Exhibit C1-11

Tab 1

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company
P.O. BOX 4190, WHITEHORSE, YUKON Y1A 3T4 • TELEPHONE (403) 633-7000 • FAX (403) 668-3965

KLON GOLD CENTE OFFICIAL

RECEIVED NOV 19 1998

November 19, 1998

Mr. Brian Morris, Chair
Yukon Utilities Board
P.O. Box 6070
Whitehorse, Yukon Y1A 5L7

Dear Mr. Morris:

Re: **The Yukon Electrical Company Limited 1998 / 1999 Forecast Revenue Requirement**

As committed to during the July 8 and 9 hearing, please find enclosed complete regulatory schedules for The Yukon Electrical Company Limited for the years 1996 through 1999.

If you should have any questions, please give me a call.

Sincerely,

THE YUKON ELECTRICAL COMPANY LIMITED

John Carroll
General Manager

Encl.

The Yukon Electrical Company Limited
Schedule Index

Schedule 4
11/19/98

The Yukon Electrical Company Limited
Cost of Capital Calculation
1996 and 1997 Actual
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
1	Actual for 1996						
2	Long-term debt		13,700	42.71%	12,718	9.04%	1,149
3	Preferred shares		6,440	20.08%	5,978	6.77%	405
4	Common stock		11,739	36.60%	10,897	13.03%	1,420
5	No cost capital		198	0.62%	184	0.00%	0
6	Total	S.5 L.3	32,077	100.00%	29,777	9.99%	2,974
7	Actual for 1997						
8	Long-term debt		15,400	46.39%	14,540	8.65%	1,258
9	Preferred shares		4,940	14.88%	4,664	6.28%	293
10	Common stock		12,461	37.53%	11,765	11.60%	1,365
11	No cost capital		399	1.20%	376	0.00%	0
12	Total	S.5 L.3	33,200	100.00%	31,346	9.30%	2,915

Tab 2

YUKON UTILITIES BOARD

DECISION 1992-2

JANUARY 17, 1992

RE

YUKON ELECTRICAL COMPANY LIMITED

4. FAIR RETURN ON RATE BASE

4.1 General

Having determined the rate base for YECL, the Board is also required pursuant to Section 32(2) of the Public Utilities Act to "fix a fair return on the rate base".

> " (2) The board, by order, shall fix a fair return on the rate base.
>
> (3) In determining a rate base the board shall give due consideration to the cost of the property when first devoted to public utility use, to prudent acquisition cost less depreciation, amortization or depletion, and to necessary working capital.
>
> (4) In fixing the fair return that the public utility is entitled to earn on the rate base, the board shall give due consideration to all those facts that in the opinion of the board are relevant.
>
> (5) Notwithstanding the other provisions of this section, the board may adopt any just and reasonable basis for determining a method of calculating a fair return on property that is being constructed or that has been constructed or acquired but is not yet being used to provide service to the public."

In fixing the fair return on rate base, the Board considers it appropriate to take into consideration the rate of return applicable to each component of the Company's capital structure which it considers to be financing the rate base.

Generally, the Board considers that a fair return on rate base is a return that will result in providing the customers of the utility with the lowest utility rates practicable consistent with the utility's duty to furnish safe, adequate and proper service on an on-going basis.

The return should be sufficient to enable the utility to maintain its property, plant and equipment in an effective and efficient operating condition, and at the same time enable the utility to maintain its financial integrity and thus enable it to obtain necessary capital on reasonable terms.

4.2 Capital Structure

Tab 5, Schedule 4 of YECL's Application sets out YECL's proposed capital structure for 1991 and 1992.

	Midyear Balance 1991 (000's)	1991	Midyear Balance 1992 (000's)	1992
Long Term Debt	$ 9,011	41.51%	$10,511	39.23%
Preferred Stock	4,940	22.76%	6,440	24.04%
Common Stock	7,408	34.13%	9,422	35.17%
No Cost Capital	347	1.60%	418	1.56%
	$21,706	100.00%	$26,791	100.00%

The Board accepts for purposes of this Decision YECL's proposed capital structure.

4.3 Cost of Debt

As noted by the City of Whitehorse in its argument, YECL proposed to raise $3 million through a debt issue in 1992 at a forecast coupon rate of 10.91%. The City of Whitehorse also noted that Canadian Utilities Limited had recently issued debt with a coupon rate of 9.92%. Given the significant reduction in long term interest rates, the Board will allow a rate of 10.0% to be applied to YECL's forecast 1992 debt issue. The Board has recalculated the embedded cost of debt for 1992 as 11.302%.

4.4 Rate of Return on Common Equity

4.4.1 Requested Rate - Fair Rate of Return

In its initial Application filed June 6, 1991, YECL requested a fair rate of return on rate base deemed to be financed by equity of 14% for each of the years 1991 and 1992.

YECL's requested fair rate of return was based on APL's requested rate of return for the years 1991 and 1992. During the course of the proceedings the Company found it necessary to file Yukon specific evidence with respect to the fair rate of return on common equity.

Two witnesses appeared on the matter of a fair rate of return. The applicant(s) presented Ms. K.C. McShane, a vice-president with the Washington based consulting firm Foster Associates. Curragh Resources Inc. presented Mr. David Parcell, a vice-president with the Virginia based firm Technical Associates Incorporated.

4.4.1.1 Evidence of Ms. McShane

Ms. McShane, YECL's expert witness, recommended a fair rate of return of 14.75% to 15% for each of the years 1991 and 1992. The Company adjusted its 1992 revenue requirement based on Ms. McShane's Yukon specific evidence and requested a 14.75% rate of return on common equity in 1992.

Ms. McShane relied upon three tests in developing her rate of return recommendation(s): the comparable earnings test, the Discounted Cash Flow ("DCF") and equity risk premium. Ms. McShane acknowledged that the results of each test vary and that the weight given to each is a matter of judgement. Ms. McShane assigned a weight of 50% to her comparable earnings results and 50% weight to her DCF and equity risk premium results taken together.

With respect to Ms. McShane's application of the comparable earnings test, the Board is basically concerned with the nature of the data on which it is based. The Board recognizes that the rate of return on common equity calculation is based on earnings values and book values which reflect the application of generally accepted accounting principles. However, the Board is concerned that the application of these principles may well result in values which, in fact, have not accurately reflected the corporation's earnings in an economic sense. The Board is led to this conclusion by, among other things, Ms. McShane's acknowledgement that a major weakness of the test may be distortion of book values in earlier years. The Board is also led to this conclusion by the significant differences, on average, between per share market prices and book values for Ms. McShane's sample companies.

Ms. McShane's analysis of price level adjusted book values supports the conclusion that substantial differences exist between the accounting values and price level adjusted values. This being the case, the Board is led to the conclusion that historical rates of return on common equity may well overstate the rate of return prospectively achievable by these companies.

Ms. McShane's position is that the values based on historical accounting data are appropriate because the fair rate of return is to be applied to utilities regulated on an original cost basis. This contention has a certain appeal; however, the Board is not convinced that the data for industrial corporations which are subject to wide variations in capital intensity and, in all likelihood, in asset vintages, will average out to provide values which fit closely enough with the economic circumstances of the two utilities that are the subject of this Decision.

While the Board remains concerned with the limitations of comparable earnings data for a determination of the appropriate level of the fair return, the Board is of the view that these data provide an indication of the trend in rates of return. The Board notes the reductions made by Ms. McShane in her estimates of 1991 rates of return for her industrial sample during the course of her various appearances in 1991. In addition, the Board is concerned that Ms. McShane's expectation concerning the possible extent of an economic recovery is somewhat optimistic. Accordingly, the Board is of the view that Ms. McShane's estimate of 1992 corporate profitability is overstated.

With respect to Ms. McShane's application of the DCF test, the Board notes that Ms. McShane raised her estimate of growth (although data the same) from her APL estimate because of the decline in the dividend yield component. Ms. McShane acknowledged that the decline in the dividend yield could also be attributed to a decline in the rate of return required by investors in common shares. In view of the contemporaneous decline in interest rates and no clear signs of improved corporate profitability, the Board feels that the decline in the dividend yield is more likely a manifestation of a decline in Investors' Required Rates of Return ("IRR"). Accordingly the Board believes that Ms. McShane's DCF estimates overstate the IRR.

In developing her estimate of the IRR based on the equity risk premium method, Ms. McShane utilized a long term Government of Canada bond rate of 9.75%. At the time of the hearing, yields on Government of Canada bonds 10 years and over to maturity were in the order of 8.98%. Notwithstanding this fact, Ms. McShane felt that her 9.75% value continued to be appropriate given her expectation that an economic recovery would soon materialize. In her view, this would rekindle investors' concerns regarding inflation and bond yields would increase accordingly. In addition, Ms. McShane stated that her 9.75% estimate was related to a longer term bond typically used a benchmark for pricing corporate bonds.

As indicated earlier, the Board is concerned that Ms. McShane's expectation as to the possible extent of an economic recovery is overly optimistic. Accordingly, it is the Board's view that, given present circumstances, the current level of Government of Canada bond yields should be given considerable weight in the application of the equity risk premium test for the 1992 test year. Further, for the purposes of this test, the Board does not accept Ms. McShane's position that the relevant Government of Canada bond is a particular issue used as a benchmark for the pricing of new corporate bond issues. In the Board's view, the relevant base yield for the equity risk premium test is the average yield on all long term Government of Canada bonds available to investors. These represent the long term investment opportunities foregone by investors who choose to invest in common stocks. Moreover, their average value is available from an independent government agency.

In determining the fair rate of return from her application of the DCF and equity risk premium tests, Ms. McShane adds a flotation cost component to her estimate of the

IRR. She incorporates this increment to ensure that the financial integrity of the common shareholders' investment is maintained. Ms. McShane's increment would, in her view, permit the utility's shares, if publicly traded, to trade under normal conditions at prices in the order of 120% of their book value. In addition, share prices would be expected to remain above book value whenever new shares were issued.

Ms. McShane stated that the business risk of YECL exceeded that of a high grade utility attributing the difference to higher market demand risk and a higher supply risk.

She acknowledged on cross-examination that YECL's load did not have a high concentration of industrial sales, however, she indicated that YECL's market demand risk was higher due to the reliance of YECL's customers on the mining industry.

Ms. McShane acknowledged that no Board or Commission had allowed a common equity rate of return equal to her recommended fair rate of return. Nevertheless, none of the utilities for which she had testified had market prices below their book values.

4.4.1.2 Evidence of Mr. Parcell

Mr. David Parcell, appearing on behalf of Curragh Resources Inc., confined his analysis to the application of the comparable earnings and equity risk premium tests. It was his position that he was unable to apply the DCF test in the Canadian context due to the absence of "pure" utilities in Canada.

Mr. Parcell acknowledged that both tests require the application of judgement. For his application of the comparable earnings test, Mr. Parcell indicated that judgement must be applied in developing a procedure to adjust the results obtained for industrial companies. In undertaking his comparable earnings analysis, Mr. Parcell relied upon two pieces of information, both of which incorporate the common book equity per share derived from each corporation's financial statements. The first item is the rate of return on common equity; the second is the ratio of per share market price to per share common book equity. Mr. Parcell was asked by the Board's consultant to comment on the implications of several accounting issues, all of which have implications for the values utilized by Mr. Parcell. Notwithstanding Mr. Parcell's responses, the Board is concerned that the accounting issues which impact on the interpretation of these data were not adequately addressed, particularly given that Mr. Parcell's market-to-book adjustment process also utilizes such data.

The Board is concerned with the efficacy of Mr. Parcell's methodology for estimating equity risk premiums. The Board finds it difficult to accept values for individual years as low as those estimated by Mr. Parcell for 1989 and 1990.

While the Board recognizes that Mr. Parcell relied upon the average for all years, the Board is not convinced that the individual values necessarily "average out" to a value in which sufficient confidence can be placed. Moreover, recognizing that the process is directed to establishing a fair rate of return for the 1992 test year, the Board would have expected, given Mr. Parcell's position that the premium depends on the stage reached in the business cycle, that Mr. Parcell would have established the value appropriate to the likely to be reached stage in the business cycle in 1992.

With respect to the degree of confidence to be placed in Mr. Parcell's beta value adjustments, Mr. Parcell acknowledged that he had not examined the "standard error of estimate" of the regression estimates. The Board notes that the "R-squared" values reported by Ms. McShane for her beta values (the latter utilized by Mr. Parcell in his testimony), are very low. The Board considers that these values indicate that Mr. Parcell's adjustment process - relying as it does on only one measure of risk - is built on a statistical foundation of questionable worth.

4.4.2 Board's Position

After giving due consideration to the evidence and argument presented in connection with the general rate application, the Board has concluded that a fair rate of return on common equity of a high grade utility with a common equity ratio of approximately 35% is 12.75% for each of the years 1991 and 1992.

The Board has also concluded that YECL's business risk does not differ materially from that of a high grade utility. The Board considers that there is ample opportunity for YECL to make application to the Board for rate relief in the event that the Company perceives that the closure of a mine would have a detrimental effect on its revenues.

Accordingly, the Board has determined that a fair rate of return, on the portion of YECL's rate based deemed to be financed by common equity, is 12.75% for each of the tests years 1991 and 1992.

5. ELECTRIC UTILITY REVENUE REQUIREMENT

5.1 Fuel Expense

5.1.1 Fuel Price

YECL forecast an average cost per litre of fuel of 31.0 cents and 32.7 cents for 1991 and 1992 respectively. During cross-examination Company witnesses indicated that the 1991 and 1992 fuel prices were forecast to increase by 5% and 6% respectively. These increases were based on the forecast inflation rate plus 1%.

During cross-examination the Company witnesses stated the following with respect to the forecast cost of fuel for 1991:

> "Due to the very high prices resulting from the Gulf War in the later part of 1990 and the effects that are still being felt in the early

Tab 3

YUKON UTILITIES BOARD

DECISION 1992-1

JANUARY 17, 1992

RE

YUKON ENERGY CORPORATION

inadvertently not deducted from retained earnings for purposes of determining the 1991 and 1992 revenue requirements. YEC advised that expected Bill Relief Program Payments are $193,538 and $467,157 for 1991 and 1992 respectively.

For the purpose of this Decision the Board has reduced YEC's retained earnings by $193,538 and $467,157 for 1991 and 1992 respectively to reflect the impact of the Bill Relief Program.

4.3 Rate of Return on Common Equity

4.3.1 Introduction

Paragraph 2 of Order of Council, 1991/62, states that:

> "2. The Board must include in the rates of Yukon Energy Corporation provision to recover a normal commercial return on Yukon Energy Corporation's equity, less one-half of one percent (.5%)."

Two witnesses appeared on the matter of a fair rate of return. The applicant(s) presented Ms. K.C. McShane, a vice-president with the Washington based consulting firm Foster Associates. Curragh Resources Inc. presented Mr. David Parcell, a vice-president with the Virginia based firm, Technical Associates Incorporated.

YEC in its evidence stated that:

> "YEC has determined that the rate of return requested by YECL represents a fair and reasonable normal commercial rate of return, and YEC will rely on the testimony of YECL with respect to the normal commercial rate of return submitted in the GRA for 1991 and 1992. In accordance with the directive, YEC has set

> its rate of return in this Application at one half of one per cent less than the rate requested by YECL." (Page 2-24)

During cross-examination by intervenors YEC's witness, Ms. McShane, indicated that her interpretation of the term "normal commercial return" is:

> "... basically the same as what would be considered the fair return on equity for any private utility." (Tr.149)

The City of Whitehorse in its argument submitted that the phrase "normal commercial return" refers to what the return would be for businesses in Yukon.

During cross-examination Ms. McShane explained that it is not appropriate to compare YEC's return to the returns of other businesses in Yukon because capital is raised in national markets and ultimately the relative cost of equity or debt is determined in national and even international markets.

YEC in its reply argument submitted that the City of Whitehorse's interpretation of Order in Council, 1991/62, is without merit. YEC submitted that Section 2 of the Order in Council must be read in conjunction with Section 4 which states:

> "4. Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with normal principles applicable in Canada for similar utilities." (Tab 12, Page 2)

The Board notes that implicit in evidence submitted by both Ms. McShane and Mr. Parcell is the assumption that "normal commercial return" is equivalent to the fair return on equity for any investor owned public utility.

The Board, for the purposes of this Decision, has interpreted "normal commercial return" to mean "fair return" on equity for a investor owned public utility with similar risk characteristics.

4.3.2 Fair Rate of Return on Common Equity

In its initial Application filed June 6, 1991, YEC requested a rate of return on rate base deemed to be financed by common equity of 13.5% for each of the years 1991 and 1992. YEC's request was based on YECL's requested rate of return on equity of 14% for 1991 and 1992 less a downward adjustment of 0.5% to reflect the direction contained in Order-in-Council, 1991/62.

YECL's initial requested rate of return was based on APL's (YECL's parent) requested rate of return for the years 1991 and 1992 before the Public Utilities Board, Alberta. During the course of the proceedings YECL and YEC filed evidence specific to YECL and YEC with respect to the fair rate of return on common equity.

4.3.2.1 Evidence of Ms. McShane

Ms. McShane, YEC's witness, recommended a fair rate of return of 14.75% to 15% for YECL for each of the years 1991 and 1992. YEC amended its 1992 revenue requirement based on

Ms. McShane's Yukon specific evidence and requested a 14.25% rate of return on common equity.

Ms. McShane relied upon three tests in developing her rate of return recommendation(s): the comparable earnings test, the Discounted Cash Flow ("DCF") and equity risk premium. Ms. McShane acknowledged that the results of each test vary and that the weight given to each is a matter of judgement. Ms. McShane assigned a weight of 50% to her comparable earnings results and 50% weight to her DCF and equity risk premium results taken together.

With respect to Ms. McShane's application of the comparable earnings test, the Board is basically concerned with the nature of the data on which it is based. The Board recognizes that the rate of return on common equity calculation is based on earnings values and book values which reflect the application of generally accepted accounting principles. However, the Board is concerned that the application of these principles may well result in values which, in fact, have not accurately reflected the corporation's earnings in an economic sense. The Board is led to this conclusion by, among other things, Ms. McShane's acknowledgement that a major weakness of the test may be distortion of book values in earlier years. The Board is also led to this conclusion by the significant differences, on average, between per share market prices and book values for Ms. McShane's sample companies.

Ms. McShane's analysis of price level adjusted book values supports the conclusion that substantial differences exist between the accounting values and price level adjusted values. This being the case, the Board is led to the conclusion that historical rates of return on common equity may well overstate the rate of return prospectively achievable by these companies.

Ms. McShane's position is that the values based on historical accounting data are appropriate because the fair rate of return is to be applied to utilities regulated on a original cost basis. This contention has a certain appeal; however, the Board is not convinced that the data for industrial corporations which are subject to wide variations in capital intensity and, in all likelihood, in asset vintages, will average out to provide values which fit closely enough with the economic circumstances of the two utilities that are the subject of this Decision.

While the Board remains concerned with the limitations of comparable earnings data for a determination of the appropriate level of the fair return, the Board is of the view that these data provide an indication of the trend in rates of return. The Board notes the reductions made by Ms. McShane in her estimates of 1991 rates of return for her industrial sample during the course of her various appearances in 1991. In addition, the Board is concerned that Ms. McShane's expectation concerning the possible extent of an economic recovery is somewhat optimistic. Accordingly, the Board is of the view that Ms. McShane's estimate of 1992 corporate profitability is overstated.

With respect to Ms. McShane's application of the DCF test, the Board notes that Ms. McShane raised her estimate of growth (although data the same) from her APL estimate because of the decline in the dividend yield component. Ms. McShane acknowledged that the decline in the dividend yield could also be attributed to a decline in the rate of return required by investors in common shares. In view of the contemporaneous decline in interest rates and no clear signs of improved corporate profitability, the Board feels that the decline in the dividend yield is more likely a manifestation of a decline in Investors' Required Rates of Return ("IRR"). Accordingly the Board believes that Ms. McShane's DCF estimates overstate the IRR.

In developing her estimate of the IRR based on the equity risk premium method, Ms. McShane utilized a long term Government of Canada bond rate of 9.75%. At the time of the hearing, yields on Government of Canada bonds 10 years and over to maturity were in the order of 8.98%. Notwithstanding this fact, Ms. McShane felt that her 9.75% value continued to be appropriate given her expectation that an economic recovery would soon materialize. In her view, this would rekindle investors' concerns regarding inflation and bond yields would increase accordingly. In addition, Ms. McShane stated that her 9.75% estimate was related to a longer term bond typically used a benchmark for pricing corporate bonds.

As indicated earlier, the Board is concerned that Ms McShane's expectation as to the possible extent of an economic recovery is overly optimistic. Accordingly, it is the Board's view that, given present circumstances, the current level of Government of Canada bond yields should be given considerable weight in the application of the equity risk premium test for the 1992 test year. Further, for the purposes of this test, the Board does not accept Ms. McShane's position that the relevant Government of Canada bond is a particular issue used as a benchmark for the pricing of new corporate bond issues. In the Board's view, the relevant base yield for the equity risk premium test is the average yield on all long term Government of Canada bonds available to investors. These represent the long term investment opportunities foregone by investors who choose to invest in common stocks. Moreover their average value is available from an independent government agency.

In determining the fair rate of return from her application of the DCF and equity risk premium tests, Ms. McShane adds a flotation cost component to her estimate of the IRR. She incorporates this increment to ensure that the financial integrity of the common shareholders' investment is maintained. Ms. McShane's increment would, in her view, permit the utility's shares, if publicly traded, to trade under normal conditions at prices in the order of 120% of their book value. In addition, share prices would be expected to remain above book value whenever new shares were issued.

Ms. McShane stated that the business risk of YEC exceeded that of a high grade utility attributing the difference to higher market demand risks and a higher supply risk. In particular, she stated a utility with relative high industrial sales is viewed as being more risky than one with a balanced customer base due to the greater volatility of industrial sales over the business cycle. She considered that YEC's dependence on Curragh Resources Inc. exposes the investor to significant risk and quantified this risk as being greater than that faced by investors in a high grade utility such as APL.

Ms. McShane noted that mitigating factors relative to YEC's risk included a $40 million flexible term note payable to the Government of Canada and the fact that YEC's equity ratio is higher than most high grade utilities.

Ms. McShane acknowledged on cross-examination that her estimate of the impact of a shutdown of the Curragh mine was based on the assumption that rates to other customers to compensate for reduced revenues from the mine would not be introduced for a full year after the mine closure. She also acknowledged that rates to other customers may possibly change sooner then one year after the mine is shut down.

Ms. McShane acknowledged that no Board or Commission had allowed a common equity rate of return equal to her recommended fair rate of return. Nevertheless, none of the utilities for which she had testified had market prices below their book values.

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4.3.2.2 Evidence of Mr. Parcell

Mr. David Parcell, appearing on behalf of Curragh Resources Inc., confined his analysis to the application of the comparable earnings and equity risk premium tests. It was his position that he was unable to apply the DCF test in the Canadian context due to the absence of "pure" utilities in Canada.

Mr. Parcell acknowledged that both tests require the application of judgement. For his application of the comparable earnings test, Mr. Parcell indicated that judgement must be applied in developing a procedure to adjust the results obtained for industrial companies. In undertaking his comparable earnings analysis, Mr. Parcell relied upon two pieces of information, both of which incorporate the common book equity per share derived from each corporation's financial statements. The first item is the rate of return on common equity; the second is the ratio of per share market price to per share common book equity. Mr. Parcell was asked by the Board's consultant to comment on the implications of several accounting issues, all of which have implications for the values utilized by Mr. Parcell. Notwithstanding Mr. Parcell's responses, the Board is concerned that the accounting issues which impact on the interpretation of these data were not adequately addressed, particularly given that Mr. Parcell's market-to-book adjustment process also utilizes such data.

The Board is concerned with the efficacy of Mr. Parcell's methodology for estimating equity risk premiums. The Board finds it difficult to accept values for individual years as low as those estimated by Mr. Parcell for 1989 and 1990. While the Board recognizes that Mr. Parcell relied upon the average for all years, the Board is not convinced that the individual values necessarily "average out" to a value in which sufficient confidence can be placed. Moreover, recognizing that the process is directed to establishing a fair rate of return for the 1992 test year, the Board would have expected (given Mr. Parcell's position that the premium depends on the stage reached in the business cycle) that Mr. Parcell would have established the value appropriate to the stage likely to be reached in the business cycle in 1992.

With respect to the degree of confidence to be placed in Mr. Parcell's beta value adjustments, Mr. Parcell acknowledged that he had not examined the "standard error of estimate" of the regression estimates. The Board notes that the "R-squared" values reported by Ms. McShane for her beta values (the latter utilized by Mr. Parcell in his testimony), are very low. The Board considers that these values indicate that Mr. Parcell's adjustment process - relying as it does on only one measure of risk - is built on a statistical foundation of questionable worth.

4.3.3 Board's Position

After giving due consideration to the evidence and argument presented in connection with the general rate application, the Board has concluded that a fair rate of return on common equity of a high grade utility with a common equity ratio of approximately 35% is 12.75% for each of the years 1991 and 1992.

The Board has also concluded that YEC's business risk does not differ materially from that of a high grade utility. The Board notes that YEC's common equity ratio is expected to be approximately 41% and 42% for the test years 1991 and 1992 respectively.

Accordingly, the Board has determined that a fair rate of return, on the portion of YEC's rate based deemed to be financed by common equity, is 12.75% for each of the tests years 1991 and 1992. After applying the provisions of Section 2 of Order-in-Council, 1991/62 the Board has determined a fair rate of return on the portion of YEC's rate base deemed to be financed by common equity to be 12.25% for each of the test years 1991 and 1992.

Tab 4

YUKON UTILITIES BOARD

DECISION 1993-8

NOVEMBER 23, 1993

RE

YUKON ENERGY CORPORATION AND
THE YUKON ELECTRICAL COMPANY LIMITED

4.5 RATE OF RETURN ON COMMON EQUITY

4.5.1 REQUESTED RATE - FAIR RATE OF RETURN

In their revised application, the Companies requested a rate of return on rate base, deemed to be financed by equity, of 13.125% for each of the years 1993 and 1994 for YECL. Paragraph 2 of Order-in-Council 1991/62 states that:

> "The Board must include in the rates of Yukon Energy Corporation provision to recover a normal commercial return on Yukon Energy Corporation's equity, less one half of one percent (.5%)."

Accordingly, the Companies have requested a rate of return of 12.625% for YEC.

Two witnesses appeared on the matter of a fair rate of return. The applicants presented Ms. K.C. McShane, a vice-president with the Washington based consulting firm of Foster Associates, Inc. Curragh presented Mr. D.C. Parcell, a vice-president with the Virginia based firm of Technical Associates Incorporated.

4.5.2 EVIDENCE OF MS. MCSHANE

Ms. McShane, YECL's expert witness, recommended a fair rate of return on common equity in the range of 13.0% to 13.9% for each of the Test Years 1993 and 1994.

Ms. McShane relied on three tests in developing her rate of return recommendations: the comparable earnings test, the discounted cash flow ("DCF") and equity risk premium.

In her comparable earnings test, Ms. McShane analyzed realized returns of low risk industrials over the past business cycle and then estimated a likely range of returns for these companies in the next cycle. She concluded that the returns for low risk industrials would fall within the range of 12.5% to 13.5%. She then applied a downward adjustment of 30 basis points to estimate a return on common equity for a high grade utility which resulted in a range of 12.25% to 13.25%. A further adjustment of 50 to 75 basis points was added to her estimate for local risk. Ms. McShane's comparable earnings test resulted in a risk adjusted return of 13.0% to 13.75%.

In her DCF test, Ms. McShane used the same group of low risk industrial companies as were selected for her comparable earnings test. She estimated that the average dividend yield and average long term growth rates over the last business cycle were 2.8% and 9.0%, respectively. This resulted in a "bare bones" cost estimate of 11.8%. Ms. McShane adjusted this "bare bones" estimate by the same 30 basis points and 50 to 75 basis points, referred to above, to raise the "bare bones" cost estimate for the Companies to 12.0% to 12.25%. Ms. McShane then increased the 12.0% to 12.25% for financing flexibility, to achieve a market-to-book ratio of 115%, raising the DCF return requirement for the Companies to 13.1% to 13.4%.

In her risk premium analysis, Ms. McShane projected that the average yield on long term Government of Canada bonds (30 year) for 1993 and 1994 would range from 8.0% to 8.5%. She concluded that the risk premium for a high grade utility would be in the range of 3.5% to 4.0%. Her "bare bones" cost of capital resulted in a range of 11.75% to 12.25%. To this, she added 50 to 75 basis points for local risk for the Companies. A further adjustment for financing flexibility to achieve a market-to-book ratio of 115% was made, resulting in an adjusted return for the Companies of 13.7% to 13.9% based on her risk premium test.

4.5.3 EVIDENCE OF MR. PARCELL

Mr. Parcell, appearing on behalf of Curragh, presented the following four analyses: comparable earnings, risk premium, discounted cash flow, and a capital asset pricing model ("CAPM").

In Mr. Parcell's comparable earnings analysis he noted that the expected earnings of low risk industrials are 11.5% to 13.5%. He concluded that:

> "... the risks of YECL and YEC should be the same as those faced by Alberta Power ('APL') and Canadian Utilities ('CU'), since all the capital of YECL is provided by its parent companies. Both APL and CU are regarded as low-risk utilities." (Page 16, Curragh Argument)

Mr. Parcell indicated that interest rates and inflation declined during the last business cycle (1983-1991), resulting in cost of capital for the current business cycle which is lower than the previous business cycle and, further, he expected lower profits in this cycle than in the previous business cycle. Mr. Parcell then made two downward adjustments to the expected returns for low risk industrial: (1) 100 basis points for the low risk of utilities; and (2) 100 basis points for high market-to-book ratio, which accompanied the industrial return on equity ("ROE").

Mr. Parcell's comparable earnings test resulted in a required return on equity of 11.5%.

In his risk premium test, Mr. Parcell compared the ROE levels of high grade utilities with annual yields on long term Government of Canada bonds and determined that a risk premium of 1.5% to 2.5% was appropriate for high grade utilities. Using an 8.3% yield on the long term Canada bonds, the average of the first 5 months of 1993, Mr. Parcell's risk premium test resulted in a cost of equity in the range of 9.8% to 10.8%.

In Mr. Parcell's DCF test he analyzed a group of 25 low risk Canadian industrials and a group of 5 Canadian utilities. He concluded that the DCF cost of capital is in the range of 11.0% to 11.5%.

Mr. Parcell employed the same two groups of companies as in his DCF analysis. In his CAPM analysis Mr. Parcell used, as the risk-free rate, the long term Government of Canada bond yield average for January to May 1993 of 8.3%. He determined a return on the market as a whole of 14%, based on an analysis of certain Toronto stock exchange indices and the returns on 25 industrials and 5 utilities. He used a Beta for Canadian utilities from a U.S. edition of Value Line to conclude that the cost of equity for Canadian utilities is 11.8%.

On the basis of his analyses, Mr. Parcell concluded that the cost of equity for YECL is 11% to 12%.

4.5.4 CITY POSITION

The City submitted that an appropriate rate of return for YECL for the test period is 10.75%, although the City did not provide any evidence to support this position. The City submitted that Ms. McShane's recommendations are in excess of what is required for the Companies as a fair rate of return on common equity. The City made reference to Canadian Utilities Limited's ("CUL") market-to-book ratio in 1992 of about 140%.

In Argument, the City stated the following:

> "The High Market-to-Book Ratio on CU Stock Strongly Suggests That Ms. McShane's Risk Premium and Discounted Cash Flow Tests Are Biased Upwards ..." (City Argument, Page 31)

The City expressed concern that Ms. McShane added an allowance of 105 to 120 basis points to her YEC/YECL "bare bones" cost of capital to:

> "... achieve a market-to-book ratio of 1.15 to permit the utilities to defray flotation costs, attract capital and maintain a reasonable degree of financing flexibility." (YEC/YECL Argument, Schedule A, Page 10)

The City noted that CUL has consistently maintained market-to-book ratios higher than 115% even though its affiliates were awarded rates of return on equity less than that recommended by Ms. McShane.

The City noted concerns regarding the reliability of the comparable earnings test and submitted that this test should be accorded little weight. The City expressed a concern with regard to a change in Ms. McShane's sample of low risk industrials from that of her Evidence in the APL proceedings. The City noted that:

> "... the three companies she added had a rate of return averaging 18% for 1983-91, while the six she subtracted had a lower rate of return of 15%." (City Argument, Page 34)

With respect to Ms. McShane's risk premium test, the City expressed concern with her analysis, which indicates that risk premiums rise significantly as interest rates fall, noting that the:

> "... last ten years show much lower levels of risk premiums than the first seven in her data." (City Argument, Page 37)

The City disagreed with YECL's proposal that the company's rate of return should be developed on a stand-alone basis. The City noted that YECL is financed through CUL for its debt and equity. The City also noted that YECL does not:

> "... transact business with CU on an arm's length stand-alone basis, as is shown by its transfer of the Fish Lake property by gift to an unregulated CU company." (City Argument, Page 39)

The Companies submitted that Ms. McShane's economic forecast is overly optimistic and further suggests that:

> "... the current business cycle is not like the last one and is likely to be characterized by lower profits." (City Argument, Page 34)

The City concluded that an appropriate rate of return for YECL is 10.75% and, based on the requirements of the Order-In-Council, the appropriate rate of return for YEC would be 10.25%.

4.5.5 CURRAGH POSITION

Curragh noted that the rate of return awarded to YECL, in its previous GRA proceeding, was 12.75%. Curragh submitted that the cost of capital has decreased since that time.

Curragh noted that Mr. Parcell made a 1% adjustment for the high levels of market-to-book ratios and that Mr. Parcell testified that:

> "... a market to book adjustment is proper because, with a higher market to book ratio, a comparable cost of capital is less than with a lower market to book ratio." (Curragh Argument, Page 21)

With respect to the risk premium test, Mr. Parcell used a risk premium of 1.5% to 2.5%, whereas Ms. McShane used 3.5% to 4.0%. Curragh submitted that Ms. McShane's risk premium does not recognize the decline in risk premiums in recent years.

In Mr. Parcell's DCF test, Curragh noted that he did not include an adjustment for financing flexibility:

> "... since the DCF costs approximate the earned ROE and the achieved M/B already exceeds 125 percent." (Curragh Argument, Page 23)

Curragh submitted that it would be inappropriate to assess YECL as a stand-alone company. Curragh noted that Mr. Parcell explained that the cost of capital of YECL is tied to the cost of capital for APL and CUL. Curragh submitted that this, in turn, reduces YECL's financial risk. Curragh further submitted that YEC's and YECL's business risk:

> "... is further reduced by being able to request the YUB to award rates retroactively to guarantee a fair return for the first year of a two year test period for rate making (1993-1994)." (Curragh's Argument, Page 24)

Curragh submitted that, based on the Evidence of Mr. Parcell, the appropriate rates of return for YECL and YEC are 11.0% and 10.5%, respectively.

4.5.6 FOA POSITION

FOA submitted that YECL and YEC should be awarded rates of return of 10.5% and 10.0%, respectively, although FOA did not provide evidence to support this position.

4.5.7 YEC/YECL POSITION

The Companies disagreed with the City and Curragh that YECL should not be assessed on a stand-alone basis. The Companies suggest that this approach:

> "... neglects both financial theory and the empirical evidence of CU's and YECL's risks." (YEC/YECL Reply Argument, Page A1)

The Companies noted that the risks of the Yukon utilities are greater than those of CUL.

In Reply Argument, the Companies opposed the City's criticism of Ms. McShane's selection criteria in her comparable earnings test. The Companies noted that Ms. McShane based her selection, in this case, on the criterion of industrials which have not decreased their dividend by more than 25% and explained that such a reduction is a sign of significant financial distress and, therefore, a risk.

With respect to the equity risk premium test, the Companies noted that the City disagreed with Ms. McShane's estimated risk premium for high grade utilities of 3.5% to 4.0%. The Companies submit that the risk premium is 70% of the risk premium for the aggregate stock market, which was supported by Mr. Parcell's CAPM test. The Companies indicated that:

> "While the City asserts that the downward adjustments of both experts are inadequate, they provide no evidence to support this claim." (YEC/YECL Reply Argument, Page A4)

The Companies noted the City's criticism of Ms. McShane's evidence where she stated that the risk premium rises rapidly as interest rates fall. The Companies also noted that risk premiums fell rapidly when interest rates rose dramatically in the early 1980's.

The Companies support the City's conclusion that, due to the difficulties with the application of the CAPM test, Mr. Parcell's results from the test should be given little weight. The Companies expressed concern regarding the intervenors' contention that the consistent high market-to-book ratios of CUL suggests that Ms. McShane's recommendation for a rate of return is overstated. The Companies submitted that:

> "... there is no connection between allowed or achieved rates of return and market-to-book ratios due to deficiencies inherent in these ratios." (YEC/YECL Reply Argument, Page A7)

The Companies expressed a concern that the City was relying on the evidence of an expert in the Alberta PUB hearings for APL. The Companies submitted that the Board, in the current Yukon proceeding, ruled that this hearing would rely on the review of new expert testimony and, therefore, it would be inappropriate to:

> "... re-argue the evidence from the earlier Alberta case." (YEC/YECL Reply Argument, Page A9)

4.5.8 BOARD FINDINGS

Having considered all the evidence and argument of the parties, and recognizing the forecast economic condition for 1993 and 1994, the Board finds that a return on common equity deemed to be financing the rate base of YECL of 11% is fair and equitable. In accordance with Order-In-Council 1991/62 YEC is allowed a return of 10.5%.

Tab 5

AN ORDER IN THE MATTER of the *Public Utilities Act*
Revised Statutes, 1986, c. 143, as amended

and

A Joint Application by Yukon Energy Corporation and The Yukon Electrical Company Limited

BEFORE:	B. Morris, Chair; and)	
	G. Duncan, Acting Vice-Chair)	April 18, 1996

<u>ORDER 1996 - 6</u>

WHEREAS:

A. On November 17, 1995 Yukon Energy Corporation and Yukon Electrical Company Limited ("YEC/YECL, the Companies") filed with the Board, pursuant to the *Public Utilities Act* ("the Act") and Order-In-Council 1995/90, an Application requesting an Order granting new rates, effective with consumption January 1, 1996 with a further increase on January 1, 1997.

B. The Board reviewed the Application and the written submissions of the parties to the matter and heard the evidence and oral submissions of the parties at a public hearing on March 18 and 19, 1996.

C. The issues on which all parties could agree were enclosed in a Negotiated Settlement Package and submitted for the Board's consideration as an attachment to Exhibit Number 142.

D. The Companies submitted, in Exhibit Number 148, a revised calculation of the revenue requirement based on the settlement package.

E. With the exception of hearing costs, the Board approved the settlement package as accepted by the parties to the process.

NOW THEREFORE the Board orders as follows:

1. The revenue requirement of the Companies as set out in Exhibit 148 is hereby approved save and except for regulatory hearing costs.

2. For the purposes of calculating revenue requirements, the Board hereby awards estimated hearing costs in the amount of $600,000.

3. Actual hearing costs will be the subject of a further Board Order. Any difference between actual hearing costs and estimated hearing costs will be adjusted in the next General Rate Application by the Companies.

4. Written reasons for this Order will follow.

DATED at the City of Whitehorse, in the Yukon Territory, this 18 day of April, 1996.

BY ORDER

EXHIBIT #14d

CONFIDENTIAL

VIA FACSIMILE
403,668-3327

March 11, 1996

COPY

Mr. Bill Byers
Yukon Energy Corporation
304 - 204 Lambert Street
Whitehorse, Yukon Y1A 1Z4

Dear Mr. Byers:

Re: Proposed Settlement of Issues
Concerning the Revenue Requirement
<u>and Rate Design Application of YEC and YECL</u>

The purpose of this letter is to record the settlements we have achieved with respect to specific issues in the YEC and YECL ("the Companies") Application. This letter remains confidential until it is submitted to the Yukon Utilities Board for consideration. I, therefore, ask that you provide to me a communication of endorsement for the proposal so that we may forward it to the Board and make it public by Wednesday, March 13, 1996.

I have taken the liberty of reordering issues in our proposed settlement working sheets so that they align better with the subject areas of discussion in the Application. I have also added words to the bullets that we have agreed upon to explain the settlement to those parties who were not present at negotiations.

The settlement participants agree with the content and details of the Application, save for the following adjustments and identification of specific issues to be reviewed by the Board in public hearing. It is recognized by all the parties that the agreement represents a package proposal within which there has been give and take by all parties. No issue is to be severed from the proposed settlement without allowing signatories the opportunity to address other related issues in the package.

The terms of the settlement are as follows:

1. <u>Return on Equity ("ROE")</u>

   It is agreed that the ROE for 1996 and 1997 is to be set at 11.25 percent and that a Diesel Contingency Fund is to be established.

2. <u>Diesel Contingency Fund</u>

   This fund is to replace the proposed rate stabilization fund. The fund will operate to smooth customer rate changes and offset forecast diesel costs. Rates and the fund will be determined using the long-term average water expected to be available for generation (105 + 246 GW.h). The initial funding will be determined based upon the funds available as at December 31, 1995. If additional funding becomes available due to other determinations with respect to diesel costs or other utility costs in 1995, the fund will be adjusted. The fund is only to be used for the purposes of stabilizing customer rates and offsetting diesel generation cost estimates and the fund is not to be accessed for other reasons, including government subsidy of rates.

   The cap on the fund is set at the initial contribution level. If the fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider to customers over the following two years. If the fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and negative cap levels. The fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.

The fund is to operate outside of rate base but an annual report detailing additions and deletions to the fund is to be filed with the Board so that the Board may oversee the fund activities. The Board will direct the Companies on the additions and deletions to the fund. The annual report to the Board will also include a forecast of available water for the following year.

3. Capital Structure

The Companies agreed to back preferred shares out of their capital structure as soon as feasible. As the preferred shares are refunded, the Board is to consider appropriate common equity levels at future GRA hearings, having regard to the most efficient capital structure for the future.

4. Demand-Side Management ("DSM")

The DSM costs identified in the Application are accepted. A working group is to be formed, under terms of reference set by the Board, to make recommendations on energy management, conservation and efficient use programs and rates. The working group will also consider rate methods to encourage industrial self-generation when this will benefit system rates. The working group will also consider joint programs with municipalities. This working group is to be convened within one month following the Decision and a report is to be filed with the Board no later than November 1, 1996.

5. Capital Projects

The proposed capital projects schedule of the Companies is agreed to with the following changes:

- The new diesel plant at Dawson is agreed to.
- The Grum Substation is to be reassessed with ARM and it will only be added if required, and if alternative generation is not feasible. The capital cost of the substation and additional works is to be recovered from ARM so that there will be no impact on other customers.
- Any new transmission, distribution or substation capital requirement for new mines is to be paid for up front by the new mine so that other customers are not burdened with these costs.
- The proposed automatic meter reading program is removed from the 1997 budget and will be reconsidered for inclusion in 1998, or later.

6. Revenue Requirement

The revenue requirement budgets are accepted with the following conditions or changes:

- The sales forecast is to be revised based on the ARM Slurry Pipeline not proceeding.
- The Companies will revise the budgets to reflect the agreed upon long-term average water levels in the Diesel Contingency Fund.
- The Companies are undertaking a revised line loss study which is to be filed before the hearing and will be considered at the hearing.

- The program of additional maintenance for upgradings which is scheduled for completion in 1996 has been reviewed and is agreed to by the parties.
- The escalating charges from YECL's parent company, including potential future customer information system charges, are to be reviewed annually and the company is to seek out least cost alternatives.
- The Companies are to provide actual rate application costs for determination of final rates.

7. Review of Land Transactions

The proposed actions to dispose of certain housing and reconstruct new housing have been reviewed and found to be generally acceptable. The Companies detailed that any revenues from the sale of existing housing has been shown on the books such that it offsets a part of the new housing construction. UCG is to consider this issue further and report back to the Board prior to the hearing if it wishes to pursue further examination of the Companies' land transactions.

8. 1995 Interim Rates

The parties agree that the 1995 Interim Rates should be confirmed as permanent.

9. ARM Interim Rates

The interim rates outstanding for ARM since 1994 are to be confirmed as permanent.

10. Rate Design Issues

The rate design philosophy of the Companies is accepted subject to review at the hearing of Issue No. 11.

YECL and YEC are to commit to provide a preliminary cost assessment of each community in the four zones based upon the same methodology as was used in the 1992 study, updated to use 1995 data. The cost assessment is to be filed with the Board by July 1, 1996.

11. Cost of Service Allocations

The cost of service allocations are to be reviewed at the public hearing along with the appropriate revenue/cost ratios that are to be achieved by various customer classes.

12. Performance Indicators

The Companies have provided performance indicators as required by previous board decisions. Further analysis is to be undertaken to determine meaningful, measurable performance indicators to be used as a tool for management to assess performance in the areas of field generation, transmission, distribution and customer service. A report is to be filed by July 1, 1996. Based on the success of performance indicators during the current test period, the companies may suggest incentives tied to performance indicators for a future GRA.

13. Home Based Businesses

The Companies' policy with respect to home based businesses has been reviewed and found to be acceptable. It is to be filed as an Electric Service Regulation.

14. Electric Service Regulations

The proposed increase in charges for dishonoured cheques and reconnection charges are agreed to as being reasonable.

15. Retention of Monthly Time Sheets for YEC

An annual reporting by March 31 of the following year, is to be filed with the board detailing time spent on YEC versus YDC activities.

16. Filing of Monthly Fuel and Outage Reports

It is agreed that these reports should be replaced by performance indicators as they are developed. Until then quarterly reporting should be adequate for Board and customer reviews.

The companies are to provide an updated filing to the Board showing the revised revenue requirements of this proposed settlement. It may be that the reductions identified will lead to lower rates in 1996. That filing is to be made by Friday, March 15, 1996.

On another matter, the participants considered the UCG complaint with respect to water spillage in 1993 and 1994. The parties were unable to achieve a consensus view to suggest a resolution of the complaint. All intervenors present have agreed that this complaint should be heard at the upcoming public hearing.

In closing, I wish to commend the efforts of the Companies and all intervenors at the workshops and settlement discussions. The extensive efforts made by all parties to understand each issue along with the concerns and interests of other parties has allowed this settlement to come to fruition.

Yours truly,

W.J. Grant

WJG/ssc

Tab 6

2005-12

Therefore, the Board accepts the Rate Base of YEC as of December 31, 2004, shown on revised Schedule 1 included as part of Exhibit B1-23, except for the adjustment noted above for the disallowance of the Mayo-Dawson transmission line (adjusted for changes in AFUDC relating to the disallowance). The Board accepts the forecast capital expenditures for 2005 as updated in Exhibit B1-23, Schedule 3.

7 CAPITAL STRUCTURE AND RATE OF RETURN ON EQUITY

YEC is capitalized at a ratio of 60% long-term debt and 40% equity. Therefore, YEC's rates are set to include a provision for a fair return on common equity, less 50 basis points pursuant to OIC 1995/90 section 2 as amended by OIC 1998/32. The rate of return on equity set during the 1996/7 GRA was 10.75%, which was then modified as a result of the Faro mine closure to 9.138% in 1998. Therefore, YEC's existing rate includes a rate of return on equity equal to 9.138% (Application, page 1-5). YEC's actual return on equity has been well below the allowed return in each year of the period 2000 to 2004 and is forecast to be 7.1% during 2005 at existing rates. Generally, increasing cost pressures have eroded YEC's return since the closure of the Faro mine. YEC is seeking to adjust their allowed return on equity to better reflect existing bond yields, compared to when the existing return was established in 1998, and to help maintain stable firm service rates during the drawdown of deferral accounts and funds pursuant to the IST proposal. Therefore, in their Application, YEC proposed that the allowed return on equity be set by reference to the BCUC formula approach, resulting in an allowed ROE of 9.05% for 2005 (Application, page 3-23)

Evidence

OIC 1998/32 requires that YEC receive a fair return on common equity, less 50 basis points, or 0.5%. Based on the material filed in section 3.4.2 of the Application, the BCUC methodology of setting utility return on equity in British Columbia has been used as a means of establishing a fair return, as ordered by OIC. The BCUC automated adjustment mechanism is a formulaic approach that sets the risk for a benchmark low-risk utility based on long Canada bond yields plus an equity premium of 350 basis points. Each individual utility, then, is assessed a risk premium based on its individual business and financial risks over and above the benchmark utility. YEC proposed that an appropriate risk premium would be 52 basis points, which is midway between the FortisBC risk premium of 40 basis points, and Pacific Northern Gas risk premium of 65 basis points (Application, page 8-4 to 8-6). Table 8.1 on page 8-6 of the Application provided a table showing the calculation in detail of the requested return on equity for YEC.

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 (Application, pages 3-23). However, YEC did not propose to move towards an annual ROE adjustment mechanism, similar to the BCUC or other jurisdictions at this time (Application, pages 8-9). YEC only requested that the Board approve an allowed return on equity based on the BCUC methodology for 2005 (Application, page 8-2).

Return on equity was reviewed through Intervenor and Board staff IRs, as well as during cross-examination of the YEC panel in the hearing. During cross-examination, questions from Percival focused on the return YEC required as compared to the return YEC has requested approval for. Percival noted that YEC's average return over the period 2000 to 2003 was approximately 7.6% (T4:716) and questioned YEC on why they did not seek relief from the Board. Based on the lack of action on the allowed returns, Percival asked if the YEC Board of Directors was willing to accept returns of approximately 7.6% (T4:719 to 720). YEC responded that the low returns were to a certain extent the result of warm weather and bad debt write-offs pertaining to the Keno mine, consistent with the response to IR YUB 1-1, and that the Board of Directors did not just accept these returns but also considered the cost to ratepayers of an application process that would be required to adjust rates (T4:726 to 727). Board counsel cross-examined the YEC panel on relative risk of YEC compared to peer utilities, such as YECL, FortisBC and PNG in an effort to understand where YEC fits into the risk premium spectrum (T5:931 to 935). YEC accepted that they are less risky than PNG but argued they are more risky than FortisBC due to the inter-tie with other utility networks, which allows it to generate less electricity and purchase more of its demand when needed.

Argument

Overall, the use of the BCUC formula as a proxy for setting a fair return on equity for 2005 was not considered unreasonable by Intervenors. McMahon in his Final Argument supported the use of the BCUC methodology for 2005 for expediency purposes in the absence of expert evidence (McMahon Final Argument, page 9). However, McMahon did not support a risk premium over and above the benchmark utility since no evidence has been introduced to support a risk premium specific to YEC (McMahon Final Argument, page 9). McMahon's suggestion would yield a return on equity for 2005 of 8.2%, given the long Canada bond yields available in April 2005.

Although the UCG did not oppose the use of the BCUC methodology, they preferred to use the method and risk premium established in the last GRA. This would result in an allowed return of 8.278% (based on a risk premium of 275 basis points) as determined at page 10 of their Final Arguments. Another area of concern for UCG was the risk premium applicable to YEC. UCG asserted that, in their view, YEC does not have a level of business risk that would support the level of risk premium being applied for. In their view, forecast risk is reduced by the IST mechanism of drawing down deferral accounts to recover any shortfall in revenue requirement, so in essence they make their allowed return through the IST mechanism (UCG Final Argument, page 10, paragraph 69), minimizing financial risk.

YECL, in their Final Argument (page 30), did not support the level of return being requested and did not support the use of an automated adjustment mechanism similar to that of the BCUC. In the view of YECL, since no evidence has been introduced by YEC on the pros and cons of such a mechanism, then the Board should not make any determination with respect to return on equity.

YEC responded to the above Intervenor concerns in their Reply Argument in section 4.4.2 at page 45.

Determination

The Board is of the opinion that the rate of return on common equity that YEC requested is reasonable, given their level of risk in relation to other utilities within their peer group. Using the BCUC automated adjustment mechanism as a proxy of rate of return on equity does not impose a precedent in the Yukon and is an expedient means of determining return for the current one-year period. As for the issue of risk premium, the Board agrees that YEC likely falls somewhere between PNG at 65 basis points and FortisBC at 40 basis points. To ensure that there is sufficient forecast risk within the revenue requirement model, YEC should be at risk for their forecasts of load, OM&A and capital expenditures.

Therefore, the Board determines that an appropriate rate of return on common equity for YEC is 9.05% (9.55% less 0.5% as per OIC 1998/32). YEC is at risk for their forecast for annual deliveries, OM&A, and capital expenditures for 2005.

Tab 7

In the Matter of the *Public Utilities Act* Revised Statutes of Yukon, 2002, c. 186 as Amended

and

An Application by Yukon Energy Corporation For Approval of 2005 Revenue Requirements

REASONS FOR DECISION

Background

Yukon Energy Corporation ("YEC", "the Company" or "the Applicant") is the main generator and transmitter of electricity in the Yukon, accounting for more than 90% of annual power generation, and providing 69 kV or 138 kV transmission facilities for the Whitehorse-Aishihik-Faro ("WAF") and Mayo-Dawson grid systems. YEC directly serves approximately 1700 customers at the distribution retail level, which represents about 11% of all electrical customers in the Yukon. Indirectly, YEC provides power to most other Yukon retail customers served on the WAF and Mayo-Dawson systems through wholesale electricity sales to the Yukon Electrical Company Ltd. ("YECL").

Application

On December 13, 2004, YEC filed with the Yukon Utilities Board ("the Board" or "YUB") pursuant to the *Public Utilities Act* ("the Act") and Order-in-Council 1995/90, an Application for 2005 Required Revenues and Related Matters ("the Application") requesting approvals that would:

1) Establish 2005 Revenue Requirements (excluding the Income Stabilization Trust, ("IST"), transfers) as set out in the Application of $26.757 million, including:

   a) Operating and Maintenance costs for 2005 of $11.254 million, including approval to adjust diesel fuel prices used in fuel costs to reflect current forecasts, approval to apply the one-time deferred fire insurance gain arising from the favourable settlement of the Whitehorse Rapids fire claim of $744,000 against the current outstanding balance in the YEC Reserve for Injuries and Damages, and approval to increase the annual appropriation to the YEC Reserve for Injuries and Damages to $150,000 from the current $50,000 level;
   b) Depreciation and amortization expenses for 2005 forecast of $6.03 million, including approval to reduce YEC's depreciation rates for fixed assets (by approximately $1.2 million) to reflect changes to service lives, salvage rates, and group procedure as set out in the Application;
   c) Mid-year 2005 Forecast Rate Base costs of $142.514 million, including costs for capital works projects brought into service since the 1996/97 GRA

The Board accepts the proposal to apply the Whitehorse Rapids Fire Insurance Gain of $744,000 to the Reserve for Uninsured Losses in 2005. The Board also approves an increase to the annual appropriation to $100,000 for 2005, 2006, and 2007.

OM&A is therefore reduced by the amount for the reduction in Administration costs of $149,000, as discussed above, and for the reduction to the appropriation for uninsured losses of $50,000. The Board approves OM&A of $11,055,000 in 2005. YEC is fully at risk for their OM&A projection, such that over or under spending will impact return on equity. In the financial forecast, YEC is to provide a forecast of 2006 OM&A for determining the 2006 drawdown of the Faro de-watering deferral account.

5 DEPRECIATION STUDY

YEC retained the services of Gannett Fleming, which has expertise in depreciation rates for utilities and other industries, to conduct a routine review of their depreciation rates and remaining asset lives. The Depreciation Study is filed in section 11 of the Application, and a description of the Study and its results commences at page 3-16 of the Application. The result of the Depreciation Study has been a significant change to annual depreciation expense, useful service lives of assets, salvage values, and Average Service Life group procedures. Incorporating the revised service lives and depreciation rates recommended by Gannett Fleming results in a reduction in the depreciation expense to $5,238,830 annually (Application, Table 1, Depreciation Study; Tab 11). Reducing annual depreciation in turn reduces the Accumulated Depreciation amount in the calculation of Rate Base, which increases Rate Base - all else being equal - compared to existing approved depreciation rates.

In the case of YEC, the reduction in depreciation expense results from two requested changes. The first being the lower deprecation rates as a result of the Depreciation Study's determination that useful service lives are longer than those determined in the 1996/7 GRA. The second reason for the lower depreciation expense is due to a change in grouping procedures. Gannett Fleming recommends using the Average Service Life procedure, which is a departure from the Equal Life Group procedure used in the 1996/7 GRA.

Evidence

The principal evidence supporting the requested changes to Depreciation Expense is the Gannett Fleming Study included as section 11 of the Application. YEC also responded to several IRs from Intervenors. McMahon requested information on the qualifications and experience of Gannett Fleming in McMahon-YEC 1-16. In their response, YEC listed the various utilities Gannett Fleming has provided depreciation studies for. McMahon also requested the rationale for choosing Gannett Flemming over any other consultant in his IR McMahon-YEC 1-39. YEC stated in their responses that there are few depreciation experts in Canada capable of doing the work, and Gannett Fleming is well recognized within that community.

During his cross-examination of the YEC panel, McMahon requested additional information on why YEC chose Gannett Fleming versus another depreciation expert. At T4:595 of the Transcript, McMahon requested details of a request for proposal process YEC undertook to get the work done. YEC responded that Gannett Fleming was available and is the recognized expert in this field in Canada, so the use of Gannett Fleming was a sole-source contract.

Determination

The Board agrees with the findings of the Gannett Fleming Depreciation Study as contained at Tab 11 of the Application. YEC is to implement the new depreciation rates and grouping procedure effective January 1, 2005, and adjust gross depreciation expense downwards to $5,283,830 from $7,071,000 at existing rates. The amount for net salvage identified in the Gannett Fleming Study, Table 1A, Tab 11, is discussed below at section 8.1 Future Removal and Site Restoration and Asset Retirement Obligations.

6 MID-YEAR RATE BASE

6.1 Mayo-Dawson Transmission Line

The Mayo-Dawson transmission project is an approximately 223 km 69 kV transmission line providing the city of Dawson with hydroelectricity from the Mayo hydroelectric generating plant. The project was brought into service in September of 2003 and meets substantially all of the electricity needs of Dawson City. YEC would continue to use diesel generators as back-ups to the Mayo-Dawson transmission line in the event of a failure. The forecast cost of the Mayo-Dawson transmission line included in the Application was $35.6 million. The Yukon Development Corporation ("YDC") is providing a non-refundable contribution in aid of construction of $5.8 million towards the project, at no cost to ratepayers, reducing the final Rate Base impact of the project to $29.8 million (Application, pages 5-11).

The Mayo-Dawson transmission project was supported on the basis of overall revenue requirement savings due to the replacement of higher cost diesel generation with low cost hydroelectric generation, and the resulting reduction in diesel fuel costs, over the life of the project. YEC compared the net present value of the expected cost savings (resulting from reduction in diesel fuel, maintenance, and engine replacements) to the expected costs of a transmission line (return on Rate Base, depreciation expense) over the economic life of the transmission line. Table 5.6 included in Tab 5 of the

8 OTHER ISSUES

8.1 Future Removal and Site Restoration (FRSR) Costs and Asset Retirement Obligations (ARO)

An issue that was explored during the hearing by Board counsel dealt with the FRSR provision that YEC charges annually in revenue requirements as a component of depreciation expense with the corresponding credit being recorded in the FRSR liability account.

YEC's treatment of FRSR and ARO was described respectively in its 2003 Audited Financial Statements (Application, Tab 9) and its draft YEC 2004 Financial Statements (Exhibit B1-23, p. 7). In the notes to the draft YEC 2004 Financial Statements, YEC stated that effective January 1, 2004, it retroactively adopted the CICA Recommendations on accounting for ARO ("Note (b)"). Note (b) explained that ARO treatment requires the Company to identify the legal obligations associated with the retirement of tangible long lived assets. It further stated that YEC has some tangible long lived assets that have future legal obligations but it anticipates using the assets for an indefinite period, the date of removal cannot be reasonably determined, and therefore an ARO has not been recorded.

Evidence

The use of FRSR by YEC was examined in YUB-YEC-1-72. In their response to YUB-YEC-1-72.3, YEC identified the balance in the reserve account at the end of 2003 as being $5,144,000 and growing to a forecast balance of $6,514,000 by the end of 2005 under the current practice. Based on their response to YUB-YEC-1-72.3, YEC charges approximately $500,000 annually to the FRSR reserve. Several questions were asked during cross-examination of YEC by Board counsel, starting at T5:875 and continuing on to T5:897. Also, the actual balance in the FRSR reserve was updated in Exhibit B1-23 to $5,757,000 as at December 31, 2004. Board counsel asked questions on how the FRSR reserve is accounted for, and Mr. Bowman explained that the charge is recorded as Depreciation Expense on the Income Statement, with a corresponding credit to the FRSR reserve on the Balance Sheet (T5:876-877).

Exhibit A-35 introduced by Board counsel provided the current prescribed Generally Accepted Accounting Principles ("GAAP") treatment regarding FRSR accounting treatment. Section 3110 of the CICA Handbook is very clear that FRSR appropriations are no longer required under GAAP and that long lived assets with retirement obligations should be recognized or disclosed in the notes to the Financial Statements if the fair value cannot be reasonably estimated. Under sections 1506 and 3110 of the CICA Handbook where ARO are required, the reserve for the ARO is to be established and the reserve for FRSR should be removed from the Balance Sheet and recorded in retained earnings.

Board counsel also questioned the YEC panel on Exhibit A-35 (CICA Handbook, sections 3110 and 1506), which deals with the prescribed accounting treatment of transitioning from FRSR to ARO. At T5:883 to 891, Board counsel queried YEC on their treatment of FRSR in relation to changes to the CICA Handbook that require companies to remove their reserves for FRSR once they adopt ARO accounting, which YEC has done effective January 1, 2004. Board counsel asked whether or not YEC agreed that they should be changing their financial reporting to take into account the transition from FRSR accounting treatment to ARO accounting treatment (T5:884 to 886). YEC does not agree currently that they should make those changes and they do not wish to take the FRSR into retained earnings in 2005 (T5:890).

Board counsel also introduced Exhibit A-36, an excerpt from the BC Hydro 2005/6 revenue requirements application. In that application, BC Hydro determined that it no longer would be making appropriations to its FRSR accounts and would now be recording ARO consistent with section 3110 of the CICA Handbook and GAAP. In BC Hydro's case, it removed the liability for FRSR from the balance sheet and proposed to transfer the balance to retained earnings. When questioned by Board counsel on whether YEC agreed with the BC Hydro treatment, YEC did not commit to the same treatment, and YEC considered the FRSR liability as a ratepayer account that should not be taken into retained earnings.

Argument

YEC discussed the FRSR and ARO obligations in their Final Argument, beginning at page 13. The YEC position was that the treatment of FRSR and ARO is controversial, and care must be taken (page 13). In their view, the Depreciation Study undertaken by Gannett Fleming proposes Site Restoration charges in the amount of $533,366 in 2005, and Gannett Fleming is an expert in this matter. Also, other jurisdictions such as the AEUB and Manitoba have maintained net salvage amounts in revenue requirement (page 14). YEC stated in their Final Argument that the only evidence before the Board is from Gannett Fleming, a recognized depreciation expert. YEC also stated at page 14 that there is no evidence currently before the Board that suggests that net salvage should not be included in revenue requirements for 2005. YEC also argues that the FRSR fund is a liability that belongs to ratepayers and it would be inappropriate to take those monies into retained earnings since ratepayers have made those contributions over time to pay for their share of the cost of site restoration or removal so as to avoid intergenerational issues (page 14 and 15).

Determination

The Board is of the view that if there is no longer a need for YEC to collect amounts for annual appropriation to the FRSR reserve, then consistent with section 3110 of the CICA Handbook, YEC should comply with GAAP and remove these charges from annual revenue requirements. Based on the Depreciation Study, the result would be a reduction in annual Depreciation Expense of $533,336. The Board agrees with YEC's concern about the GAAP requirement to transfer the balance in the FRSR liability account to retained earnings and considers that a variance from section 3110 of the CICA Handbook is required.

The Board requires that YEC discontinue recording an annual provision for FRSR effective January 1, 2005. The Board orders a variance from GAAP and requires that the December 31, 2004, balance in the FRSR account remain as a liability to be utilized for dismantling costs that are incurred in 2005 and future years. The Board requires YEC to inform Intervenors and stakeholders when the balance of the site removal liability account reaches $2.0 million.

8.2 2005 Hearing Costs

With the changes detailed above, it is expected that the Faro mine de-watering deferral account will be available to stabilize existing general service rates, with no need for a rate increase until after 2007. Therefore, the final hearing cost deferral account should be amortized over three years, beginning in 2005.

The Board therefore directs YEC, once all final costs are recorded in the 2005 Hearing Cost Deferral Account, to amortize that account equally over the three-year period beginning 2005.

8.3 Revenue Requirement Schedules

The approvals contained in this Order have made material adjustments to the Revenue Requirements requested in YEC's filed Application.

In order to ensure that all parties understand the full and final effects of this Order, the Board orders YEC to incorporate all above changes and approvals and to re-file the appropriate Schedules that make up section 7 of the Application within 30 days of issuance of this Order.

8.4 Financial Review

The Board finds that a financial review of YEC is necessary in accordance with sections 23 and 24 of the Act. The timing and the scope of the Board financial review will be determined at a later date. The focus of the financial review is expected to involve enquiry and analytical procedures in regard to the financial information provided by YEC, examinations on a test basis of documentation supporting amounts included in utility records and an assessment of compliance with Board directives. The Board will allow YEC deferral account recovery of the costs incurred in the financial review, subject to Board review and approval.

Tab 8

February 1998 there has been virtually continuous availability of secondary power up to today.

Proceeding Time 10:55 a.m. T21

MR. FULTON: Q: Thank you.

All right, Mr. Chairman, I do now want to move to a new area, and for this area it will be very helpful if all parties can have before them Exhibit B1-23 and Exhibit B1-14 YUB to YEC 1-72.

MS. WRIGHT: What was the first exhibit?

MR. FULTON: The first exhibit is B1-23 and the second one is B1-14 YUB to YEC 1-72.

MR. OSLER: A: Mr. Fulton, the first one is in effect the update we provided on April the 8th, correct?

MR. FULTON: Q: Yes, it is.

MR. OSLER: A: Thank you.

MR. FULTON: Q: And the topic that I'm intending to deal with, Mr. Chairman, is the topic of future removal and site restoration costs and asset retirement obligations. And I have provided YEC's counsel with some documents that I intend to refer to.

And perhaps panel, we can reach an agreement that I might use some acronyms as we go through this, so that for "future removal and site restoration costs" I'll refer to those as FRSRs and for "asset retirement obligations" I'll refer to them as AROs.

Now, beginning with Exhibit B1-23, if you turn to page 7, that page is a copy of the draft 2004 balance sheet for WEC?

MR. BOWMAN: A: Mr. Fulton, my pages aren't numbered but it would appear to be the 7th page is the balance sheet, yes.

MR. FULTON: Q: Thank you. And under liabilities you will see that there is a reserve for FRSRs. Agreed?

MR. BOWMAN: A: Correct.

MR. FULTON: Q: And we can also agree that the balance in that account is increased from 5,143,000 as at December 31st, 2003 to 5,757,000 as at December 31st, 2004.

MR. BOWMAN: A: Yes.

MR. FULTON: Q: Can you tell us how this account balance increases from year to year and where the offsetting entry is reporting?

MR. BOWMAN: A: Mr. Fulton, this -- my ability represents an item similar to accumulated depreciation. Based on the work of the various depreciation experts over the years and the depreciation rates approved by this Board, Yukon Energy has a provision to not only depreciate the costs of its assets over the life of those assets, but also to, during the life of those assets, set aside monies that will be required to eventually tear them

down or remove them or replace them. So that it matches the costs and the benefits.

Today's ratepayers who are using the assets are paying ultimately the cost to remove them the same as they are paying the original cost to construct them.

MR. FULTON: Q: Okay, the offset -- I'm sorry.

MR. BOWMAN: A: The offsetting amount would be recorded as depreciation on the income statement which would be the following page in the draft financial statements.

Proceeding Time 1:50 a.m. T28

So when you would see amortization of property, plant and equipment, that would be the sum of the two rates and the two charges I just explained to you. One to amortize over time the original costs of the assets, and the second to collect over time and set aside in a reserve the amounts that will ultimately be required to retire the asset or replace the asset.

MR. FULTON: Q: Okay. Is the yearly provision for FRSRs identified for specific assets, or is it a general allowance for all assets?

MR. BOWMAN: A: No, it's identified for individual asset classes the same as depreciation rates, and in the depreciation study at tab 9 there is a set of tables that deal with fixed asset depreciation and

another that would be called net salvage to my recollection but I can check, that would set out the supplementary rates that are added onto the original depreciation, to set aside these monies from today's ratepayers that will be eventually required.

MR. FULTON: Q: All right, I'm going to come back to B1-23, but if you could now look at the response to YUB 1-72, and 1-72.3 asked YEC to identify the FRSRs for 2003 to 2005 and explain if any drawdowns or transfers have occurred to this account in those years, correct?

MR. BOWMAN: A: Yes.

MR. FULTON: Q: Can you tell us how the drawdowns to the FRSR reserve are made, and -- can you tell us how those are made?

MR. BOWMAN: A: Mr. Fulton, when a capital project is undertaken at Yukon Energy, the costs of the capital project are identified separately between costs to effectively construct the new assets and where applicable, costs that were incurred to take out the old assets or to remove or salvage assets that had previously been in place. Those latter costs are not added to the cost of the capital project. They are charged against this reserve because that's the type of costs that these monies have been set aside for during the life of that asset.

MR. FULTON: Q: So then if we look at the bottom of page 2 of 3, in 2003 366,320 was charged to the FRSR reserve, and I'd like to focus in on the 200,000 for the hydro unit rewind at Aishihik and the replacement of the electrical controls at the Mayo Spill Gate of 57,000. Are these costs for the removal of those assets?

MR. BOWMAN: A: Mr. Fulton, yes, the costs that are shown there, as I explained, are the costs that would have shown up to reclaim or remove the assets that had completed their useful life and were being removed from service. The costs actually put in place, the new assets, would be recorded to the capital project. And for example the rewind at Aishihik that you're referring to is shown in Table 5.2 as a 2003 capital project costing 1.216 million. And so what that means is that ultimately 1.416 million was spent to take out the old one and put in the new one, and it was divided in this way. 1.216 related to constructing the new one and 200,000 related to taking out the old one.

MR. FULTON: Q: Thank you. If you turn to page 3 of the response, and on the third line the comment to appears:

"With respect to 2004 and 2005, Yukon Energy does not prepare forecasts for charges against the reserve for removal and

restoration."

And then on that same page there is a listing of the balances in the reserve for FRSRs for 2003 actual and forecasts for 2004-2005. Is the 2004 forecast shown as $5,999,000, would the earlier forecast of -- and earlier forecasts in the forecast of the 5,757,000 that appears in Exhibit B1-23 that we talked about a few moments ago?

MR. BOWMAN: A: Sir, the two numbers are equivalent. The 2004 forecast provided in YUB 72 was the forecast at the time the application was prepared, and based on the planning. On a forecasting basis, Yukon Energy does not forecast charges against its reserve because they mathematically have no impact as to whether they are charged against the reserve or added to capital in terms of the overall impact on rates or revenue requirements. They only have an impact on accounting. But the 2004 you referred to as the forecast, but in the draft financial statements it would be an actual balance of 5-7-5-7.

Proceeding Time 11:05 a.m. T23

MR. FULTON: Q: On the page 3 as well, there is an increase of 524,000 from the 2004 forecast of 5,990,000 to the 2005 forecast of 6,514,000. And what I'd like to know is can you tell me whether that 524,000 is included in the 2005 depreciation expense?

MR. BOWMAN: A: Yes sir, it is.

MR. FULTON: Q: Okay, if you hold onto the documents that we've been talking about and go to the application tab 11, the depreciation study, Table 1A. And just so you can confirm this for me, if you look at the second page of Table 1A there's an amount of $533,366?

MR. BOWMAN: A: Yes, that's the amount that's shown there, yes.

MR. FULTON: Q: And that is the FRSR amount being recorded in current depreciation expense?

MR. BOWMAN: A: No, sir, that is the results of the depreciation study which looked at the surviving original cost of Yukon Energy's assets to December 31st, 2003 and determined what was required for both depreciation and for net salvage. This is the work of Gannet Flemming, the depreciation expert, and what he determined is based on the surviving original cost at December 31st, 2003, in his opinion the amount of money Yukon Energy would need to be setting aside in its reserve given the current reserve levels and the assets in service, would need to be 533,000.

In the next column he uses that to derive a rate for each class of asset as we've discussed, and it is those rates that Yukon Energy is applying in this hearing to apply going forward, or to have

approved going forward. Those rates, thought, are not yet in place and have not been used in the past because we can't change depreciation rates without the approval of this Board.

MR. FULTON: Q: Can you tell us how much is in FRSR for 2005? Is it the 524,000 that we were discussing?

MR. BOWMAN: A: Yes, sir, I believe it is. I'm just checking that there's any adjustments but I don't believe there is any forecast. It would be very close to that number if it's not that number.

MR. FULTON: Q: I need an audible answer on the record.

MR. BOWMAN: A: Oh, I'm sorry, I thought we said yes, that seemed like the number. I apologize.

MR. FULTON: Q: I think we're probably at cross purposes because I thought you were checking and going to get back. So we have the answer, thank you.

MR. BOWMAN: A: Yes, sorry.

Proceeding Time 11:10 a.m. T24

MR. FULTON: Q: Returning then to Exhibit B1-23, if you could turn to the notes to the financial statements, and at this point, Mr. Chairman, I'd like to produce as an exhibit an extract from the CICA Handbook, Sections 3110 and 1506 which I previously provided to counsel for YEC.

THE CHAIRPERSON: Mr. Fulton, what is the exhibit number?

MR. FULTON: The exhibit number will be A-35.

THE CHAIRPERSON: So marked.

(EXTRACT FROM CICA HANDBOOK, SECTIONS 3110 AND 1506, MARKED EXHIBIT A-35)

MR. FULTON: Q: All right. Now, returning to the draft financial statements, the note for the AROs provides in part that as of January 1, 2004 the corporation retroactively adopted the recommendations of the Canadian Institute of Chartered Accountants, CICA, on accounting for asset retirement obligations. The CICA recommendations require the corporation to identify legal obligations associated with the retirement of tangible long-lived assets.

The Exhibit A-35 which was previously provided to you, you've had the opportunity to review Sections 3110 and 1506 of the Handbook?

MS. FENDRICK: A: Yes.

MR. BOWMAN: A: We've had a chance to generally look at them and have had a chance to talk with the person in Yukon Energy who does -- is the specialist in this areas, but yes.

MR. FULTON: Q: Okay. And are the Handbook references that are found in Exhibit A-35 the CICA recommendations that are referred to in the note?

MR. BOWMAN: A: Yes, Section 3110 is the one generally referred to as the retirement obligation section.

MR. FULTON: Q: Okay. And looking at 3110, just under the heading "Transitional Provisions" the comment appears:

"This section should be applied for fiscal years beginning on or after January 1, 2004. Earlier application is encouraged."

And then dropping down to the paragraph immediately below that:

"As of the beginning of the fiscal year in which an entity first applies this Section, the entity removes from its balance sheet any provision for future removal and site restoration costs or other amount previously recognized as a liability for asset retirement…"

And it goes on to say that certain items are recognized.

Do you agree with that statement in terms of its application to the draft financial statements that are before the Board?

MR. BOWMAN: A: Sir --

MR. FULTON: Q: And in terms of the agreement that I'm seeking really is that the passages that I read to you describe how -- and the paragraphs that follow describe how the AROs are established for the purposes of financial reporting.

MR. BOWMAN: A: Yes, we've been informed that this is the section that Yukon Energy intended to apply by making the note in its financial statements and that on its reading of this section by accountants familiar with these sections and in the context of other sections of the Handbook and as well as looking at audited statements of similar utilities including YECL and Fortis Alberta, it fully applied this statement consistent with normal utility practice.

Proceeding Time 11:15 p.m. T25

MR. FULTON: Q: And when you say that statement, are you including the entire part of paragraph 310 that appears on the page, the first page of Exhibit A-35?

MR. BOWMAN: A: I'm sorry, sir, I don't know which paragraph you're referencing.

MR. FULTON: Q: Okay.

MR. BOWMAN: A: I see A-35 has section 3110 but I don't see a paragraph 10.

MR. FULTON: Q: Sorry. What I'm talking about is the entire discussion of 3110, which is -- when I said 311-10, which is the section I'm talking about.

MR. BOWMAN: A: Okay. Yes.

MR. FULTON: Q: So that on your understanding the accountants applied that section in its entirety as it appears on the page.

MR. BOWMAN: A: Sir, yes, having due regard for this

section and the context within the entire handbook that we're talking about, including in particular the exceptions that exist for regulated utilities, they fully applied this section in the draft financial statements.

Now, I would caution these have not been audited. They've been sent to the Auditor General of Canada but they have not yet been audited. But the approach that's been taken here is identical to the approach taken by YECL in their 2004 statements that have been filed with this Board and by other utilities who have had them audited and have had this accepted by their auditors.

MR. FULTON: Q: And I didn't think I'd referred to them as audited, but if I did I apologize.

The last paragraph on the first page of B1-35 references section 1506 of the Handbook, and that section is the second page of Exhibit A-35, and the passage that I wish to refer you to in that section is the second to the last flag, which says:

"When a change in an accounting policy is applied retroactively, the financial statements of all prior periods presented for comparative purposes should be restated to give effect to the new accounting policy, except in those circumstances when the effect of the new accounting policy is not reasonably determinable for individual prior periods. In such circumstances, an adjustment should be made to the opening balance of retained earnings of the current period, or such earlier period as is appropriate, to reflect the cumulative effect of the change on prior periods."

Now, would you agree with me that the effect of the recommendations in the two sections of the Handbook that make up Exhibit A-35 have the effect of requiring that existing FRSR provisions are to be eliminated and replaced with AROs?

MR. BOWMAN: A: Mr. Fulton, I think we want to be careful. I cannot agree with that, and no one on the panel here is an expert in regards to AROs. But the understanding that we have is that these sections must be read in the context of other sections that deal with matters of regulatory accounting and provisions that have been set up under other systems. I wouldn't agree that these two can be read together to give effect to what you're stating.

Proceeding Time 11:20 a.m. T26

MR. FULTON: Q: One of the other documents that I provided to your counsel was an excerpt from a B.C. Hydro application for its 2004/2005, 2005/2006 revenue

requirement. Did you have an opportunity to review that document?

MR. BOWMAN: A: Yes, it's a two-page excerpt and we've generally reviewed the excerpt, yes.

MR. FULTON: Mr. Chairman, may this document be marked the next exhibit, A-36, and it's actually a three-page document styled "Revenue Requirements Application 2004/05 and 2005/06, B.C. Hydro, Volume 1, Chapter 1, Application Overview" and it consists of a cover page and pages 2-18 and 2-19 from that application.

THE CHAIRPERSON: So marked.

(PAGES 2-17, 2-18 AND COVER PAGE FROM "REVENUE REQUIREMENTS APPLICATION, 2004/05 AND 2005/06, B.C. HYDRO, VOLUME 1, CHAPTER 1, APPLICATION OVERVIEW", MARKED EXHIBIT A-36)

MR. OSLER: A: Mr. Fulton, just for the record, I think you've said 2-18 and 2-19. I think they are 2-17 and 2-18.

MR. FULTON: Q: Thank you, Mr. Osler.

Now, at page 2-17 beginning at line 14 there is a discussion of asset retirement obligations and B.C. Hydro's view of how those obligations are to be treated.

MR. BOWMAN: A: Yes.

MR. FULTON: Q: Do I take it from what you said earlier, Mr. Bowman, that you're not able to agree

with B.C. Hydro's position on that? Or are you?

MR. BOWMAN: A: Sir, I want to be very careful. The position that B.C. Hydro has filed is their interpretation of how these statements and these requirements of accounting in the full context of the accounting standards apply to them, and the situations will be different in different contexts.

In regards to the accounting standards and how they apply to B.C. Hydro, I'm afraid I can't speak to that, and not being an accountant, I can't speak to the full range of generally accepted accounting principles in the Handbook and how it applies to utilities. I can tell you that in many discussions about this issue it has caused -- this section of the Handbook has caused significant concern and issues, from what I have seen, for regulators throughout Canada and from what I have seen, the B.C. Hydro interpretation is the exception rather than the rule. I have not seen another utility, and we've had discussions with Manitoba Hydro and with Northwest Territories Power and have not seen another utility thinking of doing the same thing as B.C. Hydro provided here.

MR. FULTON: Q: Can you tell us, Mr. Bowman, the approach that you understand the other utilities were taking, that is different from the approach that B.C.

Hydro had proposed in its application?

MR. BOWMAN: A: Well, sir, I can tell you I was in a hearing with Manitoba Hydro where there was some discussion on this issue. They had not yet adopted the provision but their interpretation at that point in time and their presentation to their Manitoba Public Utilities Board was that when they adopted the asset retirement obligation provision they would, at most, be recording a small asset retirement obligation for those matters that fit the strict definition as is in here, the same way that Yukon Energy did, and that they would be retaining in there, effectively the same type of account as Yukon Energy has, a salvage account or an accumulated depreciation combined account, all amounts that they had previously put aside related to salvage -- for depreciation, the salvage component of depreciation rates.

Similarly YECL has taken that interpretation and has notes under it that that's a requirement, in their view, of regulatory accounting. Their auditors have signed off on those statements. And Fortis Alberta is the other one that's been referenced, that we've been referenced to who similarly has taken the same interpretation.

I'm also aware that Yukon Energy has been in discussions with Northwest Territories Power and

Nunavut Power who are the only other two utilities audited by the Auditor General of Canada. Neither of them have yet produced statements, but that the three utilities were looking to find a consistent approach in terms of dealing with the Auditor General for Canada.

Proceeding Time 11:25 a.m. T27

MR. FULTON: Q: What are the balances for the AROs for 2005?
MR. BOWMAN: A: If you're asking for Yukon Energy --
MR. FULTON: Q: Yes.
MR. BOWMAN: A: -- this would be set out in the note to the financial statements in regards to December 31st, 2004. This is a process that the corporation is required to go through every year. So in that note that you were referring me to earlier in the financial statements, Part B of note 2, although Yukon Energy has adopted the provision and it has determined that there are asset retirement obligations, and my understanding is the clear probably largest dollar value one ultimately is the terms under the water licence for the Aishihik Generating Station, but there would also be asset retirement obligations under certain easement agreements which Yukon Energy has. Those were determined by doing a process of a cross-cut, a sampling of the various *Licences Acts,* permits

and easement agreements and the like that Yukon Energy has, and that process will be repeated year after year and updated as time goes on.

But at this point in time there are a number of arrows that it's my understanding have been identified, but all of them relate to assets that have no plans to be retired and no estimates as to what it may cost to ultimately retire or replace them.

MR. FULTON: Q: Given the evidence that you've just stated, isn't it inconsistent for the $524,000 to appear in the December 31st, 2004 draft financials, because the amount for the ARO should be zero?
MR. BOWMAN: A: Well, sir, I think that there are two answers to that question depending on whether one is doing a strictly accounting-based answer or one is looking at the more regulatory and rates-focused answer, which is typically the focus here. On the strictly accounting-based answer, the reason that the 500 and some-odd thousand dollars continue to be recorded as a liability is because in the corporation's view they are a liability. This Board set up the depreciation rates that gave rise to that reserve and has control over any amounts that would show up in that reserve, and it is applying to this Board to maintain use of that reserve going forward. They're not amounts that the corporation can on its

own, simply because of what it says in a GAAP, in a *Canadian Institute of Chartered Accountants Handbook,* can take into its retained earnings. That's the simple answer on the accounting side.

On the regulatory side, those accounts continue to exist because, as Mr. Osler addressed earlier, one of the principles in setting rates is the intergenerational equity, that people should pay rates that reflect the costs to serve them in the time that they are served, and those costs should track the benefits that they're receiving. The people who are here today using the Aishihik facility, to use an example, are the ones who are receiving the benefits today from the Aishihik facility, and ultimately would need to bear the costs of removing it or the costs of removing items while they replaced on the Aishihik facility.

Absent that account, there is no way -- and the ongoing amounts being added to that account. There is no way that today's ratepayers would be paying those amounts, and ultimately those would have to be borne by future ratepayers who didn't have the benefits of the Aishihik generation when it was around.

MR. FULTON: Q: But doesn't it distill down to this, that the draft financial statements and the note that

I took you to earlier says that the company is adopting the recommendations for accounting for asset retirement obligations? And what I seem to be hearing is that, well, no, you're not really doing that.
MR. BOWMAN: A: No, sir. The company is adopting and in its view is required to adopt that section of the *Canadian Institute of Chartered Accountants Handbook* because it views it as a requirement. Other parts of the of the *Canadian Institute of Chartered Accountants Handbook* set out other rules for liabilities, which can include accounts that have been set up by a regulator that ultimately the utility will be liable for, that monies that were collected in the past and are expected to be spent in the future on certain items, it will continue to need to record as a liability.

Absent that, those monies would, strictly reading the sections you gave me, be automatically transferred to Yukon Energy's retained earnings, and in our view that was not the reason those monies were collected or does not reflect the ultimate use of those amounts.

Proceeding Time 11:30 a.m. T28

It's somewhat similar to the issue that we had with the Auditor General in regards to accounting for the fire insurance settlement. Yukon Energy had a very favourable settlement on the Whitehorse Rapids fire, and as a result saw a gain. In the Auditor General's view, the gain from insurance was to be recorded as income to Yukon Energy in that year and put into the retained earnings.

In Yukon Energy's view, that was not their money, it was ratepayers' money, and ultimately it came to this Board for a determination that it should treat it as ratepayers' money as opposed to as its own money, and got that determination and that continues to be reflected here as something called a regulatory liability.

What we're talking about is not necessarily anything different. And in particular in this case I would note it's supported by expert evidence at tab 11 that says those are the amounts that are required to be put aside to be prudent and to plan for the future.

MR. FULTON: Q: Let me try it this way: The handbook does allow for variances from GAAP for regulatory purposes, agreed?

MR. BOWMAN: A: Yes, that's my understanding, yes.

MR. FULTON: Q: And so is what you're saying here that why YEC is requesting for its treatment of the FRSRs is for a variance from GAAP?

MR. BOWMAN: A: Yes. We would view that we have that requirement right now that is a variance from GAAP,

that under the depreciation rates approved by this Board which Yukon Energy cannot change without an order of this Board, it is required to set aside monies. It setting aside monies and they are set aside.

A CICA Handbook section cannot change those depreciation rates, and so today we're asking to update the depreciation rates to continue to include a reserve provision of that sort, which would be a variance from GAAP.

MR. LANDRY: Mr. Chairman, if Mr. Fulton --

MR. FULTON: I'm just about finished, so --

MR. LANDRY: I would just like to rise to say I do have a question about what we are going to deal with in argument on this issue, but I'll wait until you are finished your cross.

MR. FULTON: Q: So that if I can summarize the position of YEC then, Mr. Bowman, is that YEC wants to keep the FRSR balance and they also want to keep the 524,000 in depreciation expense related to the FRSRs.

MR. BOWMAN: A: Yes.

MR. FULTON: Q: And I'm talking about for 2005.

MR. BOWMAN: A: Sir, yes, it wants to keep it on its balance sheet as opposed to any alternative of taking it into retained earnings. It wants to keep the amounts being put aside based on the evidence of its

depreciation expert going forward, and it's looking for the Board to approve those depreciation rates.

MR. FULTON: Q: Thank you.

I'm going to move to another area now.

MR. LANDRY: Mr. Chairman, I wonder if I could rise on this point. This is an issue that obviously Mr. Fulton and his colleagues have raised. I'm somewhat concerned because of course Board staff do not argue in the case. As I understand -- I know this is a very significant and active debate within the regulatory community, and there is a concern that the approach taken by B.C. Hydro is it effectively to take, in our submission, a ratepayer account that is there to protect for future restoration, and put it into the retained earnings of the utility.

Proceeding Time 11:35 p.m. T29

So using the fire insurance gain, it was like taking a fire insurance gain and giving it to YEC. And my only concern is I'm not so sure that people understand the significance of what this issue is about, and I want to know how we should, that is YEC, should deal with it because given the cross-examination by Mr. Fulton, it appears to me, given that he's used the application as opposed to what the order is by the BCUC, that in fact Staff's view may be that it should be transferred over to retained

earnings; and that's not Yukon Energy's view.

MR. FULTON: Two items on that, Mr. Chairman. The first is that the Board can issue a variance from GAAP, and it did that in Order 2000-3.

Secondly, in terms of final submissions, I would just be letting the parties know that, if they didn't already, that there is a decision of the British Columbia Utilities Commission of 2004 on the FRSR/ARO issue that is out there, and whether people decide to make submissions on that decision or not, it's up to them, but it's out there. And there may be decisions from the Manitoba PUB and other boards that take a different approach, but people need to be alive to them.

THE CHAIRPERSON: Mr. Landry, I think the short answer to your question you're posing is that first of all you do have the opportunity for re-examination and to state your client's position, and there are the submissions and arguments to be made at the end of this proceeding.

MR. FULTON: And just so that everyone here understands where we were going with that, in one sense is that there appeared to be an inconsistency that needed some clarification on the record, in our view, and that was the reason for spending time on that particular issue.

MR. LANDRY: Thank you, Mr. Chairman.

Tab 9

A-35

(iii) the credit-adjusted risk-free rate or rates at which the estimated cash flows have been discounted.

When the fair value of an asset retirement obligation cannot be reasonably estimated, that fact and the reasons therefor should be disclosed. [JAN. 2004]

Uncertainties affecting the measurement of a liability for asset retirement obligations are disclosed in accordance with MEASUREMENT UNCERTAINTY, Section 1508. .22

TRANSITIONAL PROVISIONS

▶ *This Section should be applied for fiscal years beginning on or after January 1, 2004. Earlier application is encouraged.* [JAN. 2004] .23

As of the beginning of the fiscal year in which an entity first applies this Section, the entity removes from its balance sheet any provision for future removal and site restoration costs or other amount previously recognized as a liability for asset retirement, and recognizes: .24

(a) a liability for any existing asset retirement obligations, adjusted for accumulated accretion to that date;

(b) an asset retirement cost capitalized as an increase to the carrying amount of the associated long-lived assets; and

(c) accumulated depreciation on that capitalized cost.

Those amounts are measured using information, assumptions and interest rates that are current at the beginning of the fiscal year in which this Section is first applied. The amount recognized as an asset retirement cost is measured as of the date the asset retirement obligation was incurred. Accumulated accretion and depreciation are measured for the period from the date the liability would have been recognized had the provisions of this Section been in effect to the date as of which this Section is first applied. Appendix B provides an example that illustrates the application of the transitional provisions of this Section.

An entity may have accounted for its liability for asset retirement obligations and the related asset retirement cost in accordance with the requirements of this Section but based on information, assumptions and interest rates as of a date prior to its initial application of this Section. These circumstances may have arisen, for example, as a result of a business combination. In such circumstances, the entity may use that information, updated as necessary, to determine the amount of the liability, the asset retirement cost and the accumulated depreciation thereon as of the beginning of the fiscal year in which this Section is first applied. .25

An entity recognizes the effect of initially applying this Section as a change in accounting policy in accordance with ACCOUNTING CHANGES, Section 1506. Accordingly, the financial statements of prior periods presented for comparative purposes are restated retroactively. .26

Tab 10

A-36

Revenue Requirement Application
2004/05 and 2005/06

BC hydro

Volume 1

Chapter 1.

Application Overview

3.7.2 F2006 Compared to F2005

Increased depreciation from F2005 to F2006 resulting from increased assets in-service is offset by the elimination of assets transferred to BCTC and no longer consolidated with BC Hydro after F2005. In particular, the transfer to BCTC of certain limited transmission assets necessary for the independent operation and dispatch of the transmission system causes the depreciation expense to decrease by $15 million. This decrease is partially offset by a $5 million increase in depreciation on transmission assets owned by BC Hydro, due to additional assets in-service, and a $3 million due to increased computer hardware and software assets in-service.

Depreciation expense also increased by a net $1 million due to increased assets in service offset by asset retirements.

The increased DSM amortization expense of $5 million results from increased DSM program activity.

3.7.3 Asset Retirement Obligations

BC Hydro's accounting for costs associated with the retirement of capital assets will change in F2005 as necessitated by a change in Generally Accepted Accounting Principles (GAAP). The change, introduced by the Canadian Institute of Chartered Accountants, effectively replaces the old accounting treatment of asset retirement costs with Section 3110 - Asset Retirement Obligations, effective for fiscal years beginning on or after January 1, 2004.

Section 3110 requires the recognition of all legal obligations associated with the retirement of a tangible long-lived asset. These legal obligations are referred to as Asset Retirement Obligations (AROs). If a reasonable estimate of the fair value can be made, the obligations must be recorded on a company's balance sheet as a liability. If a reasonable estimate of the fair value of the obligation cannot be made, they must be disclosed in the notes to the financial statements and may not be recognized until the period in which a reasonable estimate can be made which may not be until they are incurred.

Section 3110 is to be applied on a retroactive basis with a restatement of financial statements of prior years, effective F2005.

The change in accounting standard has a significant impact in F2005 on BC Hydro's depreciation expense, Future Removal and Site Restoration (FRSR) provisions, and equity.

Consistent with the existing requirements of GAAP, BC Hydro currently accounts for asset retirement costs by creating a provision for FRSR, which is a liability on BC Hydro's balance sheet that increases every year until the asset is de-commissioned. The yearly increase to the liability account on the balance is reflected as depreciation expense on the statement of operations. Actual de-commissioning costs are charged against the liability on the balance sheet as incurred.

Under the new Section 3110, the existing FRSR provisions are to be eliminated and replaced where applicable with AROs. BC Hydro has very few assets with ARO liabilities. As a result most of the FRSR provisions currently reflected on BC Hydro's balance sheet will no longer be eligible for that treatment, and may only be disclosed in the notes to the financial statements as required by Section 3110. The effect is to increase BC Hydro's retained earnings. Dismantling and site restoration costs associated with assets that do not have ARO liabilities on the balance sheet will be expensed as they are incurred.

Currently, BC Hydro's FRSR balance consists of two components: provision for future dismantling costs (credit balance of $244 million), and provision for future salvage proceeds (debit balance of $64 million). Under Section 3110 the provision for future dismantling costs ($244 million) will be transferred to retained earnings. The provision for salvage proceeds ($64 million) will be transferred to accumulated depreciation. Based on current estimates, AROs will be created with an asset cost base of $14 million. As at April 1, 2004, the accumulated depreciation on these ARO assets, which will be reflected in retained earnings, will be $7 million. The present value of the ARO liability as at April 1, 2004 will be $18 million. The accumulated accretion to April 1, 2004 on this liability, which will be reflected in retained earnings, will be $4 million.

Table 2-14. Estimated Impact of AROs on Retained Earnings, F2005

($ millions)	**Estimated Impact**
Reversal of FRSR provision	$244
Retroactive accumulated depreciation on ARO asset	(7)
Retroactive accretion on ARO liability	(4)
Net Increase in Retained Earnings	**$233**

Tab 14

YUKON ENERGY

YUKON ENERGY CORPORATION

20-YEAR RESOURCE PLAN: 2006-2025

RESOURCE PLAN UPDATE

November, 2006

INTRODUCTION

To ensure all relevant updated information on projects where there are ongoing planning activities is available to the Board, Yukon Energy has prepared this update. The update is organized into four sections:

- Summary of Updates
- Marsh Lake Fall/Winter Storage Project
- Mirrlees Life Extension Project
- Carmacks-Stewart Transmission Project

1.0 SUMMARY OF UPDATES

The following is a summary of the ongoing planning activities undertaken since the Resource Plan was filed in relation to three of the near term projects proposed in the Resource Plan.

- **Marsh Lake Fall/Winter Storage Project:** Since the Resource Plan was filed with the Board, Yukon Energy has participated with Marsh Lake residents and environmental consultants in initial investigations of the issues related to the project. As a result of that investigation, it has become clear that the Marsh Lake project will not in any likelihood be able to proceed through the licencing process in the very near term, as originally intended. Given the above assessment Yukon Energy's Resource Plan no longer includes any plans to pursue the Marsh Lake Fall/Winter Storage Project.

- **Mirrlees Life Extension Project:** Yukon Energy's investigations into the technical feasibility of the Mirrlees Life Extension have continued to confirm that despite obvious challenges, the project remains feasible. Yukon Energy has now completed partial disassembly of key components of WD3 for inspection, and observations indicate no conditions that would be fatal to the project. Further definition of the expected parts scope (and related project budgets) is now underway.

  In addition as a result of continuing positive results from investigation into the three Whitehorse Mirrlees, Yukon Energy has assessed the potential for rehabilitating a previously retired Mirrlees KV-16 unit at its Faro diesel plant. A Faro option offers two key characteristics that make it attractive as an early capacity addition. Firstly it adds new capacity (5 MW) to the system and thereby aids in addressing the shortfalls that arise due to Yukon Energy's decision not to proceed with Marsh Lake Fall/Winter Storage, and secondly, no existing units must be taken off-line to allow rehabilitation work to proceed (unlike WD3, which is required capacity on the system, cannot be taken off-line for rehabilitation work except in low load periods such as summer). This Faro Mirrlees unit has now been partially disassembled similar to WD3, and no major issues have been identified.

Due to the confirmed technical feasibility as well as the benefits of rehabilitating the retired Mirrlees at Faro, Yukon Energy expects to proceed with this (or an equivalent) Faro focused diesel project in 2007 for 5 MW of added firm capacity.[1]

- **Carmacks-Stewart Project:** Since the June filing, Yukon Energy has carried out extensive consultations with the NTFN and others and has filed its YESAB application which includes the selected route for the proposed transmission line. Further, a number of very positive developments have occurred in relation to the Minto mine. The mine owners have now received the $85 million in debt financing required to complete the mine which is now more than one third built. It is scheduled to be completed and in production in the second quarter of 2007. Although a PPA has not yet been concluded with Minto, Yukon Energy is hopeful it will be completed soon.

  Western Copper has also recently reconfirmed its interest in reaching agreement with Yukon Energy for supply of grid power and negotiations are expected to begin shortly.

  Given these developments Yukon Energy is proposing the construction of Stage 1, i.e. 138 kV line from Carmacks to Pelly Crossing, as soon as the necessary regulatory approvals are obtained and a PPA is finalized with the Minto mine which results in material ratepayer benefits (over and above the cost of the line). Yukon Energy is confident this can be achieved assuming YDC contributes approximately $5 million to the project (which amount represents the approximate value of increased payments to YDC under the FTN caused by the increased loads on the WAF system).

2.0 MARSH LAKE FALL/WINTER STORAGE PROJECT

Yukon Energy has decided not to proceed with the Marsh Lake Fall/Winter Storage project. Meetings with Marsh Lake residents and initial environmental scans have indicated a clear inability to have the project licenced in the very near term due to specific detailed concerns. Among the concerns noted were specific issues related to shoreline erosion, high fall water level impacts in low-lying areas, and related impacts on the built environment. Although there has been no detailed assessment of these issues, they are not items that can be addressed in a short period of time. As the project cannot proceed in the very near term, one of the most appealing characteristics of the project is no longer available.

As an option to enhance the output of Whitehorse Rapids, Marsh Lake Fall/Winter Storage was considered to be a suitable first step towards overall plant enhancement as it was relatively modest (1.6 MW), required no new physical works, and was expected to be one that could be completed in the very near term due to no flooding above natural levels. Further WH Rapids plant enhancement options, such as enhanced upstream storage in other parts of the Southern Lakes area or unit upgrades such as re-runnering, would then be pursued as subsequent steps.

As Marsh Lake Fall/Winter Storage cannot now be pursued quickly as a near-term resource option, it is no longer suitably thought of as a first step in enhancing the Whitehorse Rapids output. Accordingly, Yukon Energy's updated Resource Plan no longer includes any plans to proceed with Marsh Lake Fall/Winter Storage today or in the future.

[1] Yukon Energy is also assessing the used diesel market to determine whether there are any comparable used units that would offer greater benefits to the system than the Faro Mirrlees at the same cost. For example, one such option being pursued is two used 2.8 MW EMD units which Yukon Energy's initial investigations indicate could be undertaken at a comparable cost to rehabilitation of the Faro Mirrlees. Depending on the outcome of Yukon Energy's due diligence, this option may be a better fit for the Faro plant in terms of unattended operation (Yukon Energy only maintains a part time operator in Faro) and peaking operation (EMD units are better suited to standby, quick startup and peaking use, and the Faro plant is not foreseen to be a baseloaded plant under any load forecast scenario).

Yukon Energy is continuing to assess various options to enhance the Whitehorse Rapids output as described in the Resource Plan. The work at this point is focused primarily on river ice studies, as well as a review of other upstream storage options. These other enhancement options are not in an advanced enough stage of study to be available as near-term resources.

3.0 MIRRLEES LIFE EXTENSION PROJECT

Since the filing of the IRs Yukon Energy has proceeding with planning for the Mirrlees Life Extension Project at Whitehorse. This includes assessing the scope of work, determining expected parts requirements and scheduling the overhaul activities. As a result of this continuing assessment and planning, Yukon Energy has continued to confirm the capability to complete the Life Extension project on the Whitehorse Mirrlees.

The continuing investigation has also highlighted a resource option previously considered to not be available to Yukon Energy. As noted in YUB-YEC-2-10(f), there is a fourth Yukon Energy Mirrlees unit at Faro that was previously retired. However, as a result of investigations related to this unit, Yukon Energy can now confirm that the Faro Mirrlees (at 5 MW) is a suitable candidate for rehabilitation consistent with the Whitehorse Mirrlees. In addition, there are major potential benefits that arise by undertaking a Faro focused option first (in 2007) with the Whitehorse Mirrlees units to follow (in 2008, 2009 and 2010[2]). There are two clear benefits of proceeding first with the project at Faro compared to the Whitehorse units:

1. **New Capacity:** A Faro focused project brings to the system on the order of 5 MW compared to the current available capacity. In contrast, overhauling WD3 in 2007 would only secure less than 1 MW of new capacity compared to today (the main benefit is from avoiding retirement, not new additions compared to today). As a result, a Faro-focused project in 2007 more than addresses lost capacity from the decision not to pursue the Marsh Lake Fall/Winter Storage project (1.6 MW in 2007), and provides the WAF system with some added near-term capacity cushion.
2. **Less Schedule Risk:** The Faro option relates to generation that is not now considered firm capacity to the WAF system. As a result, a Faro-focused project can be started at any time, including during winter, without impacting on the amount of backup capacity available on the system. In contrast, plans for overhauling WD3 were focused on the need to start the work only after winter peak loads had subsided, and ensuring completion by the time fall loads begin to grow to cold-weather levels. Given the range of normal uncertainties associated with the Life Extension project (particularly the range of parts that might be required, and associated delivery times), it is therefore preferable to begin with Faro. The Whitehorse focused project would then not be started until the added "cushion" noted above had been established. In addition, general plant related work on the Whitehorse plant can be started in 2007 so that by the time the first Whitehorse Mirrlees unit is being addressed in 2008 the scope of work is reduced and there is less schedule related risk than by having an overhaul occur in 2007 simultaneous with the general plant work.

The cost for the rehabilitation of the Faro Mirrlees unit, is expected to be in the range of the Whitehorse capacity noted in Supplemental Materials Tab 1 (at about $0.457 million/MW, or a total of about $2.3 million (2005$)).

[2] Note however that WD3 was planned for retirement in 2007 so there would need to be a one year delay in dealing with this unit compared to the basic retirement scenario

The net capacity gains to the system as a result of the updated Mirrlees Life Extension Project is set out in Table 1.

Table 1: Impact of combining Faro Mirrlees rehabilitation with Whitehorse Mirrlees Life Extension project

Near Term Impact of Mirrlees Life Extension Project on WAF Capacity (MW)

	Mirrlees WD1, 2, and 3 and FD1 output under **retirement scenario**					Mirrlees WD1, 2, and 3 and FD1 output under Life Extension ***as originally proposed in Resource Plan***						Mirrlees WD1, 2, and 3 and FD1 output under Life Extension ***as updated***					
	WD1	WD2	WD3	FD1	**Total**	WD1	WD2	WD3	FD1	**Total**	*difference **	WD1	WD2	WD3	FD1	**Total**	*difference **
2006	3.0	4.2	4.2	0.0	**11.4**	3.0	4.2	4.2	0.0	**11.4**	*0.0*	3.0	4.2	4.2	0.0	**11.4**	*0.0*
2007	3.0	4.2	0.0	0.0	**7.2**	3.0	4.2	5.0	0.0	**12.2**	*5.0*	3.0	4.2	4.2	5.0	**16.4**	*9.2*
2008	3.0	4.2	0.0	0.0	**7.2**	3.0	5.0	5.0	0.0	**13.0**	*5.8*	3.0	4.2	5.0	5.0	**17.2**	*10.0*
2009	3.0	0.0	0.0	0.0	**3.0**	4.0	5.0	5.0	0.0	**14.0**	*11.0*	3.0	5.0	5.0	5.0	**18.0**	*15.0*
2010	3.0	0.0	0.0	0.0	**3.0**	4.0	5.0	5.0	0.0	**14.0**	*11.0*	4.0	5.0	5.0	5.0	**19.0**	*16.0*
2011	0.0	0.0	0.0	0.0	**0.0**	4.0	5.0	5.0	0.0	**14.0**	*14.0*	4.0	5.0	5.0	5.0	**19.0**	*19.0*
2012	0.0	0.0	0.0	0.0	**0.0**	4.0	5.0	5.0	0.0	**14.0**	*14.0*	4.0	5.0	5.0	5.0	**19.0**	*19.0*

* difference compared with the retirement scenario

The Faro-focused option at this point is based on costs and benefits related to rehabilitation of the Faro Mirrlees. Nonetheless, similar to the Whitehorse-related options, other "used" unit alternatives will be considered by Yukon Energy where they are cost competitive and offer other advantages. For example, with respect to the Faro plant, there exists a possible option to secure two EMD 645F4B 2.8 MW units for installation as an alternative to a Mirrlees rehabilitation with a comparable or better economic life and at a comparable total project cost. The used EMD units are newer than the Mirrlees, with better availability of parts and technical support, and are well suited to unattended and peaking operation. This is particularly relevant at Faro, where Yukon Energy maintains only a part time plant operator and the plant is not expected to be a main WAF baseload generation plant under any foreseeable load forecast scenario. These EMD units can make use of the same building as the Faro Mirrlees, as well as transformer and cooling systems. In any event, the capacity and pricing for Mirrlees rehabilitation and used EMD units are expected to be comparable, so for Resource Plan level assessment, the two are considered basically equivalent. Yukon Energy's ultimate decision with respect to Mirrlees versus used EMDs at Faro will likely focus on practical considerations such as constraints related to building layout and the condition and terms for purchase of the used units.

As a result of the decision to proceed with a Faro-focused option in 2007 with Whitehorse Mirrlees Life Extension to follow in 2008, 2009 and 2010, Yukon Energy provides the following summary of the capacity shortfalls under the proposed near-term projects, as well as system shortfalls in the event the full Carmacks-Stewart interconnection does not proceed for 2009 (see section 4 of this update):

Table 2: Updated WAF Capacity Balance (MW) with Mirrlees Life Extension, Carmacks-Stewart Transmission Line and Aishihik 3rd Turbine under 4 load scenarios

Faro and Whitehorse Mirrlees Life Extension, Carmacks-Stewart T-Line and Aishihik 3rd Turbine
Table 2

	System Load Conditions			Resource Plan - Capacity Balance							
Year	WAF Peak Load (MW)	LOLE Shortfall (MW)	N-1 Shortfall (MW)	Capacity Driver	Initial Surplus/ (shortfall) (MW)	Faro Mirrlees Rehabilitation - 2007 (MW)	Whitehorse Mirrlees Life Extension - 2008/09/10 (MW)	Carmacks-Stewart T-Line - 2009 (MW)	Aishihik 3rd Turbine - 2009 (MW)	Resulting WAF System Balance (Shortfall indicates req. for new diesel) (MW)	Shortfall Absent C-S Interconn. (MW)
Base Case Load Forecast (also reflects Base Case with Minto)											
2005	56.4	6.5	0.3	N-1	0.3					0.3	0.3
2006	57.4	5.5	(0.7)	N-1	(0.7)					(0.7)	(0.7)
2007	58.5	0.2	(6.0)	N-1	(6.0)	5.0	4.2			3.2	3.2
2008	59.6	(0.9)	(7.1)	N-1	(7.1)	5.0	5.0			2.9	2.9
2009	60.6	(6.1)	(12.3)	N-1	(12.3)	5.0	10.0	6.0	0.0	8.7	2.7
2010	61.7	(7.2)	(13.4)	N-1	(13.4)	5.0	11.0	5.9	0.0	8.5	2.6
2011	62.9	(11.4)	(17.6)	N-1	(17.6)	5.0	14.0	5.8	0.0	7.2	1.4
2012	64.0	(12.5)	(18.7)	N-1	(18.7)	5.0	14.0	5.6	0.0	5.9	0.3
Low Sensitivity Load Forecast											
2005	56.4	6.5	0.3	N-1	0.3			**		0.3	0.3
2006	56.9	6.0	(0.2)	N-1	(0.2)			**		(0.2)	(0.2)
2007	57.4	1.3	(4.9)	N-1	(4.9)	5.0	4.2	**		4.3	4.3
2008	57.9	0.8	(5.4)	N-1	(5.4)	5.0	5.0	**		4.6	4.6
2009	58.4	(3.9)	(10.1)	N-1	(10.1)	5.0	10.0	**	0.0	4.9	4.9
2010	59.0	(4.5)	(10.7)	N-1	(10.7)	5.0	11.0	**	0.0	5.3	5.3
2011	59.5	(8.0)	(14.2)	N-1	(14.2)	5.0	14.0	**	0.0	4.8	4.8
2012	60.0	(8.5)	(14.7)	N-1	(14.7)	5.0	14.0	**	0.0	4.3	4.3
						** - C-S not expected to be constructed under Low loads with no mines					
Base Case Load Forecast with 2 Mines (Minto & CC)											
2005	56.4	6.5	0.3	N-1	0.3					0.3	0.3
2006	57.4	5.5	(0.7)	N-1	(0.7)					(0.7)	(0.7)
2007	60.5	(1.8)	(6.0)	N-1	(6.0)	5.0	4.2			3.2	3.2
2008	68.6	(9.9)	(7.1)	LOLE	(9.9)	5.0	5.0			0.1	0.1
2009	69.6	(15.1)	(12.3)	LOLE	(15.1)	5.0	10.0	6.0	0.6	6.5	0.5
2010	70.7	(16.2)	(13.4)	LOLE	(16.2)	5.0	11.0	5.9	0.6	6.3	0.4
2011	71.9	(20.4)	(17.6)	LOLE	(20.4)	5.0	14.0	5.8	0.6	5.0	(0.8)
2012	73.0	(21.5)	(18.7)	LOLE	(21.5)	5.0	14.0	5.6	0.6	3.7	(1.9)
High Sensitivity Load Forecast (including Minto and CC)											
2005	56.4	6.5	0.3	N-1	0.3					0.3	0.3
2006	58.1	4.8	(1.4)	N-1	(1.4)					(1.4)	(1.4)
2007	61.8	(3.1)	(7.3)	N-1	(7.3)	5.0	4.2			1.9	1.9
2008	70.6	(11.9)	(9.1)	LOLE	(11.9)	5.0	5.0			(1.9)	(1.9)
2009	72.4	(17.9)	(15.1)	LOLE	(17.9)	5.0	10.0	6.0	0.6	3.7	(2.3)
2010	74.3	(19.8)	(17.0)	LOLE	(19.8)	5.0	11.0	5.9	0.6	2.7	(3.2)
2011	76.2	(24.7)	(21.9)	LOLE	(24.7)	5.0	14.0	5.8	0.6	0.7	(5.1)
2012	78.2	(26.7)	(23.9)	LOLE	(26.7)	5.0	14.0	5.6	0.6	(1.5)	(7.1)

Table 2 sets out the capacity requirements and Yukon Energy's updated proposals to meet these requirements with Faro Mirrlees Rehabilitation in 2007, Whitehorse Mirrlees Life Extensions in 2008, 2009, and 2010, Carmacks-Stewart Transmission Line in 2009 and Aishihik 3rd turbine in 2009. The resulting system balance is shown in the second column from the right of the sheet. The column to the far right describes the system in the event that the full interconnection of Carmacks-Steward does not occur in 2009 as planned (see section 4.3 of this update).

- Under both the **Base Case Load Forecast** and the **Low Sensitivity Load Forecast** there is enough capacity through to 2012 with or without Carmacks-Stewart interconnection being completed (note the Low Load forecast includes no mines, so no Carmacks-Stewart project is expected under that scenario).
- Under the **Base Case Load Forecast with 2 Mines** there is adequate capacity to 2012 if Carmacks-Stewart is connected. In the event that Carmacks-Stewart is not interconnected shortfalls of 0.8 MW and 1.9 MW appear on the system in 2011 and 2012 respectively.
- Under the **High Sensitivity Load Forecast** there is adequate capacity in most years with Carmacks-Stewart except 2008 (1.9 MW shortfall prior to Carmacks-Stewart completion) and 2012

(1.5 MW shortfall). However without Carmacks-Stewart shortfalls begin in 2008 and rise to 7.1 MW by 2012.

4.0 CARMACKS-STEWART

Updates to the filed materials are provided below regarding:

- Project Proposal Submission to YESAB
- Update re: Minto and Carmacks Copper Mines
- Update re: Project Economics

PROJECT PROPOSAL SUBMISSION TO YESAB

Yukon Energy filed with the YESAB Executive Committee on October 13, 2006 the Project Proposal Submission for the Carmacks-Stewart/Minto Spur (CS/MS) Transmission Project lines and substations. Copies of the Project Proposal Submission were subsequently made available to the YUB and participants in the current Resource Plan proceeding, as well as posted on YEC's web site.

The Project Proposal Submission provides the full detailed description currently available for the CS/MS project (Chapter 5 of the Submission); this information will not be materially enhanced prior to completion of engineering dynamic system model and final design work and the YESAB Draft Screening Report.

The Project Proposal Submission includes the updated CS/MS project construction schedule and stages (Figures 5.4-1 and 5.4-2 from the Submission), which are attached in Schedule "A" to this update. Recognizing that delays in bringing this project into service will adversely affect the Minto mine and existing ratepayers, the schedule describes the anticipated timing of the additional activities required to achieve in-service of Stage 1 (CS from Carmacks to Pelly Crossing plus MS construction) as soon as possible during the 3rd quarter of 2008. Three points can be highlighted from this anticipated project schedule for Stage 1:

- **Permitting and Approvals**: The schedule anticipates completion of the YESAB review, and securing all needed permits and approvals for the full project, by mid-summer 2007. The YESAB Executive Committee assessment process includes a pre-screening adequacy review (which is currently underway), screening (with public comment), release and public comment on a Draft Screening Report, and the Final YESAB Report.

- **Final Design and Tendering**: In order to secure the earliest possible construction start date, Stage 1 construction preparation involving final design and then tendering is planned to begin early in 2007, prior to completion of the YESAB review process, for completion by mid-summer 2007 so that Stage 1 construction could start as soon in fall 2007 as all approvals are secured. The schedule reflects the need for the final YEC Board of Director's decision to be based on the receipt of a tendered contract price.

- **Separation of Design and Construction Contracts**: The proposed approach separates the design and construction contracts, and ensures that the final YEC decision in mid 2007 to proceed with Stage 1 construction is based on ability at that time to award a firm construction contract price to complete the project as designed.

The Project Proposal Submission sets out the preferred route selected for the 138 kV CS project and for the 35 kV MS project based on the route evaluation process carried out by Yukon Energy in consultation with the three Northern Tutchone First Nations (NTFNs) and others. This Submission also provides information and analysis addressing YESAB assessment requirements, including:

- detailed description of the project (preliminary design specifications as needed for assessing environmental and socio-economic effects, including project description for each phase of activities),
- review of public consultations to date (including consultations with the NTFNs pursuant to the MOU),
- description of existing environmental and socio-economic conditions without the project,
- the evaluation carried out of alternative routes, and
- the assessment of environmental and socio-economic effects after consideration of mitigation measures.

The selected CS route as described in the Project Proposal Submission is approximately 172 km (as compared with 180 km initially estimated), including 42 km from the proposed new Carmacks substation to McGregor Creek, 27 km from McGregor Creek to the proposed Minto Landing substation (part of MS project), 29.5 km from the Minto Landing substation to the proposed new Pelly Crossing substation, and (Stage 2) 74 km from the Pelly Crossing substation to the expanded Stewart Crossing substation. The selected MS route (which is part of Stage 1 activity as described in the Submission) is approximately 27 km (compared with about 30 km initially estimated) from the Minto Landing substation to the Minto mine substation; at the end of the Minto mine life it is assumed in the Submission that the MS facilities crossing the Yukon River and west of the river would be decommissioned and removed (retaining the Minto Landing substation and about 2 km of 35 kV line east of the river to serve local retail customers).

In summary, the Project Proposal Submission indicates that the specified CS/MS project is expected to cause no significant adverse effects on the biophysical environments or on the socio-economic components. This conclusion reflects careful routing of the transmission lines and the consideration of mitigation measures that would reduce or eliminate remaining potential adverse effects. Some residual adverse effects (e.g., the physical presence of the facilities result in an altered landscape and other changes as long as the facilities are in place, and improved access in some areas may create concerns about potential conflicts with existing resource uses) are anticipated, but are not expected to be significant based on criteria relevant to the YESAB assessment.

The Project Proposal Submission also indicates that positive environmental and socio-economic effects are likely to result from the CS/MS project as it improves the use of the existing WAF and MD grid power resources (including existing surplus hydro generation) and consequently displaces diesel generation emissions. Overall, the estimated magnitude of displaced diesel generation during operation of the Minto mine approximates 34 GW.h/yr, which exceeds current total utility diesel generation in Yukon (estimated at less than 25 GW.h/yr). It is anticipated that the project will create associated benefits for Yukon electric utility ratepayers, enhance the feasibility and economics of new mining developments, improve access to certain areas, and provide opportunities for local jobs and business activity during construction and subsequent periodic ROW clearing and maintenance.

The Project Proposal Submission reviews briefly the following alternatives to the proposed CS/MS project:

- **35 kV line to serve Minto mine**: This alternative, which was provided for in the LOI between Sherwood Copper and YEC, would provide a 35 kV line from Carmacks to the Minto mine and would by itself result in the community of Pelly Crossing continuing to rely on diesel generation unless YEC was to extend the 35 kV line from Minto Landing to Pelly Crossing (this would be seriously considered by YEC, pursuant to the MOU with the NTFNs). The 35 kV facilities from Carmacks to Minto landing and/or Pelly Crossing would not be of sufficient voltage to supply future potential mines such as the Carmacks Copper mine in the Williams Creek area west of McGregor Creek. This alternative would also not support future interconnection between the WAF and MD power grids. Unless long-term expected service could justify its retention, the 35 kV line would be partially or fully decommissioned at the end of the Minto mine life with limited, if any, future long-term benefits to Yukoners.

- **Do not proceed with the project or any other option**: This alternative would include the following outcomes:
  - No grid power could be provided to future mine developments in this area, such as the Minto mine and the Carmacks Copper mine - this would adversely affect mine operating costs and economics, reducing royalties to government and potentially First Nations, and increasing diesel generation greenhouse gas emissions.
  - Pelly Crossing would continue to be served by diesel generation.
  - Interconnection of Yukon Energy's existing WAF and MD grids would not be realized, preventing this improvement to YEC's overall system reliability and efficiency.
  - Economic development opportunities that could be realized with the CS/MS project in the Carmacks/Stewart Crossing region with access to grid power may not be encouraged.

UPDATE RE: MINTO AND CARMACKS COPPER MINES

The Minto mine debt financing of $85 million is now secured and construction is over one-third completed. The mine will begin operating in the 2nd quarter of 2007, using on-site diesel generation. Overall power needs are now expected to be materially higher than previously estimated, and the mine life is also expected to be longer.

Sherwood Copper has provided several update press releases on the Minto mine project (see Sherwood's website at http://www.sherwoodcopper.com) since the Resource Plan was submitted to the YUB in June. The updated information available to YEC includes the following:

- **Feasibility Study**: Results of the Feasibility Study were announced on July 10, 2006 (copy of presentation on Sherwood Copper web site) and updated August 28, 2006. Based on project optimization announced August 28, 2006 the expected mine life for current financing is 7.2 years (versus 10.6 years in the Feasibility Study). Mine operation is currently planned to begin in 2007 and continue into 2014, with shut down activities and related power loads continuing thereafter until 2018; however, three or more years of additional production are projected if additional high grade resources are confirmed by drilling currently being completed in Area 2 and, in addition, stockpiled low grade material will also be available for processing in the future should economics warrant after processing of higher grade material has been completed. The mine at full production (i.e., under the current plan, after the first 12 months of operation and continuing for the next 6.2 years) is expected to utilize 32.5 GW.h/yr of electrical energy (by comparison, earlier YEC analysis assumed about 24.5 GW.h/yr); the feasibility study and current plans assume operation of the mine using on-site diesel generation (although the Feasibility Study refers to the LOI with YEC and the opportunities for the Minto mine to secure cost savings of about $4 million per year, net of capital contributions, by use of grid power by the end of 2008 with a net present value savings (discounted at 7.5% back to 2006) for Minto of about $19 million).
- **Project financing:** Closure on October 26, 2006 on approximately C$85 million senior and subordinated debt package as announced October 17, 2006 to complete the funding required for the Minto mine, and commencement to draw against the facilities to complete construction of the high grade Minto copper:gold mine – the mine is more than one-third built and is scheduled to begin production in the second quarter of 2007, producing an average of 41 million pounds of copper and 17,295oz of gold per year. The debt package is comprised of a C$65 million project loan facility (PLF) and a $20 million subordinated debt facility (SDF). The PDF carries an interest rate of LIBOR plus 2.25% and is repayable over two years commencing November 30, 2007. The SDF carries an interest rate of LIBOR plus 3% and is repayable over one year commencing November 30, 2009.

- **Other recent announcements**: On November 1 encouraging results were announced from metallurgical test work undertaken post-feasibility study. On November 2, results were announced for a further 15 drill holes from Area 2; these results continue to delineate high grade copper-gold mineralization over an area of up to 350m by 260m and well outside the original magnetic anomaly targeted, and this mineralization has the potential to lead to an extended operating life of the Minto mine at similar grades to those planned for the first six years of operation.

Yukon Energy and Sherwood Copper continue to negotiate the PPA pursuant to the LOI, focusing on assumed development of the Stage 1 CS/MS project to Pelly Crossing at 138 kV from Carmacks to Pelly Crossing and including consideration of YEC's potential use (after the project is in-service) of the 6.4 MW surplus on-site diesel generation. Minto will be pay power rates as approved by the YUB (and that fully meet the requirements of OIC 1995/90 that such rates ensure that major industrial customers as a class pay at least full cost of service determined by treating the whole of Yukon as a single rate zone)[3], be fully responsible for the costs of the MS 35 kV line, and undertake obligations that reduce YEC's risks with regard to costs for the 138 kV line. Minto will provide security with regard to its obligations in this regard. A copy of the PPA will be filed with the YUB as soon as it is concluded.

Western Copper has re-confirmed its interest in reaching an agreement with Yukon Energy for the supply of grid power to their Carmacks Copper project. Western Copper notes that it has made formal applications to both the Yukon Government and the YESAB for project approval. Until such time as it has received permits for this project from the appropriate authorities (which YEC understands is not currently expected to occur until sometime in the first half of 2007 at the earliest), Western Copper has stated that it is not prepared to enter into any formal commitment regarding a PPA. Yukon Energy has informed Western Copper that, subsequent to securing the needed formal PPA commitment, YEC will require potentially 6 to 12 months or more to prepare a YESAB Project Proposal, complete YESAB assessment of the 138 kV spur line (11 km across Yukon River from McGregor Creek to the mine site), and secure approvals as needed from governments; thereafter, construction timing could also be contingent on seasonal conditions.

UPDATE RE: PROJECT ECONOMICS

Based on the update information, Yukon Energy is proposing to proceed with the 138 kV CS project with development to occur in two stages:

- Stage 1 will proceed first with the 138 kV CS development to Pelly Crossing (and the 35 kV MS spur line), and will proceed only after a signed PPA with Minto.
- Stage 2 will proceed thereafter only when conditions will permit its development without any adverse impact on ratepayers; in this regard, firm commitment to connect the Carmacks Copper mine is currently assumed to be a precondition for Stage 2 development.

Within the above context, Yukon Energy is proposing to proceed with Stage 1 without any YTG funding commitment beyond the $0.45 million already committed for initial planning costs. Further, based on the update, YEC concludes that it will be feasible to proceed to develop the desired 138 kV long-term infrastructure without adverse effects on Yukon ratepayers, and therefore there is no need to consider

[3] See response to UCG-YEC-2-2 which reviews OIC 1995/90 and its application to industrial rates (including review of past experience and current status); the OIC is provided therein as Attachment 1. The relevant firm rate for major industrial customers (Rate Schedule 39) was developed in the 1996/97 GRA when the Faro mine was the sole customer in that class, reflects cost of service prepared for Yukon (YEC and YECL) at that time, and remains as an interim rate since the Faro mine last closed in 1998, pursuant to Board Order 1998-5. The current Rate 39 includes a Demand charge of $18.60/kVA per month (Demand based on peak Billing Demand in last 12 months, excluding April to September) and an Energy charge of $.05301 per kW.h; Rider F is applicable to Rate 39 but Rider J is not applicable to Rate 39. Assuming an annual load factor of about 84% for the Minto mine, the current Rate Schedule 39 would result in effect in an average rate of 8.334 cents per kW.h plus the current Rider F (expected to approximate about 1 cent per kW.h in near term).

further the option of developing only 35 kV facilities which would fail to contribute to development of desired long-term transmission infrastructure in Yukon.

Based on the above updates and other related current considerations, the CS project economics is affected by the following:

- Adjusted capital costs (for selected route and for review of construction market conditions).
- Adjusted present value of ratepayer benefits (to reflect Minto mine load changes), more detailed consideration of the potential rate for use of the current system resources, and consideration of YEC costs incurred regarding the Flexible Term Note (now owned by YDC)[4] due to added WAF loads.
- Assumed no-cost capital contribution of up to $5 million to be provided by YDC towards Stage 1 development in recognition of the added interest and principal payments expected to be received under the Flexible Term Note (FTN) due to increased YEC WAF sales as a result of the CS project.

The PPA is currently being negotiated with Minto; accordingly, no update is provided and no consideration is given to specific PPA terms in this update.

No updated analysis is developed with regard to the Carmacks Copper mine.

Capital Costs

The updated capital cost (2005$)[5] for the 138 kV Carmacks-Stewart Transmission Project based on the route as selected (and the adjusted line distances) in the YESAB Project Proposal Submission and the initial costing assumptions per km is $30.2 million (including $3.0 million for planning activities), with $17.2 million for Stage 1 (Carmacks to Pelly Crossing) and $13.0 million for Stage 2 (Pelly Crossing to Stewart Crossing).[6]

Yukon Energy has reviewed potential escalation of the line-related capital costs due to tight labour market conditions in Western Canada and other factors (e.g., raw material cost increases), based on review of recent Yukon Energy cost experience and also discussions in August with engineering consulting firms leading to securing expressions of interest to submit proposals on the upcoming RFP for engineering services for this project.[7] Based on this review, capital cost estimates (2005$) for evaluating the CS project are considering a range of potential overall increases of about 17% and 34%, e.g., total CS project costs ranging from $30.2 million to $40.6 million, with mid-point of $35.4 million (Stage 1 costs ranging from $17.2 million to $23.1 million, with mid-point of $20.2 million)[8].

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[4] On March 30, 2005 Yukon Development Corporation (YDC) purchased this Note from the Government of Canada for $11.3 million; the purchase price reflected the Note's reduced value (face value of $28.278 million at the time of the acquisition) due to there being no industrial customers on WAF. The terms of the Note with YEC, which remain unchanged, provide for payments of interest and principal to be deferred and abated, respectively, if YEC's power sales on the WAF distribution system are less than specified amounts. The Note bears interest at 7%, and requires principal payments of up to $1 million, payable in annual instalments; after adjusting for abated interest, the effective interest rate on the Note for 2005 was 2.90% (2004-2.86%).

[5] All costs are stated in 2005$. Assuming in-service in 3rd quarter 2008, the in-service costs reflecting inflation and interest during construction would be higher (likely by about 10% to 15% under the current project schedule) than the stated 2005$.

[6] Based on the LOI and YEC requirements, capital costs for the 35 kV Minto Spur are assumed to be assigned to the Minto mine, and thus are not considered in the assessment of YEC's economics. The updated capital cost (2005$) for the 35 kV Minto Spur based on the route as selected (and the adjusted line distances) in the YESAB Project Proposal Submission and other costing assumptions is $2.6 million; these estimates include provision for substation facilities at Minto Landing and the Minto mine site, added costs for costs for the segment crossing the Yukon River, and provision for planning and permitting costs.

[7] Yukon Energy has now received expressions of interest from ten engineering consulting firms; a short list of five firms has been selected.

[8] The equivalent mid-point capital cost estimate ($2005) for the Minto Spur is $3.4 million – the higher percent escalation reflects a higher escalation assumed for 35 kV line costs as well as weighting of line costs relative to other costs for this project.

Ratepayer Benefits

The updated (2005$) present value net operating income earned by YEC from supplying the Minto mine (ratepayer benefits) is estimated at $12.5 million (compared with $11.6 million in the earlier estimates) based on the following assumptions (as well as 7.5%/year nominal discount rate):

- Updated Minto mine loads (32.5 GWh/yr versus 24.5 GW.h/yr) and expected producing mine life served by YEC from October 2008 until about May 2017 (8.5 out of 10 years versus 6 out of slightly over 7 years); minimal loads in following 3 to 4 shut down years before full decommissioning are not considered.
- Assumed rate of 9.3 cents per kWh, without any escalation, for mine charges re: system use other than MS spur and CS line capital costs (this rate in effect reflects current interim Rate 39 plus assumed Rider F at 1 cent per kWh).
- Deduction of an estimated 1.7 cents per kWh to provide for incremental YEC interest costs associated with added FTN interest (due to terms of the Note and current level of WAF sales resulting in interest rate well below the 7% maximum rate in the Note)[9]. The present value ($2005) of these added costs is estimated at $2.8 million for interest only; higher principal payments will also occur (equal to about 50% of the added interest payments).

Ratepayer benefits present value (2005$) remain at $2.3 million for Pelly Crossing and $13.7 million for Carmacks Copper if it starts operating in 2008, less provision for added Canada Flexible Term Note interest costs to YEC of (present value) $0.2 million for Pelly Crossing sales and about $2.0 million for Carmacks Copper mine sales (which would result in maximum Note payments coming into force). Similarly, no adjustments are made at this time to estimated ratepayer benefits of connection of the two grids (about $10 million present value).

In connection with the FTN payment added costs due to the CS project new loads, as stated earlier, it is assumed that YDC will provide no cost capital to YEC for the project equal to $5 million towards Stage 1 development in recognition of the added interest and principal payments expected to be received by YDC.

Overall Summary Assessment

Overall assessment reviews both the expected YEC capital costs and the associated estimates of ratepayer benefits in order to derive a net present value benefit or cost (2005$). The update examines these net benefits without considering the present value contributions that will have to be made by the mines under the PPAs.

As indicated in the initial Resource Plan filing, full development of the CS project with both mines would provide positive net present value benefits. The updated estimate of these positive net benefits without any new YTG funding is $6 million (2005$), reflecting the extent to which net ratepayer benefits of $36.3 million exceed net capital costs of $29.95 million, based on the following:

- **Total YEC net capital costs, using update mid-point estimates, of $29.95 million** ($35.4 million mid-point cost estimate, less $0.45 million committed to date by YTG and $5.0 million assumed no cost capital provided by YDC to reflect added income from FTN payments. For the purpose of this assessment, no net capital contribution is assumed from the Minto or Carmacks Copper mines (this is assumed to avoid presumption of any specific final PPA approach).

[9] The Note adjusts interest and principal payments each year between zero and maximum levels for WAF sales by YEC between 200 and 310 GWh/year. The maximum interest is 7% per year and maximum principal payment is $1.0 million per year. The Note's balance as at March 31, 2005 was $28.3 million, and the interest rate paid in 2005 was 2.9% (i.e., WAF sales approximated 245.6 GWh/yr in 2005).

- **Total YEC net ratepayer benefits of $36.3 million** ($14.6 million from Minto mine and Pelly Crossing sales, and $11.7 million from Carmacks Copper sales, net of FTN added costs; also $10 million interconnection benefits.

Positive net benefits of about $1 million remain if the upper end of the capital cost range noted earlier is assumed for the project.

Stage 1 development alone (Carmacks to Pelly Crossing) with the Minto mine but without the Carmacks Copper mine would provide overall present value benefits (2005$) within $0.2 million of YEC net capital costs, prior to considering any net contribution by the Minto mine above the rate assumed in this analysis (9.3 cents per kWh without escalation):

- **Total YEC net capital costs, using update mid-point estimates, of $14.75 million** ($20.2 million mid-point cost estimate, less $0.45 million committed to date by YTG and $5.0 million assumed no cost capital provided by YDC to reflect added FTN payments expected to be received. For the purpose of this assessment, no net capital contribution is assumed from the Minto mine (this is assumed to avoid presumption of any specific final PPA approach).
- **Total YEC net ratepayer benefits of $14.6 million** ($14.6 million from Minto mine and Pelly Crossing sales, net of FTN added costs).

In the case of the Stage 1 development scenario as assumed above, net costs would approximate $3.0 million (2005$) if the upper end of the capital cost range noted earlier is assumed for the project, prior to considering any PPA contribution by the Minto mine.

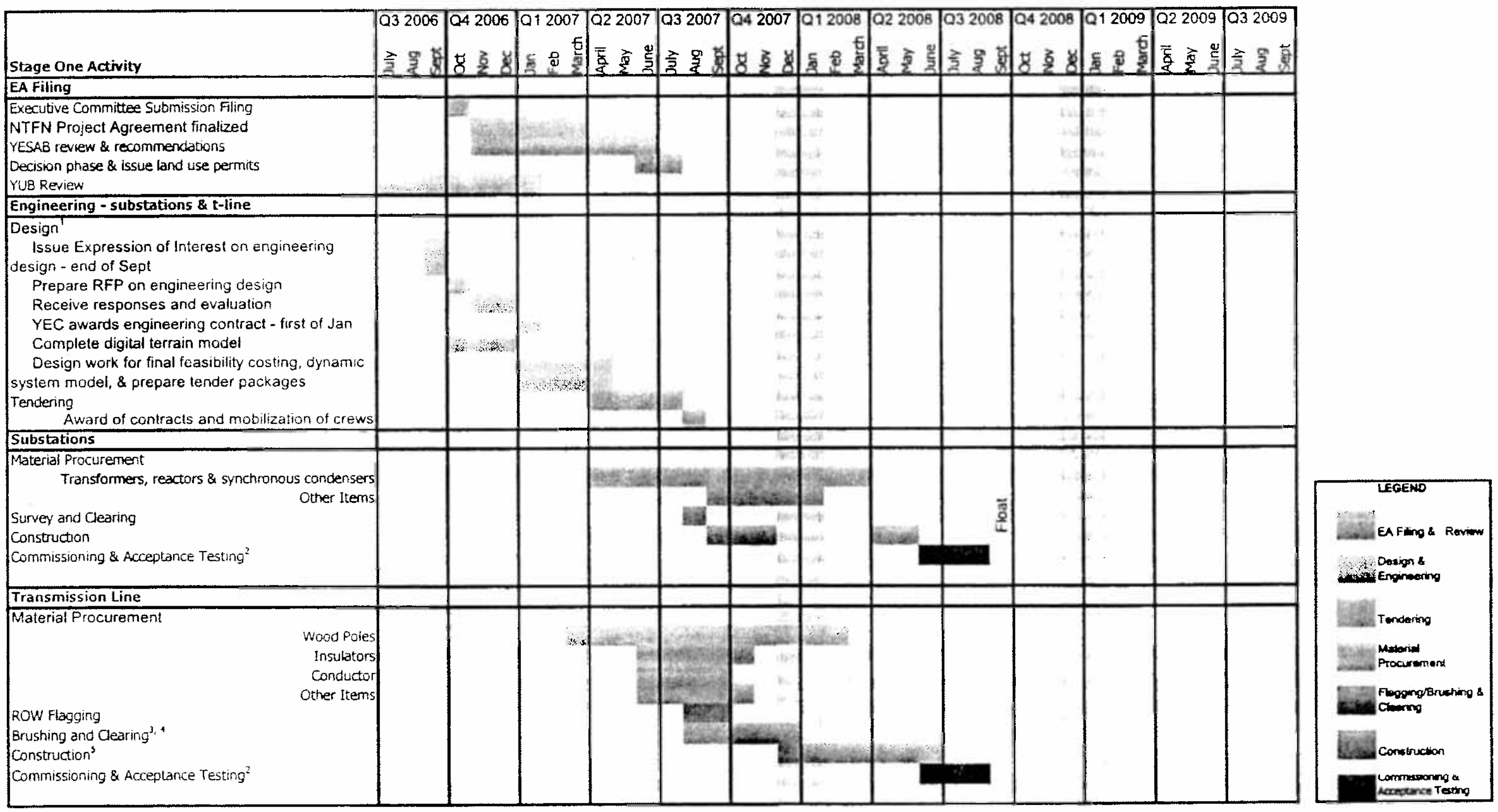
YEC and Minto are currently negotiating the PPA which is expected, among other matters, to involve Minto undertaking present value contributions that will have to be made with regard to the CS project costs as well as obligations that reduce YEC's Stage 1 risks with regard to costs for the 138 kV line. As noted earlier, Sherwood Copper's Feasibility Study has confirmed the material cost savings (about $4 million per year) that Minto is expected to receive from use of grid power to displace ongoing on-site diesel generation with a net present value savings (discounted at 7.5% back to 2006) for Minto of about $19 million. Accordingly, YEC is very hopeful that the PAP will be concluded soon, at which time it will be filed with the YUB.

SCHEDULE "A": CARMACKS-STEWART/MINTO SPUR TRANSMISSION PROJECT ANTICIPATED SCHEDULE

Figures 5.4-1 and 5.4-2 from Yukon Energy's Project Proposal Submission to YESAB Executive Committee, September 2006. Filed October 13, 2006.

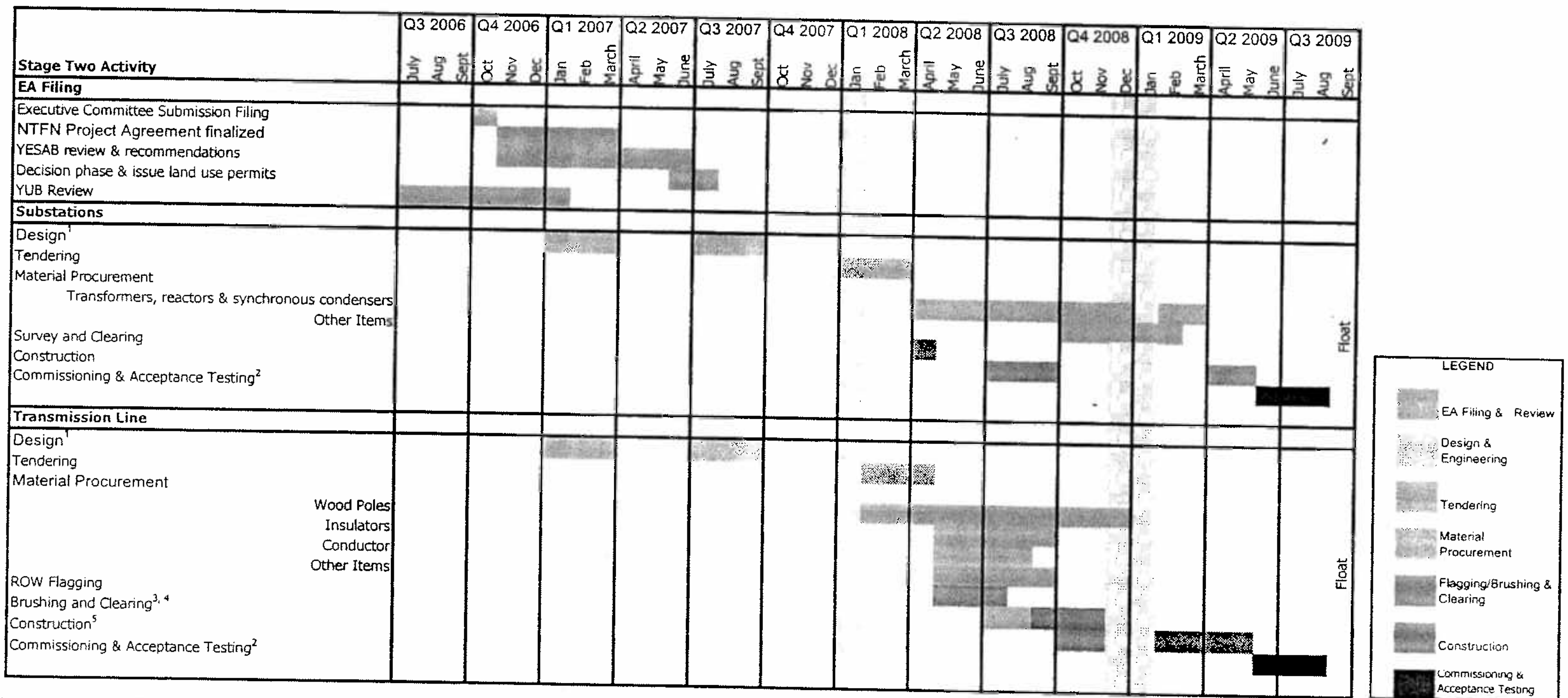
Figure 5.4-1

Anticipated Project Schedule for Stage 1



[1] Preliminary design work for Stages 1 and 2 is anticipated to be done in Q1 2007. If YTG funding for Stage 2 does not materialize, Stage 2 final engineering and design will face material delays. [2] Commissioning is done by the contractor; Acceptance Testing is done by Yukon Energy - both take approximately 6 weeks each. [3] The grey part of the clearing schedule could accommodate advance permits for cutting fuel wood and merchantable timber. Once this time frame has past the ROW is brushed and cleared to the standard required for the transmission line. It is important that any sections of the corridor used for fuel wood or timber harvesting be surveyed and flagged prior to issuing any permits. [4] The months of May and June are not used for brushing and clearing of the ROW to reduce the impact on nesting birds (Yukon Energy, 2005) and spring break-up. [5] Line construction must occur after brushing and clearing is well in hand. Line construction over the small number of wetland sites will occur primarily in winter to minimize the impact on wetlands and permafrost soils.

Figure 5.4-2
Anticipated Project Schedule for Stage 2



[1] It is anticipated that Preliminary design will occur for Stage 2 in Q1 of 2007, with final design work occurring in Q3 2007 depending on funding from YTG. [2] Commissioning is done by the contractor; Acceptance Testing is done by Yukon Energy - both take approximately 6 weeks each. [3] The grey part of the clearing schedule could accommodate advance permits for cutting fuel wood and merchantable timber. Once this time frame has past the ROW is brushed and cleared to the standard required for the transmission line. It is important that any sections of the corridor used for fuel wood or timber harvesting be surveyed and flagged prior to issuing any permits. [4] The months of May and June are not used for brushing and clearing of the ROW to reduce the impact on nesting birds (Yukon Energy, 2005) and spring break-up. [5] Line construction must occur after brushing and clearing is well in hand. Line construction will occur primarily in winter to minimize the impact on wetlands and permafrost soils.

Tab 15

previous Yukon criteria do not address the N-1 emergency criteria for systems such as WAF because the transmission facility loss was not considered in the capacity planning criteria. The overall result was to potentially expose Whitehorse area customers in particular to loss of adequate generation if the Aishihik line suffers a sustained failure at the time of system peak. In practice, this risk exposure was not material so long as there was adequate generation (including diesel units) in the Whitehorse area to reliably supply this area's loads; however, this situation is changing through growth in Whitehorse area loads and pending retirement of diesel units at the Whitehorse Rapids Diesel plant.

3.3.4 New Criteria Adopted by Yukon Energy

The new capacity planning criteria now adopted by Yukon Energy are as follows:

1. **WAF and MD System-wide capacity planning criteria:** Each system (WAF and MD) should not exceed a LOLE of two hours per year. The two hour measure is the same as that adopted in NWT and is comparable to the lower end of standards commonly used in southern Canada (which are typically from one to two hours per year LOLE).

   Although determining the LOLE requires sophisticated computer modelling, in practice the LOLE approach can generally be applied on WAF by benchmarking the two hours per year LOLE to a WAF overall "load carrying capability" of 62.9 MW. In rough terms, this load carrying capability changes by about 1 MW for every MW of non-Aishihik line generation that is added or retired (e.g., a retirement of 4 MW from the Whitehorse diesel plant will reduce this load carrying capability by about 4 MW, vice versa for additions). The benchmarking is also based on a rough assumption that the load carrying capability would be increased by about 8.0 MW if the current Aishihik transmission line constraint was removed. This could be done by twinning the line (i.e., creating a second line to allow access to Aishihik generation resources in the event of failure of the existing line).

   For MD, this criteria is well exceeded today. MD is well below two hours/year LOLE and also satisfies an N-1 condition in all locations.

2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Yukon's grids are small and isolated from major power grids, with single transmission lines connecting generation to load centres. Consequently, it was also determined to be appropriate to incorporate a standard to address the potential for sustained emergency conditions. In order to be able to address major emergencies, each system (WAF and MD) should be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single

contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source. For the case of the WAF system, the largest possible loss would currently be the Aishihik line, which connects 31.3 MW of capacity (30 MW from Aishihik, and 1.3 MW of Haines Junction diesel).

This N-1 criteria on WAF equates to a current load carrying capability (non-industrial) of 55.7 MW (excluding Haines Junction load, as it would not need to be served from the Whitehorse end of the Aishihik transmission line in the event that transmission line is out of service).

3. **WAF and MD "community" criteria:** 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.

For isolated diesel communities no change has been adopted for the capacity planning criteria. Accordingly, the previous criteria is maintained for isolated diesel systems of being able to meet 110% of the community peak with the largest unit out of service.

3.3.5 Rationale for Adopting a Two-Part Criteria on WAF and MD

The two-part capacity planning criteria adopted by Yukon Energy for the WAF and MD systems is essentially the same as the capacity criteria approved by the regulator for the Yellowknife system[5]. This approach ensures that two different concerns are addressed on an ongoing basis.

The LOLE criteria provide an overall system measure that assesses the normal balance of the system including industrial loads, and the probabilities of experiencing outages due to having inadequate generation (and transmission) installed on the system. For Yukon, a standard approximately comparable to that used in Yellowknife (at about the lower end of planning standards used in southern jurisdictions in Canada), was viewed as reasonable. The LOLE standard in effect indicates the probability that the installed BES resources will be inadequate to supply the load for the total load on the system (including

[5] The only exception is that the Yellowknife N-1 criteria (called "minimum diesel") is slightly more stringent, in that 105% of the forecast winter peak loads must be carried under the N-1 condition, not simply 100% of the forecast peak as adopted by Yukon Energy.

Tab 16

96/97 GRA FILING

to continued low UKHM loads. Generation forecasts for Fish Lake in 1996 and 1997 reflect long-term average water availability.

Combined hydro generation at the Whitehorse and Aishihik plants in 1992 (the last full year of operations by Curragh) was 403.3 GW.h. As discussed earlier, hydro generation at these plants during 1992 was affected by abnormally high precipitation filling up the Aishihik reservoir. The 1992 Board Decision incorporated updated forecasts prepared in the fall of 1991 which anticipated 400.2 GW.h combined hydro generation at the Aishihik and Whitehorse plants during 1992.

Average annual generation levels of 246.3 GW.h are included for Whitehorse Rapids hydro plant and of 104.8 GW.h for the Aishihik hydro plant for the test years. This represents a 52.2 GW.h reduction in available hydro generation versus what was available in the last full year of Curragh's operations. This reduction in hydro must be replaced by diesel generation.

It is important to note that forecast actual generation for the 1996 and 1997 test period is not expected to be significantly different from the long-term average used in this Application. This is the case despite inflows into the Aishihik Lake being only 35% (actual) and 52% (forecast) of long-term average in 1994 and 1995 respectively. The low loads in 1994 and 1995 still allowed the Companies to keep the Aishihik Lake levels above low supply levels despite the low flows over the same period. There is significant risk that actual flows in 1996 and 1997 will also be below long-term average.

Table 2.3
10/31/95

Yukon Energy Corporation
The Yukon Electrical Company Limited
Combined Yukon
Schedule of Energy Balance, Losses, Peak and Load Factor

Line No.	Description	Actual 1993	Actual 1994	Forecast 1995	Forecast 1996	Forecast 1997
1	**Sales and Losses**					
2	Total energy sales - MWh	296,526	254,985	341,005	444,001	457,736
3	Losses - MWh	41,047	38,325	43,781	59,499	61,818
4	Losses - %	13.8%	15.0%	12.8%	13.4%	13.5%
5	Total generation	337,573	293,310	384,786	503,500	519,554
6	**Source - MWh**					
7	**Hydro generation**					
8	WAF system					
9	Whitehorse	165,116	153,218	236,889	246,298	246,298
10	Aishihik	107,820	87,250	83,948	104,790	104,790
11	Fish Lake	9,677	10,181	9,216	10,042	10,042
12	Wind turbine	85	238	272	300	300
13	Total	282,698	250,887	330,325	361,430	361,430
14	Mayo	6,811	9,285	14,099	9,689	9,695
15	Total Hydro	289,509	260,172	344,424	371,119	371,125
16	**Diesel generation**					
17	WAF system	16,581	396	7,848	99,579	115,281
18	Other isolated systems	31,483	32,742	32,514	32,802	33,148
19	Total diesel	48,064	33,138	40,362	132,381	148,429
20	**Source - %**					
21	Hydro generation	85.8%	88.7%	89.5%	73.7%	71.4%
22	Diesel generation	14.2%	11.3%	10.5%	26.3%	28.6%
23	**Peak - MW**					
24	WAF system	56.5	54.4	73.1	77.3	78.0
25	Mayo System	1.3	3.3	3.0	2.2	2.2
26	Dawson system	2.1	2.7	2.3	2.4	2.5
27	Watson Lake system	3.0	2.6	2.7	2.9	2.8
28	Other isolated	1.4	1.4	1.4	1.4	1.5
29	Total peak	64.3	64.4	82.5	86.2	87.0
30	Load factor	59.9%	52.0%	53.2%	66.7%	68.2%

Tab 17

Yukon Energy Undertaking #2
Provide YECL purchased power forecasts provided to YEC for the past 3 years

Ex B19

Comparison of YECL Purchase of Power Sales Forecasts to Actuals (MW.h)

Includes WAF and MD (Keno at approximately 250 MW.h plus Stewart Crossing beginning November 2005 at about 500 MW.h)

		Sales Forecasts by Year (as provided by YECL) forecast provided in:			
Year	**Actual Sales**	**2003**	**2004**	**2005**	**2006**
2003	229,971	223,696	-	-	-
2004	235,982	224.367	226,301	-	-
2005	237.419	225,040	226.980	234,212	-
2006 (FYF)	247.179	225,715	227,661	236,554	241.862
2007	-	-	228.344	237,737	244.281
2008	-	-	229.029	238.926	246,724
2009	-	-	-	240.120	-

YUKON UTILITIES BOARD
EXHIBIT B-19
DAY | ENTERED BY YEC | DATE Nov 15/06

YECL POP analysis - All Primary Sales.xls Actual vs Forecast Sales

Yukon Electrical - 2003 BP
Purchased Power Forecast

Yukon Electrical - 2003 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
Total WAF Purch 97 (per FRTARM96)	23,916,973	21,430,505	20,164,693	17,292,658	15,777,047	14,490,308	13,986,780	14,064,550	15,526,334	17,639,078	20,496,224	23,655,321	218,470,672
Forecast Adjustments	204,617	219,219	228,281	253,799	258,115	286,064	299,812	283,608	261,653	221,701	222,305	211,186	2,950,060
Additional estimate for Fish Lake watershed	166,667	166,667	166,666	166,667	166,666	166,667	166,666	166,667	166,666	166,667	166,666	166,668	2,000,000
Less, Keno	(26,231)	(22,173)	(26,621)	(25,124)	(19,206)	(22,932)	(21,846)	(19,329)	(21,985)	(21,065)	(23,658)	(24,738)	(274,908)
Total '2002 WAF	24,288,257	21,816,391	20,589,840	17,713,125	16,201,828	14,943,039	14,453,258	14,514,825	15,954,653	18,027,446	20,864,895	24,033,175	223,420,732
Keno - 99	21,231	17,173	21,621	20,124	14,206	17,932	16,846	14,329	16,985	16,065	18,658	19,738	214,908
'02 Keno adjustment	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	60,000
	26,231	22,173	26,621	25,124	19,206	22,932	21,846	19,329	21,985	21,065	23,658	24,738	274,908
Total 2003 Forecast	24,314,488	21,838,565	20,616,461	17,738,249	16,221,034	14,965,971	14,475,104	14,534,154	15,976,638	18,048,511	20,908,553	24,057,913	223,695,63[illegible]
Approved rate	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	
Primary Expense	1,663,111	[illegible]	[illegible]	1,213,296	1,109,519	1,023,672	990,097	994,136	[illegible]	1,234,518	1,430,145	1,645,561	15,30[illegible],782
Seconary Expense	19,030	18,920	18,480	18,040	16,590	13,530	9,570	11,770	16,920	22,000	23,540	24,530	216,920
Total Expense	1,682,141	1,512,678	1,428,646	1,231,336	1,128,109	1,037,202	999,667	1,005,906	[illegible]	1,256,518	1,453,685	1,670,091	15,517,702

	kW.h purch.	Rate	Expense	Secondary	Total
2004	224,366,726	0.0684	15,346,684	300,300	15,646,984
2005	225,039,826	0.0684	15,392,724	304,700	15,697,424
2006	225,714,945	0.0684	15,438,902	304,700	15,743,602

Yukon Electrical - 2004 BP
Purchased Power Forecast

Yukon Electrical - 2004 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
Total WAF Purch '97 (per FRTARM96)	23,916,973	21,433,505	20,194,893	17,292,658	15,777,047	14,490,308	13,986,780	14,064,550	15,526,334	17,639,078	20,496,224	23,655,321	218,470,672
Forecast Adjustments													
Additional estimate for	477,576	472,759	464,697	466,005	451,963	467,581	476,333	463,595	455,925	434,462	462,840	483,933	5,579,668
Fish Lake watershed	166,667	166,667	166,666	166,667	166,666	166,667	166,666	166,667	166,666	166,667	166,666	166,668	2,000,000
Less Keno	(27,231)	(23,173)	(27,621)	(26,124)	(18,206)	(17,932)	(16,846)	(14,329)	(19,985)	(21,065)	(18,658)	(19,738)	(250,908)
Total 2002 WAF	24,561,215	22,069,931	20,826,256	17,927,331	16,395,676	15,124,556	14,629,780	14,694,812	16,146,925	18,240,207	21,125,730	24,305,922	226,050,340
Keno - 99	21,231	17,173	21,621	20,124	14,206	17,932	16,846	14,329	16,985	16,065	18,658	19,738	214,908
04 Keno adjustment	6,000	6,000	6,000	6,000	4,000	0	0	0	3,000	5,000	0	0	36,000
	27,231	23,173	27,621	26,124	18,206	17,932	16,846	14,329	19,985	21,065	18,658	19,738	250,908
Total 2004 BP	24,588,446	22,093,104	20,853,877	17,953,454	16,413,882	15,142,488	14,646,626	14,709,141	16,166,910	18,261,273	21,144,357	24,325,660	226,301,247
Approved rate	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	
Primary Expense	1,681,850	1,511,168	1,426,405	1,228,016	1,122,710	1,035,746	1,001,829	1,006,105	1,105,953	1,249,071	1,446,276	1,663,875	15,479,005
Secondary Expense	21,890	21,120	20,680	20,240	20,790	15,730	11,770	13,970	21,120	24,200	25,740	26,730	243,980
Total Expense	1,703,740	1,532,288	1,447,085	1,248,256	1,143,500	1,051,476	1,013,599	1,020,075	1,127,073	1,273,271	1,472,016	1,690,605	15,722,985

	kW.h purch.	Rate	Expense	Secondary	Total	
2005	226,960,151	0.0684	15,525,442	365,970	15,891,412	100.30%
2006	227,661,091	0.0684	15,572,019	384,268	15,956,287	100.30%
2007	228,344,074	0.0684	15,618,735	403,482	16,022,217	100.30%
2008	229,029,106	0.0684	15,665,591	423,657	16,089,248	100.30%

Yukon Electrical - 2005 BP
Purchased Power Forecast

Yukon Electrical - 2005 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
Total WAF Purch '97 (per FRTARM96)	23,916,973	21,430,505	20,194,893	17,292,658	15,777,047	14,490,308	13,986,760	14,064,550	15,526,334	17,639,078	20,496,224	23,655,321	218,470,672
Forecast Adjustments	964,316	176,271	992,631	792,238	1,165,942	1,557,710	2,290,819	2,309,121	1,015,341	900,515	1,012,599	1,112,932	14,290,434
Additional estimate for Fish Lake watershed	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,200,000
Less. Keno	(27,231)	(23,173)	(27,621)	(26,124)	(18,206)	(17,932)	(16,846)	(14,329)	(19,985)	(21,065)	(18,658)	(19,738)	(250,908)
Total 2002 WAF	24,981,289	21,706,776	21,287,524	18,184,896	17,042,989	16,148,018	16,377,599	16,473,671	16,641,675	18,639,593	21,608,823	24,868,253	233,961,106
Keno - 99	21,231	17,173	21,621	20,124	14,206	17,932	16,846	14,329	16,985	16,065	18,658	19,738	214,908
'04 Keno adjustment	6,000	6,000	6,000	6,000	4,000	0	0	0	3,000	5,000	0	0	36,000
	27,231	23,173	27,621	26,124	18,206	17,932	16,846	14,329	19,985	21,065	18,658	19,738	250,908
Total 2005 BP	25,008,519	21,729,949	21,315,145	18,211,020	17,061,195	16,165,950	16,394,446	16,488,000	16,661,660	18,660,658	21,627,481	24,887,991	234,212,01[illegible]
Approved rate	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	0.0684	
Primary Expense	1,710,583	1,486,329	1,457,956	1,245,634	1,166,986	1,105,751	1,121,380	1,127,779	1,139,655	1,276,389	1,479,320	1,702,339	16,020,1[illegible]
Secondary Expense	28,490	27,720	25,080	24,640	25,190	20,130	16,170	20,570	27,720	28,600	32,340	34,650	311,300
Total Expense	1,739,073	1,514,049	1,483,036	1,270,274	1,192,176	1,125,881	1,137,550	1,148,349	1,167,378	1,304,989	1,511,660	1,736,989	16,331,402
YECL SS Forecast	1,295,000	1,260,000	1,140,000	1,120,000	1,145,000	915,000	735,000	935,000	1,260,000	1,330,000	1,470,000	1,575,000	14,150,000

	kW.h purch.	Rate	Expense	Secondary	Total
2006	236,554,133	0.0684	16,180,303	365,970	16,546,273
2007	237,736,904	0.0684	16,261,204	384,268	16,645,472
2008	238,925,589	0.0684	16,342,510	403,482	16,745,992
2009	240,120,216	0.0684	16,424,223	423,657	16,847,880

Yukon Electrical - 2006 BP
Purchased Power Forecast

Yukon Electrical - 2006 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Primary KWh - forecast 2006	26,000,086	22,198,933	21,037,936	17,955,958	18,274,181	16,870,617	17,720,600	16,779,097	18,414,078	18,822,445	22,990,196	24,797,959	241,862,086
Provision for Keno City	(32,750)	(30,000)	(26,250)	(23,000)	(14,000)	(10,500)	(11,000)	(15,000)	(18,000)	(19,000)	(21,500)	(29,000)	(250,000)
Provision for Stewart Crossing	(52,500)	(52,500)	(47,500)	(37,500)	(27,500)	(27,500)	(27,500)	(32,500)	(27,500)	(32,500)	(37,500)	(42,500)	(445,000)
Net WAF sales	25,914,836	22,116,433	20,964,186	17,895,458	18,232,681	16,832,617	17,682,100	16,731,597	18,368,578	18,770,945	22,931,196	24,726,459	241,167,086
Per discussion with Rob then slight adjustments													
S.Xing 05 ytd then 04	52,500	52,500	47,500	37,500	27,500	27,500	27,500	32,500	27,500	32,500	37,500	42,500	445,000
Keno 05 YTD actuals then 04	32,580	29,970	26,250	23,100	13,950	10,050	11,100	14,835	18,390	18,750	21,450	28,800	249,225
Keno - for BP06	32,750	30,000	26,250	23,000	14,000	10,500	11,000	15,000	18,000	19,000	21,500	29,000	250,000
YEC Shortfall - Rider U (@14.93%)	$ 478,687	$ 448,438	$ 415,447	$ 382,730	$ 354,739	$ 335,256	$ 327,828	$ 335,716	$ 359,915	$ 390,039	$ 430,582	$ 465,186	$ 4,744,365
Actual YECL collections for 2005	$ 495,004	$ 438,985	$ 401,508	$ 396,212	$ 359,842	$ 346,608	$ 348,918	$ 340,464					
Difference	$ (16,316)	$ 9,453	$ 13,939	$ (13,482)	$ (5,103)	$ (11,352)	$ (21,290)	$ (4,748)					$ (48,899.36)
Secondary KWh	1,976,676	1,819,242	1,679,500	1,535,359	1,451,895	1,416,910	1,323,615	1,323,615	1,586,006	1,749,271	1,947,522	2,186,589	20,000,000

	Primary kW.h purch.	Less Keno City	S.Xing	Net WAF	Secondary kW.h purch.
2007	244,280,707	(250,000)	(415,000)	243,615,707	20,500,000
2006	246,723,514	(250,000)	(415,000)	246,058,514	21,000,000

Yukon Electrical - 2008 BP - Preliminary
Purchased Power Forecast

Yukon Electrical - 2008 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2008 TOTAL	2009 TOTAL	
Primary - WAF	A	27,987,856	23,694,065	23,200,000	20,100,000	17,406,914	16,967,865	17,617,927	19,350,236	19,661,620	21,750,000	24,933,320	25,600,000	258,269,804	262,374,679	1.589%
Secondary - WAF		2,742,877	2,445,210	2,310,860	2,452,603	1,840,432	1,486,134	1,513,667	1,413,871	1,794,645	2,132,189	2,539,027	3,025,893	25,697,409	25,825,896	0.500%
		30,730,734	26,139,275	25,510,860	22,552,603	19,247,346	18,454,000	19,131,594	20,764,107	21,456,265	23,882,189	27,472,348	28,625,893	283,967,213	288,200,575	
Keno	B	35,135	32,432	34,234	30,180	22,523	11,562	14,264	11,619	15,995	26,106	41,800	40,140	315,990	316,306	0.100%
Stewart	C	63,423	64,384	65,105	46,246	38,919	34,715	37,958	34,285	34,405	43,097	67,604	60,360	590,502	591,092	0.100%
		98,558	96,817	99,339	76,426	61,441	46,276	52,222	45,904	50,401	69,203	109,403	100,500	906,491	907,398	
		30,829,292	26,236,092	25,610,199	22,629,030	19,308,787	18,500,276	19,183,816	20,810,011	21,506,666	23,951,392	27,581,751	28,726,393	284,873,704	289,107,973	1.486%
YECL BP 08 forecast	A+B+C	28,086,415	23,790,882	23,299,339	20,176,426	17,468,355	17,014,142	17,670,149	19,396,140	19,712,021	21,819,203	25,042,723	25,700,500	259,176,295	263,282,077	
$$$																
YEC Shortfall - Rider 'J'		$ 507,882	$ 451,684	$ 442,533	$ 392,079	$ 366,894	$ 350,408	$ 365,483	$ 398,864	$ 399,205	$ 419,301	$ 471,016	$ 490,536	$ 5,055,885		

Review at 080904 - by YEC

	YEC Actual							YECL BP Forecast					Potential POP
YEC Actual to July YECL BP Aug-Dec	27,612,410	25,382,472	22,869,417	19,419,386	18,416,684	18,664,632	18,610,534	19,396,140	19,712,021	21,819,203	25,042,723	25,700,500	262,646,122

Yukon Electrical - 2008 BP
Purchased Power Forecast

Yukon Electrical - 2008 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAl	
Pirmary KWh - forecast 2008 per YECL	28,086,415	23,790,882	23,299,339	20,176,426	17,468,355	17,014,142	17,670,149	19,396,140	19,712,021	21,819,203	25,042,723	25,700,500	259,176,295	
Provision for Keno City	(35,135)	(32,432)	(34,234)	(30,180)	(22,523)	(11,562)	(14,264)	(11,619)	(15,995)	(26,106)	(41,800)	(40,140)	(315,990)	
Provision for Stewart Crossing	(63,423)	(54,384)	(65,105)	(46,246)	(38,919)	(34,715)	(37,958)	(34,285)	(34,405)	(43,097)	(67,604)	(60,360)	(590,502)	
Smoothing of YECL Forecast	(1,300,000)	600,000	1,800,000	700,000	1,300,000	100,000	450,000	(1,400,000)	(100,000)	(1,000,000)	(1,300,000)	150,000	-	
Addition of POP Sales by YEC	**12,144**	**5,935**	-	-	**(6,914)**	**32,135**	**32,073**	**(50,236)**	**38,380**	**(50,000)**	**66,680**	**(80,197)**	-	
Y/E BP Top Up	-	-	-	-	-	-	-	-	-	-	-	-	-	
BP08 WAF POP sales (revised @ Nov 07)	26,700,000	24,300,000	25,000,000	20,800,000	18,700,000	17,100,000	18,100,000	17,900,000	19,600,000	20,700,000	23,700,000	25,669,803	258,269,804	
2007 WAF POP - Actual Jan-Nov07 (& Dec 06)	25,517,370	24,330,770	24,450,384	20,328,042	18,303,788	16,679,544	17,685,420	17,523,664	19,104,980	20,278,462	22,383,478	25,339,950	251,925,852	2.518%
BP 08 vs FYF 07	1,182,630	(30,770)	549,616	471,958	396,212	420,456	414,580	376,336	495,020	421,538	1,316,522	329,853	6,343,952	
year to year growth (% change by month)	4.635%	-0.126%	2.248%	2.322%	2.165%	2.521%	2.344%	2.148%	2.591%	2.079%	5.882%	1.302%		
Cumulative Increase in Sales	1,182,630	1,151,860	1,701,476	2,173,434	2,569,646	2,990,103	3,404,682	3,781,019	4,276,039	4,697,577	6,014,099	6,343,952		
2009 WAF - @ 1.6% growth	27,127,200	24,688,800	25,400,000	21,132,800	18,999,200	17,373,601	18,389,600	18,186,400	19,913,600	21,031,200	24,079,200	26,080,520	262,402,121	
2010 WAF - @ 1.0% growth	27,398,472	24,935,688	25,654,000	21,344,128	19,189,192	17,547,337	18,573,496	18,368,264	20,112,736	21,241,512	24,319,992	26,341,325	265,026,142	
BP08 Secondary KWh - per YECL	2,742,877	2,445,210	2,310,860	2,452,603	1,840,432	1,486,134	1,513,667	1,413,871	1,794,645	2,132,189	2,539,027	3,025,893	25,697,409	
BP08 Secondary KWh - per YEC	2,590,550	2,462,100	2,303,350	2,352,200	1,860,050	1,533,250	961,800	1,078,800	1,427,650	1,783,000	2,235,500	2,411,750	23,000,000	
Difference between forecasts	152,327	(16,890)	7,510	100,403	(19,618)	(47,116)	551,867	335,071	366,995	349,189	303,527	614,143	2,697,409	
													$ 110,594	
YEC BP 08 Sales	26,798,559	24,396,817	25,099,339	20,876,426	18,761,441	17,146,277	18,152,222	17,945,904	19,650,401	20,769,203	23,809,403	25,770,303	259,176,295	

	Primary kW.h purch.	Less: Keno City	S.Xing	Net WAF	Primary POP $	Secondary kW.h purch.	Secondary POP $
2008	259,176,295	(315,990)	(590,502)	258,269,804	$ 17,727,659	23,000,000	943,000
2009	263,317,677	(319,150)	(596,407)	262,402,121	$ 18,010,929	23,462,500	961,963
2010	265,950,854	(322,341)	(602,371)	265,026,142	$ 18,191,038	23,462,500	961,963
2011	268,610,363	(325,565)	(608,394)	267,676,404	$ 18,372,949	23,462,500	961,963
2012	271,296,466	(328,820)	(614,478)	270,353,168	$ 18,556,678	23,462,500	961,963

Yukon Electrical - 2008 BP - Preliminary
Purchased Power Forecast

Yukon Electrical - 2008 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2008 TOTAL	2009 TOTAL	
Primary - WAF	27,987,856	23,694,065	23,200,000	20,100,000	17,406,914	16,967,865	17,617,927	19,350,236	19,661,620	21,750,000	24,933,320	25,600,000	258,269,804	262,374,679	1.589%
Secondary - WAF	2,742,877	2,445,210	2,310,860	2,452,603	1,840,432	1,486,134	1,513,667	1,413,871	1,794,645	2,132,189	2,539,027	3,025,893	25,697,409	25,825,896	0.500%
	30,730,734	26,139,275	25,510,860	22,552,603	19,247,346	18,454,000	19,131,594	20,764,107	21,456,265	23,882,189	27,472,348	28,625,893	283,967,213	288,200,575	
Keno	35,135	32,432	34,234	30,180	22,523	11,562	14,264	11,619	15,995	26,106	41,800	40,140	315,990	316,306	0.100%
Stewart	63,423	64,384	65,105	46,246	38,919	34,715	37,958	34,285	34,405	43,097	67,604	60,360	590,502	591,092	0.100%
	98,558	96,817	99,339	76,426	61,441	46,278	52,222	45,904	50,401	69,203	109,403	100,500	906,491	907,398	
	30,829,292	26,236,092	25,610,199	22,629,030	19,308,787	18,500,276	19,183,816	20,810,011	21,506,666	23,951,392	27,581,751	28,726,393	284,873,704	289,107,973	1.486%
YECL BP 08 forecast	28,086,415	23,790,882	23,299,339	20,176,426	17,468,355	17,014,142	17,670,149	19,396,140	19,712,021	21,819,203	25,042,723	25,700,500	259,176,295	263,282,077	
$$$															
YEC Shortfall - Rider 'J'	$ 507,882	$ 451,684	$ 442,533	$ 392,079	$ 366,894	$ 350,408	$ 365,483	$ 398,864	$ 399,205	$ 419,301	$ 471,016	$ 490,536	$ 5,055,885		

Yukon Electrical - 2007 BP
Purchased Power Forecast

Yukon Electrical - 2007 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAl
Pirmary KWh	29,350,554	21,976,263	22,446,876	21,317,484	16,259,635	17,878,034	17,786,235	16,201,125	18,747,676	18,903,344	23,804,665	24,055,493	248,727,384
Secondary KWh	2,307,977	1,790,344	2,163,437	2,400,802	1,637,745	1,378,427	1,104,111	1,101,518	1,345,278	2,043,186	2,508,722	2,119,135	21,900,682
YEC Shortfall - Rider 'J'	$ 532,870	$ 420,401	$ 428,908	$ 412,476	$ 340,787	$ 369,086	$ 365,960	$ 346,465	$ 388,911	$ 372,868	$ 453,080	$ 460,328	4,892,140

	Primary kW.h purch.	Secondary kW.h purch.
2008	251,214,658	22,000,000
2009	253,726,804	22,000,000

Tab 18

YUKON
ENERGY

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

COPY

October 6, 2008

Jerome Babyn, General Manager
Yukon Electrical Company Ltd
100-1100 1st Ave
Whitehorse, Yukon Y1A 3T4

Dear Mr. Babyn:

RE: 2008 and 2009 Secondary Sales Forecasts

As you are probably now aware, YEC has filed a Phase I application with the YUB today. This communication is intended to update you on certain information that affects each of our applications.

As part of the preparation of your application, Yukon Energy provided certain information, specifically a forecast of secondary sales supplied via the WAF grid. At the time, we had not fully analyzed the impact of Minto Mine and the implications for secondary sales forecasting. Accordingly, we adopted the relatively conservative stance that only very limited access to surplus hydro would occur for these customers in the summer months.

As part of our own application, we tested our assumptions rigorously and were able to determine that in fact significant sales were still expected to occur in the test years with the Minto Mine on the system. Therefore, you will note in our application, we have forecast WAF secondary sales of 19,905 MW.h and 15,983 MW.h for 2008 and 2009 respectively.

In our application we have included the following explanation of the difference in forecasts (from Tab 2, section 2.2.1, page 2-3)

> When 2008 and 2009 load forecasts for secondary sales were initially developed by Yukon Energy (in consultation with YECL), issues related to secondary sales availability following connection of the Minto Mine had not been fully considered. Due to higher firm system loads, Yukon Energy at that time adopted a conservative set of assumptions that no secondary sales were to be included in Yukon Energy's initial 2009 load forecast outside of a very limited amount of sales in summer months from excess flows at Whitehorse. This earlier Yukon Energy forecast appears to form the basis for the forecast used by YECL in its 2008/2009 GRA which reflected only 16,853 MW.h of YECL retail secondary sales in 2008, and

6,954 MWh of YECL retail secondary sales in 2009. This is 3,052 MW.h and 9,029 MW.h below Yukon Energy's current forecasts for YECL secondary sales in 2008 and 2009 respectively. As YECL only purchases an equal quantity of secondary wholesale energy from Yukon Energy as it sells at the retail level, in effect all losses on YECL's system associated with secondary sales are supplied by Yukon Energy at wholesale primary service (Rate Schedule 42). Assuming system average 6.2% distribution losses on YECL's system, this factor accounts for 189 MW.h and 560 MW.h of additional forecast wholesale primary sales in 2008 and 2009 respectively compared to YECL's forecasts

If you would like to discuss this matter please contact the undersigned at 867.393.5338 or ed.mollard@yec.yk.ca.

Yours truly,

Ed Mollard, CFO