IN THE MATTER OF YUKON ELECTRICAL COMPANY LIMITED 2008/2009 GENERAL RATE APPLICATION

FINAL ARGUMENT

YUKON ENERGY CORPORATION

October 27, 2008

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1.0 INTRODUCTION

1.1 OVERVIEW OF YECL APPLICATION AND REQUESTED APPROVALS

YECL submitted the Application to the Board on April 30, 2008 for approval of its proposed revenue requirements for the years 2008 and 2009. This is the first time that YECL has been before the Board with a revenue requirement application since the 1996/97 GRA jointly filed with Yukon Energy in late 1995, i.e., a period of approximately 12 years (Transcript p. 19, lines 3-6).

The Application states as follows regarding the requested revenue requirement during the test period:

> "This revenue requirement represents an increase over the amount that would be recovered under existing rates and riders of $2,220,000 in 2008 and $4,130,000 in 2009. This represents a 5.9% increase in 2008 and a 5.1% increase in 2009. These increases do not include fuel price increases as shown in Section 4 of the application." [Ex. B-1, page 1-3, lines 5 to 8.]

Cumulatively, over the two test years, the increase in retail primary rates throughout Yukon requested by YECL in the Application equals 11.0% excluding fuel price increases[1], and 19.9% including fuel price increases as at January 1, 2008 ($3,388,000) that are assumed in the Application[2]. A further 4.1% increase ($1,560,000) would occur if fuel prices were adopted as last assumed by YECL for the purposes of Rider F calculations included in the last Rider F change implemented August 1, 2008.[3]

The Application proposes that certain affiliate charges (totaling $854,000 in 2009) be included only as placeholders, to be updated when the appropriate approvals have been finalized and approved by the Alberta Utilities commission ("AUC").[4]

The Application also seeks approval for five deferral accounts, three of which currently exist and two of which are new. (Ex. B-1, pages 1-4 and 1-5)

[1] Ex. B-4, Schedule 2.1 line 53. Also Ex. C1-13 as reviewed at Transcript p.49.
[2] Ex. C1-13, as reviewed at Transcript pages 49-50 and page 58, lines 15-24.
[3] Transcript pages 50 and 58.
[4] Ex. B-1, p. 1-6, lines 17-21 – also Schedule 5.3, lines 9 and 11.

1.2 OVERVIEW OF YUKON ENERGY FINAL ARGUMENT

The cost and resultant rate increases proposed in the Application are very significant in the context of the costs reasonably controllable by YECL. Yukon Energy submits that YECL has not met the onus to make its case for its proposed rate increases - particularly when it is recognized that completion of Yukon Energy's new transmission facilities to Pelly Crossing in 2008 enables YECL thereafter to secure approximately $600,000 ongoing fuel and other operating cost savings that are reflected in the Application's forecasts.[5]

General regulatory oversight (and any specific analysis of prudency) must always be done in the context of the circumstances that exist in the timeframe being reviewed. Therefore, in the context of this Application, given current uncertain market conditions, the magnitude of the increase being requested (especially in light of YECL's ability to manage the utility for over 10 years without the type of cost increases it is now requesting) and the current transition period for removal of RSF subsidies it is essential and in keeping with good regulatory oversight practice, for the Board and management of Yukon utilities to take all reasonable steps wherever feasible to prevent or defer cost increases which will be borne by retail customers in Yukon.

The 12 year period since the last regulatory review of YECL revenue requirements has undermined the ability of the Board and intervenors to assess YECL's current forecasts and proposals in the context of past regulatory review of YECL. However, to the extent that evidence has been made available, YECL was able throughout the past 12 years to provide good, reliable electric service up to standards normally expected of a utility such as YECL (Mr. Babyn specifically so agreed for the last five years, from 2003: Transcript page 20, lines 7 to 23). In this context, the available evidence demonstrates that YECL's increases in reasonably controllable costs now forecast for Board approval during the test years reflect an inadequately explained sharp upward jump from cost levels that YECL previously found to be fully adequate.

Accordingly, in keeping with good regulatory oversight practice the Board should only approve overall increases in controllable YECL O&M and capital costs that are reasonably consistent with the overall annual cost increase required to prudently manage the utility over the past five years. This would not only reflect a prudent approach, it would allow reasonable increases and provide YECL with ongoing incentive to control

[5] Based on actual 2007 fuel volumes (654,000 litres) and 2009 fuel price forecasts (89.33 cents per litre) in the Application for Pelly Crossing (Exhibit B-4, Schedule 4.2), YECL cost savings in 2009 after this community is connected to the grid would approximate $584,000 for fuel plus other savings for O&M costs (See also Grattan, Transcript page 281, lines l6-29).

costs. It would also enhance the likelihood of more timely future regulatory review of YECL revenue requirements than has been experienced over the past 12 years.

Further, it is important for the Board and all parties to seek consistent regulatory treatment of Yukon Energy and YECL – particularly when regulation affects the direct interests of either ratepayers or the utilities. Past YUB decisions should provide guidance as to what can be reasonably expected on a forward looking basis, absent decisive new evidence calling for change.

YECL's Application raises a number of important issues regarding consistency by proposing changes to a number of regulatory approaches adopted in past Board decisions affecting both YECL and Yukon Energy. For example the Application raises important issues affecting depreciation and allowed return which if accepted would result in materially higher ratepayer costs than would otherwise be required in the test years - yet the Application provides no decisive new evidence to justify these proposed variances from past Board decisions.

Yukon Energy's Final Argument focuses on the above issues under three major sections:

- Section 2 addresses the reasonableness of the overall increases sought in the Application, considering the context of YECL's regulatory operations.
- Section 3 addresses specific issues identified with regard to YECL forecast costs, including regulatory consistency issues relevant to YECL's forecast costs.
- Section 4 addresses other consistency issues arising from the Application regarding sales forecasts and deferral accounts.

2.0 REASONABLENESS OF OVERALL INCREASES

The following are addressed in this section:

- Significance of Proposed Controllable Cost and Rate Increase
- Onus on YECL as Applicant
- YECL Position as to its Entitlement
- Thresholds for Controllable Cost Increases

2.1 SIGNIFICANCE OF PROPOSED CONTROLLABLE COST AND RATE INCREASE

As reviewed above and in Ex. C1-13, the Application requests an 11% increase in rates over the two test years to recover a $4.13 million net rate revenue shortfall prior to considering any fuel price increases since the 1996/97 GRA. Although Mr. Babyn would not comment on the "significance" of this increase, he did state "I consider it appropriate."[6]

YECL's Application states that, during the period since its last GRA in 1996/97, it has continued "…to provide safe, reliable and cost effective service to our customers. However, there have been significant cost pressures in recent years that require Yukon Electrical to come forward to the Board to ensure that it is possible to continue to deliver the same high standard of service to customers at fair and reasonable rates."[7]

The significance of YECL's proposed rate increase can only be assessed in the context of those costs largely within the control of YECL – and in the context of YECL's proven ability over more than 10 years to control such costs without any need to seek YUB approval of higher rates.

Within Yukon, YECL is primarily a distribution utility. However, most of its stated costs (e.g., 60% of forecast 2009 costs) are for diesel fuel or power purchases from Yukon Energy. Outside of diesel generation costs incurred to serve non-grid communities (about 6.9% of YECL's forecast generation requirements in 2009), YECL essentially purchases generation from Yukon Energy (91% of YECL's forecast generation requirements in 2009).

Although YECL's requested 11% cumulative rate increase already excludes consideration of fuel price changes since the 1996/97 GRA, assessment of YECL's proposed increase must also exclude all diesel fuel and purchase power costs so that the focus can be primarily on YECL's distribution costs increases that are driving the Application. . When this is done, it becomes clear that a 25% two year increase is being proposed for YECL costs **excluding** diesel fuel and purchase power.[8]

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[6] Transcript page 20, line 6. The questions from Mr. Landry on this matter started at Transcript page 19, line 7. Mr. Babyn stated that the increase is "appropriate for the cost pressures and what we need to provide safe and reliable service." (Transcript page 19, line 13-14) The basis for not acknowledging an 11% increase as being "significant", even if it is appropriate, (which Yukon Energy for the reasons outlined in this argument say it is not) is unclear. Lack of clarity here does little to help stakeholders in this process (and the Board) evaluate such an extraordinary increase in rates at a time when there is no extraordinary event driving costs (such as the closure of the Faro Mine in 1998 which resulted in a very significant 16% rate increase). Mr. Babyn agreed with the suggestion that it was just a coincidence that the amount YECL is requesting as an increase for 2009 when the Minto mine will be connected is similar to the previously projected revenue from this mine (Transcript page 61, lines 16-29).

[7] Application page 1-2, line 16-20.

[8] Ex.C1-13: total Group B Costs plus property taxes and income taxes equal $15.26 million in 2007 and are forecast to increase by 2009 by $3.849 million.

Yukon Energy submits that, under any reasonable standard, a 25% increase over two years in controllable costs is significant. Further, this 25% increase assessment closely tracks the effective rate increase being sought for YECL's services alone - in contrast, the 11% rate increase noted in the Application dilutes this increase by considering only its effect on overall retail rates of all YECL and Yukon Energy customers.

The last requested increase of similar magnitude occurred with the 1998 closure of Faro mine (at that time a 16.33% rate increase was requested by Yukon Energy[9]). While the closure of the Faro mine may be considered a unique, emergency situation requiring an immediate and extreme response, no extraordinary circumstances are present in YECL's current Application. While the required rate increases arising from the closure of the Faro mine were entirely uncontrollable (and measures were also taken to reduce certain costs), the significant cost increases being requested in YECL's Application are largely within the category of controllable costs (as demonstrated by YECL's ability since the 1996/97 GRA to control these costs and to secure Returns on Equity (ROE's) typically greater than those allowed its parent). Given this reality, the significant increase sought by YECL cannot be justified based merely on a stated need to approve spending increases in the test years in order to continue to provide safe and reliable service.

The YECL witnesses reviewed with Mr. Landry (Transcript page 45, line 2 to page 49, line 1) the summary of the cost increases and revenue changes as set out in Ex. C1-13 that contribute to this forecast $4.13 million rate revenue shortfall. In summary, as set out in Ex. C1-13, the following key changes since 2007 drive the forecast $4.13 million shortfall in 2009 (in order of significance):

1. **Operating & Maintenance expenses:** forecast change (excluding fuel and purchase power costs) of $2.027 million (**27.8% increase**) which accounts for **49.1% of the shortfall**;

2. **Depreciation expense:** (net of contribution amortization) forecast change of $0.73 million (**23.7% increase**) which accounts for **17.7% of the shortfall**;

3. **Revenue reduction** at Existing Rates forecast of $0.62 million (**1.5% decrease**) which account for **15.0% of the shortfall**;

4. **Return and related Income Tax expense:** forecast change of $0.601 million (**13.4% increase**, notwithstanding a decrease in ROE from 10.37% in 2007 to

[9] Board Orders 1998-3 and 1998-5.

9.25% in 2009 [Ex. B4-Schedule 8.1], as well as a decrease in income tax rate from 36% to 34% [Ex. B4-Schedule 10.1]) which account for **14.6% of the shortfall**;

5. **Amortization of Deferred Costs/credits** forecast change of $0.465 million (**248.7% increase**) which account for **11.2% of the shortfall**; and

6. **Offsets**: Purchase Power and Diesel Fuel (at 1997 GRA fuel prices) cost reduction forecast of $0.296 million, as well as Other Income increases of $0.043 million offset by $0.0261 million of property tax cost increases, which equals an overall **7.6% offset to the shortfall**.

In summary, over 80% of the 11% rate increase derives from an overall 22.6% cost increase (2009 compared with 2007) in costs largely within the control of YECL related to three activities: operation and maintenance, depreciation, and other rate base-related costs (return and related income tax). In contrast:

- Increases in amortization of deferred costs/credits, which account for 11% of the rate increase, largely reflect rate case costs, i.e., rate case costs account for 80% of this increase with the balance being due to diesel plant major overhaul costs and Fish Lake license renewal costs (Ex. B-1, Schedule 8.8).
- Rate revenue decline (at existing rates) of $0.62 million, which accounts for 15% of the overall rate increase, is entirely due to a forecast decline of $0.952 million in secondary sales due to factors beyond YECL's control. A more meaningful assessment of the **net impacts** of rate revenue changes requires review of related power purchase cost changes shows (Ex. B-4, Schedules 2.1 and 3.1):
  - **Secondary sales**: $0.182 million net revenue loss (4.4% of the $4.13 million rate increase) due to the forecast decline in secondary sales revenues less the related decline in secondary energy purchases.
  - **Other Sales and related power sources**: $0.285 million net revenue loss (6.9% of the $4.13 million rate increase) due to the forecast increase in primary energy purchases versus the forecast increase in retail and wholesale sales revenues. Increased primary energy purchases reflect taking Pelly Crossing off diesel generation (a material net cost saving, as noted earlier) as well as the Application's forecast reduction in Fish Lake generation (2.833 GWh, which adds $0.194 million to forecast primary energy purchases: Ex. B-4, Schedules 3.1 and 3.2).

Since YECL in the Application is being subjected to diesel fuel price and at least some other cost increases largely outside of its control as well as forecast losses in secondary sales net revenues, prudency and good regulatory oversight practice require YECL to make every effort to control and constrain spending in areas that are within its control.

Yukon Energy submits that the proposed 22.6% increase in controllable costs noted above for the test years must also be considered in the context of a utility that has been absent from public review for over 10 years, during which time it was able to continue to operate prudently and provide safe and reliable service (up to the test years) without material increases in its controllable costs while still earning a healthy return.[10] Despite the fact that YECL's rates have remained stable for a decade, the applicant has been able to earn returns of 10.37% in 2007 and 10.69% in 2006,[11] returns in excess of the 9.25% applied for in the Application. Further, as noted in cross-examination and illustrated in Exhibit C1-12, with the exception of 2005, YECL has routinely (for the years that actual costs were provided after 2002) earned a higher rate of return than allowed for its parent ATCO Electric and, using the utilities referenced in the Board's 2005 decision, any other comparable utility (eg Fortis BC and Pacific Northern Gas).[12]

To place the proposed two-year controllable costs increase in the context of YECL's actual cost experience in the preceding five years (2003-2007), the following can be noted with respect to the two largest controllable costs (O&M and rate base additions):

- **Operating & Maintenance costs –** Average year over year increases from 2003 to 2007 were 4.4% for labour and 5.4% for non-labour. In contrast, the Application shows a sharp jump in average year over year increases from 2007 to 2009 of 17.2% for O&M labour and 10.2% for non-labour O&M. [13]

- **Net Additions to Rate Base –** Comparing average annual net additions to rate base for the 2003-2007 period versus the two test years, the Application shows a 102% increase in average annual net additions to rate base for the test years compared to previous five year YECL experience.[14]

[10] Transcript page 20 – YECL notes it has been operating in a prudent manner over the past five years and has been able. to provide good, reliable electric service to ratepayers. Ex.C1-12 shows YECL's ROE information as provided.
[11] See Ex. C1-12.
[12] Transcript at page 24.
[13] Ex. C1-14 provides the information for this determination. This exhibit was reviewed with YECL witnesses at Transcript pages 51-52, where Mr. Babyn agreed the percentage increase year over year between 2003 to 2007 in the Group B costs as shown here (i.e., all costs other than diesel fuel, purchase power, income and property taxes) was approximately 4.8%.
[14] Ex.C1-15. this was reviewed with YECL witnesses at Transcript pages 110-112.

In summary, the increases in O&M and net capital costs going into rate base forecast for the test years display a sharp and significant upward jump compared to YECL's actual cost increases in the previous five years.

In this vein, and given the significant increases in controllable costs within YECL's Application, it would be prudent and consistent with proper regulatory oversight to provide for a limited overall increase that would encourage YECL to take a second look at areas within its control and find ways to reduce proposed spending. Using a range for an increase that is approximate to the rate of inflation (2.5% or 4%) or that lies within the range of typical spending increases prior to the test years would establish a reasonable threshold. Any increase beyond this level requires clear and convincing evidence which justifies the increase. In this case no such clear and convincing evidence exists.

Controlling O&M and net rate base costs in this way would have a significant impact on YECL's required increase in retail rates, e.g., limiting these cost increases to 10% from 2007 to 2009 (an annual average of 5%) would reduce the required two year rate increase from 11% to approximately 5%.[15] Further reductions could then be secured through separately addressing various regulatory consistency and other specific issues, including issues related to depreciation, ROE and other return determinations, forecast Fish Lake hydro long-term average production, and the Application's forecasts for secondary sales and retail sales.

2.2 ONUS ON YECL AS APPLICANT

The onus is properly on the utility to demonstrate that its revenue requirement is reasonable and that it has taken all measures available to reduce its own costs before passing those costs on to ratepayers.[16] YECL has not, in Yukon Energy view, met this onus in relation to the Application generally and most specifically in relation to or the above noted controllable cost increases.

YECL has nowhere in its filed evidence or testimony provided a single example of an area where they have taken measures to cut costs or to examine options that would reduce the current rate increase sought for Board approval.

[15] One example of such an assessment is provided in the response to undertaking by Mr. Grattan to Mr. Landry at page 52, lines 25-29.

[16] This issue was discussed by counsel for YECL at the prehearing conference (Transcript pages 18-19) after YEC requested more years of actual data be provided on the record, where Mr. Keough noted, "the onus is on YECL to demonstrate to you that its forecasts are reasonable and hopefully get the approval it is requesting. But it is taking the risk; it is saying to you, 'We think that is enough information'. The onus is on the applicant to make its case."

Given the magnitude of the controllable cost increase requested it is unreasonable for YECL to simply come to the Board with an Application that proposes rate increases sufficient to enable the applicant to sharply increase its costs; the onus is on YECL to clearly demonstrate that every reasonable cost-cutting measure has been examined and exhausted so as to reduce the necessary rate increases at this time, and that the costs as proposed cannot be reduced or deferred without serious harm to safety or reliable service.

2.3 YECL POSITION AS TO ITS ENTITLEMENT

YECL argues in the response provided to the undertaking at page 52, lines 25-29 of the transcript that YECL is "legally entitled to have its revenue requirement established in a manner which provides it with a reasonable opportunity to recover prudently incurred forecast costs," and notes that it is inconsistent with this requirement to "artificially constrain" forecasted costs (i.e., O&M, Depreciation, Amortization, return) based on "an arbitrary percentage that bears no relationship to the expenditures justified by the evidence."

The key here, of course, is the phrase "expenditures justified by the evidence".

Yukon Energy submits that the very sharp and significant jump in controllable costs has not been justified by the evidence.

In response, YECL appears in effect to be taking the position that the onus is on the Board and intervenors to find that the revenue requirement presented is not reasonable and that this may only be done by specifically examining each line item in minute detail and testing whether or not it is justified. Given the significance of the overall controllable cost increase, and the sharp jump from YECL's typical annual cost increases managed prior to the Application, Yukon Energy submits that it is not reasonable to place the onus on the Board and intervenors "to find specific cost items that can be justified for removal from the Application".

2.4 THRESHOLDS FOR CONTROLLABLE COST INCREASES

A reasonable method for reviewing controllable cost increases may be to look at past year over year increases in order to establish a threshold for the test years - anything above the expected trend would require closer review and justification.

In the circumstances, taking a threshold approach to the review of YECL's revenue requirement is necessary and preferable to an exhaustive line by line review and approval of each item to be reflected in the revenue requirement. Given the fact that in the ten years since its last public review YECL has been able to control its spending such that it has in most years (including four of the past five years, i.e., all such years other than 2005) achieved a return on equity higher than was allowed to its parent, there is no clear cost increase trend evident in the YECL performance to justify any approach other than setting a reasonable threshold for cost increases over the test period based on forecast inflation or review of overall annual percent cost increases over the past five years. Setting a revenue requirement based on an assessment of what reasonable cost increases in the test year should look like (rather than based on a tally of proposed spending on each item in the Application that the Board specifically approves) would allow the utility to take a second look at its budget and itself determine which items are essential, which items may be deferred and whether there are measures or methodologies available to reduce overall costs.

By contrast, an exhaustive line by line approach whereby each expense is reviewed by the regulator and allowed (or not allowed) into revenue requirement serves neither regulatory process efficiency nor the utility. It is simply not feasible for the Board or the intervenors to conduct such an exhaustive review within the hearing process. For example, while Yukon Energy has raised significant concerns with certain key O&M items and capital expenditures, it was not possible to review and test each expense item and the Board should not then be constrained in limiting its evaluation of the justification for the revenue requirement based only on the items discussed. The utility is in the best position, after the overall limit is set, to determine how to manage its spending to fit within the budget constraints provided.

3.0 SPECIFIC ISSUES REGARDING FORECAST COSTS

Section 3 addresses specific issues identified with regard to YECL forecast costs, including regulatory consistency issues relevant to YECL's forecast costs as well as issues regarding specific controllable costs. The following are addressed:

- Consistency Issues – Fish Lake Hydro
- Consistency Issues - Depreciation
- Controllable Cost Issues - O&M
- Controllable Cost Issues – Capital Additions
- Consistency Issues - Allowed Return

3.1 CONSISTENCY ISSUES – FISH LAKE HYDRO

YECL's Fish Lake hydro plant operates on the WAF grid. Compared with 2007, the Application forecasts a reduction of 2.833 GW.h in each test year for Fish Lake hydro generation. This reduced Fish Lake generation consequently increases YECL's forecast purchase power costs for primary energy purchases in each test year by $0.194 million – thereby becoming a factor affecting the requested rate increase.

In Yukon Energy's view, consistency is required in dealing with hydro generation in GRA's filed by Yukon Energy and YECL. In this regard, the Application's treatment of Fish Lake hydro raises two specific consistency issues:

- Failure to Confirm Appropriate Long Term Average Generation
- Failure to capitalize power purchases required for plant rebuild

3.1.1 Failure to Confirm Appropriate Long Term Average Generation

For the purposes of setting rates in Yukon, the Diesel Contingency Fund (DCF) as established in the 1996/97 GRA Settlement (Ex.C1-11, Tab 5) directs that "Rates and the fund will be determined using the long-term average water expected to be available for generation". In this context, the DCF calculations of "long-term average water expected to be available for generation" in the 1996/97 GRA (reflecting typical practice by major hydro generation utilities in Canada) was based on the full hydrological record available for each facility, adjusted as required where feasible to deal with changes to regulatory regimes and/or hydro generation capability. Based on this approach, in the 1996/97 GRA, YECL's long-term average generation forecast for Fish Lake hydro was 10.042 GWh/yr (Ex.C1-11, Tab 16).

Yukon Energy applications for rates since the 1996/97 GRA have retained use of long-term average hydro generation based on the principles and methods approved in the 1996/97 GRA.

In contrast with the 1996/97 GRA approved approach and long-term average Fish Lake hydro generation, the Application forecasts generation at Fish Lake throughout the 2008 and 2009 test period at only 6.2 GWh (Schedule 3.2), which is a 3.8 GWh reduction from the 10 GWh of generation available in 1996/97 when YECL was last before the Board for review. This is also a material reduction from 2006 and 2007 when reported actual generation was 8.2 GWh and 9.0 GWh respectively.[17]

[17] YUB-YECL-5 Attachment 1.

This 3.8 GWh reduction in forecast generation at Fish Lake in effect leads to a corresponding increase in forecast purchase power costs for YECL. YECL has noted in its Application, and in testimony on the record, that this 6.2 GWh forecast during the test years reflects the following:

1. A 10 year average of actual generation (1998-2007) at Fish Lake of 6.963 GWh; less

2. A downward adjustment of 0.8 GWH/yr specific in the test years to reflect anticipated down time for planned rebuilds to the unit.[18]

Yukon Energy submits that the Application has failed to provide, as required for consistency with the 1996/97 GRA approved Settlement and ongoing practice followed by Yukon Energy, the necessary documented determination of long-term average water expected to be available for generation at Fish Lake based on all years of available data. The Application and evidence provide no attempt to explain why only a 10-year period of record was adopted, or why this specific 10-year record (which shows an average of approximately 7.0 GWh/yr) should now replace the 10.0 GWh/yr long term average included in the 1996/97 GRA, as approved by the Board, based on the full data record then available.

Given YECL's historic long absence from regulatory review, using a hydro generation forecast specific only to a 10-year period of record (i.e., the period since the last GRA), which is then adjusted to an artificial lower level to reflect specific rebuild work, is problematic as well as inconsistent with Yukon regulatory practice. Looking beyond the test years, the Application presumably anticipates that generation at Fish Lake would return to at least the 10 year average of approximately 7.0 GWh and purchase power costs for YECL would be lower than forecast for the test years. A key consideration in setting up the DCF in the 1996/97 GRA was to base rates and operation of the DCF on a reliable long-term average of water availability and related hydro generation – and the Application entirely fails to address this requirement.

At this point, the information on the record is unclear regarding what the long term average generation at Fish Lake actually is. YECL currently uses a 10 year average which approximates 7.0 GWh; however, when YECL last appeared before the Board, it used 10.042 GWH/yr as its long-term average generation at Fish Lake. YECL has not

[18] YEC-YECL-5(d); Transcript at pages 275-77; Ex.B1, page 3-1.

attempted to assist in understanding why the last 10-year average is 30% lower than the recorded average prior to that time. YECL also has not assisted in providing the information needed to determine the appropriate long term average as required for consistency with the 1996/97 GRA approvals.

Yukon Energy recommends that the Board direct YECL to adjust its Application so that Fish Lake hydro generation reflects Fish Lake hydro long-term average water expected to be available for generation at Fish Lake based on all years of available data (and not based only on the average for the last 10 years of record), i.e. the record that shows the basis for calculating the 10.042 GWH/yr average adopted in the 1996/97 GRA as well as the adjusted average when including the additional years of record now available.

3.1.2 Failure to Capitalize Power Purchases Required for Plant Rebuild

In order to reflect fully in capital costs all relevant costs associated with the hydro rebuild, and to avoid artificially raising test year rates to recover added purchase power solely related to a hydro rebuild, Yukon Energy submits that regulatory practice consistent with the 1996/97 GRA and with hydro utility practice requires that power purchases needed for the Fish Lake rebuild be capitalized with the other rebuild costs and not charged as an expense in the test years.

YECL did not adopt this recommended and consistent approach. In contrast, YECL made a determination in the Application to reflect the cost of increased purchase power due to required down time at Fish Lake (while rebuilds were taking place) in the forecast of test year generation rather than in the costs of the capital rebuild. The result is a forecast for generation at Fish Lake that underestimates the generation normally available (as required under the DCF and 1996/97 GRA principles), overestimates the costs to be spent on purchase power outside the test years, and understates the capital cost for the rebuilds.

Instead of providing a forecast that overstates the purchase power costs due to the rebuilds, Yukon Energy submits that YECL certainly had the option to account for the increased purchase power expenses in the test years as part of the costs of the rebuild project itself. This would have provided a Fish Lake Forecast and purchase power costs more consistent with actual performance.

YECL's position at the hearing was that they have "…not considered including added purchase power costs to the capital cost of Fish Lake rebuilds as typically energy costs are expensed." YECL provided no rationale regarding why this could not be done and conceded that this was a possibility that could have been explored further.[19] The capital costs that are incurred for the rebuild are amortized over time because there is an enduring benefit that the facility and ratepayers get over time. A cost to be incurred to undertake the rebuild is the cost of shutting the unit down. During the down time, purchase power costs increase. This expense should, in Yukon Energy's submission, be considered directly related to the rebuild project.

Accordingly, Yukon Energy recommends that the Board direct YECL to amend the Application so that any power purchase costs needed for the rebuild of Fish Lake are included in the capital costs for the Fish Lake rebuild. On this basis, it is recommended that the Application be required to forecast Fish Lake hydro generation based on the appropriate long term average generation without any reductions to reflect Fish Lake rebuild power purchase requirements.

3.2 CONSISTENCY ISSUES - DEPRECIATION

In the last revenue application reviewed by the Board (i.e., Yukon Energy's 2005 Required Revenues and Related Matters application), the Board approved a requested change in depreciation methods (from the Equal Life Group ("ELG") approach to the Average Service Life ("ASL") approach) for Yukon Energy that served to reduce test year costs and thereby assist current ratepayers.[20] In Order 2005-12, notwithstanding arguments to the contrary from Yukon Energy and YECL, the Board also directed Yukon Energy to discontinue recording its annual depreciation provision for Future Removal and Site Restoration ("FRSR") costs effective January 1, 2005 (which the Board estimated in its Order at $533,336), ordered a variance for Yukon Energy from Generally Accepted Accounting Principles ("GAAP"), and required that the December 31, 2004 balance in the FRSR account for Yukon Energy remain as a liability to be utilized for dismantling costs that are incurred in 2005 and future years.[21]

Approval of ASL depreciation methods and/or directions to discontinue annual depreciation provisions for FRSR costs each resulted in very significant reductions to test year costs included in Yukon Energy's revenue requirements for 2005 (as well as in Yukon Energy's current GRA for 2008 and 2009). These cost changes, which tend to

[19] Discussion at page 275-77 describes this as a "grey area" where there can be interpretations of treatment.
[20] Ex.C1-11, Tab 7 re: Order 2005-12, section 5.
[21] Ex.C1-11, Tab 7 re: Order 2005-12, section 8.1. The Board required Yukon Energy to inform intervenors and stakeholders when the balance of the site removal liability account reaches #2.0 million.

shift potential costs from current to future ratepayers, are solely to the benefit of current ratepayers and do not purport to adversely affect the utility or its shareholders.[22]

Yukon Energy submits that, to meet requirements for regulatory consistency in Yukon for the two electric utilities as well as to consider all available options to reduce test year costs for ratepayers and the very significant increase in rates being requested in this application, the YECL Application should have seriously considered the need to adopt the ASL approach as well as the FRSR-related directions of the Board to Yukon Energy in Order 2005-12.

Yukon Energy submits that appropriate depreciation methodologies and approaches to net salvage were available to YECL that were consistent with established practice in the Yukon, and that would reduce the impact of depreciation on the revenue requirement. In the case of ASL, the methodology was certainly considered appropriate by the YUB in the 2005 proceeding, as well as by Yukon Energy and by many other utilities and regulators throughout North America. In the case of the FRSR matter, the Board made this determination in its 2005[23] order and YECL's Application therefore should have directly considered this direction.

However, the evidence indicates that YECL did not seriously consider adopting either the ASL approach or the Board's last FRSR directions to Yukon Energy. Instead, YECL's evidence elected in effect to challenge the appropriateness of Order 2005-12 on these two matters. In the event that YECL's challenges on these matters are successful, the Board might see a need to revisit (in dealing with Yukon Energy's 2008-2009 GRA as currently filed) both ASL and FRSR determinations from Order 2005-12 as regards Yukon Energy.

In short, the implications for ratepayers in the test years with regard to these depreciation related matters are very significant, ranging from securing major test year cost reductions as regards YECL's Application (if Order 2005-12 directions and approvals are applied to YECL) to facing major test year cost increases (if Order 2005-12 directions and approvals are changed for Yukon Energy's current 2008-2009 GRA and Yukon Energy depreciation is now required to be on the same basis as proposed in YECL's Application).

Specific issues related to these two depreciation-related matters are reviewed separately below.

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[22] In review with Mr. Landry, Mr. Freeman agreed that selection of ASL rather than ELG would not impact YECL's return but that there would be less cash from the perspective of YECL. (Transcript, page 67, lines 8-23)
[23] Order 2005-12.

3.2.1 Methodology – ELG Vs ASL

YECL's key rationales for utilizing the ELG depreciation methodology in its Application are that it is widely used, it was approved for YECL 12 years ago, and that it provides superior matching of the consumption of service value of utility assets to the depreciation expense component of the revenue requirement. YECL provided no evidence that it considered the overall effect on test year rates, or issues related to consistent regulatory treatment with Yukon Energy.

It is noted that Mr. Kennedy did not in his filed evidence in the 2005 proceeding find the ASL method to be inappropriate. In the current proceeding, Mr. Kennedy has sought to distinguish the fact that ASL is "a widely accepted method" from this method being "appropriate" in his view (wherein Mr. Kennedy refers to his view that ELG "is superior").[24] In both the 2005 and current Gannett Fleming reports for Yukon Energy and YECL, the view of Gannett Fleming is clearly stated that ELG is superior to ASL in matching depreciation expense with the loss of service value. Notwithstanding this opinion, ASL was adopted by Yukon Energy and approved by the Board in 2005, and has also been "widely accepted" by other power utilities and regulators in Canada.

Mr. Kennedy has argued that ELG is a technically superior methodology and asserted his opinion that it is most appropriate from a purely accounting perspective; however, Mr. Kennedy (and YECL's) assessment of what is most appropriate in the context the currently proposed significant increase in controllable costs as well as other factors affecting rates and ratepayer bills has been left unconsidered. In the circumstances of the Application and its impact on ratepayers, ASL may be considered more appropriate than ELG for the following reasons:

- **"Other Considerations" not provided** - Mr. Kennedy notes in his response to YEC-YECL-17(b) and (c) that, "in the absence of any other business or economic considerations, the use of the ASL procedure was not considered appropriate by either Yukon Electrical or Gannett Fleming." Mr. Kennedy's evidence dwells on his assessment of the technical superiority of ELG, but neither Mr. Kennedy, nor YECL, provide any assessment of any other considerations that may need to be balanced against a technically superior approach.
- **Need to balance utility and ratepayer interests** - The role of the regulator is to balance both utility and ratepayer interests in determining just and reasonable rates. Mr. Kennedy has argued that ELG is a technically superior methodology and asserted his opinion that it is most appropriate from a purely accounting

[24] Transcript page 241, lines 1-11.

perspective; however, YECL and Mr. Kennedy have failed to justify how the use of the ELG methodology provides for just and reasonable rates in the context of very significant increases in the utility's controllable costs, ongoing increases in non-controllable costs (i.e., diesel fuel costs at the time of the Application), the 2005 Board decision approving ASL for Yukon Energy, and the general need at this time to moderate rate increase for retail customers affected by removal of the RSF. Where a utility is seeking a rate increase that incorporates a very high increase in controllable costs, such considerations must be balanced against Mr. Kennedy's technical preferences. Nowhere in the response to YEC-YECL-17(b&c) does Mr. Kennedy acknowledge any of these important ratepayer considerations.

- **ASL is an approach widely accepted in Canada** - Mr. Kennedy agrees that there were a number of Canadian regulatory bodies, including BCUC that have accepted ASL as an appropriate depreciation methodology for utilities.

  YEC-YECL-II-1(a) notes the following utilities that use ASL depreciation methodologies (power utilities are bolded): **BC Hydro**, British Columbia Transmission Ltd., Centra Gas Manitoba, Canadian Pacific Railway, Consumers Gas Inc., **Fortis BC**, Enbridge Pipelines Inc., Kinder Morgan Canada (Vancouver Airport Pipeline), **Manitoba Hydro**, **Northwest Territories Power Corporation**, Plateau Pipeline Ltd., TransCanada Pipelines Ltd., Terasen Gas Inc, **Yukon Energy,** Alliance Pipeline Ltd., **Hydro One**, Kinder Morgan (Trans Mountain Pipeline system), **Ontario Power Generation**, and Union Gas Inc.[25] Clearly ASL is a methodology that is considered appropriate over a wide range of regulated utilities in Canada, including many major regulated power utilities.

  The ASL method of depreciation was approved by the Board for YEC in Order 2005-12; this change resulted in a significant reduction in YEC's allowed depreciation expense.[26]

- **Mr**. **Kennedy has determined that rate stability needs to be considered when assessing ASL -** During the 2005 hearing it was noted that utilizing the ASL approach over the ELG approach has a material impact on the revenue requirement, providing for significant reductions in the test years. In evidence provided during the current YECL hearing, Gannett Fleming's depreciation study

[25] This is also discussed at transcript at page 249.
[26] Yukon Energy's 2005 application (page 3-18) estimated the effect of changing to ASL at about $0.66 million for test year 2005, net of customer contributions and amortization of fire insurance recoveries.

completed on behalf of Yukon Energy for the 2005 application, and supporting use of ASL, was provided and referenced.[27] As reviewed in the hearing, the 2005 Gannett Fleming report for Yukon Energy noted that, "Gannett Fleming agrees that toll stability is an overall rate making objective that needs to be considered in the development of appropriate depreciation policies. As such, Gannett Fleming accepts the decision of Yukon Energy Corporation to convert to the average service life procedure in the calculation of the depreciation rates.[28] " Mr. Kennedy agreed that, at the time of writing his report for Yukon Energy, rate stability was an overall rate making objective that needed to be considered in the development of appropriate depreciation policies. (Transcript, pages 247-48)

Yukon Energy submits that, based on the available evidence and the above considerations, it is both appropriate and timely for the Board to direct adoption of the ASL method by YECL for the test years.

If YECL is directed to apply the ASL method, the forecast depreciation expense in the Application would be reduced by $391,000 for 2008 and $419,000 for 2009.[29]

3.2.2 Future Removal and Site Restoration

Yukon Energy submits that YECL should be subject to the same treatment regarding FRSR depreciation as directed by the Board with regard to YEC in Order 2005-12. The evidence, however, shows that YECL did not seriously consider this requirement.

In its response in YEC-YECL 1-17(g), YECL attempted to argue that the Board Order 2005-12 was based on specific circumstances applicable to Yukon Energy that are not applicable to YECL's Application. However, contrary to this response, YECL's subsequent response to YEC-YECL-II-2 confirmed that YECL has a salvage provision built into its depreciation rates similar to what Yukon Energy had provided for in its depreciation rates prior to the Board's Order 2005-12, and also has the means for separately accounting for this provision.

It is a matter of record that Yukon Energy argued in its 2005 hearing for the same FRSR treatment as is now being advocated by YECL. It was also noted that both Yukon Energy and YECL were dealing with the issue of ARO by placing a note in their financial statements. (Exhibit C1-11, tab 8, transcript page 880 and 884-85)

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[27] YEC-YECL-17(b&c) provided a quote from Gannett Fleming's study for Yukon Energy filed with Yukon Energy's 2005 application. See also Mr. Kennedy's discussion with Mr. Landry, transcript page 245 line 15 to page 246 line 6.
[28] Transcript page 246, lines 25-30; see also report attached to IR YEC-YECL-II-2(b)(iii) Attachment 1 at page I-5.
[29] YEC-YECL 17(e).

Despite Yukon Energy's oral testimony during the hearing and arguments thereafter, in Order 2005-12 the Board held that it was no longer appropriate for Yukon Energy to collect amounts for annual appropriation to the FRSR reserve. YEC was ordered to remove these charges from the annual revenue requirements. The Board ordered a variance from GAAP and required the December 31, 2004 balance in the FRSR reserve remain as a liability to be utilized for dismantling costs incurred in 2005 and future years. YEC was required to inform intervenors and stakeholders when the balance of the site removal liability account reached $2.0 million. (Page 48 of Appendix A to Order 2005-12; ExC1-11, Tab 7, section 8.1)

While Yukon Energy altered its approach to accounting for net salvage to comply with the Board's clear direction in Order 2005-12, YECL has continued in the Application to use the approach advocated by Yukon Energy at the 2005 Revenue Requirement hearing. YECL notes that it intends to continue using this method of providing for net salvage requirements. YECL has attempted to distinguish its circumstances from YECL (in response to IR YEC-YECL-17(g)); however, it must be reiterated that Yukon Energy's past approach and arguments regarding this issue are identical to those being employed by YECL at present. There is no distinction.
Specifically, the following have now been (or can be) established:[30]

- During the period 2003 to 2007, YECL annual depreciation provisions for FRSR costs averaged $559,959 per year as compared with average annual costs incurred for salvage and site restoration of $123,372 (Transcript page 71, line 20-25).
- As at the end of 2007, the FRSR liability account provisions of YECL equalled $4.688 million, the Application forecast this liability to grow over the next two years by 38% to $6.448 million by the end of 2009. (Transcript page 71, line 26 to page 72, line 14; page 74, lines 13 to page 76, line 4; page 85, lines 9 to 24). By comparison, Board Order 2005-12 noted that Yukon Energy's forecast balance in the FRSR account was $5.144 million at the end of 2003, growing to a forecast balance of $6.514 million by the end of 2005 under the then current practice (i.e., an increase of about 26.6% over the two years).
- During the test years, YECL's revenue requirement includes annual depreciation provisions for FRSR costs of $945,000 in 2008 and $1,003,000 in 2009. (Transcript page 72, lines 15 to 25).

[30] YECL data in YEC-YECL-II-2(c), Attachments 1 and 2 (separate transcript references noted where relevant). Board Order 2005-12, section 8.1 on FRSR matters from 2005 regarding Yukon Energy is in C1-11, Tab 7.

YECL and its depreciation expert Mr. Kennedy asserted at the hearing that IFRS presents an intervening event since 2005 that creates uncertainty regarding the future accounting treatment of net salvage; however, IFRS will not be implemented until 2011, well outside of the test period. Further, and in any event, other than raising the spectre of IFRS (which was at best new evidence introduced at the hearing that could not be challenged, and which Yukon Energy does not accept), no evidence was provided as to what effect IFRS would have.

In summary, there is no material distinction between the arguments that were rejected by the Board in 2005 and the arguments being reiterated by YECL in this proceeding.

In order to provide consistent regulatory direction to both utilities, and to provide test year revenue requirement reductions of material benefit to ratepayers and without penalty to either utility, Yukon Energy recommends that the Board direct YECL to discontinue recording its annual depreciation provision for FRSR costs effective January 1, 2008, along with other related directions consistent with Board Order 2005-12 directions to Yukon Energy on FRSR related matters.

If YECL is directed to apply as recommended above as regards FRSR annual depreciation, the forecast depreciation expense in the Application would be reduced by $945,000 in 2008 and $1,003,000 in 2009.

3.3 CONTROLLABLE COST ISSUES - O&M

The 2009 test year forecasts project that YECL's non-fuel O&M costs for 2009 are projected to increase over 2007 actuals by 28% ($1.468 million increase for 2008 over 2007 actuals, and $2.027 million increase in 2009 over 2007 actuals). (Ex.B4, Schedule 5.1). Review of the Application indicates that significant percentage increases for 2007 to 2009, ranging from 22% to 38%, also apply across each of the major O&M cost groups, i.e., with costs of at least $0.2 million.

As reviewed in Section 2 of this argument, the significant 28% O&M cost increase from 2007 to 2009 reflects a sharp upward jump from YECL's O&M cost increases in the years prior to the Application. For the reasons set out in Section 2 of this argument, Yukon Energy recommends that the Board approve rates that assume recoverable O&M cost increases will be limited by a reasonable threshold that lies within the range of typical spending increases prior to the test years. This approach is particularly appropriate with a utility that historically has not returned for public review with any regularity, and where there is no clear historic trend or other evidence confirming the need for allowing into rates O&M cost increases well above reasonable benchmark thresholds. If in reality ongoing experience confirms a basis for higher costs to supply safe and reliable service, the utility has the ready remedy in those circumstances to apply to the Board to have its revenue requirement and rates reviewed. However, where an unrealistically high O&M cost increase is allowed into rates, there is little incentive for the utility to return to the Board for review and adjustment.

In addition to the above recommendations and assessments, the following specific O&M issues are examined further below:

- Salaries and Collective Agreement
- Vacancy rate – Justifications for reductions from historic trends
- Inflation rate – Justification for 5% Alberta rate.

3.3.1 Salaries and Collective Agreement

O&M labour cost increases from 2007 to 2009 equal 36.7%, as compared with average annual increases of about 4.4% from 2003 to 2007 (Ex.C1-14).

In many cases YECL justifies its labour cost increases by stating it needs to be competitive with ATCO Electric. The Application (page 5-2) notes that compensation issues have yet to be negotiated between YECL and its employee association, but that a 9.5% job class wage increase is forecast based on the 2008-2009 wages negotiated between ATCO Electric and its employee association. (This may be compared with the forecast 7.5% wage increase for non-collective agreement staff).

Notably no requirement to pay the 9.5% exists in the collective agreement with YECL's employee association, and the 9.5% figure is largely based on assumptions derived from remaining competitive with an Alberta-based market as opposed to a Yukon-based market.

Yukon Energy submits that the Application has simply not provided sufficient evidence to support the assumed 9.5% increase and it would not be prudent or in keeping with good regulatory oversight to approve in revenue requirement extraordinary labour costs when the increase being forecasted has yet to be even negotiated.

3.3.2 Vacancy Rate – Justification for reductions from historic levels

Determining with accuracy the vacancy rate that will likely apply over the test period is important to ensuring that costs assumed in rates are representative of the actual costs to be experienced by the utility.

Notwithstanding the obvious relevancy of vacancy rates (whether it be off of YUB approved or YECL Board approved FTE's) YECL has not been forthcoming with regard to disclosing information on historic vacancy rates. During the IR process, YECL was asked several questions by various parties related to its historic vacancy rates (between 2003 and 2007),[31] and provided only the following response in each instance:

> Vacancy rates are calculated based on an approved complement for FTEs. As such vacancy rates are not applicable given that there were not Board approved FTEs for this period.

Although this position has been reiterated throughout the hearing process it has no merit. YECL admitted that it has internal budgets, and that vacancies in each year are an item that are considered by the utility for budgeting purposes.

Given the fact that YECL has not been before the Board for a review in more than 10 years, the historic FTEs and vacancies that have occurred over that period are essential to understanding what the utility has experienced in the past (when it has earned substantially higher ROE than its parent has been allowed) and what the utility can be expected to experience on a go-forward basis. Looking at recent historic results,[32] actual annual vacancies from 2003 to 2007 (based on targeted FTE's per management) averaged 7.04% (ranging from 10.77% in 2003 to 5.17% in 2007) during a period that YECL has confirmed that it sustained good performance with respect to safe and reliable utility operation. This may be contrasted with the significantly lower rates of 4% forecast in the Application for 2008 and 1.7% forecast in 2009.

YECL's 2008/2009 GRA Application assumes a 4% vacancy rate in 2008 (2.25 FTEs) and 1.7% vacancy rate for 2009 (1.0 FTE), noting that the drop in vacancy rate in 2009 is a result of only 1 FTE being forecast to be added in 2009. YEC-YEC-8(n) Revised notes a 4.2 FTE increase in 2008 over 2007 FTEs and a 2.2 FTE increase in 2009 over 2008 FTEs for a total increase of 6.4 FTEs over the test period. This is a 23% increase in base

[31] YEC-YECL-8(f), YUB-YECL 3(b), YUB-YECL-12(a), YUB-YECL-8(d), CW-YECL-27(a).
[32] Provided in response to undertaking at page 103 of the transcript.

wages ($841,000) in the test period compared to 2007 actuals, with a $498,000 increase in base wages occurring in 2009 (approximately 60% of the increase).

Since a higher vacancy rate corresponds with a lower revenue requirement amount for labour costs, a drop in the vacancy rate from 4% in 2008 to 1.7% in 2008 would serve to increase the revenue requirement related to labour costs in 2009.[33] Conversely, an approved forecast vacancy rate of 1.7% in 2009, with an actual vacancy rate for 2009 closer to the 4% rate forecast in 2008, would result in a positive impact on YECL's income statement – essentially a windfall to YECL (i.e., they would have applied for and been provided with a higher revenue requirement in that year for base wages that was not ultimately required due to positions not being filled).

While YECL argues that it is implementing programs designed to reduce vacancies, this cannot negate the importance of historic data in determining the type of realistic vacancy rate that may be expected. Beyond wishful thinking, no evidence is available that would provide any assurance that the programs (and higher costs) proposed by YECL to reduce vacancies will be successful or that the vacancy rates will be materially different that those experienced over the past decade especially given YECL's apparent need to earn a ROE higher than approved by the YUB.

If programs are successful at reducing vacancy rates (thereby increasing base salary expense) then YECL may always elect to return for an adjustment to its revenue requirement. It is also noted that despite higher vacancy rates through the past ten years, YECL has been able to operate prudently and to provide safe and reliable service.

Yukon Energy recommends that the Board set YECL's O&M costs for revenue requirements based on the evidence regarding actual YECL average annual vacancy rates from 2003 to 2007.

3.3.3 Inflation Rate – Justification for 5% Alberta Rate

Inflation rate assumptions are one of many factors affecting O&M costs.

A Yukon-based inflation rate would appear to be the most relevant inflation rate for a utility operating within the Yukon – this would provide for a rate of inflation closer to 2.5% (as noted for Whitehorse in YEC-YECL-9(d)), rather than the 5% applied for in the Application based on Alberta experience.

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[33] Transcript at page 105.

As reviewed below, the record also illustrates that YECL has selected the highest inflation rate available, even including Alberta inflation figures, with recent CPI numbers for Alberta (August 2007 through August 2008) reflecting only a 4% increase rather than the 5% noted in the Application (based on Alberta CPI numbers from January 2007 to December 2007).

With reference to YECL's response to YEC-YECL-9(d), YECL selected the highest year-over-year inflation rate since 1998 for any of Canada, Alberta, Whitehorse and British Columbia. The statistics provided by YECL in the response indicate that up to the end of 2007, Whitehorse had not seen a year over year increase greater than 2.5%; the 12-month CPI for Canada and Whitehorse for August 2007 through August 2008 was 3.5% and 4.4% respectively. YECL confirmed in cross examination (at page 96 of the transcript) that Statistics Canada reports the 12-month CPI increased by 4.0% for Alberta for August 2007 through August 2008.

YECL's response to the undertaking at page 97, volume 1 of the transcript provides that should the 4% inflation rate actually experienced year over year for Alberta from August 2007 to August 2007 be used, the net effect would be a $40,000 reduction in revenue requirement in 2008 and a $46,000 reduction in revenue requirement in 2009. Further, should the 2.5% year over year inflation rate for Whitehorse noted in YEC-YECL-9(d) be applied the net effect would be a $103,000 reduction in revenue requirement in 2008, and $119,000 reduction in revenue requirement in 2009.

Based on the evidence, Yukon Energy recommends that the Board set YECL's O&M costs for revenue requirements based on the 2.5% inflation rate reported for Yukon.

3.4 CONTROLLABLE COSTS - CAPITAL ADDITIONS

YEC has a substantial capital program planned for 2008 and 2009, well in excess of capital programs in recent years including several major projects. YECL notes that the increase in return on rate base from 2007 to 2009 is in large part due to capital additions which are projected to increase from actual amounts of $6.72 million and $7.65 million in Actual 2006 and Actual 2007 respectively to $9.72 million and $13.50 million respectively over test years 2008 and 2009 (Application page 8-3). The $13.5 million addition to rate base in 2009 is 87% higher than YECL's average annual additions to rate base since 2006/07.[34]

[34] Exhibit C1-15 – Comparison of YECL Capital Additions and Contributions in Aid of Construction 2003 to 2009; average net additions to rate base from 2004 to 2007 compared to test years shows a fairly dramatic increase in net additions to rate base.

YECL's capital program has not been reviewed since 1996/97. YECL has in its recent filing (including in interrogatory responses) failed to provide adequate justification for certain capital projects undertaken since the last GRA and proposed over the test years. With regard the proposed new Carcross diesel plant (and prior to the test period the addition of the Haines Junction Diesel unit), YECL has failed to provide adequate justification for any business case that the units are required for safety or reliability reasons or that the units are cost efficient compared to other options considered in the 20-Year Resource Plan or available to enhance local reliability. Spending on other items such as Automated Meter Reading are not essential to YECL's ongoing operations at this time and the utility can continue to provide safe and reliable service absent this essentially discretionary purchase.

Given the significant increase in YECL's controllable costs as reviewed in Section 2 of this argument, it has no merit to provide for these major capital expenditures without a solid business case or other rationale confirming that such facilities are absolutely necessary for the continued safe operation of the utility during the test years and/or immediately thereafter.

Further to the above, issues are reviewed below in more detail regarding the following specific capital additions carried out or proposed since the last GRA:

- Haines Junction Diesel Unit
- Carcross Diesel Plant
- Automated Meter reading (AMR).

3.4.1 Haines Junction Diesel Unit

The Haines Junction diesel unit, purchased after the 1996/97 GRA (and not considered in the 1996/97 GRA forecasts), is a proposed addition to approved rate base in YECL's Application. YEC-YECL-25(a) at page 18, notes that $542,000 was spent on a mobile units at Haines Junction in 1997 (a 1.5 MW generator and a 480V – 14.4kV/25kV step up bank).

The only justification provided in YECL's written evidence is "extended outages, lengthy restoration time." The only benefit provided is stated to be "contingency supply for Haines Junction." This justification was reiterated at the hearing as the only justification provided for the purchase of the unit at Haines Junction; YECL's witnesses had no recollection as to whether any discussions had taken place with YEC regarding whether the diesel unit was required to address issues with outages. (Transcript page 115, lines 13-25 and page 116, lines 1-3)

In the response to the undertaking at page 114, lines 12-13, it was noted that the revenue requirement impact for test years is $65,000 in 2008 and $60,000 in 2009. It is not clear if this simply reflects only the original unit cost impacts or if it includes all subsequent capital related cost impacts incurred for this unit since it was installed plus all ongoing O&M related costs.

There is no information provided to confirm that having the unit at this location has materially reduced the impact of outages, or that this unit has provided a cost effective option to enhance local reliable service.

3.4.2 Carcross Diesel Plant

YECL proposes in its Application to spend $2.0 million on a Carcross 1.5 MW Power Plant in 2009.[35]

YECL's justification for the diesel units has changed since its initial filing where it was justified solely based on criteria provided in the YEC 20-Year Resource Plan. Once it was pointed out to YECL that the 20-Year Resource Plan in effect provides no justification or support for the location of a diesel unit at Carcross at this time, YECL evolved its justification for the units as the hearing progressed, culminating with the proffering into evidence Exhibit B-17 on the last afternoon of the hearing. It is noted that YECL's evolved position regarding the justification for the Carcross diesel unit has no foundation in the written evidence provided prior to the oral hearing, and the one piece of written evidence provided by YECL in support of the units, i.e., Exhibit B-17, once it is reviewed carefully provides no evidentiary foundation to support YECL's new position.

YECL has failed to justify the acquisition of the $2.0 million 1.5MW unit at Carcross based on the following:

- It has failed to justify the purchase based on criteria contained in the YEC 20-Year Resource Plan
- It has failed to provide credible evidence to justify the purchase based on reliability concerns at Carcross
- It has failed to justify the purchase as a preferred option
- It has failed to justify the purchase as a cost-effective option

[35] Page 9-1 of the Application. CW-YECL-46 page 2 notes. The transcript at page 116 notes that the unit has not been purchased yet.

Failure to Justify Purchase Based on YEC 20-Year Resource Plan

In the Application, the following was the only justification or rationale provided for the purchase of the new 1.5 MW diesel unit to be installed at Carcross:

> It has been determined that communities over 1.0 MW should have local generation to serve them if the grid should stop serving the community in accordance with the YUB approved Yukon Energy 20 year resource plan. Carcross and Tagish are fed off the same 25kv substation. The peak load in the 2007 winter was close to the 1MW threshold.[36]

The WAF and MD Community Criteria noted in the 20-Year Resource Plan do not require communities over 1.0 MW to have a diesel generator but note that such communities would be considered as a preferred location for new diesel units, providing grid support as well as local generation during line failures[37]. Mr. Grattan noted his understanding regarding the criteria was that "communities with one megawatt or more of load should be considered, whether it's a priority or however you want to phrase it, for new diesel generation on a go-forward basis, if capacity is required.[38]"

YECL provided no record of any discussion with Yukon Energy regarding the impact that this unit would have on system capacity requirements, and no analysis or assessment regarding how the location of a diesel unit at Carcross would serve system needs[39]. However, the evidence from the Resource Plan hearing and the PPA hearing has established that Yukon Energy already has committed spending on Mirrlees Diesel Life Extension (including the Faro Mirrlees rehabilitation), plus purchase of the Minto diesel units, fully sufficient to supply WAF grid system capacity planning criteria through the test years and for several years thereafter.[40] In short, there is no current need for new diesel units to meet grid system requirements - and accordingly, based on Yukon Energy's 20-Year Resource Plan (including the referenced "WAF and MD 'Community'

[36] Page 9-23 of Application; This justification is also noted in YEC-YECL-25(a) attachment 1 at page 57 of 59: "In the YEC 20 yr Resource Plan, it was recommended that all communities over 1MW be equipped with local generation to serve the immediate area during grid or line failure. The Southern Lakes area, including Carcross and Tagish, fits this criteria Yukon Electrical plans to install a generator in/near the Carcross substation. This generator would be no less than 1.5MW as this is adequate sizing for the cold load pick up of the area."

[37] Exhibit C1-11, Tab 15 at page 3-21: "For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more should be considered as a preferred location for new diesel units if that community does not already have back-up from another source (e.g. having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located."

[38] Transcript, Volume 3, page 393 lines 20-27.

[39] Transcript, Volume 1, page 118-121.

[40] Ex.C1-11, Tab 14 provides the November 20, 2006 update to the Resource Plan, including section 3 on Mirrlees Life Extension Project.

Criteria"), there is no justification to consider a 1.5 MW diesel unit at Carcross at this time.

Failure to Justify Purchase Based on Reliability Concerns at Carcross

The Application and interrogatory responses filed by YECL did not provide any other rationale underlying the requirement for a diesel unit at Carcross other than the community criteria as set out in the YEC 20-Year Resource Plan. Prior to cross-examination at the hearing, the obligation to provide safe and reliable service and reduce outages was not clearly enunciated as a justification driving the purchase of this unit.

On cross-examination by Mr. Landry, YECL suddenly shifted the justification for the units away from the 20-Year Resource Plan and towards reliability concerns at Carcross[41]. Notably, YECL now elected to emphasize concerns (that would justify the $2 million expenditure) regarding reliability and outages at Carcross that had not previously been raised in either the Application or in interrogatory responses.

While the response to YEC-YECL-38(c) notes that, "Yukon Electrical did look at the outage statistics for the area", it provides no further information regarding what the outage statistics were and whether they supported the case for purchase of the diesel unit or failed to support such a case. Regardless, even in this interrogatory response, the primary justification for the unit was the system planning criteria set out in the YEC 20-Year Resource Plan. Notably, the project justification provided in YEC-YECL-25(a) Attachment 1 page 57 of 59 provides under the heading "what changed".

> It has been determined in the Yukon that for communities that have loads over 1MW that back up generation should be considered.

In summary, the written record prior to the hearing would suggest that the primary driver underlying the justification for the unit was the community criteria contained in the YEC 20-Year Resource Plan. Further, no written evidence was made available prior to the hearing to address possible local reliability concerns at Carcross, or consideration of options to address such concerns.

[41] Transcript, Volume 1, page 116 YECL noted "that area and group of customers have experienced a higher level of outage time than other customers in the service area, and particularly other customers who have standby diesel to go on when grid is not available," and "the level of service associated with regard to our customers – Yukon Electrical customers – in the Carcross and Tagish area has been negatively impacted as a result of the large amount of outages due to them being at the end of a long radial line, and that is what is driving this debate."

On the final afternoon of the hearing, in response to a question by UCG, YECL produced a new exhibit (Exhibit B-17) which purported to justify the need for a diesel unit at Carcross by demonstrating statistics for the number of customers affected by outages longer than one hour over a 10-year period for the Carcross-Tagish system versus a similar type system with standby diesels (e.g., Haines Junction, Carmacks or Teslin). With regard to Exhibit B-17 Mr. Babyn noted, "without a doubt, customers are exposed to significantly more outages in the Carcross-Tagish area than other customers that have a standby generator."[42]

On its face Exhibit B-17 purports to demonstrate disproportionately large numbers of customers affected by outages in the Carcross/Tagish area. However, the graph is at best misleading as it has not been standardized for the number of customers in each community, and fails to include any information related to the number of customers in each of the communities for which number of outages per customer is provided (Carcross/Tagish, Haines Junction, Carmacks and Teslin).

With reference to YUB-YECL-4 it is noted that the number of residential customers in Carcross/Tagish is double and in some cases triple the number of residential customers in the other communities listed (i.e., there are 610 residential customers in Carcross/ Tagish compared to 350 residential customers in Haines Junction, 200 residential customers in Carmacks and 240 residential customers in Teslin). Without being standardized with regard to the number of customers in each community, this graph simply cannot be relied upon to justify the purchase of the diesel.

Further, in cross-examination, Mr Babyn conceded that the underlying data necessary to support the case that there are significant reliability issues in Carcross that would be addressed by the addition of a diesel generator in the community was not on the written record,[43] noting:

- There was nothing on the written record that would provide the data necessary to support the alleged significantly higher outages in Carcross/Tagish that were noted in Exhibit B-17.
- There was no information on the written record discussing the causes of outages indicated in Exhibit B-17 (besides YUB-YECL-1 which asked for performance stats of the overall system).

[42] Transcript Volume 3, page 332, lines 6-8.
[43] Transcript Volume 3, page 364-366.

- There is no analysis as to the options to resolve the outages (besides discussion around a tie from Jake's Corner which was discounted after a high level assessment as provided in response to YEC-YECL-25(a) Attachment 1 page 57 of 59 and YEC-YECL-38(c))
- No cost-benefit analysis has been provided that would point to Carcross diesel as the best option to address any local reliability concerns (versus for example upgrading the radial line).
- No information on the record that would suggest that the operation of diesels in Haines Junction, Carmacks or Teslin reduces outages or the duration of outages in those communities.

Other than YECL's oral testimony and the deeply flawed Exhibit B-17 which was provided on the final day of the hearing, there is nothing on the record that would justify the major expenditure represented by the Carcross diesel units.
To assess whether reliability is a material issue, more detailed information and analytical rigour is required. If the purchase of this unit is to be justified based on reliability concerns then YECL must first provide, as baseline, information to support reliability issues in the area. YECL has failed to provide any recognized indicators (SAIFI[44], SAIDI[45] or CAIDI[46]) that could be used to benchmark distribution reliability in the area, and has failed to provide any breakdown as to the causes of outages in the area. Prior to this capital addition being considered, YECL should provide industry standard measurements of reliability for the years 2006 and 2007 for the WAF connected communities as well as the CEA average numbers[47] for benchmarking purposes in order to help assess whether reliability concerns are justifiable.

Without this preliminary assessment, the purchase of the diesel units based upon reliability concerns should not be considered. Were such baseline information provided, further assessment of the options available to address reliability issues would then be required. Any assessment of the Carcross unit as a viable option would have to address whether the location of a diesel generator at Carcross would meaningfully and cost-effectively mitigate the duration or incidence of outages in Carcross.

[44] SAIFI is a measure of average number of outages a customer experienced or the average outage Frequency.
[45] SAIDI is a measure of the average length of an outage experienced by customers or the average outage Duration.
[46] CAIDI is a measure of the average length of time to restore the last customer affected by an outage event or the average System Duration.
[47] CEA publishes an annual reliability report which may be used for benchmarking purposes. The CEA member average may be used as a reasonable benchmark if applied using at least a 3 year rolling average to account for significant year to year variances due to major events such as ices storms and forest fires.

Failure to Justify Purchase as Preferred Option

As noted there is no meaningful evidence or analysis to support YECL's position that reliability is a material issue in Carcross, that having a unit at Carcross will reduce or alleviate any issues related to outages, or that the purported reliability problem at Carcross cannot be addressed through distribution improvements or other measures. No detailed analysis has been provided to support the requirement for the unit or that it is the best option amongst all other options considered.

The Application provides no analysis to support the purchase and location of diesel units at Carcross as a means of addressing the issue of reliability and outages cited by YECL at the oral hearing. Exhibit B-17 confirms that even with a diesel generator, Haines Junction, Carmacks and Teslin each suffer outages in excess of one hour. Until Exhibit B-17 is standardized to account for the number of customers per community, there is nothing to suggest that there are significant issues in Carcross/Tagish compared to the other communities noted on the graph. Further, there is no information provided on the record to suggest that the number and duration of outages in these communities materially improved with the provision of a back-up diesel generator.

YECL's Application already proposes spending on distribution improvements, such as pole replacements at Carcross and Tagish, justified in part by the need to address safety and reliability issues[48]. It would be prudent to first undertake these measures, designed, in part, to improve reliability, and then determine if they have any effect on outages in the Carcross and Tagish area. Notably, YECL has not even considered, as an alternative to purchasing the units, improving reliability to the 34 kV line to Carcross. No analysis has been provided related to whether improving distribution in these areas will mitigate the incidence and duration of outages. Given YECL itself has in the past, and continues to, utilize distribution improvements when addressing reliability, distribution improvements should at the very least be included as an option to the purchase of the diesel units. Without a fully informed debate on this option good regulatory oversight requires that such a capital expenditure not be approved at this time.

The only alternatives to the purchase of the Carcross diesel unit that were considered by YECL are provided in response to YEC-YECL-25(a) Attachment 1 page 57 of 59, which notes the following:

[48] See Application page 9-7, 9-18, 9-25 which note specific distribution improvement projects in the Carcross and Tagish area including: $76,834 spent on ROW Widening at Carcross in 2006; $150,000 on Carcross Km 129-131.5 Hwy (south of Annie Lake Rd) in 2008; $150,000 on Carcross Relocate 34 kV Stage 2 in 2009 and $200,000 Tagish Section to Taku 2.5 km in 2009.

- Status quo - Communities of Carcross and Tagish remain without an alternate generating source.
- Grid source from Jake's Corner – this feed has same source for first 20km of line and is estimated to be a more expensive option.

YEC-YECL-38(c) notes that "The option of installing a substation at Jake's Corner to give the area a second feed was also evaluated at a high level. The cost was higher than the backup generator option providing very little benefit due to the fact that the line to Carcross and the line to Teslin are one in the same for the first 20 km."

No other analysis or information is provided.

The purchase of the unit to be included in rate base should be deferred until a more rigourous and detailed analysis is provided and subjected to full review by the Board. There is no evidence that the purchase of the unit is immediately required, especially given the fact that improvements to distribution designed to improve reliability are already underway.

Failure to Justify Purchase as Cost-effective Option

YECL has not demonstrated (a) that this is the lowest cost solution available, or (b) that it would provide good return on investment in terms of materially reducing the number of outages in excess of one hour in the area. Such analysis is required before the purchase of the units can be considered as an addition to rate base.

When the cost of the unit at Carcross is benchmarked against either the refurbishment of the Mirrlees or the purchase of the Minto diesel units, it is not justified as a cost-effective option. Exhibit C1-11 at Tab 14, page 3, notes that the proposed refurbishment of the Whitehorse Mirrlees could be undertaken at an approximate cost of $450,000 to $500,000 per MW. The purchase of unit at Carcross does not remain within this competitive price range at a cost $1.3 million per MW.[49]

During the PPA hearing the purchase of the Minto diesels was justified on a cost basis when compared with other options such as the refurbishment of the Whitehorse Mirrlees. In Order 2007-5 the Board accepted as reasonable the price provided for the units – noted by YEC as a comparatively low cost addition to WAF winter peak capacity at a price of approximately $0.350 per MW. The purchase of the Minto Diesel units is now justified at

[49] Discussion at Transcript page 123.

an approximate cost of $0.498 million /MW.[50] While the price for the units has been revised upwards in the Yukon Energy 2008/2009 General Rate Application, it is still within the range of the Mirrlees refurbishment and well below the $1.3 million per MW cost for the Carcross diesels.

Mr. Grattan argued that comparing the cost per MW of the Carcross diesel unit to the cost per MW of the Mirrlees was an “apples and oranges” comparison;[51] however, he provides no clear rationale regarding why the cost of the Carcross diesel should not be assessed against the cost of other comparable options currently being pursued in order to determine its cost-effectiveness.

Summary

YECL cannot justify including the diesel units in rate base for the test years, or any other near term period, based on evidence that is currently on record based on the following:

- YECL has failed to justify the need for the units based on the community criteria in the 20-Year Resource Plan.
- YECL has failed to provide any meaningful evidence that there are material reliability concerns in Carcross and Tagish, or that such concerns would be meaningfully address by the purchase and location of a diesel unit at Carcross.
- Exhibit B-17 which is provided as the only support regarding reliability issues in Carcross and Tagish is misleading, and there is no evidence on record that would support the information portrayed therein.
- YECL has failed to provide any evidence that other options were meaningfully considered and that the purchase of the diesel unit at Carcross is the most feasible and cost-competitive option available.

Based on the evidence and the above considerations, Yukon Energy recommends that the Board not approve the proposed Carcross diesel unit as an addition to YECL’s rate base for the test years or any other near term period.

[50] See Yukon Energy 2008-2009 General Rate Application page 5-9 at lines 7-8.

[51] Transcript Volume 1, page 123 at line 17 and in re-direct, Transcript Volume 3, lines 20-27 “Mr. Landry, as I understood his question, was referencing overhauls of existing diesel units in existing plants, complete with roofs, leak detection systems, fuel tanks, et cetera. That’s the way I understood the question. In the case of what is proposed with regard to Carcross — the diesel plant, as Mr. Steinbach has just pointed out — it is proposed to be a self-contained mobile plant, to be stationed — complete with fuel tank, et cetera. It is proposed to be based in Carcross and that it will be designed in a way that it can be moved in an emergency response situation to other locations. That’s why I said what I said.

3.4.3 Automated Meter Reading (AMR)

The Application proposes significant spending on Automated Meter Reading (AMR) technology ($0.330 million in 2008 and $3.855 million in 2009) in the test years.[52] At a cost of $4,185,000, this is a major capital expenditure relative to other capital expenditures proposed in the Application.

The rationale underlying the purchase is that ATCO Electric (YECL's parent company) has already converted a number of meters in Alberta and that YECL would benefit from their expertise in implementing AMR. The justification provided a page 9-27 of the Application notes that "it would be beneficial for Yukon Electrical to draw on their expertise and consider implementing AMR to increase operational efficiency and move toward other features and benefits."

While YECL's Application and response to YUB-YECL-15(c) note benefits that include efficiency, improved accuracy, reduction of billing inquiries, the ability to implement time of use rates and improved monitoring of meter performance, YECL has acknowledged that the purchase of the meters is not essential for the utility to continue to operate in a prudent manner.[53] The evidence also confirms that proposed expenditures and/or commitments on AMR are primarily forecast for 2009.

Given the significant increase in controllable costs present in the Application, significant spending on an item such as AMR that is not absolutely required or essential for the utility to operate prudently and continue to provide safe and reliable service in the test years should be deferred. Accordingly, Yukon Energy recommends that AMR expenditures not be allowed in rate base for the test years.

3.5 CONSISTENCY ISSUES – ALLOWED RETURN

Up to and including the 1996/97 GRA, consistency in regulatory treatment between YECL and Yukon Energy was facilitated by a process of joint YEC/YECL filings and Board reviews. In dealing with allowed return on rate base for each utility in these revenue requirement applications, the Board addressed the capital structure of each utility, the determination of a fair rate of return on common equity (subject to OIC directions regarding YEC), each utility's specific costs of debt, and (in the case of YECL) related income tax costs attracted by the allowed return on equity.

[52] Application page 9-11.
[53] Page 126 lines 20-28 and page 127 lines1-3.

In Yukon Energy's view, it is important for the Board to retain consistency in addressing allowed return included in revenue requirements for each utility (both as between the utilities, and over time from one proceeding to the next), while also encouraging cost efficient regulatory processes.

In summary, YECL's Application proposes a 9.25% return on equity (ROE) with a target equity structure of 47.5%,[54] and with new cost of debt forecast at 6.6% (based on 4.55% Long Canada Bond yield forecast, a 200 basis point spread, and 5 basis points for issue costs). The income tax rate on equity return is assumed at 34%.

YECL's Application raises many consistency concerns. Most significantly, the Application seeks Board approval of an increased common equity ratio which represents a material departure from the common equity ratios approved to date by the Board, and which adds to the average rate of return sought on rate base plus (equally importantly) adds to YECL's forecast income tax costs to be passed on to ratepayers. The Application also moves away from the YUB and BCUC regulatory practices adopted with regard to allowed return on equity (ROE) determinations, which adds complexity as well as proposals to seek a higher allowed ROE.

More specifically, the approach adopted in the Application fails to follow past YUB practice with regard to determining a fair rate of return for YECL (based on Board decisions issued when YECL was previously reviewed by the YUB: 1992-1; 1992-2; 1993-8 and 1996-6), significantly deviates from the AUC benchmarking methodology[55] which it "uses as a point of departure" for determining a fair return, and moves away from the approach utilized by YEC in 2005 to determine its return on equity during the Required Revenues and Related Matters hearing.[56]

The following are reviewed below:

[54] Application at page 8-2.

[55] YECL directed Foster Associates to arrive at the ROE using the Alberta based approach which provides as follows:
(1) Adopt the Alberta EUB ROE of 8.75% assuming a capital structure that fully compensates for YECL's business risk (estimated by Fosters Associates at 52.5% equity); (2) Based on Fosters Associate's assessment, because the benchmark ROE is below the level consistent with a fair and reasonable return, a capital structure with an equity ratio of 47.5% was recommended with an added risk premium of 0.50% to compensate for the lower equity level; (3)Recommends a target capital structure with 47.5% equity with an ROE of 9.25% .
The approach is also discussed at page 191-92 of the transcript.

[56] One of the reasons YEC moved to BCUC approach in 2005 was to reduce costs of providing rate of return evidence. Tab 6 page 44 cites Board Order 2005-12, Appendix A and notes, "YEC proposed to use the BCUC approach for 2005 only as a means of establishing a fair return without having to incur the cost of providing a full cost of capital review, which is time consuming and expensive. YEC believed that it is appropriate to adopt approaches that can avoid the need for such expert evidence thereby reducing cost burden on ratepayers."

- Departure from Past Regulatory Experience in Yukon
- Hybrid AUC Approach to ROE Adopted
- BCUC Approach to ROE Ignored
- Cost of Debt Issues
- Conclusions

3.5.1 Departure from Past Regulatory Experience in Yukon

Historically the common equity ratio applicable to YECL has been maintained below that of Yukon Energy (which has been approximated 40%). Exhibit C1-17 notes that between 1991 and 1994 the capital structure approved by the YUB for YECL has been comprised of approximately 34-35% equity component and a 39-41% debt component.[57] In the 1996/97 General Rate Application, in response to the elimination of the Public Utilities Income Tax Transfer Act (PUITTA) by the Federal Government and the resultant reduction in benefits of preferred share financing, YECL proposed to adjust its target capital structure to 37% equity, 48% debt, and 15% preferred shares[58]. In the 1996/97 GRA, YECL noted as follows: "The majority of the preferred share reduction has been transferred to debt as interest payments on debt are tax deductible and result in a lower overall revenue requirement for our customers."[59] The 1996/97 GRA Settlement as approved by the Board noted that preferred shares were to be backed out of the capital structure as soon as feasible, and stated: "As the preferred shares are refunded, the Board is to consider appropriate common equity levels at future GRA hearings, having regards to the most efficient capital structure for the future."[60]

Over the period from 2003 to 2007, when YECL was not before the Board and all preferred shares had been backed out, the equity component of YECL's capital structure was in the range of 40.87% (2007) to 42.86% (2003). The Application, however, proposes that the equity component now be increased markedly to 47.5% by the end of 2008. If approved, this increased equity component would be a material departure from past regulatory experience in Yukon, increasing costs for ratepayers through both higher ROE versus debt rates as well as the higher income tax costs attracted by the increased equity component.

[57] In 1991: 34.13% equity; 41.51% debt; 22.76 preferred and 1.60% no cost capital. In 1992: 35.17% equity; 39.23% debt; 24.04% preferred and 1.50% no cost capital. In 1993: 35.14% equity; 40.13% debt; 24.02% preferred and 0.71% no cost capital. In 1994: 34.55% equity; 40.40% debt; 24.18% preferred and 0.87% no cost capital.
[58] Ex.C1-16, p2-27: YECL proposed this change, as compared to its existing target ratios of 35% common equity, 40% debt and 25% preferred.
[59] Ibid.
[60] ExC1-11, Tab 5: Order 1996-6, item 3 in the attached Exhibit Number 142.

Similarly, on the matter of the allowed ROE on the equity component, the Application departs from past regulatory experience in Yukon.

As demonstrated in Exhibit C1-12, in the period from 2003 to 2007 when YECL was not before the Board, YECL has routinely earned ROEs in excess of that allowed ATCO Electric (with the exception of 2005). However, in the past when YECL was before it, the Board has consistently allowed a ROE for YECL that is equal to, or below, that of its parent company, despite YECL in each instance in past proceedings providing evidence that the allowed ROE should be in excess of that provided for its parent (APL or ATCO). Exhibit C1-12 notes that for each of 1991, 1992 and 1993 ATCO Electric was allowed to earn an ROE of 13.50%, 13.25% and 11.88% respectively, while the YUB allowed YECL a lower ROE of 12.75%,[61] 12.75%[62] and 11.0% respectively. In 1996, ATCO and YECL each were allowed an ROE of 11.25%.[63]

While Ms. McShane has argued in evidence submitted in the 1991/92 proceeding that Yukon Energy's business risks exceeded that of a high grade utility, the YUB has consistently concluded in past reviews of YECL, that both utilities' business risk "does not differ materially from that of a high grade utility".[64]

By requesting an adjusted ROE of 9.25% (higher than the benchmark 8.75% ROE established for ATCO Electric), YECL's current Application requests that the YUB ignore all established past precedent in this jurisdiction and approve a ROE that is higher than its parent company, along with a revised capital structure with a far higher equity ratio than has historically been approved for either YECL or its parent.

3.5.2 Hybrid AUC Approach to ROE Adopted

The evidence of Ms. McShane recommends adopting as the benchmark ROE applicable to YECL the generic return on equity applicable to Alberta utilities, adjusted for forecast changes in interest rates. She calculates an equity ratio at the upper end of a 47.5% to 52.5% range as fully compensating the business risks to YECL. The generic benchmark ROE used by the AUC for 2008 is 8.75% based on a long-term Canada bond yield of 4.55%. Ms. McShane then departs from the established benchmark.

[61] In Order 1992-2 the Board determined a fair rate of return on the portion of YECL's rate base deemed to be financed by common equity was 12.75% for each of 1991 and 1992 (12.25% for YEC). In its initial application YECL filed for a rate of return equal to APL (YECL's parent at that time), then changed during the course of the proceedings when YECL found it necessary to file Yukon-specific evidence increasing the applied-for rate of return from 14.0% (based APL), to 14.75% to 15%. See Exhibit C1-11 Tab 2 and cross examination of John Landry at transcript Volume 1 page 33, line 21-28 and page 34 lines 1-5.

[62] In Order 1993-8, the Board determined a fair rate of return for YECL of 11% (10.5% for YEC). The companies jointly filed for a rate of return of 13.125% for YECL and 12.625% for YEC. See Exhibit C1-11, Tab 4 pages 56 and 63.

[63] In Order 1996-6 related to the 1996 Negotiated Settlement, the Board approved an ROE of 11.25% for 1996 and 1997.

[64] See for example Exhibit C1-11, Tab 2 page 25.

The rationale for departing from the established AUC benchmarking approach is that, "a common equity ratio of 52.5% represents a material departure from the actual common equity ratio of approximately 40% that has been historically maintained.[65]" To reach 52.5%, it was noted that there would need to be "a material equity infusion" - and, a result of this consideration, the recommended equity ratio was lowered to a more palpable level of 47.5%.[66] It was also noted that since shareholders were unlikely to invest the amount of equity required based on a 8.75% return, a higher return was necessary.[67] Under the proposal, the overall cost of capital (in total dollars of allowed return and income tax costs) remained constant while the lower equity ratio was offset by increasing the return on equity from 8.75% to 9.25%.[68]

The hybrid approach adopted by Ms McShane raises the following issues and concerns:

- **YECL has both a higher common equity level and a higher ROE than comparable Canadian utilities** - Ms McShane argues that the upward adjustment to the ROE is necessary based on the rate of return being lower than comparable U.S. utilities. However, when measured against comparable Canadian utilities (i.e., British Columbia or Alberta), the 8.75% return would be comparable, since it would be derived using methods similar to those employed by the AUC formula or the BCUC formula[69]. As noted in cross-examination[70] Schedule 5, page 1 of the Foster Associates evidence provides six different Alberta-based utilities that have adopted ROEs of 8.75%, with common equity at less than 40% (between 33%and 39%); ATCO Electric Distribution, the most comparable Alberta utility had 37% common equity, 56.1% debt and 6.9% preferred.

- **Last Board approved capital structure was less than 40% common equity -** In cross-examination it was noted that in 1996 the companies agreed to back

[65] As set out at page 36, lines 944-95 of the evidence submitted by Foster Associates.
[66] Transcript Volume 2, page 192 liens 18 to 26.
[67] See page 36, lines 949 to 956 and Transcript volume 2, page 197 liens27-30 and page 198 lines 1 to 15;
At page 36 lines 949 to 956 the evidence of Ms. McShane notes her concern with the AUC benchmarking approach, i.e., that it produces a relatively low benchmark ROE: "While the shareholders may be willing to accept the Alberta benchmark return on equity as a point of departure for setting the allowed return on equity for Yukon Electrical, the benchmark return on equity is viewed as relatively low. The very fact that shareholders in Yukon Electrical (as well as shareholders in other Canadian utilities with similar allowed returns) consider the allowed returns for Canadian utilities to be to [sic] low to be compatible with the fair return standard begs the question of why utility investors would want to invest additional equity in order to have the opportunity to earn an inadequate return."
[68] Footnote 34 at page 37 of Ms McShane's evidence notes that the 9.25% is "based on a cost of debt equity to the 4.55% forecast 30-year Long Canada yield plus the April 2008 indicated spread for a new 30-year CU Inc. debt issue of 160 basis points, and the 2009 statutory corporation income tax rate of 34%."
[69] Transcript Volume 2 Page 198, lines 19-29.
[70] Transcript Volume 2, page 202, lines 21-27 and page 203, lines 1-8.

preferred shares out of their capital structure and that the Board would consider the appropriate level of common equity at future proceedings, “having regard to the most efficient capital structure for the future.” Exhibit C1-17 provides a summary of the capital structure approved by the Board up to 1996/97 and the actual levels of debt and equity experienced (with preferred shares eliminated) since 1999. Over the past 12 years, the equity ratio has increased from 35-37% as last approved by the Board in 1996 to a range between 41% to 43% experienced between 2003 to 2007. YECL’s equity is increasing by approximately $4 million per year. Compared to an annual net income of less than $2 million, forecasts for the test years appear to be based on YECL financing the utility by suspending dividends, and securing new share capital at 9.25%. The massive increase beyond the 40% level has never been considered or approved by the Board.

It was further noted in cross-examination that common equity is the most expensive component in the capital structure, with debt the least expensive component (depending on the state of the preferred market).[71]

In summary, the Application proposes the Board now consider adopting a hybrid of an AUC approach for ROE determination different from anything that the Board has considered to date in Yukon. Aside from the specific issues noted, it remains unclear why consideration of this AUC hybrid approach helps the Board in the context of its Yukon regulation, particularly at a time when it appears that the AUC will be reviewing its benchmarking.

Historically, the Board has been informed as to the allowed ROE and equity structure of YECL’s parent, and approved an allowed ROE and equity capital structure for YECL equal to, or less, that allowed for its parent. On that basis, and on the evidence, the allowed ROE for YECL in this Application should not exceed 8.75% and its equity ratio also should not exceed 40%.

3.5.3 BCUC Approach to ROE Ignored

In contrast to the AUC hybrid approach, the Board has past experience with the BCUC approach to setting a benchmark ROE.

For the 2005 Required Revenues and Related Matters Application, YEC used a BCUC benchmark ROE, adding a risk premium based on business risks specific to YEC. As cited at the 2005 hearing, this approach sets the risk for a benchmark “low risk” utility

[71] Transcript Volume 2, page 203, lines 25-28 and page 204, lines 1-4.

based on long Canada bond yields plus an equity premium of 350 basis points; the approach also allows for annual adjustment of this benchmark. Where appropriate, each individual utility is assessed a risk premium based on individual business and financial risks above the benchmark utility. At the 2005 proceeding it was determined that 52 basis points over the BCUC benchmark utility was an appropriate risk premium for Yukon Energy.[72]

Given YECL's involvement in the 2005 Required Revenues and Related Matters hearing, YECL acknowledged an awareness of the BCUC approach to determining ROE and Yukon Energy's rationale for utilizing this approach, i.e., to reduce regulatory costs. YECL acknowledged that it did not consider using the BCUC approach for determining ROE.[73] However, it was noted by Ms. McShane[74] that, "each approach can be equally valid, as long as there is sort of an after-the-fact testing to make sure the results are internally consistent."

As noted in cross examination of Ms. McShane, both the BCUC benchmarking method and the AUC method are "equally valid,"[75] are essentially designed to achieve similar purposes, that the formulas to get from one year to the next are "virtually identical," and that the BCUC approach results in a lower benchmark ROE than AUC ("about 12 basis points").[76] The fundamental difference between the two approaches has been confirmed to be their treatment of the utility's capital structure: BCUC accepts the capital structure of the utility as-is and applies a risk premium to a benchmark ROE, while AUC uses the unadjusted benchmark ROE and adjusts the capital structure to account for differences between utilities.

It is useful for the Board to consider, based on the evidence, how the BCUC approach would apply to YECL's Application.

YECL is a low risk utility[77] that has managed to perform well since it was last publically reviewed by the Board 10 years ago.[78] As has been acknowledged in evidence in past

[72] Order 2005-12, Appendix A at page 43-45: The Board determined that the rate of return on common equity was reasonable given the level of risk in relation to other utilities within their peer group and that using the BCUC automated adjustment mechanism as a proxy of rate of return on equity did not impose a precedent in Yukon and was an expedient means of determining return for the test year.
[73] Transcript, Volume 1, page 30, lines 11-14.
[74] Transcript Volume 2, page 191.
[75] Ibid.
[76] Transcript, page 190, lines 11-16.
[77] Transcript Volume 2, page 206 lines 4-7 Ms. McShane acknowledges that relative to YECL, YEC has more risk.
[78] In 2007 YECL earned a return on rate base between 10.76% and 10.36% (2007 Key Performance Indicators (March 31, 2008 at page 6). By comparison, in Letter No. L-75-06 the BCUC provided an allowable ROE of 8.37% for a low risk benchmark utility for

proceedings and in the current proceeding, Yukon Energy is exposed to greater business risks than YECL based on the following considerations:[79]

- As noted in evidence submitted in the 1991 proceeding, "a utility with relative high industrial sales is riskier than one with a balanced customer base due to greater volatility in industrial sales over the business cycle." YEC primarily services industrial customers in the Yukon, while YECL is a distribution utility that primarily provides service to residential and general service customers. In the present proceeding Ms. McShane noted that providing service to Minto mine would primarily affect YEC, and any potential affect on YECL would be indirect.[80]
- As noted in evidence in 1991 and re-affirmed by Ms McShane at the current hearing, generators and transmitters are exposed to more risk than distributors.[81]

Based on the above considerations, the BCUC risk premium for YECL would be lower than the 52 basis point adjustment that the Board has approved for Yukon Energy.[82] In this regard, a risk premium not exceeding the 40 basis points approved for Fortis BC would be appropriate (Fortis BC is a distribution utility, even though it may have more generation weighting than YECL).

With the 2008 BCUC benchmark ROE of 8.62%, had the BCUC approach been applied to YECL, with a 40 basis point adjustment as proposed above, an allowed ROE of 9.02% for 2008 would result.[83] More importantly, under this approach, the Board would retain the equity structure of YECL at 40% - an approach which, in addition to its simplicity and solid consistency with past Board decisions, would reduce overall return costs and related income tax costs for ratepayers.

3.5.4 Cost of Debt Issues

In order to assess the full costs of allowed return, debt costs also need to be addressed. Two issues of concern are noted with regard to the Application's cost of debt:

2007. If a risk premium equal to that granted YEC was assumed, adding 0.52% (per Order 2005-12), YECL still maintained a higher ROE than similarly situated low risk utilities.

[79] Transcript Volume 2, page 206, lines 4-7.

[80] Transcript Volume 2, Page 205, lines 22-27.

[81] Transcript Volume 2, page 205 13-22.

[82] Board Order 2005-12, page 43, notes that the 52 basis points is midway between the Fortis BC risk premium of 40 basis points and the Pacific Northern Gas risk premium of 65 basis points. At page 45, the Board agreed that YEC likely falls somewhere between the risk premium of these two utilities.

[83] Transcript page 30 reviews this same calculation assuming a 52 basis point risk premium as approved for YEC.

- **Issues with method of calculating interest –** YECL's calculation of interest is not based on interest to be actually incurred in the test years but is based instead on a calculation that takes the average cost rate as at January 1 plus the average cost rate at December 31 divided by 2. This calculation reaches back in time as opposed to looking at interest costs associated with long term debt during the year. When calculating its average interest rate on debt, YECL should instead use the actual interest incurred during the year applied against the mid-year rate base. Based on Schedule 8.3 in the Application (which states dates for each new debt, and allows calculation of actual interest forecast within each test year), and without any adjustment to new debt costs (see below), the true average cost of YECL debt is 6.77% for 2008 (rather than 7.01% as shown) and 6.65% for 2009 (rather than 6.83%).

- **The cost of new debt utilized by YECL is too high –** The cost of new debt assumed by YECL is 6.6% (as noted on Schedule 8.3); however, this is based on the forecast cost of CU debt during the test year (4.55% Long Canada Bond yield forecast, a 200 basis point spread, and 5 basis points for issue costs). Yukon Energy recommends, based on the evidence, that the cost of new debt should be calculated using the same spreads used in Ms. McShane's evidence at page 37, and Canada Long Term Bond Yields of 4.2%; this yield reflects current experience, and is consistent with Canada bond yields as of the last time debt was issued by YECL in 2006 (at that time YECL was able to secure Long Term Debt at 5.07%). YEC-YECL-39(g) provides an updated forecast of long-term Canada bonds to June 2008; the updated forecast for six months to June of 2008 is 4.08%/ 4.1%. Spreads to the latest debt utilized by YECL are less than 200 basis points[84]. Overall, with an adjusted cost of new debt assumed at 6.2% based on the above, and the adjusted average test year interest calculation as recommended above, the average cost of YECL debt in the Application would become 6.77% for 2008 (rather than 7.01% as shown) and 6.61% for 2009 (rather than 6.83%).

3.5.5 Conclusion

Yukon Energy recommends that the allowed YECL ROE for the test years be determined based on either (a) the 8.75% ROE allowed for YECL's parent, or (b) the accepted BCUC benchmarking approach for 2008 with an allowed YECL ROE of 9.02%, as described above. In either case, Yukon Energy recommends that the Board approve a capital structure for YECL with no more than 40% equity.

[84] Transcript, Volume 1, page 128.

The above BCUC approach will materially reduce YEC's allowed return, e.g., by $91,000 in 2008 and $198,000 in 2009. This approach will also reduce YECL's forecast income tax expense charges to ratepayers. By way of example, assuming the 34% income tax rate adopted in the Application, the income tax saving would equal $191,000 given the forecast $371,000 reduction of equity return in 2009 (from $2.216 million in the Application [Schedule 8.1] to $1.845 million assuming 40% equity and a ROE of 9.02%).[85]

4.0 OTHER CONSISTENCY ISSUES

Other consistency issues regarding the Application and Yukon Energy experience and regulation are reviewed in this section regarding the following topics:

- Purchase Power and Sales Forecasts
- Deferral Accounts

4.1 PURCHASE POWER AND SALES FORECASTS

YECL's purchase power forecasts are clearly relevant to Yukon Energy's forecast of wholesales, particularly as regards firm or primary wholesales. Consistency in these forecasts as between the utilities is therefore important. As reviewed below, different issues arise in this regard for primary versus secondary purchase power costs as included in the YECL Application.

4.1.1 Primary Purchase Power Costs and Retail Sales

YECL has in the past consistently forecast purchase power levels that are low compared to actual requirements – as demonstrated in Exhibit C1-18 which compared actual sales from 2003 to 2008 to forecast sales from YECL's business plan. Differences from forecast to actual ranged from 2.7% for 2003 to 4.1% in 2004, 1.4% in 2005, 4.0% in 2006 and 2.4% in 2007. A lower than actual level sales forecast will overstate the revenue requirement for the test years. It was acknowledged by YECL that where the forecast is low and sales are higher, there would be an incremental benefit to YECL through additional sales revenues assuming 90% of sales are on WAF.[86]

When YECL purchase power sales forecasts are compared to actual sales from 2003 to 2007 a pattern of lower forecast sales in the approximate 1.4% to 4.1% range is discerned. This historical pattern may indicate that a lower level of sales has been

[85] The assumptions and calculations in effect correspond to those in Fosters Associates evidence, Table 11 at page 37.
[86] Page 262; 267-68.

forecast for each of the test years, leading to an overestimate of YECL's revenue requirement in the test years.

YEC-YECL-2(e) Revised notes that actual sales in MWH were higher for both 1996 and 1997 than had been forecast for the test years (8,932 MWH or 3.9% higher in 1996 and 3,535 MWh or 1.5% higher in 1997), and revenues were also higher ($1.342 million or 4.8% higher in 1996 and $0.430 million or 1.5% higher in 1997).

For forecasts provided to YEC by YECL for purchase power sales, the actual have been materially higher than what YECL has forecast during those years.[87] Pre-2003 information was not available for review.

4.1.2 Secondary Sales

YECL prepared its GRA using secondary sales forecasts available from Yukon Energy at the time the Application was drafted; however as noted in Exhibit C1-11, Tab 19, Yukon Energy's current forecasts are higher than the initial conservative forecasts provided to YECL earlier in the year.

Compared to Yukon Energy's adjusted secondary sales forecast, YECL's sales forecast shows lower secondary sales by 3,052 MW.h, and 9,029 MW.h in test year 2008 and 2009 respectively. As a result, YECL's forecast lowers revenue at existing rates by approximately $220,000 and $650,000 in test year 2008 and 2009 respectively; corresponding reductions also occur in YECL's forecast secondary energy power purchases of approximately $186,000 in 2008 and $551,000 in 2009. Based on this evidence, if YECL were to adopt Yukon Energy's more recent secondary sales forecasts, the resulting impact would be an overall reduction to YECL's net rate revenue shortfall of $34,000 in 2008 and $99,000 in 2009.

YECL should be directed to change its forecast for secondary sales based on the revised Yukon Energy forecast.

4.2 DEFERRAL ACCOUNTS

The following justification is provided for these accounts (Application, p. 1-5, line 15):

> Ongoing and new deferral accounts meet the typical criteria for the establishment of a deferral account and are required as the costs related to these deferral accounts are:

1. Not under the control of the company and are not reasonably forecastable; or

2. An error in forecasting could produce a loss or gain of a substantial magnitude.

YECL justifies deferral accounts as essentially balancing risk and benefits between YECL and its customers (transcript page 208 lines 15-16). YECL fails to define what a loss or gain of "substantial magnitude" is, but notes in response to YUB-YECL-2(a) that it "a matter of judgement [sic] and would be determined on a case by case basis."

Two deferral account topics are addressed below"

- Proposed Pelly Crossing Deferral Account
- Previous Rate Case Reserve Account

4.2.1 Proposed Pelly Crossing Deferral Account

In its Application (at page 1-5, lines 3-8) YECL notes that since the timing of commencement of grid service to Pelly Crossing is uncertain, and the costs associated with the November 1, 2008 assumption are material, "Yukon Electrical is seeking a deferral account for the incremental costs associated with changes that result from a reliance on the current assumption".

With regard to the proposed Pelly Crossing deferral account, YECL states that the Pelly Crossing Deferral Account "balances risk" related to the timing of the connection of Pelly Crossing to the grid.

YECL confirmed that a deferral account was not established or deemed necessary to manage benefits and risks when Stewart Crossing was being hooked up to the Mayo Dawson grid.[88] It was noted in cross examination that YECL continues to benefit from the connection of Stewart Crossing to the Mayo Dawson grid through the availability of less costly grid electricity compared to escalating diesel prices that would otherwise be incurred.[89] In 2005 the cost reduction would have been roughly $70,000 to $80,000 based on 160,000 litres of fuel purchased at prices of 50 to 65 cents per litre. With the escalation in fuel costs since 2005, the savings accruing to YECL would be even more material.

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[87] Transcript page 266.
[88] Transcript Volume 3, page 284, lines 26-30 and page 285, lines 109.

The Application (at page 4-3) proposes a Pelly Crossing Deferral Account that appears to address only YECL's risks of increased diesel use after November 1, 2008, i.e., Yukon Electrical is seeking a deferral account for the incremental costs associated with a change in the assumption of the connection to the main grid effective November 1, 2008. The proposed calculations for this account all address potential recoveries by YECL if diesel use at Pelly Crossing subsequent to November 1, 2008 exceeds forecasts in the Application (forecast 500 litres in 2008 after November 1, 2008 and 3,000 litres in 2009).

In cross exam with Mr. Landry, Mr. Freeman agreed that if Pelly Crossing is hooked up to the grid sooner that November 1, 2008, the Pelly Crossing deferral account is intended to provide the benefits of this early connection to ratepayers.[90] It is not clear how in fact the account as proposed in the Application would do this; nor is it clear that the account will be closed after such time as Yukon Energy is able to connect Pelly Crossing to the main grid, i.e., the deferral account is not appropriate for addressing anything other than impacts regarding this one critical connection date assumption. Accordingly, if the Board approves this new deferral account, Yukon Energy recommends that the Board direct that it be clarified to enable a true balancing of risks and benefits between ratepayers and YECL as well as for termination of the account after such time as Yukon Energy is able to connect Pelly Crossing to the main grid.

4.2.2 Previous Rate Case Reserve

Based on Yukon Energy's understanding of YECL's previous rate case reserve account, it would appear that YECL's Application should reflect the deferred rate case reserve credits of approximately $450,000 taken into retained earnings in 2005. If correct, this amount would be available today to help offset the current rate case costs.

After the 1996/97 GRA and until 2005, YECL had been allocating approximately $75,000 per year to a reserve account for rate case purposes, accumulating $450,000 by 2005. After the 2005 hearing, the $450,000 amount was removed from the reserve account and taken into retained earnings.[91] YECL justified this treatment on the basis that the 1996/97 GRA was a joint hearing with joint hearing costs.[92] YECL acknowledged that this resulted in a benefit to the company compared to the previous treatment.[93]

[89] Transcript Volume 3 page 283, lines 17-30 and page 284 lines 1-19.
[90] Transcript page 281, line 12-15.
[91] Transcript page 87 -89.
[92] Ibid.
[93] Ibid.

With regard to the rate case reserve YECL has argued for a consistent approach to that taken by Yukon Energy and approved by the Board in 2005. YEC-YECL-45(c) notes that at the time of the 1996/97 proceeding YECL had a rate case reserve but that "in 2005, however, this treatment changed to be consistent with the treatment followed by YEC and supported in Board Order 2005/17." YECL in response to YEC-YECL-45(h) justified the treatment of deferred credits taken into income since 1996 from the rate case reserve on the same basis.

Yukon Energy did not establish a rate case reserve at the time of the 1996/97 GRA. However, YECL did apparently establish such a reserve, which resulted in annual expenses being charged and reported annually to the Board until the reserve was taken into retained earnings in 2005, without review or approval of the Board.

This is a matter for review by the Board to determine if the earlier YECL rate case reserve was, from a regulatory perspective, properly put into retained earnings given that at the time it was a ratepayer account or whether this amount should be properly applied to the Application's rate case costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

P. John Landry
Counsel for Yukon Energy Corporation

October 27, 2008

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