) the N-1 calculation would not change due to the KGS report. In considering the above two operating philosophies, the following points are noted:
  - **Adaptive:** Under the adaptive philosophy (operate in the range of 24-25 MW for early part of winter, drop to 15 MW as needed for adverse ice conditions) the system would have a new N-1 type of event related to ice (10 MW, related to dropping from 25 MW to 15 MW), but since it is less than the 30 MW due to the Aishihik line, it does not change the N-1 conclusions in regards to the system.
  - **Steady State:** Under the steady state philosophy, the WH Rapids plant would be operated at 21 MW under a standard rule for at a minimum the early part of winter. As a result, the N-1 event driving the system would remain the Aishihik transmission line (loss of 30 MW) but the remaining generation during this even would be 3 MW lower than assumed to date (as WH Rapids only operates at 21 MW, not 24 MW as previously reflected in the N-1 mathematics). In other words, under the N-1 calculations, this would drive a requirement for 3 MW added capacity from other sources compared to calculations used in the Resource Plan filing.
- **LOLE:** The icing events should be considered in the context of an LOLE analysis. However, a number of scenarios should be run using the WAFSREL software to determine the materiality of the impact. This should be done for two scenarios in order to aid in YEC assessing the response to the icing study – once for the steady state operating philosophy (maintaining the WH plant rating at 21 MW) and once for the adaptive operating philosophy (weighting the cases by the calculated probability associated with each case). For example, the worst icing case today is assumed to be a 1 in 14 event, or about 7%; however for output levels above 25 MW to about 30 MW output, the second worst icing event would also cause issue (for a 14% chance of being cut back to some degree). Scenarios with output levels above 30 MW would not be considered as at this output level YEC begins to run risk that maintaining licenced minimum flows while still avoiding flooding may be incompatible (10 MW is approximately equal to licenced minimum flows). The LOLE and LOEE measured under each operating philosophy and scenario should be

compared to determine the appropriate modelling approach, and to determine the net impact of the icing study on the measured Whitehorse capability. This analysis may also aid in assessing the merits of the two alternative operating philosophies.

For the purposes of modelling, Dr. Billinton indicated that compromised winter output levels are likely best modelled in the WAFSREL without the complexity of reflecting partial winter effects (e.g., assuming compromised output in low flow years occurs for the winter in question, rather than partial season effects).

The LOLE/LOEE analysis has now been completed, and the results are summarized as follows:

- All LOLE/LOEE analysis has been performed on the system as it existed at the time of the Resource Plan (i.e., it does not yet reflect the refurbishment of the Faro Mirrlees) but does include the Aishihik 3rd turbine. This assumption appears reasonable, as the analysis at this stage only focuses on the change in peak load carrying capacity using the three different conditions (RP assumptions, new icing constraints under a steady state operating philosophy, and new icing constraints under an adaptive philosophy), not on the absolute carrying capacity.
- The cases run using the modelling software (WAFSREL) are summarized as follows:
    - The ***Resource Plan case*** reflected a 2.0 hours/year LOLE and a 6.5 MWh/year LOEE at a 63.4 MW peak. Given 2.0 hours/year was adopted as the LOLE planning criteria, this was the maximum system peak that could be carried by the system under this criteria.
    - ***If the icing study is adopted using a steady state philosophy*** (assuming 21 MW operating maximum in the early part of winter) the same target LOLE of 2.0 hours/year (and same level of LOEE of 6.5 MWh/year) would occur at a peak load of 59.9 MW to 60.1 MW, or a net negative impact on load carrying capability of 3.4 MW.
    - ***If the icing study is adopted by way of an adaptive philosophy at a maximum 25 MW in early winter*** the system target LOLE would occur at a peak load 63.1 MW, or a reduction in system capability of 0.3 MW. The LOEE equivalent of 6.5 MWh/year would be achieved at a peak load of 62.3 MW, a reduction of 1.1 MW[3]
    - ***If the icing study is adopted by way of an adaptive philosophy at a hypothetic maximum 30 MW in early winter*** the data is not yet fully assessed. This is largely hypothetical as the system is not otherwise today assumed to be capable of this scale of output in winter – it will only be a relevant consideration in the event major new upstream storage is considered for

[3] Note however that this in particular may overstate the full LOEE impact as it is based on the assumption that 7% of the years the system will be limited to 15 MW for the entire winter, which is not correct – as noted above, the peak would be allowed to trend up starting a few weeks after the icing event.

development[4]. The full analysis of this approach would assume 30 MW for 86% of winters, 18 MW for 7% of winters (represented by the second worst year on record) and 10 MW for 7% of winters (represented by the worst year on record). A simplified analysis has been conducted which focuses on only two states – 30 MW for 86% of years, and 10 MW for 14% of years. This yields a carrying capacity at the LOLE target of 2.0 hours/year that is 59.9 MW (3.5 MW below the Resource Plan assumptions) and an LOEE of 6.5 MWh/year at 55.8 MW, 7.6 MW below the Resource Plan assumptions. However note that this simplified "two state" approach is overly pessimistic to some degree compared to a full (but more complicated) "three state" approach (30 MW at 86%, 18 MW at 7%, 10 MW at 7%).

In summary, with respect to capacity, adopting the ice study conclusions by way of implementing a new 21 MW "cap" to output in the early part of winter appears to drive a requirement for on the order of 3 MW of new capacity elsewhere on the system (using Resource Plan assumptions, this impact may be assumed at $0.8 to $0.9 million/MW (2005$) or $2.4 to $2.7 million requirement for incremental capital investment (if achieved through new thermal capacity)). If instead YEC chooses to implement a new adaptive regime based on retaining a 24-25 MW operating target for the early part of winter, knowing that in a certain percentage of years this will be cut back as far as 15 MW on short notice, then the incremental capacity required to address the conclusions of the ice study ranges from 0 MW (during the period N-1 is the driving constraint on capacity additions) to 0.3 MW (when LOLE is the driving constraint) or less than $0.3 million in incremental capital investment (if achieved through new thermal capacity).

Peaking Energy Implications

As noted above, the choice of new operating philosophies for the system to incorporate the conclusions of the ice study may drive some changes to the degree of peaking diesel required to operate the system. To estimate this impact, the 8 year period 2009-2016 inclusive was considered, assuming Minto was on the system at 32.5 GW.h/year, and all other assumptions as per the Resource Plan base case. Under the Resource Plan assumptions, the adoption of a steady state model for the system in the early part of winter (capped at 21 MW) appears to drive added peaking diesel costs over 8 years in the range of $0.7 million (slightly less than $0.1 million per year on average).

In contrast, adoption of an adaptive philosophy would drive no new assumed peaking diesel in 93% of years, and added diesel for the 7% of years where bad ice events occur (as the Whitehorse plant would be limited to 15 MW for sustained periods of time). An rough initial estimate of the impacts of peaking diesel during these bad ice events is less than $0.3 million for the 8 year period (under $0.04 million per year).

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[4] The degree of storage would need to be very large (on the range of 6 MW increase in winter outputs – by comparison Marsh Fall/Winter storage was only assumed at 1.6 MW, and large scale Atlin storage schemes from the early 1990s do not even approach this magnitude).

These results require further consideration before using for planning purposes or, for example, in discussions with industrial customers. At a comparative level, however, they support the conclusion that restricting operation to 21 MW in the early part of winter in all years results in adverse impacts on peaking diesel in excess of that occurring if electing to use an "adaptive" approach operating at 24-25 MW in most years, and 15 MW for portions of bad ice years (7% of the years assumed).

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REFERENCE: **YEC Application**

ISSUE/SUB-ISSUE: **Capital Projects, Section 5.2.1**

QUESTION:

a) Are Yukon ratepayers responsible for the $3.744 million cost overrun related to the Stage One CS/MS development? If so, please explain how this fulfills the condition that ratepayers would not be adversely affected by this project.

b) Please provide an updated business plan related to the CSTP.

c) What are the incremental costs with respect to purchasing the Minto diesel units if YEC chooses to relocate the units to another location on the system? Please provide detailed cost-benefit analyses with but not limited to the following three options: existing substation, a new substation or sale.

d) Please provide a detailed comparison between forecast and actual costs related to the Faro Mirrlees (FD1) re-commissioning project and variance explanations.

e) Provide a cost-benefit analysis respecting the timing of refurbishment of Whitehorse Unit #1 (Mirrlees unit) that includes the option of "mothballing".

f) Please describe YEC's policy in regard to the expensing or capitalizing "… early planning and feasibility work (as well as permitting work …).

g) Is it YEC's view that the use of its diesel units is limited to one that of peak shaving unless an emergency exists on the grid? In the answer, please provide a detailed explanation and business case as to YEC's strategy in the near- and long-term.

h) Considering the current cost of fuel, is the addition of the third turbine at Aishihik still an economically viable option? Please provide an updated business case.

ANSWER:

(a)

Yes. Yukon Energy's business plan for Stage 1 CSTP as set out in the filing for an Energy Certificate allowed for such added costs, if they occurred, to be borne by ratepayers, subject to the constraint that the Project had to result in an overall net benefit savings for ratepayers after consideration of the new connected Minto Mine and Pelly Crossing loads being served by surplus WAF hydro generation.

Yukon ratepayers have not been adversely affected by the CSTP. The 2008/2009 General Rate Application incorporates net benefits to ratepayers due to provision of grid service to Minto mine and Pelly Crossing through the proposed rate reduction of $0.360 million in 2008 and $1.334 million in 2009 (3.48%). As noted in the table provided below, absent the additional revenues provided through grid service to Minto mine and Pelly Crossing through completion of CS Stage 1, Yukon Energy's retail rate revenue requirement would be $0.567 million and $2.572 million higher in 2008 and 2009 respectively. In summary, without CS Stage 1 Yukon Energy's retail rate revenue requirement would require a firm retail rate increase in 2009 of $1.238 million (+3.23% if applied as an across-the-board retail rate rider).

As shown in the table below, the absolute amount of the revenue requirement would be lower without the Minto connection in service (due to removal of the CSTP net cost referenced in the IR). However, due to the materially decreased sales volumes absent the Minto and Pelly Crossing connections (31,323 MW.h lower total sales in 2009), the overall net impact on ratepayers absent CSTP would be a requirement for a rate increase to meet the revenue requirement.

The approximate quantified details of benefits and costs to ratepayers of the Stage 1 CSTP (including the Minto and Pelly Crossing connections) are provided in the table below. This table does not include more minor effects of CSTP and related Minto load, such as potentially modestly higher use of diesel for peaking or incremental transmission O&M, but also does not include the full benefits of CSTP from connecting Pelly Crossing – only the new wholesale revenues are included (at 6.84 cents) and not the full benefits of taking Pelly off of diesel (which accrue to ratepayers via a lower YECL revenue requirement, not YEC's revenue requirement).

Approximate Impact of CSTP on YEC retail rate revenue requirement ($000s)

	2008 w/o CSTP	2008 with CSTP	2008 Difference	2009 w/o CSTP	2009 with CSTP	2009 Difference
Lost Revenues w/o CSTP						
Sales (MW.h)						
Primary wholesale	*258,439*	*258,989*	*-550*	*264,626*	*266,926*	*-2,300*
Primary major industrial	*0*	*6,845*	*-6,845*	*0*	*29,023*	*-29,023*
Industrial Revenue (incl "fixed" Rider F)	0	749	-749	0	3,312	-3,312
Wholesale Revenue	17,681	17,719	-38	18,130	18,287	-157
Change in Revenues at Existing Rates			**-787**			**-3,469**
Cost Savings w/o CSTP						
Net CSTP Depreciation (per YUB-YEC-1-9)			-30			-118
Rate base (adjustment per YUB-YEC-1-9 and UCG-YEC-1-73)	*144,283*	*145,212*	*-929*	*147,749*	*151,415*	*-3,666*
Change in return on rate base (using average cost of capital in GRA - 6.86% and 7.17% respectively)			-64			-263
Canada Flexible Term Note savings						
Interest expense (due to lower WAF sales)	1,129	1,255	-126	1,195	1,712	-517
Approximate Change in GRA Rev Req			**-220**			**-897**
Net Impact of situation with no CSTP						
Retail Rate Revenue Requirement would be higher by:			**567**			**2,572**

(b)

The Application (Section 5.2.1.1) provided update information on the business plan for Stage 1 CSTP which the Board had previously reviewed; the overall Application addressed the matter of overall net benefits that resulted in the proposed rate decrease for all retail Yukon ratepayers. Further updated information consolidating and summarizing information on ratepayer net benefits is provided in the table included above in **(a)**.

(c)

Under the terms of the PPA, YEC is obligated to keep all four units at the existing location adjacent to the Mine for two years. After that, two units must be at that site for an additional six years, or until YEC's security interests are discharged, whichever is earlier. Under all scenarios, Minto has certain rights to repurchase the units if and when YEC wants to move them from the site. YEC would not intend to move a unit from the site except under these conditions and supporting analysis that such a move was beneficial to Yukon Energy's ratepayers.

Analysis of the incremental cost of moving any of the skid-mounted units has not been undertaken to date, and detailed cost-benefit analysis of the options identified cannot be provided at this time. Such costs and benefits could vary depending on when and where the units would be moved (i.e. enhancement to an existing YEC diesel plant compared to developing a new YEC diesel site), what the system planning model for firm supply requirement were indicating at the time of the move, and what options Yukon Energy could consider at that time. Sale options, beyond sale back to Minto, would depend on then current market conditions.

(d)

The original budget for this project in total, as set out in the November update to the Resource Plan, and reviewed in section 6.9 of the Board's Recommendations on the Resource Plan, was $2.3 million.

The project in total comprises a number of small activities as well as the major task of performing a major overhaul on the unit. The 2007 spending comprises $0.407 million spent on the unit (as shown in Table 5.2 under Major Projects) plus a series of other items recorded in the Generation component of Table 5.2, totaling $0.225 million, for a total 2007 spending of $0.631 million. The forecast 2008 spending in the GRA was $1.158 million to complete the project. While the project was not completed by year-end 2008, the total spending required to complete the project is still forecast at approximately this same level, and remains below the $2.3 million level forecast in the Resource Plan.

(e)

The timing of the refurbishment of Diesel Unit #1 at Whitehorse (WD1) is not a cost benefit question per se, it is a question of when the required firm capacity is needed. If not required under the N-1 standby criteria, a later date for the refurbishment is preferable since the funds would not need to be expended until later. No cost estimate of mothballing the unit has been developed at this time. As set out at Tab 5, page 5-9, no decisions regarding rebuild versus mothball are expected to be made until closer to 2012, based on resources and load then expected to be on the system.

(f)

The reference is in the context of planning for new generation. In this instance, the cost of early planning and feasibility are recorded in a capital work-in-process (WIP) account. This WIP account accumulates costs until a construction decision point is reached (i.e., a go/no-go decision). If the decision is made to proceed with the project, these costs will be included in the overall final cost of the project. If the decision is made to not proceed, the costs will be written off over five years on a straight line basis.

(g)

In the test years, Yukon Energy is forecasting that diesel generation requirements will be for peaking and other non-baseload generation as described in the Application. These units would also be used as required to address emergency conditions.

Beyond the test years, Yukon Energy has noted that reduction/utilization of the hydro generation surplus may occur and would require Yukon Energy to use some of these diesel units for baseload generation, absent new or expanded renewable power sources being brought on line. It is well known, however, that under sustained baseloaded conditions, there can be an opportunity to develop new renewable generation on an economic basis for long-term benefits related to cost savings, environmental aspects, and development of local resources. Yukon Energy is working to minimize the need for baseload generation through timely development of additional renewable energy generation. The business case for each such addition needs to be assessed on its own merits. For example, see YUB-YEC-1-38(a).

(h)

Yes.

Updated cost and contribution information is provided in the Application, Section 5.2.1.5.

The Resource Plan reviewed the economics of an Aishihik 3rd turbine on the basis of diesel at $0.70 to $0.75 per litre and concluded it was an economic project even without government funding. Since that time, $5 million of government funding has been committed.

Current and projected fuel prices imply an increase, rather than a decrease, in these net benefits.

Please see response to UCG-YEC-1-17.

REFERENCE: **YEC GRA**

ISSUE/SUB-ISSUE: **Capital Additions, Section 5.2.2**

QUESTION:

a) Please provide Table 5.2 in an Excel spreadsheet complete with formulae that underpin the calculations.

b) Please provide an explanation as to why the Mirrlees Electrical Upgrades expenses are not included in the associated Mirrlees project that is greater than $1 million (Section 5.2.1.3).

c) Please provide a business case that justifies the $1-million Financial Systems Software Replacement expenditure.

d) With respect to L170 Line Assessment Phase 2 Carmacks - Faro, please explain what is included in the line assessment and how often a transmission line assessment is performed. Please present the findings of the 2006-07 line assessment and what type of maintenance that is required on the line.

e) Please describe YEC's pole-replacement and brushing programs in detail.

ANSWER:

(a)

As noted in response to UCG-YEC-1- 81(a), page 5-25 in the Application, which shows customer extension spending for 2005 to 2007, contains an error in the categorization of certain elements of distribution spending. A corrected version of Table 5.2 will be provided once available.

(b)

The Whitehorse Mirrlees Refurbishment is not one single project, but involves a staged refurbishment of three separate units (WD3, WD2 and WD1) over a period of years, as well as separate smaller projects (i.e., less than $1 million) involving upgrades to common systems. Page 5-9 of Tab 5 of the 2008/2009 General Rate Application details the Mirrlees Refurbishment being undertaken by Yukon Energy at this time, noting in addition to refurbishment activities specific to each of unit #3, unit #2 and unit #1, “a series of projects on “common” systems occurring in 2007 (0.468 million), 2008 ($0,450 million) and anticipated for the following years (2010 – 2012, $1.465 million).”

(c)

Yukon Energy purchased and installed the JDEdwards financial package in 1999. Since that initial installation, JDE & Co has been “acquired” twice – once by Peoplesoft who were in turn bought out in a hostile takeover by Oracle Corporation in late 2004. At the time of the acquisition, Oracle announced intention to amalgamate the three products into one. These acquisitions created concern for Yukon Energy around:

1. How long JDEdwards would be supported as a stand-alone product. The current version that Yukon Energy uses (XE) has not been supported by Oracle since February 2007;

2. The fact that Oracle database structures are not compatible with Yukon Energy’s current database structure; and

3. The perception that Oracle products are too “up-scale” for a small company like Yukon Energy.

Management made the decision at that point not to invest in large scale upgrades of the existing system, with the view that a replacement system would be necessary in the next few years. In addition, the quote below is an extract from the Business Impact Assessment, dated January 2006:

> While the financial systems are based on JDEdwards One World, it is not fully utilized but is in place and managed internally with some help from outside contractors. On more than one occasion the corporation has unsuccessfully tried to modify JDEdwards to fit its mode of operations. As a result of these failed attempts and the perceived rigidity of the product YEC finds itself with a sub-optimal JDEdwards configuration. Furthermore, One World is at end of life and a replacement is planned for 2008. One World is the source of several challenges from a Business

Impact Assessment point of view. With a chart of accounts that is described by users as clumsy or awkward, there is little incentive to use JDE as it is intended to be used, a fully functional Enterprise Resource Planning (ERP) system which touches most, if not all aspects of the business. Because of this, a number of isolated stand alone systems are also in use – HRManager for example which disintegrates the business functionality of the Human Resources group. A fully disintegrated model might even be preferable to the patchwork that is now in place supported by spreadsheets and errant databases. Without JDE Finance would find functioning to be a challenge but the system is not used for the tasks required of it.

Specifically, the purchase of a new system is planned to correct a number of deficiencies in existing programming:

1. Integrated system will eliminate duplication of data in key areas such as budgeting, forecasting, inventory and maintenance;

2. New system will have the functionality to track projects against committed costs;

3. New system will have enhanced reporting capabilities that will allow project managers to access data on a more timely basis without intervention from Finance staff;

4. Eliminate manual processes and “work-arounds”; and

5. Optimize chart of accounts for utility business.

(d)

Yukon Energy’s transmission line assessments involve a ‘fine toothed comb’ field inspection and audit of every structure, pole, and piece of hardware on the line. The inspectors are trained and experienced to spot hardware issues on each component of the line, and to rate issues from ‘fix immediately’ to ‘repair/replace in 5-10 years’, or ‘information only’. A photographic library of each structure at the time of inspection is compiled, and GPS location data of each asset recorded to include in our mapping system. As the line is quite old (original construction in 1968), certain components either wear out, become loose, degrade, or succumb to stress over time and need to be repaired or replaced. A detailed inspection is a way of finding those issues, tracking the condition of the line, and prioritizing repair and replacement of defects to avoid an in-service failure.

The priority system used by the consultant is as follows:

Priority 1
Indicates a very serious reliability or safety concern. Repairs or modifications should be made immediately (probably within 1 to 2 days). Examples - broken pole or cross-arm, trees burning in the line, etc.

Priority 2
Indicates a reliability or safety concern which is serious enough it should be rectified in the not too distant future (possibly within 3 months). Condition is serious enough that it would probably be dealt with prior to the next scheduled routine maintenance. Examples include trees within limits of approach to line, ground clearances which do not appear to meet the ECUC, seriously damaged conductor, etc.

Priority 3
Indicates a reliability or safety concern which should be corrected, but that is minor enough that it could be rectified as part of a planned maintenance program (possibly within the next 1 to 5 years). Examples include cross-arms which do not appear to be in good shape but will probably last a few more years, loose hardware, synthetic insulators with corona damage, etc.

Priority 4
Indicates a reliability or safety concern which is minor enough it would only be corrected if convenient to do so. Corrections would only be made if other work were being done in the same area or on the same pole. Examples include flashed or chipped insulators, danger trees which appear stable, etc.

Priority 5
Indicates a comment which is recorded for information only – no corrective action is required. Examples include synthetic insulators which have corona rings, swamp guys which are slightly slack, etc.

Priority 9

Indicates work was minor enough that it could be completed as part of the inspection being done. In this case it is a list of corrective work which was completed by EHV Line Consultants when doing the line inspection. Examples include re-tensioning guys, replacing structure number tags, digging out buried pre-form grips, etc.

Based on the above-noted priority system, the number of priority issues found are as follows:

1- 0
2- 120
3- 1280
4- 1890
5- 449
9- 586

A plan is being formulated to deal with the highest priority of these issues.

(e)

All transmission lines are inspected both from the air (annually) and on the ground (particular sections identified from the air). Brushing requirements and any other issues or problems, such as poles that need replacement, are identified. These inspections are then converted into work plans for the highest priority areas and issues. All transmission line right-of-ways are brushed every 3-4 years.

REFERENCE: YEC GRA

ISSUE/SUB-ISSUE: Deferred Cost, Section 5.3

QUESTION:

a) Considering current fuel prices, please provide a cost-benefit analysis for the near-term Mayo B hydro generation expansion.

b) Please provide details as to what customers can expect in regard to YEC's proposed "Other Generation Feasibility" significant $7.6 million expenditure over the test years?
   ii. Please define what is meant by a "pre-feasibility study".
   iii. Does YEC perform the studies or are these third-party studies? Please explain.
   iiii. Please provide a cost-benefit analysis for the $7.6 million expenditure.

ANSWER:

(a)

The Mayo Hydro Enhancement Project ("Mayo B" or "the Project") involves enhancements to the existing Yukon Energy Mayo hydroelectric facilities to increase power production. It comprises the construction of a new powerhouse and related facilities, as well as adjustments to the management of water on the Mayo River system. The Project has a planned in-service date of late 2011.

Yukon Energy Corporation (Yukon Energy) is undertaking all required planning, consultation, environmental, engineering and other related activities in order to obtain authorizations and approvals necessary to allow for a decision to commence construction of the Project in 2010. At this time, Yukon Energy has made no final decision to proceed with the Project.

Yukon government and Federal government regulatory approvals and decisions are required before any construction activities may be undertaken; however, these approvals and decisions may only be made after the required screening assessment by the Executive Committee of the Yukon Environmental and Socio-economic Assessment

Board (YESAB) of the Project Proposal Submission (Project Proposal). On February 27, 2009, Yukon Energy submitted the Project Proposal to YESAB.

As noted in the Project Proposal, the Project cost estimates to date reflect a period of study oriented to confirming the technical ability to construct the Project, and the timing and configuration of major Project components. The estimates reflect activities oriented towards a "Level 3 – Feasibility" stage of study, and are subject to design refinement, and changing market conditions (including general economic conditions for construction in western Canada).

The cost of the Project is presently estimated at $120 million (including escalation, interest during construction, and contingencies of 15% to 25% depending on the Project component). This estimate has been subjected to a preliminary third-party review. This review indicated that there may be a potential upward adjustment to the cost of up to 5%.

Similar to other hydro projects, a material component of the Project costing cannot be confirmed with reasonable certainty until the Project is tendered. The selection of a canal format (as opposed to a tunnel) likely reduces the degree of tender price risk, and future geotechnical risk to Project costs, but this uncertainty cannot be eliminated prior to the tendering process being completed.

At $120 million (and ignoring potential government infrastructure funding), the full assumed output of the plant of 38.4 GWh (under full long-term load conditions) yields a levelized cost of energy ("LCOE") for the capital cost of the project of $0.142/kW.h. In the near-term under reasonably foreseeable load conditions, integration of the Project into Yukon power systems would be expected to yield a somewhat smaller net firm energy benefit, potentially as low as approximately 30 GW.h of firm energy (plus up to 10 GW.h of enhanced potential secondary energy should there be loads available to purchase this supply). In such a case the levelized cost of energy would approximate $0.182/kW.h. By comparison, diesel costs in the application are forecast at $0.3737/kW.h, and per UCG-YEC-I-62 remains at $0.248/kW.h at today's fuel prices.

In order to enhance the opportunity for stakeholders to secure benefits from the Project including Canada, Yukon, ratepayers and NND, a variety of possible financing approaches are being considered. No further details on the precise form and source of financing are available at this time. However, in order to keep costs and risks to Yukon ratepayers within acceptable bounds (e.g., more in line with B.C green market power purchase costs of 8 to 10 cents/kW.h) it is anticipated that government infrastructure funding will be secured for a material portion of the project costs. Also there are ongoing discussions with NND relating to the possibility of NND investing in the Project.

(b)

The other supply options category comprises $0.7 million in 2008 and a further forecast $6.8 million in 2009. The current plan adopted by Yukon Energy for 2009 is reduced from the level assumed at the time of the GRA, to a level of $4.3 million, approximately as follows based on current draft plans:

- **Aishihik Diversions (Gladstone):** $800,000. This project has the potential of increasing Aishihik output by up to 18 GW.h/year on average, at a relatively low capital cost.

- **Atlin River:** $700,000. This small scale storage project has the potential to increase Whitehorse Rapids average annual output by up to 18 GW.h/year.

- **Marsh Lake Fall/Winter Storage:** $300,000. This project, previously reviewed by the YUB, is an attractive source of enhanced output at Whitehorse Rapids (up to 7.7 GW.h) and an update is required based on the new results of work completed by the Yukon Government, as well as Yukon Energy, with respect to the effects of high water levels on Marsh Lake.

- **Geothermal:** $1 million. This project remains in investigatory stages. No specific energy output has been identified.

- **Other Larger Hydro:** $600,000. Yukon Energy has updated its inventory of hydro sites in the 50-100 GW.h range, but has not done comparable work for larger sites in Yukon.

- **Existing System Operating Studies:** $220,000. Both Mayo and Aishihik plants have operating issues that may serve to alter the generation potential of the plants in future. For example, Aishihik's long-term output is currently constrained by the conditions of a Fish Act Authorization, which is subject to review based on ongoing fisheries work. The impact of more restrictive fish conditions could readily be 5 or more GW.h per year on average, depending on load conditions.

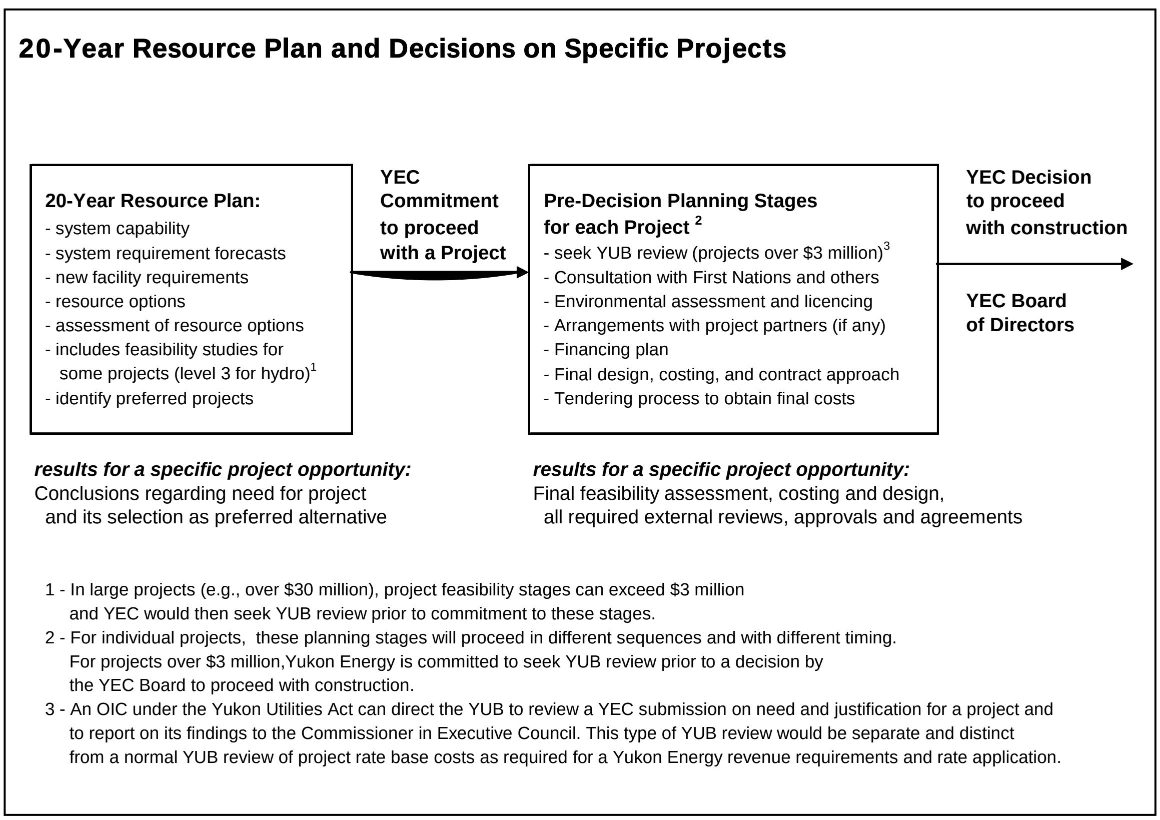
- **Wind:** $30,000. Develop longer-term monitoring plan and assess the results of pre-feasibility work completed in 2008.

- **Internal Efficiency Projects and Overall Management:** $650,000. Budgets for internal reviews of the potential for significantly improving the output of existing facilities from re-runnering or other similar improvements in the generation or electrical areas.

(i)

Pre-feasibility studies are consistent with the activities noted in Figure 1.1 from the 20 Year Resource Plan (repeated below) as the activities leading to the selection of a specific project as a "preferred alternative" and the initiation of "pre-decision planning stages".

Figure 1.1 from 20 Year Resource Plan



(ii)

Yukon Energy staff are involved in the studies, but typically they involve significant external expertise and support, particularly for generation projects.

(iii)

As noted above, the expenditure is now slated at the lower value of $4.3 million in 2009. No cost-benefit analysis is possible as the specific cost and output values associated with each project are not yet available, nor is the technical or environmental/licencing feasibility established (this is the basis for the pre-feasibility work).

REFERENCE: **Report to Yukon Minister of Justice, YEC Application for an Energy Project Certificate and Energy Operation Certificate Regarding the CSTP (May 31, 2007)**

ISSUE/SUB-ISSUE: Costs of Stage One of CSTP

On Page 13 of 17 of the report: The Board recommends that the Minister direct YEC to consult with the Minister before making any decision to proceed if the tendering process results in a capital cost that is materially above the high end of YEC's estimate of $25.9 million or if schedule delays result in the in-service date slipping beyond the end of 2008.

PREAMBLE:

During the process (Application for an Energy Project certificate …) financial details were not available to the Board.

QUESTION:

a) Please provide a copy of the winning tender for the CSTP project.

b) Given the capital costs exceeded $25.9 million, please provide a copy of the letter to the Minister where YEC sought consultation to proceed with the project.

c) What was YEC's stop point for the project? That is, at what capital cost was YEC not going to proceed? Please show all calculations on how that point was determined.

ANSWER:

(a)

There were several key tenders (rather than only one winning tender) that were let as part of the construction phase of this project. Each tender/contract document covers a wide range of issues and is not suited to being copied for distribution here. Information is provided below on the tender process and key outcomes related to financial information.

Focusing on the financial budget related elements of the tenders and contracts, the table below summarizes the contracts tendered[1] and related cost awards estimated for Minto Spur and CSTP Stage I portions at the time the YEC's Board decided in September 2007 to proceed with the project (subject to receipt of all required permits and approvals):

Work Description[2]	**Minto Spur**	**CSTP Stage I**	**Contract Total**
Project Management	311,645	686,165	997,810
Survey	157,863	534,616	692,479
Clearing	456,273	2,945,852	3,402,125
Line Construction	2,166,010	13,551,626	15,717,636

The above line survey, clearing and construction estimates reflected tenders based on YEC's proposed route, and did not reflect subsequent adjustments needed in response to the subsequent Final YESAB Recommendations affecting the Tatchun Creek CSTP re-route and finalizing the Yukon River crossing (and related MS line location leading to this crossing). See response to YECL-YEC-1-9(b) regarding the financial impact of these specific scope changes.

As at September 2007, YEC had initial engineering cost estimates for substation civil and electrical work; beyond an early order for the major transformer, other tenders and contracting for this substation work was deferred until early in 2009, reflecting the fact that this work had to be deferred until that time and the overall costs for this component were expected to be a relatively small portion of the overall project budget.

The figures in the above table were included in the accumulated budget package approved for construction by the YEC Board of Directors in September 2007. The total approved budget for CSTP Stage I at that time was as follows (contingencies included in the above assessments were pooled under one category below):

[1] The clearing contract was awarded, pursuant to the Project Agreement with NTFN, to a nominee of the NTFN. The other contracts listed were each awarded after a competitive tender or RFP process.

[2] The successful Consultant/Contractors for all winning tenders are identified in response to YECL-YEC-1-16(d), along with the current YEC Board approved contact amounts.

Project Management	686
Survey	535
Clearing	2,945
Line Construction	13,552
Substations	1,654
Owner's Costs & Contingency	6,034
Planning	2,382
Total	**$27.788**

In spring 2008**,** tenders were issued for the substation work and for the commissioning work, thereby completing the package of contracts awarded for the CSTP/MS project.[3]

(b)

In compliance with the YUB's recommendation YEC met with both the Minister of Justice and the Minister of Energy and reviewed in detail the project costs when it became apparent that the capital costs of the Project would exceed $25.9 Million. No letter was sent to the Minister in this regard. Prior to start of construction of the CSTP Stage 1, YEC received the necessary Energy Certificate from the Minister of Justice.

(c)

There was no specific stop point ever adopted by the Board of Directors. Instead the Board focused on confirming, based on the available information, that Yukon ratepayers would indeed still secure net benefits from connection of the Minto load and Pelly Crossing.

The project was planned throughout using a phased approach whereby the Board could review results at defined decision points prior to putting more budget dollars at risk. At the September 2007 meeting where the construction was approved, the Board had tendered costs for the items in (a) above, approved funding from YG and YDC and an approved PPA from Minto committing to a $7.2 million contribution to the project. At that point, the Board concluded that there was acceptable risk given the future revenue

[3] See YECL-YEC-1-16(d) for successful contractors and the current YEC Board approved contact amounts. See YECL-YEC-1-9(b) regarding the cost increases associated with the substation contract awards. See YUB-YEC-1-40(a) for a review of cost increases affecting the Minto Spur, including substation cost increase impacts. See response to LE-YEC-1-46 and 47 for review of CSTP and MS budgets (at time of last YUB review, and at time of September 2007 YEC Board decision to proceed) and final costs.

stream versus the expected in-service cost (net of contributions), and allowing for reasonable contingencies. In the end, the project cost was within 5% of the above budget (excluding YESAB-ordered scope changes).