YUKON
ENERGY

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 5L6
(867) 393-5300

March 29, 2010

Mr. Bruce McLennan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, YT Y1A 6L3

Dear Mr. McLennan:

Re: Board Order 2010-5 and UCG Request for Further Information

In a Notice of Motion dated March 15, 2010 UCG made an application for further information from Yukon Energy.

In a letter dated March 17, 2010, the Yukon Utilities Board sought YEC comments on this request. Yukon Energy provided its response on March 18, 2010, and in that letter YEC provided further clarification to some of its earlier responses.

In Board Order 2010-5, the Board directed YEC to provide further responses to the following IRs:

- UCG-YEC-1-5(b) – provide aggregate energy and demand totals by rate class;
- UCG-YEC-1-6(c) – provide the original estimated cost and the final costs for the past 10 years; and
- UCG-YEC-1-6(d) – show the cost-benefit analysis for those projects greater than $1 million for the past 10 years.

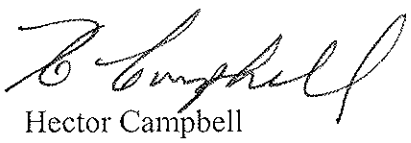
In compliance with Board Order 2010-5 attached are revised responses to UCG-YEC-1-5 (b) and UCG-YEC-1-6 (c) and (d).

In addition to assist all parties, the attached revised responses also include the clarifications to other questions provided by YEC in its March 18, 2010 letter. To be specific, UCG-YEC-1-5 REVISED and UCG-YEC-1-6 REVISED include revised responses to UCG-YEC-1-5(b), (e), (f), and (k), and UCG-YEC-1-6(a) which include YEC's March 18, 2010 clarifications. In addition YEC-1-1(b), UCG-YEC-1-3(c), and UCG-YEC-1-27(a) also include the clarifications provided in YEC's letter dated March 18, 2010.

Separately, YEC attaches the following additional revised responses to correct and/or clarify the response:

- **YUB-YEC-1-21** - Table 1 is corrected (the Mayo B analysis breaking out Mayo A versus Mayo B generation had incorrectly included some secondary energy in some years).
- **YUB-YEC-1-30A (c)** - The revised response includes additional information and a new Table 1 to clarify the difference between net and gross generation at Mayo B and why this varies with different grid loads; the revised response highlights the impacts of the higher minimum summer flow conditions at Mayo B on Whitehorse firm generation under some conditions.

Yours truly,



Hector Campbell
Director Resource Planning and Regulatory Affairs

Attachments

UTILITIES CONSUMERS' GROUP
(UCG)

TOPIC:

REFERENCE:

Application, page 1

YEC indicates that "the planned in-service date for Mayo B of late 2011 reflects requirements of Yukon Energy's funding agreement with the federal government for Mayo B and Stage 2 of the Carmacks-Stewart Transmission Project (CSTP) connecting the Mayo-Dawson (MD) and Whitehorse-Aishihik-Faro (WAF) grids. The timing for Mayo B also reflects the opportunity to displace diesel generation energy requirements associated with growing power loads on both grids".

QUESTION:

a) Please explain the requirements of the funding agreement with the Federal government that are determining the construction schedule of this Yukon infrastructure project.

b) What efforts have been taken to extend the funding agreement timeframes to allow for a more complete and thorough review of this project? Please provide all correspondence related to these efforts.

ANSWER:

(a)

Section 3 of the Federal Funding Agreement sets out the obligations of the parties; section 3.1 notes the contribution to be paid by Canada is subject to the Terms and Conditions of the agreement, including Schedule B. Section 3.1(a) states that Canada will not pay more than 50% of the Eligible Costs (up to $71 million) during the three Fiscal Years starting in 2009-2010 and ending in 2011-2012. Section 3.2 obligates the funding recipient (YEC) to be responsible for complete, diligent and timely Project Implementation within the costs and deadlines specified in the Agreement. This would include the requirement to have the project complete by funding deadline of March 31, 2012 per the timeline provided in Section 3.1(a) and in Schedule B2 (estimated completion date of December 31, 2011).

(b)

YEC is obligated to meet the terms and conditions of the Agreement, in order to be eligible to receive the $71 million in federal funding towards the Legacy Project. This includes meeting the timelines provided in Schedule B.

See also, response to CW-YEC-1-12.

Further response on March 18, 2009

The answer provided to part (b) noted that YEC is obligated to meet the timeline under the GIF funding agreement. The follow-up from UCG now requests information on "negotiation" of the agreement. To address the further information requested, in the context of the original question, no efforts have been taken by Yukon Energy to extend the GIF funding agreement timelines for the $71 million of federal funds. There was no negotiation with the Federal Government related to these timelines, as it was understood by Yukon Energy that in order to obtain the funding under GIF, Yukon Energy was required to complete the Legacy Project by March 31, 2012. As set out in YEC's YESAB Mayo B Project Proposal Submission filed in February 2009, YEC also understood that this could be achieved within a proper regulatory review period.

TOPIC:

REFERENCE:

Application, pages 2

"Mayo B was included in YEC's 20 Year Resource Plan 2006-2025 (the "Resource Plan") as part of an inventory of hydro project options (see Appendix B of the Resource Plan) available to meet forecast load growth scenarios. The projects included in Appendix B of the Resource Plan represented "the primary alternatives identified based on review of the numerous studies conducted in Yukon." Mayo B was specifically discussed as one of a group of small projects being considered (within the 5 to 10 MW range). Small hydro projects in the range of 5 to 10 MW were considered potential candidates for development under the 25 MW industrial scenario or larger (see Resource Plan, Chapter 5). These projects could also potentially be part of a development plan under the larger 40 MW scenario".

QUESTION:

a) Please explain any differences between the "Mayo B" project proposed in Appendix B of the Resource Plan and the Mayo Hydro Enhancement Project currently before the YUB.

b) Please provide evidence where the YUB referenced the "Mayo B" project in its January 15, 2007 Report to Commissioner in Executive Council regarding YEC's 20-Year Resource Plan.

c) Please provide details of the specific review that was conducted of the Mayo Hydro Enhancement Project during the review of the Resource Plan.

ANSWER:

(a)

The project as discussed in the 20-Year Resource Plan was discussed as a potential enhancement to the existing facility at Mayo. The response to UCG-YEC-1-89(c) filed

during the Yukon Energy 2008/2009 GRA provides an excerpt from Appendix B of the 20-Year Resource Plan which notes as follows regarding Mayo B:

> The existing hydro site at Mayo has the potential to be enhanced by various changes in configuration, either to develop further head below the existing reservoir or an expansion of capacity utilizing the same head. This leads to multiple potential alternatives. However, as a supply option to WAF, these various projects are only of relevance if the Carmacks- Stewart transmission line is previously in service. The full capability of various potential Mayo enhancements to supply an interconnected WAF and MD system (as opposed to MD on its own) has not been fully studied, and should be re-examined in the event that the interconnection proceeds. One configuration alternative considered is a 10 MW, 48 GW.h, $101 million (2005$) variation based on a separate conveyance route from the existing reservoir to a new plant lower in elevation than the existing plant, which would be able to operate in parallel with the existing plant. This concept has an initial LCOE of 11.2 cents/kW.h. Various other concepts require further study. However, although work is still in preliminary stages, it must be recognized that it is possible no credible facility enhancements of this type exist at Mayo.

The currently proposed project has been subject to, and further defined by, more rigorous, detailed review and feasibility planning (as discussed in detail in the project description provided in section 3.1 of the Mayo B Part III Application and Attachment A2-1 which describes alternatives and alternative configurations considered). Conceptually, the current Mayo B project reflects the configuration alternative as discussed in the Resource Plan, but with a lower level of expected overall added generation.

(b)

The Mayo B project is not specifically referenced[1] in the Board's report, however, the Board does address and endorse in the report the long term planning approach of YEC.

[1] Much of the focus of attention at the time of the 20-year Resource Plan and the Board's report was meeting near term capacity requirements discussed in Chapter 4 of the 20-Year Resource Plan, as well as other near term developments proposed by YEC. However, longer term planning requirements and scenarios were reviewed and addressed in the report (without specific reference to Mayo B or any other small hydro projects in the range of 5-10 MW that may be candidates for development under Chapter 5 forecasts under the 25 MW industrial scenario or larger).

While not recommending a specific longer-term project such as Mayo B, the Board sets out a process for review of the next project determined to be required to meet longer term load requirements.

In its report the Board recommended that YEC continue to monitor potential material load additions and, when warranted, make a filing with the Board when new facilities are required to meet increased loads, outlining the risk of proceeding, the benefits to existing ratepayers, and sensitivities to existing ratepayers if the economic life of the project is shorter than forecast.

Specifically, the report to the Commissioner in Executive Council regarding the 20-Year Resource Plan notes at page 7 (with regard to discussion of longer term industrial load forecast discussed in detail in Chapter 5 of the 20-year Resource Plan):

> The Board is cognizant of the risks within this type of forecast and yet sees benefits to all ratepayers when infrastructure is constructed for industrial developments. The Board recognizes the efforts of YEC in investigating future potential industrial loads and the planning guidelines it follows when assessing these potential developments and agrees with the balanced approach that YEC utilizes. It is recommended that YEC continue to monitor these potential material load additions and, when warranted, make a filing with the Board when new facilities are required to meet these increased loads. Within the filing, YEC should outline the risk of proceeding, the benefits to existing ratepayers, and sensitivities to existing ratepayers if the economic life of the project is shorter than forecast. Further, YEC should outline how its contribution policy is being applied and what contributions it will receive from the industrial customer for the infrastructure created to satisfy the load.

At page 49, the report notes that it agrees with YEC's long term planning approach utilized in the Resource Plan and notes that, "when YEC proposes a new facility, YEC is to outline the risk of proceeding, the benefits to existing ratepayers, and sensitivities to existing ratepayers if the economic life of the project is shorter than forecast.[2]"

[2] Specifically, the Board notes at page 47 of the Report to the Minister that, "The Board agrees with the long-term planning approach utilized by YEC in the Plan. The approach by YEC in assessing the industrial development factors versus the Yukon Energy factors is balanced. On a go-forward basis, YEC should attach probabilities to the industrial development scenarios. This would assist the Board in comparative analysis when future resource plans are filed or when applications

(c)

The Mayo B Expansion was discussed in Chapter 5 of the Yukon Energy 20-Year Resource Plan (see, Chapter 5 and Appendix B of that filing) as part of an inventory of hydro project options. The details provided were summaries from previous studies, and included an estimated LCOE as noted.

As noted at page B-1 of the Resource Plan, the projects included in Appendix B represented "the primary alternatives identified to date based on review of the numerous studies conducted in Yukon." Mayo B was specifically discussed in that document as one of a group of small projects being considered (within the 5 to 10 MW range) at page B-10. The Resource Plan noted that small hydro projects in the range of 5-10 MW were potential candidates for development under Chapter 5 forecasts under the 25 MW industrial scenario or larger. These projects could also potentially be part of a development plan under the larger 40 MW scenario.

Further response March 18, 2010

To clarify further, when discussing longer-term planning for projects to be committed after 2008 (the last year for projects included in the Chapter 4 near term plan), the Resource Plan hearing reviewed potential load scenarios, and the need to plan for such scenarios arising, and did not specifically review the merits of any one project in this regard such as Mayo B. As noted in the response to UCG-YEC-1-3(b), the Board recommended that YEC continue to monitor potential load additions and make a filing with the Board when new facilities are required to meet increased loads. YEC has followed the Board's recommendation in this regard.

As noted in the response, Mayo B was therefore discussed in the 20-Year Resource Plan as one potential small hydro project [among a suite of options in the range of 5-10 MW] that may be developed to meet the 25 MW industrial load forecast scenario). While Chapter 4 of the Resource Plan addressed in detail projects related to meeting near term capacity requirements (to be met by 2009), Chapter 5 of the Resource Plan (and Appendix B wherein Mayo B was specifically outlined) discussed and addressed longer

under Part 3 of the Public Utilities Act are submitted. As recommended in the Load Forecast section, when YEC proposes a new facility, YEC is to outline the risk of proceeding, the benefits to existing ratepayers, and sensitivities to existing ratepayers if the economic life of the project is shorter than forecast."

term planning scenarios and options available to meet these scenarios. Chapter 5 was not a review per se of any individual project; it was a review of a plan for proceeding with longer-term supply options, including how to ensure supplies could be brought on line when required. Mayo B was included in that filing as one option among a suite of possible options for addressing a particular longer term industrial load scenario that YEC would need to plan to address. In particular, Mayo B was noted as meeting some key preferred characteristics that would guide ongoing actions – such as being an enhancement to an existing project rather than entailing the complexities of a new "Greenfield" project.

TOPIC:

REFERENCE:

Application, page 5, 12; Application Attachment E; December 18, 2009 Letter from Minister to YUB

On page 5, the application states that the Mayo Hydro Enhancement Project will be developed at an estimated cost of $120 million "to help supply growing MD and WAF grid power loads with renewable energy that displaces required diesel generation".

On page 12, the application contains a table showing a breakdown of project costs and financing. Yukon ratepayers are contributing $66.65 million and Federal taxpayers are contributing $53.35 million of the current $120 million estimated cost of a project expected to add 10 MW to the gross generation capacity at Mayo.

In her December 18, 2009 letter to the YUB, the Yukon's Minister of Justice stated that "Mayo B will receive up to 53.3 million dollars from the Government of Canada as part of the Canada-Yukon Energy Corporation Green Infrastructure Fund: Agreement for the Yukon Green Energy Legacy Project 2009-1012011-2012".

QUESTION:

a) Please confirm YEC's understanding that for the YUB's energy generation model analysis used during its review of YEC's 20 Year Resource Plan, the YUB assumed that hydro generation in the Mayo-Dawson grid was not assumed to supply WAF loads due to line losses.

b) Please provide details of the electricity customer base served by the Mayo-Dawson grid.

c) Please explain how any single infrastructure project estimated to cost $120 million (or $12 million per MW) could be justified for a ratepayer base identified in (b) or even a Yukon-wide ratepayer base of less than 17,500.

d) Please provide illustrations of what similar projects have cost per MW and per ratepayer in other jurisdictions.

e) Please compare the cost per MW of the proposed Mayo B project with the cost of installing new site-specific diesel generation (estimated to be $1.035 million per MW in the 2008-2009 GRA).

f) Please provide YEC's explanation of how the Federal government's contribution to the proposed Mayo B project would be less than $53.3 million.

g) Please reconcile YEC's assumption of $53.35 million contribution from the Federal government and the Minister's determination of a maximum $53.3 million contribution from the Federal government.

h) Please provide details of the annual carrying costs that will be incurred by the staggered funding outlined in Attachment E to the Application.

i) Please provide details by cost component of costs incurred to date for the proposed Mayo B project for each historical year and estimated for subsequent years.

j) Please discuss the risks to ratepayers that the capital costs could exceed $120 million.

k) Please provide details of how YEC determined that the proposed project would only qualify for $53.3 million of the $71 million available from the Federal government.

ANSWER:

(a)

Confirmed, as reviewed in UCG-YEC-1-6(b).

Notwithstanding this specific comment in the YUB report, discussion of the CSTP project in the YEC Resource Plan was not based on any such premise. As reviewed in response to UCG-YEC-1-3, Resource Plan references to Mayo B specifically noted a need to have the CSTP connection in place as a precondition to further examination of this development.

(b), **(c)**, **(d)** and **(e)**

Contrary to the second paragraph of the above preamble, YEC has secured $83.5 million in contributions towards the Mayo B project ($53.35 million of federal funding provided through the federal contribution agreement and $30.15 million of no cost capital contribution from YDC), reducing the overall project costs to ratepayers from $120 million to $36.5 million (and not $66.65 million as above-noted).

As noted in the Mayo B Application, this project is being advanced to meet the near term and long term electricity requirements of the Yukon integrated grid by providing a source of renewable generation that will be available to displace the increasing requirement for costly baseload diesel generation. Mayo B is not being proposed to supply specifically the electricity customer base served by only the current Mayo Dawson grid.

Contributions towards the project provided by Canada and YDC, have materially reduced the LCOE to within or below 8 to 10 c/kWh levelized cost target range. As noted, such costs are well within the range of current BC hydro development project costs to ratepayers (see also YUB-YEC-1-27(c)).To ensure ratepayers are not adversely affected in the initial years of project in service, flexible debt financing will also be provided by YDC that will cap annual net generation costs at 10-11 cents/kWh (2012$).

It is not meaningful, for the purpose of assessing ratepayer cost per kW.h of useful energy, to compare capital cost per MW of a hydro generation unit with the capital cost per MW of a diesel generation unit. The meaningful cost comparison is present value LCOE per kW.h assessed over the economic life of the hydro generation option, as provided in the Application.

Further response on March 18, 2010 re: (b)

YEC reiterates that Mayo B is not being proposed to supply specifically the electricity customer base served by only the current Mayo Dawson grid. By the time the project is projected to be in service, the MD and WAF grids will be integrated by the CSTP, so there is no basis to analyze either individual grid on a standalone basis. However, to expand on YEC's response, for 2009, the Mayo Dawson forecast grid loads were set out in Table 2.3 of YEC's 2008/09 GRA which indicated 1108 residential customers, 378 general service customers, and 3 wholesale delivery locations (Stewart Crossing and Keno). At that time there was no industrial customer on the Mayo-Dawson system. This

customer base is to be increased in 2010 with the planned connection of the Alexco mine and mill load. By early 2011, after completion of CSTP Stage 2, the Mayo Dawson grid will become connected to the WAF grid.

Further response on March 29, 2010 re: (b)

By the time the project is projected to be in service, the MD and WAF grids will be integrated by the CSTP, so there will be no further standalone "MD grid" per se.

For 2009, the Mayo Dawson forecast grid loads were set out in Table 2.3 of YEC's 2008/09 GRA which indicated 1108 residential customers, 378 general service customers, and 3 wholesale delivery locations (Stewart Crossing and Keno). At that time there was no industrial customer on the Mayo-Dawson system. This customer base is to be increased in 2010 with the planned connection of the Alexco mine and mill load.

Energy usage in test year 2009 is also set out in Table 2.3 of the 2008/09 GRA, as follows:

- Residential – 8,759 MW.h
- General Service – 13,976 MW.h
- Industrial – 0 MW.h
- Streetlights – 180 MW.h
- Space Lights – 13 MW.h
- Wholesale (Stewart Crossing and Keno) – 857 MW.h (note that this is the approved value from the compliance filing – it was adjusted pursuant to Order 2009-8 from the value included in Tab 2 of the GRA)
- Secondary – 630 MW.h

YEC does not have demand totals by rate class for the Mayo Dawson grid. Table 2.6 of the 2008/2009 GRA the system peak demand forecast for the 2009 test year is 5 MW, with total forecast annual generation of 30.686 GW.h.

Retail loads are forecast to increase at the same 1.85%/year as for all Yukon retail loads.

By early 2011, after completion of CSTP Stage 2, the Mayo Dawson grid will become connected to the WAF grid.

Further response on March 18, 2010 re: (e)

Yukon Energy reaffirms its response to this question - it is simply not meaningful, for the purpose of assessing ratepayer cost per kW.h of useful energy, to compare capital cost per MW of a hydro generation unit (which brings with it both capacity and energy) with the capital cost per MW of a diesel generation unit (which is only focused on capacity – the energy costs must also consider fuel). The meaningful cost comparison at a minimum requires the present value LCOE per kW.h assessed over the economic life of the hydro generation option, as provided in the Application. Yukon Energy's present value assessment in the Application only considered savings in diesel generation incremental operating costs (fuel and incremental O&M) and did not consider savings in diesel generation capital costs (due to deferral of such facilities over the life of Mayo B).

However, to expand on YEC's response, YEC notes that the projected ratebase cost per MW for Mayo B is $3.61 million/MW in 2012$ ($36.5 million divided by 10.1 MW as the estimated installed capacity) and for new site-specific diesel generation no updates have been completed since the 2008/09 GRA cited by UCG (which estimated costs at $1.035 million/MW in 2009$).

(f), **(g)** and **(h)**

Please see response to CW-YEC-1-2, CW-YEC-1-25, and CW-YEC-1-21(f) as regards the Federal Funding Agreement and cash flow assessments relevant to YEC.

Further response on March 18, 2010 re: (f)

The response to CW-YEC-1-2 provides the circumstances in which the full level of funding (up to $71 million) would not be available. Under section 3.1(a) of the Agreement Canada will not pay more than 50% of the total Eligible Costs during the three Fiscal Years starting in 2009-2010 and ending in 2011-2012, i.e., if such costs are less than $142 million, or fail to be in accordance with the Fiscal Year breakdown in Schedule B2, as amended in accordance with the Agreement, Canada could not pay the full $71 million.

Except as noted in the response, YEC is not able to identify any reasonable way in which the federal funding would be less than $53.3 million. YEC also notes that the most

up to date estimates for Mayo B demonstrate that eligible costs will be beyond what is necessary to qualify for the $53.3 million.

(i)

Please see response provided to CW-YEC-1-5(a) and CW-YEC-1-2(f) and (g).

Further response on March 18, 2010

To expand on YEC's response, costs incurred to date for Mayo B are $1.880 million to the end of 2008 and a cumulative total (including 2008) of $7.441 million to year-end 2009. In the cost category breakdown in CW-YEC-1-5(a) these are entirely in the category of pre-construction and other permitting/regulatory planning costs.

(j)

Please see discussion provided at page 35-36 of the Part III Application and response provided to CW-YEC-1-12 and CW-YEC-1-13.

(k)

The allocation was based on the estimated Eligible Costs as filed in the application for federal funding and Canada's award of up to $71 million for the Legacy Project. Please see response to CW-YEC-1-2(a), (b) and (c).

Further response on March 18, 2010

YEC's answer is responsive. YEC has provided a copy of the Federal Funding Agreement. The $53.3 million amount of funding available for Mayo B is governed by the Federal Agreement (see Schedule B2 of that Agreement available in Attachment E of the Mayo B Application, which reflects fully the information that Canada relied upon to determine the $71 million funding amount and the allocation of this funding between Mayo B and CSTP Stage 2 components of the Legacy Project).

TOPIC:

REFERENCE:

Response to YUB-YEC-1-38 – YEC 2008-2009 GRA

"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%."

QUESTION:

a) Please provide a copy of the third party review of the $120 million cost estimate.

b) Please confirm YEC's understanding that for the YUB's energy generation model analysis used during its review of YEC's 20 Year Resource Plan, the YUB assumed that hydro generation in the Mayo-Dawson grid was not assumed to supply WAF loads due to line losses.

c) For all capital projects completed over the last 15 years, currently underway or currently proposed valued at over $1 million, please provide the original estimated cost, the date this cost estimate was made and the final cost (or updated cost if not finished).

d) For all projects identified in (c), please provide the cost-benefit worksheets used by the YEC's Project Review Committee.

e) For all projects identified in (c), please provide details of the costs paid by any party other than ratepayers (i.e., government grants / loans, third party contributions).

ANSWER:

(a)

The third party review noted was performed January 2009 at a very early stage in cost estimating. Since that time the scope of the project has been further refined, such that the earlier review is no longer relevant.

See discussion of the project description in the Application at section 3.1.1 of the Application which notes the YESAB filing was revised in July 2009 to delete the Mayo enhanced storage and then updated November 20, 2009 to reflect ongoing design refinements resulting from geotechnical field studies and engineering (i.e., the canal/penstock option was determined to not be cost effective and it was determined to extend the penstock through the entire distance to the new powerhouse; routing changes for the penstock were also required to avoid a zone of discontinuous permafrost; and tunnel construction was modified to move the connection at the existing intake closer to the intake structure).

Further Response on March 18, 2010

To expand on its response, the requested report is provided as an attachment to this correspondence. The report consists of a one page letter dated February 3, 2009 and a one page table attached at that time (totaling to $115.690 million) which was amended in a February 5, 2009 table based on further discussion with the project engineers (totaling to $113.016 million). Consistent with ensuring maximum value for future competitively tendered unit price subcontracts that are expected to be let for the Mayo B project, unit pricing has been redacted from the attached report.

The independent review on its face indicated overall costs at approximately 5% lower than KGS' estimates. However, the key reason for the review was to cross-check specific individual line items rather than the simple focus on one overall number. In this context, KGS' views upon review of the IPE report was that project costs could in fact be 4-5% higher than previously estimated by KGS. Specifically, upon review of the

individual line items KGS was concerned that the IPE review indicated higher cost estimates on the key items KGS wanted independent review of (i.e., canal bulk excavation and camp man days – IPE increased man days by 50%), this indicated to KGS the potential to revise these particular items in their own estimate upwards. The IPE report did indicate lower cost estimates on other items (powerhouse mechanical and electrical and low pressure penstock, which also lowered related contingencies); however, KGS was comfortable with its estimates on these items and therefore no revision was made by KGS to its estimates. It was noted that being within 5% of this type of estimate indicates that the estimates are on track and not that they need to be materially revised.

(b)

As stated in response to UCG-YEC-1-5(a), this is confirmed as reviewed below. Notwithstanding this specific comment in the YUB report, discussion of the CSTP project in YEC's Resource Plan was not based on any such premise. As reviewed in response to UCG-YEC-1-3, Resource Plan references to Mayo B specifically noted a need to have the CSTP connection in place as a precondition to further examination of this development.

The question is in effect referencing what the Board noted at page 23 of its report.[1] When addressing its own assessment of annual diesel generation for YEC's and an alternative expansion plan (to assess the potential relevance of fuel cost savings in assessing different specific alternatives then under review), the Board noted that "it should be emphasized that, due to many assumptions made and several modeling limitations, these generation figures are only adequate for the purpose of comparing the relative merits of one plan over the other and to verify YEC's assertion". At footnote 18 the Board went on to note as follows with regard to the assumptions used by the YUB in its model:

> The Board used an energy generation model that "dispatches" generating units to supply the load, which was represented by the same load duration curves (LDC) used in the LOLE calculation. This model also accounts for random outages of generating units using the equivalent load method, i.e. the LDCs are modified using the FOR of each generator after dispatched, so that the next generator in the staking order would face a slightly higher load that accounts for

[1] The YUB Report to Commissioner in Executive Council re YEC 20-Year Resource Plan – Jan. 15/07.

the outages of generators already dispatched. Only units connected to the WAF were used in the analysis and there was no consideration of must-run units and/or units that run for emergency standby or voltage support purposes. Also, hydro generation in the MD grid was not assumed to supply WAF loads due to line losses.

(c), **(d)** and **(e) [Revised March 29, 2010]**

The information requested is not relevant and in any event simply cannot be assembled in the time frame set out for responding to IRs. Further all projects of such magnitude that are in Rate Base have already been subjected to review by the YUB.

The current proceeding is to obtain the YUB's report and recommendations on the potential benefits, costs, risks and customer impacts that influence whether or not Mayo B should proceed as proposed. Please refer to the Minister's Terms of Reference for this proceeding.

Further Response on March 29, 2010

In Order 2010-05 the Board directed that YEC provide in response to part (c) "the original estimated cost and the final costs for the past 10 years" and directed that YEC respond to part (d) by showing the cost-benefit analysis for those projects greater than $1 million for the past 10 years. No further response was required for part (e), as the Board does not consider the information requested relevant to this proceeding.

There are seven capital projects completed by YEC over the last 10 years valued at over $1 million. For each of these projects, the original estimated cost (i.e., the estimate available when final approval to proceed with the project was sought within YEC), the final cost, and the cost benefit analysis used by YEC when the project was approved are as follows[2]:

1. **Wind Generator Project** – This project was completed in 2000; it was subject to public review and costs were approved to be included in ratebase as part of the 2005 Required Revenues and Related Matters Application.

[2] Slight differences in reported actual and GRA application numbers relate to prior years spending, final accounting adjustments for AFUDC and ES&G etc for the other projects.

The costs approved by the YUB as applied for in the 2005 Application were $1.974 million in 2000 and $0.029 million in 2001 (for total of $2.003 million). The final cost of the project was $2.080 million.

Attachment 2 provides the December 15, 1998 Capital Expenditure Approval Request (CEAR) approval for a commercial-scale wind research and development project in amount of $2 million. The project was initiated to utilize $2 million of available no cost funding from the Yukon Government.

2. **Whitehorse Rapids Dam Seismic Restraint –** This project was completed 2002; it was reviewed and costs were approved to be included in ratebase as part of the 2005 Required Revenues and Related Matters Application (total of $1.054 million with $0.183 million in 2001 and $0.871 million in 2002 as described in the Application). Final costs for this project were $0.189 million for Phase 1 and $0.862 million for Phase 2 (total $1.051 million).

   The original business case (December 21, 2000) for developing an updated cost estimate for the Whitehorse Rapids Upstream Wingwall Seismic Restraint is provided as Attachment 3, with an original cost estimate of approximately $0.721 million. This project was to address Canadian Dam Safety Guidelines with respect to earthquake loads.

3. **MH 1 and MH2 Capacity Increase –** This project was completed in 2002; it was reviewed and its costs were included in ratebase as part of the 2005 Required Revenues and Related Matters Application (total of $1.026 million for MH1). Table 5.2 of that Application notes $0.284 in 2001 and $0.742 in 2002 for a total of $1.026 spending on the MH1/MH2 Capacity Increase (this relates directly to costs incurred for MH1). The Application also includes $0.959 for MH2 Rebuild/Runner Replacement.

   Total final costs for the MH1 project were $1.017 million (relates to MH1/MH2 Capacity Increase noted above); total final costs of $0.962 were incurred for MH2 (relates to the rebuild/runner replacement). The cost differences between final costs and the 2005 Required Revenues Application costs are due to reallocation of consultation costs between work orders ($0.070 consulting costs moved to work orders for C02038 Exciter Upgrade from Mayo Hydro and C02111 MH2). Also MH2 final costs included costs transferred from MH1 (consulting costs to assess both units were initially charged to MH1).

The CEAR revision requests in February 2003 for MH1 and MH2 are provided as Attachment 4 and provide the cost history and cost benefit of the project. Original cost estimates (at February 19, 2003) are indicated in this CEAR information to have been approximately $1.91 million for MH1 and MH2.

4. **Mayo Dawson –** This project was completed and brought into service in 2003. It was been reviewed in detail by the YUB and other parties and its costs were approved to be included in ratebase as part of the 2005 Required Revenues and Related Matters Application. YUB-YEC-1-19 filed during the 2005 Required Revenues and Related Matters proceeding (provided in Attachment 5) provides a detailed description and explanation of the Mayo Dawson Project costs. It notes that the approved original budget for the project was $29.046, and the final cost to the end of 2005 was $33.746 million. A detailed review of these cost variances was also provided in the response, including scope changes, extra costs needed to be incurred to address contractor deficiencies, Yukon Energy's added costs due to the significantly increased workload with respect to management and engineering that arose as a result of underperformance by the construction contractor, and the material outstanding matters remaining today with respect to claims and counterclaims between the contractor and Yukon Energy.

   Other materials provided as part of that public review process, also included in Attachment 5 are as follows[3]:

   a. Tables 5.4, in the 2005 Required Revenues and Related Matters Application provided the summary of the economics over the life of the project and Tables 5.5 and 5.6 in that filing provided the detailed annual impacts for 2005 and each following year.
   b. McMahon-YEC-1-17(b) filed during the 2005 Required Revenues proceeding also summarized the record in the Application materials on the Project benefits and costs

   The response to YUB-YEC-1-13 filed during the 2008/2009 GRA (and included in Attachment 5) provides the calculation of the "substantial benefits to ratepayers" due to the Mayo Dawson Transmission Project based on the fuel prices in effect at the end of 2008.

[3] The Mayo Dawson Transmission Line Project Feasibility Study was also provided as a response to UCG-YEC-1A35(i) in that 2005 proceeding.

5. **Aishihik #1 (AH1) Rewind –** This project was fully completed in 2004; it was reviewed and its costs were included in ratebase as part of the 2005 Required Revenues and Related Matters Application (total of $1.216 million).

   Attachment 6 provides the February 2004 CEAR review of the project costs. The cost included in the CEAR request is noted as $1.210 million (previous CEAR approval of $0.975 million with additional request of $0.235 million[4]).

6. **Aishihik #2 (AH2) Rewind** – This project was completed 2006; it was reviewed and its costs were included in ratebase as part of the 2008/2009 Yukon Energy General Rate Application. Total costs approved by the YUB during that proceeding were $1.304 million (these costs were included in table 5.2 of the Application as $0.731 million for rewind stator; $0.268 million for rewind rotor and $0.305 million for rewind mechanical).

   The PID reviewed by the YEC Board (provided as Attachment 7) notes that AH2 budget was estimated at $1.3 million and this estimate was increased to $1.55 million. Total final costs for the project were $1.332 million. The AH2 rewind was less than budgeted due to lower than expected stator rewinding costs.

7. **Carmacks Stewart Transmission Project (CSTP) ($38.383 million, with customer and other contribution offsets of $34.639 million) –** This project was completed in 2008 and its costs were reviewed by the YUB and approved for inclusion in ratebase in 2009 as part of the 2008/2009 GRA. The business case for this project (including costs and benefits assessment) has been previously reviewed in detail as part of the 20-Year Resource Plan[5], the Minto PPA hearing,

[4] It notes $0.700 million budgeted in 2003 for replacement of stator coils and repairs to thrust collar and a subsequent decision to rebuild all rotor poles while unit was apart and rewind contractor was on site – adding additional cost of $200,000. During disassembly problem areas were discovered that needed to be addressed, adding a further $75,000 to project cost for total of $975,000. A CEAR revision was provided in 2004 for $235,000 ($135,000 for hydro alignment, to address unit balancing required to be undertaken in two stages and delays due to Remote Terminal Unit undergoing simultaneous upgrade which delayed testing and commissioning of unit); second increase of $100,000 as contingency to address $103,000 of work items claimed by GEC and disputed by YEC.

[5] The following references from the Resource Plan hearing process are provided as support for the business case for the project. (Note materials filed during the Resource Plan hearing process, including the 20-Year Resource Plan are available on the Board's website at http://yukonutilitiesboard.yk.ca/proceedings/yec_20/). Pages 7-11 of the Summary section of the 20-Year Resource Plan provides an overview of near term options to address near term requirements and opportunities to 2012 and to provide for over 21 MW of new WAF firm winter capacity by 2012. These options included Whitehorse Mirrlees, Carmacks-Stewart Transmission Project and Aishihik 3rd Turbine. Chapter 4 of the Resource Plan addresses in detail the near term capacity requirements, including planning approach and timeline and a review of requirements, options, assessment of options and proposed actions. Further materials filed during that review process include the following:

the CSTP Part III hearing. Subsequent to the Resource Plan hearing the CSTP economics were reviewed as part of the Minto PPA hearing and as part of the Part 3 Hearing. The Part 3 Application related to this project included the following material relevant to the business case for the CSTP[6]. These extensive earlier public reviews addressed the rationale, options, and initial cost estimates, as well as benefits and potential impacts of the projects on ratepayers. The recommendations of the YUB from each of these proceedings is part of the public record.

Updated information for 2008/2009 was provided Section 5.2.1 of the 2008/2009 GRA (provided in Attachment 8); it was noted that this information did not fundamentally change the earlier rationale or business case for the project. During the 2008/2009 GRA, the Board assessed the prudence of these project expenditures prior to approving the inclusion of project costs in ratebase.

Per the Summary Cost Table provided in Appendix 7[7], the original estimated cost (i.e., construction approval budget) approved by the YEC Board was $8.813 million for the Minto Spur and $27.788 million for the CS Main Line. The final cost for the Spur line was $10.582 million (a 20.1% variance from Board of Director's budget), and the final cost for the CS Main Line was $27.873 million (a 0.3% variance from Board of Director's budget). These costs and cost changes were reviewed and explained in detail during the 2008/2009 GRA.

(1). Supplementary Materials (filed May, 2006) – this filing provided an update on Resource Plan information related to the Carmacks-Stewart Transmission Project (Tab 2 of document);
(2).Exhibit B-16 (filed November, 2006) – provided updated information for the Carmacks-Stewart Transmission Project (pages 6-12). Table 2 provided at page 5 of the document set out the capacity requirements and Yukon Energy's updated proposals to meet these requirements with Faro Mirrlees Rehabilitation in 2007, Whitehorse Mirrlees Life Extensions in 2008, 2009, and 2010, Carmacks-Stewart Transmission Line in 2009 and Aishihik 3rd turbine in 2009. The resulting system balance is shown in the second column from the right of the sheet. The column to the far right describes the system in the event that the full interconnection of Carmacks-Steward does not occur in 2009 as planned;
(3) The discussion of the CSTP included an update on the YESAB filing and a discussion of alternatives to the project, as well as updates related to Minto and Carmacks Copper mines and project economics (page 9-12). This included a discussion of capital costs and ratepayer benefits.

[6] See, Application for an Energy Project Certificate and an Energy Operation Certificate regarding the Proposed Carmacks-Stewart Transmission Project): (1) Summary of project economics is provided at page 7; (2)Assessment of justification and need for the project (pages 12-15); (3) Assessment of risks (pages 15 – 19) including assessment of both Stage 1 risks and Stage 2 Risks; and (4) Assessment of effect of project on ratepayers (pages 19 – 20).

[7] Stage I Carmacks-Stewart/Minto Spur Transmission Projects Initial Cost Estimates, Construction Budgets, and Final Costs

Information detailing initial costs, final costs and explaining how these costs evolved is provided in Attachment 8 as follows:

- **Section 5.1.2 of the 2008/2009 GRA** provides a review of the Project, its costs, how these costs changed and the justification for inclusion of the costs in ratebase.
- **Stage I Carmacks-Stewart/Minto Spur Transmission Projects Initial Cost Estimates, Construction Budgets, and Final Costs (Summary Cost Table)** noting Sept 07 YEC BOD Construction approval Budget (i.e., costs when final decision to proceed with construction the Project was made by the YEC Board of Directors); Final Cost at February 2009; scope changes and cost implications due to YESAB Decision document requirements; contributions and net cost to ratepayers.
- **LE-YEC-1-46 and LE-YEC-1-47** - filed during the 2008/2009 GRA detailing costs for CS Main Line and Minto Spur.
- **YECL-YEC-1-9** - describes in detail all scope changes in the construction of the CSTP to Minto Mines spur line and Pelly Crossing and the costs associated with each change.
- **YUB-YEC-1-36 (a) and (b)** – details and updates overall net benefit of project to ratepayers.

TOPIC:

REFERENCE:

Application, Attachment A2, page 3

A decision to not proceed with the Project or any other renewable generation enhancement project in Yukon, would be expected to result in the following:

- The Yukon power systems will experience ongoing growth that cannot be served from existing renewable power sources. Consequently, given Yukon Energy's general obligation to serve customers who request service within its franchise area, the utility will be required to utilize non-renewable generation to service the loads, almost certainly diesel generation.

- Long-term power costs in Yukon will not benefit from the enhanced stability associated with capital intensive renewable power generation such as increased hydro (and that accordingly would occur with Mayo B). This would likely lead to materially higher power rates over time than would be the case with the Project, and separately may lead to more industrial customers electing to generate their own on-site power with fossil fuel generation rather than connect to the grid.

- Ongoing diesel generation in Yukon that arises, which could otherwise have been displaced by the Project, will generate approximately 700 tonnes of GHG emissions per GW.h of electricity generated.

- Economic development opportunities that could be realized from the project will not occur.

QUESTION:

a) Please provide details of the likelihood that the growth in electricity demand in the Mayo area will be anything but minimal.

b) Please provide details of the analysis used to determine that "materially higher power rates" would occur without the proposed Mayo B project.

c) Please confirm that on-site generation would be a viable alternative to the proposed Mayo B project for any industrial load that may only exist for a limited life (e.g., 7-10 years) of a mine.

d) Please provide details of the "economic development opportunities that could be realized" only because of the proposed Mayo B project and without any of the alternative electricity supply options available.

ANSWER:

(a)

The above quote is not specific to Mayo and notes that "Yukon power systems will experience ongoing growth that cannot be served from existing renewable power sources."

The grid is expected to be integrated before 2012 via the completion of CSTP Stage 2. Attachment D of the Application notes consolidated electrical loads on the integrated system are expected to increase from approximately 368 GW.h in 2009 (the sum of WAF and MD) to more than 600 GW.h by 2042. Load growth on MD will include 5.8 GWh of new industrial load (Alexco) along with 1.85% forecast growth in non-industrial load. It is noted that after 2011 (when the grids are expected to be interconnected) Minto and Alexco are both expected to add new loads until 2012-13 when both mines are expected to reach full capacity at a combined load of 50 GWh (excluding losses). Carmacks Copper is expected to add a further 52 GWh in 2012, with overall loads on the system expected to grow to 495 GWh through 2016.

Further response on March 18, 2010

Yukon Energy's response noted that the referenced quote in the Application was not specific to the Mayo area. To respond to the specific information requested, focusing on the request for information on individual delivery locations on the integrated system (as opposed to overall integrated system loads that must be served in a coordinated fashion), YEC notes that the Mayo area sales (excluding all other integrated system loads, such as Dawson and the Alexco mine site) are entirely retail sales, and total approximately 6.3 GW.h non industrial firm power sales in Mayo, Elsa and Keno area

(this excludes 0.6 GW.h of secondary sales). The firm sales are forecast to grow at the standard 1.85% used for all retail sales (on the order of 0.1 GW.h per year).

(b)

Figure D-2 at page D-5 of Attachment D notes material requirements to supply baseloads from diesel generation, driving material fuel-related costs on the system which would be reflected in rates. Figure D-3 provides the annual diesel cost without Mayo B from 2012 until 2031, and notes forecast transition to material diesel generation from 2012 to 2017 would drive costs (absent Mayo B) 30-40% higher than current Yukon-wide revenue requirements. The analysis underlying the tables provided in Attachment D is provided in response to YUB-YEC-1-25(a).

(c)

The Minto mine connection, which was reviewed and recommended by the YUB in a similar Part III review of the CSTP, is one example where a mine in fact started its operation as an isolated diesel site and was then connected to the grid. However, on a go-forward basis, all of the mine loads included in the Application's load forecasts are now not isolated diesel site options. Please see responses to YUB-YEC-1-37 (c) and (d). Industrial customers that are connected to the hydro grid system, such as Minto and Alexco (as well as Carmacks Copper in future forecasts), make up a portion of the grid firm load requirements that Yukon Energy must plan for and serve from utility generation on a non-discriminatory basis.

(d)

Specific examples have not been referenced at this time. In the past, however, it was demonstrated that the major mining operations at Faro and Keno, which provided the basis to develop the hydro infrastructure that benefits Yukon ratepayers today, were highly dependent on development of new hydro generation resources. In the longer term, future economic development opportunities in Yukon may well be foregone if the supply of cost effective renewable hydro generation such as Mayo B is not developed to displace reliance on diesel generation.

YUKON UTILITIES BOARD
(YUB)

TOPIC: Generation Planning/Mayo A Plant

REFERENCE:

The Application

PREAMBLE:

On pages 5 and 6 of the Application, YEC addresses the operation of the existing power plant at Mayo subsequent to the commissioning of the Mayo B project.

QUESTION:

a) Without the Mayo B project, what would be the annual energy production expected from the existing Mayo A units for each year of the period 2009 to 2019?

b) What would be the plant's capacity factor in each year of that period?

c) With the Mayo B project, both with and without the additional Mayo Lake drawdown, what would be the annual energy production expected from the existing Mayo A units for each year of that same period?

d) What would be the plant's capacity factor in each year of that period?

e) For the Mayo B project, both with and without the additional Mayo Lake drawdown what would be the annual energy production expected from the Mayo B units for each year of that same period?

f) What would be the Mayo B plant's capacity factor in each year of that period?

g) What sorts of maintenance outages would require the Mayo B plant to be entirely or partially taken out of service?

h) How frequently would such outages be required? For instance footnote 44 on page 30, dealing with operating and maintenance costs appears to suggest once in 10 years for a major overhaul.

i) Except for maintenance outages, doesn't the Mayo B project render the Mayo A plant virtually redundant given the reduction in energy output at Mayo A with the commissioning of the Mayo B plant? Explain the reasons for your answer.

j) If the Mayo A plant is not redundant, what reduction in its economic value occurs once the Mayo B project is commissioned because the full amount of annual energy it is currently capable of producing is not likely to be produced in the future?

ANSWER:

(a), **(b)**, **(c)**, **(d)**, **(e)** and **(f)**

Modeling for the Mayo B project and the integrated grid is focused on the system following connection of the two current grids (WAF and MD) with the completion of CSTP Stage 2 in 2011 and of Mayo B by the end of 2011. Forecasts of the type requested are available for the period only after 2011.

For 2012 to 2016, firm grid loads as reviewed in the referenced Table 1 as required to be served from dispatchable generation increase from 456 GW.h in 2012 to about 495 GW.h in 2016, and are therefore generally in a range approximating the 468 GW.h grid load level that has been modeled in detail.[1] Accordingly, to address the issues in this question for the period from 2012 to 2016, analysis is provided for the 468 GW.h grid load level.

The gross generation information requested for this load level is presented in Table 1 below for Mayo A and Mayo B firm generation output assuming long term average water flows. It is noted that the overall IS generation model used in the Application addresses generation by the overall system, and by overall plant (i.e, the Mayo plant, for combined Mayo A and Mayo B output) and does not provide assessments broken out separately for Mayo A versus Mayo B. In preparing separately the assessment below, overall Mayo plant generation it is necessary to assign the system wide secondary energy to each individual plant. As a result, while the analysis helps to explain "gross" versus "net" generation and the relative utilization of Mayo A versus Mayo B, the overall plant results

[1] The Application addresses net generation from the Mayo B project at this load level, e.g., at page 27 of the Application, estimated net generation of 28.2 GW.h is shown for this load level. This assessment reflects overall IS model analysis.

are difficult to compare with the Application's IS model net generation assessments without specific reference to both firm and secondary loads.

Table 1: Mayo A and Mayo B output

Mayo A and B plant output (GW.h/year) and Capacity Factor at a 468 GW.h grid load level

	Mayo A generation (GW.h/year)	Capacity factor at 5.4 MW installed capacity	Mayo B generation (GW.h/year)	Capacity factor at 10.1 MW assumed peak capacity
No Mayo B	36.1	76.4%	n/a	n/a
Mayo B (with Mayo Lake Enhanced Storage)	13.7	29.1%	59.2	66.9%
Mayo B - no Mayo Lake Enhanced Storage	14.0	29.5%	56.0	63.3%

After 2016, the forecast load to be served from dispatchable generation drops to a lower load level (439 GW.h in 2018 and 391 GW.h in 2019) due to assumed mine closings. The load level of 417 GW.h was fully modeled and exhibits values very close to those in Table 1 (either very close or lower by no more than approximately 2 GW.h).

(g) and **(h)**

In general terms, the only activities requiring a complete plant outage would be on any equipment that is common to both units such as penstock, trash racks, head gate, unit TIV valves or tailrace. In addition there is some common electrical equipment such as station service system or common bus/switchgear or substation maintenance requiring a full plant outage.

Individual unit outages would be more frequent.

Most outages would be of very short duration in relation to annual energy production (e.g., hours). As noted in footnote 44, major outages (lasting weeks at a time, such as for major overhauls) would typically be very infrequent, such as once every 10 years.

(i) and **(j)**

No. See the response to part (c) of this question. Mayo A remains an important source of generation on the Yukon system even after the commissioning of Mayo B, in large part

because of its ability to use water that would otherwise be required to be spilled for fish and fish habitat protection. Despite a reduced output, Mayo A remains a valuable and low cost source of energy for Yukon, and also provides enhanced overall reliability of generation at the Mayo plant than would occur if only the new Mayo B plant was retained.

TOPIC: Displaced diesel/hydro generation

REFERENCE:

Mayo Hydro Enhancement Project (Mayo B) Application; page 13

"Net generation" impacts of Mayo B are sensitive to assumed overall loads on the WAF/MD systems, and changes to annual grid generation load are forecast to change long term average net generation from Mayo B; for example, under the base case forecast, Mayo B net generation contribution to the system (**with Mayo Lake enhanced storage**) approximates 26.4 GW.h in 2012, and ranges from 14.9 to 41.4 GW.h/yr over the Project's assumed 65 year economic life, **reflecting the impact of changes during this period in overall forecast WAF/MD annual dispatchable generation loads.** By comparison, gross generation at Mayo B during this same period would be expected to fluctuate considerably less under the same forecast load conditions. **[Emphasis added]**

PREAMBLE:

The YUB wishes to understand the above.

QUESTION:

a) Please provide the study, assumption and accompanying analysis that led to the base case forecast, wherein "Mayo B net generation contribution to the system approximates 26.4 GW.h in 2012, and ranges from 14.9 to 41.4 GW.h/yr over the Project's assumed 65 year economic life."

b) Please provide the base case forecast, i.e. the approximate GW.h in 2012 and the range of output (GW.h) over the Project's assumed 65 year economic life, without Mayo Lake enhanced storage.

c) Please explain what is meant by the statement, "By comparison, gross generation at Mayo B during this same period would be expected to fluctuate considerably less under the same forecast load condition." Please provide an example.

d) YUB notes the statement that:

"Net Generation" impacts of Mayo B are sensitive to assumed overall loads on the **WAF/MD systems**, and changes to annual grid generation load are forecast to change long-term average net generation from Mayo B" **[Emphasis added]**

a) Please provide sensitivity analyses wherein the changes to annual grid generation load are within +/- 10% and +/- 5% of the base case generation load forecast.

e) Provide a detailed explanation regarding the water conditions that were used, i.e. extreme low, median water and extreme high water conditions, over the Project's assumed 65-year economic life.

ANSWER:

(a)

The net generation values used in each scenario are provided in the response to YUB-YEC-1-25(a).

Mayo B's "net generation contribution to the system" is in effect the diesel generation that Mayo B is forecast to displace that would otherwise be required on the existing and currently committed system, given the forecast firm grid loads to be served. "Net generation" from Mayo B varies therefore from year to year, as noted, depending on the forecast firm grid load levels. The base case load forecast assumptions and analysis adopted for this assessment are set out in Attachment D of the Application, and explain the varying integrated system loads assumed for 2012, 2019 and the remainder of the assumed 65 year economic life of the Mayo B project.

In order to estimate Mayo B net generation at any specific forecast firm grid load levels, the analysis in YUB-YEC-1-25(a) uses a method of estimating the mean net generation contribution of Mayo B corresponding to each particular load level (with different contribution values depending on whether enhanced storage at Mayo Lake is included in the analysis). The net effect of this analytical approach, which is explained in more detail below, is shown in Figure 1 below. The loads in Figure 1 do not arise from any particular forecast or scenario – they are the comprehensive modeling to show the relationship between load and generation at each load level:

Figure 1: Mean Generation to Serve Loads at Varying Levels

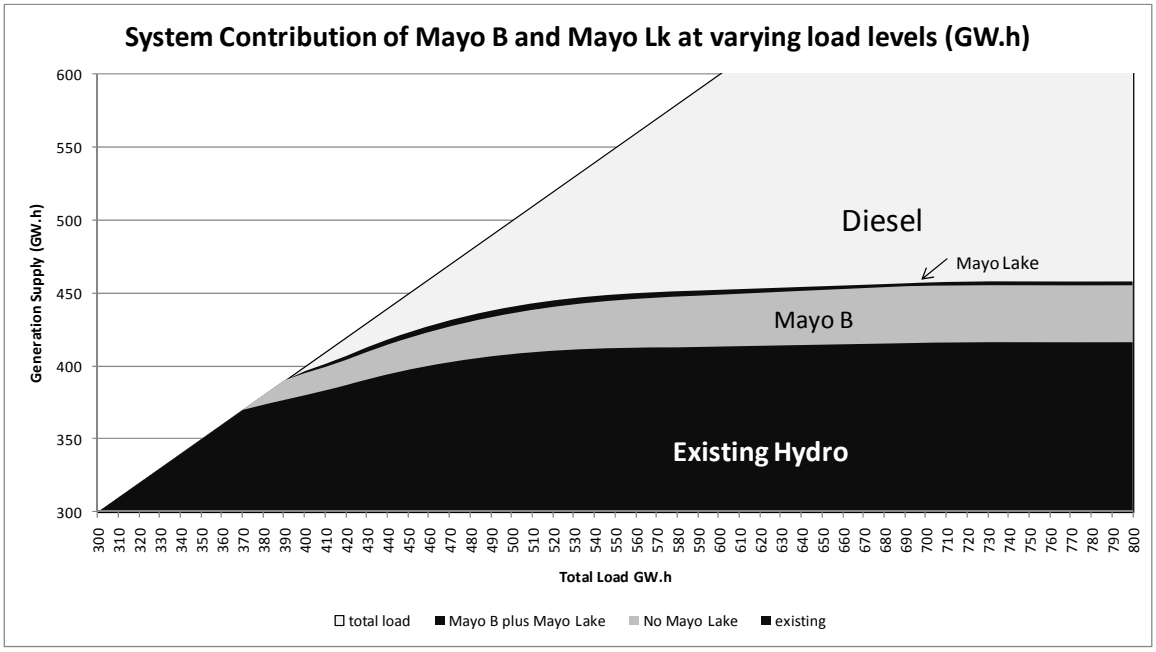


Figure 1 was derived from a detailed hydrologic model that was developed for Yukon Energy. That model considers the full range of potential inflows based on records for each location over the period 1987 to 2007 inclusive. The model runs on a weekly time step and is designed to replicate the dispatch of YEC's hydroelectric stations that would be used in the operation of the integrated system given the specific loads forecast to arise in each week including, for example, the following key modeling aspects:

- Key parameters for each plant such as head losses, efficiency, and maximum peak flows;
- Water licence and fisheries permit conditions for each plant; and
- Peaking constraints, as relevant.

The model produces a full range of possible generation values depending on the water flow and overlapping intra-year effects (such as water in storage at year-end). For economic modeling purposes, the model is used to generate mean output values at

select representative annual firm integrated grid load levels (for example, 417 GW.h, 468 GW.h, and 575 GW.h) for three output variables[1]:

- Hydro generation to serve firm load;
- Diesel generation to serve all residual firm load; and
- Excess hydro generation which can be used to supply secondary loads without affecting the management of water on the system.[2]

Figure 1 represents the interpolation of mean firm generation results for firm load levels between these modeled values, and largely linear extrapolation for values outside this range. To ensure very high load levels are not excessively extrapolated, the maximum generation from the hydro system is capped at the firm plus secondary hydro generation arising in the highest modeled (575 GW.h) load case.[3]

The specific Mayo B assumptions used in deriving these values are as follows:

- Maximum Mayo B plant flow of 19 cms, corresponding to 10.1 MW maximum peak;
- Minimum required flows of 5 cms in winter from Mayo A, and in summer 6 cms from Mayo A, with a total 11 cms in summer downstream from Mayo B;

[1] The values were selected to generally represent the approximate near-term grid loads with Minto and Alexco but without Carmacks Copper (417 GW.h), near-term loads with Carmacks Copper (468 GW.h) and a higher load level representative of longer-term loads, or loads in the near term were all 3 of the noted mines to arise, plus approximately an additional 100 GW.h of industrial load (total 575 GW.h).

[2] This value represents only the generation that could have occurred at times when a plant was simultaneously spilling water and was not fully loading all turbines, such that the specific quantity of water could equally be run through the generating station without having to draw down the water in storage.

[3] To be specific, in the 575 GW.h case, there remains certain situations where the model will indicate secondary energy is available which could be generated to displace diesel generation if only there were loads to use this quantity of power. In the case of Mayo B, the 575 GW.h case indicates a net contribution to serve firm loads of 38.0 GW.h, plus a net contribution to secondary power availability of 3.4 GW.h. It is assumed that the absolute maximum net benefit of Mayo B is the sum of these two values (41.4 GW.h) which based on extrapolation would be achieved once loads reach approximately 720 GW.h. This approach may slightly understate the true maximum benefits of Mayo B, as a fully considered load case at the 720 GW.h level may also indicate some water management changes that could be implemented to further increase the net benefit of the plant; however, these load levels are very high and only assumed to occur far into the future, so are of limited consequence to the discounted economic analysis and as such were not individually modeled.

- 1.5% of output of Mayo B is assumed for station service;

- Mayo Lake licenced range as stated for the case (either existing, or with enhanced storage) with a 2.8 cms minimum outflow from Mayo Lake;

- Mayo B generating efficiency of 0.904 at full flow (19 cms);

- Rule curves are implemented for winter generation, to ensure that Mayo Lake is not drawn down so far at a given time during the winter that, should the lowest recorded inflows occur, YEC will not be able to simultaneously meet both the minimum licenced elevation constraint and the minimum outflow constraints for the remainder of the winter; and

- An effective 1% forced outage rate is assumed for Mayo B, only applied to situations where the plant is operating at full load[4]. Other Yukon plants use 3% as the forced outage rate, but the lower value for Mayo B reflects the fact that during forced outages of Mayo B, if there is no ability to store the given water there is the alternative ability to generate using this same water at Mayo A such that the effect of forced outages is of less magnitude than, for example, at Whitehorse in summer (where if the plant is otherwise operating at full load, a forced outage will inevitably lead to increased spill).

(b)

Please see YUB-YEC-1-25(a).

(c)

The statement means that forecast annual gross firm load generation at Mayo B and A (i.e., actual plant generation output) is much less sensitive to grid firm load levels than is the case for this plant's forecast annual net generation (i.e., estimated plant generation that displaces diesel generation that would otherwise have been required on the grids). To demonstrate, the Application describes (at pages 27-28) the Mayo B "net generation" (the Mayo B contribution to system diesel displacement) as 19.2 GW.h at a grid load of

[4] At times when operating at partial load, a forced outage would result in the given quantity of water being stored for later use, so no net effect on generation – if operating at full load such later makeup could not be as readily assumed to practically occur.

416.7 GW.h, 28.2 GW.h at a grid load of 468.1 GW.h, and 38.0 GW.h at a grid load of 575 GW.h – which reflects a variance of 18.8 GW.h over this range of grid load. In contrast, Mayo B "gross generation" for firm load, ignoring potential secondary sales generation, varies only 5.8 GW.h over this same range of grid load.[5]

This statement is explained in large part by the way in which the Mayo plant is assumed to be operated within the overall integrated grid system. The Mayo generation system (comprising Mayo B and Mayo A, as well as Mayo Lake storage) once completed will be one of the more flexible resources on Yukon Energy's system, given the annual storage available, but will not be as flexible as Aishihik which has a storage range that is more of a multi-year nature and a larger relative installed capacity (particularly once the Aishihik 3rd turbine is completed). The new Mayo B operation, however, will also have higher minimum flow requirements than currently exist at Mayo A, which will set new generation priorities for the Mayo plant relative to Whitehorse plant (under summer low flow conditions in particular). Consequently in most situations on the new integrated system Mayo generation will be dispatched to a full output level in priority to Aishihik, and to the extent there is excess water on the system under some seasonal or annual situations the spillage would tend to occur at Aishihik (while Mayo's generation would remain near its full potential). The Mayo plant will also be dispatched to its new low flow requirements in priority to other plants where required. The overall result of this mode of operation is that gross generation at the Mayo plant will tend to be maintained through a wide range of load levels, and the impact of grid loads on changes to grid hydro generation will tend to be focused at the Aishihik plant for various loads and at the Whitehorse plant during low flow summer conditions.

By way of example, under the present situation on WAF (e.g., 2009 test year loads), there is typically surplus hydro generation. Were a new wind turbine to be installed, for example, under these load conditions, the "net" contribution to the grid would be basically zero. However given the very inflexible nature of wind generation, the new wind turbine itself would be very high priority in the dispatch order and would typically generate its full "gross" potential, but the "net" effect would solely be to drive increased spillage typically at Aishihik compared to what would have been the case without the new wind turbine.

[5] Overall gross generation contribution of Mayo B at the Mayo plant is approximately 39.9 GW.h at 416.7 GW.h grid load, 36.8 GW.h at 468.1 GW.h, and 42.6 GW.h at 575 GW.h grid load.

To use a Mayo B specific example, at the 468 GW.h load level, the response to YUB-YEC-1-21REVISED(a) indicates that absent Mayo B, the existing Mayo A plant would generate 36.1 GW.h. With Mayo B under this same scenario, the existing plant would generate 13.7 GW.h and Mayo B would generate 59.2 GW.h for a total 72.9 GW.h from the Mayo complex. This is an increase in generation of 36.8 GW.h. However, due to changes that occur at other hydro plants at this load level, the "net contribution" of Mayo B under this load level is 28.2 GW.h, which underlies the analysis shown in YUB-YEC-1-25(a)[6]. Although Aishihik shows a net reduction of 2.6 GW.h in firm generation, Whitehorse shows a net reduction 6.0 GW.h in firm generation almost all due to summer impacts related to minimum flow requirements[7] (i.e., additions of summer generation required at Mayo to meet new low flow requirements that, under certain low load conditions, cause the need to spill small quantities of run of river generation at Whitehorse). This is set out in Table 1 below:

Table 1: Changed production, by plant, from the addition of Mayo B at a 468 GW.h Dispatchable Load Level

	With Mayo B			No Mayo B			Difference		
468.1 GW.h load	Firm	Secondary	Total	Firm	Secondary	Total	Firm	Secondary	Total
Whitehorse	243.3	13.9	257.3	249.3	6.6	255.9	-6.0	7.4	1.4
Aishihik	114.3	7.1	121.4	116.9	4.8	121.7	-2.6	2.2	-0.3
Mayo	72.9	7.0	79.9	36.1	1.2	37.3	36.8	5.8	42.5
Mayo A	*13.7*		*0.0*	*36.1*		*0.0*	*-22.4*		*0.0*
Mayo B	*59.2*		*0.0*	*0.0*		*0.0*	*59.2*		*0.0*
Diesel	37.5	0.0	37.5	65.7	0.0	65.7	-28.2	0.0	-28.2
TOTAL	468.1	28.0	496.0	468.1	12.6	480.6	0.0	15.4	15.4

NOTES:
- Does not distinguish betwteen secondary energy produced at Mayo A or B.
- Secondary Energy noted is the potential to serve secondary from water otherwise required to be spilled, where turbines are available to generate with this water. It does not reflect using storage for the purposes of serving secondary.

[6] See YUB-YEC-1-21 (a) to (f) where it is noted that, due to different models used, the overall plant results provided in that response (i.e., the 36.8 GW.h noted here) are difficult to compare with the Application's IS model net generation assessments (i.e., the 28.2 GW.h noted here) without specific reference to both firm and secondary loads.

[7] Overall, 5.5 GW.h of the 6.0 GW.h reduction at Whitehorse occurs in summer months.

(d)

For YEC's approach to determining the net contribution of Mayo to the system under differing load scenarios, see YUB-YEC-1-30A(a). The LCOEs arising from the requested cases are as follows in Table 2:

Table 2: LCOE sensitivity to variations in load forecast

(throughout the entire 65 year scenario)

Scenario	LCOE (cents/kW.h)
Base Case (with Carmacks Copper and Mayo Lake)	6.69
All loads (including industrial and losses) up by 10% throughout the scenario	5.92
All loads (including industrial and losses) up by 5%	6.24
All loads (including industrial and losses) down by 5%	7.53
All loads (including industrial and losses) down by 10%	8.77

(e)

Please see YUB-YEC-1-30A (a). The range of water conditions was also reviewed in Attachment C to the Application (Table C-1 reviews impacts on existing generation of this range).

UCG-YEC-1-6

ATTACHMENTS

ATTACHMENT 1

INTERNATIONAL PROJECT ESTIMATING

KGS Group
865 Waverly Street
Winnipeg, Manitoba
R3T 5P4

Feb 3 2009

Re: Yukon Energy-Mayo B Hydroelectric Project – Estimate Review

Attention: Mr Shaun Beatty, Senior Structural Engineer

Dear Shaun

I have reviewed your estimate for the Mayo B Hydro-electric project and have included a comparison on the attached spreadsheet. I have compared your project against other detailed estimates I have completed over the past several years.

The rates include Contractor Direct Costs, Indirect Costs and Profit. I have assumed that the Contractor Indirect costs were in the order of 30% of Contractor Direct costs and that the profit was in the order of 20% of Contractor Total costs.

There were several large variances which I will comment on in this letter;

- The Mobe-Demobe costs are included in my unit rates.
- I assumed the Canal Excavation was 80% Rock and 20% Overburden. If the excavation is all overburden then your rate was OK.
- I assumed the canal lining was rock and not concrete.
- I assumed the Steel Penstock has a 20mm wall thickness.
- I was significantly less on the Balance of Plant. My budget was based on previous estimates of similar size.
- I increased the contingency on the civil works to account for quantity risk.
- You must have made a mistake on your contingency on balance of plant.
- I increased the camp man-days which would include all labour, subcontractor labour, engineering site visitors, camp staff etc.

If you have any questions please do not hesitate to contact me.

Sincerely

Paul Hewitt M.Sc.P.Eng
Principal
International Project Estimating Limited

Yukon Energy-Mayo B Hydroelectric Project - Estimate Review

Item	Description	KGS Group Quantity	Units	Unit Cost	Cost	International Project Estimating Quantity	Units	Unit Cost	Cost	Variance	Notes
1	Mob and Demob	[redacted]			2,000,000	[redacted]			0	-2,000,000	included in unit rates
2	Access Road - powerhouse to canal outlet				150,000				240,000	90,000	assumes access road includes rock cuts
3	Access Road - surfacing of canal berm				75,000				195,000	120,000	granular base 300mm thick x 7 m wide
3	Care of water at new tailrace				300,000				300,000	0	
4	Care of water at Wareham intake/tunnel				300,000				300,000	0	
5	Existing tunnel expansion				1,600,000				1,240,000	-360,000	[redacted]
6	Tunnel infill concrete				250,000				150,000	-100,000	assume nominal formwork or rebar required
7	New Vertical Shaft [redacted]				460,000				798,000	338,000	assume no concrete lining required
8	Penstock low pressure [redacted]				5,520,000				4,600,000	-920,000	
9	Penstock-to-canal outlet structure				880,000				600,000	-280,000	
10	Clearing				675,000				1,035,000	360,000	assume clear & grub
11	Canal excavation				9,000,000				16,200,000	7,200,000	assume 80% rock + 20% overburden
12	Canal lining				2,100,000				2,800,000	700,000	assume this is a rock ling and not concrete lining
13	Canal-to-penstock inlet structure				880,000				600,000	-280,000	
14	Steel penstock: canal to p/h [redacted]				11,340,000				13,770,000	2,430,000	assume 20 mm thick
15	Steel penstock foundation & backfill				1,360,000				1,360,000	0	
16	Penstock bifurcation				500,000				500,000	0	
17	W2W Turbine Generator				15,000,000				16,000,000	1,000,000	
18	Powerhouse bedrock excavation				120,000				120,000	0	
19	Powerhouse Civil (concrete)				4,400,000				3,000,000	-1,400,000	
20	Tailrace excavation				1,040,000				1,040,000	0	assume done in wet
21	Powerhouse Electrical				3,250,000				1,000,000	-2,250,000	
22	Mechanical - balance of plant				2,500,000				750,000	-1,750,000	
23	Mayo B substation (two 10 MVA transformers)				1,100,000				1,100,000	0	
24	Mayo Hydro substation upgrade (not KGS scope)				0				0	0	
25	Transmission Line - 69 kV plus communications				900,000				864,000	-36,000	
26	Transmission Line - 13.8 kV station power & transforme				51,000				51,000	0	
27	Environmental mitigation measures				1,000,000				1,000,000	0	
28	Land acquisition				250,000				250,000	0	
29	Major spares				250,000				250,000	0	
					67,251,000	0	0	0	70,113,000	2,862,000	
30	Unidentified Unknowns	10 %			6,700,100	20 %		0	14,022,600	7,322,500	includes contingency on civil quantities
31	**Subtotal of Direct Costs**				73,951,100	0	0	0	84,135,600	10,184,500	
31	Contingencies on turbine-generator	15 %			2,250,000	15 %		0	2,400,000	150,000	
32	Contingencies on balance of plant	25 %			14,737,775	30 %		0	525,000	-14,212,775	
33	**Total Direct Costs**				90,938,875	0	0	0	87,060,600	-3,878,275	
32	Planning to date (pre-eng & site investigations)	1 ls		1,500,000	1,500,000	1 ls		1,500,000	1,500,000	0	
33	Detailed Engineering, tender prep & support	8 %			7,275,110	8 %		0	6,964,848	-310,262	
34	Construction Management & administration	4 %			3,637,555	4 %		0	3,482,424	-155,131	
35	Environ and Licensing (excludes Mayo Lake)	4 %			3,637,555	4 %		0	3,482,424	-155,131	
36	Interest during construction	8 %			7,275,110	8 %		0	6,964,848	-310,262	
37	Owner Adminstration	0.5 %			454,694	0.5 %		0	435,303	-19,391	
38	YEC staff - training & commissioning	1 ls			50,000	1 ls		50,000	50,000	0	
39	Diesel costs during Mayo outages for construction	0 MW-hrs		300	0	0 MW-hrs		0	0	0	
40	Construction camp infrastructure	1 ls		500,000	500,000	1 ls		500,000	500,000	0	
41	Camp and housing	20,000 man da		200	4,000,000	30,000 man days		175	5,250,000	1,250,000	
42	**Total Project Costs**				119,268,899				115,690,447	-3,578,452	
43	Total cost in $/kw				11,927				11,569	-358	

Yukon Energy-Mayo B Hydroelectric Project - Estimate Review

Item	Description	Quantity	Units	Unit Cost	Cost	Quantity	Units	Unit Cost	Cost	Variance	Notes
1	Mob and Demob	[redacted]			2,000,000	[redacted]			0	-2,000,000	included in unit rates
2	Access Road - powerhouse to canal outlet				150,000				175,000	25,000	assumes no rock cuts
3	Access Road - surfacing of canal berm				75,000				195,000	120,000	granular base 300mm thick x 7 m wide
3	Care of water at new tailrace				300,000				300,000	0	
4	Care of water at Wareham intake/tunnel				300,000				300,000	0	
5	Existing tunnel expansion				1,600,000				1,240,000	-360,000	[redacted]
6	Tunnel infill concrete				250,000				150,000	-100,000	assume nominal formwork or rebar required
7	New Vertical Shaft				460,000				798,000	338,000	assume no concrete lining required
8	Penstock low pressure				5,520,000				4,600,000	-920,000	
9	Penstock-to-canal outlet structure				880,000				600,000	-280,000	
10	Clearing				675,000				1,035,000	360,000	assume clear & grub
11	Canal excavation				9,000,000				10,800,000	1,800,000	assume 100% overburden
12	Canal lining				2,100,000				3,500,000	1,400,000	assume granular plug geomembrane
13	Canal-to-penstock inlet structure				880,000				600,000	-280,000	
14	Steel penstock: canal to p/h				11,340,000				11,340,000	0	assume 10-13 mm last section 20 mm thick
15	Steel penstock foundation & backfill				1,360,000				1,360,000	0	
16	Penstock bifurcation				500,000				500,000	0	
17	W2W Turbine Generator				15,000,000				16,000,000	1,000,000	
18	Powerhouse bedrock excavation				120,000				120,000	0	
19	Powerhouse Civil (concrete)				4,400,000				3,000,000	-1,400,000	
20	Tailrace excavation				1,040,000				1,040,000	0	assume done in wet
21	Powerhouse Electrical				3,250,000				1,000,000	-2,250,000	
22	Mechanical - balance of plant				2,500,000				750,000	-1,750,000	
23	Mayo B substation (two 10 MVA transformers)				1,100,000				1,100,000	0	
24	Mayo Hydro substation upgrade (not KGS scope)				0				0	0	
25	Transmission Line - 69 kV plus communications				900,000				864,000	-36,000	
26	Transmission Line - 13.8 kV station power & transformer				51,000				51,000	0	
27	Environmental mitigation measures				1,000,000				1,000,000	0	
28	Land acquisition				250,000				250,000	0	
29	Major spares				250,000				250,000	0	
30	Unidentified Unknowns				67,251,000	0	0	0	62,918,000	-4,333,000	
31	**Subtotal of Direct Costs**	10 %			6,700,100	10 %		0	6,291,800	-408,300	excludes contingency on civil quantities
31	Contingencies on turbine-generator				73,951,100	0	0	0	69,209,800	-4,741,300	
32	Contingencies on balance of plant & civil work	15 %			2,250,000	15 %		0	2,400,000	150,000	
33	**Total Direct Costs**	25 %			14,737,775	25 %		0	13,302,450	-1,435,325	
32	Planning to date (pre-eng & site investigations)				90,938,875	0	0	0	84,912,250	-6,026,625	
33	Detailed Engineering, tender prep & support	1 ls		1,500,000	1,500,000	1 ls		1,500,000	1,500,000	0	
34	Construction Management & administration	8 %			7,275,110	8 %		0	6,792,980	-482,130	
35	Environ and Licensing (excludes Mayo Lake)	4 %			3,637,555	4 %		0	3,396,490	-241,065	
36	Interest during construction	4 %			3,637,555	4 %		0	3,396,490	-241,065	
37	Owner Adminstration	8 %			7,275,110	8 %		0	6,792,980	-482,130	
38	YEC staff - training & commissioning	0.5 %			454,694	0.5 %		0	424,561	-30,133	
39	Diesel costs during Mayo outages for construction	1 ls			50,000	1 ls		50,000	50,000	0	
40	Construction camp infrastructure	0 MW-hrs		300	0	0 MW-hrs		0	0	0	
41	Camp and housing	1 ls		500,000	500,000	1 ls		500,000	500,000	0	
42	**Total Project Costs**	20,000 man day		200	4,000,000	30,000 man days		175	5,250,000	1,250,000	
43	Total cost in $/kw				119,268,899				113,015,751	-6,253,148	
					11,927				11,302	-625	

ATTACHMENT 2

YUKON ENERGY

COPY

CAPITAL EXPENDITURE REQUEST

CEAR NUMBER: 98-90034 **Revision:** 0 **Date:** December 15, 1998

PROJECT NAME: NEW WIND TURBINE

LOCATION: WHITEHORSE – YUKON TERRITORY

TYPE: GENERATION

PROJECT LEADER: JOHN F. MAISSAN

DESCRIPTION:

The Yukon Government has made $2 million available through the Yukon Development Corporation for the installation of an additional wind turbine.

The objective of this project is to adapt proven commercial wind generation equipment with proven and developing methods for coping with low temperature and rime ice to yield wind generated electricity that is cost competitive with diesel generation.

IN-SERVICE DATE:	December 31, 1999
CEAR Request:	**$2,000,000**
Previous Approval:	
1998 Business Plan	$00
CEAR Total:	**$2,000,000**

REQUEST FOR APPROVAL

Technical Services Approval _____ Date 98-12-22

Management Approval _____ Date 98-12-23

YUKON ENERGY

YUKON ENERGY CORPORATION

CAPITAL BUDGET – NEED STATEMENT

Originator: John F. Maissan Date: Dec. 15, 1998 Urgency: A

Project: New Wind Turbine

Project No.: 98-90034 Start: Dec. 15, 1998 Complete: Dec. 31, 1999

Business Plan/GRA: neither Revision Date:

Project Category (as per attached)
8. Research & Development, plus
7. Generation Increase

Critical Time of Year Window:
Summer Construction

What is to be done:

See Attached

Why Should this Project be Done:

See Attached

Estimated Cost of Project

Materials: (Attach Details as Appropriate)	1,450,000
Contracts:	275,000
Rentals, Supplies, Associated Training, Miscellaneous	100,000
Yukon Energy Corporation Labour	50,000
Contingency	75,000
ES & G (Flat Rate)	50,000
Total	**$2,000,000**

Originator: _____ Date: 98-12-22

Approval: _____ Date: 98-12-23

Urgency **A**: Must be done ASAP **B**: Do Next Business Plan Year **C:** Do As Funds Available

NEW WIND TURBINE PROJECT

WHAT IS TO BE DONE:

Based on 5 ½ years of practical experience and adaptation to severe rime icing with the 150 kW Bonus stall regulated wind turbine, YEC is to draw up specifications and requirements for a new wind turbine. The new wind turbine will have features that address problems with the Bonus wind turbine that result in power generation losses. The proposed wind turbine must also be a full size commercial unit with a proven track record and backed by a sound supplier willing to work with YEC.

WHY THIS PROJECT SHOULD BE DONE:

The Bonus wind turbine has proven that commercial wind turbines can be adapted to run in sub-arctic conditions, including severe rime icing. The Bonus machine still looses about 20% of its potential power production to the effects of rime icing (principally on the blades). This percentage loss would not likely yield power costs competitive with diesel generation in wind farm applications. YEC staff feel that a significantly lower percentage loss is possible by choosing specific features in a wind turbine that will minimize these losses, including: blade pitch regulation for power control rather than stall regulation; blades without tip brakes to get away from electrical contact problems in the blade heating systems; and a turbine pitch control program (in the computer) that seeks to maximize power output when the blades are affected by rime ice.

Success in this project would open the door to commercial wind generation that is cost competitive with diesel for when electrical loads on WAF are higher. The proposed project would not (and probably could not) be done by the private sector because of the high level of risk and capital cost involved.

The timing of the project, 1999 installation, is largely driven by the availability of $2 million from YTG through YDC this year. If the project does not proceed this year the monies might not be available in the following year.

NEW WIND TURBINE PROJECT

ESTIMATED PROJECT COSTS

MATERIALS:

Wind Turbine Purchase	$1,350,000
Transformers, Cabling, Metering	75,000
Control System & Tools	25,000
Sub Total	$1,450,000

CONTRACTS:

Foundations	150,000
Road Upgrading	50,000
Electrical Installations	25,000
Project Supervision	50,000
Sub Total	$ 275,000

RENTALS:

Crane Rental	$ 100,000

YEC LABOUR:

In-House Staff	$ 50,000

CONTINGENCY: $ 75,000

ES & G

ES &G (Flat Rate)	$ 50,000

PROJECT TOTAL **$2,000,000**

YUKON ENERGY CORPORATION
WORK ORDER

RESPONSIBILITY NO.	0950	WORK ORDER NO.	C98093
PROJECT NO.	98-90034	REVISION NO.	
BUDGET ITEM	Y/N	$	DISTRICT WHITEHORSE
PURCHASE ORDER			DATE DEC. 15, 1998

SHORT DESCRIPTION: NEW WIND TURBINE

DETAILS AND EXPLANATION OF WORK

SEE ATTACHED 'NEEDS STATEMENT'

O&M ALLOCATION

Reference Sketch or drawing

ESTIMATE:

DESCRIPTION	UNIT COST	
MATERIALS		1 450 000
CONTRACTS		275,000
RENTALS, SUPPLIES, TRAINING, MISC.		100,000
YEC LABOUR		50,000
CONTINGENCY		75,000
ES&G		50,000
TOTAL		2,000,000

	SIGNED	DATE
SUBMITTED BY.		98-12-21
APPROVED BY.		98-12-23
STARTED:		
COMPLETED:		
COMMISSIONED:		

ATTACHMENT 3

Yukon Energy Corporation
Business Case for Whitehorse Rapids Upstream Wingwall Seismic Restraint

1. Executive Summary

Yukon Energy has adopted the guidelines set out in the Canadian Dam Association (CDA) Dam Safety Guidelines as the minimum requirement for safety at its facilities. The CDA guidelines are nationally recognized and accepted as the *de facto* national standard for dams in this country. In particular, in a jurisdiction that does not have its own provincial/territorial dam safety requirements, the CDA guidelines server as the only practical guide.

The present wall does not meet current CDA criteria with respect to earthquake loads since the design earthquake would result in sliding and displacements sufficient to fail the core and release water from the reservoir. For the Whitehorse Rapids GS, the design earthquake is required to be a minimum 1 in 10 000 year event. Execution of the planned works would limit displacements of the wall and bring the performance of buttress retaining wall in compliance with CDA guidelines.

This business case recommends support for proceeding with the completion of an updated cost estimate, specifications, drawings, construction and installation of a toe block anchor system as detailed in the Seismic Retrofit Design (see attached report).

The estimated cost is as follows:

Revised Estimate:	$9 500
Tender Documentation/Specifications/Drawings:	$22 000
Construction Contract:	$488 815
Project Management/Dive Inspection:	$70 000
Contingency:	$65 000
ES&G:	$65 532
Total:	**$720 847**

The Work will be performed during winter months, when the spillway gates can be kept closed to avoid currents in the area.

The Work comprises the installation of concrete blocks in front of (on the water side of) the three buttresses. The blocks will be anchored to bedrock with corrosion-protected, post-tensioned rock anchors grouted into the foundation. Between each concrete

block and buttress an elastomer bearing pad will be installed to permit some movement of the wall as dynamic load is transferred to the block. The purpose of the blocks is to restrain the wing wall in the unlikely event of a major earthquake (see attached drawing).

The general description of the project is as follows.

1) Mobilize to and demobilize from the Site, including provision of site trailer for personnel, recompression chamber and barges for work over ice and water.
2) Remove existing spillway stoplogs and overhead gantry monorail from storage area near east upstream wing wall prior to operations on and in the water. Replace same after completion of operations on and in the water.
3) Install barges for working platform on ice over wing wall. Remove after completion of operations in the water.
4) Prepare anchor block foundations.
5) Place leveling concrete upon which anchor blocks will be constructed.
6) Construct concrete formwork, steel reinforcement, embedments and elastomeric bearings for anchor blocks.
7) Install formwork and reinforcement.
8) Place concrete in forms.
9) Drill for anchors, water test in drill holes and, if necessary, grout drill holes, let grout set, and redrill holes. Repeat as required to minimize grout loss from drill holes.
10) Alternatively, if grout takes are excessive, install geotextile grout sleeves over anchors to seal locations of excessive grout takes.
11) Install anchors in drill holes and grout.
12) Test anchors.
13) Tension anchors and lock off.
14) Install protective caps over top of anchors and fill caps with anti-corrosion compound.

2. Background

The Whitehorse Rapids Generating Station is located a few kilometers upstream from downtown Whitehorse and a breach of the dam would result in extreme damage and loss of life. As such, the CDA guidelines classify the facility as a Very High Consequence structure.

Based on the consequence category, a criteria for design earthquake is determined. Analysis performed in a 1997 Seismic

Deficiency Investigation showed that the during the 1 in 10 000 year earthquake event, factors of safety for sliding and overturning are both unacceptable, and estimated displacement is 5 to 17 inches. This particular wall retains the dam fill immediately adjacent to the core's contact with the spillway end block, and soil deformations in this area are most undesirable. The probable consequence during a large earthquake event would be the wall sliding, earthfill dam and core undergoing considerable movement, and seepage paths being openned that result in a piping failure of the dam.

The 1997 Seismic Deficiency Report concluded by recommending that a design for the stabilization work be carried out on the upstream wingwall along with tender drawings, specifications and an engineer's cost estimate. In February 2000 a final design for the East Upstream Spillway was completed and it is this design that construction approval is being sought.

3. *Alternatives Considered*

Options:

1. Rock Anchor Option:

This option involves placing mass concrete between the buttress walls and post-tensioned rock anchors are needed to directly provide overturning resistance and also increase frictional resistance to sliding.

2. Buttress Wall Extension:

Involves forming extensions to the buttress underwater, tying extensions and new buttress sections together, and anchoring into the foundation rock.

3. Buttress Wall Toe Block:

This concept requires a block of reinforced concrete to be anchored to the foundation rock, in front of each buttress wall, with post tensioned vertical rock anchors

4. *Risk / Safety Analysis*

The CDA guidelines require that a dam be evaluated for its ability to withstand the ground motions associated with the Maximum

Design Earthquake (MDE). The MDE for a Very High consequence structure is a 1 in 10 000 year event, or it can be thought of as the biggest conceivable earthquake specific to a particular area.

All three options will succeed in bringing the wall into compliance with the CDA guidelines, however, the increased cost due to the relative complexities of some of the options and increased flow restrictions makes some options less desirable as discussed in the next section.

A work site safety risk analysis will be performed before any construction work takes place to ensure work site safety is adequately managed throughout the duration of the project.

5. *Option Selected*

Option 1 is not recommended because the volume of concrete required to fill in the buttress would be much greater than the preferred option, thus increasing the cost. There would be increased foundation preparation since the footprint for this option is larger than with the toe blocks. To tie the infill concrete to the buttress wall would be technically more difficult than the rock anchors proposed in the toe block solution. All these considerations made this option more costly and challenging.

Option 2 is not recommended for two reasons. Extending the relatively thin, and sloping buttress section was technically more difficult than placing a toe block at the end. The formwork and tying the old section with the new is more complex and costly. Secondly, the new buttress sections would intrude into the flow channel above the level of the bottom of the spillway and cause hydraulic problems at higher flows.

Option 3 is recommended because it is the simplest to construct and provides a direct load path into the foundation rock which is structurally more efficient. The toe blocks will likely intrude into the spillway approach channel; however, the intrusion is below the ogee crest and will be less of an intrusion than with the buttress extension option. The total capacity of the spillway is 54% greater than the estimated probable maximum flood, so a minor restriction if flow should be no concern.

6. *Implementation Process*

Project Organization:

Owner's Designate: Ron Gee
Construction Manager: Stan Williams (Klohn Crippen)
Project Manager: Garry Stevenson (Klohn Crippen)

7. *Approvals Required*

This level of expense requires President approval.

No permits are believed to be required from regulatory agencies. Notification letter stating the scope of work along with schedule will be provided to DIAND and DFO. The land that the project is taking place on is YEC land, and there are no triggers to water license requirements as far as we know.

ATTACHMENT 4

YUKON ENERGY

CAPITAL EXPENDITURE APPROPRIATION REQUEST

CEAR NUMBER: 01-90002 **Revision:** 2 **Date:** February 7, 2003

WORK ORDER NUMBER: C01007

PROJECT NAME: Mayo Hydro Units – Runner Replacement & Unit Overhaul
(Previous Project Name: Mayo Hydro Units – Preliminary Engineering)

LOCATION: Mayo, Yukon Territory

TYPE: Generation Improvements

PROJECT LEADER: Les Rowland

DESCRIPTION:

This CEAR is a continuation of CEAR 01-90002 to take the Mayo upgrade project into the manufacture and installation phase of the project. It was decided to do this as a CEAR revision to ensure that all the costs of this project are captured under a single capital work order.

This CEAR will include the engineering set out in the previous revision, and will add the following work:

1. The manufacture and delivery of two new runners. General Electric Canada is to manufacture runners to replace the existing 50 year old runners. The new runners will give YEC an increase of capacity and efficiency, resulting in 21% more power from MH1 and 12% more power from MH2.

2. The complete disassembly and re-assembly of MH1 with the new runner, and the refurbishment or replacement of all other components as required. This will also include all work necessary to increase the maximum wicket-gate opening angle to allow the necessary increased water flow. The assembly and commissioning of MH1 will be done under GEC technical supervision.

3. Repairs to the draft tubes. This work is necessary because 50 years of operation has worn away a lot of the concrete in the draft tubes. This has exposed rebar and is causing turbulent downstream flow. This turbulent flow is increasing the back pressure on the units and contributing to accelerated erosion.

4. A complete Babbitt rebuild of all main bearings for MH1. The bearing surfaces have separated from the journal, and would eventually contact the rotating portion of the unit if not rebuilt.

5. Testing and replacement if necessary of all electrical components for MH1, and

6. Cleaning of the rotor and stator for both units. This is to be a mechanical-type clean of all the windings. This work is necessary to increase the air flow in and around the windings to decrease the temperature rise of the generator. This temperature rise is expected to be the limiting factor on the unit's power output.

CEAR Revision 2 Changes
This revision of the CEAR Revision 1 above is due to three factors:

1. Cost over-runs occurred due to a shifting of the upper end of the powerhouse around MH1. Because of this movement, the unit could no longer be assembled vertically, but instead had to be installed at a slight angle. This meant adjusting or shimming all the main unit components all the way up.

2. The cost of certain auxiliary components (eg tailrace, piping and electrical cabling), although verbally described in the original CEAR, was missed when it came to the financial section.

3. There was a reduction in the overall CEAR value as the cost of designing and manufacturing the two runners was split in half, with one half of the total being journal vouchered over to C02111 (MH2 rebuild). This gives a better and more accurate indication of the actual cost of refurbishing each unit.

IN-SERVICE DATE:	December, 2002
CEAR Request:	**$ 11,000**
Previous Approval:	$980,000
2001 Business Plan:	$500,000
(2002 Business Plan:	$800,000)
CEAR TOTAL:	**$991,000**

REQUEST FOR APPROVAL

Project Manager	W.J.L Haydock (For Les Rowland)	Date:	19 Feb 03
Supervisor	N/A	Date:	
Technical Services	W.J.L Haydock	Date:	19 Feb 03
Chief Financial Officer		Date:	19 Feb 03
President & CEO		Date:	2003.03.12
Board of Directors		Date:	

YUKON ENERGY

YUKON ENERGY CORPORATION
MEMORANDUM

DATE February 19, 2003

TO: File (attachment to final CEARs for MH1 &MH2 Rebuilds)

From: Bill Haydock
Technical Services

Subject: MH1 &MH2 Business Plan and CEAR Clarification

The purpose of this memo to file is to explain some of the discrepancies between the 2001-2002 capital budget, the CEARs and the actuals for the MH1 and MH2 upgrades.

The 2002 Business Plan identifies three related costs under two headings:

a. $500,000 in 2001 – this was the cost for the design and manufacture of both MH1 and MH2 runners.

b. $300,000 in 2002 – this was for upgrades/replacements to unit auxiliary components (tailrace concrete repairs; cooling, firefighting and domestic water piping; misc. electrical and mechanical plant work)

These two costs above were labeled under 'MH1 Capacity Increase-phase 1'.

c. $500,000 in 2002 – this was for the actual teardown, runner installation and re-assembly for MH1.

This cost was mislabeled in the business plan. It reads 'MH2 Capacity Increase', but should have read 'MH1 Capacity Increase-**phase 2**'.

All three of these costs (totaling $1,300,000) were carried out under capital work order C01007. However, the CEAR-Rev 1 for C01007 forgot to include b. above, the $300,000, in the costing portion. Therefore it ended up being a request for $980,000 instead of $1,300,000. (CEAR-Rev 0 for C01007 was $200,000 for studies and engineering only. To avoid multiple CEARs on the same unit, it was decided to substantially increase the same CEAR to continue the work on MH1 to completion).

It was not anticipated when doing up the 2002 budget that YEC would have the time to do the MH2 capacity increase prior to the M/DC line being energized, so it was not included in the 2002 budget. It was only in July 2002 that it became apparent that there would be time to do MH2. At that time a further sum of $612,000 was requested to do MH2 (capital work order C02111). This request was approved, and work on MH2 was completed by October, 2002.

The final step in this process was to move some costs that belonged to MH2 over to C02111 from the original C01007 work order. This included the design and manufacture of the MH2 runner, and some of the auxiliary component costs. This resulted in the need for new CEARs (Rev 2 for MH1, and Rev 1 for MH2).

Bill Haydock
Mech/Civil Supervisor

YUKON ENERGY

CAPITAL EXPENDITURE APPROPRIATION REQUEST

CEAR NUMBER: 01-90002 **Revision:** 1 **Date:** February 18, 2002

WORK ORDER NUMBER: C01007

PROJECT NAME: Mayo Hydro Units – Runner Replacement & Unit Overhaul
(Previous Project Name: Mayo Hydro Units – Preliminary Engineering)

LOCATION: Mayo, Yukon Territory

TYPE: Generation Improvements

PROJECT LEADER: Bill Haydock

DESCRIPTION:

This CEAR is a continuation of CEAR 01-90002 to take the Mayo upgrade project into the manufacture and installation phase of the project. It was decided to do this as a CEAR revision to ensure that all the costs of this project are captured under a single capital work order. It should be read in conjunction with the original CEAR (attached).

This CEAR will include the engineering set out in the previous revision, and will add the following work:

1. The manufacture and delivery of two new runners. General Electric Canada is to manufacture runners to replace the existing 50 year old runners. The new runners will give YEC an increase of capacity and efficiency, resulting in 21% more power from MH1 and 12% more power from MH2.

2. The complete disassembly and re-assembly of MH1 with the new runner, and the refurbishment or replacement of all other components as required. This will also include all work necessary to increase the maximum wicket-gate opening angle to allow the necessary increased water flow. The assembly and commissioning of MH1 will be done under GEC technical supervision.

3. Repairs to the draft tubes. This work is necessary because 50 years of operation has worn away a lot of the concrete in the draft tubes. This has exposed rebar and is causing turbulent downstream flow. This turbulent flow is increasing the back pressure on the units and contributing to accelerated erosion.

4. A complete Babbitt rebuild of all main bearings for MH1. The bearing surfaces have separated from the journal, and would eventually contact the rotating portion of the unit if not rebuilt.

5. Testing and replacement if necessary of all electrical components for MH1, and

6. Cleaning of the rotor and stator for both units. This is to be a mechanical-type clean of all the windings. This work is necessary to increase the air flow in and around the windings to decrease the temperature rise of the generator. This temperature rise is expected to be the limiting factor on the unit's power output.

IN-SERVICE DATE:	December, 2002
CEAR Request:	**$780,000**
Previous Approval:	$200,000
2001 Business Plan:	$500,000
(2002 Business Plan:	$500,000)
CEAR TOTAL:	**$980,000**

REQUEST FOR APPROVAL

Technical Services Approval: W.J. Haydock Date: 25 June 02

Management Approval: [signature] Date: 2002.07.07

YUKON ENERGY

Sent to John for TS sig. 8-28-01

COPY

CAPITAL EXPENDITURE APPROPRIATION REQUEST

CEAR NUMBER: 01-90002 **Revision:** 0 **Date:** August 28, 2001

WORK ORDER NUMBER: C01007

PROJECT NAME: Mayo Hydro Units – Preliminary Engineering

LOCATION: Mayo, Yukon Territory

TYPE: Generation Improvements

PROJECT LEADER: Bill Haydock

DESCRIPTION:

Preliminary engineering for replacement of runner and possibly the discharge ring on MH1 and MH2, as well as rotor and stator rewinding.

It has been projected that soon after the Mayo/Dawson line is in service, peak power will have to be supplied with diesel, given the existing load limits of the Mayo hydro units. Upgrading the runners and discharge rings will increase output by 10 to 20 percent, thus reducing diesel generation required. Economic analyses based on preliminary cost and capacity increase estimates indicate that these upgrades are cost effective. The rotor/stator rewinds will be necessary to complement the upgraded capacity of the turbines

This replacement maximizes the long-term hydro availability and minimizing the long-term diesel requirements will minimize long-term ratepayer costs.

IN-SERVICE DATE: December, 2001

CEAR Request: **$200,000**

Previous Approval: 0

2001 Business Plan: $500,000

CEAR TOTAL: **$200,000**

REQUEST FOR APPROVAL

Technical Services Approval:_____ Date:_____

Management Approval:_____ Date:_____

ATTACHMENT 5

for inspection until 2007, Yukon Energy has decided to have all its dams inspected at once to reduce costs of flying inspectors to the territory from southern Canada.

Required Revenue and Related Matters Review - $200,000

Preparation, filing and review of Yukon Energy's Required Revenues and Related Matters Application for 2005. The 2005 amounts are in addition to forecast spending of $300,000 prior to January 1, 2005.

5.3 MAJOR CAPITAL PROJECTS 2000-2004

This section reviews the major capital works projects and deferred costs undertaken by Yukon Energy since the last GRA, focusing on the 2000-2004 period[2]. Two projects were of a substantial size and financial commitment (over $10 million), the Mayo-Dawson Transmission Line Project and the Whitehorse Rapids Generating Station Fire Rebuilding Project, and each of these is addressed separately in following sections. In addition, all projects over $1 million are noted.

5.3.1 Mayo-Dawson Transmission Line Project

The Mayo-Dawson Transmission Line Project ("Mayo-Dawson") is an approximately 223 kilometre 69 kV transmission line that provides Dawson City with surplus hydro generation from the Mayo Generating Station. The project was brought

[2] Table 5.1 and Table 5.2 provide details on capital works spending during these years.

into service in September 2003 and now supplies nearly all of the energy requirements of Dawson City. Diesel generators will continue to be maintained as a back-up source in Dawson City.

The costs for the Mayo-Dawson project projected to the end of 2005 are approximately $35.6 million. Of this amount, $5.8 million has been provided by Yukon Development Corporation ("Yukon Development", or "YDC") at no cost to ratepayers.

Mayo-Dawson Project Economics

The Mayo-Dawson Project uses surplus power from Yukon Energy's existing Mayo system to replace high cost diesel generation in Yukon Energy's Dawson City system. As a result, the bulk power costs to the system are very low, as the hydro generation would otherwise be spilled at Mayo. The delivered cost of power to Dawson now comprises largely capital-related costs with respect to the transmission line (depreciation and return on rate base) compared to the largely operating costs of diesel generation (fuel, variable O&M, as well as some costs for diesel engine replacement). The nature of the avoided diesel costs is significantly different than the nature of the transmission line costs when looked at on an annual cost basis:

- diesel generation has high annual operating costs that typically become more expensive to operate in future with normal inflation and other cost pressures;
- a transmission line is most costly in the initial years, as the annual costs are primarily depreciation and return on the undepreciated

capital cost, which together are at their maximum in the first years of the project.

The overall cost-benefit of the Mayo Dawson Project is assessed by comparing the present value of its forecast costs and benefits (e.g., savings in diesel fuel generation costs) over its expected economic life. As a result of the difference in cost profile between the Mayo Dawson Project and the diesel fuel generation which it displaces, however, the Mayo-Dawson Project (absent the Mayo-Dawson Note, a flexible financing instrument provided by YDC) would normally result in higher costs than diesel generation in the first number of years of operation, and lower costs than diesel generation for the rest of the life of the project. In other words, up until the "crossover point" where the transmission line becomes less costly than diesel generation, ratepayers would otherwise be burdened with higher costs with the transmission line than with the diesel generation[3].

In order to prevent ratepayers from paying higher costs at any time due to the Project than would occur with diesel generation [i.e., in those years before the "crossover point" is reached], Yukon Development has provided flexible debt financing to Yukon Energy to ensure ratepayers will be protected so that they are not paying, in any year, more than they would have paid had Dawson remained on diesel fuel generation.

[3] Based on current information, the "crossover point" will be effectively reached in 2005 (due to high current and forecast fuel prices).

The Mayo-Dawson Project exhibits very favourable long-term economics compared to retaining Dawson on diesel generation, even before the YDC debt financing provisions are considered. Table 5.4 indicates the economic assessment of the project based on a final overall capital cost of $35.6 million (project cost to Yukon Energy of $29.8 million net of YDC contributions) over a 50-year economic life and current diesel fuel prices:

- **Internal Rate of Return of 12.1%:** On a simple cash flow basis, the project results in an Internal Rate of Return of 12.1%. This assessment indicates that the Mayo Dawson Project remains economic to Yukon Energy at any average cost of capital of 12% per year or less.
- **Net Present Value of Savings at over $16 million:** The Table 5.4 assessment of the Project's economics also indicates that the net present value of cost savings (before application of the YDC flexible financing) evaluated at an 8% annual discount rate (i.e., a rate slightly higher than Yukon Energy's current average cost of capital) is over $16 million[4].

For Yukon ratepayers, the benefits also include those benefits that result from the YDC financing discussed in detail below (and shown in Table 5.6). Assessment of

[4] Sensitivity analysis based on the costs set out in Table 5.4 indicates that the Mayo Dawson Project would continue to yield an overall positive net present value to Yukon Energy (at 8.0% discount rate) at diesel fuel prices starting in 2006 at 31 cents per litre or higher and increasing at 2% per year.

the Project's impact on ratepayers over a 50-year economic life (using the same costs and forecasts as above) shows that the net present value of cost savings to ratepayers is over $20 million (including the benefits of the Mayo Dawson financing).

Mayo-Dawson Project History

The Mayo Dawson Project is the first large-scale transmission infrastructure development project undertaken by Yukon Energy since the NCPC transfer in 1987. A brief history of the project is as follows:

- The Project was initially examined in the early 1990's by Alberta Power on behalf of Yukon Energy because of its potential to significantly reduce rates of Yukon ratepayers. Engineering and costing work was done and a transmission right of way was submitted to the relevant regulators for environmental assessment. The initial feasibility studies on the project were reviewed by the YUB in the 1992 Major Capital Projects hearing. In Recommendation #42 of that hearing, the Board recommended that "no further studies be performed on the Mayo-Dawson transmission project unless demand changes sufficiently to warrant a further review of the project". At the time of the review, Dawson City annual consumption was approximately 12 GW.h (per page 73 of the "1992 Resource Plan Supply Side Binder A"), diesel fuel cost was forecast at approximately $0.31/litre and the cost of capital (debt plus equity) was forecast at 11.5% (pages 124-132 of Board interrogatory BD-1-25 from the Capital Projects proceeding).

- Prior to the 1992 capital hearing, Yukon Energy decided not to proceed with the Project at that time. However, the transmission line right-of-way was protected in the final land claim agreements of the Nacho Nyak Dun and Tr'ondëk Hwëch'in First Nations and a licence of occupation was formally granted in 1998.
- Because of the change in demand in Dawson and the decreasing cost of capital, Yukon Energy developed and refined a feasibility assessment of the project over the 1998 to 1999 period, including design, costing, and technical review by Utilitech Consulting Inc., Valard Construction Limited, B.C. Hydro and A.B. Sturton Consultants Inc. The feasibility study indicated favourable economics for the project.
- In order to proceed in a manageable and cautious staged approach, over the course of 1999 to 2000 Yukon Energy engaged B.C. Hydro to conduct a peer review of Yukon Energy's feasibility study and engaged B.C. Hydro International Limited (BCHIL) to do a detailed Preliminary Engineering and Cost Estimating study. The result of this work continued to reflect that Mayo-Dawson was a viable project. Yukon Development provided $400,000 in a non-repayable contribution towards this work.
- Yukon Energy's Board of Directors reviewed the feasibility work on the project in 2000, and requested YDC to provide financial arrangements to allow the project to proceed and mitigate risks to ratepayers,

particularly in the early years of the project. To alleviate the problem of any potential short term increase in revenue requirement before the significant cost savings anticipated for ratepayers arise in the future, YDC agreed to provide flexible debt financing for the Project. In addition, YDC agreed to provide a $4 million contribution to the capital cost of the line and to assist with an additional $900,000 in project upgrades related to rural electrification and land acquisition.

- In light of current conditions and Yukon Development's agreement to manage the market risks, it was decided by Yukon Energy to proceed with the project on an "engineer, procure, construct and manage" basis, subject to satisfactory completion of the contract tendering and related issues.
- In 2000, pursuant to the Yukon Development Corporation Act regulations, the Minister Responsible for Yukon Development Corporation ("Yukon Development") gave approval for the project to proceed.

Mayo-Dawson Project Cost and Timeline

The Mayo-Dawson project was initially approved by Yukon Energy's Board at a projected cost to the Corporation of $27.246 million, or $23.246 million net of a $4 million unallocated Yukon Development non-repayable grant.

In addition, at that time Yukon Development approved an additional $1.25 million in expenditures for which it would provide a non-repayable capital grant, and an

additional $50,000 in land acquisition for which it would provide an interest free advance that would only become repayable should Yukon Energy relocate the Dawson diesel plant to the Callison location at some point in the future. Subsequent to project approval (in 2001), Yukon Development determined it appropriate to fund a scope change on the project (to utilize a large conductor) and provided a further $500,000 non-repayable grant to finance this scope change. In total, Yukon Development provided approval and financing for $1.8 million of additional project costs.

As a result, a projected cost of $29.046 million for the Mayo-Dawson Project was approved, with a projected in-service date of September 30, 2002 and a projected net cost to Yukon Energy of $23.246 million.

The projected cost for the project as of year-end 2005 is $35.589 million (or $29.789 net of YDC contributions) and the actual in-service date was September 6, 2003. However, in-service did not reflect final resolution of all matters relating to the project. There remain a number of outstanding matters with respect to claims and counter-claims between the contractor and Yukon Energy. Discussions are continuing with the contractors. Yukon Energy cannot determine at this time the likely outcome of that claims process. Any positive claims settlement will be applied to reduce the costs of the project, and any adverse claims will increase the costs of the project. Accordingly, the projected value of the project recorded for year-end 2005 is $35.589 million. Net of contributions from Yukon Development Corporation, the total project cost to Yukon Energy forecast for year-end 2005 is $29.789 million.

Although the final capital cost is higher than initial estimates, the Project's economics are still very positive especially given the significantly higher diesel prices

presently being experienced (compared to $0.35 per litre price assumed for 2004 when the project was approved), and the increase in the service life arising out of the recent depreciation study. Furthermore, in any event, based on the Mayo-Dawson Note's provisions, there will be no adverse impact to overall rates as a result of the Project. Ratepayers are fully protected and they will never, in any year, pay more than they would have paid had Dawson remained on diesel fuel generation.

Mayo-Dawson Note

As a component of financing the Mayo-Dawson Project, Yukon Development committed to providing Yukon Energy with a package of grants and financing, as noted below (see a copy of the agreement attached as Appendix 5-1 to this Tab of the Application):

- $5.75 million in non-repayable capital contributions
- $50,000 in an interest free advance to purchase additional land at the Callison substation site that will become repayable should Yukon Energy relocate the Dawson diesel plant to the Callison site
- $18 million in a Promissory Note ("Mayo-Dawson Note") at a face interest rate of 6.55%[5], but actual interest payable in any year can be adjusted downwards to ensure that ratepayers are not paying any more in any year of the Project than the costs that would have been faced had Dawson remained on diesel generation.

[5] Interest rate at 120 basis points over a Canada Benchmark long-term bond at 5.35%, of similar 20-year average life to the Note, and assessed approximately as at the Project in-service date (September 6, 2003).

Subject to Yukon Energy not paying interest in any year greater than the face interest rate of 6.55%, the structure of the Mayo-Dawson Note measures the "Maximum Interest Payable" as effectively:

- the Avoided Diesel Costs (meaning the amounts saved compared to what Yukon Energy would have paid had Dawson remained on diesel generation); plus,
- the "other benefits" (meaning any revenues gained from sales of greenhouse gas emission credits, wholesale sales to Stewart Crossing, secondary sales in Dawson, plus any incremental sales to "new" customers not previously served by Yukon Energy or YECL); less,
- the Incremental Transmission Costs (meaning the Depreciation, O&M and Return on Equity for the transmission line).

Under the Mayo Dawson Note, if the costs of having the transmission in service (compared to the costs of Dawson remaining on diesel) are such that in any given year the Maximum Interest that Yukon Energy must pay is less than the full 6.55%, YDC will forgive the remainder of the interest.

The Note provides for a further reduction in interest paid by Yukon Energy until an application is filed with the Board to address updating diesel fuel prices reflected in Yukon Energy's revenue requirement. Prior to such an application adjusting Yukon Energy's revenue requirement, interest paid by Yukon Energy is further reduced (the Fuel Price Adjustment) to reflect the Fuel Price Variance between current actual diesel fuel prices and the last approved GRA diesel fuel price in Dawson. Without the Mayo

Dawson Project, ratepayers would have paid for this fuel price adjustment through the Rider F Fuel Price Adjustment mechanism; however, after the Mayo Dawson Project, came into service this fuel price adjustment has not been reflected in current rates. The Note provides that at the time of the next required revenue application by Yukon Energy (i.e., the current 2005 Application), such Fuel Price Adjustments to date are to be added back to interest payments due during the first two subsequent years – subject to provision that total interest paid under the Note in any year cannot exceed the face interest at 6.55%.

In 2003, as detailed in Table 5.5 of this submission, the result of the Mayo Dawson Note was that Yukon Energy paid no interest to YDC, and received a payment from YDC of approximately $94,000. This payment was a result of a Fuel Price Adjustment under the Note of approximately $160,000.

In 2004 and 2005, as detailed in Table 5.5, the interest forecast to be payable on the Note is as follows (based on Yukon Energy filing this Application for 2005 and a forecast Fuel Price Adjustment under the Note of approximately $892,000 for 2004):

	Forecast Interest on Note ($000)	
	2004	**2005**
Interest Otherwise Due	$1,170	$1,140
Maximum Interest Payable	(290)	1,631
Interest Payable (lesser of above)	$(290)	$1,140
Interest Forgiven	$1,460	0

As noted above the net present value of ratepayer savings, including the effects of the Note, is estimated to exceed $20 million over the 50-year economic life of the Mayo Dawson Project (see Table 5.6 of this submission). This analysis in effect carries

forward beyond 2005 the benefit and cost assessments as set out in Table 5.5, showing positive ratepayer cost savings being forecast in each of these years.[6]

Based on this Application and the provisions of the Note, full interest of 6.55% is forecast to be payable on the Note in 2005 and 2006 so long as diesel fuel prices at Dawson are approximately 47 cents/kW.h or higher in 2005 and 45.5 cents/kW/h or higher in 2006. This reflects the Note's provisions to recover in 2005 and 2006 some or all of Fuel Price Adjustments in prior years. In 2007, however, the Note is forecast to provide for some level interest forgiveness at fuel prices below about 58 cents per litre. If for any reason in 2005 or future years Yukon Development forgives interest under the Note. Yukon Energy will use the reduction in costs to pay for costs incurred to supply power to Dawson, and any remainder forgiven will be maintained in an account to the credit of ratepayers (i.e., in the Income Stabilization Trust). For example, if the transmission line is out of service for some duration resulting in Yukon Development forgiving some portion of the interest otherwise payable, Yukon Energy would use the savings to pay for the costs it incurs to generate the required power with diesel at Dawson, and would credit any additional interest forgiven to the IST for future application to the benefit of ratepayers. This is consistent with the intent that the Note is to protect ratepayers from underperformance of the line, ensuring ratepayers will not pay more in any year than they would have had Dawson remained on diesel generation.

[6] Table 5.6 indicates an apparent net cost impact on ratepayers in 2005 of about $35,000, as well as material ratepayer cost savings (totaling about $1,052,000) in 2003 and 2004. The impact in 2005 under the Note reflects partial recovery of prior year ratepayer savings.

Table 5.4

Mayo-Dawson Economics - IRR based on cash flows ($000)

Diesel prices at Actuals 2003, forecast 2004, forecast 2005 plus 2% inflation per year thereafter

	Project Benefits (Cash)					Project Costs (Cash)			Net Costs (Benefits) before MD Note
	1	2	3	4	5	6	7	8	9
	Diesel Fuel cost savings	Diesel O&M cost savings	Diesel Capital Cost Savings	Other benefits	Sub total - Benefits	Capital Costs	O&M costs	Sub total - Costs	Total Benefits less Costs
2003	496.0	62.3	2,150.0	5.9	2,714.2	28,117.0	-	28,117.0	25,402.8
2004	2,083.9	221.2	800.0	33.0	3,138.1	997.0	158.0	1,155.0	(1,983.1)
2005	2,265.8	229.8		59.1	2,554.7	675.0	90.0	765.0	(1,789.7)
2006	2,325.0	235.8		60.3	2,621.1		91.8	91.8	(2,529.3)
2007	2,385.7	242.0		61.5	2,689.2		93.6	93.6	(2,595.6)
2008	2,448.0	248.3		62.8	2,759.1		95.5	95.5	(2,663.5)
2009	2,512.0	254.8		64.0	2,830.7		97.4	97.4	(2,733.3)
2010	2,577.6	261.4		65.3	2,904.3		99.4	99.4	(2,804.9)
2011	2,644.9	268.2		66.6	2,979.7		101.4	101.4	(2,878.4)
2012	2,714.0	275.2	1,830.0	67.9	4,887.2		103.4	103.4	(4,783.8)
2013	2,784.9	282.4	800.0	69.3	3,936.6		105.4	105.4	(3,831.2)
2014	2,857.6	289.8		70.7	3,218.1		107.6	107.6	(3,110.6)
2015	2,932.3	297.4	1,500.0	72.1	4,801.7		109.7	109.7	(4,692.0)
2016	3,008.8	305.2		73.5	3,387.5		111.9	111.9	(3,275.6)
2017	3,087.4	313.1		75.0	3,475.6		114.1	114.1	(3,361.4)
2018	3,168.1	321.3		76.5	3,565.9		116.4	116.4	(3,449.5)
2019	3,250.8	329.7		78.0	3,658.6		118.8	118.8	(3,539.8)
2020	3,335.7	338.3		79.6	3,753.6		121.1	121.1	(3,632.5)
2021	3,422.9	347.1		81.2	3,851.2		123.6	123.6	(3,727.7)
2022	3,512.3	356.2		82.8	3,951.3		126.0	126.0	(3,825.3)
2023	3,604.0	365.5		84.5	4,054.0		128.5	128.5	(3,925.5)
2024	3,698.2	375.1		86.2	4,159.4		131.1	131.1	(4,028.3)
2025	3,794.8	384.9		87.9	4,267.5		133.7	133.7	(4,133.8)
2026	3,893.9	394.9		89.6	4,378.4		136.4	136.4	(4,242.0)
2027	3,995.6	405.2		91.4	4,492.2		139.1	139.1	(4,353.1)
2028	4,099.9	415.8		93.3	4,609.0		141.9	141.9	(4,467.1)
2029	4,207.0	426.7		95.1	4,728.8		144.8	144.8	(4,584.1)
2030	4,316.9	437.8		97.0	4,851.8		147.7	147.7	(4,704.1)
2031	4,429.7	449.2		99.0	4,977.9		150.6	150.6	(4,827.3)
2032	4,545.4	461.0		101.0	5,107.3		153.6	153.6	(4,953.7)
2033	4,664.1	473.0		103.0	5,240.1		156.7	156.7	(5,083.4)
2034	4,785.9	485.4		105.0	5,376.3		159.8	159.8	(5,216.5)
2035	4,910.9	498.1		107.1	5,516.1		163.0	163.0	(5,353.1)
2036	5,039.2	511.1		109.3	5,659.6		166.3	166.3	(5,493.3)
2037	5,170.8	524.4		111.5	5,806.7		169.6	169.6	(5,637.1)
2038	5,305.9	538.1		113.7	5,957.7		173.0	173.0	(5,784.7)
2039	5,444.5	552.2		116.0	6,112.6		176.5	176.5	(5,936.2)
2040	5,586.7	566.6		118.3	6,271.6		180.0	180.0	(6,091.6)
2041	5,732.6	581.4		120.6	6,434.7		183.6	183.6	(6,251.1)
2042	5,882.4	596.6		123.1	6,602.0		187.3	187.3	(6,414.7)
2043	6,036.0	612.2		125.5	6,773.7		191.0	191.0	(6,582.7)
2044	6,193.7	628.1		128.0	6,949.9		194.8	194.8	(6,755.0)
2045	6,355.5	644.6		130.6	7,130.6		198.7	198.7	(6,931.9)
2046	6,521.5	661.4		133.2	7,316.1		202.7	202.7	(7,113.4)
2047	6,691.8	678.7		135.9	7,506.3		206.8	206.8	(7,299.6)
2048	6,866.6	696.4		138.6	7,701.6		210.9	210.9	(7,490.7)
2049	7,045.9	714.6		141.4	7,901.9		215.1	215.1	(7,686.8)
2050	7,230.0	733.2		144.2	8,107.4		219.4	219.4	(7,888.0)
2051	7,418.8	752.4		147.1	8,318.3		223.8	223.8	(8,094.5)
2052	7,612.6	772.1		150.0	8,534.7		228.3	228.3	(8,306.4)
2053	7,811.5	792.2		153.0	8,756.7	7,447.3	232.8	7,680.1	(1,076.6)
PV ###	38,191.3	3,894.3	6,197.3	893.7	47,751.8	35,530.7	1,450.8	31,228.4	(16,523.4)

Internal Rate of Return
12.1%

Table 5.5
Mayo-Dawson Note Interest ($000)

Line	Calculation Elements in Note		Actual 2003	Forecast 2004	Forecast Existing 2005	Forecast Proposed 2005
	Project Benefits					
1	Diesel Fuel cost savings	Note 1	496.0	2,083.9	2,265.8	2,265.8
2	Diesel O&M cost savings	Note 2	62.3	221.2	229.8	229.8
3	Diesel Capital cost savings	Note 3	82.0	314.0	321.0	321.0
4	Other benefits	Note 4	5.9	33.0	53.1	59.1
5	Sub total - Benefits	Note 5	646.2	2,652.1	2,869.7	2,875.7
	Project Costs					
6	Depreciation	Note 6	313.9	979.0	989.0	741.0
7	Equity Return	Note 7	265.7	913.6	937.4	939.6
8	O&M costs	Note 8	-	158.0	90.0	90.0
9	Sub total - Costs	Note 9	579.6	2,050.6	2,016.4	1,770.6
	Maximum Interest Payable					
10	Benefits (ln 5)	Note 5	646.2	2,652.1	2,869.7	2,875.7
11	Costs (ln 9)	Note 9	(579.6)	(2,050.6)	(2,016.4)	(1,770.6)
12	Fuel Price Adjustment (FPA)	Note 10	(160.2)	(891.6)	(1,026.9)	-
13	One half of all prior year FPA	Note 11	-	-	-	525.9
14	Total - Maximum Interest Payable	Note 12	(93.6)	(290.0)	(173.5)	1,631.0
15	**Interest Otherwise Payable**	Note 13	374.7	1,170.0	1,140.2	1,140.2
16	**Interest Payable**	Note 14	(93.6)	(290.0)	(173.5)	1,140.2

Notes: [Reference to "variable name" in Schedule 1 to Mayo Dawon Note -see Appendix 5-1 of Application]:

1 Variable "q" - Mean diesel fuel price (variable "e"); $0.4842/l (2003), $0.5729/l (2004), and $0.5995/l (2005).
2 Variable "r" - average cost at $0.016 per kW.h
3 Variable "a" - As specified in the Note.
4 Variable "bb" - Incremental retail, wholesale and secondary sales.
5 Variable "s" plus "bb"
6 Variable "l" - 2005 Proposed reflects adjusted depreciation.
7 Variable "x" - ROE for 2003, 2004 and 2005 Existing at 9.138% and for 2005 Proposed at 9.05%.
8 Variable "j" -
9 Variable "aa" -
10 Variable "u" - (Total Firm Energy/3.8) times fuel price variance from $0.3278/l [1997 GRA price]
11 Variable "v" divided by 2
12 Variable "cc"
13 Variable "dd" - Interest at face interest rate of Note (6.55%)
14 Lesser of Lines 14 and 15

Table 5.6

Mayo-Dawson Economics - NPV based on annual impacts on ratepayers ($000)

Diesel prices at Actuals 2003, forecast 2004, forecast 2005 plus 2% inflation per year thereafter

		Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)							Net Impact
		1	2	3	4	5	6	7	8	9	10	11	12	13
		Diesel Fuel cost savings	Diesel O&M cost savings	Diesel Capital Cost Savings	Other benefits	Sub total - Benefits	Depreciation	Equity Return	O&M costs	Sub total - Costs	Fuel Price Adjustment	Interest Payable (benefits less costs max 6.55%)	Total Costs	Net impact on Ratepayers (savings)
2003		496.0	62.3	82.0	5.9	646.2	313.9	265.7	-	579.6	(160.2)	(93.6)	486.0	(160.2)
2004		2,083.9	221.2	314.0	33.0	2,652.1	979.0	913.6	158.0	2,050.6	(891.6)	(290.0)	1,760.5	(891.6)
2005		2,265.8	229.8	321.0	59.1	2,875.7	741.0	939.6	90.0	1,770.6	525.9	1,140.2	2,910.7	35.0
2006		2,325.0	235.8	312.0	60.3	2,933.1	741.0	913.2	91.8	1,746.0	525.9	1,110.7	2,856.7	(76.4)
2007		2,385.7	242.0	302.0	61.5	2,991.2	741.0	886.9	93.6	1,721.5	-	1,081.2	2,802.7	(188.4)
2008		2,448.0	248.3	293.0	62.8	3,052.1	741.0	860.6	95.5	1,697.1	-	1,051.7	2,748.8	(303.3)
2009		2,512.0	254.8	284.0	64.0	3,114.7	741.0	834.2	97.4	1,672.6	-	1,022.3	2,694.9	(419.8)
2010		2,577.6	261.4	275.0	65.3	3,179.3	741.0	807.9	99.4	1,648.3	-	992.8	2,641.0	(538.2)
2011		2,644.9	268.2	265.0	66.6	3,244.7	741.0	781.6	101.4	1,623.9	-	963.3	2,587.2	(657.5)
2012		2,714.0	275.2	429.0	67.9	3,486.2	741.0	755.2	103.4	1,599.6	-	933.8	2,533.4	(952.7)
2013		2,784.9	282.4	528.0	69.3	3,664.6	741.0	728.9	105.4	1,575.3	-	904.4	2,479.7	(1,184.9)
2014		2,857.6	289.8	527.0	70.7	3,745.1	741.0	702.6	107.6	1,551.1	-	874.9	2,426.0	(1,319.1)
2015		2,932.3	297.4	651.0	72.1	3,952.7	741.0	676.2	109.7	1,526.9	-	845.4	2,372.3	(1,580.4)
2016		3,008.8	305.2	651.0	73.5	4,038.5	741.0	649.9	111.9	1,502.8	-	815.9	2,318.7	(1,719.8)
2017		3,087.4	313.1	651.0	75.0	4,126.6	741.0	623.5	114.1	1,478.7	-	786.5	2,265.1	(1,861.4)
2018		3,168.1	321.3	651.0	76.5	4,216.9	741.0	597.2	116.4	1,454.6	-	757.0	2,211.6	(2,005.3)
2019		3,250.8	329.7	651.0	78.0	4,309.6	741.0	570.9	118.8	1,430.6	-	727.5	2,158.1	(2,151.4)
2020		3,335.7	338.3	651.0	79.6	4,404.6	741.0	544.5	121.1	1,406.7	-	698.0	2,104.7	(2,299.9)
2021		3,422.9	347.1	651.0	81.2	4,502.2	741.0	518.2	123.6	1,382.8	-	668.6	2,051.3	(2,450.9)
2022		3,512.3	356.2	651.0	82.8	4,602.3	741.0	491.9	126.0	1,358.9	-	639.1	1,998.0	(2,604.3)
2023		3,604.0	365.5	651.0	84.5	4,705.0	741.0	465.5	128.5	1,335.1	-	609.6	1,944.7	(2,760.3)
2024		3,698.2	375.1	651.0	86.2	4,810.4	741.0	439.2	131.1	1,311.3	-	580.1	1,891.4	(2,918.9)
2025		3,794.8	384.9	651.0	87.9	4,918.5	741.0	412.9	133.7	1,287.6	-	550.7	1,838.3	(3,080.2)
2026		3,893.9	394.9	651.0	89.6	5,029.4	741.0	386.5	136.4	1,263.9	-	521.2	1,785.1	(3,244.3)
2027		3,995.6	405.2	651.0	91.4	5,143.2	741.0	360.2	139.1	1,240.3	-	491.7	1,732.0	(3,411.2)
2028		4,099.9	415.8	651.0	93.3	5,260.0	741.0	333.9	141.9	1,216.8	-	462.2	1,679.0	(3,581.0)
2029		4,207.0	426.7	651.0	95.1	5,379.8	741.0	307.5	144.8	1,193.3	-	432.8	1,626.0	(3,753.8)
2030		4,316.9	437.8	651.0	97.0	5,502.8	741.0	281.2	147.7	1,169.8	-	403.3	1,573.1	(3,929.6)
2031		4,429.7	449.2	651.0	99.0	5,628.9	741.0	254.8	150.6	1,146.5	-	373.8	1,520.3	(4,108.6)
2032		4,545.4	461.0	651.0	101.0	5,758.3	741.0	228.5	153.6	1,123.1	-	344.3	1,467.5	(4,290.9)
2033		4,664.1	473.0	651.0	103.0	5,891.1	741.0	202.2	156.7	1,099.9	-	314.9	1,414.7	(4,476.4)
2034		4,785.9	485.4	651.0	105.0	6,027.3	741.0	175.8	159.8	1,076.7	-	285.4	1,362.1	(4,665.3)
2035		4,910.9	498.1	651.0	107.1	6,167.1	741.0	149.5	163.0	1,053.5	-	255.9	1,309.4	(4,857.7)
2036		5,039.2	511.1	651.0	109.3	6,310.6	741.0	123.2	166.3	1,030.5	-	226.4	1,256.9	(5,053.7)
2037		5,170.8	524.4	651.0	111.5	6,457.7	741.0	96.8	169.6	1,007.4	-	197.0	1,204.4	(5,253.3)
2038		5,305.9	538.1	651.0	113.7	6,608.7	741.0	70.5	173.0	984.5	-	167.5	1,152.0	(5,456.7)
2039		5,444.5	552.2	651.0	116.0	6,763.6	741.0	44.2	176.5	961.6	-	138.0	1,099.6	(5,664.0)
2040		5,586.7	566.6	651.0	118.3	6,922.6	741.0	17.8	180.0	938.8	-	108.5	1,047.4	(5,875.2)
2041		5,732.6	581.4	651.0	120.6	7,085.7	741.0	-	183.6	924.6	-	79.1	1,003.6	(6,082.0)
2042		5,882.4	596.6	651.0	123.1	7,253.0	741.0	-	187.3	928.3	-	49.6	977.8	(6,275.2)
2043		6,036.0	612.2	651.0	125.5	7,424.7	741.0	-	191.0	932.0	-	20.1	952.1	(6,472.6)
2044		6,193.7	628.1	651.0	128.0	7,600.9	741.0	-	194.8	935.8	-	-	935.8	(6,665.0)
2045		6,355.5	644.6	651.0	130.6	7,781.6	741.0	-	198.7	939.7	-	-	939.7	(6,841.9)
2046		6,521.5	661.4	651.0	133.2	7,967.1	741.0	-	202.7	943.7	-	-	943.7	(7,023.4)
2047		6,691.8	678.7	651.0	135.9	8,157.3	741.0	-	206.8	947.8	-	-	947.8	(7,209.6)
2048		6,866.6	696.4	651.0	138.6	8,352.6	741.0	-	210.9	951.9	-	-	951.9	(7,400.7)
2049		7,045.9	714.6	651.0	141.4	8,552.9	741.0	-	215.1	956.1	-	-	956.1	(7,596.8)
2050		7,230.0	733.2	651.0	144.2	8,758.4	741.0	-	219.4	960.4	-	-	960.4	(7,798.0)
2051		7,418.8	752.4	651.0	147.1	8,969.3	741.0	-	223.8	964.8	-	-	964.8	(8,004.5)
2052		7,612.6	772.1	651.0	150.0	9,185.7	741.0	-	228.3	969.3	-	-	969.3	(8,216.4)
2053		7,811.5	792.2	651.0	153.0	9,407.7	741.0	-	232.8	973.8	-	-	973.8	(8,433.8)
PV	8.0%	38,191.3	3,894.3	5,801.3	893.7	48,780.7	9,599.3	8,421.0	1,450.8	19,471.0	#	8,787.1	28,258.2	(20,522.5)
													NPV at 8.0%	**(20,523)**

Mayo Dawson Note calc.xls,Table 5.6 ,12/3/2004

QUESTION:

Reference: Application, p. 5-10, Mayo-Dawson Transmission Line Project

(19.1) The February 2005 Auditor General's Report on the Mayo-Dawson City Transmission System Project identified as main points:

- shortcomings in defining the project scope and costs;
- substantial risks in using the chosen construction approach as YEC did not have the required experience and expertise;
- weak project management;
- significant deficiencies in contracting for construction and services; and
- inadequate financial management and project cost controls.

In view of these observations by the Auditor General, why should any of the costs in excess of the original budget of $27.246 million be included in rates? Please provide a detailed response.

(19.2) Please provide a detailed cost category breakdown of the project with the expected cost for each category based on the original approval of $27.246 million and the latest projected cost of $35.589 million. For each of the cost categories that have increased, please provide a detailed assessment of why YEC believes that the increases were prudently incurred.

(19.3) Please discuss the remaining outstanding matters with respect to claims and counterclaims between the contractor and YEC.

(19.4) For the 30 percent cost overrun with respect this project, please detail any scope changes that occurred along with the reasons for any scope changes.

(19.5) Please provide any reports YEC has complied (either internally or by outside consultants) which describe the as built condition and deficiencies with the line.

(19.6) How does YEC intend to correct these deficiencies?

(19.7) Will the deficiencies have an impact on future maintenance or reliability of the line? Please describe how.

(19.8) What does YEC anticipate future maintenance costs on this line to be and how do these costs compare to a line constructed to proper standards?

ANSWER:

(19.1)

The test applicable to review by the YUB of Mayo Dawson Project capital costs, in accordance with the Yukon *Public Utilities Act* provisions for the YUB to determine rate base, is on the basis of an "original-cost" standard, incorporating the "prudent investment" principle. Under the prudent investment principle, the Board should include investments in the rate base of Yukon Energy if those investments were made by the utility in the exercise of reasonable business judgment. In this regard, the Board must judge the reasonableness of an investment based on what was known at the time of the investment, and not on the basis of whether the investment is deemed necessary or beneficial in hindsight. Ordinarily, under this test, investments are presumed to be prudent and allowable.

In this instance, the evidence is clear that the investment is now in service, is used and useful, and is highly beneficial to Yukon ratepayers. It has effectively removed about one-half of Yukon diesel fuel generation requirements, and is projected (after considering its current projected costs) to yield net present value savings to ratepayers in excess of $20 million over its economic life (see Table 5.6 of the Application). Moreover, these updated net present value savings are significantly (i.e., more than 40%) higher than the $14 million projected in mid-2000 at the time that the Yukon Energy Board approved the project (see McMahon-YEC-1-52(b)). Finally, the Mayo Dawson Note in effect shelters ratepayers in each year from the risk of any added overall cost beyond what would occur without the project if Dawson City continued to be served solely by diesel generation (see McMahon-YEC-1-52(b)).

Yukon Energy's "original cost" to the end of 2005 for the Mayo Dawson Project is $35.589 million less funds provided by Yukon Development ($5.8 million), as set out in the Application. The approved original budget for this project was $29.046 million, not $27.246 million (see YUB-YEC-1-19.2). The final cost to the end of 2005 is about 22% higher ($6.5 million) than the approved original budget, with about $2.5 million of this being construction cost variance, about $4.7 million being owner's cost variance, and about $0.7 million being a positive variance saving related to interest and inflation allowances. A more detailed review of these cost variances is provided separately, including scope changes, extra costs needed to be incurred to address contractor deficiencies, Yukon Energy's added costs due to the significantly increased workload

with respect to management and engineering that arose as a result of underperformance by the construction contractor, and the material outstanding matters remaining today with respect to claims and counterclaims between the contractor and Yukon Energy. (See YUB-YEC-1-19.2 for review of the original budget and the variances related to the final costs, YUB-YEC-1-19.4 regarding scope changes, YUB-YEC-1-19.3 regarding claims and counterclaims between the contractor and Yukon Energy, and YUB-YEC-1-19.5 to 19.8 regarding deficiencies and any related costs and claims.)

Overall, the above final costs incurred by Yukon Energy were those reasonably required to complete the Project under the circumstances and conditions that Yukon Energy faced. Costs reflect actual amounts incurred, or forecast to be incurred, by the end of 2005. Where relevant, these costs reflect invoices approved to confirm that the amounts are reasonably payable for goods and services provided to Yukon Energy. As such, these costs are submitted to be prudently incurred notwithstanding when the costs vary from those forecast in the approved budget. In certain instances, these costs also remain subject to resolution of outstanding claims - however, it is not feasible or appropriate at this time to assess the likely outcomes of the outstanding claims or any possible changes to the above costs that may arise due to these claims.

As detailed separately (see McMahon-YEC-1-50), Yukon Energy carried out extensive feasibility and pre-engineering work on the Project from 1998 to 2000 and spent what its Board, management, and experienced advisors considered necessary to obtain the technical and other information required to make an informed decision on the project and to define adequately the project scope and cost requirements. The Board of Directors proceeded cautiously in its assessment of the project's scope and design approaches and the related feasibility and pre-engineering costs, which likely exceeded what would have been necessary for a similar extension from a stronger grid supply, were prudently incurred and provided the scope and direction necessary to prudently proceed with the project as at mid-2000.

As detailed separately (see McMahon-YEC-1-54), Yukon Energy carried out extensive review throughout 2000 of the contracting approach options for the Project, including significant input from its experienced professional advisors. Overall, Yukon Energy's management and Board concluded that the design-build approach was likely to better meet Yukon Energy needs and capabilities which existed at that time relative to the alternatives then available. In this regard, key considerations taken into account by management and the Board included Yukon Energy's lack of internal staff resources and

experience in dealing with a project of this magnitude, and its need to address risk related to management of the design and construction. In summary, Yukon Energy exercised reasonable business judgment, based on what was known at the time of the decision, when it chose the design build approach and proceeded to implement this approach through processes to select a design-build contractor (see McMahon-YEC-1-66 and 67), an experienced project manager, and an experienced project engineer.

With respect to management of the project (including contracting for construction and services), Yukon Energy's management believed at the time that it took the reasonable steps necessary to establish an effective management and contracting regime for the project based on the selected design build contract approach and given the circumstances that Yukon Energy faced, and the advice it received from its experienced professional advisors. In Yukon Energy's opinion, the prime source of cost overrun problems related to the performance of the design build contractor which created unforeseen and serious delays and disputes well beyond what might be reasonably anticipated for a project of this nature. As a result, in order to achieve ultimate completion of the project, the internal management regime was called upon to carry out activities well beyond, and for far longer than, what could have reasonably been anticipated when the design build contract was executed in 2001. In addition, as a result Yukon Energy is now also pursuing material outstanding claims against the contractor.

As detailed separately (see McMahon-YEC-1-68 and 71), Yukon Energy's financial management and project cost controls ensured value was received for payments through review by the project manager of work performed and invoices received, i.e., payments were made only on the basis of invoices for work actually performed and only after approval of the invoice by the project manager. Yukon Energy acknowledges the need for improved financial management systems and project cost controls systems, and has taken steps to address the concerns set out in the Auditor General's report (see McMahon-YEC-1-53 and 72); however, Yukon Energy does not believe that these specific concerns as such had a material impact of the final costs required for the Project.

Overall, in assessing the reasonableness of the Project costs, it is relevant to note the significant contributions to the Project provided by Yukon Development Corporation both in terms of non-repayable contributions and the Mayo Dawson Note. As detailed separately (see YECL-YEC-1-1(c)), specific detail has been provided on the rationale for the $5.75 million non-repayable YDC contribution which (as set out in the Mayo-Dawson

Agreement) includes (per Section 2.1) "to ensure that the Yukon Territory rate payers do not pay for any costs incurred by Yukon Energy in completing the Project which are the result of Yukon Energy building capacity in executing major projects." Although the contribution is non-repayable, the related agreement specifically provides that Yukon Energy must use the contribution for certain defined purposes – including "to fund in the first instance any capital costs incurred by Yukon Energy in developing the Project which are not allowed by the YUB as part of Yukon Energy's rate base, with any remainder used to fund a no-cost contribution towards Yukon Energy's rate base."

In conclusion, in Yukon Energy's view the full $35.6 million of costs required for the Project were prudently incurred and Yukon Energy is not aware of any reasonable basis for not including in rate base as at the end of 2005 the net amount ($29.8 million) of Yukon Energy costs as set out in the Application.

(19.2)
The table at the end of this answer provides a breakdown of the original budget to final costs as per the Application.

At the outset, it is necessary to note that there was never a budget approved for only $27.246 million to complete the full project. From the outset there was an additional $1.3 million in specified costs for work that was to be part of the Yukon Energy project, and paid for by Yukon Development as a non-refundable grant ($1.25 million) or an interest-free contingent repayable grant ($50,000 – see YUB-YEC-1-61). As a result, the total original projected project budget as at June 2000 was $28.546 million. This was later supplemented in February 2001 by $500,000 for a larger conductor to be paid for by YDC, which brought the full approved project budget to $29.046 million. The table below reconciles to this number.[1] (The $1.3 million and the $500,000 of allocated amounts to be paid by Yukon Development, as noted above, are in addition to the $4 million non-refundable contribution provided by YDC.)

The table below shows in the first column the original Yukon Energy estimates leading to $27.246 million and separately the YDC components to bring the total to $29.046 million. In the second and third columns, this YDC contribution is re-allocated to the appropriate components of the project, and a number of additional re-allocations are made to the original (June 2000) budget to reflect the consolidations and adjustments necessary to

[1] See Auditor General's report, paragraph 23 as well as Exhibit 4.

get the proper "baseline" budget of $29.046 million for the purposes of comparing to the final cost figures (the re-allocations are explained in more detail at page 2 of the table).

The final cost figures to the end of 2005 are shown in the fourth column, totaling $35.589 million per the Application. This reflects an increase in project costs of $6.543 million compared to the budget of $29.046 million. The $6.543 million is made up of the following variances[2]:

CONSTRUCTION

- **Chant construction costs:** The payments to Chant of $23.676 million was $1.911 million more than the $21.766 million originally budgeted (and also higher than the $22.071 million of the original Chant contract). This reflects the impacts of change orders as set out in detail at YUB-YEC-1-19.4.
- **Non-Chant construction costs:** On top of activities performed by Chant, Yukon Energy ultimately required the services of other contractors during the project ($798,000 plus $80,000 for materials) and subsequent to the project (contractor and internal costs of $1.589 million net of reimbursement received from Chant[3]) to complete items that were effectively related to constructing the project or correcting deficiencies. Yukon Energy was also required to address the heating requirements of the Dawson diesel plant ($285,000) which was a cost that had been originally unbudgeted in the project planning stages (see also McMahon-YEC-1-51(b)). There is a small credit related to a transformer purchased by Chant which was not used on the project and has since been transferred to Yukon Energy's inventory[4].

[2] Note that the variance is different than that shown in the Auditor General ("AG") report for two reasons. First, the Auditor General only reconciled the costs to total completion of $33.5 million, not the full $35.589 million to the end of 2005. Second, the AG used a simple breakdown of Chant costs (which they called Construction Costs) Internal Costs, Interest and Inflation, and Rural Electrification – this breakdown is not entirely correct as substantial costs that the AG classified as Internal Costs were in fact Construction Costs (but were needed to be paid to other contractors, not Chant, as the work was not performed by Chant).

[3] The $1.589 million consists of $1.050 million related to the vibration dampeners, $450,000 related to correcting transmission line deficiencies and hardware tightening, $54,000 to doing the legal survey, $135,000 for a drawing upgrade and $100,000 for correcting substation deficiencies. This totals $1.789 million. Chant provided Yukon Energy a payment of $200,000 towards this work; after this contribution, the net cost to Yukon Energy is $1.589 million.

[4] The $35,000 transformer was purchased to install at Stewart Crossing. However, YECL later requested three-phase service. The three phase transformer installation project is scheduled for completion in 2005.

The total variance on construction was $4.628 million. However, the project construction component was budgeted from the outset with a $2.1 million contingency for a net variance from original budget of $2.528 million.

OWNER'S COSTS

- **Feasibility:** The feasibility portion of the budget ultimately included all budgeted amounts for tender preparation, heritage, geotechnical, and a portion of the right-of-way/licence costs. The total of these costs had a positive variance from forecast of $89,000.
- **Project Management/Project Engineering/Regulatory:** The most significant variance arises in the area of project management, engineering and regulatory ($2.046 million). The primary reason for the variance is the significantly increased workload with respect to management and engineering that arose as a result of underperformance by the construction contractor. This required substantial extra time and expense in supervision, due diligence in assessing the work completed, reviewing and fixing various drawings, and re-engineering of various components of the project. There was also no specific budget to address added environmental regulatory aspects of the project (such as re-routing) or dealing with complaints made by intervenors to the YUB (these environmental and utility regulatory amounts ultimately totaled $145,000).
- **Yukon Energy staff costs and associated overheads:** As a result of the ongoing difficulties dealing with the contractor and construction, Yukon Energy was required to spend considerable additional staff time and associated overheads on the project. The led to a variance of $1.347 million.
- **Public Consultation:** The difficulties encountered with re-alignment, trespass and forest clearing issues required additional costs related to public consultation. This led to a variance of $53,000.
- **Insurance:** The original budget did not include any provision for insurance costs. Yukon Energy had originally intended to have the contractor address all insurance requirements. However, after discussions with its broker, Yukon Energy was advised to acquire insurance directly to address issues with respect to certainty of coverage. The cost for insurance totaled $344,000.
- **Legal (post-DBA):** The original budget did not include any provision for legal costs after the signing of the Design-Build Agreement (legal costs prior to that time were included in the feasibility stage costs). Legal costs after the signing of the DBA were assumed to be minimal. Ultimately, the issues with respect to the performance of the contractor led to significant requirement for legal services

(including parties supporting the legal processes, such as the referee) for a total cost of $911,000.

- **Land Acquisition:** The budget did not specifically include a separate provision for land acquisition outside of the $50,000 paid for by YDC. The total variance for land acquisition was $64,000.

The above variance related to Owner's Costs totals $4.687 million.

The project had additional positive variances from budget on Interest During Construction/AFUDC (due to low cost financing arranged by Yukon Energy) of $330,000, as well as a $341,000 inflation allowance built into the total budget.

The above variances yield the $6.543 million total variance on the project costs.

For the reason set out in response to YUB-YEC-1-19.1, Yukon Energy believes that the increases detailed above were prudently incurred.

Yukon Energy Corporation - Reconciliation of Mayo-Dawson Budget to 2005 Forecast ($000s)

	Original Budget	Reallocation	Budget Adjusted incl. all final approvals	Actual	Variance
CONSTRUCTION COSTS					
Callison Substation	2,750	0	2,750	2,596	154
Mayo GS	1,358	0	1,358	1,208	150
Dawson City Diesel GS	1,123	0	1,123	437	686
Transmission Line	14,451	1,061	15,512	16,991	-1,479
Project and Construction Management	1,393	-438	956	2,377	-1,422
Stewart Crossing Substation	0	67	67	67	0
Total Chant Construction	21,075	691	21,766	23,676	-1,911
less: Transformer put in inventory, not used on proj.			0	-35	35
Other Contractors Required	0		0	798	-798
Other Materials Required	0		0	80	-80
Forecast Deficiency Correction, hardware tightening, survey, drawings	0		0	1,589	-1,589
Dawson Diesel Plant Standby Upgrades	0		0	285	-285
Rural Electrification Projects		222	222	222	0
Total Construction with Contingency	21,075	913	21,988	26,615	-4,628
Contingency (at 10%)	2,100		2,100	0	2,100
Total Construction with Contingency	23,175	913	24,088	26,615	-2,528
OWNER'S COSTS					
feasibility	1,000	738	1,738	1,649	89
tender prep, etc.	200	-200	0		0
YEC project management	150	650	800	2,856	-2,056
made up of: *project manager*				*383*	
project manager support costs				*155*	
project engineer				*1,837*	
project engineer support costs				*336*	
regulatory (env'l and utility)				*145*	
YEC staff costs	100	-50	50	1,146	-1,096
Overhead and directly allocated internal costs	50		50	301	-251
Right of Way, licence, permits, stumpage	25	-25	0		0
Heritage	50	-50	0		0
Geotechnical	25	-25	0		0
Legal surveys	200	-200	0		0
Public Consultation	25		25	78	-53
Insurance (property, third party liability, errors and omissions)				344	-344
Legal (post Design-Build Agreement)				911	-911
Land Acquisition		50	50	114	-64
Total Owner's Costs	1,825	888	2,713	7,399	-4,687
TOTAL YUKON ENERGY COSTS					
Subtotal before interest and inflation	25,000	1,800	26,800	34,014	-7,214
AFUDC	1,905		1,905	1,575	330
Inflation	341		341		341
Subtotal	27,246	1,800	29,046	35,589	-6,543
plus: items paid for by YDC not yet included above					
items known at June 2000	1300	-1300	0	0	0
larger conductor added Feb 2001	500	-500	0	0	0
Total Project Costs	29,046	0	29,046	35,589	-6,543

Yukon Energy Corporation - Reconciliation of Mayo-Dawson Budget to 2005 Forecast ($000s) - page 2

NOTES

COSTS APPROVED TO BE PAID FOR BY YDC

COSTS IDENTIFIED PRIOR TO OR AT TIME OF PROJECT APPROVAL IN 2000

Additional Feasibility Study Amounts from 1998	400
Transmission Line	
Stewart Crossing and other PT sites	357
underbuild	271
Callison Substation	
Acquire land for future diesel plant	50
Rural Electrification	222
Total Project Cost Approved as at June 2000	1,300

PLUS: SUBSEQUENT PROJECT SCOPE CHANGES FUNDED BY CONTRIBUTIONS (Feb 2001)

Transmission Line Larger Conductor	500
TOTAL SPECIFIC PROJECT COSTS FROM YDC	1,800

NOTES REGARDING RE-ALLOCATIONS

- The $500k for larger conductor was re-allocated into the project budget as part of the Chant construction costs (transmission line)
- The $271 in YDC funding was re-allocated into the project budget as part of the Chant construction costs (transmission line)
- The $357k for PT sites was allocated to Chant for transmission line ($290k) and Stewart Crossing connection ($67k).
- $200k was re-allocated from Owner's costs to Chant construction (project management category) for the survey
- The $25k for ROW, licence and permits was re-allocated 1/2 to Chant construction (proj. mgmt category) and 1/2 to Owner's costs for feasibility (as both owner and Chant conducted portions of the licencing etc.)
- $650k for project management was re-allocated from the Chant construction contract to the Owner's costs based on the expectation from the outset that Chant would require additional supervision and oversight than originally anticipated.
- The $222k Rural Electrification was re-allocated from YDC funding to non-Chant construction costs
- $200k for tender prep, $50k for YEC staff costs, $50k for heritage, $25k for geotechnical, and the $400k YDC contribution was allocated to be included in feasibility costs
- The $50k for YDC contribution to land acquisition was re-allocated to the land acqusition category

(19.3)

Please see response to YUB-YEC-1-54. Costs shown in YUB-YEC-1-19.2 exclude consideration of any recoveries or extra costs (including legal and other process costs) related to the remaining outstanding matters with respect to claims and counterclaims between the contractor and Yukon Energy.

(19.4)

As detailed in YUB-YEC-1-19.2, the total Yukon Energy project cost variance to the end of 2005 is $6.543 million, which represents a cost overrun of 22.5% (not 30%) relative to the approved budget of $29.046 million.

Please refer to ATTACHMENT YUB-YEC-1-19.4: Mayo–Dawson City Transmission System Project Scope Changes attached to this response for detailed information on the approximately $1.6 million of scope changes to the contractor's original scope of work

(these were compensated by Yukon Energy). The project costs as shown in YUB-YEC-1-19.2 do not include any impacts of scope changes to this contract beyond those listed in the attachment.

Please see response to YUB-YEC-1-19.2 regarding details for other changes in scope reflected in costs for non-Chant construction costs as well as Owner's costs.

(19.5)

Yukon Energy does not have any reports prepared that address the as-built condition of the line or the outstanding deficiencies faced today. Earlier reports were prepared in the fall of 2003 setting out deficiencies for review with the referee. In January 2004, Yukon Energy and the contractor entered into an agreement that the project was complete and settled a number of issues (the referee's work also ended that month), including many issues related to deficiencies. Subject to outstanding claims as noted below and payment by Chant of $200,000 towards this work, Yukon Energy agreed to correct the remaining deficiencies as well as complete the as built drawings in order to resolve matters and complete the Chant contract.

The current outstanding deficiencies with the line include four items that are the subject of outstanding claims (the issue of mitigation of Aeolian vibration of the line, lack of low temperature hardware, any potential damage to the conductor resulting from the method used by Chant to string the line (backdragging), and some equipment that fails to meet the "low loss" standard specified by Yukon Energy – also see YUB-YEC-1-19.7). There are also numerous small items relating to the line and substations that have been identified as deficiencies (including many items such as missing locknuts, slack guys and insulators that are not plumb on the transmission line; poor cable terminations and fencing issues at the substations).

As noted in YUB-YEC-1-19.2, Yukon Energy has included in its capital program for 2005 provision to address the smaller items that need attention at this time as well as amounts to address the vibration issue[5]. Once these items have been completed the line will no longer have any deficiencies that currently require correction (the lack of low loss equipment, the

[5] The $1.050 million budget for the vibration dampeners in 2004 and 2005 is intended to address the vibration issue that arises due to the line tension. Yukon Energy will not be able to confirm with certainty that this approach has worked until the next period of extreme cold when the line will be at its most taut (e.g. the winter of 2005/06). This item remains an outstanding claim against Chant as well as the subject of an insurance claim. Yukon Energy will not settle on this claim until it is clear that the vibration issue has been fully and adequately addressed. See also response to YUB-YEC-1-48, YUB-YEC-1-49, and YECL-YEC-1-76 (a).

lack of low temperature hardware and any damage to the conductor due to backdragging represent concerns as to potential adverse longer-term costs that require more assessment and as such will be addressed through the claim process and will not be addressed by repair or replacement at this time).

(19.6)
Most of the substation deficiencies were corrected by Chant before Total Completion was achieved. Yukon Energy is correcting the transmission line deficiencies it considers should be corrected over the course of the current (2005) winter. This is being done in conjunction with the tightening of hardware and the installation of vibration dampers as one project to minimize costs. See also response to YUB-YEC-1-19.5.

(19.7)
It is not expected that any deficiencies that affect the long term reliability of the line in any significant way will be left uncorrected after the end of the work planned for 2005.

There are two deficiencies (claims against Chant) that have the potential to increase maintenance costs in future. The first is due to the approach Chant used to string the line, which was an approach that can potentially result in damage to the conductor during installation (see YUB-YEC-1-19.5). No specific incremental costs to maintain the line have been forecast to date due to this factor, but there is a possibility that any damage that occurred will result in increased maintenance costs in future (should high load levels be experienced in future that may cause failure of the line in any areas damaged). The second item is the failure by Chant to use low temperature hardware. Again, Yukon Energy has not specifically forecast any incremental line maintenance costs due to this factor, but there is the possibility that in future incremental maintenance costs will need to be incurred to address this deficiency (to date no components have failed due to low temperature conditions). As noted in response to YUB-YEC-1-19.5, the above represent concerns as to potential adverse longer-term costs that require more assessment and as such will be addressed through the claim process and will not be addressed by repair or replacement at this time.

(19.8)
Yukon Energy anticipates future maintenance costs of the line itself to be in the order of $15,000 per year (excluding brushing) in the near term and, similar to other transmission lines, increasing as the facility ages. Yukon Energy does not expect that these maintenance costs would vary materially from a line constructed to the desired standards.

Chant Contract Scope Changes Paid to Date ($000s)

Number	Description	Reasons for scope change	Cost ($000)
	Original Chant Contract		**22,071**
1	Installation of guy guards	Public safety, not included in project specifications	20
2	Rerouting line along Hunker Creek and over Australia mountain	Airport expansion and regulation change made the contract route impractical and virtually impossible. This scope change included the installation of about 5 km of underbuild upgrade to three phase from single phase to serve customers along the Hunker Creek route. This was cost effective compared to upgrading at a later time.	550
3	Deletion of tension stringing requirement in non-sensitive areas.	Reduce cost to contractor and Yukon Energy.	-17
4	Study the provision of project enhancements to: first, enable a local service person in either the Dawson City Plant or the Callison substation to see the status of equipment in the other location and to be able to exercise control of his equipment. Second, to enable future "visibility" and control of the system from the system control centre in Whitehorse.	To enable system restoration from disturbances by one service person rather than two, and to reduce the required restoration time. To enable the installation of interface equipment that would allow the system control centre in Whitehorse to "see" the new system and to control it from Whitehorse where staff monitor the power system 24 hours per day (enables very fast response to disturbances).	44
5	Clearing of tree screens – narrow strips of trees between the line and the highway.	YTG highways did not want narrow strips of trees left because of risk of trees blowing over.	35
6	Prepare out an environmental impact assessment report.	Because of the concern over the environmental performance of the contractor by regulatory	4

		agencies, a third party was hired to objectively assess their performance. This was cost shared between the contractor and Yukon Energy.	
7	Removal of timber from the cleared line right of way.	The Land Use Permit granted Yukon Energy only 6 months to have the timber removed from the ROW instead of the customary two years, thus there was no real time for the First Nations or the public to access the salvaged wood. First Nations were also upset at the amount of what they considered to be salvageable wood being burned by the contractor, and were complaining to regulatory authorities and the YTG. Hauling the timber off the ROW and onto First Nations land solved both issues. Yukon Energy would have had to deal with any timber that remained after two years to the satisfaction of the regulatory agencies in any case.	384
8	Addition of a feeder entry to the Callison substation layout, including a breaker and related control changes.	Eliminate the need for sending power into Dawson City, transforming it down then up again to send down the Klondike Highway. This eliminated the step-up transformer bank altogether and reduces electrical losses. This is also the first step of the eventual (long term) move of the Dawson City diesel plant and substation to Callison.	41
9	Add current transformers (CTs) to the Mayo-Elsa-	For the new system to be able to operate and control the two	33

	Keno City 69 kV line.	lines out of the Mayo substation independently, the CTs previously used would no longer be useful because of where in the system they were located.	
10	Legal Survey	Yukon Energy originally expected to complete the legal survey itself. However, it was decided to add this to the Chant contract and have them perform the survey.	212
11	Increase in Transmission Line cap	Yukon Energy agreed to an increase in the original Chant contract related to the costs of building the transmission line portion of the project.	300
	Final Paid to Chant		**23,676**

QUESTION:

Reference: Tab 3 – Return on Rate Base, Section 3.4

YEC indicates that the Mayo-Dawson transmission line *"is now fully economic based on forecast diesel fuel price"*.

(a) Please provide a copy of the detailed economic and business analysis (beyond the summary in Table 5-4) that justifies this statement.
(b) Please provide quantified details of all the benefits and costs to ratepayers of the Mayo Dawson transmission line and explanations of where these benefits have been incorporated in the Application material.

ANSWER:

(a)
Table 5.4 is the summary economics over the life of the project. The detailed annual impacts for 2005 and each year beyond are shown in Tables 5.5 and 5.6.

(b)
The quantified details on the benefits and costs to ratepayers of the Mayo-Dawson transmission line are set out in Table 5.5. The location of the savings are as follows:

Project Benefits ($000)

- **Diesel fuel cost savings ($2,265.8):** These savings are reflected in the fuel costs portion of operating and maintenance costs, Tab 3 Table 3.2. This is based on 14,363 MW.h of avoided generation (13.996 MW.h of Dawson sales per Table 2.2 of Tab 2, plus 1,366 MW.h of local distribution losses that would have had to be supplied by diesel generation had the line not been built (based on historical experience of 9.76%) less the 1,000 MW.h that are still assumed to be supplied by diesel in 2005 (for peaking and line maintenance). Note that to the extent this generation is lower than forecast, the benefits of the line will be higher than $2,265.8. The value also reflects a diesel efficiency of 3.8 kW.h/litre based on historical base load experience in Dawson.
- **Diesel O&M cost savings ($229.8):** Reflected in production costs, Tab 3 Table 3.3 as well as reduced overhaul costs, Tab 5, Table 5.3. This is based on 1.6

cents/kW.h for variable O&M based on loads indicated above which is the last approved variable O&M cost for setting run-out rates in Yukon (from the 1996/97 GRA).

- **Diesel Capital cost savings ($321.0):** Reflects replacement of diesel engines that would have otherwise been required had the transmission line project not proceeded. These savings are reflected in depreciation costs Tab 3, Table 3.1.1 (a savings of $123.9), as well as costs related to return on rate base ($197.2). These savings reflect an estimated savings related to two units: 1) $2.15 million that would have otherwise been spent on the Dawson diesel plant in the 2000-2003 period for a new 1.0 MW module to be located at Callison to replace a 700 kW diesel dating from 1975, and 2) $800,000 for a second 1.0 MW module in 2004 to replace a 1.0 MW unit with approximately 100,000 hours on it. Neither of these older units has been replaced as a result of being reduced to backup duty.
- **Other benefits ($59.1):** Related to incremental retail and wholesale sales shown in detail at Table 2.3 (the benefits shown in Table 2.3 from other revenues is $61 due to rounding).

Project Costs ($000)

- **Depreciation ($741.0):** Included in depreciation costs, Tab 3 Table 3.11.
- **Equity Return ($939.6):** Based on a project mid-year ratebase of $27,564 (calculated in the Table below) financed 40% by equity at 9.05%. These costs are included in the Return on Ratebase shown at Table 3.1 of Tab 3.
- **O&M costs ($90.0):** This includes $40 for grants-in-lieu on the Callison substation (see YECL-YEC-1-40(a)) which is included in Table 3.2 of Tab 3, and $32 for the First Nations apprenticeship program related to the Mayo-Dawson benefits agreement which is included in Administration – General at Table 3.8 of Tab 3 and $18 for transmission line O&M which is included in transmission costs at Table 3.4 of Tab 2.

Yukon Energy Corporation - Calculation of Mayo-Dawson mid-year ratebase ($000s)

	2004 Forecast	2005 Forecast
GROSS PLANT		
Opening Balance	$33,695	$34,692
Contributions	$5,800	$5,800
Opening Balance Net of Contributions	$27,895	$28,892
Additions	$997	$675
Closing Balance Net of Contributions	$28,892	$29,567
Mid Year Gross Plant Net of Contributions		$29,230
ACCUMULATED AMORTIZATION		
Opening Balance	$316	$1,295
Depreciation (note 1)	$979	$741
Closing Balance	$1,295	$2,036
Mid Year Accumulated Amortization		$1,666
Net Ratebase		$27,564

note 1: Includes appropriation to reserve for future removal and restoration account and amortization of customer contributions

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%.

ATTACHMENT 6

YUKON ENERGY

04-019

CAPITAL EXPENDITURE APPROPRIATION REQUEST

CEAR NUMBER:	03-90001	**REVISION:**	1	**DATE:**	Jan 19, 2004
WORK ORDER NUMBER:	C03009			**FILE#:**	
PROJECT NAME:	AH1 Unit Rewind				
LOCATION:	Aishihik, Yukon Territory				
TYPE:	Generation				
PROJECT LEADER:	Les Rowland				

DESCRIPTION:

In 1992 Westinghouse Canada Inc. and YEC staff completed a major inspection and test of AH1. Their report at that time identified corona damage to the generator windings, and recommended continued monitoring of this problem and that further work be done in five years time. Westinghouse also identified "serious looseness" between the shaft and thrust collar. Since then, the corona has worsened, and mechanical damage to the windings has been discovered. Therefore $700,000 was budgeted for 2003 for replacement of the stator coils and repairs to the thrust collar.

After meetings between Finance, Technical Services and Operations departments, it was further decided to rebuild all the rotor poles (10) while the unit was apart and the rewind contractor General Electric Canada (GEC) was on site. This added an additional cost of $200,000 to the project.

During disassembly, several other problem areas were discovered which either had to be addressed immediately, or were components that would fail at some future date and it made sense to include them in the existing scope of work. The exciter need to be cleaned and the armature remachined, the lower guide bearing had separation of babbitt from the casing and had to be re-surfaced, and the exciter cables needed replacing, as well as some other minor deficiencies. This added a further $75,000 to the project, for a total project cost of $975,000.

Completion of this project will improve reliability of the unit and reduce the probability of the unit going down in an emergency situation due to failure of any of the components described above. Such an emergency shutdown could put the unit out of service for up to 6 months, since this is the lead time required for new stator coils to be ordered/installed.

CEAR Revision 1 Changes
This CEAR revision for $235,000 is made up of two parts:

The first is $135,000 funding that is definitely necessary due to the following issues:

1. A hydro unit alignment, done during re-assembly, typically takes 1-2 days. The alignment of this unit took 6 days, and significant extra costs were incurred trying to get all the unit components lined up to meet original equipment manufacturer's (OEM) specifications. The reasons for the alignment difficulties are still not entirely known, although it is suspected that it originated with problems in the vertical and horizontal alignment of the upper bracket. Further investigation into this issue is ongoing, particularly since YEC may face the same problems when it comes time to re-wind and re-furbish AH2 in 2006.

2. After unit assembly was completed, BC Hydro International Ltd. and YEC attempted to balance the unit. The unit, however, was far enough out of balance that it was shaking the stationary portion of the supporting structure, and this meant that we could not obtain data on where to place any balance weights. To solve this problem, it was necessary to do the balancing in two stages, monitoring both the unit and the surrounding structure. This took more time than an ordinary unit balance job, and was work not anticipated by YEC or GEC. One way of minimizing this issue for the work to be done on AH2 is to ensure that GEC numbers and weighs each pole prior to starting any work on them, and weighs each of them again on completion of their re-insulation. This will minimize the chance of one or more poles imparting an imbalance to the unit after re-assembly that is large enough to impact the surrounding structure.

3. The remote terminal unit (RTU) was also undergoing a capital upgrade at this time. Problems with the RTU and the XYCOM caused delays in testing and commissioning the unit, thereby increasing costs. This item will also have to be discussed further. If the two projects are done together the above issue may occur. But if they are done separately, the unit is out of service for a longer period of time.

The second is a $100,000 maximum funding contingency. There is $103,000 in 8 work items that GEC claims were extras to the fixed price re-wind project. All eight of these extras are being disputed by YEC as invalid in some cases and overcharged in others. A letter from YEC to GEC (attached) outlines the extras and our response to each.

IN-SERVICE DATE:	**October, 2003**
CEAR Request:	**$235,000**
Previous Approval:	**975,000**
2003 Business Plan:	**700,000**
CEAR TOTAL:	**$1,210,000**

REQUEST FOR APPROVAL:

Project Manager	[signature]	Date:	Jan 27/04
Supervisor	W J L Haydock	Date:	27 Jan 04
Technical Services	[signature]	Date:	Jan 27 2004
Chief Financial Officer	[signature]	Date:	Jan 27, 2004
President & CEO	[signature]	Date:	
Board of Directors	[signature]	Date:	

YUKON ENERGY

YUKON ENERGY
CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 5L6
(867) 393-5300

01-019

Our File: C03009

12 December, 2003

COPY

Mr. R. Griffiths
Regional Sales Manager
General Electric Canada Inc.
19609-96th Ave
Langley, B.C.
V1M 3C9

Dear Rick:

Re: Invoice #716-200312-4

Yukon Energy Corporation was surprised at the contents of your subject invoice, both by the individual and collective amounts and by some of the items that were included. Furthermore, we have received no breakdown of how these individual item amounts were calculated for inclusion in the subject invoice.

Also troubling to us was the fact that there was a complete breakdown on GEC's part with respect to the normal process for inclusion of extras that were deemed by GEC to be outside the normal scope of the Aishihik unit #1 re-wind project. There were no change order requests submitted before or after any of the so-called extra work items, and no attempt to seek the approval of YEC project managers prior to going ahead. Although there was general discussion of some extras, we were under the impression that they were minor in nature, and we certainly never agreed to a 'carte blanche' system where the size and nature of these extras would only be revealed to us after the completion of the project.

This method of charging large extras to YEC is clearly in conflict with both your "Master Goods and Services Contract" (Appendix A), and with your attached "Terms and Conditions". In fact, in section 20 of these Terms and Conditions, it states:

"Buyer may, by **written change order**, make mutually agreed to changes in the Goods and Services. If any such change results in any increase or decrease in the cost or time required for the performance of the work under the Order or affects the warranties, there shall be an equitable adjustment in the Order price and the scheduled delivery date. Seller shall not be obligated to proceed with the changed or extra work until the price of such change and its affect on the scheduled delivery date have been agreed upon in a **written change order**."

Because of the fixed-price turn-key nature of the work to the rotor and stator, YEC kept had only one electrician out there during this time, mostly to fulfill the requirements of our safety policy. If there were major extras contemplated, they should have been estimated at GEC Langley and sent to YEC for consideration instead of going ahead without even informing us at that time. It is by no means certain that we would have agreed to the estimate or the extra work if we had known about it. In fact, when we received the invoice last week, there was some confusion as to what work was even being referred to, and this confusion remains on a couple of items.

Taking a look at each item individually:

Production Delay due to Elevator Breakdown. The elevator was out of action from about noon Wednesday 23 July until about noon Saturday 26 July. Using the rates set out in your CSA, I calculate that standby charges and per diems for the 4 GEC staff would total about $12,000.00. However, this does not take into account the fact that YEC supplied an extra person to help your staff with the re-wind directly as a result of this issue. This was done by mutual agreement between Alex Love and Rick Trsek to make up the time lost by the elevator breakdown. This person ended up spending 90 hours helping your staff, close to the same number of hours that your crew lost due to the elevator breakdown.

We will therefore need to see a cost breakdown of this item taking into account the YEC-supplied manpower before we can make any further decisions.

Stator Core Repairs. No material or labour estimates/costs to do this work were submitted at any time. YEC will need more information to assess this item. Were any pictures taken of the completed repairs?

Lead Support Insulators. No material or labour estimates/costs to do this work were submitted at any time. Also, YEC project managers should have been told that there was work going on involving asbestos contamination, since it was occurring in our plant. What precautions were taken, and did this include any of our staff on-site at the time? Where did the insulators containing this asbestos go? Why did GEC assure us before the start of the project that there was no asbestos in this unit to be concerned with? YEC will need more information to assess this item.

Rotor Pole Wedges. No material or labour estimates/costs to do this work were submitted at any time. While YEC understands that the existing wedges may have been unsuitable for re-use, we have no way of confirming this. We also have no documentation regarding the number of wedges manufactured, or even what material the wedges were made from. The fact that new wedges were made up would also imply that there was a time saving in not having to re-work or clean up the old wedges, work which would have been part of your original contract.

Additional Manpower (Re: poles) & T&L Additional Manpower). These claims for extras are not valid. A set price contract always has, or should have, a contingency built in to cover difficult portions of any work. I somehow doubt that YEC would get a comparable refund if the poles came out easily, nor would we expect to, that is the nature of a set price contract. YEC cannot accept these extras.

Additional Transport Charge (Re: poles). There was no change order for this extra. If this item refers to shipping, it was covered under the original contract.

If it pertains to using the elevator instead of the crane to move poles, coils, etc. up and down between the power house and the upper building, this extra is invalid. The elevator is a much faster method of moving equipment compared to the crane. Also, in meetings prior to the start of the work, it was made clear to GEC that the roof would only be opened if it were necessary to move something that the elevator could not handle. In fact, opening the roof during the project would have made the main work area underneath unusable due to the moisture entering the powerhouse from the crane chimney.

Hazardous Waste Handling. There was no change order or any other documentation for this item, and YEC is unsure as to the nature of this extra. Once again, for any handling of hazardous waste, there should have been supporting paperwork. If this is referring to the pallet of epoxy that GEC sent up, and which your workers on-site subsequently refused to use, this has nothing to do with YEC. In fact, YEC incurred overtime labour to ship your materials back to your shop.

The extras outlined above are of a magnitude that they should have been done through a formal change order process. YEC cannot be expected to evaluate the merits of a change to the original contract without any supporting paperwork at all. In some cases we are still not clear what an extra is referring to, and therefore cannot reasonably assess its validity.

Therefore, please delete any invalid extras from your invoice, and take another look at the remaining items based on our comments above, prior to sending back the revised invoice with all supporting documentation for the remaining extras.

Yours truly,

Alex Love, P.Eng.
Director, Technical Services
phone: (867) 393-5313
fax: (867) 393-5322
e-mail alex.love@yec.yk.ca

W.J.L. Haydock.

Bill Haydock, P.Eng.
Supervisor, Mechanical Engineering
phone: (867) 393-5312
fax: (867) 393-5322
e-mail bill.haydock@yec.yk.ca

Internal Dist:

Dave Wray
Prem Patni
Sulem Darani
Les Rowland

ATTACHMENT 7

2955-

Yukon Energy — Project Identification

Complete by Originator

Project Title:	Generator Rewind AH2		
Location:	Aishihik Plant	Priority A, B or C:	B
Originator:	Dave Wray	Total Cost Estimate Multi Year Project	1,550,000 No
Date:	June 2, 2004	Primary Justification:	REL
Unit or Line ID:	AH2	Secondary Justification:	EA
Start Date:	Jan. ~~2006~~ June 06 Jan 106 ok?	Completion Date:	Dec ~~2006~~ Oct 06
Assets being replaced?	YES	If yes, see #4.	

Complete by PRC

Assigned Department:	95-EE	Project File #:	P04-003
Budget Year(s):	2006	Priority:	Necessary
Reviewer	L Boisvert	Business Function:	Generation
Capital / Maintenance/Other:	Capital	Proj. Brief &/or Economic Analyses :	Yes
Recommendation / Rejection Rational:	Recommend – proceed as scheduled		

① C06003 AH2 Rewind Mechanical
② C06004 AH2 Rewind Rotor
③ C06005 AH2 Rewind Stator
④ C06006 AH2 Commissing

WO #: C06003 (Parent)

Capital Plan approved Budget: 2006: $1,300,000

To be Complete prior to start of project

	Print Name	Signature	Date
Project Manager:	Ravindra Mutukutti		Jan 19, 2006
Dept./Section Head:			
Dir Tech Services:	Alex Love		Jan 19/06
Actg CFO:	Wendy Fendrick		Jan 23/06
President Approval: (projects > $250,000)	David Morrison		FEB21/06
Board Approval: (projects > $1,000,000)	WILLARD PHELPS	Willard Phelps	FEB21/06

Revs

Revision	Description	By Who	Date
Rev 1	Reviewed	L Boisvert	Aug 9 2004
Rev 2	Cost estimate is changed to $1,550,000 from $1,200,000	Ravi M.	Jan 18, 2006

Note ESSG @ 25 90.

Project Identification

1) Description of problem and why this should be undertaken:
(see the attached Project Brief Sheet for more details)
Due to Corona and Mechanical damage to the AH2 Stator Coils and possibly to some of the rotor poles it was recommended by Westinghouse and agreed to by YEC Operations and Technical Services staff that a replacement of the stator coils and repairs to Rotor Poles are required in the near future. This project will improve reliability and allow completion this project on a planned schedule rather than emergency situation. For reliability, environmental and maintenance consistency the Rotor poles should all be re-insulated at the same time the stator coils are replaced. The rotor poles have asbestos in the insulation that would be removed during repair.

2) Options/Alternatives (include the do nothing option):
Do Nothing:
Run until the unit fails (which would involve long waiting times for parts and could cause grid generation shortfalls and potential major damage to the generator).
Other Options:
Replace the coils one at a time as they fail.
Recommended Option:
Replace all the coils and re-insulate the poles on a planned outage before a failure occurs.
(See the attached Project Brief Sheet for more details)

3) Describe the timing of cash flow.
Project will start in Mid June 2006 and end on early October 2006.

4) Identify existing assets that are being replaced:
The generator coils would be replaced.

5) Estimate the costs/proceeds of disposing of existing assets and/or restoring a site to its natural state.
The cost of disposing of the coils would be covered in the rewind contract.

6) Reviewer notes:
This may be able to be postponed by monitoring the generator at least annually. This would involve bringing General Electric or similar to site to conduct partial discharge monitoring at a cost of about $10,000 per year.

7) Cost Estimate (include costs of disposing of existing assets & restoring a site to its natural state)
(See the attached project brief for breakdown of $1,550,000 estimate.)
Estimate increase from $1,300,000 to $1,550,000 as a result of actual bids higher than anticipated.

ATTACHMENT 8

5.2.1 Major Projects Over $1 million

The five major projects undertaken by Yukon Energy since 2005, each with costs in excess of $1 million over the period 2005 (actual) to 2009 (forecast), have total projected costs of $48.488 million by the end of 2009 ($5.909 million in 2007, $38.329 million in 2008 and $4.250 million in 2009). Projected customer contributions offset $39.639 million of these costs. Each major project is reviewed separately below (see also Tables 5.1 and 5.2):

- Carmacks-Stewart/Minto Spur Transmission Project ($38.383 million, with customer and other contribution offsets of $34.639 million).
- Minto Diesels Units ($3.190 million).
- Whitehorse Mirrlees Diesel (WD3) Rebuild ($1.1 million).
- Faro Mirrlees Diesel (FD1) Recommissioning ($1.565 million).
- Aishihik Third Turbine ($4.250 million in the test years, with contribution offsets of $5.000 million).

5.2.1.1 Carmacks-Stewart/Minto Spur (CS/MS) Transmission Project

The CS/MS Transmission Project is being developed to connect the 138 kV Whitehorse-Aishihik-Faro ("WAF") and the 69 kV Mayo Dawson electricity grids. It involves the construction of a new 138 kV transmission line of approximately 172 km between the WAF grid at Carmacks and the Mayo-Dawson grid at Stewart-Crossing, along with new transmission substations in Carmacks and Pelly Crossing, and expansion of the existing Stewart Crossing substation.

The Stage One CSTP involves a new 138 kV transmission line of approximately 98 km between the WAF grid at Carmacks and Pelly Crossing, and a new switching station at Carmacks. It has been developed in conjunction with the 25 kV transmission line and related YEC substations (the "Minto Spur") required to connect Stage One of the CSTP in the Minto Landing area to the copper-gold project operated by Minto Explorations Ltd. ("Minto Explorations"). This stage is scheduled for completion by October, 2008.

Stage Two of the CSTP entails construction of a new 138 kV transmission line of approximately 74 km from Pelly Crossing to Stewart Crossing, including new substations at Pelly Crossing and Stewart Crossing. Stage Two of the project is anticipated to occur concurrent with the development of a second industrial customer, either Carmacks Copper mine owned by Western Copper Corporation, or the reopening of the Elsa/Keno mine now owned by Alexco Resource Corp.

Project History

- **Yukon Energy 20-Year Resource Plan:** The CSTP was included as a major project in the YUB hearing to review Yukon Energy's 20-Year Resource Plan 2006-2025, and was addressed in the January 2006 Resource Plan filed with the Minister, Yukon Energy's May 2006 Supplemental Update, Yukon Energy's November 9, 2006 Update (also known as Exhibit B-16 from the Resource Plan Hearing), two rounds of Board information requests to Yukon Energy, one round of information requests to Yukon Energy from intervenors, the public hearing transcript (November 14 to 16, 2006), the final and reply arguments of the parties, and the Board's January 15, 2007 Report to the Commissioner in Executive Council. In that report the Board noted that it could not make a firm recommendation in the absence of an approved Power Purchase Agreement between Yukon Energy and Minto Mine, but based on the information then provided (including evidence that the line could be developed such that ratepayers would not be adversely affected, but would see benefits from the project), Yukon Energy's proposed first stage of the line should proceed.[2] At this time the CSTP had yet to be designated pursuant to Part 3 of the Public Utilities Act. With respect to the second stage of the Carmacks-Stewart line, the Board agreed with Yukon Energy's strategy not to pursue this project without a firm commitment to connect the Carmacks Copper Mine, and under the same condition that ratepayers would not be adversely affected.

- **YESAB Review:** The CSTP and the Minto Spur together were included in Yukon Energy's October 13, 2006 Project Proposal Submission to the Yukon Environmental and Socio-economic Assessment Board ("YESAB") Executive Committee. The Executive Committee's

[2] The Board noted in its report to the Commissioner in Executive Council at page 32 that, "This view is based on the fact that the Minto Mine is under construction, the mine owners have secured financing to complete the mine, key terms of a PPA have been agreed to by YEC and the mine owners, and YEC has asserted that ratepayers would not be adversely affected by the expenditures required to implement this project."

Recommendations were issued November 7, 2007, and Decision Documents were issued accepting the recommendations November 14, by Selkirk First Nation, November 20 by Little Salmon-Carmacks First Nation, and November 23, 2007 by the YTG. All required permits and authorizations have since been issued to construct Stage One.

- **Part 3 Hearing Review:** On March 16, 2007, the Commissioner in Executive Council designated the CSTP as a regulated project under Part 3 of the Public Utilities Act. Yukon Energy was required to apply to the YUB for an Energy Project Certificate and an Energy Operation Certificate. A hearing process was established to review the project which included Interrogatories for Yukon Energy as well as oral hearing dates. Subsequently, on May 31, 2007, the YUB submitted its report to the Minister of Justice in accordance with section 41(1) of the Public Utilities Act, noting that the Board was satisfied as to the need for the project and recommending that an energy project certificate be granted for CSTP Stage One. The Energy Project Certificate was granted December 2007.

- **YUB PPA Review:** On February 8, 2007 Yukon Energy filed an application with the YUB for approval of the Power Purchase Agreement ("PPA") between Minto Explorations and YEC for the supply of electricity by YEC from the WAF grid to the Mine from Stage One of the CSTP and the Mine Spur. The Board's PPA Review included YEC response to information requests from the Board and intervenors, Argument and Reply Argument. In Order 2005-7, issued April 30, 2007 the Board denied the PPA as filed, directing Yukon Energy to revise the PPA based on the Board Order and re-file the revised version by May 31, 2007. Yukon Energy subsequently reached an agreement on May 14, 2007 with Minto Explorations to amend the PPA to incorporate the changes desired by the Board. The Amended PPA was filed with the Board and the PPA with amendments was approved by the Board in Order 2007-6. In Order 2007-6, the Board noted that the Yukon Government would be fixing Rate Schedule 39 "as required by the amended PPA". On June 4, 2007, the Yukon Government issued Order-in-Council ("OIC") 2007-94 to amended OIC 1995/90 to include provision that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary as attached to Schedule A of the OIC.

- **August 2008 Filing with Board to Approve Rate Schedule 39:** The Minto mine is currently expected to be connected to Yukon Energy service through Stage One of the CSTP and the Minto Spur by October 2008. Accordingly, prior to commencement of service to Minto, it was necessary for Yukon Energy in August 2008 to seek Board approval for a Rate Schedule 39 that conforms to the rate schedule attached as Schedule A to OIC 2007/94. This application is currently pending.

- **May 25, 2007 Amendment to PPA**: On May 25, 2007 a further amendment regarding changes to the Actual Daily Processing Level was agreed to between Yukon Energy and Minto Explorations. This amendment provides greater protection to Yukon Energy (and now Yukon Development Corporation, who has assumed from YEC the financial risk of the Minto Capital Cost Contribution) in the event that increases to the processing level at the mine site result in a shorter than anticipated mine life. Pursuant to this amendment, if Minto Explorations applies to increase the Licensed Daily Processing Level as permitted under its Yukon Quartz Mining Licence, then Minto Explorations is required (a) to provide documentation to Yukon Energy that confirms the Mill Name Plate Daily Processing Level applicable after such amendment and the Adjusted Mine Life, and (b) to pay the outstanding balance of the Capital Cost Contribution, including accrued interest, to YEC, in full, no later than twelve months prior to the end of the Adjusted Mine Life. These provisions would serve to modify the requirement established by section 5.2(a) and (b) of the PPA which only require the Capital Cost Contribution to be paid out in full by the seventh Annual Payment Date. The amendment further notes that these provisions are intended only to provide for payment of the Capital Cost Contribution sooner than otherwise provided for under the PPA, and under no circumstances will such payment period be extended beyond the dates provided for in the PPA.[3]

[3] In 2008, Minto Explorations applied for (and received as of July 25, 2008) an amendment to its Quartz Minting Licence to increase its Licensed Daily Processing Level, requesting an increase of the average milling rate from 2,500 tonnes per day (tpd) to 3,200 tpd. Yukon Energy is currently seeking documentation from Minto Explorations as to the Adjusted Mine Life as provided for in the May 25, 2007 PPA Amendment.

Stage One CS/MS Cost Changes Since PPA and Part 3 Hearings

Currently, the net capital cost to Yukon Energy of the Stage One CS/MS development being brought into service in fall 2008, after all customer and other capital contributions, is forecast at $3.744 million (as compared to zero net cost as forecast in the Part 3 hearing).

Since the Part 3 hearing, forecast Stage One CSTP costs have increased by approximately $5.8 million (from $22.60 million (2007$) to approximately $28.394 million), primarily reflecting increased civil and electrical substation construction costs and line construction costs (including cost increases required for the Tatchun Creek re-routing required by the YESAA assessment and permitting process). Since the Part 3 hearing, forecast capital cost contributions have increased by approximately $2.0 million to $24.650 million, including $10.45 million from the Yukon Government, $7.2 million from Minto Explorations, and $7.0 million from Yukon Development Corporation (including approximately $2.0 million as required by agreement with Yukon Energy pursuant to the PPA as amended May 14, 2007 [Section 3.1(m)] related to any amount of the Carmacks-Minto Landing Capital Cost Contribution principal amount in excess of $7.2 million as required under Section 5.1 of the PPA as amended).

Since the PPA and Part 3 hearings, forecast Minto Spur capital costs have increased by $6.159 million (from the PPA estimated in-service costs of $3.83 million to current forecast costs of $9.989 million). This increase reflects higher substation costs as well as higher line costs. Minto Explorations is responsible for the entire cost increase for the Minto Spur capital costs pursuant to the PPA. Section 5.4 of the PPA provides for an adjustment to the time period within which Mine Spur capital cost financing must be paid by Minto Explorations if the Mine Spur Capital Costs exceed $4.8 million.[4]

5.2.1.2 Minto Diesel Units

At the time that the initial 20-year Resource Plan was prepared in 2005, the potential acquisition of the Minto Diesel units was not considered as a capacity option for the WAF system. Prior to the Resource

[4] Under Section 5.4, a two year extension will be provided for payments under Section 5.2(b)(i) where (a) Minto has provided confirmation by December 31, 2008 under section 5.2(d) regarding its ability and commitment to process Additional Reserves at the Mine prior to December 31, 2017, sufficient to sustain an additional three years of processing at the Mine at the Daily Processing Level, and (b) the extension of the payments will not go beyond the date which Minto confirms in writing to the satisfaction of YEC that ore reserves at the Mine are planned to be processed at the Mine, provided the processing level planned is not less than the Daily Processing Level. Any extension of such payment period is now also limited under the provisions of the May 25, 2007 PPA amendment.

Stage I Carmacks-Stewart/Minto Spur Transmission Projects							
Initial Cost Estimates, Construction Budgets, and Final Costs ($million)							
Yukon Energy Corporation							
GRA 2008/09							
Time/Source	Reference	Spur (MS)		Main Line (CS)		Total CS/MS	
April 07 - Part 3 YUB Hearing on CSTP - Initial Cost Estimate	Part 3 Filing, Page 5-7						
Low Estimate		3.830		19.300		23.130	
Mid-Point Estimate		3.830		22.600		26.430	
High Estimate		3.830		25.900		29.730	
Sept 07 YEC BOD Construction approval Budget	LE-46/LE-47	8.813		27.788		36.601	
GRA (July 08 #'s)	Application, Page 5-7	9.989		28.394		38.383	
Final Cost (Feb-09)	LE-46/LE-47	10.800		29.684		40.484	
% Variance from BOD budget		*22.5%*		*6.8%*		*10.6%*	
Less Final YESAB material scope changes	YECL-9(b)	0.218		1.811		2.029	
Final ex. Final YESAB impacts		**10.582**		**27.873**		**38.455**	
% Variance from BOD budget		*20.1%*		*0.3%*		*5.1%*	
Contributions							
Yukon Government				**10.450**		**0.051**	
YDC				**7.000**		**0.051**	
Minto Explorations		10.800		**7.200**		**0.101**	
Total		**10.800**		**24.650**		**35.450**	
Net Cost to YEC		**-**		**5.034**		**5.034**	

REFERENCE: Tab 5 Capital Projects; P 5-7, L 7

QUESTION:

a) Please provide a detailed cost breakdown of the $22.6 million CSTP Stage One budget and the same breakdown for the final or latest known costs ($28,394 or otherwise).

ANSWER:

(a)

A detailed cost breakdown of the original CSTP Stage One budget and current (not yet finalized) CSTP Stage One budget is provided below ($000s):

	Original Budget		Construction Approval	Current
CSTP Stage 1 Costs				
Planning	2.700		2.382	2.550
Project Management	n/a	(1)	0.756	1.187
Line Construction	16.400		20.760	21.081
Substations	1.900		1.654	3.250
Owners Costs	n/a	(1)	1.054	1.112
AFUDC	1.000		0.940	0.504
Inflation	0.500		0.242	
	22.500		27.788	29.684
	(2)		(3)	

Notes:

(1) At early stages of planning, project management and owner's costs were not budgeted separately, but instead provided for in the construction costs.

(2) These estimates were prepared prior to any engineering costing. Differences between the Original Budgets totals and $22.6 million total quoted are due to rounding.

(3) Construction approval budget included tendered costs for project management and line construction (including clearing and survey) and engineering cost estimates (substations).

REFERENCE: Tab 5 Capital Projects; P 5-7, L 17

QUESTION:

a) Please provide a detailed cost breakdown of the $3.83 million Minto Spur budget and the same breakdown for the final or latest known costs ($9.989 million or otherwise).

ANSWER:

(a)

The detailed cost breakdown of the original Minto Spur budget and the current (not yet finalized) Minto Spur cost budget is provided below ($000s):

Minto Spur Costs	Original Budget		Construction Approval	Current
Planning	0.300		0.904	0.917
Project Management	n/a	(1)	0.492	0.588
Line Construction	2.700		3.623	3.313
Substations	0.500		3.132	5.345
Owners Costs	n/a	(1)	0.289	0.455
AFUDC	0.200		0.298	0.182
Inflation	0.100		0.075	
	3.800		8.813	10.800
	(2)		(3)	

Notes:

(1) At early stages of planning, project management and owner's costs were not budgeted separately, but instead provided for in the construction costs.

(2) These estimates were prepared prior to any engineering costing.

(3) Construction approval budget included tendered costs for project management and line construction (including clearing and survey) and engineering cost estimates (substations).

REFERENCE: **Page 8 of the Application**

TOPIC: **CSTP Connection of Minto Mine and Pelly Crossing Loads**

PREAMBLE:

"Net revenue losses due to delays in final connection, Minto Mine and Pelly Crossing. ($197,000 approximately).

QUESTION:

a) Please describe in detail what caused YEC to be delayed in connecting the Minto mine load.

b) Please describe in detail all scope changes in the construction of the CSTP to Minto Mines spur line and Pelly Crossing and the costs associated with each change. For each scope change indicate what alternatives were considered and ultimately selected and why.

c) Please provide a detailed explanation as to why customers through the Faro Dewatering Account should compensate YEC, due to YEC's inability to execute the planned Minto and Pelly connections on time.

ANSWER:

(a)

The CSTP Stage I/Minto Spur project was approved with a very aggressive in-service date of September 30, 2008. There was a high degree of risk due to weather factors, supply issues (over-heated economy at the time made sourcing of critical equipment on a timely basis uncertain), and regulatory matters (first project through Executive Committee screening of YESAB). The decision was made to proceed with this schedule because there was a significant upside to early completion (approximately $250,000 in new revenues per month to the benefit of ratepayers).

Right-of-way clearing and line construction were generally completed on time; however, the more complex work on substations took longer than anticipated. This was a result of key engineering personnel shortages during the detailed design phase. This resulted in some delays in the placement of orders for some of the major equipment. Also, some manufacturers were not able to meet their delivery dates. Wherever possible, management worked with suppliers to expedite delivery so as to maintain construction schedules. The shortage of personnel also caused a delay in the provision of some of the construction design details to the substation construction contractor which delayed the field work.

(b)

Scope changes addressed here related to changes made after the initial construction tenders and decision to proceed made in September 2007.

Material scope changes occurred due to the Final YESAB recommendation requirements for route adjustments at Tatchun Creek (CSTP) and the Yukon River crossing (MS). The final cost of these changes was $1.811 million and $0.218 million, respectively.

The original design called for a more complex substation at Carmacks. This was replaced by a simple switching station as a means to reduce project costs.

The original plan called for a 138kV to 25kV substation at Pelly Crossing to serve local load. Based on the modest load at Pelly and the high tendered cost of this installation ($2.5 million), the decision was made to energize the 138kV transmission line at 25kV and thereby defer the expense to Stage II.

(c)

Yukon Energy's test year revenue requirement comprises the costs to operate the system. Revenues that are not derived from secondary sales customers or the Minto mine must be recovered from other regulated ratepayers. Yukon Energy has proposed to use the residual amounts in the Faro Dewatering Account (which are effectively ratepayer funds that can only be applied under the direction of the Board) as opposed to adjusting the rate proposal to increase the requested rates. In the event the Faro dewatering account withdrawal is not approved as the source of these amounts, they

would necessarily be recovered the same as any other component of YEC's revenue requirement, through firm rates.

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			2009		
	w/o CSTP	with CSTP	Difference	w/o CSTP	with CSTP	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)**.