YUKON ENERGY

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July 21, 2006

Mr. Brian Morris, Chair
Yukon Utilities Board
19-1114 First Avenue
Whitehorse, Yukon Y1A 1A3

Dear Mr. Morris,

RE: Yukon Energy Corporation (Yukon Energy) 20 Year Resource Plan Board Staff Preliminary Information Requests

Enclosed please find seven copies of Yukon Energy's response to the information requests ("IR") of the Yukon Utilities Board ("YUB").

Yukon Energy is distributing the package electronically to all parties noted in the Board's July 11 email, as well as the Alberta Energy and Utilities Board staff.

Yukon Energy will bring a number of paper copies of the responses to the July 25 workshop for distribution to any interested parties requiring the responses in hard copy form.

Yukon Energy will be producing electronic versions of the responses to be made available at http://www.yukonenergy.ca/environment/reports/resource. CDs containing all responses will be produced and distributed to all intervenors and interested parties once all rounds of interrogatory responses in this proceeding have been completed.

Yours truly

for David Morrison
President & CEO

Enclosure

YUKON ENERGY CORPORATION

20-YEAR RESOURCE PLAN: 2006-2025

RESPONSE TO PRELIMINARY INFORMATION REQUESTS

July 21, 2006

REFERENCE:

QUESTION:

The Resource Plan indicates that reliability experts were hired from the University of Saskatchewan in 2004 (under the direction of Dr. Roy Billinton) to review YEC's then established capacity planning criteria (i.e. the criteria as reviewed in the 1992 Resource Plan), including the probabilities inherent in those criteria. Please provide a copy of the report prepared by Dr. Billinton as well as a copy of the terms of reference for the study.

ANSWER:

Please see the attached reports prepared by Drs. Billinton and Karki. The report dated February 2005 is the main review of the current system ("main report"), while the supplement dated July 2005 is an additional review YEC had undertaken related to the reliability conditions that existed at the time of the last major YUB review when the Faro mine was operating, in 1996/97 ("supplemental report").

The following is the agreed to Scope of Work for Drs. Billinton and Karki:

1. To complete an analysis of the WAF Grid to identify key areas and system characteristics relevant for the review of the Required Firm Capacity Planning Criteria (for example – relatively small loads located at the end of long transmission lines may require a different approach than at Whitehorse.)
2. To identify/recommend a planning approach to ensure that sufficient capacity is available to meet load demands at key areas, as identified above (i.e. deterministic, probabilistic, other).
3. To develop reliability model(s) for the WAF Grid.
4. To complete a Loss of Load Expectation (LOLE) and Loss of Energy Expectation (LOEE) analysis for the Whitehorse-Aishihik-Faro Grid based on the current operating regime and experience. (LOLE expressed in hours/year, LOEE expressed in MW.h/year).
5. To complete a comparative LOLE analysis of alternative operating regimes (i.e. the existing operating regime and any alternatives considered/recommended as part of this project) for the Whitehorse-Aishihik-Faro Grid.
6. To identify recommended operating regime(s) and provide rationale(s) for the recommendation(s).

RELIABILITY EVALUATION OF THE WHITEHORSE - AISHIHIK - FARO SYSTEM

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February 2005

EXECUTIVE SUMMARY

This report contains a basic annual reliability evaluation of the Whitehorse–Aishihik-Faro (WAF) system analyses considering seasonal hydro generating capacity variations, reliability studies including the effect of transmission line constraints, and assessment of the impacts of diesel unit retirements on the WAF system adequacy. The annual risk profiles as a function of the system peak load have been evaluated and plotted for the different system considerations. The risk profiles can be used to obtain the system Loss of Load Expectation (LOLE) or the Loss of Energy Expectation (LOEE) for an anticipated peak load.

The deterministic criterion used by the Yukon Energy Corporation (YEC) to plan the firm capacity requirement for the WAF system has been converted to equivalent probabilistic indices. The maximum allowable peak load under the deterministic criterion is 68.7 MW. The equivalent LOLE is 1.15 hours/year and the LOEE is 3.90 MWh/year based on available data. The LOLE index is within the range used by most Canadian electric power utilities to assess generating capacity adequacy. The equivalent LOLE index of 1.15 hours/year was used as the criterion value in the subsequent WAF system probabilistic reliability studies in this report. The maximum allowable peak load is 78.1 MW from a basic generation adequacy evaluation without considering seasonal capacity limitations. The analyses show a significant decrease in system reliability when the seasonal capacity limitations of the Whitehorse hydro units are considered.

Analyses considering the ability of the transmission line L171 to transfer the power generated by the Aishihik hydro units to the WAF system load are included in the report and sensitivity studies with different line outage data are presented. The maximum allowable peak load under these conditions using the LOLE criterion is 60.5 MW. This value was obtained using representative transmission line outage data from the Canadian Electricity Association - Equipment Reliability Information System (CEA-ERIS).

The report provides an evaluation of the WAF system adequacy considering the effect of a potential WD1 unit retirement, WD1 and WD2 unit retirements, and WD1, WD2 and WD3 unit retirements. The WAF system risks are presented for these cases with and without considering the transmission line constraints. The maximum peak load carrying capabilities under these conditions and including the assumed transmission line unavailability are 57.5 MW, 53.3 MW and 49.1 MW respectively. The maximum peak load carrying capabilities are 65.8 MW, 61.7 MW and 57.7 MW when the transmission line is assumed to be completely reliable.

The report also contains a reliability evaluation of the Whitehorse area alone, conducted at the request of YEC. The Whitehorse risk indices were found to be significantly higher than the WAF system risk indices, and indicate the adequacy of the Whitehorse generation to serve the local area load.

The numerical risk values obtained are highly dependent on the generating unit and transmission line failure and repair parameters used in the analyses. Representative data taken from the CEA-ERIS have been used to supplement the data provided by YEC.

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1. INTRODUCTION

The basic function of an electric power system is to supply the customer load requirements as economically as possible and with a reasonable assurance of continuity and quality. The ability to generate the required energy is an integral component in the provision of an acceptable level of supply reliability. The generation facilities should be matched with an appropriate transmission network such that the overall reliability of the composite generation and transmission system provides an acceptable level of reliability at the bulk system supply points.

Basic generation capacity reliability evaluation does not normally include the ability of the transmission facilities to deliver the generated energy to the major load points. This is particularly true in those systems in which the generation is dispersed throughout the system. Relevant transmission facilities can be considered in the analysis for those systems in which a significant portion of the installed generating capacity is located remotely from the major load points.

A wide range of indices have been developed to quantify the reliability of electric power systems. These indices are described in detail in [1]. The basic concepts used to obtain the results provided in this report are also discussed and illustrated in [1]. The most commonly used indices in generating capacity reliability evaluation are:

Loss of Load Expectation (LOLE): The expected number of days or hours in the specified period when the load exceeds the available generating capacity.

Loss of Energy Expectation (LOEE): The expected energy not served as a result of system generating capacity inadequacy.

Table 1.1 shows the range of indices used by Canadian electric power utilities to assess generating capacity adequacy. These indices were obtained by a survey conducted by the Canadian Electrical Association (CEA).

Table 1.1: Basic Generation Adequacy Criteria used by Canadian Utilities

Utility/System	Criterion	Index
British Colombia Hydro & Power Authority	LOLE	1 day/10 years
Alberta Interconnected System	LOLE	0.2 days/year
Saskatchewan Power Corporation	EUE	200 UPM
Manitoba Hydro	LOLE	0.1 days/year
Ontario Hydro	EUE	25 SM
Hydro Quebec	LOLE	2.4 hours/year
New Brunswick Electric Power Commission	CRM*	Largest unit or 20% of the system peak (whichever is larger)
Nova Scotia Power Corporation	LOLE**	0.1 days/year
Newfoundland and Labrador Hydro	LOLE	0.2 days/year

* With supplementary checks for LOLE

** With supplementary checks for CRM

EUE = expected unserved energy = LOEE

CRM = capacity reserve margin

$$\text{UPM} = \text{units per million} = \frac{\text{EUE}}{\text{Annual Energy Demand}} \times 10^6$$

$$\text{SM} = \text{system minutes} = \frac{\text{EUE}}{\text{Peak Load}} \times 60$$

Historically, the LOLE is the most widely used index. It was first used in Canada by Ontario Hydro in 1964. The LOLE indicates the number of hours (days) in a year when the available generating capacity cannot meet the entire demand. It does not indicate the extent of the difficulty, but only the fact that the installed capacity is inadequate. The LOEE index has received increased attention in recent years as it indicates the expected unserved energy due to generating capacity deficiencies. The expected unserved energy includes the magnitude of the deficiency together with the frequency and duration of the shortfalls. Utilities that have utilized the expected unserved energy as their capacity planning criterion have usually extended the analysis by considering the customer monetary losses due to power supply failures.

This report contains conventional analysis of the overall generation facilities, and further analyses including the 138 kV transmission network linking the Aishihik hydro plant with the WAF system. The initial studies were conducted on an annual basis assuming fixed generating unit capacities. A series of studies was also conducted recognizing the seasonal variability in the hydro capacity. The LOLE and LOEE indices are dependent on the reliability of the generation and transmission facilities. The basic studies were conducted using reliability data obtained from the Yukon Energy Corporation and the Canadian Electricity Association (CEA). Additional studies were performed in order to illustrate the impact on the predicted indices of transmission line data uncertainty.

2. ANALYSIS OF THE BASIC SYSTEM DATA

2.1 WAF Generating System Data

The total installed capacity of the Whitehorse-Aishihik-Faro (WAF) system is 103,000 kW. The unit types and ratings are given in Table 2.1 and Table 2.2.

Table 2.1: WAF System Generation Data

Location	Unit Type	Unit ID	MCR, kW	Total, kW
Whitehorse	Hydro	WH1	5800	40000
		WH2	5800	
		WH3	8400	
		WH4	20000	
	Diesel Mirrlees	WD1	3000	22400
		WD2	4200	
		WD3	4200	
	Diesel EMD	WD4	2500	
		WD5	2500	
		WD6	2700	
	Cat 3612	WD7	3300	
Aishihik	Hydro	AH1	15000	30000
		AH2	15000	
Faro	Cat 3612	FD7	3000	5300
	Cat 3516	FD3	1000	
		FD5	1300	

Table 2.2: YECL Generation Data

Location	Unit Type	MCR, kW	Total, kW
Carmacks	Diesel	1300	5300
Haines Junction	Diesel	1700	
Teslin	Diesel	1300	
Ross River	Diesel	1000	

In the absence of actual detailed data on the hydro units at Whitehorse and Aishihik, generating unit data compiled by the Canadian Electricity Association - Equipment Reliability Information System (CEA- ERIS) [2] were used to estimate the forced outage rates (FOR) of the hydro units in Table 2.1. These data are shown in Appendix A. A FOR of 10% was used for all the diesel units. This is based on the historic availability of the WAF diesel units of approximately 90%. The FOR values shown in Table 2.3 were used in the studies described in this report.

Table 2.3: Generating Unit FOR

Unit Type	FOR (%)
Hydro	3
Diesel	10

Seasonal variations in maximum continuous ratings of hydro units have significant impacts on system adequacy. Based on the information provided by YEC, the two hydro units in the Aishihik area are capable of generating constant output approximately equal to their rated MCR throughout the year. The effective capacity of the Whitehorse hydro plant during the winter season is considered to be 24,000 kW, due to hydrological constraints. The generation model for the Whitehorse hydro plant for this period is given in Table 2.4. The total effective capacity of the WAF System during the winter season is therefore 87,000 kW. The winter season was considered to consist of the months from November to March, with the remaining months grouped into the summer category.

Table 2.4: Whitehorse Hydro Plant Winter Generation Model

Capacity (kW)	Probability
24000	0.96997381
20000	0.02740638
14200	0.00169362
11600	0.00084681
8400	0.00002619
5800	0.00005238
0	0.00000081

2.2 WAF Load Data

Historical data on the total chronological hourly generation to meet the WAF system load for the past five years (1999-2000 to 2003-2004) were used in the analysis. The chronological hourly loads from February 1 2003, 1:00 AM to midnight January 31 2004 are shown in Figure 2.1.

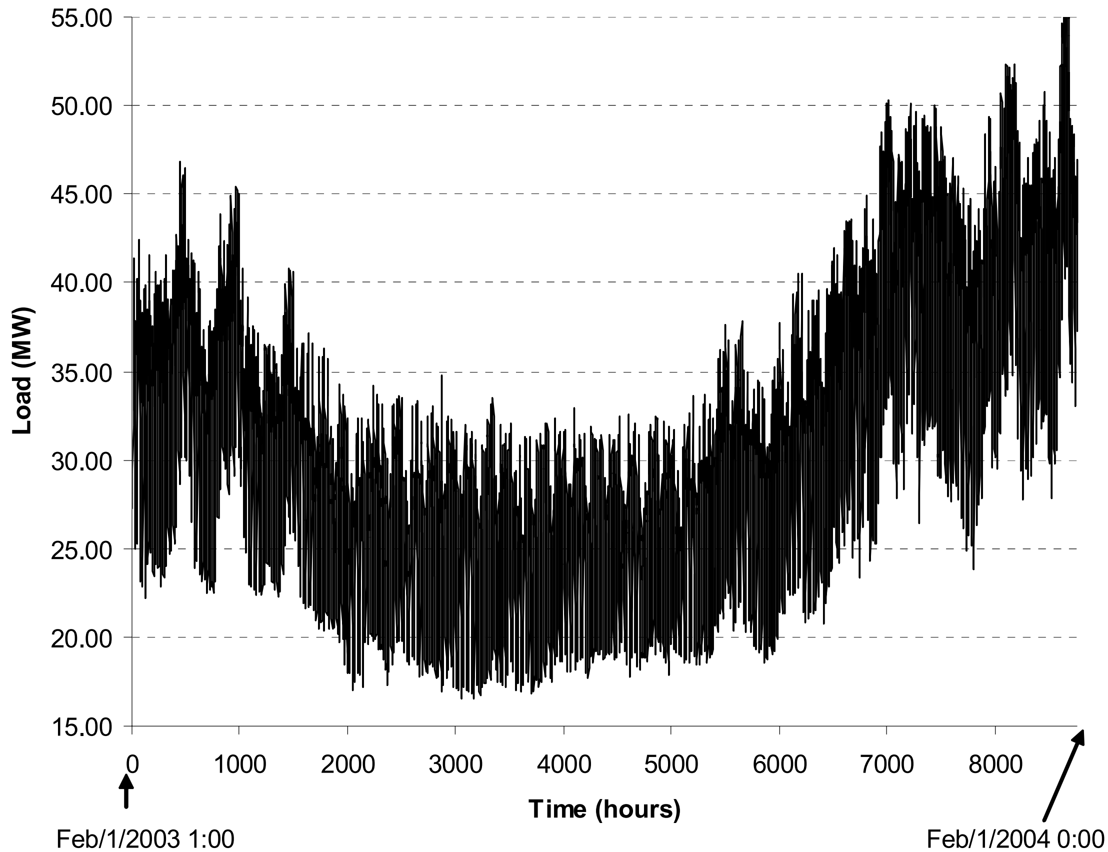


Figure 2.1: Chronological Hourly Load for the Year 2003-04

The hourly data for each year were sorted in decreasing order, expressed in per unit of the peak load, and plotted against time to create the annual load duration curve (LDC). The LDC for the past five years are shown in Figure 2.2.

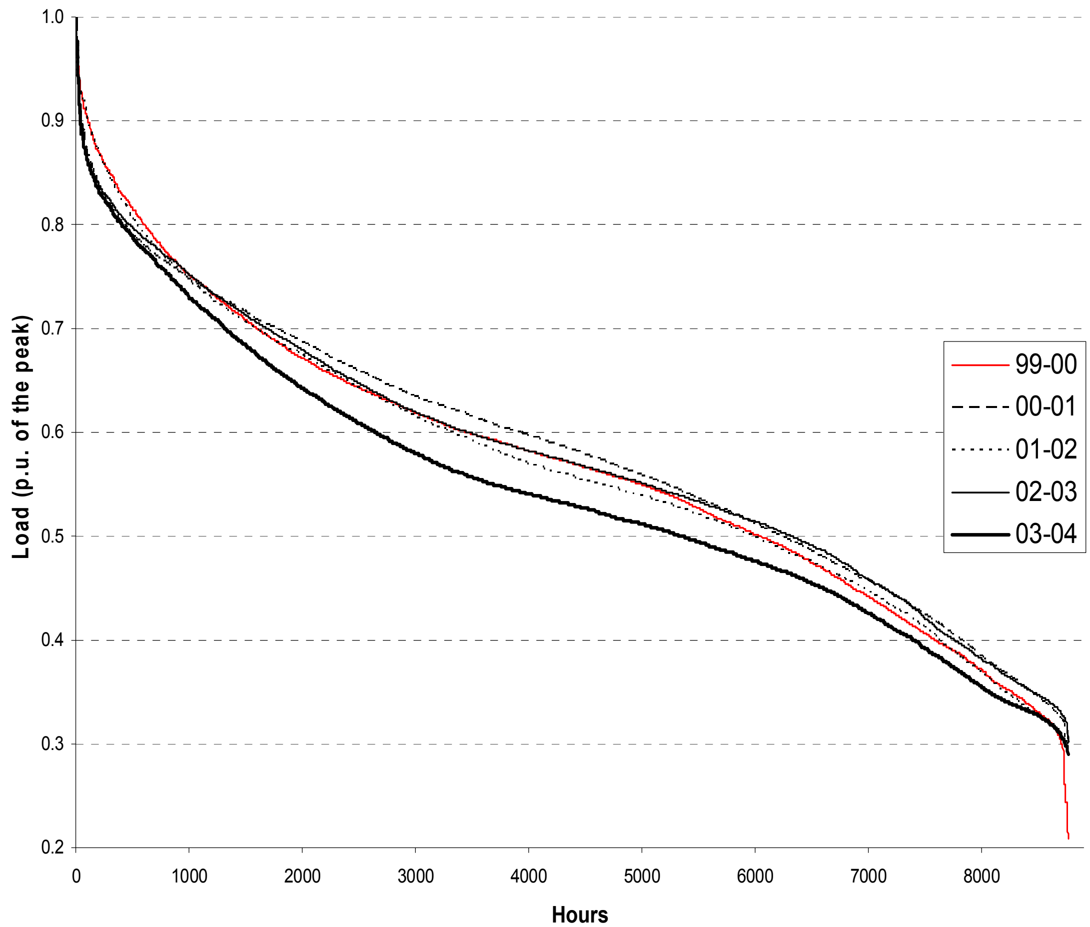


Figure 2.2: WAF Annual Load Duration Curves

The average of the five LDC was evaluated and used as the load model in the analysis. Figure 2.3 shows the average LDC for the WAF system. The average annual load factor is 0.568.

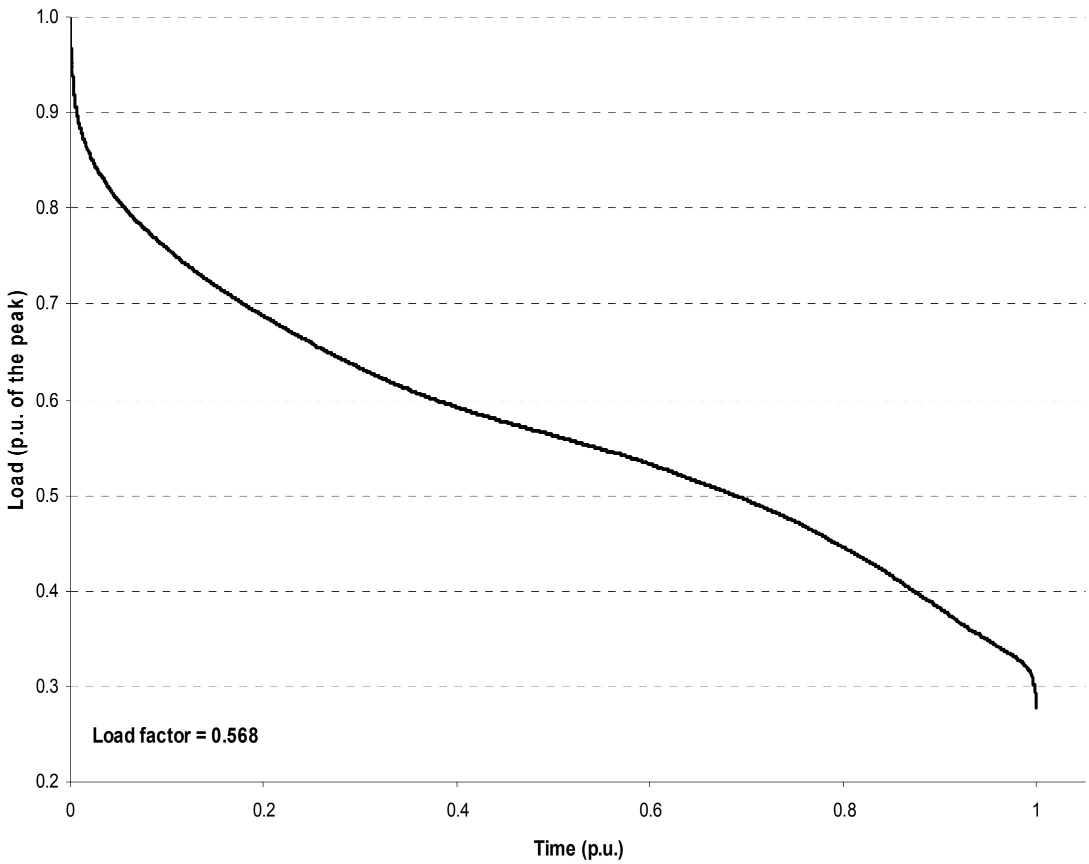


Figure 2.3: Annual Load Model for the WAF System

Separate load models were created for the summer and winter seasons for system analyses considering seasonal variations. The hourly load data for the summer and winter seasons were separated, and the average LDC were created for the two seasons. Figure 2.4 shows the summer and winter LDC for the WAF system.

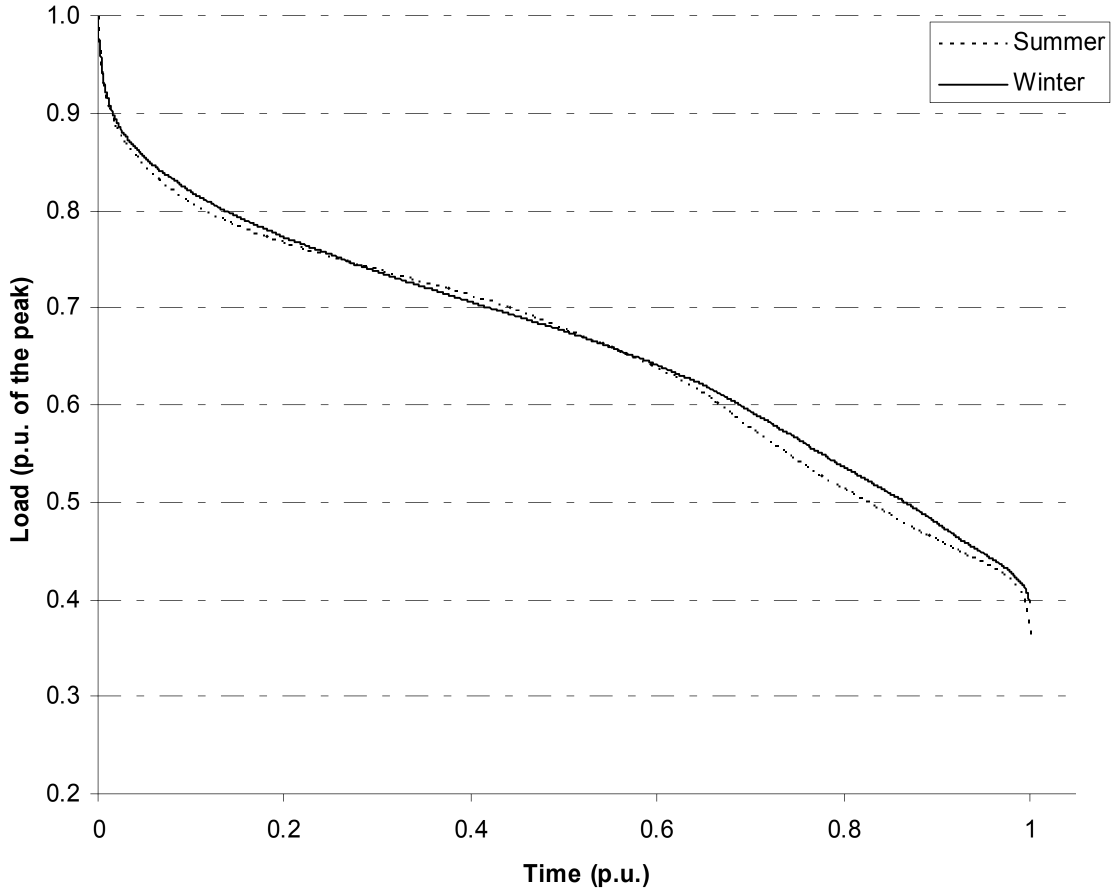


Figure 2.4: Summer and Winter Load Models for the WAF System

The peak loads during the summer and the winter seasons are shown in Table 2.5 for the five consecutive years. The average summer peak load is approximately 76.7% of the annual peak load based on the available five-year load data.

Table 2.5: Summer and Winter Peak Loads

Year	Winter Peak Load (MW)	Summer Peak Load	
		(MW)	p.u. of Annual Peak
1999-2000	48.65	35.69	0.733607
2000-2001	47.70	39.73	0.832914
2001-2002	50.81	38.00	0.747884
2002-2003	50.81	39.95	0.786263
2003-2004	57.13	41.96	0.734465

3. GENERATING SYSTEM RELIABILITY EVALUATION

3.1 System Model

Generating system adequacy evaluation is the assessment of the ability of the generating facilities to satisfy the total system load. The transmission network is not considered at this level. The basic system model is shown in Figure 3.1.

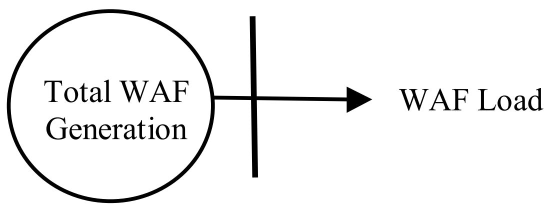


Figure 3.1: Basic Model for Generating System Adequacy Evaluation

3.2 Basic Evaluation on an Annual Basis

The initial analysis was conducted using the model in Figure 3.1. The generating system shown in Table 2.1 was convolved with the load model shown in Figure 2.2 to obtain the LOLE and LOEE indices for the WAF system. The risk profiles as a function of the annual peak load for both the LOLE and LOEE indices are shown in Figures 3.2 and 3.3 respectively.

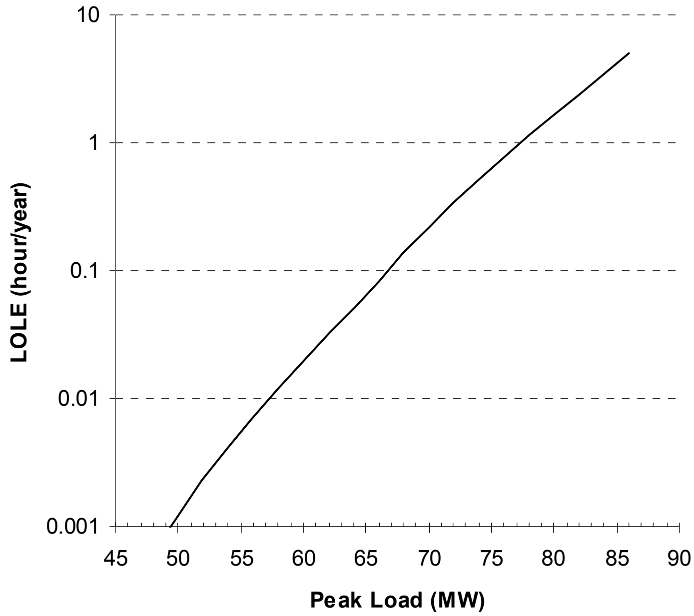


Figure 3.2: Annual LOLE Risk Profile

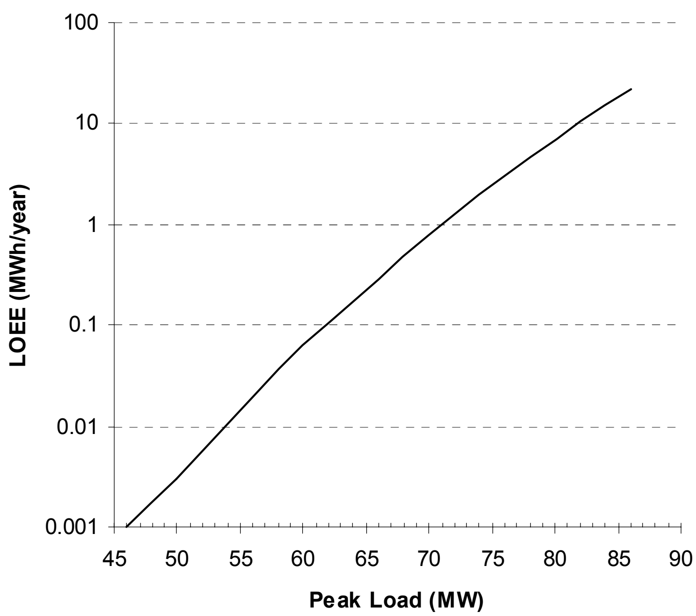


Figure 3.3: Annual LOEE Risk Profile

The annual system risk can be obtained from Figures 3.1 and 3.2 for any anticipated annual peak load. Table 3.1 shows the annual risk indices for the years from 1997-98 to 2002-03.

Table 3.1: Annual Risk Indices for the Past Seven Years

Year	Peak Load (MW)	LOLE (hours/year)	LOEE (MWh/year)
1997-1998	73.00	0.4183	1.569
1998-1999	53.64	0.0037	0.010
1999-2000	48.65	0.0008	0.002
2000-2001	47.70	0.0005	0.001
2001-2002	50.81	0.0016	0.004
2002-2003	50.81	0.0016	0.004
2003-2004	57.13	0.0096	0.029

3.3 Risk Evaluation Considering Seasonal Capacity Variations

This section examines the effect of capacity limitations of the Whitehorse hydro generators due to seasonal variations in river flow. The generation data for this case and the load models for the summer and the winter seasons are given in Section 2. The system reliability was evaluated separately for the summer and winter seasons. The seasonal risk indices were weighted by the number of months in each season and combined to obtain the annual indices. Figures 3.4 and 3.5 show the annual LOLE and LOEE respectively as a function of the annual peak loads.

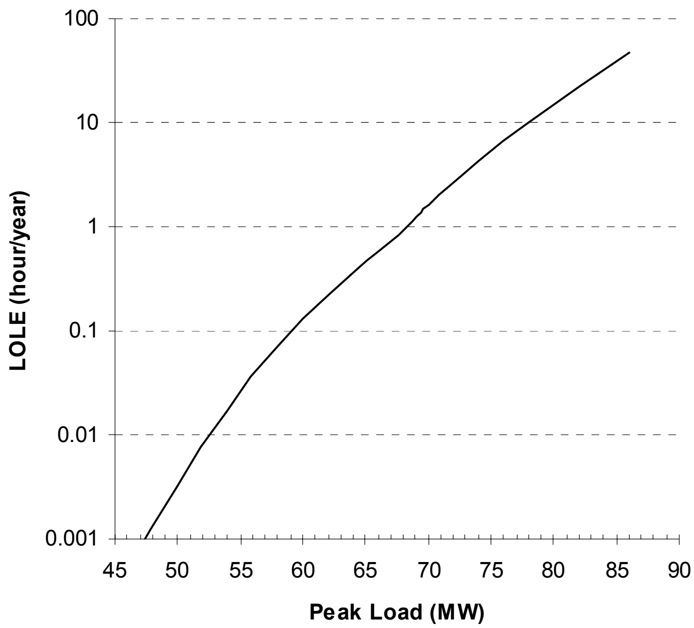


Figure 3.4: Annual LOLE Risk Profile Considering Seasonal Variations

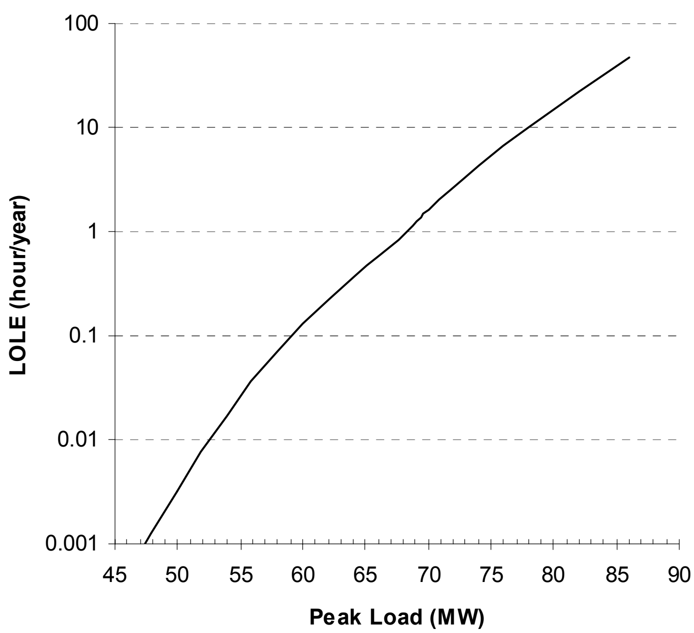


Figure 3.5: Annual LOEE Risk Profile Considering Seasonal Variations

The annual system risk indices considering seasonal variations in generation capacities can be obtained from Figures 3.4 and 3.5 for an anticipated annual peak load. Table 3.2 shows the annual risk indices for the WAF system during the years 1997-98 to 2003-04.

Table 3.2: Annual Risk Indices for the Past Seven Years Considering Seasonal Capacity Variations

Year	Peak Load (MW)	LOLE (hours/year)	LOEE (MWh/year)
1997-1998	73.00	3.3461	11.624
1998-1999	53.64	0.0149	0.031
1999-2000	48.65	0.0017	0.003
2000-2001	47.70	0.0011	0.002
2001-2002	50.81	0.0045	0.009
2002-2003	50.81	0.0045	0.009
2003-2004	57.13	0.0532	0.126

3.4 Assessment of the Existing Adequacy Criterion

The deterministic criteria presently used by YEC are as follows:

1. for all local diesel generation grids (i.e. local diesel community only) the criteria is: sufficient capacity to meet 110% of the forecast system peak for the upcoming year with loss of the largest diesel genset.

2. for the Whitehorse (WAF) grid the criteria is: sufficient capacity to meet 100% of the forecast system peak for the upcoming year with the loss of 15 MW of hydro and 10% of the diesel capacity.

The firm capacity requirement for the WAF system is given by Equation (1).

$$IC \geq 100\% \text{ of } PL + 15 \text{ MW Hydro Capacity} + 10\% \text{ of Diesel Capacity} \qquad (1)$$

where, IC is the total installed capacity and PL is the system peak load.

The Whitehorse hydro plant capacity is considered to be 24000 kW in the above criterion. The IC for the WAF system is, therefore, 87,000 kW, and the diesel capacity is 33,000 kW. The maximum allowable peak load (MAPL) under this condition is:

$$MAPL = 87{,}000 – 15{,}000 - 0.1 \times 33{,}000 = 68{,}700 \text{ kW}$$

The probabilistic risk indices for the WAF system at the maximum allowable peak load were calculated under similar conditions considering the seasonal capacity limitations of the Whitehorse hydro plant. The results are shown in Table 3.3.

Table 3.3: Existing Adequacy Risk Criteria

Peak Load (kW)	LOLE (hours/year)	LOEE (MWh/year)
68,700	1.154	3.903

The existing firm capacity criterion is equivalent to the probabilistic indices shown in Table 3.3. Many Canadian electric power utilities use a LOLE criterion between 0.1 and 0.2 days/year in generation planning. This is roughly equivalent to a range of 1.0 to 2.0 hours/year. These criteria can be compared with the existing WAF criterion of 1.2 hours/year in Table 3.3. As noted in Table 1.1, there is no universal agreement on a single numerical risk index. The selection of a particular index value is ultimately a management decision. The deterministic criterion given in Equation (1) considers the total generating capacity and the peak load of the system. The Whitehorse hydro plant capacity of 24,000 kW is considered in the deterministic criterion in order to account for the seasonal capacity limitations. The LOLE criterion of 1.2 hours/year was obtained under similar conditions to that of the deterministic criterion given in Equation (1), and therefore, this value is used as the benchmark to compare different system scenarios in the studies described later in this report.

3.5 Impact of Seasonal Capacity Limitations on System Risk

The impact of seasonal variations on the overall generating system reliability can be assessed by comparing the system LOLE results in Figure 3.4 with the results in Figure 3.2. Figure 3.6 shows the system LOLE profiles for the two cases.

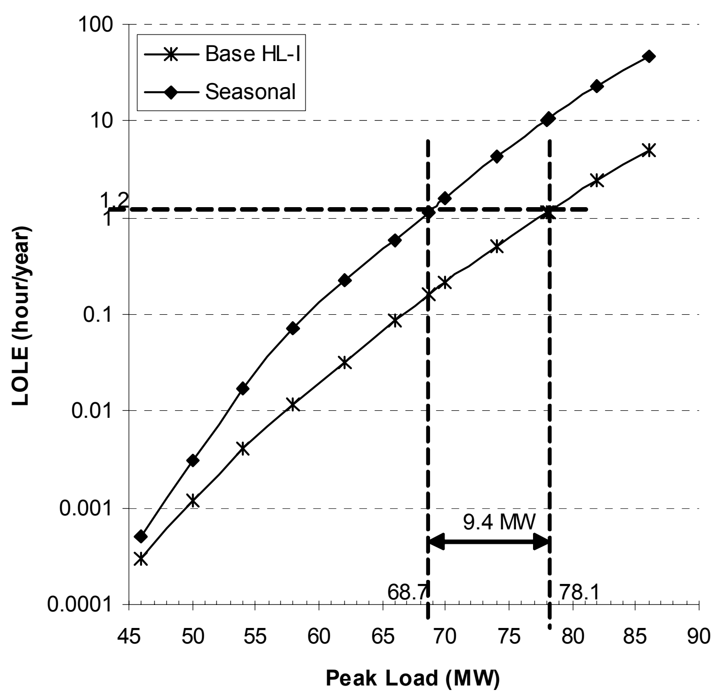


Figure 3.6: Impact of Seasonal Variations on System LOLE

It can be see from Figure 3.6 that there is a significant increase in the system risk, or in other words, a significant decrease in system reliability when the Whitehorse hydro units are derated during the winter season. A peak load of 78.1 MW can be served at the risk criterion (LOLE of 1.2 hours/year) corresponding to the accepted deterministic firm capacity criterion when the seasonal capacity limitations are not considered. Figure 3.6 shows that the peak load that can be served at the specified LOLE is reduced to 68.7 MW when the Whitehorse hydro unit deratings due to seasonal variation in river flow are incorporated. The decreased generation during the winter season has the effect of reducing the peak load carrying capability of the WAF generating system by 9.4 MW.

Table 3.4 compares the WAF system risk indices with and without considering seasonal capacity limitations in the Whitehorse hydro units for the past six years.

Table 3.4: Annual Risk Indices With and Without Seasonal Capacity Consideration for the Past Seven Years

Year	Peak Load (MW)	LOLE (hours/year)		LOEE (MWh/year)	
		without considering seasonality	considering seasonality	without considering seasonality	considering seasonality
1997-1998	73.00	0.4183	3.3461	1.569	11.624
1998-1999	53.64	0.0037	0.0149	0.010	0.031
1999-2000	48.65	0.0008	0.0017	0.002	0.003
2000-2001	47.70	0.0005	0.0011	0.001	0.002
2001-2002	50.81	0.0016	0.0045	0.004	0.009
2002-2003	50.81	0.0016	0.0045	0.004	0.009
2003-2004	57.13	0.0096	0.0532	0.029	0.126

The above studies show that the seasonal variations in generation capacities have a significant impact on the annual risk indices. The results obtained in Section 3.2 do not consider seasonal capacity limitations, and therefore provide a highly optimistic measure of system reliability. The results from the analysis in this section clearly indicate that it is important to consider the seasonal variations in the hydro generation in order to obtain a realistic reliability assessment. Seasonal capacity limitations of the Whitehorse hydro units are therefore included in all the subsequent analyses in this report.

4. GENERATING SYSTEM RELIABILITY EVALUATION CONSIDERING THE TRANSMISSION SYSTEM

4.1 System Model and Relevant Transmission Line Data

The WAF system is primarily supplied by hydro generation plants located at Aishihik and Whitehorse. The load at the Aishihik area is assumed to be insignificant compared to the bulk of the WAF system load, based on the information provided by YEC. Power generated by the Aishihik hydro units is delivered to the WAF load through a 130 kilometre transmission line, L171. This section examines the effect of including the L171 transmission line constraint in the reliability evaluation of the WAF system. The system model used for this study is shown in Figure 4.1.

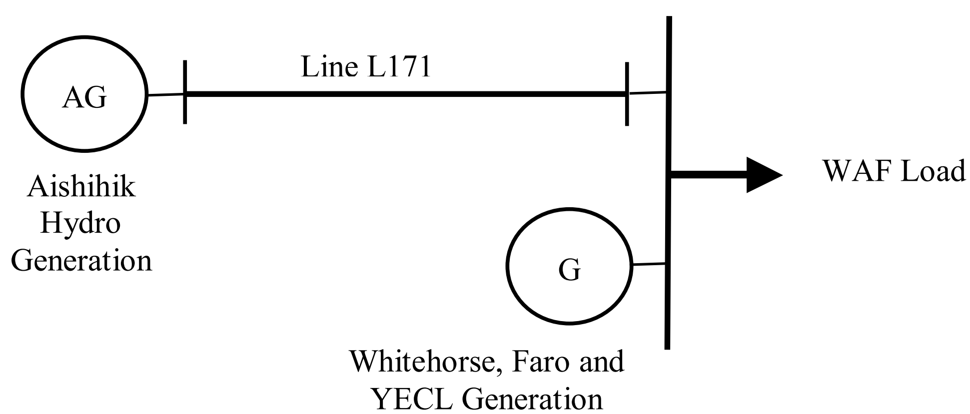


Figure 4.1: System Model Considering Transmission Line L171

The Haines Junction diesel unit and the Aishihik hydro plant are connected to the Whitehorse area load by line L171. The Haines Junction generating capacity is sufficient to meet the Haines Junction load. The main impact of a L171 outage is the loss to the WAF of the Aishihik plant capacity. An outage of L171, therefore, has a relatively minor impact on the Haines Junction reliability. The Aishihik generating units capacity constrained by L171 were aggregated at location AG in the reliability model shown in Figure 4.1. The generating units not capacity constrained by L171 were aggregated at location G in the model. The Haines Junction diesel unit was, therefore, also considered to be at location G in the reliability analyses.

Reliability evaluation of the system shown in Figure 4.1 requires additional data on transmission line outages. Transmission line data compiled by the CEA-ERIS were used to estimate the line unavailability for L171. The CEA Report on Forced Outage Performance of Transmission Equipment published in April 2004 [3] includes transmission outage data from January 1998 to December 2002. These data are shown in Appendix A, and were used in the analysis. A general description of transmission line L171 is given in Table 4.1.

Table 4.1: Basic Data for Line L171

Line Length	130 km
Voltage Rating	138 kV
Structure Type	Wooden H-Frame
Unavailability	0.006639

CEA data on 138 kV transmission lines using wood double pole structures were used to estimate the unavailability of line L171 shown in Table 4.1. The relevant calculations are shown in Appendix A.

4.2 Reliability Evaluation Considering the Line L171 Constraint

The evaluation method consists of developing a capacity model for the Aishihik hydro plant, moving the capacity model through the transmission line considering the line constraints, developing the overall generation model for the WAF system, and convolving the generation model with the system load model to obtain the reliability indices. The capacity model for the Aishihik hydro plant is shown in Table 4.2.

Table 4.2: Capacity Model for the Aishihik Hydro Plant

Capacity Outage (MW)	Probability
0	0.9409
15	0.0582
30	0.0009

The Aishihik hydro generation capacity is constrained by the tie line L171 when delivering power to the WAF system load. Table 4.3 shows the tie line constrained equivalent capacity model for the Aishihik hydro plant.

Table 4.3: Tie Line Constrained Equivalent Capacity Model for the Aishihik Hydro Plant

Capacity Outage (MW)	Probability
0	0.93465295
15	0.05781359
30	0.00753346

The equivalent capacity model in Table 4.3 was combined with the rest of the WAF and YECL generation to create the overall WAF generation model. Separate generation models were created for the summer and winter seasons and convolved with the corresponding load durations curves shown in Figure 2.4 to obtain the system risk considering seasonality. Figures 4.2 and 4.3 show the annual LOLE and LOEE respectively as a function of the annual peak loads.

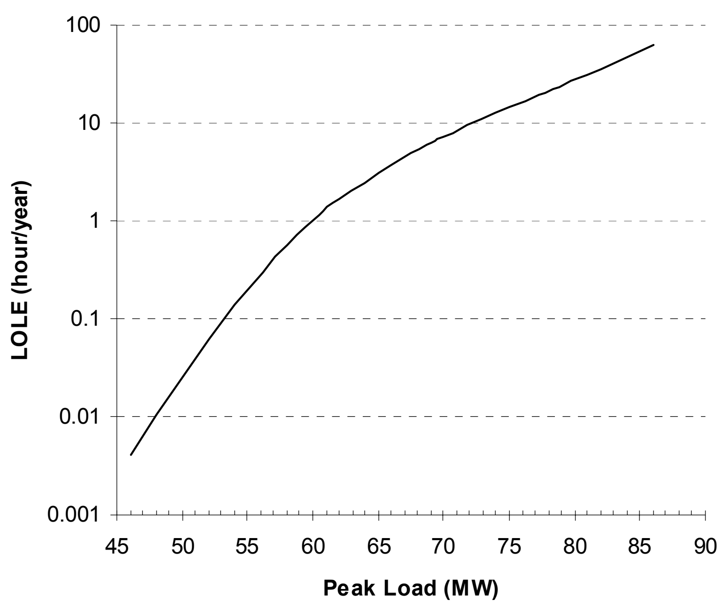


Figure 4.2: Annual LOLE Risk Profile Considering the L171 Constraint

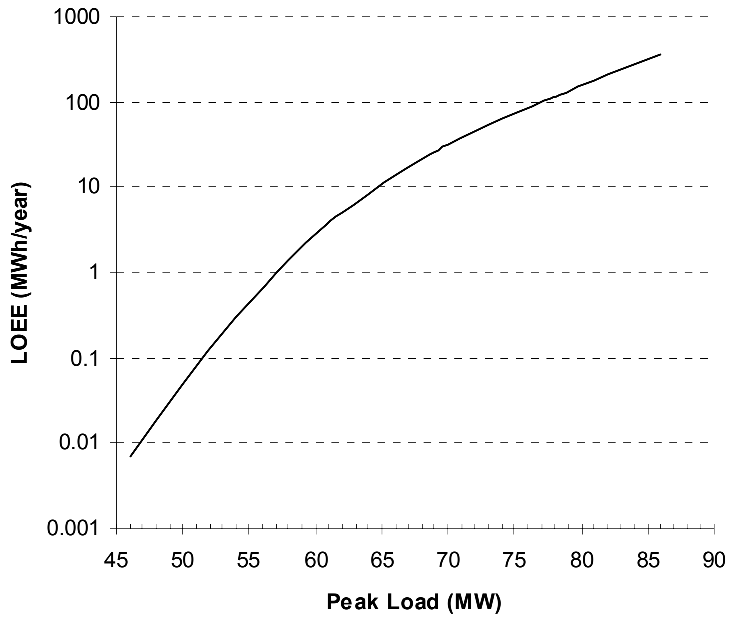


Figure 4.3: Annual LOEE Risk Profile Considering the L171 Constraint

The annual system risk indices considering the line constrained Aishihik hydro generation can be obtained from Figures 4.2 and 4.3 for an anticipated annual peak load. Table 4.4 shows the annual risk indices for the WAF system for the 1997-98 to 2003-04 period.

The impact of transmission line constraints on the overall generating system reliability can be assessed by comparing the system LOLE results in Figure 4.2 with the results in Figure 3.4 where the tie line was not considered. Figure 4.4 shows the system LOLE profiles for the two cases.

Table 4.4: Annual Risk Indices for the Past Seven Years Considering the Line-Constrained Aishihik Hydro Generation

Year	Peak Load (MW)	LOLE (hours/year)	LOEE (MWh/year)
1997-1998	73.00	10.9244	53.444
1998-1999	53.64	0.1225	0.257
1999-2000	48.65	0.0140	0.026
2000-2001	47.70	0.0090	0.017
2001-2002	50.81	0.0374	0.073
2002-2003	50.81	0.0374	0.073
2003-2004	57.13	0.4288	1.032

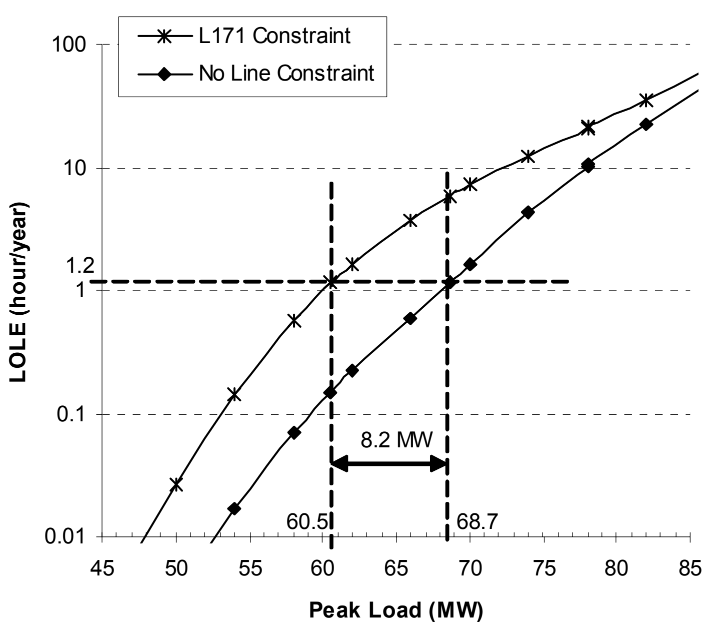


Figure 4.4: Impact of the Line Constrained Aishihik Generation on the System LOLE

It can be seen from Figure 4.4 that there is a significant increase in the system risk when the Aishihik hydro capacity is constrained by the transmission line L171. It is shown earlier in Figure 3.6 that a peak load of 78.1 MW can be served at the LOLE criterion of 1.2 hours/year when transmission constraints and seasonal capacity effects are not considered. The peak load carrying capability is reduced to 68.7 MW when the Whitehorse hydro unit deratings due to seasonal variations in river flow are considered. Figure 4.4 shows that the peak load carrying capability further reduces to 60.5 MW when transmission line constraints on the Aishihik hydro generation are also considered. The transmission line L171 constraints have the effect of reducing the peak load carrying capability of the WAF generating system by 8.2 MW.

4.3 Variation in Transmission Line Unavailability

The CEA-ERIS outage database includes a large quantity of similar equipment data collected over a rolling five-year period. These data, therefore, provide useful representative data for reliability studies, and are often used when actual data are unavailable or inadequate to assess the performance of the equipment. There were no reported failures on the transmission line L171 based on the YEC records. The results in Section 4.2 were obtained using transmission line outage data from the CEA-ERIS [3]. The unavailability of line L171 was estimated to be 0.006639 based on these data, and the calculation is shown in Appendix A.

This study illustrates the effect of line L171 unavailability on the overall WAF reliability. The unavailability of line L171 was varied from 0 to 0.01 and the corresponding system risk evaluated for different peak loads. Each curve in Figure 4.5 shows the system LOLE versus the peak load for a given transmission line unavailability value.

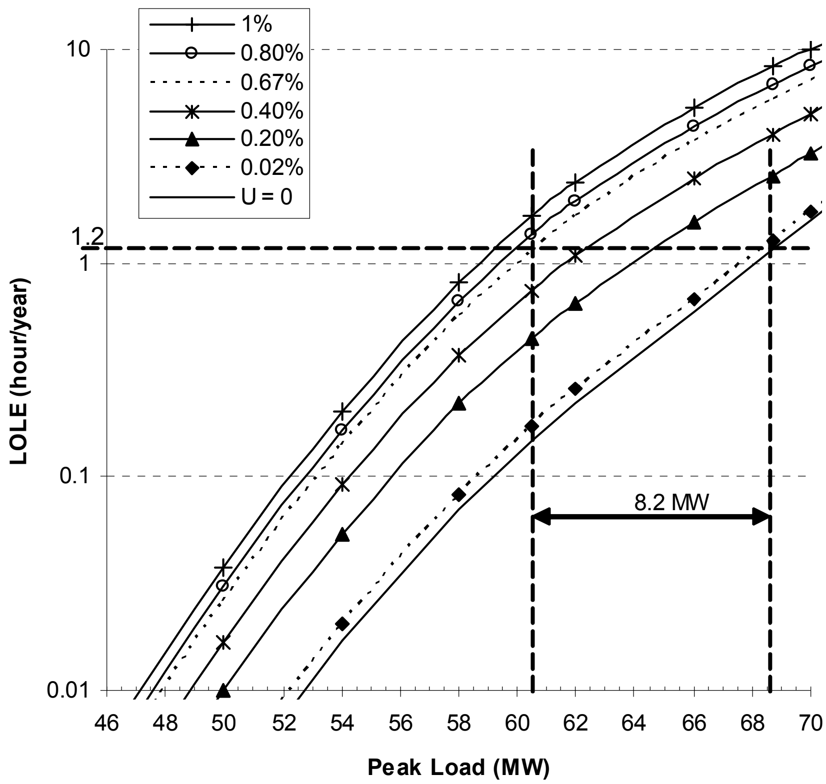


Figure 4.5: System Risk Profiles with Variable Transmission Line Unavailability

The curve farthest to the right shows the system risk when the line unavailability is zero. The system model in this case, is that shown in Figure 3.1.

A number of outages were reported on the 328 km long transmission line L170 based on the YEC records. These outage data were used to estimate the unavailability of line L171. The unavailability of line L171 was estimated to be 0.00017, and the calculation is shown in Appendix A. The system LOLE using this unavailability is shown by the dashed curve indicated by U = 0.02% in Figure 4.5.

The peak load that can be served at the LOLE criterion of 1.2 hours/year can be obtained from Figure 4.5. It can be seen that as the transmission line unavailability increases, the curves shift to the left, and the maximum peak load that can be carried decreases. The dashed curve on the left illustrates the case when the CEA-ERIS data is used. Figure 4.5 shows, as indicated earlier in Figure 4.4, that the peak load carrying capability decreases by 8.2 MW when the transmission line is incorporated using CEA data. The reduction in peak load carrying capability for selected L171 unavailability values can be obtained from Figure 4.5.

5. GENERATING SYSTEM RELIABILITY EVALUATION CONSIDERING GENERATING UNIT RETIREMENTS

5.1 Generating Unit Retirement Cases

This section examines the effect of generating unit retirements on the reliability of the WAF system. The retirements of diesel units located in the Whitehorse area were considered in this study. The following three different cases of diesel unit retirements were analyzed:

(i) Retirement of Unit WD1
(ii) Retirements of Units WD1 and WD2
(iii) Retirements of Units WD1 and WD2 and WD3

The capacity limitations of the Whitehorse hydro generating units due to seasonal variation in river flow were included in the evaluation. The impact on the system risk of the three unit retirement cases were assessed with and without considering the effect of transmission line constraints.

5.2 Risk Evaluation without Considering the Transmission System

The WAF system risks were evaluated for the three different cases noted in Section 5.1 without considering transmission line outages. The system risks were also compared with the base case indices in which generating unit retirements were not considered. The system LOLE and LOEE as a function of the annual peak load are shown in Figure 5.1 and Figure 5.2 respectively.

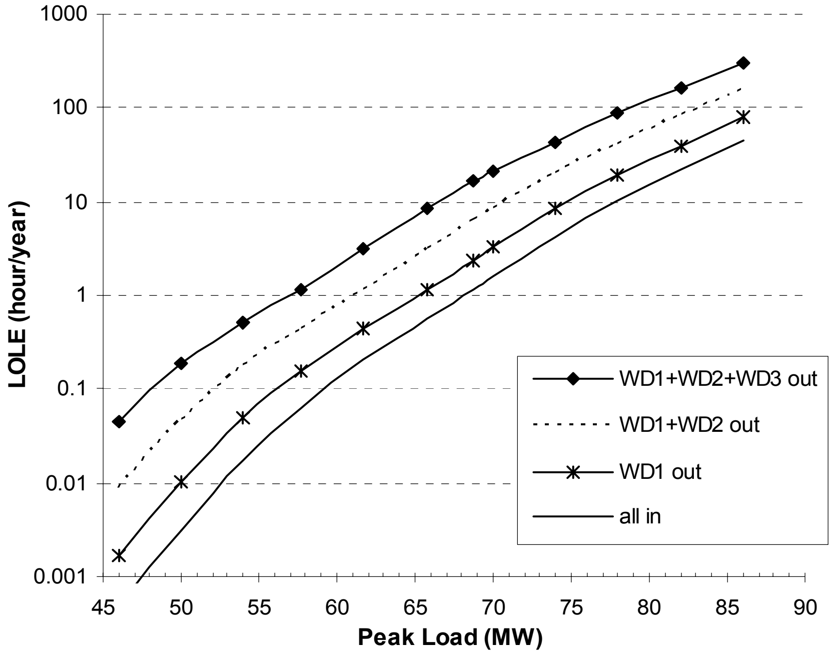


Figure 5.1: Annual LOLE Risk Profile Considering Generating Unit Retirements

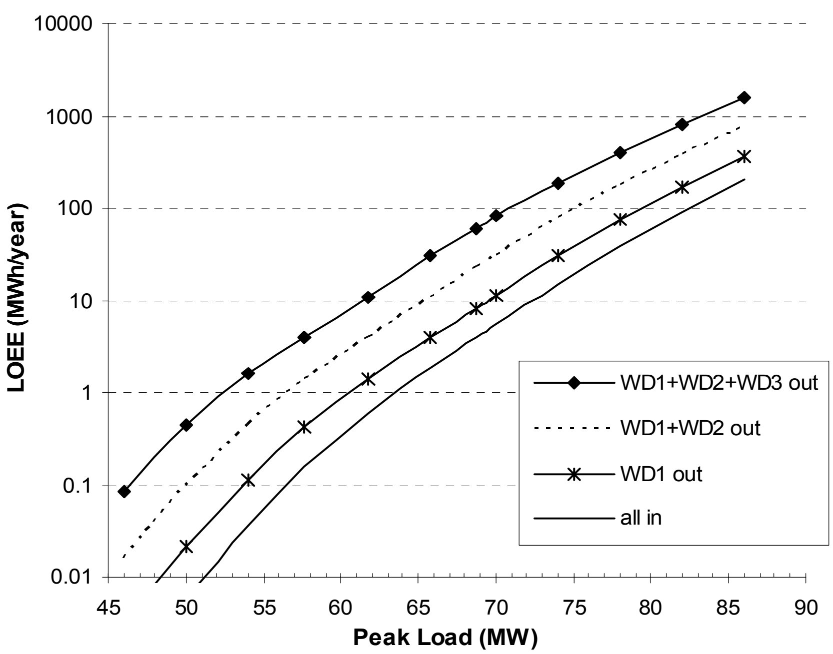


Figure 5.2: Annual LOEE Risk Profile Considering Generating Unit Retirements

The annual system risk indices considering the three cases of diesel unit retirements in the Whitehorse area can be obtained from Figures 5.1 and 5.2 for an anticipated annual peak load. The figures show that the risk profile shifts to the left as the number of retiring units increase. In other words, the system risk increases for a given peak load, or the peak load carrying capability decreases for a given risk level, as the number of retiring units increase.

Figure 5.3 shows the peak load carrying capabilities at the LOLE criterion of 1.2 hours/year for the three unit retirement cases. The lowest curve is for the base case, in which unit retirements are not considered.

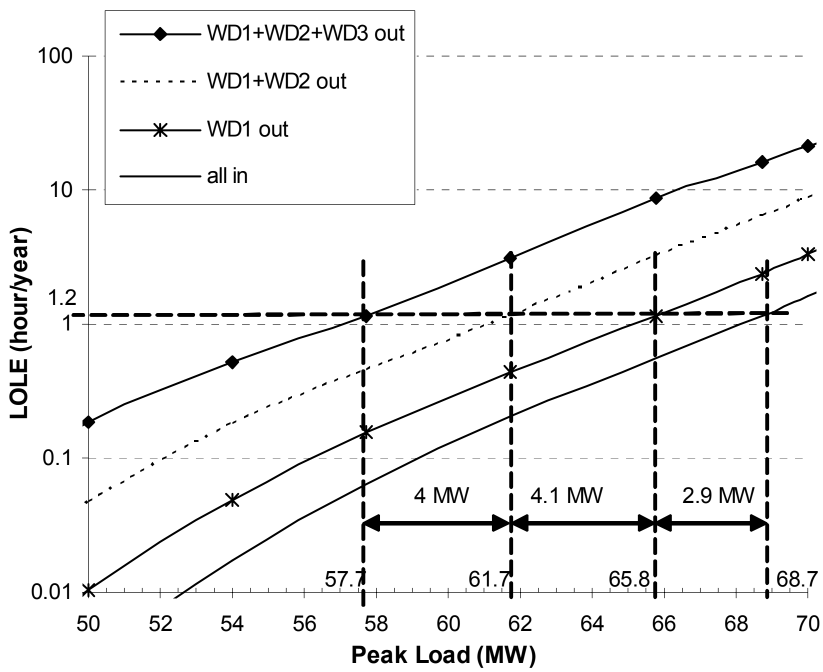


Figure 5.3: Peak Load Carrying Capability with Generating Unit Retirements

It can be seen from Figure 5.3 that the system risk increases significantly with increase in the number of generating units removed from the Whitehorse diesel plant. It is shown earlier in Figure 3.7 that a peak load of 68.7 MW can be served at the LOLE criterion of 1.2 hours/year when all the WAF generating units are considered, and the seasonal capacity limitations of the Whitehorse hydro units are taken into account. That information is also obtained from the lowest curve in Figure 5.3. The peak load carrying capability reduces to 65.8 MW at the LOLE criterion with the retirement of the 3 MW diesel unit WD1. The peak load carrying capability of the WAF generating system drops to 61.7 MW when both the WD1 and WD2 units are retired. When the three units, WD1, WD2 and WD3, are retired, the WAF system can only carry a peak load of 57.7 MW at the specified risk criterion. It should be noted that both the WD2 and WD3 units have the same capacity rating of 4.2 MW. It can be seen that the drop in the peak load carrying capability is approximately equal to the capacity of the diesel unit removed from service when the transmission line is not considered in the assessment.

5.3 Risk Evaluation Considering the Line L171 Constraint

The WAF system risks were evaluated for the three different unit retirement cases noted in Section 5.1 considering the ability of the transmission line L171 to transfer the power generated by the Aishihik hydro plant. The CEA forced outage data [3] were used for the transmission line in the study. The system risks were also compared with the base case indices in which generating unit retirements were not considered. The system LOLE and LOEE as a function of the annual peak load are shown in Figure 5.4 and Figure 5.5 respectively.

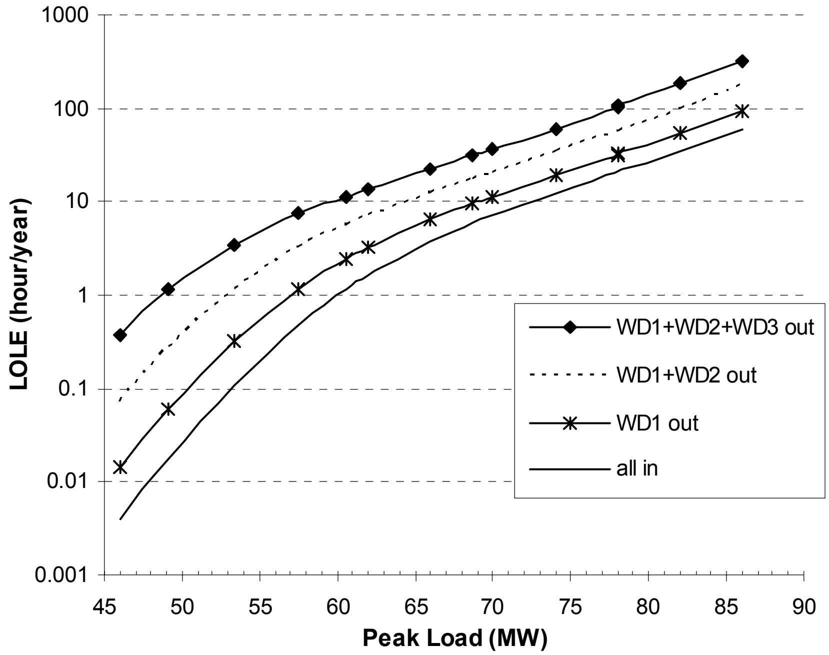


Figure 5.4: Annual LOLE Profile Considering Unit Retirements and L171 Constraint

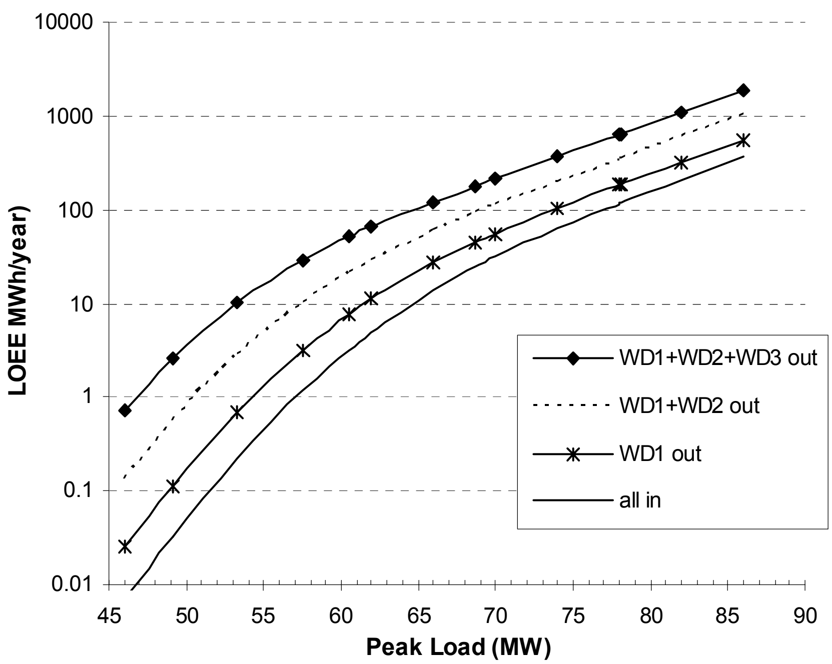


Figure 5.5: Annual LOEE Profile Considering Unit Retirements and L171 Constraint

The annual system risk indices considering both the line L171 constraint and the three diesel unit retirement cases can be obtained from Figures 5.4 and 5.5 for an anticipated annual peak load. The figures show that the system risk increases for a given peak load, or the peak load carrying capability decreases for a given risk level, as the number of retiring units increase.

Figure 5.6 shows the peak load carrying capabilities at the LOLE criterion of 1.2 hours/year for the three unit retirement cases. The lowest curve is for the base case, in which unit retirements are not considered.

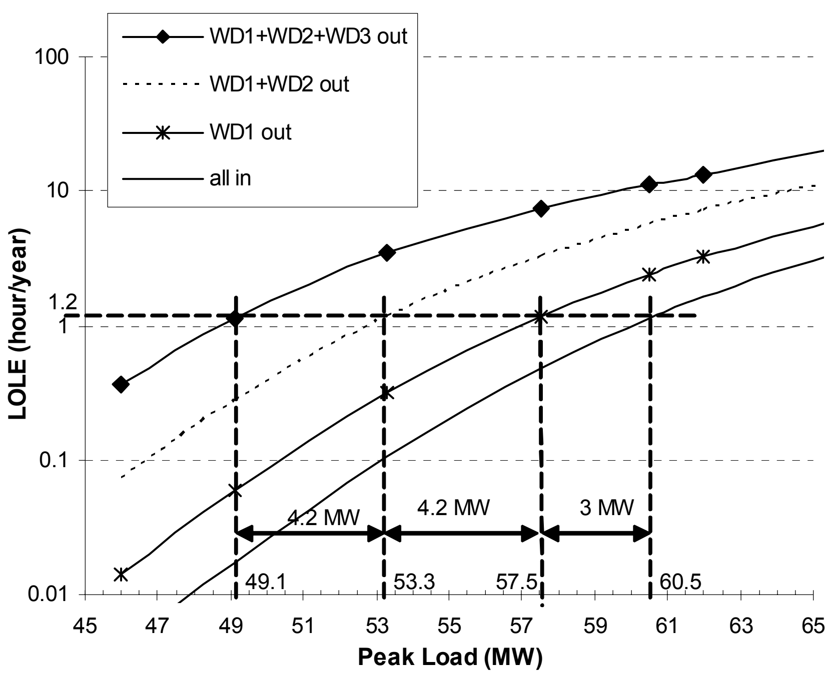


Figure 5.6: Peak Load Carrying Capability with Generating Unit Retirements Considering L171 Constraint

It can be seen from Figure 5.6 that the system risk increases significantly with increase in the number of generating units removed from the Whitehorse diesel plant. Figure 4.4 shows that a peak load of 60.5 MW can be served at the LOLE criterion of 1.2 hours/year when all the WAF generating units are considered, and the line L171 transmission constraint and seasonal capacity limitations of the Whitehorse hydro units are taken into account. That information is also obtained from the lowest curve in Figure 5.6. The peak load carrying capability reduces to 57.5 MW at the LOLE criterion with the retirement of the WD1 unit. The retirement of this 3 MW unit causes the peak load carrying capability of the WAF system to drop by 3 MW. The peak load carrying capability of the WAF generating system further drops to 53.3 MW when both the WD1 and WD2 units are retired. When the three units, WD1, WD2 and WD3, are retired, the WAF system can only carry a peak load of 49.1 MW at the specified risk criterion. It should be noted that the drop in the peak load carrying capability is approximately equal to the capacity of the retired unit in both the cases of considering and not considering the line constraint.

The system risk profiles can be compared in Figure 5.7 with and without considering the line constraints when the diesel unit WD1 is removed from the Whitehorse plant. The lower curve shows the LOLE profile with varying peak loads when the transmission system is not considered. The upper curve shows the system risk profile when CEA outage data is used to evaluate the transmission constraint. The system risk profile will lie between the two curves shown in Figure 5.7, if the unavailability of the line is less than the CEA derived value. The risk curve will be above the upper curve if the actual line unavailability is greater than the CEA data used in this study. In that case, the peak load carrying capability of the WAF system will be less than 57.5 MW. Figures 5.8 and 5.9 show similar results for the other two cases of WD1 and WD2 unit retirements, and WD1, WD2 and WD3 unit retirements respectively. The figures show that the drops in peak load carrying capability due to line effect are 8.3 MW, 8.4 MW and 8.6 MW respectively for the three cases of unit retirements. The results indicate that the effect of the line unavailability increases as the number of retiring units is increased.

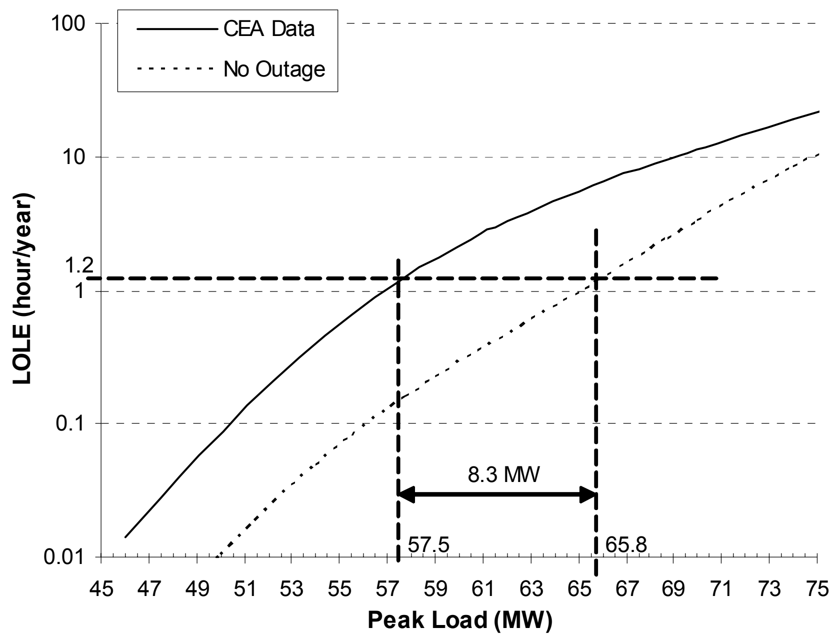


Figure 5.7: Risk Profiles with the Retirement of the WD1 Unit

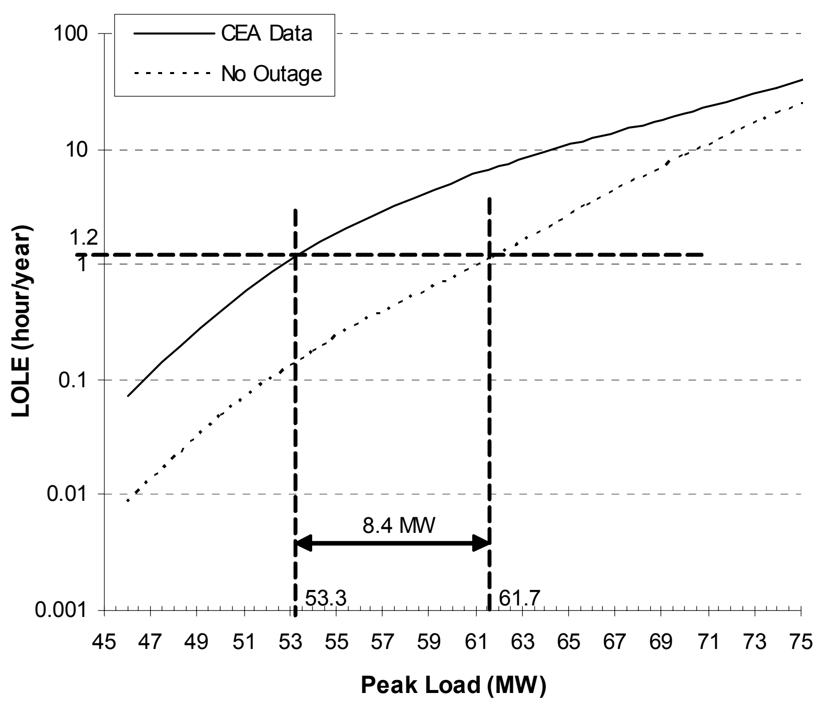


Figure 5.8: Risk Profiles with the Retirement of the WD1 and WD2 Units

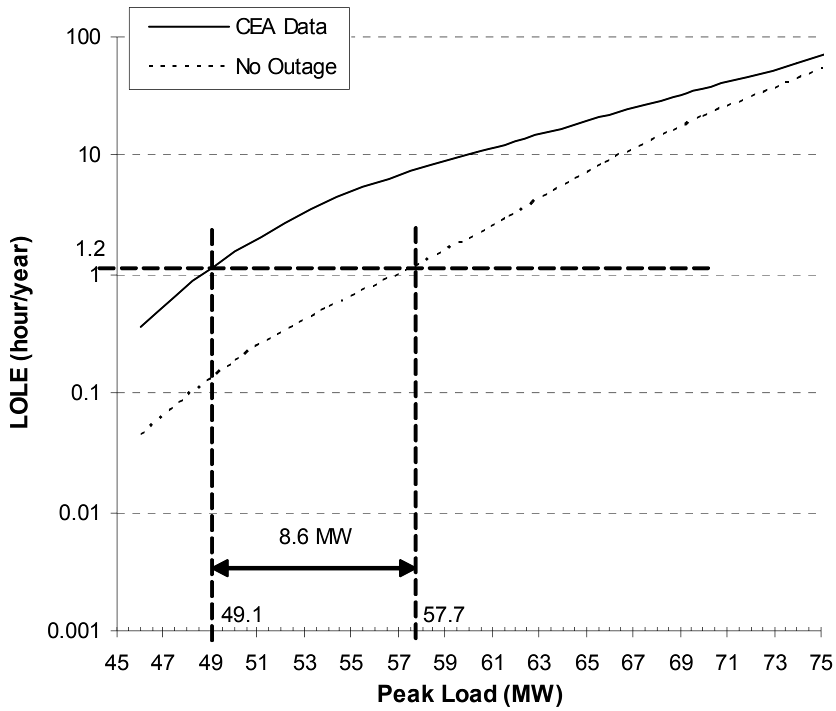


Figure 5.9: Risk Profiles with the Retirement of the WD1, WD2 and WD3 Units

6. GENERATING SYSTEM RELIABILITY EVALUATION OF THE WHITEHORSE SYSTEM

6.1 Whitehorse System Data

A study was conducted on the local Whitehorse system at the request of YEC. The Aishihik, Faro and YECL systems were not considered in this analysis. The total installed generating capacity of the Whitehorse system is 62,400 kW. The total generation capability during the winter season is 46,400 kW as the hydro plant capacity is limited to 24,000 kW. The local generating capacity can therefore satisfy a peak load level of 46,400 kW with all the units in service. The generation model for the Whitehorse hydro plant for this period is given in Table 2.4. The months from November to March are considered to be in the winter season, and the remaining months grouped into the summer category. The unit types and ratings are given in Table 6.1.

A FOR of 10% was used for all the diesel units, based on the historic availability of the WAF diesel units of approximately 90%. A FOR of 3% was used in the studies described in this report for the Whitehorse hydro units. This value was obtained from the outage statistics for hydro generating units in the 5 – 23 MW class from the "CEA-ERIS Generation Equipment Status Report – 2002".

Data on the total chronological hourly load for the Whitehorse area were available from YEC for the period between January 2003 and September 2004. The hourly loads from February 1 2003, 1:00 AM to midnight January 31 2004 were used to create an annual load model in this study.

Separate load models were created for the summer and winter seasons for system analyses considering seasonal variations. The hourly load data for the summer and winter seasons were separated, and the load duration curves (LDC) were created for the two seasons. Figures 6.1 and 6.2 show the summer and winter LDC respectively for the Whitehorse system.

Table 6.1: WAF System Generation Data

<table>
<tr><th rowspan="2">Unit Type</th><th rowspan="2">Unit ID</th><th colspan="2">MCR, kW</th><th colspan="2">Total, kW</th></tr>
<tr><th>Summer</th><th>Winter</th><th>Summer</th><th>Winter</th></tr>
<tr><td rowspan="4">Hydro</td><td>WH1</td><td>5,800</td><td rowspan="4">24,000</td><td rowspan="11">62,400</td><td rowspan="11">46,400</td></tr>
<tr><td>WH2</td><td>5,800</td></tr>
<tr><td>WH3</td><td>8,400</td></tr>
<tr><td>WH4</td><td>20,000</td></tr>
<tr><td rowspan="3">Diesel Mirrlees</td><td>WD1</td><td>3,000</td><td>3,000</td></tr>
<tr><td>WD2</td><td>4,200</td><td>4,200</td></tr>
<tr><td>WD3</td><td>4,200</td><td>4,200</td></tr>
<tr><td rowspan="3">Diesel EMD</td><td>WD4</td><td>2,500</td><td>2,500</td></tr>
<tr><td>WD5</td><td>2,500</td><td>2,500</td></tr>
<tr><td>WD6</td><td>2,700</td><td>2,700</td></tr>
<tr><td>Cat 3612</td><td>WD7</td><td>3,300</td><td>3,300</td></tr>
</table>

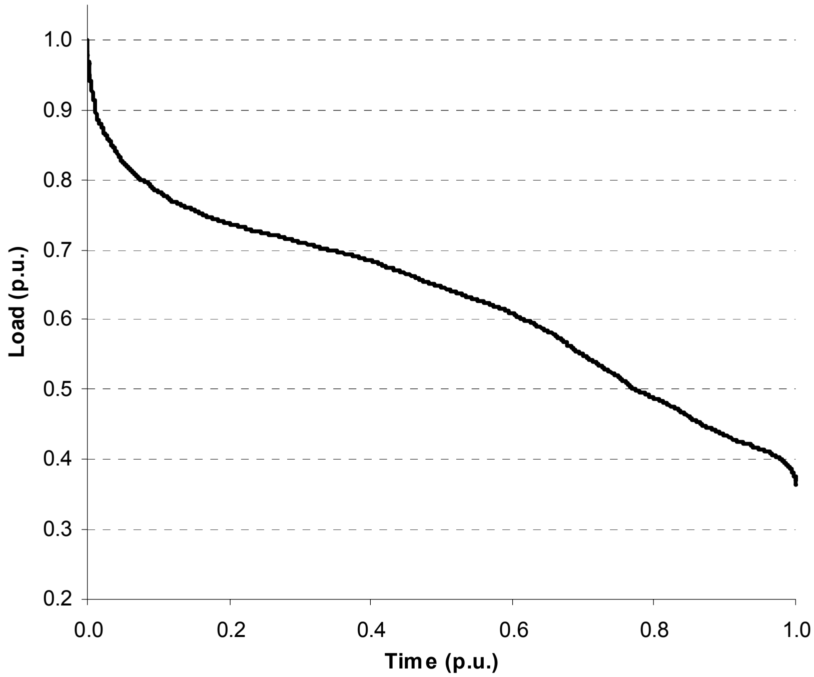


Figure 6.1: Summer Load Model

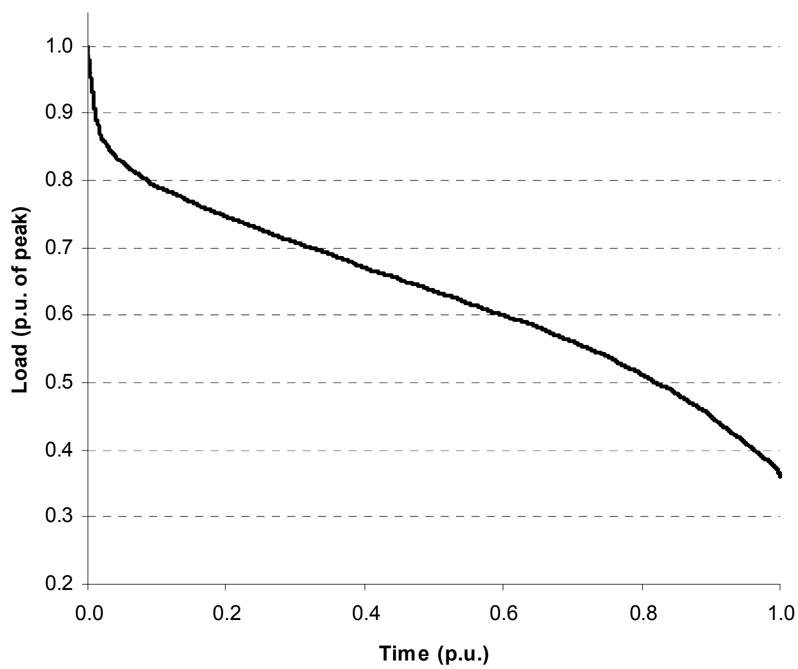


Figure 6.2: Winter Load Model

6.2 Reliability Assessment Considering Seasonal Capacity Limitations

The system risks for the Whitehorse area were evaluated considering the capacity limitations of the Whitehorse hydro generators due to seasonal variations in the river flow. The risk profiles as a function of the annual peak load for both the LOLE and LOEE indices are shown in Figures 6.3 and 6.4 respectively.

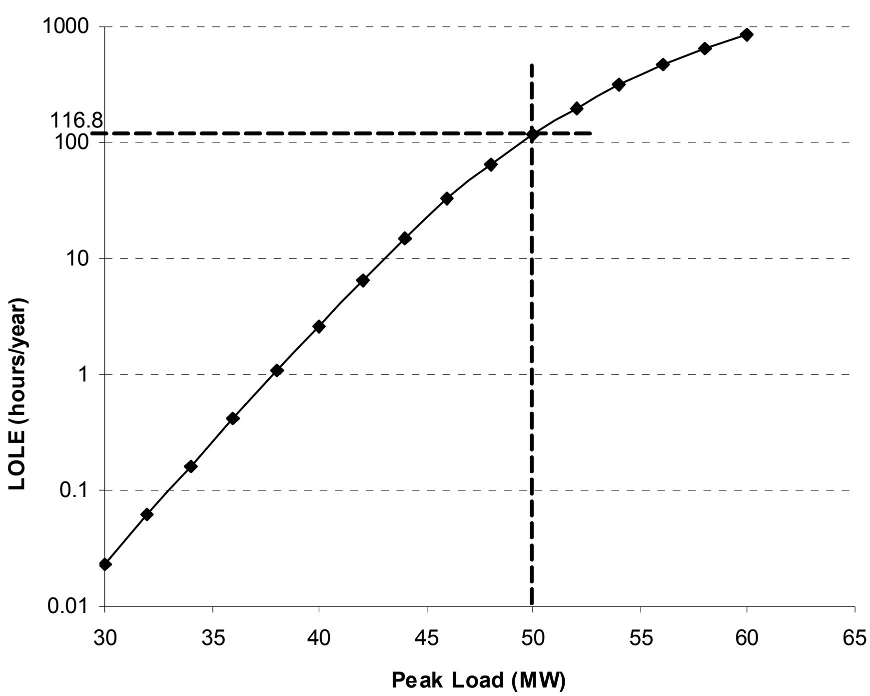


Figure 6.3: Annual LOLE Risk Profile for the Whitehorse System

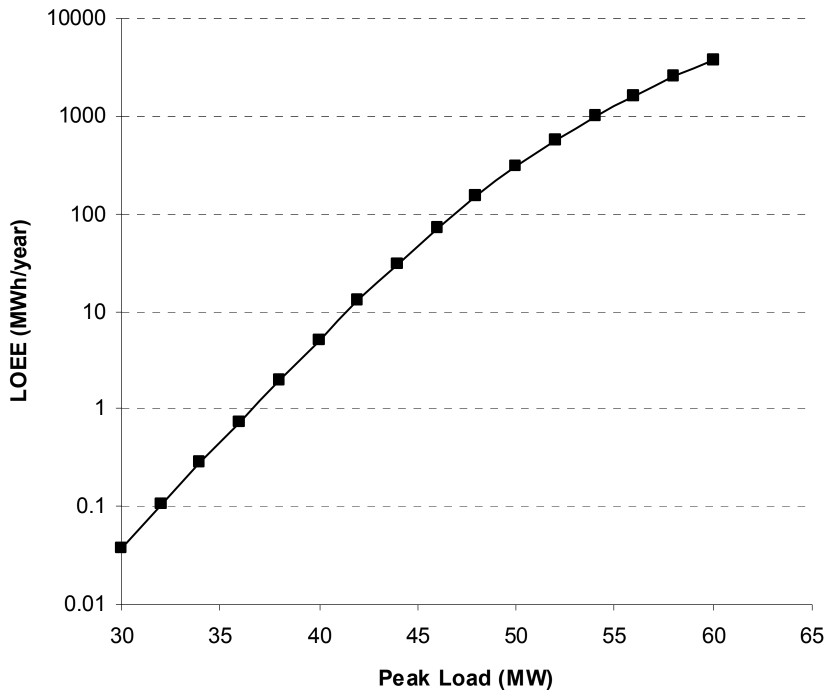


Figure 6.4: Annual LOEE Risk Profile for the Whitehorse System

The annual system risk can be obtained from Figures 6.3 and 6.4 for an anticipated annual peak load. The system peak load for the Whitehorse system is 50,000 kW based on the 2003 – 2004 load data. It can be seen from Figure 6.3 that LOLE for a peak load of 50,000 kW is 116.8 hours/year. This is the expected number of hours in a year that the local Whitehorse generating system would not meet the local area load. The corresponding LOEE is 304.8 MWh/year.

6.3 Risk Evaluation Considering Diesel Unit Retirements

This section examines the effect of changes in the generating system configuration as a result of unit retirements in the Whitehorse system. The following three different diesel unit retirement cases were considered in the study:

(i) Retirement of the WD1 unit

(ii) Retirements of the WD1 and WD2 units

(iii) Retirements of the WD1 and WD2 and WD3 units

The system LOLE as a function of the annual peak load are shown in Figure 6.5 for the three cases. The risk profiles are also compared with the base case in which none of the generating units are retired. Figure 6.6 shows similar results for the LOEE indices.

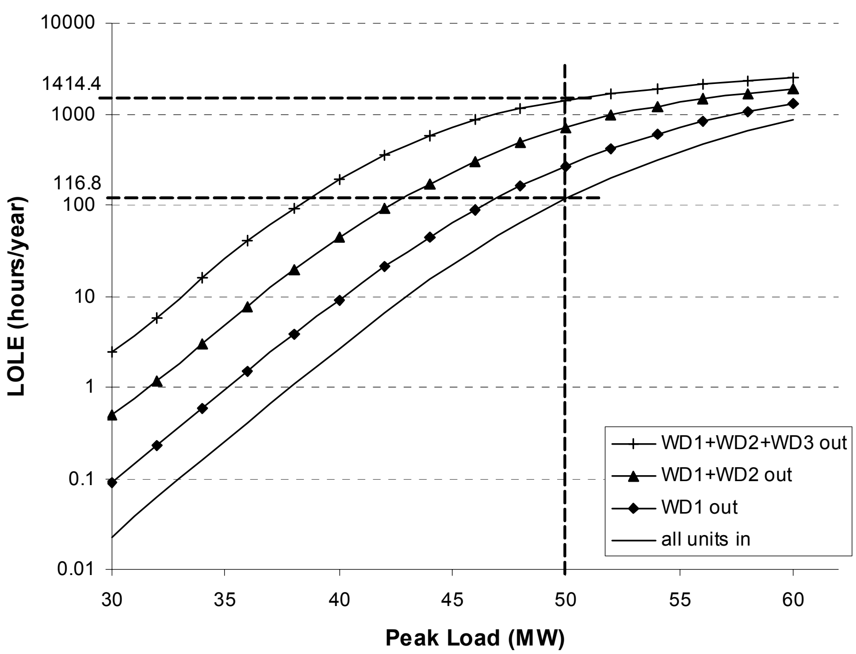


Figure 6.5: Annual LOLE Risk Profile for the Whitehorse System with Unit Retirements

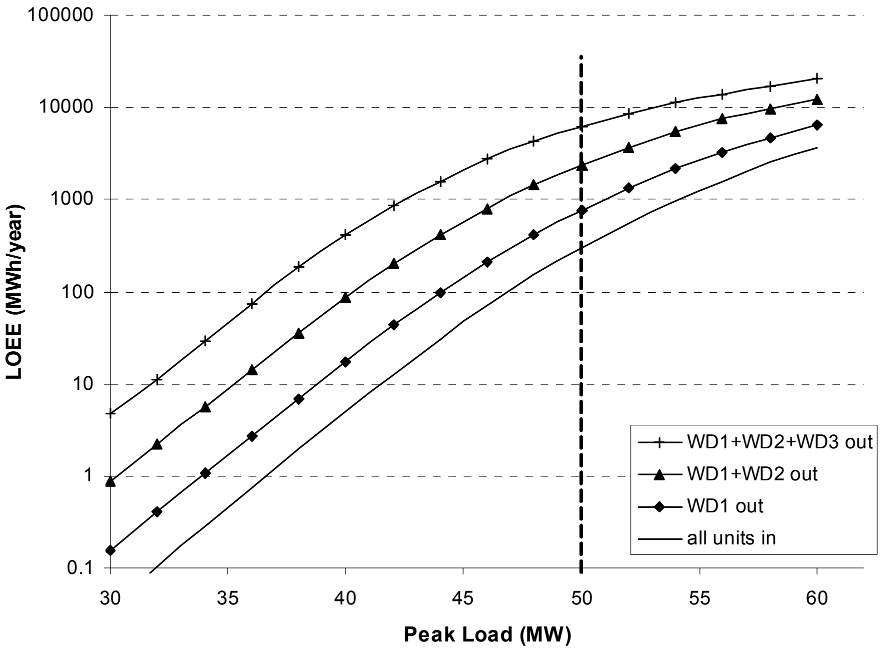


Figure 6.6: Annual LOEE Risk Profile for the Whitehorse System with Unit Retirements

The annual system risk indices considering the three diesel unit retirement cases can be obtained from Figures 6.5 and 6.6 for an anticipated annual peak load. Figure 6.5 also shows the annual LOLE indices for the Whitehorse system for the peak load of 50 MW obtained for the year 2004. The risk indices at a 50 MW peak load for the different unit retirement cases are shown in Table 6.2.

Table 6.2: Annual Risk Indices with Diesel Unit Retirements

	LOLE (hour/year)	LOEE (MWh/year)
No unit retirements	116.8265	304.841
WD1 retired	263.8141	767.648
WD1 and WD2 retired	721.1984	2401.332
WD1 and WD2 and WD3 retired	1414.416	6244.994

It can be seen from Table 6.3 that the expected number of hours in a year that the local Whitehorse generating system would not meet the local area load increases as the number of local generating unit retirements is increased. The expected hours of load curtailment in a year increases from 116.8 hours to 263.8 hours when WD1 is retired. This value is further increased to 721.2 hours when WD1 and WD2 units are both retired. There will be 1414.4 hours per year that the local generation system would not meet the local area load when the three WD1, WD2 and WD3 units retire.

7. CONCLUSIONS

The numerical results obtained for the different system studies depend highly on the data used in the respective evaluations. Relevant data obtained from YEC have been analyzed and used where applicable. Hydro generating unit and transmission line outage data obtained from CEA-ERIS have been used in the evaluations. CEA-ERIS data provide useful representative data for reliability studies, and are often used when actual data are unavailable or inadequate to assess the performance of the relevant equipment. Sensitivity studies are included in this report to illustrate the impact of variations in the transmission line reliability.

This report contains a basic annual reliability evaluation of the WAF system, analyses considering seasonal capacity variations, and reliability studies including the effect of transmission line constraints. The report also contains analyses of the impacts of diesel unit retirements on the WAF system adequacy, and on the adequacy of the Whitehorse area alone.

The existing WAF system firm capacity criterion was used to determine corresponding numerical risk indices using a basic annual evaluation. The corresponding LOLE criterion was determined to be 1.2 hours per year based on the assumed generating unit reliability data. This risk index includes the effect of component failures and load variations, and provides a more consistent adequacy appraisal than the accepted deterministic criterion. The evaluated LOLE criterion is used as a benchmark to compare different system scenarios in the studies conducted in this report. As noted in Table 1.1, there is no universal agreement on a single numerical risk index. The selection of a particular index value is ultimately a management decision.

The annual risk profiles as a function of the system peak load have been evaluated and plotted for the different system considerations. These graphs show that the system risk rises rapidly as the peak load increases. The risk profiles can be used to obtain the system LOLE or LOEE for an anticipated peak load.

The impact of seasonal capacity variations on the overall generating system reliability has been assessed by comparing the system LOLE results with the case in which the seasonal variations were not considered. The results show that there is a significant decrease in system reliability when the Whitehorse hydro units are derated during the winter season. The decreased generation during the winter season has the effect of reducing the peak load carrying capability of the WAF generating system by 9.4 MW.

The power generated by the Aishihik hydro units is delivered to the WAF system through the transmission line L171. The report also examines the effect of including the L171 transmission line constraint in the reliability evaluation of the WAF system. The impact of transmission line constraints on the overall generating system reliability was assessed by comparing the system LOLE values with those obtained without considering this line. The transmission line L171 constraint has the effect of reducing the peak load carrying capability of the WAF generating system by 8.2 MW at the LOLE criterion of 1.2 hours per year. The combined effect of the transmission constraint and the seasonal hydro capacity limitations results in a 17.6 MW reduction in the peak load carrying capability of the WAF system. These numerical values were obtained using the CEA transmission line forced outage data. Sensitivity studies with different line outage data are presented in the report. The reduction in peak load carrying capability for selected line L171 unavailability values are shown in Figure 4.5.

It was indicated that the diesel units WD1, WD2 and WD3 located at the Whitehorse area are close to the end of their equipment lives. The report provides evaluation of the WAF system adequacy considering the effect of the WD1 unit retirement, the WD1 and WD2 unit retirement, and the WD1, WD2 and WD3 unit retirement cases. The results show that the system reliability decreases significantly with unit retirements. The WAF system risks are presented for studies conducted with and without considering the transmission line constraints. The results show that the drop in the peak load carrying capability is approximately equal to the capacity of the diesel unit removed from service. The WAF system can only carry a peak load of 49.1 MW at the LOLE criterion of 1.2 hours per year considering line outages when the three units, WD1, WD2 and WD3, are retired.

The report also contains a reliability evaluation of the Whitehorse area alone, conducted at the request of YEC. System generation and load models were created for the Whitehorse area, and the risk indices were evaluated considering seasonal hydro capacity limitations and diesel unit retirements. The Whitehorse area risk indices were found to be much greater than the WAF system risk indices, and indicate the adequacy of the Whitehorse generation to serve the local area load.

This report provides a basic generating capacity reliability evaluation of the Whitehorse-Aishihik-Faro (WAF) system. It clearly shows the effect of seasonal capacity variations and transmission line constraints. The numerical risk values are highly dependent on the generating unit and transmission line failure and repair parameters used in the analyses. Representative data taken from the CEA Equipment Reliability Information System have been used to supplement the data provided by YEC. It is important to obtain actual system and equipment specific data for realistic reliability evaluation. It is strongly recommended that a routine data collection scheme be established to record system events involving generation and transmission equipment forced outages and the relevant failure and repair data be extracted and compiled on an annual basis.

8. REFERENCES

1. R. Billinton and R. N. Allan, “Reliability Evaluation of Power Systems – Second Edition”, Plenum Press, 1994.

2. Canadian Electricity Association, “Generation Equipment Status Annual Report”, December 2003.

3. Canadian Electricity Association, “Forced Outage Performance of Transmission Equipment”, April 2004.

APPENDIX A. EQUIPMENT OUTAGE DATA

A.1 CEA-ERIS Generation Outage Data

The most recent data on generating unit outages are reported in the “CEA-ERIS Generation Equipment Status Report – 2002” [2] published in December 2003. This report includes generating unit outage data collected in the past five years, i.e. 1998 to 2002.

Page 24 of the report presents the outage statistics on hydro generating units in the 5 – 23 MW class. The relevant forced outage data are shown in Table A.1.

Table A.1: CEA Forced Outage Data on 5 – 23 MW Class Hydro Units

FOR	2.9 %
DAFOR	3.06 %

FOR – Forced Outage Rate
DAFOR – Derated Adjusted Forced Outage Rate

A.2 CEA-ERIS Transmission Line Outage Data

The latest data on transmission equipment outages are reported in the “Forced Outage Performance of Transmission Equipment – 2002 Report” [3] published in April 2004. This report includes transmission equipment outage data collected in the past five years, i.e. January 1998 to December 2002.

Pages 17, 32 and 45 of the report present the outage statistics on 138 kV transmission line wood double pole structures. The relevant forced outage data are shown in Table A.2.

Table A.2: CEA Forced Outage Data on 138 kV Line, Wood Double Pole Structure

Forced Outage Type	Failure Rate (failures/year)	Average Repair Time (hours)
Sustained	0.9739 / 100 km	43.8
Line Related Transient	1.1929 / 100 km	-
Terminal Related	0.1395	9.7

The failure rates of the major transmission lines in the WAF system calculated using the data in Table A.2 are shown in Table A.3.

Table A.3: Failure Rate of Key Transmission Lines on the WAF System

Line	Length (km)	Failure Rate (failures/year)		
		Sustained type	Line Related Transient type	Terminal Related type
L170	328	3.1944	3.9127	0.1395
L171	130	1.2661	1.5508	0.1395
L172	25	0.2435	0.2982	0.1395

Table A.4 shows the calculation of the unavailability of the transmission line L171 which carries the power generated from Aishihik Hydro to Takhini, for delivery to the WAF system load.

Table A.4: Transmission Line L171 Availability Calculation

Component	Failure rate (failures/year)	Average Repair Time (hours)	Unavailability (hours/year)
Sustained	1.2661	43.8	55.45518
Transient	1.5508	0	0
Station (one end)	0.1395	9.7	1.35315
Station (other end)	0.1395	9.7	1.35315
Total	3.0959	18.78661455	58.16148

Unavailability of L171 (including terminal stations) = 58.16148 / 8760

= 0.006639

A.3 YEC Generation and Transmission Line Outage Data

The available generating unit and transmission line outage data for the period ranging from the year 1997 to 2004 are given in Table A.5.

Table A.5: YEC Generation and Line Outage Data

Equipment	Date	Tripped At	Closed	Variance	CLR #	Holder
Feeder						
L170 (S164 52-3)	11/7/2004	16:30:14	0:27:52	7:57:38	ES 04-237	Jack Wier
L170 (S164 52-3)	27/04/04	20:26:59	21:48:50	1:21:51	ES 04-135	Jack Wier
L170 (S164 52-3)	9/12/2003	3:58:00	5:53:00	1:55:00	ES 04-464	Jack Wier
L356 (Ross River)	18/06/03	16:35:25	18:23:49	1:48:24	ES 03-189	Gary Jones
L170 (S164 52-3)	30/04/03	20:28:45	22:00:00	1:31:00	ES 03-120	Jack Wier
L170 (S164 52-3)	17/07/2002	15:52:24	17:10:59	1:18:35	ES 04-243	Jack Wier
L170 (S164 52-3)	1/7/2004	18:13:00	18:18:54	0:05:54	N/A	N/A
L170 (S164 52-3)	4/7/2001	15:58:41	July 5,1:48	N/A	N/A	N/A
L170 (S164 52-3)	26/04/2000	11:02:00	11:35:00	0:33:00	N/A	N/A
L170 (S164 52-3)	11/5/1999	1:01:50	1:35:28	0:33:02	N/A	N/A
L170 (S164 52-3)	22/08/1999	7:22:47	9:21:47	2:00:00	N/A	N/A
L170 (S164 52-3)	20/06/1999	4:44:00	10:05:00	5:20:00	N/A	N/A
L170 (S164 52-3)	13/06/1998	20:47:44	21:03:00	0:15:45	N/A	N/A
Generating Unit						
WH4	6-Jul-00	9:09:46	13:08	3:58:14		
WH4	18-Sep-00	8:13:57	Sep20,15:00			
FD7	19-Sep-00	8:08:51	8:09:37	46s		
AH2	23-Jan-01	19:09:36	Jan24,15:43			
AH2	18-Jun-02	16:47:08	18:00:42	1:13:34		
AH1	6-Jun-04	13:36:27	23-Jun-04			

The transmission line outage data for L170 in Table A.5 used to calculate the unavailability for WAF system transmission lines L170 and L171 are shown in Table A.6.

Table A.6: Transmission Line Unavailability Calculation Using YEC Data

Transmission Line L170	
First outage date	13/06/98 (assume this is the first outage in the year)
Last outage date	11/07/04
Total exposure time	6.53 years
Total outage duration	24.63 hours
Number of outages	13
Average outage duration	24.63 / 13 = 1.895 hours
Failure frequency	13 / 6.53 = 1.992 f/year
Unavailability	(1.992 x 1.895) / 8760 = 0.000431
Transmission Line L171	
Unavailability	0.000431 x 130 / 328 = 0.000171

RELIABILITY ASSESMENT OF THE WAF SYSTEM USING 1996-97 SYSTEM DATA

Rajesh Karki and Roy Billinton

June 2005

1. Introduction

This report contains a basic annual reliability assessment of the Whitehorse–Aishihik-Faro (WAF) system considering 1996-97 generation data and 1996 load data. The deterministic criterion used by the Yukon Energy Corporation (YEC) to plan the firm capacity requirement for the WAF system has been converted to equivalent probabilistic indices for the 1996-97 period. The equivalent LOLE [1] criterion, and the system risk for this period are compared with the LOLE criterion of 1.2 hours per year [2] obtained from the 1999-2004 WAF data. The seasonal Whitehorse hydro generating capacity variations are considered in the evaluation. The annual risk profiles as a function of the system peak load have been evaluated and plotted with and without considering the effect of the unavailability of line L171.

2. WAF Generating System Data

The total installed capacity of the Whitehorse-Aishihik-Faro (WAF) system was 113,200 kW in 1996-97. This is 10,200 kW more than the total capacity considered in [2]. The unit types and ratings are given in Table 1 and Table 2.

Table 1: WAF System Generation Data (1996-97)

Location	Unit Type	Unit ID	MCR, kW	Total, kW
Whitehorse	Hydro	WH1	5800	40000
		WH2	5800	
		WH3	8400	
		WH4	20000	
	Diesel Mirrlees	WD1	4000	25000
		WD2	5000	
		WD3	5000	
	Diesel EMD	WD4	2500	
		WD5	2500	
		WD6	2700	
	Cat 3612	WD7	3300	
Aishihik	Hydro	AH1	15000	30000
		AH2	15000	
Faro	Diesel	FD1	5000	13600
		FD2	1000	
		FD3	1000	
		FD4	1000	
		FD5	1300	
		FD6	1300	
		FD7	3000	

Table 2: YECL Generation Data (1996-97)

Location	Unit Type	MCR, kW	Total, kW
Carmacks	Diesel	1300	4600
Haines Junction	Diesel	0	
Teslin	Diesel	1300	
Ross River	Diesel	1000	
Fish Lake	Diesel	1000	

The FOR values shown in Table 3 were used in the studies reported in [2]. The same values are used in the studies described in this report. Generating unit data compiled by the Canadian Electricity Association - Equipment Reliability Information System (CEA-ERIS) [3] were used to estimate the forced outage rates (FOR) of the hydro units in Table 1. A FOR of 10% was used for all the diesel units based on the historic availability of the WAF diesel units.

Table 3: Generating Unit FOR

Unit Type	FOR (%)
Hydro	3
Diesel	10

The effective capacity of the Whitehorse hydro plant during the winter season is considered to be 24,000 kW, due to hydrological constraints. The generation model for the Whitehorse hydro plant for this period is given in Table 4. The total effective capacity of the WAF System during the winter season is therefore 97,200 kW. The winter season was considered to consist of the months from November to March, with the remaining months grouped into the summer category.

Table 4: Whitehorse Hydro Plant Winter Generation Model

Capacity (kW)	Probability
24000	0.96997381
20000	0.02740638
14200	0.00169362
11600	0.00084681
8400	0.00002619
5800	0.00005238
0	0.00000081

3. WAF Load Data

The annual load duration curve (LDC) for the year 1996 is shown in Figure 1. The annual load factor is 64.59%.

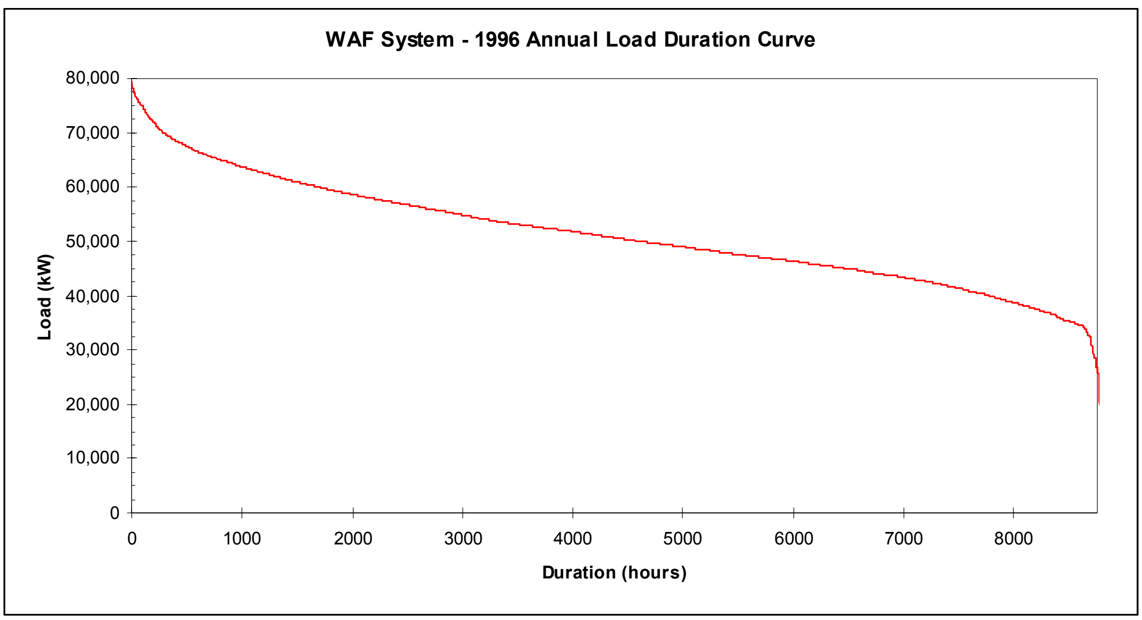


Figure 1: WAF Annual Load Duration Curve for Year 1996

Separate load models were created for the summer and winter seasons for system analyses considering seasonal variations. The hourly load data for the summer and winter seasons were separated, and the LDC were created for the two seasons. Since the year 1996 is a leap year, the winter LDC was created without considering the February 29th data. Figure 2 shows the summer and winter LDC for the WAF system for the year 1996.

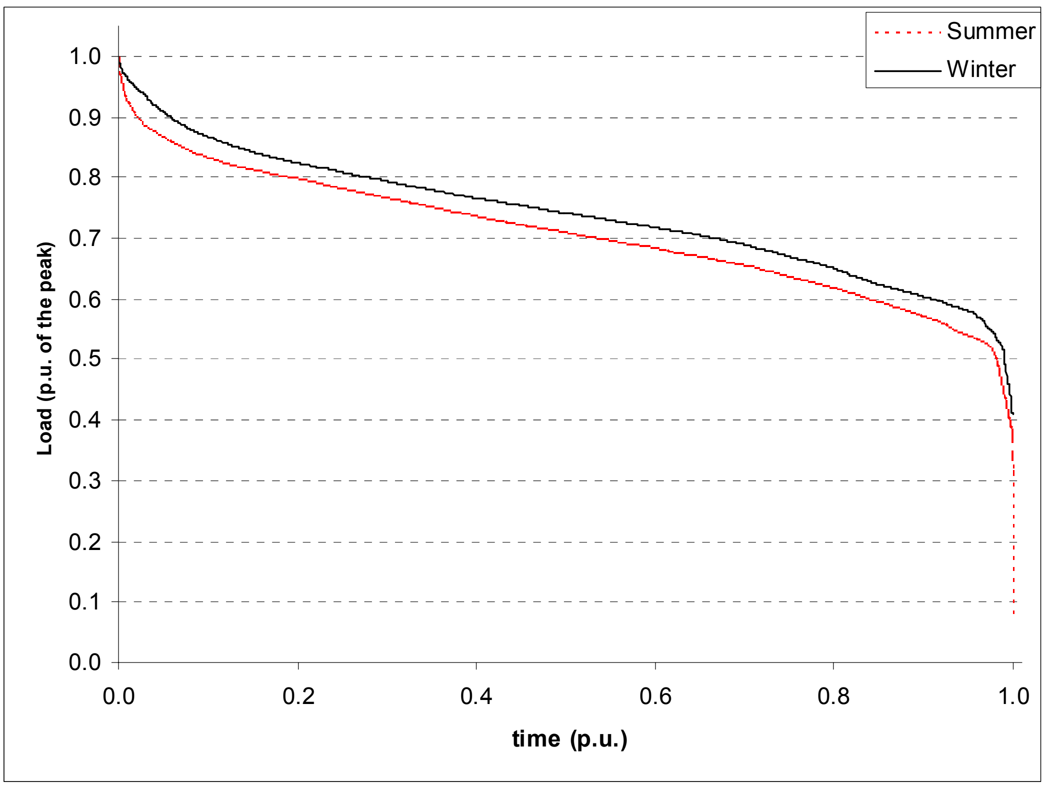


Figure 2: Summer and Winter Load Models for the WAF System for the Year 1996

The peak loads for the summer and the winter seasons are 65.4 MW and 79.53 MW respectively. The summer peak is 82.2% of the annual peak in the year 1996.

4. Assessment of the Existing Adequacy Criterion using the 1996 System Data

The deterministic criteria presently used by YEC are as follows:

1. for all local diesel generation grids (i.e. local diesel community only) the criteria is: sufficient capacity to meet 110% of the forecast system peak for the upcoming year with loss of the largest diesel genset.

2. for the Whitehorse (WAF) grid the criteria is: sufficient capacity to meet 100% of the forecast system peak for the upcoming year with the loss of 15 MW of hydro and 10% of the diesel capacity.

The firm capacity requirement for the WAF system is given by Equation (1).

$$IC \geq 100\% \text{ of } PL + 15 \text{ MW Hydro Capacity} + 10\% \text{ of Diesel Capacity} \quad (1)$$

where, IC is the total installed capacity and PL is the system peak load.

The Whitehorse hydro plant capacity is considered to be 24000 kW in the above criterion. The IC for the WAF system is, therefore, 97,200 kW, and the diesel capacity is 43,200 kW. The maximum allowable peak load (MAPL) under this condition is:

$$MAPL = 97{,}200 – 15{,}000 - 0.1 \times 43{,}200 = 77{,}880 \text{ kW}$$

5. Generating System Risk Evaluation

Generating system adequacy evaluation is the assessment of the ability of the generating facilities to satisfy the total system load. The transmission network is not considered at this level. The basic system model is shown in Figure 3.

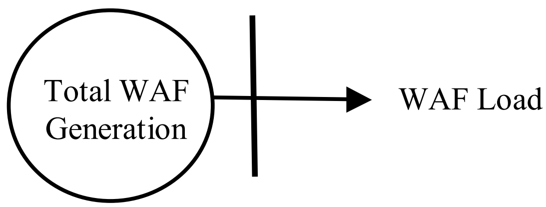


Figure 3: Basic Model for Generating System Adequacy Evaluation

The maximum allowable peak load (MAPL) under the deterministic criterion based on the 1996-97 data is 77,880 kW. The probabilistic risk indices for the WAF system at the maximum allowable peak load were calculated under similar conditions considering the seasonal capacity limitations of the Whitehorse hydro plant. The results are shown in Table 5. The deterministic criterion is equivalent to an LOLE criterion of 2.9 hours/year based on the 1996-97 system generation data.

Table 5: Adequacy Risk Criteria Based on the 1996-97 Data

MAPL (kW)	LOLE (hours/year)	LOEE (MWh/year)
77,880	2.91	10.065

Table 6 shows the annual LOLE and LOEE for the year 1996. The capacity limitations of the Whitehorse hydro generators due to seasonal variations in river flow were considered in the evaluation. Figure 4 shows the annual LOLE as a function of the annual peak loads.

Table 6: Annual Risk Indices for the Year 1996

Year	Peak Load (MW)	LOLE (hours/year)	LOEE (MWh/year)
1996	79.53	4.40	15.480

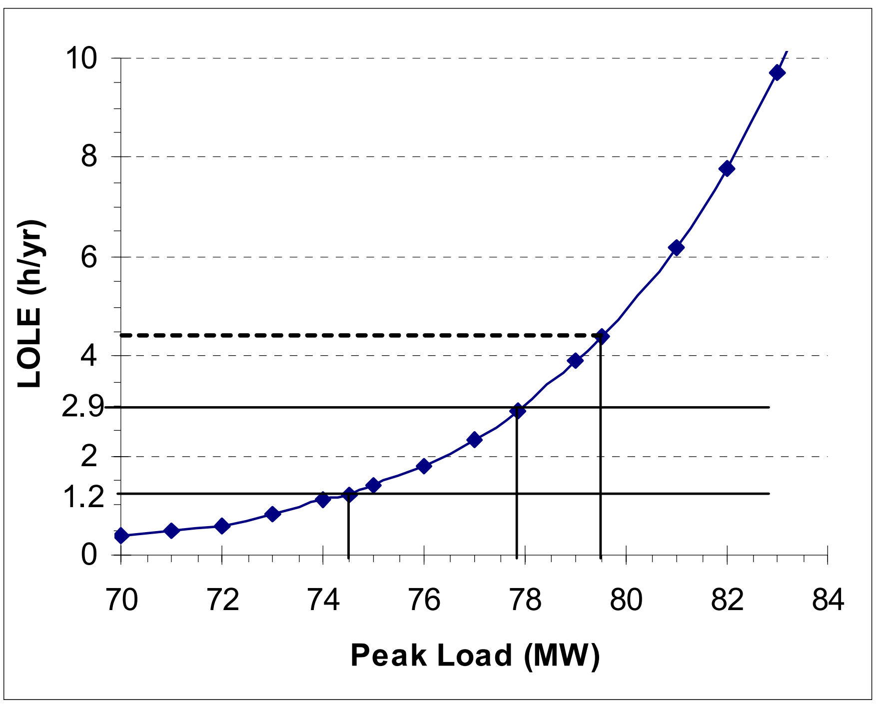


Figure 4: Annual LOLE Risk Profile Based on 1996-97 Generation Data

The annual system risk indices can be obtained from Figure 4 for an anticipated annual peak load. It can be seen that the 1996 system peak load of 79.53 MW results in a system risk (i.e. LOLE of 4.4 hours/year) higher than the LOLE criterion of 2.9 hours/year. Figure 4 also shows that a maximum allowable peak load is only 74.5 MW if the acceptable risk criterion is an LOLE of 1.2 hours/year.

6. Generating System Risk Assessment Considering the Aishihik Transmission Line

The delivery of 30,000 kW of hydro generation from the Aishihik hydro plant to the WAF load is dependent on the availability of the 130 kilometre transmission line, L171. This section examines the effect of including the L171 transmission line constraint in the reliability evaluation of the WAF system. The system model used for this study is shown in Figure 5 [2].

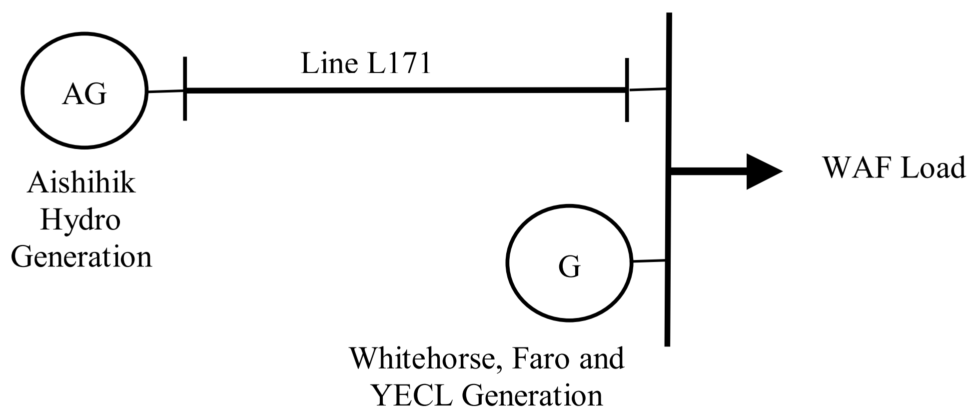


Figure 5: System Model Considering Transmission Line L171

Transmission line data compiled by the CEA-ERIS [4] were used to estimate the line unavailability for L171. An unavailability of 0.006639 [2] was used for the line L171 in the evaluation. The Aishihik hydro generation capacity is constrained by the tie line L171 when delivering power to the WAF system load. Figure 6 shows the annual LOLE as a function of the annual peak loads.

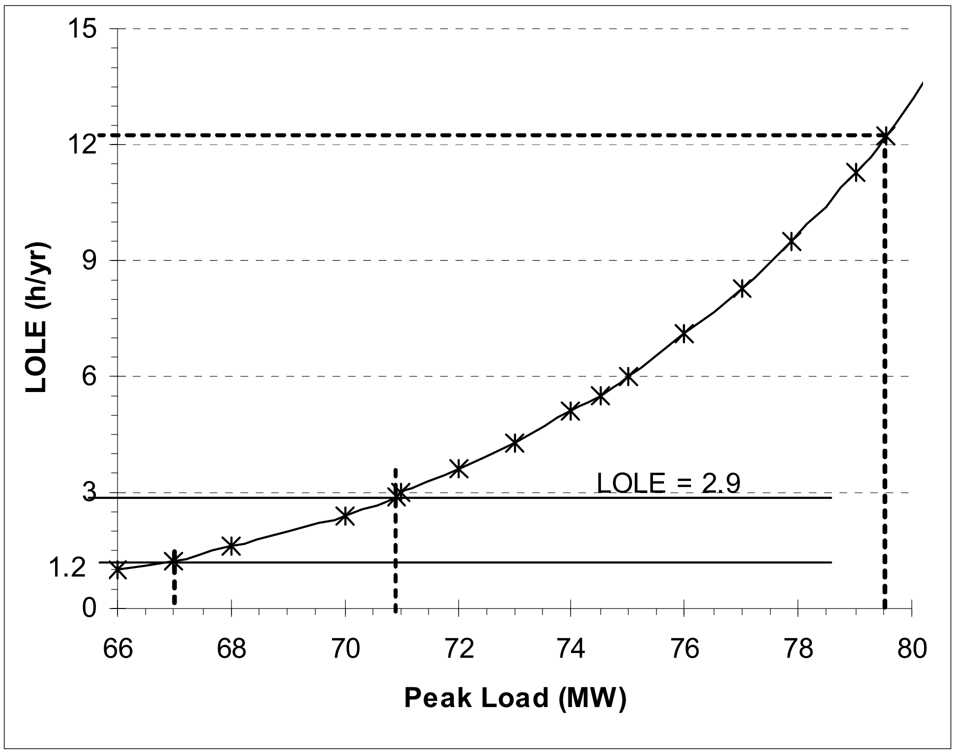


Figure 6: Annual LOLE Risk Profile Considering the L171 Constraint

The annual system risk indices incorporating the forced outages of the line L171 can be obtained from Figure 6 for an anticipated annual peak load. It can be seen the actual system risk, considering the line constrained Aishihik hydro generation, is a LOLE of 12.2 hours/year in the year 1996. This risk is considerably higher than the 2.9 hours/year criterion. The maximum allowable peak load at this criterion is 70.9 MW. A maximum peak load of only 67 MW can be satisfied by the system if the acceptable criterion is a LOLE of 1.2 hours/year.

The impact of transmission line constraints on the overall generating system reliability can be assessed by comparing the system LOLE results in Figure 6 with the results in Figure 4 where the tie line was not considered. Figure 7 shows the system LOLE profiles for the two cases.

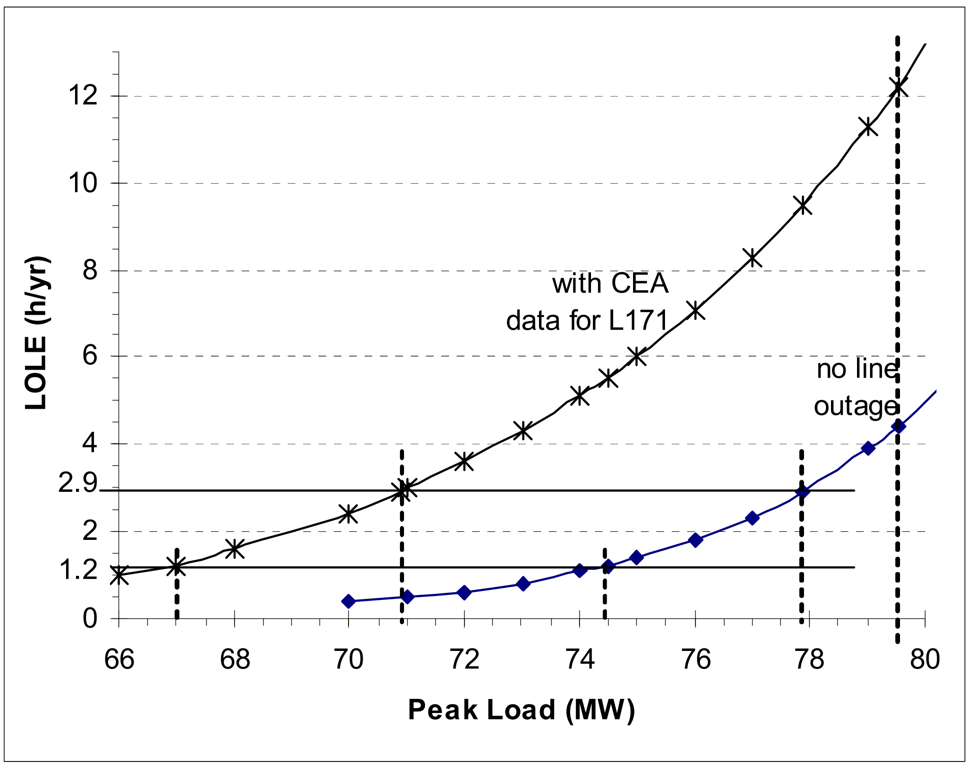


Figure 7: Impact of the Line L171 Unavailability on the System LOLE

It can be seen from Figure 7 that there is a significant increase in the system risk when the Aishihik hydro capacity is constrained by the transmission line L171. A maximum peak load of 78.9 MW can be served at the LOLE criterion of 2.9 hours/year when transmission constraints are not considered. The peak load carrying capability is reduced to 70.9 MW when transmission line constraints on the Aishihik hydro generation are considered. The transmission line L171 constraints have the effect of reducing the peak load carrying capability of the WAF generating system by 8 MW. The line L171 unavailability effect results in a 7.5 MW reduction in the peak load carrying capability (from 74.5 MW to 67 MW) if the accepted LOLE criterion is considered to be 1.2 hours/year.

7. References

1. R. Billinton and R. N. Allan, "Reliability Evaluation of Power Systems – Second Edition", Plenum Press, 1994.

2. R. Karki and R. Billinton, "Reliability Evaluation of the Whitehorse-Aishihik-Faro System", February 2005.

3. Canadian Electricity Association, "Generation Equipment Status Annual Report", December 2003.

4. Canadian Electricity Association, "Forced Outage Performance of Transmission Equipment", April 2004.

REFERENCE:

QUESTION:

The Resource Plan indicates that YEC studied the practices of other utilities to arrive at its new planning criteria. In this respect:

a. How many utilities in Canada use the same planning criteria as proposed by YEC, i.e. an N-1 criteria in addition to a LOLE criteria? How many use different criteria? What percentage of North American utilities use criteria similar to that proposed by YEC?

b. How many other utilities incorporate transmission outages into their probability assessment?

c. Of the utilities which do not incorporate transmission outages into the probability assessment, what method do they use to measure the forecast average hours of system outages per year?

ANSWER:

a. and b.

YEC is only aware of one utility that uses nearly the exact two-part criteria as YEC, namely the Northwest Territories Power Corporation ("NTPC") for its Snare-Yellowknife system (as noted at page 3-21 of the Resource Plan).

With respect to YEC's newly adopted criteria, there are three key aspects that are integrated into the assessment, and each is well-founded in utility practice in North America and core theory of utility reliability planning. Each of these three key aspects is discussed below. However, the particular integrated use of these three aspects in conjunction for generation adequacy planning, as adopted by YEC, reflects relatively unique considerations of Yukon Energy's system that are not common among most other jurisdictions in North America, particularly the more common thermal based systems.

- **Use of a probabilistic-based generation adequacy criteria** - as shown on page 7 of the February 2005 main Billinton report (provided in YUB-YEC-1-1), most major Canadian jurisdictions now use, or have used in the past, a probabilistic planning criteria for determining generation adequacy. This table is sourced from an IEEE paper[1] prepared by Dr. Billinton, which is the last major survey of Canadian utilities generating capacity planning criteria.

  This type of probabilistic generation adequacy criteria is often stated in terms of an LOLE (or equivalent terminology) focused on the amount of time that loads are expected to go unserved during a period, although Saskatchewan and Ontario in that table instead focused on the amount of kW.h that would go unserved (normalized for either Units per Million, or for System Minutes); however, both these cases are similarly probabilistic in their assessment.

  Yukon Energy does not have information on generation adequacy planning for United States utilities.

- **Incorporation of transmission line limitations in generation adequacy criteria:** YEC has a material component of its winter generation (30 MW) at Aishihik that can only be accessed by the core WAF system loads (the Whitehorse to Faro component) if the non-redundant L171 transmission line is in service. In this regard, although the L171 is functionally a transmission line, its role is more appropriately thought of as "generation integration" (a concept more often discussed in terms of hydro system cost-of-service analysis).

  Professionally in system planning disciplines, one would normally approach system evaluation separately with respect to the adequacy of the generation system and for the transmission system. Generation system inadequacies

[1] The IEEE paper ("Criteria Used by Canadian Utilities in the Planning and Operation of Generating Capacity"; IEEE Transactions on Power Systems, Vol. 3, No. 4, November 1988, pp 1488-1493) summarizes the generation adequacy planning criteria used by a number of different Canadian utilities. It also summarizes results from similar surveys in 1964, 1969, 1974, 1977. As systems in each respective jurisdiction evolve, there are in some cases updates or changes to the type of criteria used. For example, as of the 1988 IEEE paper, the Alberta Interconnected System used a Generation Adequacy criteria of an LOLE of not more than 0.2 days/year. Since that time, Alberta has moved to a market driven system for development of new generation instead of central planning of this type, so such LOLE measures are no longer the trigger for addition of new generation.

(not enough or the right type of MW installed) are typically addressed via generation additions, while transmission system inadequacies (transmission systems that are not sufficiently durable to continue to serve loads in the case of a potential loss of one or more elements) are addressed by transmission system additions. In the case of the Aishihik line the distinction is not so clear – this WAF transmission system inadequacy (the exposure to a loss of L171) has traditionally been addressed by added generation resources (added diesel capacity at Whitehorse or Faro) and is proposed to continue to be addressed by such measures (as opposed, for example, to twinning the Aishihik line) for economic reasons. In addition, the main report prepared by Drs. Billinton and Karki sets out further rationales for this approach in Section 4.

In this regard, the Yukon system is most equivalent to the NTPC Yellowknife system, where loss of a single non-redundant transmission line (the L199 line from the Snare Hydro sites) can impact the ability to meet winter capacity requirements in Yellowknife. NTPC does incorporate transmission system unavailability in their generation adequacy criteria.

This system topology is also similar to some extent to the Manitoba Hydro integrated system where loss of the two major north south HVDC lines (and corresponding loss of almost all ability to access Nelson River hydro generation) can adversely impact on the ability to serve southern Manitoba winter peak loads (although in Manitoba Hydro's case the ability to import relatively large quantities of power over what are traditionally export-oriented lines can ameliorate much, if not all, of the supply issues related to core southern Manitoba loads – the major issues are instead related to the cost of such imports and the extent to which such supplies are contractually secured in advance or solely made available at the time based on Manitoba Hydro's ability to source sufficient short-term capacity at any price from neighbouring utilities). Although Manitoba Hydro's system is not today cited as being capacity constrained, efforts to put in place a third north-south transmission line in part for reliability reasons are today being explored, with discussion at times of conceptual alternatives to this third line including potentially expanded generation capacity in the south (such as gas turbines, or potentially enhanced interchange capability). This reflects a similar conceptual approach as YEC by mixing transmission inadequacies into determining a requirement for new generation.

Yukon Energy is only aware of NTPC as the single example of formally incorporating transmission unavailability into a probabilistic assessment of generation adequacy analogous to the approach adopted by YEC.

- **Separate N-1 consideration of transmission line limitations:** YEC is aware of the use of N-1 transmission planning criteria as the standard throughout North America, as part of the NERC (North American Electric Reliability Council) reliability standards. This standard is also effectively used in most non-interconnected power systems (including YEC's previous deterministic criteria) which require the system to be able to meet loads with the largest single unit out of service (however the previous YEC criteria considered a single wheel at Aishihik as the largest unit, rather than the full Aishihik transmission line). In the case of YEC's new criteria, the N-1 condition gives rise to very different planning considerations compared to large integrated power systems, but the concept is basically the same – that the system should be able to fully handle the loss of the largest single contingency and meet the load requirements at any time during the year.

c. To YEC's knowledge, utilities that use probabilistic generation adequacy criteria are typically based solely on the generation availability model (without consideration of transmission limitations) convolved against the load duration curve.

In planning these utilities, separate transmission system planning criteria (such as the N-1 criterion) would be utilized to determine when transmission system inadequacies arise and transmission additions are required.

REFERENCE:

QUESTION:

The Resource Plan indicates that YEC has adopted 2 hrs/year LOLE system-wide capacity planning criteria. The LOLE criteria is then used to determine a capacity shortage in the WAF as early as 2008, as shown on Table 3.5 of the Resource Plan. Please provide the following information with respect to the computer software and the data used by YEC to calculate LOLE, unless it is provided in the Billinton Report:

a. Describe the software used for calculating LOLE. Is it a commercially available software or one developed in-house? Does it use analytical methods, or Monte Carlo simulation, or other methods?

    i. If analytical, does it use the capacity outage probability table method, or the equivalent load method, or other method?

    ii If Monte Carlo, how many iterations were used to achieve statistical significance? How does the software use random variables to determine how long generating units will remain in a state of availability?

b. Was the annual LOLE computed over 8,760 hourly peak loads, or 365 daily peak loads, or another period of time? Provide the system load data as it was used in the model, either chronological load, load duration curves, or in any other form that was used by the model. (Provide data in Excel electronic format)

c. With respect to generation data used in the calculation of LOLE, provide a complete list of generating units including unit name, Maximum Continuous Rating (MCR), forced outage rate (assuming a two-state model for generators), seasonal derates, if any, and planned outage rates.

d. If the software uses a multi-state model for generator outages, provide the state probabilities of outage and explain how the model treats multi-state generating units.

e. For each generator, please provide YEC's number of outage hours per year for the past 10 years to support the probabilities of outage used in the model.

f. Does the software model hydro units differently than it does for thermal units? For example, does it account for seasonal minimum and maximum outputs and energy limitations on hydro generation?

g. How was planned maintenance outages accounted for in the software?

i Does the software develop a maintenance schedule? If yes, describe the method it uses for scheduling unit maintenance.

ii Was a maintenance schedule produced externally and entered into the model? If yes, please provide it.

ANSWER:

Most information requested is provided in the February 2005 Billinton/Karki report[1].

a. The software used for calculating LOLE is proprietary software created in-house at the University of Saskatchewan. The program uses analytical methods. As noted on page 26 of the Billinton/Karki main report, the program develops a composite generation system availability (capacity outage probability table) based on the units available, their seasonal capacities, and their Forced Outage Rates. This system is convolved with the load duration model by season to determine the LOLE values.

b. The load data is hourly. The Excel file with YEC's hourly load data (as shown on page 13 of the Billinton/Karki main report) is attached. The model used by Billinton/Karki uses all the hourly values in a seasonal or annual period.

c. and d.

The model uses two state modes for most generating units as shown in Table 2.1 on pages 9-10 of the Billinton/Karki main report. Two exceptions are the Whitehorse Rapids Hydro Plant winter generation model, which is a multi-state model shown on page 11 of the Billinton/Karki main report, and in cases when the L171 transmission line limitations are considered, the Aishihik Hydro GS generation model, which is shown on page 29 of the Billinton/Karki main report.

[1] provided in YUB-YEC-1-1 Attachment 1

Note that the Billinton/Karki report analysis reflects unit capacities that reflect the analysis at that time. Since that report, in preparation of the Yukon Energy Resource Plan, a number of modest adjustments have been made to unit capabilities. In particular, the Haines Junction diesel which is noted in the Billinton/Karki main report as 1.7 MW has since been confirmed as 1.3 MW and the Billinton/Karki main report does not include Fish Lake in the loads or generation sources (with a firm winter capacity of 0.4 MW[2])

e. The generation outage probabilities used in the LOLE models are based on Canadian Electricity Association indices (aggregated estimates of availability based on actual utility data) for the appropriate generating unit type, in this case 3% Forced Outage Rate ("FOR") for hydro. With respect to diesel, a FOR of 10% was used, as described in the Billinton/Karki main report at page 10 as "the historic availability of the WAF diesel units of approximately 90%". This is also consistent with the accepted practice in Yukon of taking 10% of the installed diesel as a "reserve" in the previous capacity planning criteria formula, and is generally consistent with the diesel FOR used in NWT of 12.9%.

The probabilities are not based on YEC's own unit experience due to largely the same data issues as reviewed in YUB-YEC-1-6(a) with respect to transmission. Yukon Energy can readily track the amount of time its generating units are out of service (see Attachment YUB-YEC-1-3(e)) but the data to determine whether these are forced outages as opposed to planned outages is not readily available.

f. The only hydro seasonal limitations in peak capacity output are those related to flow conditions at Whitehorse Rapids, which are discussed at Section 3.2.1 of the Resource Plan and page 11 of the Billinton/Karki main report.

Yukon Energy's hydro systems are not otherwise seasonally constrained.

g. Planned maintenance is not addressed in the model. Planned maintenance is assumed to occur outside the designated winter season and is not expected to make a significant contribution to the annual LOLE.

[2] The 0.4 MW firm capability of Fish Lake arises from the known output during the winter months of 2003/04.

	2005		2004		2003		2002	
	Unit Available (%)	Unit Outage (hr)	Unit Available (%)	Unit Outage (hr)	Unit Available (%)	Unit Outage (hr)	Unit Available (%)	Unit Outage (hr)
WH1	77.01	2013.92	96.44	312.71	93.57	563.27	94.83	452.89
WH2	91.24	767.38	73.61	2318.10	96.93	268.93	92.53	654.37
WH3	93.33	584.29	92.57	652.65	69.74	2650.78	93.26	590.42
WH4	88.71	989.00	90.65	821.30	97.28	238.27	88.86	975.86
AH1	98.06	169.94	96.55	303.05	67.20	2873.28	98.08	168.19
AH2	94.00	525.60	96.65	294.26	99.34	57.82	90.48	833.95
WD1	99.85	13.14	99.86	12.30	70.39	2593.84	99.34	57.82
WD2	99.89	9.64	99.67	28.99	86.56	1177.34	77.65	1957.86
WD3	99.81	16.64	97.39	229.26	100.00	0.00	96.67	291.71
WD4	34.63	5726.41	99.56	38.65	98.90	96.36	87.73	1074.85
WD5	20.51	6963.32	84.10	1396.66	75.19	2173.36	85.55	1265.82
WD6	99.69	27.16	99.73	23.72	87.33	1109.89	86.40	1191.36
WD7	99.69	27.16	99.94	5.27	100.00	0.00	86.36	1194.86
FD2								
FD3	99.16	73.58	97.31	236.29	100.00	0.00	100.00	0.00
FD4								
FD5	100.00	0.00	95.66	381.23	98.90	96.36	94.49	482.68
FD7	99.84	14.02	99.61	34.26	100.00	0.00	99.86	12.26

	2001		2000		1999	
	Unit Available (%)	Unit Outage (hr)	Unit Available (%)	Unit Outage (hr)	Unit Available (%)	Unit Outage (hr)
WH1	86.70	1165.08	94.43	487.93	86.31	1199.24
WH2	88.11	1041.56	74.85	2203.14	93.41	577.28
WH3	94.84	452.02	92.73	636.85	87.95	1055.58
WH4	87.76	1072.22	94.60	473.04	91.06	783.14
AH1	91.61	734.96	86.01	1225.52	93.08	606.19
AH2	93.70	551.88	97.70	201.48	87.21	1120.40
WD1	98.79	106.00	91.87	712.19	85.94	1231.66
WD2	99.05	83.22	99.13	76.21	80.21	1733.60
WD3	81.84	1590.82	70.07	2621.87	97.44	224.26
WD4	26.63	6427.21	94.32	497.57	99.50	43.80
WD5	98.86	99.86	96.43	312.73	52.09	4196.92
WD6	93.55	565.02	85.71	1251.80	98.98	89.35
WD7	100.00	0.00	95.74	373.18	59.51	3546.92
FD2	retired		68.49	2760.28	99.95	4.38
FD3	98.63	120.01	99.57	37.67	98.36	143.66
FD4	retired		68.49	2760.28	99.97	2.63
FD5	97.50	219.00	93.06	607.94	41.18	5152.63
FD7	99.86	12.26	89.52	918.05	97.34	233.02

Note: Unit outage (hr) is the number of hours in a year where the unit is unavailable to generate power, without distinction as to Forced Outages and planned outages.

REFERENCE:

QUESTION:

Does the resource plan account for YECL production in your forecasting models? Have you accounted for any potential expansion of YECL production and/or new YECL capacity projects?

ANSWER:

The Resource Plan forecasts for WAF include YECL hydro generation (from Fish Lake) at expected long-term annual output levels (7 GW.h per year) and firm winter capacity levels (0.4 MW)[1]. The Resource Plan also takes account of the four YECL WAF diesel units, as shown in Table 2.1 (page 2-4), as firm capacity.

Yukon Energy is not aware of any YECL production expansion projects or new capacity projects planned. The Resource Plan does contemplate the potential addition of an approximately 1 MW diesel units at Carcross/Tagish, at page 4-61, (likely by YECL) to the extent such addition is required for WAF firm capacity and can also play a role in local backup of the radial transmission lines serving the area. However, this project is not to YEC's knowledge part of YECL's current capital plan.

The Resource Plan is otherwise basically neutral with respect to ownership of other projects reviewed (such as major new generation discussed in Chapter 5, which could be developed as IPPs, as noted at page 5-36, or jointly with First Nations, for example). With respect to major additions of capacity or other generation resources, Yukon Energy has the role as the primary bulk power supplier on WAF (whereas YECL has the primary role as a distribution utility). As such, Yukon Energy's role on the two integrated systems extends to:

1. forecasting and planning for how to serve future system loads, securing future options such as water rights and First Nation agreements where in the interests of future power projects;

[1] As noted at page 9-10 of their report, Drs. Billinton and Karki did not include YECL's Fish Lake generation in the analytical exercises in their report, and treated all loads as net of Fish Lake output. For the purposes of the Resource Plan, Yukon Energy developed and analyzed integrated "native" system loads by including all WAF system loads and including Fish Lake generation at long-term average levels and firm winter capacity levels noted above.

2. arranging power supply agreements where needed with major industrial customers; and,
3. planning, developing, constructing and financing major new generation and transmission, or alternatively coordinating the development and power purchase agreements required for non-utility generation and/or transmission development, including assessing and managing the impacts on existing ratepayers.

REFERENCE:

QUESTION:

The Resource Plan states that 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. In this regard:

a. Do the LOLE calculations shown on Table 3.5 take into account transmission outages?

b. If yes, provide the transmission outage data used by the model.

c. Explain how the model accounts for transmission outages. (For example, does the model produce equivalent multi-state units at certain buses combining transmission outage probabilities with the outage probabilities of the generators that would be affected by transmission outages?)

ANSWER:

a., b. and c.

The LOLE calculations at Table 3.5 take into account transmission outages on the key L171 transmission line (linking Whitehorse with the Aishihik GS). The data, with respect to transmission outages, is set out at Section 4 and Appendix A of the Billinton/Karki main report[1]. The transmission outage data is based on the Canadian Electrical Association – Equipment Reliability Information System data for similar lines (138 kV wood double pole structure).

The model combines L171 transmission outage data with Aishihik GS generation outages to create a multi-state model as shown at Table 4.3, page 29 of the Billinton/Karki main report.

[1] provided in YUB-YEC-1-1 Attachment 1

REFERENCE:

QUESTION:

The Resource Plan also indicates that YEC determined it to be appropriate to incorporate a standard to address the potential for sustained emergency conditions. This standard calls for each system (WAF and MD) to be able to carry the forecast peak winter loads under the largest single contingency (N-1), which in the case of WAF would be the loss of the Aishihik line and attendant 31.3 MW of generation. In this respect:

a. The N-1 criteria look at a single outage event that may happen at the time of the annual peak load. What is the likelihood of an outage of the Aishihik line at the time of the annual peak load? Provide any historical outage records (duration and timing) for the Aishihik line to support your answer.

b. If the probabilities of transmission outages have been accounted for in the LOLE calculation, why does YEC consider it necessary to adopt the N-1 criteria?

c. Did YEC perform a "risk-cost evaluation"[1] to put risk and economic factors on a unified scale of monetary value? If not, why, not?

d. Is the single-contingency, the N-1 principle, a mandate or imperative requirement?

e. What are the economic and operational consequences of retaining the previous capacity planning criteria?

f. What are the economic and operational consequences of adopting the LOLE planning criteria without the N-1 criteria?

[1] The risk evaluation should include expected frequency of load curtailment and expected duration of load curtailment indices.

ANSWER:

a. Yukon Energy has difficulties with consistency of data with respect to transmission line outages on L171. This is in part because the line was constructed and operated initially by the Northern Canada Power Commission before the assets were purchased by Yukon, and subsequently the assets were managed by a third-party for 11 years prior to 1998 when YEC took over direct management of the assets. In addition, a major facility fire at the YEC Corporate Offices and Whitehorse Hydro site in 1997 destroyed many of the records of this type.

Between 1998 and 2005, there are no recorded unplanned outages of the L171 transmission line. Since 2005 there have been three outages related to L171 or its main supply – one on August 15, 2005 due to a lightning strike (repair of damaged equipment took approximately 6 hours), one on May 19, 2006 caused by a fault in the insulation system[2] (outage of approximately 5 hours), and one on January 29, 2006 that was the subject of a detailed report to the YUB dated April 11, 2006 (this latter outage was related to the cabling that ultimately supplies Aishihik generation to L171 and resulted in a total outage of 40 hours, plus an additional partial outage of approximately 512 hours). Combined, this would suggest the line has an exceedingly low failure rate (three failures in about eight years requested compared to 3.0959 failures per year based on CEA national averages), but slightly higher unavailability compared to similar transmission of this construction elsewhere in Canada[3].

As to the likelihood of an outage in future, the recorded YEC data is not considered a good representation of the reliability of this line, partially due to the relatively small sample set represented by the YEC data, and partially due to the inconsistent record availability. As a result, YEC has accepted the

[2] The faulty insulator is a concern because with the exception of the relatively few insulators replaced post construction, all the insulators are approximately the same age. With a recent insulator failure on the line, it could indicate increasing risk of failure due to age.

[3] This represents a total of 51 hours of total outage over approximately 8 years, or an unavailability of 0.000728, or approximately 11% of the expected CEA-ERIS national average for this type of line of 0.006639 shown in the Billinton/Karki report YUB-YEC-1-1 Attachment 1 at page 58. Including the partial outage resulting from the derated condition of the line after the January 29 2006 outage, the unavailability equals 0.008034, or slightly higher than the CEA-ERIS national average.

recommendations of Drs. Billinton and Karki to use the national averages for this type of transmission construction from the CEA-ERIS database.

b. See YUB-YEC-1-6(d)

c. YEC did not conduct a risk/cost evaluation with respect to the planning criteria as such an exercise is lengthy, detailed and complicated and requires considerable data that is not available to YEC (in particular with respect to customer damage functions). In addition, YEC reviewed the standards used by Canadian utilities provided in the main Billinton/Karki[4] report and noted that very few if any Canadian utilities today use such a criteria.

In order to measure the Cost of Unserved Energy (CUE), substantial data in respect of customer damage functions arising as a result of outages is required for the particular jurisdiction and customer types. Such data is not currently available for Yukon (or other northern Canada jurisdictions) and collection would potentially be a lengthy process (typically involving customer surveys and other customer profile techniques). In addition, the CUE can vary over different customer types (such as industrial as compared to residential). As such, the use of CUE within a single generation planning standard is likely to be onerous to implement and maintain and would be expected to lead to divergences in the justification for generation investment for different customer classes that could not readily be fully reconciled.

d. YEC is not externally mandated to maintain an N-1 criterion by any regulator, by NERC, or by Territorial or Federal legislation.

The N-1 criterion is, however, an imperative component of the criteria adopted by YEC as set out in detail at pages 3-21 to 3-23 of the Resource Plan, which focuses on the potential seriousness of an outage at peak winter times and the practical difficulties associated with isolating and repairing transmission system failures in a timely way in very cold temperatures with few hours of daylight.

[4] provided in YUB-YEC-1-1 Attachment 1

In addition, the N-1 criterion is required and justified for the following reasons:

- The use of an N-1 criterion with respect to transmission system reliability to address exposure to unavailability conditions is a standard utility practice throughout North America.
- The most comparable system to the WAF in Canada – the Northwest Territories Power Corporation (NTPC) system has adopted a comparable but slightly more onerous[5] N-1 criterion in combination with an LOLE standard of 2 hours/year.
- Yukon has traditionally maintained an effective N-1 requirement for all its systems, and continues to propose that such criteria (ability to meet system peak loads with the largest unit out of service) be maintained for all isolated systems and all generation locations on the WAF grid. The key difference proposed today is merely to recognize the Aishihik transmission line L171 as the key "-1" component rather than the previous approach of solely considering a single 15 MW wheel at Aishihik as the key component.
- Even with the N-1 criterion in place, there remains risks to the system that the supply cannot be fully maintained at Whitehorse were the Aishihik line to be unavailable at peak times:
  - The proposed N-1 criterion requires that the forecast integrated hourly peak be less than the installed capacity; however, the operational requirements for a system are to meet the instantaneous peak at all times not just the integrated hourly peak. In the case of Yukon this hourly "swing" can be as much as 1 MW during winter months.
  - With the scale of generation at Aishihik, a sudden loss of the L171 transmission line during winter will result, in almost all cases, with a grid blackout followed by restoration of power using other WAF resources. At these times, the required supply is not only the steady system peak loads, but also the system "cold load pickup" resulting from increased load coincidence. Consequently, restoration efforts can require additional MW in excess of that recorded as system peak demands when normal levels of load coincidence are being experienced.
- The N-1 criterion is the only component of YEC's capacity criteria that distinguishes between reliability standards for retail and wholesale customers (residential and commercial) versus industrial customers (such as mines;

[5] In the case of the Snare-Yellowknife system, the N-1 criterion requires that the forecast peak load plus 5% reserve be carried with the largest single unit out of service.

YEC has no industrial customers at present). The N-1 criterion solely applies to loads from retail and wholesale customers. In this regard, the criteria recognizes the key distinction between industrial loads (who typically maintain sufficient on-site diesel to ensure their critical processes are maintained[6]) and core residential and commercial loads who do not typically maintain backup generation.

e. The short-term consequences of retaining the previous criteria arise principally from the fact that under the previous criteria (with the current system configuration), the WAF system is determined to require approximately 13 MW less generation than under the newly adopted criteria (per Table 3.5 of the Resource Plan page 3-24). This is equivalent to an LOLE of approximately 5.9 hours/year before new generation is indicated to be required, which is well below the normal standards for Canadian utilities of about 1-2 hours/year.

This gives rise to both operational and economic consequences.

- Economically, customer damages would arise to the extent further outages and increased exposure to outages occurs due to the lower generation adequacy reliability standard. Under the previous criteria (during most of the 1980s and 1990s), these damages were largely constrained to the Faro mine, which was the first load to be curtailed from full supply when the system was in a constrained condition (the Faro mine supply peaked at about 25 MW, but during major system constraints, this could typically be reduced to about half, reflecting almost solely the diesel generation available from the Faro diesel plant).
- Operationally, the current system is notionally viewed by the system operators as providing a balance between loads and generation. Retaining the previous criteria indicates that today the system would be sufficient with all 3 Mirrlees units retired. Based on the experience of Yukon during the January 29 outage, reliable utility-standard electrical supply could not be provided by YEC if its system were without the three Mirrlees units today. Most notably, were the 3 Mirrlees to be retired, the Whitehorse local winter generation capacity would be only 35.4 MW even though the local peak is in

[6] This is also consistent with the supply conditions for the Faro mine when it was operating, although it did not have material on-site diesel, but YEC maintained substantial diesel capacity in the town of Faro. At that time, supply constraints on the WAF system were typically met first by interruption of a portion of the Faro mine load in excess of the diesel resident in Faro.

excess of 50 MW. This would result in a substantial risk exposure at Whitehorse that does not occur at any other generation point on the system, whereby loss of the main supply (access to grid supply from bulk transmission) would result in substantial capacity deficits over many hours of the year.

Also note that with respect to system planning, the projects proposed in the Resource Plan in each case reflect means to optimize the production potential of existing developments, and may be suitable for YEC to pursue regardless of the new capacity criteria:

- The Aishihik 3rd turbine is proposed as a project to provide peaking energy benefits (from displaced diesel generation at peak times) and as such is not justified on the basis of the capacity criteria.
- The Marsh Lake Fall/Winter storage enhances the output of the existing Whitehorse Rapids GS, and even if the 1.6 MW capacity enhancement were not required (due to retaining the previous criteria), the project is expected to provide $10 million (NPV, 2005$) in diesel savings under Base Case load forecasts.
- The Carmacks-Stewart transmission line project is fundamentally proposed to provide an opportunity to supply one or two new mining customers with firm power from what would otherwise be surplus (spilled) hydro generation and to interconnect the two Yukon systems. This project is also proposed in the Resource Plan on the basis that YTG infrastructure funding is available to offset any adverse rate impacts on existing Yukon ratepayers.
- The Mirrlees Life Extension project, as noted in footnote 20 on page 4-39, remains a project that should receive careful consideration even under the previous criteria: "*However, even if the previous capacity planning criteria were still in place, it would remain relevant to assess the feasibility of 10 to 20 years Life Extension for the three Mirrlees diesel units at Whitehorse as a cost effective way to retain 14 MW of capacity capability on WAF*".

f. See YUB-YEC-1-6 d.

REFERENCE:

QUESTION:

Table 3.5 shows the timing of capacity requirements in the WAF for the previous criteria and the newly adopted LOLE, and the N-1 criteria. The table also shows annual WAF peak load forecast from 2005 to 2012. Clarify which load growth forecast has been used in Table 3.5. Is it the base case, low sensitivity case, base case including mines, or high sensitivity case including mines?

ANSWER:

Table 3.5 uses the base case load growth forecast.

REFERENCE:

QUESTION:

Please provide supporting data to verify the assumptions made to arrive at the near-term non-industrial forecast. Specifically:

a. YEC's recorded electricity consumption.

b. Bureau of Statistics population growth projections.

c. City of Whitehorse population increases.

d. Provide the per capita electricity use in the Yukon and expand on the assumed 0.5% increase, which is referenced as being assumed by other Canadian utilities.

e. Please provide historical secondary sales numbers for the past 10 years (on an annual basis) and also provide forecast secondary sales (on an annual basis) to 2016.

f. As new loads come on to the system, how does YEC expect to deal with secondary sales?

ANSWER:

a. The sales and energy loads for 2005 are based on the 2005 Annual Forecasts shown in Tables 2.1 to 2.5 of the 2005 Required Revenue and Related Matters filing to the YUB (Attachment 1 to this response). Fish Lake generation was included at 7 GW.h, for a "native" YECL load 7 GW.h higher than the wholesale volume recorded for WAF in Table 2.5.

With respect to peak loads, 2005 WAF peak loads are based on 56.4 MW. This is the sum of 55.8 MW measured YEC peak[1] plus the assumed Fish Lake generation of 0.6 MW[2].

[1] This peak was from Thursday January 13, 2005 where the high temperature reached -41.7C and the low temperature was -46.6C, which is representative of the "normal" winter planning peak temperatures. The peak consumption this day was 55.8 MW at 18:00. All secondary sales were off.

YEC Losses were assumed on WAF at 7.7% of all sales. Note however, that the largest portion of YEC sales on WAF are wholesale sales to YECL, so distribution losses are largely accounted for in the wholesale sales numbers. As a result, YEC's losses are largely transmission level losses.

YEC does not have and is not provided with any information on YECL's sales, losses, or customer load characteristics by class.

b. The Bureau of Statistics Territory-wide "Medium Growth" population projections to 2015 were used as the basis for the low load sensitivity population growth of 0.4% per year (Attachment 2 to this response). Of note:
   1. The Bureau of Statistics figures are Yukon-wide, whereas WAF communities (particularly Whitehorse) often exhibit above-average growth while isolated and smaller communities have tended to exhibit lower growth (if any).
   2. The population increase is not necessarily indicative of the increase in the number of utility customers, as the number of persons per residential account for many utilities has exhibited a slow reduction over the past number of years[3] and therefore number of utility accounts will grow faster than the average population growth rates.
   3. The Low growth projections from the Bureau of Statistics reflect about -0.6% growth per year and the High growth projections reflect about 1.5% per year.

c. The Bureau of Statistics Population Reports (a semi-annual publication available at http://www.gov.yk.ca/depts/eco/stats/sannual.html back to December 2002) indicates Whitehorse population at December 2001 of 22,545 residents, and at December 2005 at 23,511, an average annual growth rate of 1.05%.

d. As noted in YUB-YEC-1-8(a), Yukon Energy primarily serves wholesale loads and does not have YECL retail customer data provided to it (also see YUB-YEC-1-18).

In regards to other utilities, Yukon Energy reviewed the readily available load forecasts for residential customers without electric heat (as Yukon Energy's end-

[2] Since Fish Lake is not metered by YEC, output was assumed at 0.6 MW based on the recorded actual average output for December 2004.

[3] For example, the Nova Scotia Power May 2005 Load Forecast indicates "Although the NS population is expected to be relatively stagnant or even decrease, as in most other areas of North America lifestyle changes are continuing to increase the headship rate (i.e. fewer persons per household) resulting in an increase in households and electric customers for a given population."

use customers are disproportionately residential and do not typically use electric heat) from:

- **Manitoba Hydro:** For residential non-electric heating loads, Manitoba Hydro's Load Forecast for 2003/04 to 2023/24 sets out forecast (weather normalized) average use per customer in 2003/04 of 9,567 kW.h/year and for 2023/24 of 10,668 kW.h/year, an average annual growth rate of 0.55%.
- **Nova Scotia Power:** The Nova Scotia Power May 2005 Load Forecast does not set out specific values for residential customer numbers, but does note "With an ever-increasing array of new technology available, usage per customer continues to grow, despite efficiency improvements for many household appliances".[4]
- **BC Hydro:** The December 2005 BC Hydro load forecast sets out forecasts for the residential "use rate" or average use per customer (not distinguished between electric heat and non-electric heat). In that forecast, BC Hydro notes the following: "The current forecast for the growth in the use rate is 0.7% over the next 5 years, 0.4% over the next 10 years, and 0.3% over the next 20 years."[5]

Yukon Energy used an estimate of 0.5% annual growth for the Resource Plan forecasts.

e. The secondary sales volumes under the Base Case loads are as set out below (in kWh). Note that for Mayo-Dawson, retail secondary energy sales did not begin until 2002; prior to that the sales were to the UKHM mine.

[4] NS Power 2006 Load Forecast May 2005, page 15.
[5] BC Hydro December 2005 Load Forecast, page 30.

Yukon Energy Secondary Sales volumes 1996-2016F (kW.h)

	WAF	MD	Total
1996	8,280	4,674,681	4,682,961
1997	1,218,784	2,327,729	3,546,513
1998	1,768,685	1,432,244	3,200,929
1999	562,464	1,439,037	2,001,501
2000	2,555,760	1,360,992	3,916,752
2001	4,979,160	825,656	5,804,816
2002	8,126,620	270,000	8,396,620
2003	13,039,105	582,320	13,621,425
2004	15,998,420	518,160	16,516,580
2005F	19,812,710	800,000	20,612,710
2006F	20,407,390	1,500,000	21,907,390
2007F	21,019,612	2,000,000	23,019,612
2008F	21,650,200	2,000,000	23,650,200
2009F	22,299,706	2,000,000	24,299,706
2010F	22,968,697	2,000,000	24,968,697
2011F	23,657,758	2,000,000	25,657,758
2012F	24,367,491	2,000,000	26,367,491
2013F	25,098,516	2,000,000	27,098,516
2014F	25,851,471	2,000,000	27,851,471
2015F	26,627,015	2,000,000	28,627,015
2016F	27,425,826	2,000,000	29,425,826

f. Secondary sales are made available under the Terms of Rate Schedule 32 (see YUB-YEC-1-9). This Rate Schedule sets out the conditions under which new loads can be connected, and the terms on which existing loads will be interrupted. Pursuant to that Rate Schedule, Yukon Energy will implement interruptions of potentially unlimited duration should there be no surplus hydro available, either due to peaking conditions, droughts, or development of new loads (such as starts to emerge in the Base Case with Mines load sensitivity).

Yukon Energy Corporation

Summary of Customers, Energy Sales and Revenues - Company

Table 2.1
November 30, 2004

Line No.	Description	Actual 2000	Actual 2001	Actual 2002	Actual 2003	Forecast 2004	Forecast Existing 2005	Forecast Proposed 2005
1	**Residential**							
2	Customers	1,186	1,233	1,257	1,286	1,287	1,302	1,302
3	Sales in MWh	9,889	9,543	9,716	9,968	10,102	10,201	10,201
4	MWh sales per customer	8.3	7.7	7.7	7.8	7.9	7.8	7.8
5	Revenue ($000s)	1,167	1,142	1,161	1,188	1,192	1,208	1,208
6	Cents per KWh	11.80	11.96	11.95	11.92	11.80	11.84	11.84
7	**General Service**							
8	Customers	428	430	434	433	440	446	447
9	Sales in MWh	12,503	12,513	12,692	13,345	13,540	13,808	16,808
10	MWh sales per customer	29.2	29.1	29.3	30.8	30.8	31.0	37.6
11	Revenue ($000s)	1,725	1,739	1,794	1,829	1,865	1,912	2,305
12	Cents per KWh	13.80	13.90	14.13	13.71	13.78	13.84	13.71
13	**Industrial**							
14	Sales in MWh	1,561	1,302	884	452	407	0	0
15	Revenue ($000s)	109	91	62	32	28	0	0
16	Cents per KWh	7.00	7.00	7.00	7.00	7.00	7.00	7.00
17	**Street lights**							
18	Sales in MWh	230	247	256	257	254	252	252
19	Revenue ($000s)	62	64	66	66	65	65	65
20	Cents per KWh	26.76	25.81	25.62	25.62	25.62	25.75	25.75
21	**Space lights**							
22	Sales in MWh	11	13	13	13	12	13	13
23	Revenue ($000s)	3	2	3	3	3	2	2
24	Cents per KWh	24.04	18.76	20.82	20.89	20.89	19.76	19.76
25	**Total Company - Firm Retail**							
26	Customers	1,615	1,663	1,690	1,719	1,726	1,748	1,749
27	Sales in MWh	24,193	23,618	23,561	24,034	24,315	24,274	27,274
28	Revenue ($000s)	3,066	3,038	3,085	3,118	3,154	3,187	3,580
29	Cents per KWh	12.67	12.86	13.10	12.97	12.97	13.13	13.13
30	**Wholesale sales**							
31	Sales in MWh	218,774	217,417	220,875	229,971	233,017	234,542	234,542
32	Revenue ($000s)	14,964	14,871	15,108	15,730	15,938	16,043	16,043
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84	6.84
34	**Total Company - Firm**							
35	Sales in MWh	242,967	241,035	244,437	254,005	257,332	258,816	261,816
36	Revenue ($000s)	18,030	17,909	18,193	18,848	19,092	19,230	19,623
37	Cents per KWh	7.42	7.43	7.44	7.42	7.42	7.43	7.49
38	**Secondary**							
39	Sales in MWh	3,917	5,805	8,118	13,892	18,533	20,613	20,613
40	Revenue ($000s)	101	137	180	315	416	462	916
41	Cents per KWh	2.58	2.36	2.22	2.27	2.24	2.24	4.44
42	**Total Company**							
43	Sales in KWh	246,884	246,840	252,555	267,897	275,865	279,428	282,428
44	Revenue ($000s)	18,131	18,046	18,373	19,163	19,508	19,692	20,538
45	Cents per KWh	7.34	7.31	7.27	7.15	7.07	7.05	7.27
46	Rider J revenue ($000)	4,257	4,186	5,411	5,027	5,111	5,163	5,173
47	Total Sales of Power ($000)	22,388	22,232	23,784	24,190	24,619	24,855	25,711
48	ARM dewatering (MW.h)	2,304	5,090	4,020	3,758	3,433	3,000	0

Notes:

1 ARM dewatering sales are sales to the Faro mine site under Rate Schedule 34. Pursuant to Board Order 1998-5, all revenue received from this rate schedule less reasonable incremental costs have been assigned to a deferral account for future application to the benefit of customers. This Application proposes, effective January 1, 2005, to terminate Rate Schedule 34 and reclassify this site to General Service-Government.

2 "Industrial sales" from 2000 through 2004 are sales to the UKHM mine site. During 2004, this site was changed to a General Service-Government rate.

3 2005 revenue change (Proposed versus Existing) for Secondary sales assume rate change as proposed effective January 1, 2005.

Yukon Energy Corporation

Summary of Customers, Energy Sales and Revenues - Dawson

Table 2.2
November 30, 2004

Line No.	Description	Actual 2000	Actual 2001	Actual 2002	Actual 2003	Forecast 2004	Forecast Existing 2005	Forecast Proposed 2005
1	**Residential**							
2	Customers	742	754	761	771	768	776	776
3	Sales in MWh	5,809	5,459	5,547	5,678	5,737	5,775	5,775
4	MWh sales per customer	7.8	7.2	7.3	7.4	7.5	7.4	7.4
5	Revenue ($000s)	687	657	667	680	677	684	684
6	Cents per KWh	11.83	12.04	12.02	11.98	11.80	11.84	11.84
7	**General Service**							
8	Customers	297	298	298	293	301	299	299
9	Sales in MWh	7,988	7,931	7,687	8,135	8,107	8,105	8,105
10	MWh sales per customer	26.9	26.6	25.8	27.7	26.9	27.1	27.1
11	Revenue ($000s)	1,105	1,102	1,097	1,122	1,117	1,122	1,122
12	Cents per KWh	13.83	13.90	14.27	13.79	13.78	13.84	13.84
13	**Industrial**							
14	Sales in MWh	0	0	0	0	0	0	0
15	Revenue ($000s)	0	0	0	0	0	0	0
16	Cents per KWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	**Street lights**							
18	Sales in MWh	97	109	112	113	111	108	108
19	Revenue ($000s)	26	28	29	29	28	28	28
20	Cents per KWh	26.71	25.92	25.92	25.92	25.62	25.75	25.75
21	**Space lights**							
22	Sales in MWh	6	8	9	8	8	8	8
23	Revenue ($000s)	1.7	1.4	1.5	1.3	2	1.5	1.5
24	Cents per KWh	27.19	17.26	17.74	17.22	20.89	19.76	19.76
25	**Total - Firm Retail**							
26	Customers	1,039	1,052	1,059	1,064	1,069	1,076	1,076
27	Sales in MWh	13,900	13,507	13,355	13,934	13,963	13,996	13,996
28	Revenue ($000s)	1,820	1,789	1,795	1,833	1,824	1,835	1,835
29	Cents per KWh	13.09	13.25	13.44	13.15	13.06	13.11	13.11
30	**Wholesale sales**							
31	Sales in MWh	0	0	0	0	0	0	0
32	Revenue ($000s)	0	0	0	0	0	0	0
33	Cents per KWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	**Total - Firm**							
35	Sales in MWh	13,900	13,507	13,355	13,934	13,963	13,996	13,996
36	Revenue ($000s)	1,820	1,789	1,795	1,833	1,824	1,835	1,835
37	Cents per KWh	13.09	13.25	13.44	13.15	13.06	13.11	13.11
38	**Secondary**							
39	Sales in MWh	0	0	0	0	0	0	0
40	Revenue ($000s)	0	0	0	0	0	0	0
41	Cents per KWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	**Total**							
43	Sales in KWh	13,900	13,507	13,355	13,934	13,963	13,996	13,996
44	Revenue ($000s)	1,820	1,789	1,795	1,833	1,824	1,835	1,835
45	Cents per KWh	13.09	13.25	13.44	13.15	13.06	13.11	13.11

Yukon Energy Corporation

Table 2.3
November 30, 2004

Summary of Customers, Energy Sales and Revenues - North Klondike
(customers arising from the Mayo Dawson Project completion in Septermber 2003)

Line No.	Description	Actual 2000	Actual 2001	Actual 2002	Actual 2003	Forecast 2004	Forecast Existing 2005	Forecast Proposed 2005
1	**Residential**							
2	Customers	0	0	0	0	3	5	5
3	Sales in MWh	0	0	0	1	8	12	12
4	MWh sales per customer	N/A	N/A	N/A	7.7	2.7	2.3	2.3
5	Revenue ($000s)	0	0	0	0	1	1	1
6	Cents per KWh	N/A	N/A	N/A	11.72	11.80	11.84	11.84
7	**General Service**							
8	Customers	0	0	0	2	4	6	6
9	Sales in MWh	0	0	0	150	179	168	168
10	MWh sales per customer	N/A	N/A	N/A	69.4	41.4	30.1	30.1
11	Revenue ($000s)	0	0	0	18	25	23	23
12	Cents per KWh	N/A	N/A	N/A	11.80	13.78	13.84	13.84
13	**Industrial**							
14	Sales in MWh	0	0	0	0	0	0	0
15	Revenue ($000s)	0	0	0	0	0	0	0
16	Cents per KWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	**Street lights**							
18	Sales in MWh	0	0	0	0	0	0	0
19	Revenue ($000s)	0	0	0	0	0	0	0
20	Cents per KWh	N/A	N/A	N/A	N/A	N/A	25.75	25.75
21	**Space lights**							
22	Sales in MWh	0	0	0	0	0	0	0
23	Revenue ($000s)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Cents per KWh	N/A	N/A	N/A	N/A	N/A	19.76	19.76
25	**Total - Firm Retail**							
26	Customers	0	0	0	2	7	11	11
27	Sales in MWh	0	0	0	151	188	180	180
28	Revenue ($000s)	0	0	0	18	26	25	25
29	Cents per KWh	N/A	N/A	N/A	11.80	13.69	13.71	13.71
30	**Wholesale sales**							
31	Sales in MWh	0	0	0	0	105	330	330
32	Revenue ($000s)	0	0	0	0	7	23	23
33	Cents per KWh	N/A	N/A	N/A	N/A	6.84	6.84	6.84
34	**Total - Firm**							
35	Sales in MWh	0	0	0	151	293	510	510
36	Revenue ($000s)	0	0	0	18	33	47	47
37	Cents per KWh	N/A	N/A	N/A	11.80	11.23	9.26	9.26
38	**Secondary**							
39	Sales in MWh	0	0	0	0	325	250	250
40	Revenue ($000s)	0	0	0	0	11	8	14
41	Cents per KWh	N/A	N/A	N/A	N/A	3.3	3.3	5.5
42	**Total**							
43	Sales in KWh	0	0	0	151	618	760	760
44	Revenue ($000s)	0	0	0	18	44	55	61
45	Cents per KWh	N/A	N/A	N/A	11.80	7.06	7.30	8.02

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues - Mayo

Table 2.4
November 30, 2004

Line No.	Description	Actual 2000	Actual 2001	Actual 2002	Actual 2003	Forecast 2004	Forecast Existing 2005	Forecast Proposed 2005
1	**Residential**							
2	Customers	227	231	228	232	230	233	233
3	Sales in MWh	2,334	2,298	2,288	2,247	2,295	2,325	2,325
4	MWh sales per customer	10.3	10.0	10.0	9.7	10.0	10.0	10.0
5	Revenue ($000s)	272	269	267	262	271	275	275
6	Cents per KWh	11.65	11.69	11.69	11.64	11.80	11.84	11.84
7	**General Service**							
8	Customers	61	62	64	62	63	65	65
9	Sales in MWh	1,879	1,863	2,112	2,020	2,240	2,513	2,513
10	MWh sales per customer	30.6	30.0	33.0	32.5	35.7	38.9	38.9
11	Revenue ($000s)	265	265	304	284	309	348	348
12	Cents per KWh	14.10	14.20	14.40	14.05	13.78	13.84	13.84
13	**Industrial**							
14	Sales in MWh	1,561	1,302	884	452	407	0	0
15	Revenue ($000s)	109	91	62	32	28	0	0
16	Cents per KWh	7.00	7.00	7.00	7.00	7.00	7.00	7.00
17	**Street lights**							
18	Sales in MWh	46	46	46	46	47	46	46
19	Revenue ($000s)	12	12	12	12	12	12	12
20	Cents per KWh	26.79	25.98	25.97	25.98	25.62	25.75	25.75
21	**Space lights**							
22	Sales in MWh	2	2	2	2	2	2	2
23	Revenue ($000s)	0.5	0.6	0.6	0.6	1	0.5	0.5
24	Cents per KWh	26.51	26.51	26.51	26.51	20.89	19.76	19.76
25	**Total - Firm Retail**							
26	Customers	289	293	292	294	293	298	298
27	Sales in MWh	5,822	5,513	5,332	4,768	4,991	4,887	4,887
28	Revenue ($000s)	659	637	646	590	620	636	636
29	Cents per KWh	11.32	11.56	12.12	12.36	12.43	13.01	13.01
30	**Wholesale sales**							
31	Sales in MWh	274	279	237	240	256	251	251
32	Revenue ($000s)	19	19	16	16	18	17	17
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84	6.84
34	**Total - Firm**							
35	Sales in MWh	6,096	5,792	5,569	5,008	5,247	5,138	5,138
36	Revenue ($000s)	678	656	662	606	638	653	653
37	Cents per KWh	11.12	11.33	11.89	12.10	12.16	12.71	12.71
38	**Secondary**							
39	Sales in MWh	1,361	826	115	853	414	550	550
40	Revenue ($000s)	45	27	4	28	14	18	30
41	Cents per KWh	3.3	3.3	3.3	3.3	3.3	3.3	5.5
42	**Total**							
43	Sales in KWh	7,457	6,617	5,684	5,861	5,661	5,688	5,688
44	Revenue ($000s)	723	683	666	634	652	671	683
45	Cents per KWh	9.69	10.33	11.72	10.82	11.51	11.80	12.01

Notes:
1 "Industrial sales" from 2000 through 2004 are sales to the UKHM mine site. Duirng 2004, this site was changed to a General Service-Government rate.
2 2005 revenue change (Proposed versus Existing) for Secondary sales assume rate change as proposed effective January 1, 2005.

Yukon Energy Corporation

Summary of Customers, Energy Sales and Revenues - WAF

Table 2.5
November 30, 2004

Line No.	Description		Actual 2000	Actual 2001	Actual 2002	Actual 2003	Forecast 2004	Forecast Existing 2005	Forecast Proposed 2005
1	**Residential**								
2	Customers		217	249	268	283	286	288	288
3	Sales in MWh		1,746	1,785	1,881	2,042	2,062	2,089	2,089
4	MWh sales per customer		8.0	7.2	7.0	7.2	7.2	7.3	7.3
5	Revenue ($000s)		208	216	227	247	243	247	247
6	Cents per KWh		11.91	12.08	12.07	12.08	11.80	11.84	11.84
7	**General Service**								
8	Customers		70	70	72	76	71	76	77
9	Sales in MWh		2,636	2,719	2,893	3,039	3,014	3,022	6,022
10	MWh sales per customer		37.8	38.9	40.3	40.1	42.2	39.8	78.2
11	Revenue ($000s)		356	372	393	406	415	418	811
12	Cents per KWh		13.49	13.68	13.57	13.36	13.78	13.84	13.47
13	**Industrial**								
14	Sales in MWh		0	0	0	0	0	0	0
15	Revenue ($000s)		0	0	0	0	0	0	0
16	Cents per KWh		N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	**Street lights**								
18	Sales in MWh		87	92	97	97	96	97	97
19	Revenue ($000s)		23	24	24	24	25	25	25
20	Cents per KWh		26.79	25.59	25.12	25.12	25.62	25.75	25.75
21	**Space lights**								
22	Sales in MWh		3	3	2	2	2	2	2
23	Revenue ($000s)		0.4	0.4	0.6	0.6	0.4	0.5	0.5
24	Cents per KWh		14.36	16.15	26.24	27.29	20.89	19.76	19.76
25	**Total - Firm Retail**								
26	Customers		287	319	339	359	357	364	365
27	Sales in MWh		4,472	4,599	4,874	5,181	5,173	5,211	8,211
28	Revenue ($000s)		587	612	645	678	683	691	1,084
29	Cents per KWh		13.13	13.30	13.23	13.08	13.21	13.27	13.21
30	**Wholesale sales**								
31	Sales in MWh		218,500	217,138	220,638	229,731	232,656	233,961	233,961
32	Revenue ($000s)		14,945	14,852	15,092	15,714	15,914	16,003	16,003
33	Cents per KWh		6.84	6.84	6.84	6.84	6.84	6.84	6.84
34	**Total - Firm**								
35	Sales in MWh		222,971	221,737	225,512	234,912	237,829	239,172	242,172
36	Revenue ($000s)		15,533	15,464	15,736	16,391	16,597	16,694	17,087
37	Cents per KWh		6.97	6.97	6.98	6.98	6.98	6.98	7.06
38	**Secondary**								
39	Sales in MWh		2,556	4,979	8,003	13,039	17,794	19,813	19,813
40	Revenue ($000s)		56	110	176	287	391	436	872
41	Cents per KWh		2.2	2.2	2.2	2.2	2.2	2.2	4.4
42	**Total**								
43	Sales in KWh		225,527	226,716	233,515	247,951	255,623	258,985	261,985
44	Revenue ($000s)		15,589	15,574	15,912	16,678	16,989	17,130	17,959
45	Cents per KWh		6.91	6.87	6.81	6.73	6.65	6.61	6.85
46	ARM dewatering (MW.h)	#	2,304	5,090	4,020	3,758	3,433	3,000	0

Notes;

1 ARM dewatering sales are sales to the Faro mine site under Rate Schedule 34. Pursuant to Board Order 1998-5, all revenue received from this rate schedule less reasonale incremental costs have been assigned to a deferral account for future application to the benefit of customers. This Application proposes, effective January 1, 2005, to terminate Rate Schedule 34 and reclassify this site to General Service-Government.

2 2005 revenue change (Proposed versus Existing) for Secondary sales assume rate change as proposed effective January 1, 2005.

BUREAU

of Statistics

Population Projections to 2015

IN BRIEF:

Projections for the Yukon's population in 2015 estimate:

- Low-growth: a population of **29,285;** or,
- Medium-growth: a population of **32,610**; or,
- High-growth: a population of **36,088**.

The current population of the Yukon (June 2005) is 31,222.

HOW WILL THE YUKON'S POPULATION CHANGE BY 2015?

Low-growth projection

- Total population would fall by 1,937, or 6.2%.
- The number of aboriginal people in the Yukon would decrease by 166, or 2.4%.
- The number of non-aboriginal people in the Yukon would fall by 1,771, or 7.3%.
- The number of women in the Yukon would decrease by 929, or 6.0%, while the number of men would decrease by 1,008, or 6.4%.
- Changes in the age distribution of the Yukon show that all age groups 55 and over would increase, as well as the age group 5-to-9, while all age groups 54 and under (with the exception of 5-to-9) would decrease.

Medium-growth projection

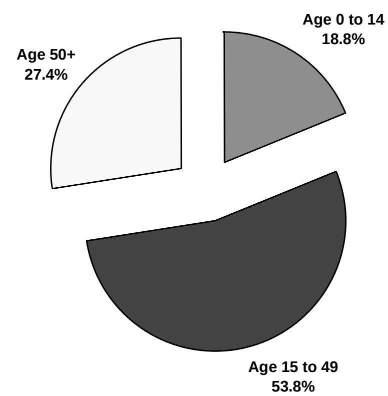
- Total population would increase by 1,388, or 4.4%.
- The number of aboriginal people in the Yukon would increase by 363, or 5.2%.
- The number of non-aboriginal people in the Yukon would increase by 1,025, or 4.2%.
- The number of women in the Yukon would increase by 525, or 3.4%, while the number of men would increase by 863, or 5.5%.
- Changes in the age distribution of the Yukon show that all age groups 55+ would increase, while seven of eleven age groups below 55 would decrease. The 15-to-19-year-old age group would decrease the most (33.7%), while the 65-to-69-year-old age group would exhibit the largest increase (109.8%).

High-growth projection

- Total population would increase by 4,866, or 15.6%.
- The number of aboriginal people in the Yukon would increase by 911, or 13.0%.
- The number of non-aboriginal people in the Yukon would increase by 3,955, or 16.3%.
- The number of women in the Yukon would increase by 2,003, or 12.9%, while the number of men would increase by 2,863, or 18.3%.
- Changes in the age distribution of the Yukon show that all age groups 50+ would increase. Five age groups would decrease. The greatest decrease would be in the 15-to-19-year-old age group (28.5%). The largest increase would be in the 65-to-69-year-old age group (118.9%).

IMPLICATIONS FOR THE FUTURE

The current population figures show the following age breakdown:



Each projection for the Yukon's population in 2015 shows a larger and older population in the Yukon:

- The **Low-growth projection** shows the 50+ age groups comprising **39.3%** of the population by 2015; and
- The **Medium-growth projection** shows the 50+ age groups comprising **37.3%** of the population by 2015; and
- The **High-growth projection** shows the 50+ age groups comprising **35.7%** of the population by 2015.

LOW-GROWTH POPULATION PROJECTION: Detail

The following tables show the LOW growth projection as it compares to the Yukon's population as of June 2005. Figures are presented by ethnicity (aboriginal/non-aboriginal), by gender and by age. Differences are shown in actual numbers and as percentages.

ASSUMPTIONS:

- Fertility rates are down 10%.
- Mortality rates are constant.
- Net migration each year is -300.

Total non-aboriginal Yukoners

Age Group	June 2005	June 2015	Difference No.	Difference %
0-4	1,110	1,273	163	14.7%
5-9	1,228	1,481	253	20.6%
10-14	1,574	1,033	-541	-34.4%
15-19	1,789	942	-847	-47.3%
20-24	1,488	1,004	-484	-32.5%
25-29	1,423	1,291	-132	-9.3%
30-34	1,687	1,368	-319	-18.9%
35-39	1,765	1,386	-379	-21.5%
40-44	2,324	1,529	-795	-34.2%
45-49	2,674	1,537	-1,137	-42.5%
50-54	2,454	2,056	-398	-16.2%
55-59	1,784	2,336	552	30.9%
60-64	1,154	2,048	894	77.5%
65-69	671	1,380	709	105.7%
70-74	472	824	352	74.6%
75-79	302	431	129	42.7%
80+	305	514	209	68.5%
Total	**24,204**	**22,433**	**-1,771**	**-7.3%**

The above table shows changes in the Yukon's non-aboriginal population.

- There would be 1,771, or 7.3%, fewer non-aboriginal Yukoners in 2015 compared to 2005.
- Most of the decline would be in the 10-to-24 and the 40-to-49-year-old age groups, with all age groups over 55 showing growth.

Total aboriginal Yukoners

Age Group	June 2005	June 2015	Difference No.	Difference %
0-4	691	481	-210	-30.4%
5-9	597	500	-97	-16.2%
10-14	661	621	-40	-6.1%
15-19	551	466	-85	-15.4%
20-24	589	503	-86	-14.6%
25-29	432	466	34	7.9%
30-34	513	595	82	16.0%
35-39	495	469	-26	-5.3%
40-44	652	470	-182	-27.9%
45-49	412	374	-38	-9.2%
50-54	377	517	140	37.1%
55-59	367	338	-29	-7.9%
60-64	233	342	109	46.8%
65-69	172	316	144	83.7%
70-74	122	176	54	44.3%
75-79	78	119	41	52.6%
80+	76	99	23	30.3%
Total	**7,018**	**6,852**	**-166**	**-2.4%**

The above table shows changes in the Yukon's aboriginal population.

- Overall, the aboriginal population would decrease by 166, or 2.4%
- Highest growth would be in the 65-to-69 (83.7%) age group, and the largest decline would be in the 0-to-4 (-30.4%) age group.

Total female Yukoners

Age Group	June 2005	June 2015	Difference No.	Difference %
0-4	897	861	-36	-4.0%
5-9	914	991	77	8.4%
10-14	1,072	819	-253	-23.6%
15-19	1,133	719	-414	-36.5%
20-24	1,062	770	-292	-27.5%
25-29	1,024	847	-177	-17.3%
30-34	1,194	1,005	-189	-15.8%
35-39	1,168	1,035	-133	-11.4%
40-44	1,593	1,063	-530	-33.3%
45-49	1,536	911	-625	-40.7%
50-54	1,361	1,322	-39	-2.9%
55-59	1,021	1,316	295	28.9%
60-64	571	1,119	548	96.0%
65-69	364	795	431	118.4%
70-74	284	445	161	56.7%
75-79	170	282	112	65.9%
80+	219	354	135	61.6%
Total	**15,583**	**14,654**	**-929**	**-6.0%**

- The table at the bottom of the previous column (low-growth projection for the Yukon's female population) shows that the female population would decline 6.0%, to 14,654, by the year 2015.
- All age groups 55 and over would show growth, with the 65-to-69 age group increasing the most, by 118.4%.
- With the exception of 5-to-9 year-olds, all age groups under 55 would decline in population.

Total male Yukoners

Age Group	June 2005	June 2015	Difference No.	Difference %
0-4	904	893	-11	-1.2%
5-9	911	990	79	8.7%
10-14	1,163	835	-328	-28.2%
15-19	1,207	689	-518	-42.9%
20-24	1,015	737	-278	-27.4%
25-29	831	910	79	9.5%
30-34	1,006	958	-48	-4.8%
35-39	1,092	820	-272	-24.9%
40-44	1,383	936	-447	-32.3%
45-49	1,550	1,000	-550	-35.5%
50-54	1,470	1,251	-219	-14.9%
55-59	1,130	1,358	228	20.2%
60-64	816	1,271	455	55.8%
65-69	479	901	422	88.1%
70-74	310	555	245	79.0%
75-79	210	268	58	27.6%
80+	162	259	97	59.9%
Total	**15,639**	**14,631**	**-1,008**	**-6.4%**

- The number of male Yukoners would decrease by 1,008, or 6.4%, by the year 2015.
- Only two age group below 55 would grow (5-to-9 and 25-to-29 year olds), with all age groups 55 and over showing growth.
- The largest percentage decrease would be in the 15-to-19-year-old age group, which would decline by 518 males, or 42.9%.

MEDIUM-GROWTH POPULATION PROJECTION: Detail

The following tables show the MEDIUM growth projection as it compares to the Yukon's population as of June 2005. Figures are presented by ethnicity (aboriginal/ non-aboriginal), by gender and by age. Differences are shown in actual numbers and as percentages.

ASSUMPTIONS:

- Fertility rates are constant.
- Mortality rates are constant.
- Net migration each year is zero.

Total non-aboriginal Yukoners

Age Group	June 2005	June 2015	Difference No.	Difference %
0-4	1,110	1,534	424	38.2%
5-9	1,228	1,646	418	34.0%
10-14	1,574	1,147	-427	-27.1%
15-19	1,789	1,054	-735	-41.1%
20-24	1,488	1,181	-307	-20.6%
25-29	1,423	1,597	174	12.2%
30-34	1,687	1,706	19	1.1%
35-39	1,765	1,664	-101	-5.7%
40-44	2,324	1,761	-563	-24.2%
45-49	2,674	1,759	-915	-34.2%
50-54	2,454	2,258	-196	-8.0%
55-59	1,784	2,492	708	39.7%
60-64	1,154	2,156	1,002	86.8%
65-69	671	1,445	774	115.4%
70-74	472	856	384	81.4%
75-79	302	446	144	47.7%
80+	305	527	222	72.8%
Total	**24,204**	**25,229**	**1,025**	**4.2%**

The above table shows changes in the Yukon's non-aboriginal population.

- There would be 1,025, or 4.2%, more non-aboriginal Yukoners in 2015 compared to 2005.
- The 55-to-59, 60-to-64 and 65-to-69-year-old age groups show significant increases (a total of 2,484 people).
- The largest decrease, 915 people, would be in the 45-to-49 age group.

Total aboriginal Yukoners

Age Group	June 2005	June 2015	Difference No.	Difference %
0-4	691	553	-138	-20.0%
5-9	597	540	-57	-9.5%
10-14	661	648	-13	-2.0%
15-19	551	498	-53	-9.6%
20-24	589	545	-44	-7.5%
25-29	432	516	84	19.4%
30-34	513	645	132	25.7%
35-39	495	517	22	4.4%
40-44	652	517	-135	-20.7%
45-49	412	414	2	0.5%
50-54	377	546	169	44.8%
55-59	367	359	-8	-2.2%
60-64	233	356	123	52.8%
65-69	172	324	152	88.4%
70-74	122	182	60	49.2%
75-79	78	121	43	55.1%
80+	76	100	24	31.6%
Total	**7,018**	**7,381**	**363**	**5.2%**

The above table shows changes in the Yukon's aboriginal population.

- Overall, the aboriginal population would increase by 363, or 5.2%.
- Highest growth would be in the 65-to-69 (88.4%) age group and and the largest decline would be in the 40-to-44 (20.7%) age group.

Total female Yukoners

Age Group	June 2005	June 2015	Difference No.	Difference %
0-4	897	1,023	126	14.0%
5-9	914	1,091	177	19.4%
10-14	1,072	888	-184	-17.2%
15-19	1,133	791	-342	-30.2%
20-24	1,062	865	-197	-18.5%
25-29	1,024	1,002	-22	-2.1%
30-34	1,194	1,177	-17	-1.4%
35-39	1,168	1,172	4	0.3%
40-44	1,593	1,176	-417	-26.2%
45-49	1,536	1,018	-518	-33.7%
50-54	1,361	1,416	55	4.0%
55-59	1,021	1,386	365	35.7%
60-64	571	1,166	595	104.2%
65-69	364	825	461	126.6%
70-74	284	461	177	62.3%
75-79	170	289	119	70.0%
80+	219	362	143	65.3%
Total	**15,583**	**16,108**	**525**	**3.4%**

- The table at the bottom of the previous column would see the medium-growth projection for the Yukon's female population increase 3.4% to 16,108 by the year 2015.
- All age groups 50 and over would show growth, with the 65-to-69-year-old group increasing the most by 126.6%.
- Seven female age groups would decline: 10-to-14 (17.2%), 15-to-19 (30.2%), 20-to-24 (18.5%), 25-to-29 (2.1%), 30-to-34 (1.4%), 40-to-44 (26.2%) and 45-to-49 (33.7%) year-olds.

Total male Yukoners

Age Group	June 2005	June 2015	Difference No.	Difference %
0-4	904	1,064	160	17.7%
5-9	911	1,095	184	20.2%
10-14	1,163	907	-256	-22.0%
15-19	1,207	761	-446	-37.0%
20-24	1,015	861	-154	-15.2%
25-29	831	1,111	280	33.7%
30-34	1,006	1,174	168	16.7%
35-39	1,092	1,009	-83	-7.6%
40-44	1,383	1,102	-281	-20.3%
45-49	1,550	1,155	-395	-25.5%
50-54	1,470	1,388	-82	-5.6%
55-59	1,130	1,465	335	29.6%
60-64	816	1,346	530	65.0%
65-69	479	944	465	97.1%
70-74	310	577	267	86.1%
75-79	210	278	68	32.4%
80+	162	265	103	63.6%
Total	**15,639**	**16,502**	**863**	**5.5%**

- The number of male Yukoners would increase by 863, or 5.5%, by the year 2015.
- The age groups with the largest percentage increases would be the 65-to-69 (97.1%), 70-to-74 (86.1%), 60-to-64 (65.0%) and age groups.

HIGH-GROWTH POPULATION PROJECTION: Detail

The following tables show the HIGH growth projection as it compares to the Yukon's population as of June 2005. Figures are presented by ethnicity (aboriginal/non-aboriginal), by gender and by age. Differences are shown in actual numbers and as percentages.

ASSUMPTIONS:

- Fertility rates are up 10%.
- Mortality rates are down 10%.
- Net migration each year is +300.

Total non-aboriginal Yukoners

Age Group	June 2005	June 2015	Difference No.	%
0-4	1,110	1,851	741	66.8%
5-9	1,228	1,855	627	51.1%
10-14	1,574	1,265	-309	-19.6%
15-19	1,789	1,151	-638	-35.7%
20-24	1,488	1,322	-166	-11.2%
25-29	1,423	1,888	465	32.7%
30-34	1,687	2,069	382	22.6%
35-39	1,765	1,966	201	11.4%
40-44	2,324	2,002	-322	-13.9%
45-49	2,674	1,983	-691	-25.8%
50-54	2,454	2,463	9	0.4%
55-59	1,784	2,647	863	48.4%
60-64	1,154	2,258	1,104	95.7%
65-69	671	1,507	836	124.6%
70-74	472	891	419	88.8%
75-79	302	469	167	55.3%
80+	305	572	267	87.5%
Total	**24,204**	**28,159**	**3,955**	**16.3%**

The above table shows changes in the Yukon's non-aboriginal population.

- There would be 3,955, or 16.3%, more non-aboriginal Yukoners in 2015 compared to 2005.
- The majority of the total increase would be in age groups 55 and over.

Total aboriginal Yukoners

Age Group	June 2005	June 2015	Difference No.	%
0-4	691	626	-65	-9.4%
5-9	597	577	-20	-3.4%
10-14	661	672	11	1.7%
15-19	551	522	-29	-5.3%
20-24	589	577	-12	-2.0%
25-29	432	566	134	31.0%
30-34	513	705	192	37.4%
35-39	495	577	82	16.6%
40-44	652	567	-85	-13.0%
45-49	412	451	39	9.5%
50-54	377	570	193	51.2%
55-59	367	378	11	3.0%
60-64	233	375	142	60.9%
65-69	172	338	166	96.5%
70-74	122	192	70	57.4%
75-79	78	130	52	66.7%
80+	76	106	30	39.5%
Total	**7,018**	**7,929**	**911**	**13.0%**

The above table shows changes in the Yukon's aboriginal population.

- Overall, the aboriginal population would increase by 911, or 13.0%.
- Highest growth would be in the 65-to-69 (96.5%) and 75-to-79 (66.7%) age groups.

Total female Yukoners

Age Group	June 2005	June 2015	Difference No.	%
0-4	897	1,213	316	35.2%
5-9	914	1,213	299	32.7%
10-14	1,072	956	-116	-10.8%
15-19	1,133	851	-282	-24.9%
20-24	1,062	942	-120	-11.3%
25-29	1,024	1,146	122	11.9%
30-34	1,194	1,363	169	14.2%
35-39	1,168	1,325	157	13.4%
40-44	1,593	1,288	-305	-19.1%
45-49	1,536	1,113	-423	-27.5%
50-54	1,361	1,499	138	10.1%
55-59	1,021	1,448	427	41.8%
60-64	571	1,205	634	111.0%
65-69	364	851	487	133.8%
70-74	284	478	194	68.3%
75-79	170	304	134	78.8%
80+	219	391	172	78.5%
Total	**15,583**	**17,586**	**2,003**	**12.9%**

- The table at the bottom of the previous column would see the high-growth projection for the Yukon's female population increase 12.9%, to 17,586, by the year 2015.
- All age groups 50 and over would show growth, the 65-to-69-year-old group the most (by 133.8%).

Total male Yukoners

Age Group	June 2005	June 2015	Difference No.	%
0-4	904	1,264	360	39.8%
5-9	911	1,219	308	33.8%
10-14	1,163	981	-182	-15.6%
15-19	1,207	822	-385	-31.9%
20-24	1,015	957	-58	-5.7%
25-29	831	1,308	477	57.4%
30-34	1,006	1,411	405	40.3%
35-39	1,092	1,218	126	11.5%
40-44	1,383	1,281	-102	-7.4%
45-49	1,550	1,321	-229	-14.8%
50-54	1,470	1,534	64	4.4%
55-59	1,130	1,577	447	39.6%
60-64	816	1,428	612	75.0%
65-69	479	994	515	107.5%
70-74	310	605	295	95.2%
75-79	210	295	85	40.5%
80+	162	287	125	77.2%
Total	**15,639**	**18,502**	**2,863**	**18.3%**

- The number of male Yukoners would increase by 2,863, or 18.3%, by the year 2015.
- Only five age groups would decrease: 10-to-14 (15.6%), 15-to-19 (31.9%), 20-to-24 (5.7%), 40-to-44 (7.4%) and 45-to-49 (14.8%) year-olds.
- The age group with the largest percentage increase would be the 65-to-69 age group, increasing by 515 men, or 107.5%.

Additional Information:
The Yukon Government
Executive Council Office
Bureau of Statistics, (A-8C)
Box 2703, Whitehorse, Yukon Y1A 2C6
Telephone: (867) 667-5640; Fax: (867) 393-6203
Email: ybsinfo@gov.yk.ca
Website: www.gov.yk.ca/depts/eco/stats/

REFERENCE:

QUESTION:

The application indicates that new generating capacity is not planned for opportunity loads as they are interruptible. Has YEC accounted for interruptible load becoming firm load in the future? If yes, please explain.

ANSWER:

No.

Yukon Energy's interruptible loads are serviced under Rate Schedule 32 (see YUB-YEC-1-9 Attachment 1) which has substantial provisions to ensure these loads are not converted to firm load under any practical circumstances. In particular, this Rate Schedule is only available for electric heating loads, requires that the customer maintain a fully capable non-electric means of providing this same quantity of heat, and requires lengthy delays before the customer can convert the load to firm service (12 months) and prohibitions from ever switching that same load back to interruptible in future to prevent gaming.

As this rate is only available for servicing General Service electric heating loads and the customers are maintaining a fully capable alternative heating system (typically oil or propane), the only conditions under which YEC would expect customers to seek to switch interruptible service to firm is if there were a major and indefinite interruption of secondary service (such as with a major new mine loads of the size of the Faro mine) and Yukon firm General Service electric rates and bills (net of any subsidies) were lower than the variable (fuel) cost of supplying the heat with oil or propane. Given today's firm electric rates in Yukon (for General Service loads above basic levels, which do not receive YTG subsidies via the Rate Stabilization Fund), it is not expected that firm power electric heating would at that time be a preferred or economic choice for these customers.

RATE SCHEDULE - 32

SECONDARY ENERGY

AVAILABLE:

Secondary energy is available from time to time to General Service or Industrial customers in parts of the WAF and Mayo-Dawson systems as determined by Yukon Energy based on the availability of surplus hydro.

The rate is only available to new secondary loads in areas where there is sufficient surplus distribution system capacity at the time of connection. In areas were there is insufficient surplus distribution capacity at the time of connection, the customer will be required at that time to pay for any distribution upgrades required to service the new secondary load or, where the required upgrades are already planned for a future date, the cost of advancing those upgrades.

Yukon Energy has discretion to end subscription to the program (and limit quantities delivered) on a system when the supply of surplus energy on that system becomes fully contracted. The specific subscription limit will be dependent on the types of loads that enroll in future, their seasonality and load diversity.

APPLICABLE:

Secondary energy is applicable only to customers satisfying all of the following conditions:

(1) The secondary energy is provided on a separate service fully interruptible at the request of the utility.

(2) The utility distributing the secondary energy (i.e., Yukon Energy or YECL) is satisfied that the secondary energy usage by the customer is in excess of normal consumption and represents incremental electric usage displacing an alternative fuel source by an appliance primarily installed in order to provide space or process heating.

(3) A viable alternative fuel source is available to the customer, capable of providing the same quantity of

space or process heating in the event of electric power interruptions of unlimited duration.

(4) Customers taking Secondary Energy will not be allowed to have these loads shifted to be served by any firm (primary) service without providing the distributing utility (i.e., Yukon Energy or YECL) with 12 months notice (unless waived at Yukon Energy's discretion). Once any such Secondary Energy load is switched to firm service, it will not be able to switch back to Secondary Energy service in future.

RATE:

Charges for service in any one billing month during any Rate Period shall apply the Secondary Energy Charge for that Rate Period.

The Secondary Energy Charge for any three month Rate Period, starting January 1, 2005 and adjusted thereafter on the first day of every third subsequent month (i.e., on April 1, July 1 and October 1 in 2005 and similarly in each following year), is to be published and filed with the Board by Yukon Energy at least 30 days in advance of the Rate Period. The Secondary Energy Charge for any Rate Period is to be set in accordance with the following procedure:

Step A: Determine a price per MJ for heat energy from oil: The Oil Price Index (cents/litre net of GST) for the Rate Period (as determined below) divided by 38.2 MJ/litre to yield a price in cents per MJ.

Step B: Determine a price per MJ of delivered heat from oil: Divide the result from step A by an efficiency rate of 90%.

Step C: Convert price of delivered heat energy from oil to an equivalent price for heat energy from electricity: multiply the result from step B by 3.6 MJ/kW.h to yield a price in cents per kW.h.

Step D: Set at 66.7% ratio: Multiply the result from Step C by 66.7% to yield the quarterly Secondary Energy Charge for the Rate Period in cents/kW.h.

The Secondary Energy Charge derived in Step D for any Rate period shall be applied to all Secondary Energy kW.h consumed in each month during that Rate Period.

The Oil Price Index for each Rate Period shall equal the lowest of the three most recently reported Retail Heating Fuel Price values for Furnace Oil in Whitehorse (as collected bi-weekly and reported by the Yukon Bureau of Statistics) prior to the 20^{th} day of the mid-month in the prior Rate Period (e.g., for the Rate Period starting January 1, 2005, the three latest prices published prior to November 20, 2004).

In accordance with the above procedure, the Secondary Energy Charge for the three month Rate Period starting January 1, 2005 is 5.2 cents per kW.h.

INTERRUPTIONS: Customers have two options with regards to interruption:

(1) Customers can opt for installing a SCADA-controlled service that allows Yukon Energy to initiate interruptions on 15 minutes notice, as and when required only for actual real-time diesel generation being required on the respective system or for system emergencies or outages, or

(2) Customers can have a standard metered service. Under this option, the customers' supply will be interrupted after 24 hours notice at any time that Yukon Energy forecasts a need to run diesel units for more than 10% of the hours in the subsequent seven day period, or that Yukon Energy begins running diesels for unforecast reasons and expects the diesel operation to continue for more than 48 hours.

INSTALLATION COST: The customer is responsible for any cost of installing the separate service, metering and any SCADA load control apparatus that is in excess of the relevant Utility Investment provision in the Electrical Service Regulations. The customer is also responsible for any costs of upgrading or advancing distribution system capacity improvements necessitated by their Secondary Energy load.

SERVICE
<u>REGULATIONS:</u>

The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.

RATE SCHEDULE - 43

WHOLESALE SECONDARY

AVAILABLE: Wholesale secondary energy is available to YECL from time to time in parts of the WAF and Mayo systems as determined by Yukon Energy based on the availability of surplus hydro. Wholesale secondary energy is fully interruptible.

APPLICABLE: To The Yukon Electrical Company Limited for facilitating secondary retail sales to YECL's customers under Rate Schedule 32. The monthly quantity of Rate Schedule 43 energy shall be equal to the kW.h quantity of Rate Schedule 32 Secondary Energy sales made by YECL to qualified customers each month.

RATE: Energy Charge

The energy charge shall be equal to the energy charge per kW.h applicable under Rate Schedule 32, less 1.1¢/kW.h.

ELECTRIC SERVICE REGULATIONS: The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.

REFERENCE:

QUESTION:

YEC has identified a number of near-term projects to address capacity deficits during the 2006 to 2012 time period and their timing and sequencing are summarized in Table 4.15. In this respect:

a. Has the YEC conducted any studies to determine an optimal expansion sequence for these near-term projects so that the planning criteria are met and rate increases are minimized? If yes, can these studies be provided?

b. What would be the timing and sequencing of projects under the four-load forecast scenarios?

c. Please provide the business cases and all economic models (electronic or otherwise) used for each of the four near-term projects as currently proposed.

d. Without a capacity requirement to serve the Faro mine, what has happened to that previously installed capacity? Would that excess capacity contribute to the reliability assessment?

ANSWER:

a. Yukon Energy has conducted an analysis of the capacity projects set out in Table 4.15 to determine an optimal sequence, focused primarily on the practical limitations of size and earliest potential in-service date.

   The primary driving factor in this analysis is the timing to ISD required to develop each respective project in Table 4.15:

   - The Aishihik 3rd turbine project is of limited firm capacity benefits – the project is instead being pursued for peaking energy benefits (to offset winter peaking diesel requirements as the load on the system grows). This project could potentially be put in service by the third quarter of 2008, but due to the economics of load conditions, it is not proposed until the third quarter of 2009 or perhaps as late as 2011 or 2012 (once load development has occurred to ensure sufficient peaking diesel use can be offset by the unit).

- The Marsh Lake Fall/Winter Storage (1.6 MW) requires licencing amendments that cannot be expected to be secured any sooner than fall 2007 under best-case scenarios.
- The Carmacks-Stewart transmission line cannot be practically licenced and constructed for full in-service any sooner than the third quarter of 2009 (per Supplemental Filing Tab 3 – as compared to third quarter 2008 in the main Resource Plan document).
- The Mirrlees Life Extension (14 MW) can only practically be scheduled for one unit per year, starting in 2007.

Based on these constraints, the only options that are available to address winter 2007/08 shortfalls (6.0 MW) are the Mirrlees Life Extension for WD3 for 5.0 MW (rather than retiring this unit as would otherwise be planned in summer 2007) and the Marsh Lake Fall/Winter Storage project for 1.6 MW. With those commitments in place in 2007/08, residual modest shortfalls in the winter of 2008/09 can only practically be met by a Mirrlees Life Extension for WD2 (which secures 0.8 MW of benefits compared to the currently de-rated capacity on this unit, and a further 4.2 MW in winter 2009 when this unit would have otherwise been retired). The proposed sequence compared to shortfalls is set out in the following table (focused on N-1 criteria; LOLE criteria not driving capacity in this period under base case loads):

WAF System Capacity Shortfalls (MW) 2005-2012 under base case loads

Year	Planned Retirements	Initial Surplus/ (shortfall)	Aishihik 3rd turbine - 2009	Marsh Fall/Winter Storage - 2007	Carmacks-Stewart T-Line - 2009	Mirrlees Life Extension - 2007/08/09	Resulting WAF System Balance
2005		0.3					0.3
2006		(0.7)					(0.7)
2007	WD3	(6.0)		1.6		5.0	0.6
2008		(7.1)		1.6		5.8	0.3
2009	WD2	(12.3)	0.0	1.6	6.0	11.0	6.3
2010		(13.4)	0.0	1.6	5.9	11.0	5.1
2011	WD1	(17.6)	0.0	1.6	5.8	14.0	3.8
2012		(18.7)	0.0	1.6	5.6	14.0	2.5

In contrast, the full Carmacks-Stewart interconnection is planned to be in-service for third quarter 2009 based on a requirement to first prioritize the Carmacks-Pelly segment for in-service in 2008 (including the Minto mine and Carmacks Copper mine spur lines) in order to secure the benefits of maximizing service to the mines from sales of otherwise surplus hydro-electricity.

In summary, the analytical basis for the development sequence set out in Figure 4.15 is driven by the least-cost projects selected, the associated timing constraints of these projects, and the overall system capacity requirements. Rate impacts, to the extent they arise, are addressed in section 4.4.4 and are minimized, to the extent possible, by the proposed development sequence.

b. The proposed development sequence in Chapter 4 reflects the requirements to meet the Base Case loads and the Base Case with Mines loads (these two cases are not materially different with respect to capacity requirements as the mining load does not contribute to N-1 capacity shortfalls). The main difference between the two cases is as follows:

- the **Base Case with Mine Sensitivity (21.5 MW by 2012)** can be met with all projects listed including Carmacks-Stewart (which is expected to be constructed concurrent with the Minto and Carmacks Copper mine loads, and including a modest assumed diesel generation installation at each mine as backup for core functions).
- the **Base Case Loads (18.7 MW by 2012)** case similarly be met by the same suite of projects – however, the Carmacks-Stewart Interconnection is not likely to proceed in the absence of the mine loads. Consequently, Yukon Energy has assessed further long-term planning with respect to the Whitehorse diesel plant (as set out in the Supplemental Filing Tab 1) and is proposing the Mirrlees Life Extension project (14 MW), the Marsh Lake Fall/Winter Storage project (1.6 MW) and, by 2011, a separate enhancement to Whitehorse Diesel Plant of at least 3.1 MW. At the time of preparing the Resource Plan filing, this additional enhancement is set out in Figure 4.15 as installation of potentially a new 4 MW unit or retirement of WD1 and replacement with an 8 MW unit; however, as noted in the Supplemental filing, the retirement of WD1 is no longer a recommended alternative. Instead, the focus has evolved to more fully consider the entire plant leading to consideration of concepts set out in Section S1.3 (page S1-5, bullet 1) in respect of potential relocation of EMD units from the Whitehorse Plant and addition of considerably larger units, including potentially a simple cycle turbine in the bays currently occupied by the EMD units.

For the alternative load sensitivity cases, the following development sequences are consistent with the actions set out in the Resource Plan:

- **Low Sensitivity Case (14.7 MW by 2012):** Under the low sensitivity case, the WAF system requires 14.7 MW of capacity by 2012. This includes no new mining loads. Consequently, the Mirrlees Life Extension Project (14 MW) is proposed for completion as planned (although the later Mirrlees overhauls may be delayed by one or more years to the extent there are benefits from such a delay – at the present time it is not assumed that there are material benefits from such delay). In addition, the Marsh Lake Fall/Winter Storage is proposed for a further 1.6 MW. The Carmacks-Stewart project is not expected to be undertaken (given the lack of mine loads under this sensitivity) and the Aishihik 3rd turbine would be delayed, as described at page 4-58, to at least 2011 or 2012 or potentially beyond to the extent that load developments are experienced at these lower levels and the avoided peaking diesel benefits of the project may not arise as quickly as in the base case.
- **High Sensitivity Case (26.7 MW):** Under the high sensitivity case, WAF load growth is higher than forecast under the Base Case plus the two mines (Minto and Carmacks Copper) connecting to the system. In that event, pursuit of the four proposed projects would proceed (including Mirrlees Life Extension for 14 MW, Marsh Lake Fall/Winter Storage for 1.6 MW, Carmacks-Stewart for a net 5.2 MW[1] and an Aishihik 3rd turbine at about 2009 for benefit of 0.6 MW under this scenario (as the capacity shortfalls are being driven by the LOLE criteria) and up to a further 5.3 MW of capacity may be required (depending on the quantity of on-site diesel capacity installed by the mines). This would require consideration of the further Whitehorse Diesel Plant enhancements noted above (under Base Case loads).

c. The four proposed projects have varying forms of economic assessment and business case bases.

- **Aishihik 3rd Turbine** - This project is predicated on the present value of diesel savings exceeding the capital costs of the project. Detailed economic analysis of this project is provided in Appendix C of the Resource Plan under various load and supply conditions, including overall IRR calculations based on cash flows (each respective Table A) and ratepayer impacts based on

[1] The contribution of Carmacks-Stewart to capacity depends on the loads forecast on the Mayo-Dawson system. Under Base Case scenarios, at 2012 the Carmacks-Stewart contribution is about 5.6 MW; however under High Load Sensitivities, the MD load is similarly assumed to grow faster than base case as for WAF, as a result the surplus capacity available to WAF is reduced.

annual accounting costs and revenue requirement impacts (each respective Table B).

- **Carmacks-Stewart Transmission Line** – This project is proposed to provide an opportunity to sell surplus hydro power at firm rates to new industrial customers. However, the economics of the full project to interconnect the WAF and MD grids requires Yukon Government funding to ensure no adverse rate impacts on existing ratepayers. Yukon Energy does not have a formal commitment of this YTG funding to date and as such no specific detailed "business case" analysis of the type provided for Aishihik 3rd turbine can yet be conducted. To the extent economic evaluation and business case information is available, it is provided in the Supplemental Materials Tab 2. This project will not proceed without sufficient YTG funding as is necessary to ensure ratepayers are not adversely impacted by the project.
- **Marsh Lake Fall/Winter Storage –** The business case for proceeding with the Marsh Lake Fall/Winter Storage project reflects a combination of capacity benefits (1.6 MW) and energy benefits (up to 7.7 GW.h per year based on long-term average water flows and WAF conditions including industrial customer loads). At this point, it is very difficult to estimate the costs of proceeding with a Marsh Lake Fall/Winter Storage project as the costs are likely to be almost entirely, if not entirely, related to environmental licencing which are extremely difficult to estimate or control. Yukon Energy has estimated the licencing process will cost no more than $1 million. At this price, the cost of solely capacity benefits of $0.625 million per MW are well ahead of new diesel units (estimates at $0.930 million per MW per Table S-1 at page S1-4) ignoring entirely the enhanced hydro (energy and avoided diesel cost) benefits of the project. The energy (avoided diesel cost) for the Marsh Lake business case and economic model, consistent with the Aishihik 3rd turbine models (provided in Appendix C of the Resource Plan) are attached indicating a 21.55% IRR[2].
- **Mirrlees Life Extension** – The business case analysis for proceeding with the Mirrlees Life Extension project (given a confirmed requirement for this 14 MW of largely standby generation) is effectively set out at Table 4.3 to reflect the key focus on the lowest capital-cost-per-MW. In this regard, the comparative capital costs required to meet the capacity shortfalls on the

[2] Note however that the attached Marsh Lake business case ignores the capacity benefits discussed above, otherwise the IRR would become uncalculable, since the net capital cost of the project would be less than zero, at $1 million (2005$) capital cost less diesel capital cost savings of $1.49 million (2005$).

system (assuming commitment of Aishihik 3rd turbine and Marsh Lake Fall/Winter Storage) with a Mirrlees Life Extension project are substantially below all other alternatives (this remains true even with the higher Mirrlees Life Extension cost set out in the Supplemental Filing Tab 1 of $6.4 million compared to the estimated $3.0 to $4.5 million set out in the original Resource Plan). Given that none of the scenarios alter YEC's expected dispatch to supply WAF loads with hydro or diesel and consequently are almost neutral with respect to operating costs, the only point of comparison for business case analysis is related to total capital costs required to service the peak loads, as shown in the final column of that table.

d. Since the closure of the Faro mine, there has been two impacts on the capacity of the system that were previously available to service that load. First, as noted at page 2-17, the Faro diesel plant has been reduced by 8.3 MW due to retirements (5.0 MW), relocations (2.0 MW) and conversion of one unit to a mobile unit (1.3 MW). In addition, the Mirrlees units at Whitehorse have been temporarily de-rated by 2.6 MW until such time as they undergo life extension or are retired.

   The other factor over the period has been non-industrial load growth which has increased the requirement for capacity compared to non-industrial loads when the Faro mine was operating.

YUB-YEC-1-10(c) Table A - Lifetime Economic Analysis of Marsh Lake Fall/Winter Storage - (65 years) - IRR based on cash flows ($000s)
IGNORES CAPACITY BENEFITS of 1.6 MW [equals approximately $1.49 million (2005$) at $0.93 million/MW for new diesel]
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	total litres saved (000s)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	177	45	(132)	3.48	38	38	26	2	not assessed	28	1,040	5	1,046	1,018
2008	-	-	-	3.9	-	279	125	(154)	3.48	44	44	31	3	not assessed	33	-	5	5	(28)
2009	-	-	-	3.9	-	399	221	(177)	3.48	51	51	36	3	not assessed	39	-	5	5	(33)
2010	-	-	-	3.9	-	547	333	(215)	3.48	62	62	44	4	not assessed	48	-	6	6	(43)
2011	-	-	-	3.9	-	741	466	(275)	3.48	79	79	58	5	not assessed	63	-	6	6	(57)
2012	-	-	-	3.9	-	999	635	(365)	3.48	105	105	78	7	not assessed	85	-	6	6	(79)
2013	-	-	-	3.9	-	1,341	858	(483)	3.48	139	139	106	9	not assessed	115	-	6	6	(109)
2014	-	-	-	3.9	-	1,786	1,155	(631)	3.48	181	181	141	12	not assessed	153	-	6	6	(147)
2015	-	-	-	3.9	-	2,352	1,546	(806)	3.48	232	232	184	16	not assessed	199	-	6	6	(193)
2016	-	-	-	3.9	-	3,055	2,051	(1,004)	3.48	288	288	233	20	not assessed	253	-	6	6	(247)
2017	-	-	-	3.9	-	3,909	2,687	(1,222)	3.48	351	351	289	25	not assessed	314	-	6	6	(308)
2018	-	-	-	3.9	-	4,926	3,471	(1,455)	3.48	418	418	352	30	not assessed	382	-	6	6	(375)
2019	-	-	-	3.9	-	6,116	4,415	(1,702)	3.48	489	489	419	36	not assessed	455	-	7	7	(449)
2020	-	-	-	3.9	-	7,488	5,531	(1,957)	3.48	562	562	492	42	not assessed	534	-	7	7	(527)
2021	722	-	(722)	3.9	185	8,327	6,829	(1,497)	3.48	430	616	549	49	0	598	-	7	7	(591)
2022	7,299	-	(7,299)	3.9	1,872	3,506	8,318	4,811	3.48	(1,383)	489	445	56	0	501	-	7	7	(494)
2023	13,997	6,297	(7,700)	3.9	1,974	-	3,706	3,706	3.48	(1,065)	909	844	91	0	935	-	7	7	(928)
2024	20,819	13,119	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	1,870	179	0	2,049	-	7	7	(2,042)
2025	27,768	20,068	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	1,907	183	0	2,090	-	7	7	(2,083)
2026	34,845	27,145	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	1,945	187	0	2,132	-	8	8	(2,124)
2027	42,053	34,353	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	1,984	190	0	2,174	-	8	8	(2,167)
2028	49,394	41,694	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,024	194	0	2,218	-	8	8	(2,210)
2029	56,871	49,171	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,064	198	0	2,262	-	8	8	(2,254)
2030	64,486	56,786	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,105	202	0	2,308	-	8	8	(2,299)
2031	72,242	64,542	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,148	206	0	2,354	-	8	8	(2,345)
2032	80,142	72,442	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,191	210	0	2,401	-	9	9	(2,392)
2033	88,188	80,488	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,234	214	0	2,449	-	9	9	(2,440)
2034	96,383	88,683	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,279	219	0	2,498	-	9	9	(2,489)
2035	104,729	97,029	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,325	223	0	2,548	-	9	9	(2,539)
2036	113,230	105,530	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,371	228	0	2,599	-	9	9	(2,589)
2037	121,888	114,188	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,418	232	0	2,651	-	9	9	(2,641)
2038	130,706	123,006	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,467	237	0	2,704	-	10	10	(2,694)
2039	139,687	131,987	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,516	242	0	2,758	-	10	10	(2,748)
2040	148,835	141,135	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,567	246	0	2,813	-	10	10	(2,803)
2041	158,151	150,451	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,618	251	0	2,869	-	10	10	(2,859)
2042	167,640	159,940	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,670	256	0	2,927	-	10	10	(2,916)
2043	177,305	169,605	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,724	261	0	2,985	-	11	11	(2,974)
2044	187,148	179,448	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,778	267	0	3,045	-	11	11	(3,034)
2045	197,174	189,474	(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,834	272	0	3,106	-	11	11	(3,095)
2046			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,890	277	0	3,168	-	11	11	(3,157)
2047			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	2,948	283	0	3,231	-	11	11	(3,220)
2048			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,007	289	0	3,296	-	12	12	(3,284)
2049			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,067	294	0	3,362	-	12	12	(3,350)
2050			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,129	300	0	3,429	-	12	12	(3,417)
2051			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,191	306	0	3,498	-	12	12	(3,485)
2052			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,255	312	0	3,567	-	13	13	(3,555)
2053			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,320	319	0	3,639	-	13	13	(3,626)
2054			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,386	325	0	3,712	-	13	13	(3,698)
2055			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,454	332	0	3,786	-	13	13	(3,772)
2056			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,523	338	0	3,862	-	14	14	(3,848)
2057			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,594	345	0	3,939	-	14	14	(3,925)
2058			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,666	352	0	4,018	-	14	14	(4,003)
2059			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,739	359	0	4,098	-	15	15	(4,083)
2060			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,814	366	0	4,180	-	15	15	(4,165)
2061			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,890	373	0	4,263	-	15	15	(4,248)
2062			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	3,968	381	0	4,349	-	15	15	(4,333)
2063			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,047	389	0	4,436	-	16	16	(4,420)
2064			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,128	396	0	4,524	-	16	16	(4,508)
2065			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,211	404	0	4,615	-	16	16	(4,598)
2066			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,295	412	0	4,707	-	17	17	(4,690)
2067			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,381	421	0	4,801	-	17	17	(4,784)
2068			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,468	429	0	4,897	-	17	17	(4,880)
2069			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,558	438	0	4,995	-	18	18	(4,978)
2070			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,649	446	0	5,095	-	18	18	(5,077)
2071			(7,700)	3.9	1,974	-	-	-	3.48	-	1,974	4,742	455	0	5,197	-	18	18	(5,179)
PV (2005)	7.52%											10,074	961		11,035	900	85	985	(10,050)
																Internal Rate of Return			**21.55%**

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YUB-YEC-1-10(c) Table B - Marsh Lake Fall/Winter Storage Economics (65 years) - NPV based on annual impacts on ratepayers ($000s)
IGNORES CAPACITY BENEFITS of 1.6 MW [equals approximately $1.49 million (2005$) at $0.93 million/MW for new diesel]
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (000s)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	38	26	2	not assessed	28	16	78	5	99	71
2008	44	31	3	not assessed	33	16	76	5	98	65
2009	51	36	3	not assessed	39	16	75	5	97	58
2010	62	44	4	not assessed	48	16	74	6	96	48
2011	79	58	5	not assessed	63	16	73	6	94	32
2012	105	78	7	not assessed	85	16	72	6	93	8
2013	139	106	9	not assessed	115	16	70	6	92	(23)
2014	181	141	12	not assessed	153	16	69	6	91	(62)
2015	232	184	16	not assessed	199	16	68	6	90	(109)
2016	288	233	20	not assessed	253	16	67	6	89	(164)
2017	351	289	25	not assessed	314	16	66	6	88	(226)
2018	418	352	30	not assessed	382	16	64	6	87	(295)
2019	489	419	36	not assessed	455	16	63	7	86	(370)
2020	562	492	42	not assessed	534	16	62	7	85	(449)
2021	616	549	49	0	598	16	61	7	84	(514)
2022	489	445	56	0	501	16	60	7	83	(418)
2023	909	844	91	0	935	16	58	7	82	(854)
2024	1,974	1,870	179	0	2,049	16	57	7	80	(1,969)
2025	1,974	1,907	183	0	2,090	16	56	7	79	(2,011)
2026	1,974	1,945	187	0	2,132	16	55	8	78	(2,053)
2027	1,974	1,984	190	0	2,174	16	54	8	77	(2,097)
2028	1,974	2,024	194	0	2,218	16	52	8	76	(2,142)
2029	1,974	2,064	198	0	2,262	16	51	8	75	(2,187)
2030	1,974	2,105	202	0	2,308	16	50	8	74	(2,233)
2031	1,974	2,148	206	0	2,354	16	49	8	73	(2,281)
2032	1,974	2,191	210	0	2,401	16	48	9	72	(2,329)
2033	1,974	2,234	214	0	2,449	16	46	9	71	(2,378)
2034	1,974	2,279	219	0	2,498	16	45	9	70	(2,428)
2035	1,974	2,325	223	0	2,548	16	44	9	69	(2,479)
2036	1,974	2,371	228	0	2,599	16	43	9	68	(2,531)
2037	1,974	2,418	232	0	2,651	16	42	9	67	(2,584)
2038	1,974	2,467	237	0	2,704	16	40	10	66	(2,638)
2039	1,974	2,516	242	0	2,758	16	39	10	65	(2,693)
2040	1,974	2,567	246	0	2,813	16	38	10	64	(2,749)
2041	1,974	2,618	251	0	2,869	16	37	10	63	(2,806)
2042	1,974	2,670	256	0	2,927	16	36	10	62	(2,865)
2043	1,974	2,724	261	0	2,985	16	34	11	61	(2,924)
2044	1,974	2,778	267	0	3,045	16	33	11	60	(2,985)
2045	1,974	2,834	272	0	3,106	16	32	11	59	(3,047)
2046	1,974	2,890	277	0	3,168	16	31	11	58	(3,110)
2047	1,974	2,948	283	0	3,231	16	29	11	57	(3,174)
2048	1,974	3,007	289	0	3,296	16	28	12	56	(3,240)
2049	1,974	3,067	294	0	3,362	16	27	12	55	(3,307)
2050	1,974	3,129	300	0	3,429	16	26	12	54	(3,375)
2051	1,974	3,191	306	0	3,498	16	25	12	53	(3,444)
2052	1,974	3,255	312	0	3,567	16	23	13	52	(3,515)
2053	1,974	3,320	319	0	3,639	16	22	13	51	(3,588)
2054	1,974	3,386	325	0	3,712	16	21	13	50	(3,661)
2055	1,974	3,454	332	0	3,786	16	20	13	49	(3,736)
2056	1,974	3,523	338	0	3,862	16	19	14	48	(3,813)
2057	1,974	3,594	345	0	3,939	16	17	14	47	(3,891)
2058	1,974	3,666	352	0	4,018	16	16	14	47	(3,971)
2059	1,974	3,739	359	0	4,098	16	15	15	46	(4,052)
2060	1,974	3,814	366	0	4,180	16	14	15	45	(4,135)
2061	1,974	3,890	373	0	4,263	16	13	15	44	(4,220)
2062	1,974	3,968	381	0	4,349	16	11	15	43	(4,306)
2063	1,974	4,047	389	0	4,436	16	10	16	42	(4,394)
2064	1,974	4,128	396	0	4,524	16	9	16	41	(4,483)
2065	1,974	4,211	404	0	4,615	16	8	16	40	(4,575)
2066	1,974	4,295	412	0	4,707	16	7	17	39	(4,668)
2067	1,974	4,381	421	0	4,801	16	5	17	38	(4,763)
2068	1,974	4,468	429	0	4,897	16	4	17	38	(4,860)
2069	1,974	4,558	438	0	4,995	16	3	18	37	(4,959)
2070	1,974	4,649	446	0	5,095	16	2	18	36	(5,059)
2071	1,974	4,742	455	0	5,197	16	1	18	35	(5,162)
PV (2005)		10,074	961		11,035	196	764	85	1,045	(9,990)
7.52%							**20 year NPV (2006-2025)**			**(1,934)**

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REFERENCE:

QUESTION:

For all the near-term projects to reinforce the power system, please provide the summary of the following cost estimations (in Excel electronic spreadsheet format) and associated details of the respective calculations for each year from the beginning to the completion of the projects:

a. Annual additional capital expenditure and the present value of the total expenditure.

b. Annual fuel cost for new generation.

c. Annual additional operation and maintenance expenses.

d. Annual additional revenue requirement and its calculation.

e. Peak transmission system losses in MW and levelized annual transmission losses in MWh and their calculation.

f. Please explain how the $3-million threshold was determined for YUB review of YEC projects.

ANSWER:

a. to e.:

The requested information is summarized in the table below:

	Marsh Lake Storage	Aishihik 3rd Turbine	Carmacks-Stewart T-line	Mirrlees Life Extension
a. annual additional capital expenditure	The only planned capital costs associated with the Marsh project is the original costs to licence and implement the project, estimated at $1 million (2005$). This capital would be expected to be depreciated as a hydro asset over about 65 years.	The only planned capital expenditure associated with the Aishihik 3rd Turbine project is the original capital cost ($7.155 million in 2005$ per page S3-1). This capital would be expected to be depreciated as a hydro asset over approximately 65 years	The cost of this project is estimated at $31.2 million (2005$ per page S2-13). No annual additional capital expenditures are expected. The original capital cost would be expected to be depreciated similar to other YEC transmission assets over approximately 50 years.	The cost of this project is estimated in the Supplemental Filing materials at $6.4 million (2005$, although this includes $1.6 million in "common" diesel plant spending and $4.9 million in spending specific to the Mirrlees units). No other capital spending is expected to be associated with this project. The capital investment is expected to be depreciated consistent with YEC's diesel assets, over approximately 30 years.
b. annual fuel cost for new generation	No added annual fuel cost is expected as a result of this project. For annual fuel cost savings, see YUB-YEC-1-10(c).	No added annual fuel cost is expected as a result of this project. For annual fuel cost savings, see Appendix C of the Resource Plan.	No added annual fuel cost is expected as a result of this project. For annual fuel cost savings, see YUB-YEC-1-14.	No added annual fuel cost is expected as a result of this project, as no change in system operations are expected (the same peaking diesel requirements arise with this project versus the Diesel Replacement/Expansion Project).

	Marsh Lake Storage	Aishihik 3rd Turbine	Carmacks-Stewart T-line	Mirrlees Life Extension
c. annual additional operating and maintenance costs	At this time, there are no material additional annual O&M costs expected to be associated with the project. Yukon Energy assumes a standard 0.5 cents/kW.h variable cost of hydro generation for planning purposes.	As a normal planning estimate, Yukon Energy estimates the annual O&M costs at approximately 1% of the total capital cost ($0.07 million per year, 2005$)	The level of annual O&M spending is expected to be small. This has been estimated at $0.1 million/year (2005$), which is consistent with or above the level of O&M spending on the Mayo-Dawson line.	The Mirrlees Life Extension project does not inherently drive higher O&M expenses than other options to secure the same amount of diesel capacity. However, as set out at bullet 5 page S1-6, there will be ongoing O&M expenses in excess of that experienced in recent years with respect to the Mirrlees to reflect: 1) Fuel budgets sufficient to ensure proper “exercising” of the units bi-monthly for 4 hour runs at 1/3 load, for a cost of approximately $0.03 million per year in O&M costs[1]. 2) increased inventory levels for parts, estimated at $0.25 million. 3) increased training for YEC staff on the Mirrlees units, to maintain skills and familiarity – no specific estimate of costs. None of these cost estimates is inconsistent with what would be expected were new diesel units installed as an alternative.

[1] The Mirrlees units combined are 14 MW, six four-hour runs per year at one-third load would therefore produce 112 MW.h. At a lower efficiency of start-up runs and fuel prices of approximately $0.65/litre, the total cost is $25,000 in fuel plus lube oil and other incidentals

	Marsh Lake Storage	Aishihik 3rd Turbine	Carmacks-Stewart T-line	Mirrlees Life Extension
d. annual additional revenue req.	The additional revenue requirement impacts and impacts on rate levels is set out in section 4.4.4. Further detail is also available in YUB-YEC-1-10(c) with respect to Marsh Lake and Appendix C of the Resource Plan with respect to the Aishihik 3rd Turbine			
e. peak transmission system losses in MW and levelized annual transmission losses in MW.h and their calculation	The Marsh Lake project enhances output at the existing Whitehorse Rapids GS, so there are no incremental transmission losses associated with the project.	The Aishihik 3rd turbine connects via the existing Aishihik substation to the WAF 138 kV system. Transmission losses on YEC's WAF system (primarily the 138 kV transm) are estimated at 7.7% for energy. There is no relevant measure of peak transmission losses for the 3rd turbine, as it is not included in the N-1 calculation and under the LOLE the system only receives 0.6 MW of net benefits from the project.	Transmission losses associated with the Carmacks-Stewart project have not been assessed in any detail to date, pending further information on design and expected industrial loads (for the purposes of the Resource Plan energy modelling, losses on energy are assumed at about 2.0 GW.h to 2.5 GW.h per year, or about an 8% increase in transmission losses on the two systems combined)	The Mirrlees Life Extension project will drive no new peak or energy transmission losses compared to the existing system.

f. Yukon Energy determined the $3 million threshold based on the distinction between "normal" large capital projects to sustain assets (such as hydro rewinds or dam rehabilitations) that can range from $1 million to $2 million and major new bulk power additions (such as large new diesel units of 4 MW or more) which would exceed this limit.

Yukon Energy also considered the limit of $5 million for a requirement for Capital Project Permits in the Northwest Territories legislation (the *Public Utilities Act*), but determined such a threshold would be too high as it would not result in review of additions of diesel generators in the 4-5 MW range.

REFERENCE:

QUESTION:

In evaluating new generation options to supply future industrial developments, the Resource Plan focuses on energy rather than capacity requirements. (Section 5.3 on page 5-27 of the 20-Year Resource Plan). Would YEC consider extending the planning criteria to include the annualized expected energy not supplied, MWh/yr (EENS) indices for the options being considered taking into consideration constraints of the transmission network? If not, why not?

ANSWER:

An annual EENS standard (conceptually consistent with the LOEE measurement in the Billinton/Karki main report[1]) would not be a preferred capacity planning criteria for Yukon even under the conditions set out in Chapter 5 (with major new industrial loads and increased diesel-on-the-margin on the WAF system). The energy-focused analysis in Chapter 5 reflects economic considerations as the best way to serve energy (kW.h) requirements (from high fixed cost/low variable cost generation such as hydro as compared to high variable cost/low fixed cost generation such as diesel). Nothing in this chapter results in a shift in the factors related to appropriate capacity planning criteria to EENS from the LOLE and N-1 approaches adopted by YEC.

The use of an EENS or LOEE type standard has been adopted in two cases in Canada (Ontario and Saskatchewan as per the survey result provided in the Billinton/Karki report page 7[2]), with only Saskatchewan continuing to use such a standard. As discussed in YUB-YEC-1-6(c), this type of criteria on occasion is used to allow consideration of cost/worth evaluation of capacity additions, but the relatively extensive data required for this type of exercise is not available in Yukon and would be time consuming and expensive to collect.

In contrast, the LOLE and N-1 approaches adopted by Yukon Energy are routinely used in many jurisdictions in Canada (LOLE) and generally throughout North American (N-1, focused on transmission planning). They are also practical to implement and readily

[1] Provided in YUB-YEC-1-1 Attachment 1
[2] The Alberta Energy and Utilities Board accepted a similar index (UPM) to that used by Saskatchewan, prior to deregulation in Alberta.

measured with the data available. As such they are reasonable, appropriate and adequate approaches for planning the system in Yukon today.

REFERENCE: 4.3.1 Aishihik Third Turbine Project

QUESTION:

Please provide the economic analysis and models which reflect the rate impacts of proceeding with this project.

ANSWER:

Aishihik 3rd Turbine economic analysis and models which reflect rate impacts of proceeding with this project are outlined in Appendix C of the Resource Plan. There are six separate conditions each of which has two sets of tables. Each of these six conditions is modeled by year first, based on the IRR of cash flow impacts of the project (each respective Table A) and subsequently looking at the overall ratepayer impacts (each respective Table B).

REFERENCE: 4.3.3 Carmacks-Stewart Transmission Project

QUESTION:

Please provide the economic evaluation and models used to support this project. Assuming no new mine projects, can this project displace or defer any diesel generation?

ANSWER:

There are no detailed economic evaluations or models used in the Resource Plan to support the Carmacks-Stewart project at this time. This is because the project economics were assumed to be heavily dependent on YTG funding, which has not been clarified or confirmed. As reviewed in the Supplemental Materials Tab 2 (page S2-1), the Resource Plan noted that development of this project was subject to provision of Yukon Government funding plus mine customer contributions to ensure that there is no net cost to Yukon Energy or Yukon ratepayers beyond what would be required for any other option to provide required capacity and energy.

Ongoing work as reviewed in the Supplemental Materials Tab 2 indicates that the project economics fundamentally reflect three major components:

- Benefits related to the opportunity to sell basically zero cost hydro power at firm power rates to one or two mining operations (Minto and Carmacks Copper mines), and to displace diesel generation at Pelly Crossing. The present value benefits from displacing diesel generation at Pelly Crossing, however, have been estimated at only about $2.3 million in 2005$ (see page S2-9).
- Costs related to the net capital costs of the project to YEC after all customer contributions (from the mining customers) and YTG funding. There are also expected to be relatively modest operating costs associated with the line.
- Other WAF benefits from (1) displaced diesel as a result of surplus Mayo hydro being available to WAF to help meet peaking loads, and (2) avoided capital costs related to avoided diesel units on WAF due to the contribution toward firm capacity of interconnecting the currently installed Mayo-Dawson generating capacity.

Recent assessments (Supplemental Materials, page S2-13) indicate that if both mines are operating in the second half of 2008 and also enter into final purchase power arrangements with Yukon Energy as described in Supplemental Materials Tab 2, the economics for the full Carmacks Stewart Transmission (CS) Project development from Carmacks to Stewart Crossing (estimated cost of $31.2 million ($2005)) would be as follows (all values in 2005$):

- **Net capital costs** after mine capital cost contributions are estimated at $20.5 million to about $23.4 million, depending on final mine funding commitments.
- **Ratepayer benefits** (estimated present value) in contrast are estimated to exceed net capital costs and be potentially $30.7 million, consisting of:
    - Net operating income earned from supplying the two mine (net of rebates) of $18.4 million;
    - Diesel generation cost savings of $2.3 million from displacing diesel generation at Pelly Crossing; and
    - Capital cost and diesel fuel cost savings of about $10 million from connecting the two grids, assuming no additional new mining loads on the Mayo Dawson grid.

The above picture changes dramatically, however, if only the Minto mine is assumed to be operating with the assumed purchase power arrangements:

- **Net capital costs** after mine capital cost contributions are estimated at $26.5 million
- **Ratepayer benefits** (estimated present value) are reduced to less than about $20 million.

Building only Stage 1 (from Carmacks to Pelly Crossing) would reduce the above net capital costs after mine contributions to about $13.8 million; however, with only the Minto mine being developed, the present value of ratepayer benefits without the grid connection would also be reduced to about $11.3 million.

Various combinations of YTG and Yukon Energy funding options for proceeding with Stage 1 and/or the full CS Project are reviewed in the Supplemental Materials Tab 2 (pages S2-14 and S2-15).

In the event that no further Yukon Government funding commitments can be provided, Yukon Energy would be unlikely to proceed at this time with the full CS Project to connect the two grids and would likely have two options remaining to consider with regard to developing transmission facilities from Carmacks to Pelly Crossing (see Supplemental Materials pages S2-15 and S2-16):

- **Short-term Mine-Focused Option –** Potential for 138 kV transmission from Carmacks to McGregor Creek and 35 kV transmission for the extension beyond McGregor Creek to the Minto Landing area. This option in particular is being considered in the event that only the Minto mine development proceeds.
- **Long-term Infrastructure Option –** Yukon Energy would incur the added costs needed to establish the 138 kV infrastructure as needed for Stage 1 from Carmacks to Pelly Crossing.
    - If only the Minto mine was developed, this added cost (relative to the Mine-Focused Option) would approximate $7.6 million, resulting in total YEC costs of about $13.3 million compared with ratepayer benefits of about $11.3 million.
    - In contrast, if both mines were to be developed, this added cost would approximate $5 million, resulting in overall YEC costs ranging between $7.3 million and $10.6 million compared with ratepayer benefits of about $20.7 million.

REFERENCE: 4.3.4 Mirrlees Life Extension Project

QUESTION:

a. If the Carmacks-Stewart Transmission project proceeds, is the Mirrlees Life Extension Project necessary?
b. If YECL's Fish Lake Unit is expanded, would that alleviate the need to expand at Mirrlees?
c. Please provide runtime hours for each unit at Mirrlees on an annual basis from 1998 to 2005 inclusive. On an annual basis, how often were the units operating concurrently?
d. Please provide the economic analysis and electronic models for the Mirrlees Expansion Project.

ANSWER:

a. Yes, assuming load conditions likely to be associated with Carmacks Stewart Transmission Project commitment, i.e., Base Case with Mines. Also see YUB-YEC-1-10 (b) in respect of solely Base Case loads (if no mines are developed).

   Both projects (plus others, including Marsh Lake Fall/Winter Storage and potentially further new diesel additions) are required to meet the capacity requirements under Base Case with Mines and High Sensitivity load conditions (see YUB-YEC-1-10(b)).

   The Resource Plan also notes, even if the full scale of capacity is not required (e.g., if loads were lower or the capacity planning target were reduced), the Mirrlees Life Extension project is a cost-effective way of maintaining 14 MW of useful capacity on the system and (as noted in YUB-YEC-1-6(e) and on page 4-39 (footnote 20) of the Resource Plan) the Mirrlees Life Extension project should be carefully considered on this basis alone.

b. No. The Fish Lake hydro plant is very small, and YEC is not aware of any opportunity for expansion. There is a potential for a third hydro plant downstream on McIntyre Creek (as proposed by YECL and reviewed by the YUB in 1992). However, this project is not currently planned to be put into service as YEC understands it is subject to outstanding issues related to First Nations and is very small (0.62 MW).

c. Attached (YUB-YEC-1-15 Attachment 15c) are the runtimes for each unit at Mirrlees on an annual basis from 1999 to 2005 inclusive (data for 1998 is not readily available). Yukon Energy cannot easily determine if units were operated concurrently prior to 2005. In 2005 the units were not operated concurrently. So far in 2006, the Whitehorse Mirrlees WD1, WD2, and WD3 have been operated concurrently for 5 hours and WD2 and WD3 for 11 additional hours, all to service the January 29, 2006 outage. The following is a list of the dates and hours of their concurrent operation:

1/29/2006 @ 20:00 - WD1/WD2/WD3
1/29/2006 @ 21:00 - WD1/WD2/WD3
1/29/2006 @ 22:00 - WD1/WD2/WD3
1/29/2006 @ 23:00 - WD1/WD2/WD3
1/29/2006 @ 0:00 - WD1/WD2/WD3

1/30/2006 @ 1:00 - WD2/WD3
1/30/2006 @ 2:00 - WD2/WD3
1/30/2006 @ 3:00 - WD2/WD3
1/30/2006 @ 4:00 - WD2/WD3
1/30/2006 @ 5:00 - WD2/WD3
1/30/2006 @ 6:00 - WD2/WD3
1/30/2006 @ 7:00 - WD2/WD3
1/30/2006 @ 8:00 - WD2/WD3
1/30/2006 @ 9:00 - WD2/WD3
1//30/2006 @ 19:00 - WD2/WD3
1//30/2006 @ 20:00 - WD2/WD3

d. See YUB-YEC-1-10(c). There are otherwise no specific economic models produced or needed to address the economics of the Mirrlees Life Extension project.

	2005		2004		2003		2002	
	Operating Factor	# of Hours Operating	Operating Factor	# of Hours Operating	Operating Factor	# of Hours Operating	Operating Factor	# of Hours Operating
WD1	0.0006	5.26	0.0009	7.91	0.0005	4.38	0.0037	32.41
WD2	0.0001	0.88	0.0005	4.39	0.0007	6.13	0.0025	21.90
WD3	0.0000	0.00	0.0006	5.27	0.0001	0.88	0.0018	15.77

	2001		2000		1999	
	Operating Factor	# of Hours Operating	Operating Factor	# of Hours Operating	Operating Factor	# of Hours Operating
WD1	0.0015	13.14	0.0009	7.91	0.0489	429.54
WD2	0.0009	7.88	0.0000	0.00	0.0283	248.59
WD3	0.0168	147.17	0.0000	0.00	0.0269	236.29

Note: In 2005, the units were not run concurrently. However, Yukon Energy cannot determine if units were operated concurrently prior to 2005.
Operating hours for 1998 cannot be located.

REFERENCE: 4.3.5 Whitehorse Diesel Replacement and Expansion Project

QUESTION:

Please provide the economic analysis for the above noted project including details on the assessment of the impact on rates to end-use customers.

ANSWER:

Yukon Energy's economic assessment of the Whitehorse Diesel Replacement and Expansion Project is effectively the base case for assessing all other projects. The capital spending commitments required are set out in Table S-1 page S1-4 indicating a likely need for $22.5 million (2005$) by 2012 to secure 24 MW of diesel generation (this is somewhat in excess of the shortfalls, but reflects practical sizing requirements of units in the range of 8 MW) or about $0.93 million/MW. Other than this capital component, there are no incremental fuel or O&M aspects to the project compared to other diesel-related options. Fuel savings and other cost changes that arise compared to this option for the recommended projects are set out in each respective project assessment:

- **Major Capacity Projects:** Are compared against the Whitehorse Diesel Replacement/Expansion Project in Table 4.3 focused solely on capital cost comparisons as the key distinction. This is because the Whitehorse Diesel Replacement/Expansion Project does not give rise to materially different O&M costs or generation dispatch than either of the two other major capacity project options (the Mirrlees Life Extension Project or the Aishihik 2nd Transmission Line Project)[1].

[1] The project does not give rise to material operating costs distinct from the major alternative of the Mirrlees Life Extension Project (Yukon Energy uses an assumed $4,400/MW/year (2005$) as fixed operating and maintenance costs for diesel units, and 1.6 cents/kW.h (2005$) as variable O&M costs). To the extent WAF hydro generation is not sufficient to supply the full annual energy on the system (leading to baseload diesel requirements) or the hydro capacity is not sufficient to meet the peak loads without dispatching diesel (leading to peaking diesel requirements), the cost of meeting this energy with the Mirrlees as compared to new diesels is not likely to be materially different (There may be small variances in the efficiency of new units as compared to the Mirrlees units, but under Base Case loads, relatively little diesel is expected to be required in the next 20 years so the cost impact of any efficiency differences is expected to be minimal compared to the capital cost distinction between the Whitehorse Diesel Replacement and Expansion Project and the Mirrlees Life Extension Project.) The project also does not give rise to materially different operating and maintenance costs than the Aishihik 2nd transmission line that would affect the assessment, as in either case operating costs are expected to be relatively insignificant compared to capital costs of the projects.

- **Opportunity Projects and Major Energy Projects:** The Opportunity Projects (Chapter 4 – Aishihik 3rd Turbine, Marsh Lake Fall/Winter Storage, and Carmacks-Stewart Transmission Line) and major energy projects (Chapter 5) are effectively measured against diesel (including the Whitehorse Diesel Replacement and Expansion Project) as the base means of producing energy against which to compare these alternatives. The economic analysis of these projects as alternatives to diesel are set out at Appendix C of the Resource Plan (for Aishihik 3rd Turbine) and YUB-YEC-1-10(c) (for Marsh Lake Fall/Winter Storage); as noted in YUB-YEC-1-14 there is no similar economic model currently in place for the Carmacks-Stewart Transmission Line Project.

The Whitehorse Diesel Replacement and Expansion Project is proposed as a contingency project to secure reliable WAF capacity in the event that the Mirrlees Life Extension Project is not pursued (or potentially other projects that are planned to provide capacity enhancement to the system such as the Marsh Lake Fall/Winter Storage Project or the Carmacks-Stewart Transmission Project are not ultimately pursued). In this regard, the project can be pursued in its entirely (to secure all needed MW by 2012, 18.7 MW under the Base Case Loads) or in part (e.g., only 17.1 MW are required under the Base Case Loads if Marsh Lake Fall/Winter Storage is simultaneously pursued but not Mirrlees Life Extension nor Carmacks-Stewart Transmission Line).

With respect to rate impacts on customers, as noted in Section 4.4.4, annual cost impacts (revenue requirement) of $360,000 are likely to drive approximately 1% increases in customer rates compared to what would be the case without the impact. The Whitehorse Diesel Replacement and Expansion Project under Base Case Loads (assuming Marsh Lake Fall/Winter Storage already in place) is expected to require 17.1 MW by 2012 (ignoring practical realities of sizing limitations), at an estimated cost of $0.93 million/MW (per page S1-4) for a total of $15.9 million[2] (2005$). At an average depreciation of 30 years on diesel assets ($0.53 million), plus first year return at 7.52% ($1.20 million) the average total rate impact of the project (compared to a situation where no such capacity was installed) is about 4.8% at the end-use customer level in the first years of the project (this compares to the estimate in the original Resource Plan of 4.1% to 4.6%, based on the earlier capital cost estimates).

[2] This compares to a range of $13.7 to $15.4 million set out in the Resource Plan at Table 4.3, based on the earlier estimates of $0.8 to $0.9 million per MW.

REFERENCE: 6.2 Role of Public Involvement

QUESTION:

Please explain your consultation process and any issues that arose from that process.

ANSWER:

Yukon Energy's consultation process has included a number of aspects:

- Publishing the entire Resource Plan as well as the Overview document on its website and making them available to interested parties and the public. Copies were also made available for review at Yukon Energy's district offices and at community public libraries throughout Yukon.
- Providing press briefings and a media release to summarize the key aspects of the Resource Plan. The media release also notes contact information should parties be seeking further detail.
- Conducting public meetings in most Yukon communities to explain the plan and solicit feedback from Yukoners
- Providing project specific information (focused at this point on Carmacks-Stewart) via a newsletter (attached) – from May 2006 and a website on project information.

After filing the Resource Plan document with the YUB and providing copies to Interested Parties, Yukon Energy conducted public meetings in Yukon Communities to solicit additional feedback from Yukoners. Yukoners were notified of the meetings based on the ad below that was placed on the company's website and local newspapers:

The meetings concluded with the July 20 session in Tagish. Yukon Energy does not yet have a full summary of the meetings prepared, but plans to produce a full report on the public meetings, attendance and issues by community.

To this point, attendance at the community meetings varied from none at Teslin to over 30 people at the Marsh Lake Fire Hall.

A sample of comments and issues that arose during these public meetings (in no particular order):

- Routing of Carmacks-Stewart transmission project
- Salvage of timber from brushing on Carmacks-Stewart Project
- Local Employment on Carmacks-Stewart project
- High water effects on Marsh Lake
- Potential for upstream storage from Marsh Lake in Southern Lakes region
- Electrical rate impacts from Carmacks-Stewart project and connection of new mining customers
- Impact of Alaska Highway Pipeline
- Consideration of switching from fossil fuel heating use to electric heat in load forecast
- Consideration of climate change in hydrological modeling
- “The plan seems very reasonable”

The Marsh Lake meeting in particular was well attended due to local concern about the Marsh Lake Fall/Winter Storage Project. This is a project to increase the winter capacity and energy available at the Whitehorse Hydro Plant by changing the way Yukon Energy manages Marsh Lake in the fall months. Yukon Energy has yet to prepare an Environment Impact Assessment on the project or seek the necessary licence amendments from its regulator. There was agreement at the Marsh Lake meeting to form a community committee to work with Yukon Energy to identify the impacts and possible solutions to mitigate the impacts of keeping lake levels higher primarily during the months of October and November each year.

Attached to this response are the following documents:

- The press release issued by Yukon Energy in respect of the Resource Plan (YUB-YEC-1-17 Attachment 1)
- A copy of the presentations and materials used at the Public Meetings (YUB-YEC-1-17 Attachment 2A and 2B)
- A copy of the May 2006 Carmacks-Stewart Newsletter (YUB-YEC-1-17 Attachment 3)

Yukon Energy Outlines Plan for Meeting Future Power Needs

Jun 13, 2006

Yukon Energy has filed a 20-year Resource Plan with the Yukon Utilities Board. The plan addresses the Yukon's major electrical generation and transmission needs from 2006 to 2025.

"This plan will guide us in making sound strategic and long-term decisions regarding our assets and infrastructure," Yukon Energy President David Morrison said. "It addresses the capacity and energy needs of Yukoners, particularly those supplied on the territory's Whitehorse Aishihik Faro grid and the Mayo Dawson grid."

The Resource Plan provides background information on the Yukon's power systems and gives an overview of what Yukon Energy expects its near-term and longer-term requirements will be, taking into account a number of industrial development scenarios. It also sets out some new capacity planning criteria recently adopted by Yukon Energy to better protect customers from outages.

Four near term projects are proposed in the Resource Plan. These projects include installing a third hydro turbine at Aishihik, building a transmission line from Carmacks to Stewart to connect Yukon Energy's two power grids, extending the lives of three diesel units at the Whitehorse Rapids Generating Station, and applying for an amendment to the Whitehorse Rapids water license that would allow the energy company to hold back water in Marsh Lake during the fall. That water would then be used to generate added firm power during the coldest months of winter.

The Resource Plan also proposes activities to enable Yukon Energy to start construction on other projects before 2016 if opportunities arise, to meet the needs of potential new industrial customers, including various potential mines and the Alaska Highway pipeline project. The Resource Plan identifies hydro and coal energy supply options that offer substantial opportunities to produce power over the long term at a cost lower than diesel generation.

"No final decision has been made to implement any of these proposed projects," Morrison said. "We are first seeking input from Yukon Utilities Board and from Yukoners. Prior to the Utilities Board hearing, public meetings will take place to allow individuals and groups to participate in a review of our Resource Plan."

Locations and times of the public meetings will very shortly be advertised in the local media. The Yukon Utilities Board will determine when it will hold a public hearing regarding the Resource Plan.

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Backgrounder

Yukon Energy has filed a 20-year Resource Plan submission with the Yukon Utilities Board (YUB) that addresses our major electrical generation and transmission needs from 2006 to 2025. The last time we submitted a Resource Plan to the YUB was in 1992.

The Resource Plan provides background information on the Yukon's power systems and gives an overview of what we expect our near-term and longer-term requirements will be, taking into account a number of industrial development scenarios as well as new capacity criteria recently adopted by Yukon Energy to better protect customers from outages.

No final decision has been made to implement any of the projects proposed in this plan. We are first seeking review by the Yukon Utilities Board, and input from Yukoners through a series of public meetings.

New Capacity Planning Criteria

Yukon Energy has adopted new capacity planning criteria to better protect customers from outages. The criteria is based on the approach used by other

Canadian utilities today. It requires that we plan our grid systems so that on average we would expect no more than two hours of system outages per year as a result of the amount of generation and related transmission we have installed. It also ensures that even if we lose our system's single largest winter generating or transmission source, we can continue to provide power to residential and commercial customers.

Near Term Requirements

In the short term (the next few years) Yukon Energy is proposing four major projects to meet electrical needs on the Whitehorse-Aishihik-Faro grid to 2012. Together, the following four proposed projects will provide over 21 megawatts of firm winter capacity, and be sufficient to meet likely power needs through to 2012;

Aishihik Third Turbine

This is a proposal that was initially reviewed by the Yukon Utilities Board in 1992. A third turbine can be installed at the existing Aishihik generation station at a cost of about $7 million to reduce future costly diesel generation. Yukon Energy received environmental and Water Board approvals for this project under our new Aishihik Water License. If this project proceeds, we expect the turbine to go into production between late 2009 and 2012, depending on electrical needs and what other initiatives are put in place.

Marsh Lake Fall/Winter Storage License Revision

This proposed project would see an amendment to our Whitehorse Rapids water license by August 2007 that would allow us to hold back up to an additional foot of water in Marsh Lake during the fall (from August 15 to the end of September) in non-flood years. That water would then be used to increase the Whitehorse Rapids hydro facility winter power by 1.6 megawatts. At a capital cost not exceeding $1 million, this project would have no effect on summertime water levels during non-drought years. During flood years, there would also be no change to operations in August and September until after the high water levels have subsided. During drought years, we would alleviate summer drought conditions to ensure the lake reached its regulated full supply capacity level each year.

Carmacks-Stewart Transmission Project

This project would see a transmission line running from Carmacks to Stewart Crossing, connecting Yukon Energy's two power grids. The project will encourage economic development along the corridor and enhance overall system reliability and flexibility. It will enable the Minto mine, the proposed Carmacks Copper mine and the community of Pelly Crossing to have access to hydro power and not need to rely on local diesel generation. The line is forecast to provide the Whitehorse-Aishihik-Faro grid with an additional 5.6 megawatts of firm winter capacity in 2012 at a cost in 2005 dollars of $31.2 million. If the line is built, we are currently planning for it to be in service by mid to late 2008. This project will only go ahead after meaningful consultation occurs with First Nations, review by the Yukon Utilities Board is completed, and all environmental permits are obtained. As well, this project will only proceed if Yukon government infrastructure funding ensures no adverse impact on ratepayers.

Diesel Units Life Extension or Replacement

There are seven diesel generators at our Whitehorse Rapids Generating Station. Our three oldest ones are currently scheduled for retirement between 2007 and 2011. We have confirmed that it is technically feasible to refurbish these units, thus extending their lives by 20 years or more at an expected capital cost of $6.4 million, and work is progressing in a staged manner on this project. Refurbishing these units will provide an added 14 megawatts of winter power on the Whitehorse-Aishihik-Faro grid.

Replacing these three units with new diesel units would likely cost, in 2005 dollars, about $6 million more than the estimated refurbishing capital cost.

Replacing these three units by building a second, back-up, transmission line from Aishihik to Whitehorse would also be more expensive than diesel-related improvements. We would only look at this project if new mines are connected to our Whitehorse-Aishihik-Faro grid without the completion of the Carmacks-Stewart line and without the diesel generators' life extension being completed.

Longer-term Industrial Development Opportunities

The Resource Plan also proposes activities to enable Yukon Energy to start construction on other projects before 2016 if opportunities arise to meet the needs of potential new industrial customers, including various potential mines and the Alaska Highway pipeline project. Hydro supply options are identified that offer substantial opportunities, if required, to produce power over the long term at a cost lower than diesel generation, provided that specific energy supply resource options are properly matched to expected system loads. New energy-focused power development is contingent, however, on sufficient new industrial power loads materializing. Without new industrial power loads, the plan forecasts that surplus hydro energy generation is likely to remain on the Whitehorse Aishihik Faro grid for at least 15 of the next 20 years.

Yukon Energy
20-Year Resource Plan: 2006-2025

Summary and Overview

June, 2006

YUKON ENERGY

Yukon Energy's Current System

June, 2006 2

Planning Criteria

New Planning Criteria – 2 conditions to be met:

1. Loss of Load Expectations ("LOLE") approach similar to other Canadian utilities.
   - Target 2 hours: this requires that on average we would expect no more than 2 hours of system outages per year
   - Other Canadian utilities use 1 to 2 hours
2. Emergency planning criteria will forecast peak winter load under the largest contingency (known as "N-1")
   - Focuses on system capability assuming the loss of the system's single largest generating or transmission-related generation source
   - N-1 criterion will not be extended to major industrial customer loads which typically maintain sufficient on-site diesel for their own emergency purposes

June, 2006 3

Near Term Requirements (2)

Four major projects proposed:

- Aishihik Third Turbine
- Marsh Lake Fall/Winter Storage License Revision
- Carmacks-Stewart Transmission Project
- Diesel Units Life Extension or Replacement

All projects focused on how to make better use of existing assets.

June, 2006 4

Near Term Requirements (3)

Aishihik Third Turbine

- Initially reviewed in 1992 YUB Resource Plan Hearing
- Will provide 7 MW of added peaking capacity and about 5.4 GW.h/yr of long –term average hydro energy supply
- Not "firm" capacity in the planning criteria, but provides economic benefits from offsetting peaking diesel
- Capital cost of about $7.155 million (2005$)
- Yukon Energy received environmental Water Board approvals for this project under our new Aishihik Water License
- If this project proceeds, we expect the turbine to go into production between late 2009 and 2012

June, 2006 5

Near Term Requirements (4)

Marsh Lake Fall/Winter Storage License Revision

- Is an enhancement opportunity
  - increase the firm winter capacity of the Whitehorse Rapids hydro facility by about 1.6 MW
  - increase long term average hydro from this facility by about 7.7 GW.h/yr
  - Capital cost expected to be of no more then $1 million (2005$)
- This project would have no effect on summertime water levels during non-drought years
- During flood years there would be no change until after the high water levels have subsided
- During drought years, would alleviate summer drought conditions to ensure the lake reaches its regulated full supply capacity level each year

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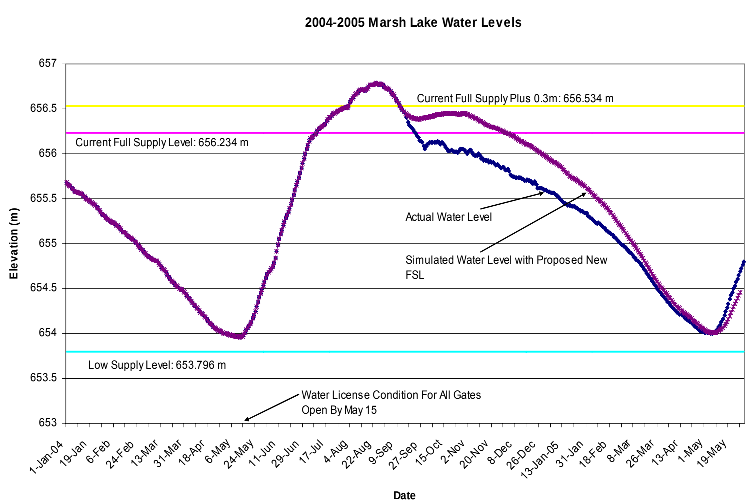
Near Term Requirements (5)

June, 2006 7

Example of Marsh Lake Higher Fall Storage



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Near Term Requirements (6)

Carmacks-Stewart Transmission Project

- Currently considering connecting the Whitehorse-Aishihik-Faro and Mayo/Dawson power grids.
- This would include a new 138 kV transmission line between Carmacks and Stewart Crossing.
- Process currently underway to select a preferred transmission route, including public consultation.
- Currently expected to be developed in two stages:
  - Stage 1 would be from Carmacks to Pelly Crossing and include a spur line between the Minto mine site and the vicinity of Minto Landing (tentative plan to be in service by end of 2008)
  - Stage 2 would be from Pelly Crossing to Stewart Crossing. This would connect the WAF grid to the MD grid (tentative plan to be in-service by the end of 2009)
- This project is expected to cost around $31 million (2005$)

June, 2006 9

Near Term Requirements (7)

Diesel Units Life Extension or Replacement

- 3 of the 7 diesel generators at our Whitehorse Rapids Generating Station are scheduled for retirement between 2007 and 2011
  - We have confirmed that it is technically feasible to refurbish these units, extending their lives by 20 or more years at a capital cost of $6.4 million (2005$)
  - This would provide an added 14 MW of winter power on the WAF grid
- Replacing the 3 units would cost about $6 million more than refurbishing
- Replacing the 3 units with a back-up transmission line from Aishihik to Whitehorse would also be more expensive, about $14 million more than refurbishment of the diesels

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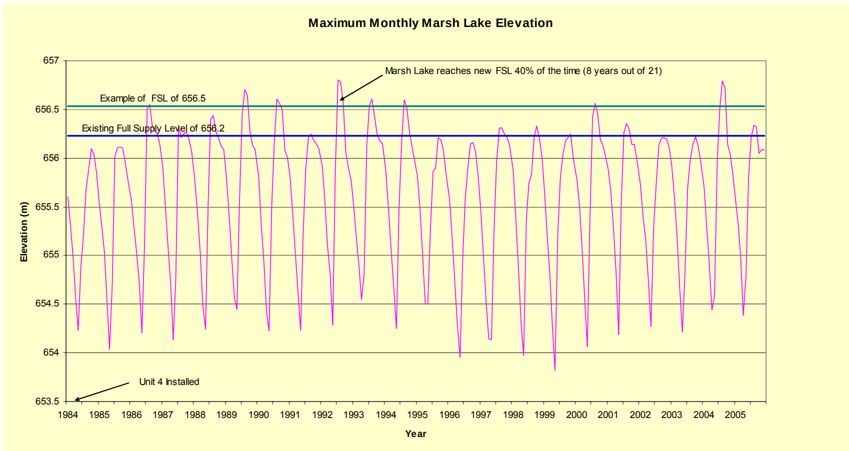
Marsh Lake Historical Lake Elevations



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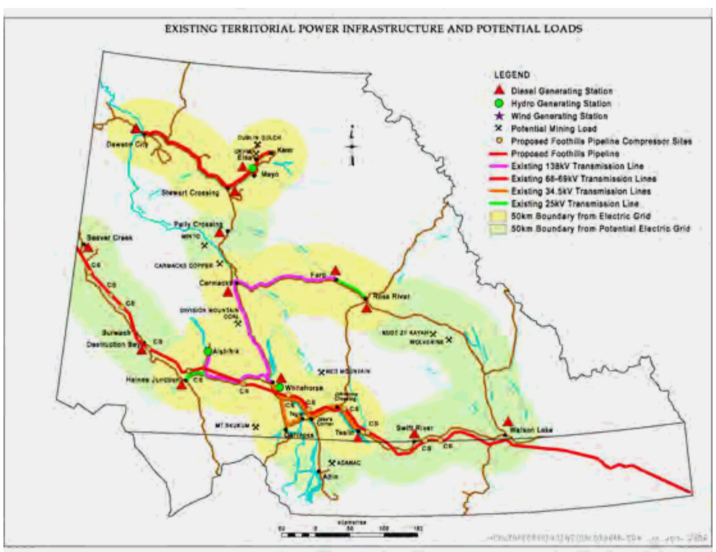
Resource Plan Potential Loads



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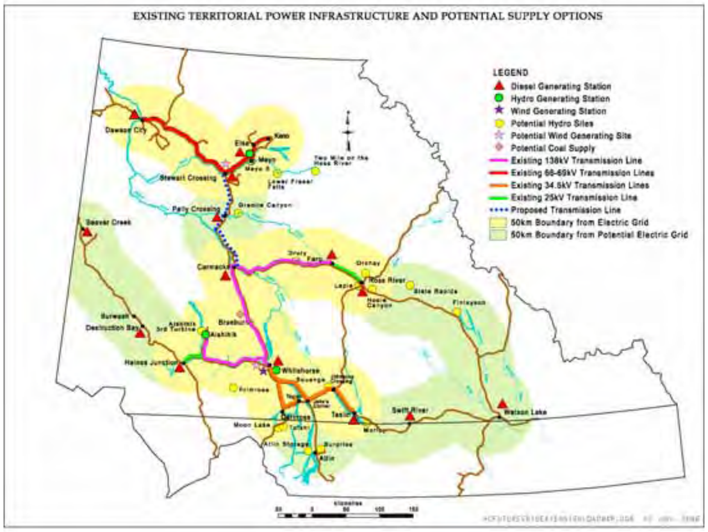
Resource Plan Potential Supply Options



June, 2006 13

Old Electrical System Capability Criteria

Whitehorse-Aisihik-Faro Grid

Unit	Capacity at time of Peak (MW)
Whitehorse Hydro (4 units)	24.0
Whitehorse Diesel Unit 1	3.0
Whitehorse Diesel Unit 2	4.2
Whitehorse Diesel Unit 3	4.2
Whitehorse Diesel Unit 4	2.5
Whitehorse Diesel Unit 5	2.5
Whitehorse Diesel Unit 6	2.7
Whitehorse Diesel Unit 7	3.3
Faro Diesel Unit 3	1.0
Faro Diesel Unit 5	1.3
Faro Diesel Unit 7	3.0
Aishihik Hydro Unit 1	15.0
Aishihik Hydro Unit 2	15.0
Carmacks Diesel (YECL)	1.3
Haines Junction Diesel (YECL)	1.3
Teslin Diesel (YECL)	1.3
Ross River Diesel (YECL)	1.0
Fish Lake Hydro (2 units - YECL)	0.4
TOTAL	***87.0***
Less: Largest Hydro Unit	-15.0
Less: 10% Diesel Capacity	-3.3
Max Allowable Peak Load or Capability	***68.7***

Mayo-Dawson Grid

Unit	Capacity at time of Peak (MW)
Mayo Hydro Unit1	2.6
Mayo Hydro Unit 2	2.8
Mayo Diesel Unit 1	1.0
Mayo Diesel Unit 2	1.0
Dawson Diesel Unit 1	0.8
Dawson Diesel Unit 2	1.0
Dawson Diesel Unit 3	1.0
Dawson Diesel Unit 5	1.5
Stewart Crossing (YECL)	0.4
TOTAL	***12.1***
Less: Largest Hydro Unit	-2.8
Less: 10% Diesel Capacity	N/A
Max Allowable Peak Load or Capability	***9.3***

New Electrical System Capacity Criteria

Whitehorse-Aisihik-Faro Grid

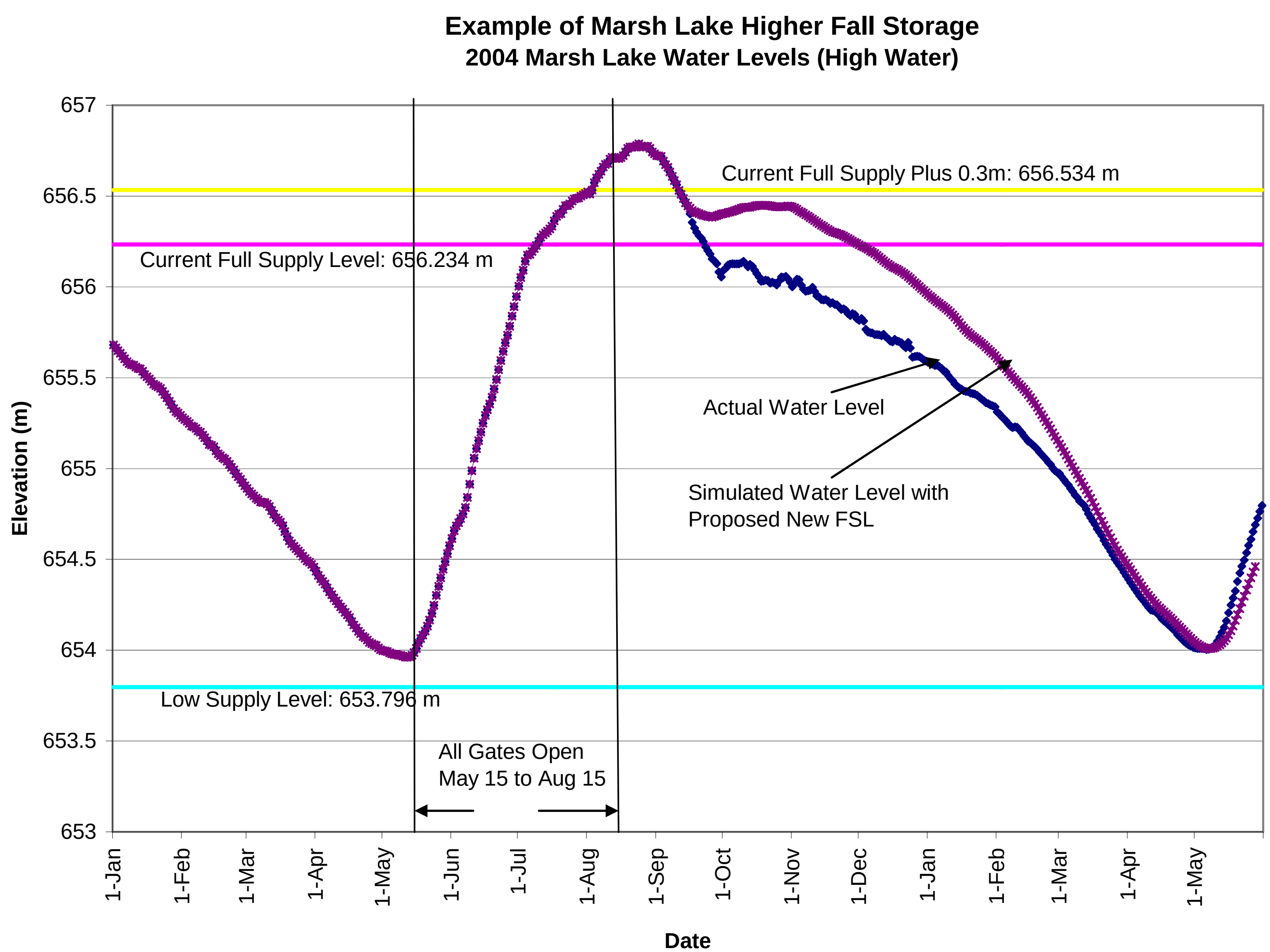
Year	Peak Demand (MW)	Old Criteria Capability (MW)	Surplus/ (Shortfall)	LOLE Capability (MW)	Surplus/ (Shortfall)	N-1* Capability (MW)	Surplus/ (Shortfall)
2005	56.4	68.7	12.3	62.9	6.5	55.7	0.3
2006	57.4	68.7	11.3	62.9	5.5	55.7	(0.7)
2007	58.5	64.9	6.4	58.7	0.2	51.5	(6.0)
2008	59.6	64.9	5.3	58.7	(0.9)	51.5	(7.1)
2009	60.6	61.1	0.5	54.5	(6.1)	47.3	(12.3)
2010	61.7	61.1	(0.6)	54.5	(7.2)	47.3	(13.4)
2011	62.9	58.4	(4.5)	51.5	(11.4)	44.3	(17.6)
2012	64.0	58.4	(5.6)	51.5	(12.5)	44.3	(18.7)

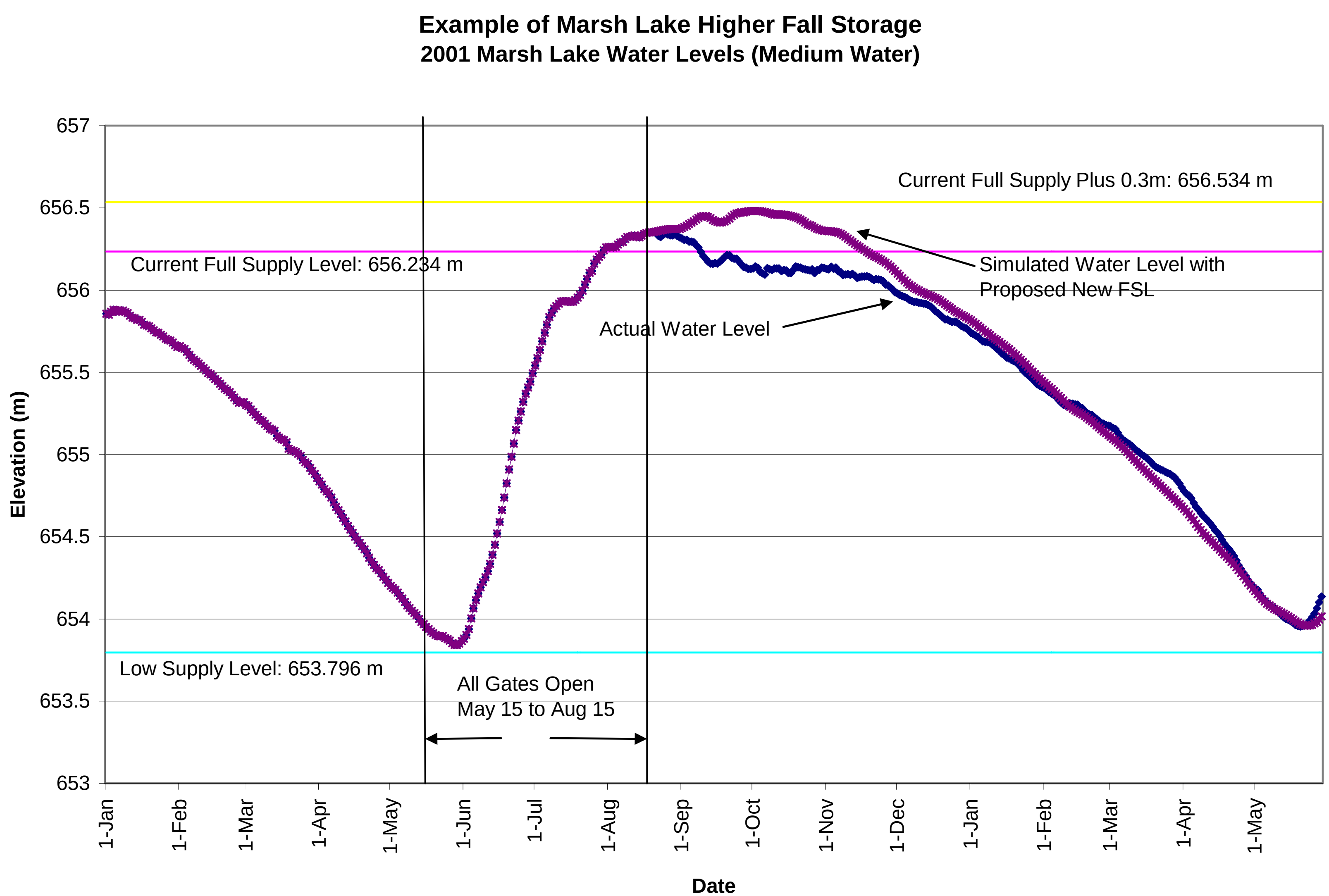
* Note   Peak demand for purposes of N-1 criteria excludes Haines Junction as it would not be affected

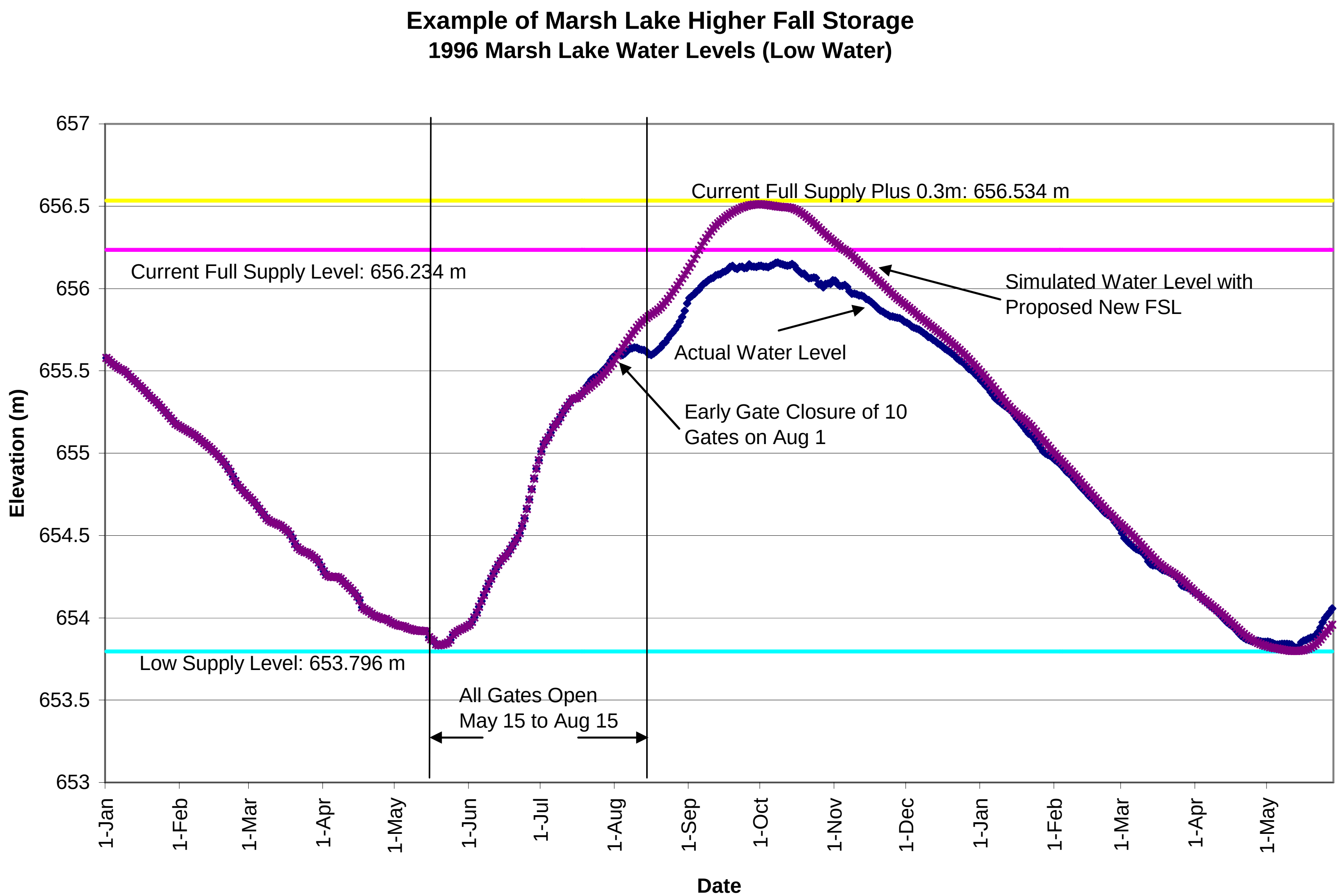
Mayo-Dawson Grid

Year	Peak Demand (MW)	Old Criteria Capability (MW)	Surplus/ (Shortfall)	LOLE Capability (MW)	Surplus/ (Shortfall)	N-1** Capability (MW)	Surplus/ (Shortfall)
2005	4.9	9.3	4.4	N/A	N/A	6.7	1.8
2006	5.2	9.3	4.1	N/A	N/A	6.7	1.5
2007	5.3	9.3	4.0	N/A	N/A	6.7	1.4
2008	5.4	9.3	3.9	N/A	N/A	6.7	1.3
2009	5.5	9.3	3.8	N/A	N/A	6.7	1.2
2010	5.6	9.3	3.7	N/A	N/A	6.7	1.1
2011	5.7	9.3	3.6	N/A	N/A	6.7	1.0
2012	5.8	9.3	3.5	N/A	N/A	6.7	0.9

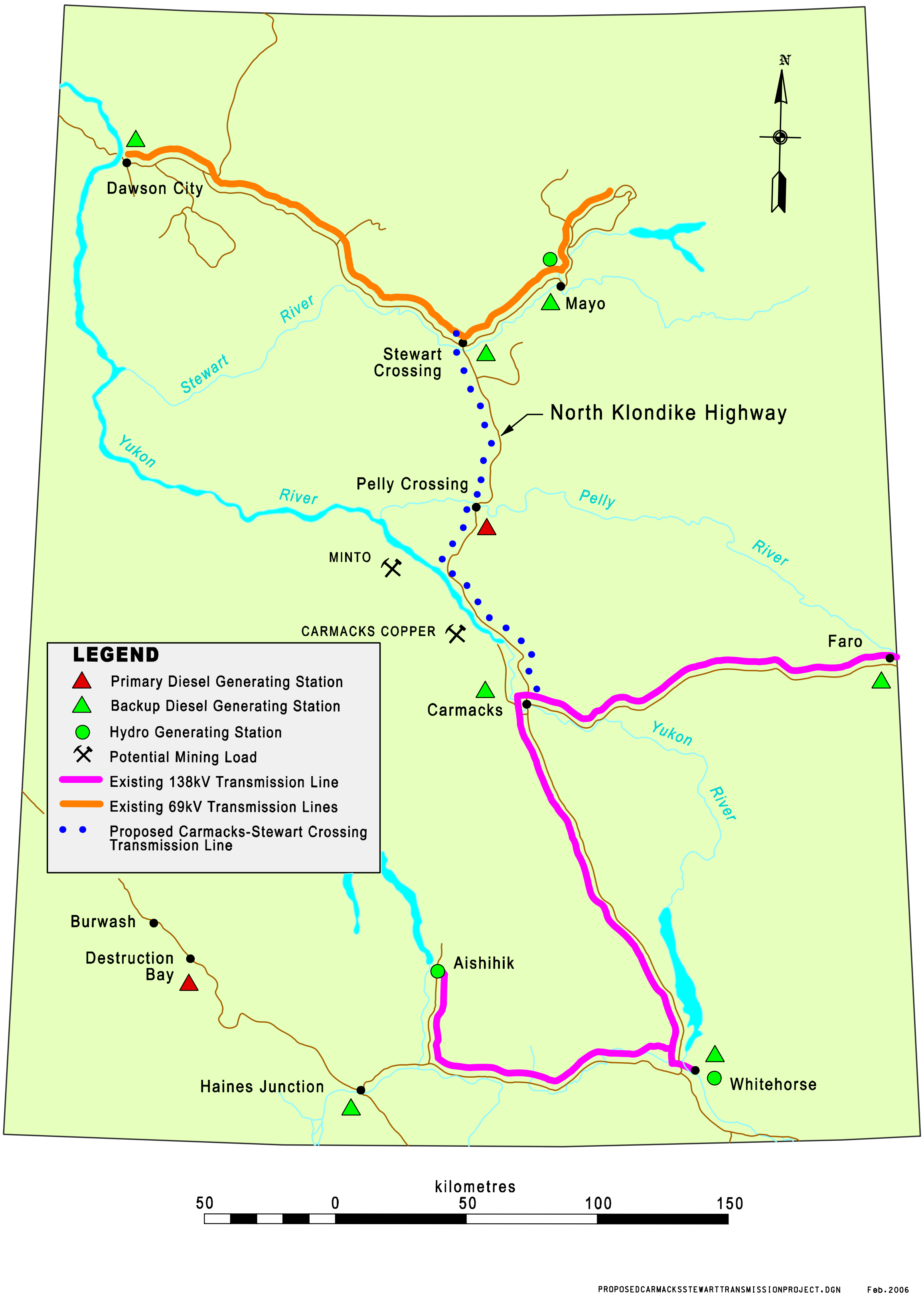
**Note   The N-1 criteria is assumed to be loss of Mayo Hydro generation of 5.4 MW

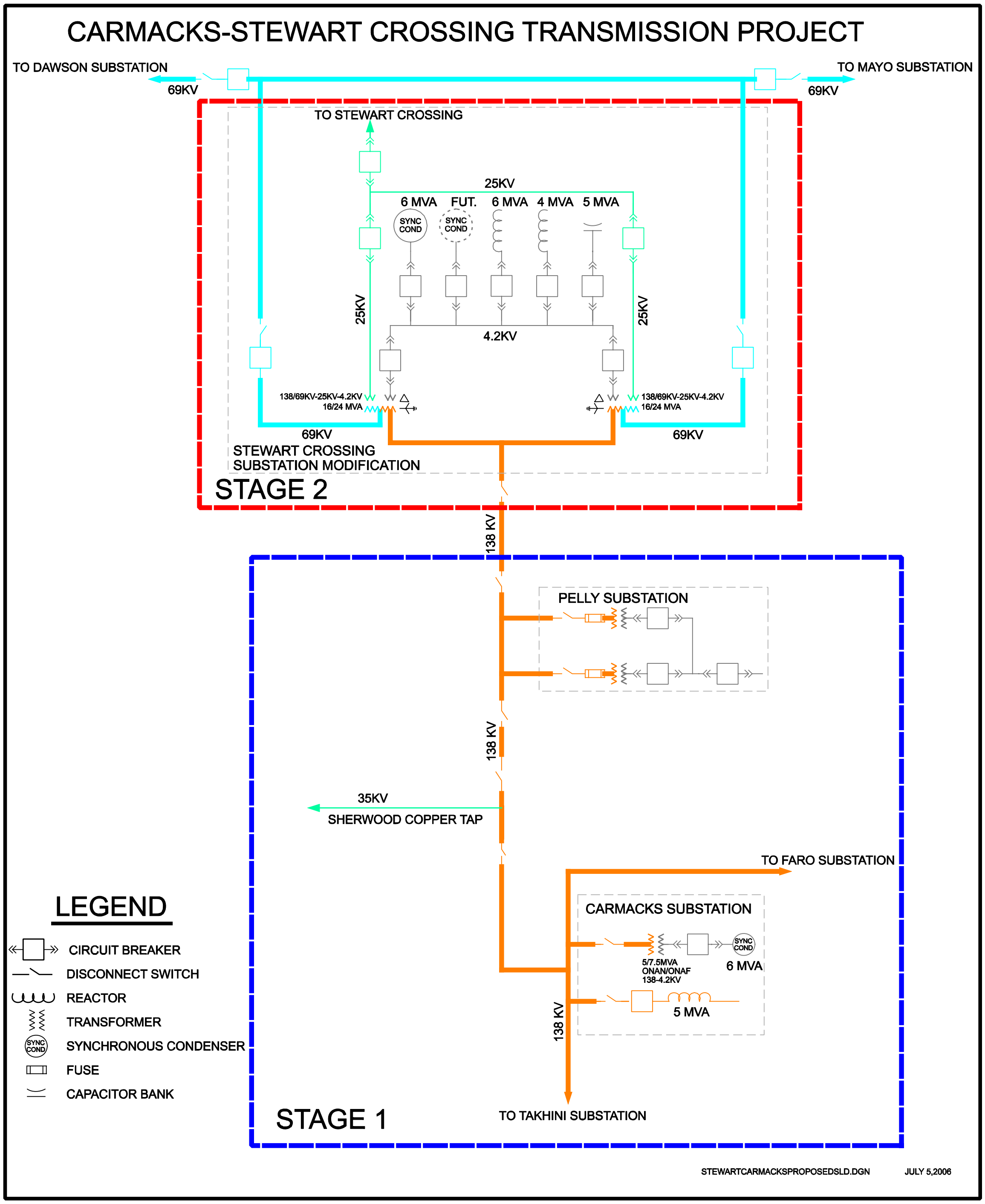

Example of Marsh Lake Higher Fall Storage
2004 Marsh Lake Water Levels (High Water)
657
656.5
656
655.5
655
654.5
654
653.5
653
Elevation (m)
Current Full Supply Plus 0.3m: 656.534 m
Current Full Supply Level: 656.234 m
Actual Water Level
Simulated Water Level with
Proposed New FSL
Low Supply Level: 653.796 m
All Gates Open
May 15 to Aug 15
1-Jan
1-Feb
1-Mar
1-Apr
1-May
1-Jun
1-Jul
1-Aug
1-Sep
1-Oct
1-Nov
1-Dec
1-Jan
1-Feb
1-Mar
1-Apr
1-May
Date


Example of Marsh Lake Higher Fall Storage
2001 Marsh Lake Water Levels (Medium Water)
Current Full Supply Plus 0.3m: 656.534 m
Current Full Supply Level: 656.234 m
Simulated Water Level with Proposed New FSL
Actual Water Level
Low Supply Level: 653.796 m
All Gates Open May 15 to Aug 15
Elevation (m)
657
656.5
656
655.5
655
654.5
654
653.5
653
Date
1-Jan
1-Feb
1-Mar
1-Apr
1-May
1-Jun
1-Jul
1-Aug
1-Sep
1-Oct
1-Nov
1-Dec
1-Jan
1-Feb
1-Mar
1-Apr
1-May

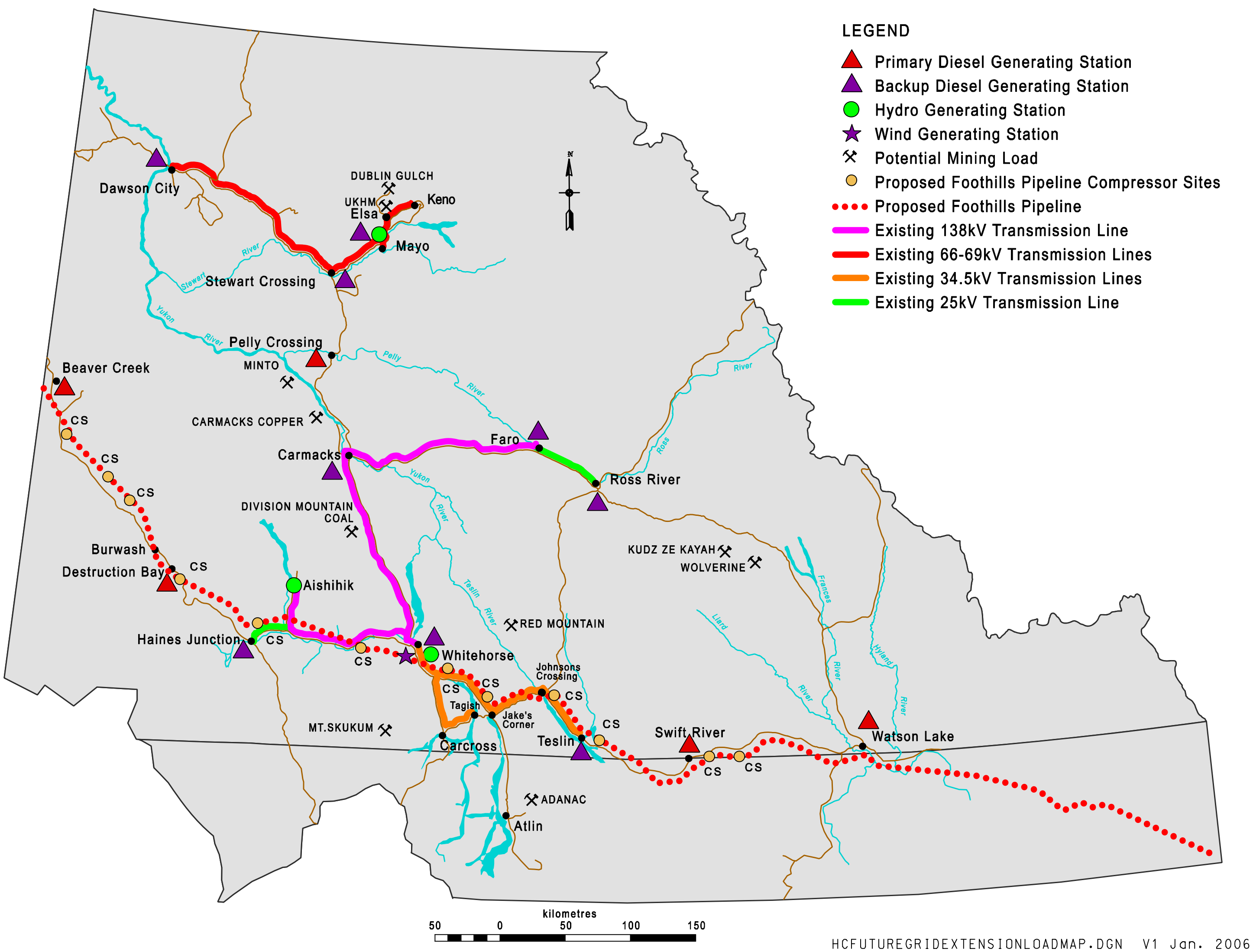

Example of Marsh Lake Higher Fall Storage
1996 Marsh Lake Water Levels (Low Water)
Elevation (m)
657
656.5
656
655.5
655
654.5
654
653.5
653
Current Full Supply Plus 0.3m: 656.534 m
Current Full Supply Level: 656.234 m
Simulated Water Level with
Proposed New FSL
Actual Water Level
Early Gate Closure of 10
Gates on Aug 1
Low Supply Level: 653.796 m
All Gates Open
May 15 to Aug 15
1-Jan
1-Feb
1-Mar
1-Apr
1-May
1-Jun
1-Jul
1-Aug
1-Sep
1-Oct
1-Nov
1-Dec
1-Jan
1-Feb
1-Mar
1-Apr
1-May
Date

PROPOSED CARMACKS TO STEWART CROSSING TRANSMISSION PROJECT



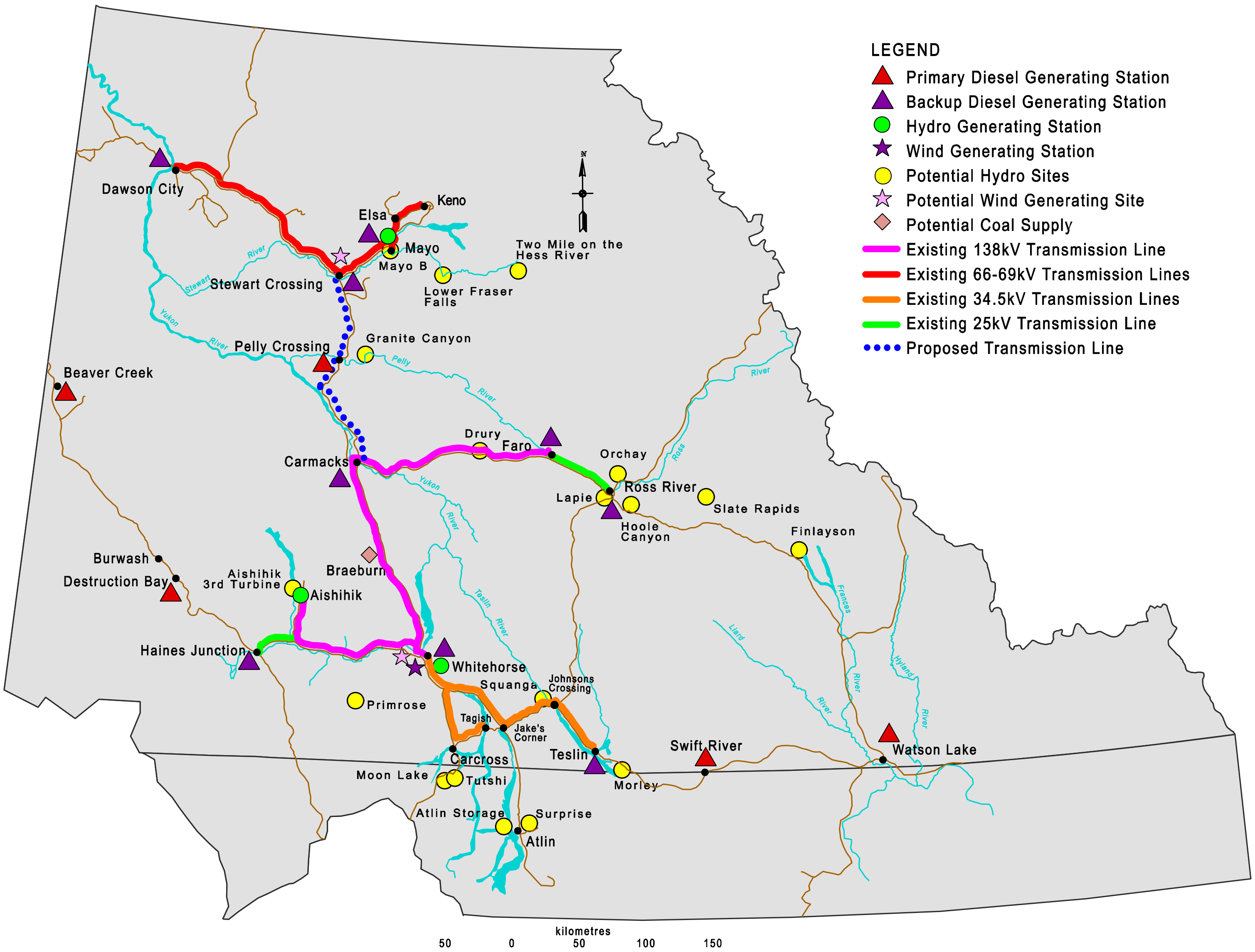

CARMACKS-STEWART CROSSING TRANSMISSION PROJECT
TO DAWSON SUBSTATION
69KV
TO MAYO SUBSTATION
69KV
TO STEWART CROSSING
25KV
6 MVA
FUT.
6 MVA
4 MVA
5 MVA
SYNC COND
SYNC COND
25KV
4.2KV
25KV
138/69KV-25KV-4.2KV
16/24 MVA
138/69KV-25KV-4.2KV
16/24 MVA
69KV
69KV
STEWART CROSSING
SUBSTATION MODIFICATION
STAGE 2
138 KV
PELLY SUBSTATION
138 KV
35KV
SHERWOOD COPPER TAP
TO FARO SUBSTATION
CARMACKS SUBSTATION
5/7.5MVA
ONAN/ONAF
138-4.2KV
6 MVA
5 MVA
138 KV
TO TAKHINI SUBSTATION
STAGE 1
LEGEND
CIRCUIT BREAKER
DISCONNECT SWITCH
REACTOR
TRANSFORMER
SYNCHRONOUS CONDENSER
FUSE
CAPACITOR BANK
STEWARTCARMACKSPROPOSEDSLD.DGN
JULY 5,2006

EXISTING TERRITORIAL POWER INFRASTRUCTURE AND POTENTIAL LOADS



July 21, 2006

EXISTING TERRITORIAL POWER INFRASTRUCTURE AND POTENTIAL SUPPLY OPTIONS



July 21, 2006

May 2006

PROPOSED CARMACKS-STEWART TRANSMISSION PROJECT

YUKON ENERGY

What is involved in the project?

Yukon Energy is considering development of the Carmacks-Stewart Transmission Project to connect the Whitehorse-Aishihik-Faro and Mayo/Dawson power grids. The project would include a new 138 kV transmission line generally along the Klondike Highway as well as new transmission substations at Carmacks and Pelly Crossing, and changes to the substation at Stewart Crossing.

A process is underway to select a preferred transmission route based on various factors including environmental, socio-economic, engineering and cost. Public consultation to identify areas to be avoided and/or used will be a key factor in determining the final route for the 180 kilometre line. A 500 metre wide study area corridor has been identified to guide assessment of route alternatives; however parts of the final route could potentially be sited outside this study area. If the project proceeds, the final right of way for the transmission line would be 60 metres in width (see photo below). Poles will be wood and could be either a single or H frame.

A 138 kV H-Frame transmission pole – Whitehorse-Aishihik-Faro Transmission Line

The 60 metre right of way provides for access, minor realignments of the individual pole structures and line within the right of way during construction, and control of other activities or tree growth that would affect the reliability and safety of the line.

What Regulatory Approvals and Reviews are necessary?

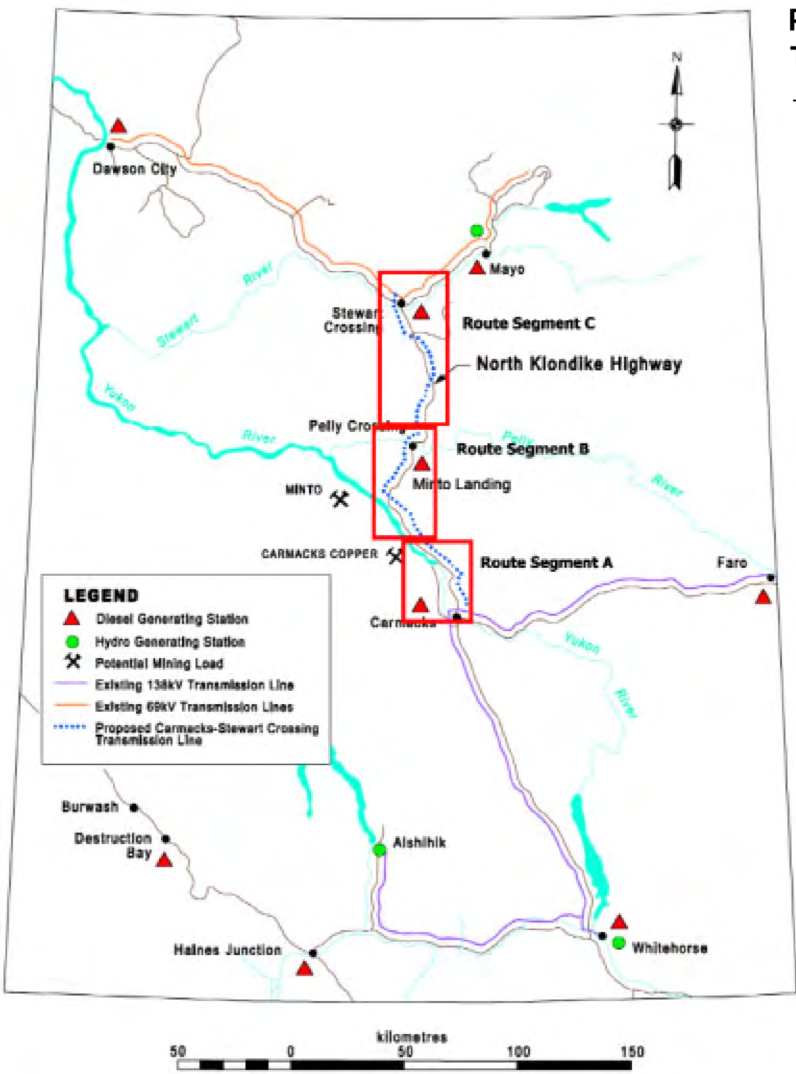
- Regulatory permits/approvals are required for land use, river crossings and other activities.
- Before such permits/approvals can be issued, environmental and socio-economic assessment is required under the Yukon Environmental and Socio-Economic Assessment Act (YESAA).
- An Executive Committee screening assessment of the project will be required by the Yukon Environmental and Socio-Economic Assessment Board (YESAB).
- YESAB's recommendations will be accepted, rejected or varied by decision making bodies within the Yukon government, First Nations with affected settlement lands and the federal government.

What are the benefits?

If developed as currently planned, the project will enable the Minto mine and the proposed Carmacks Copper mine to access surplus grid power rather than rely on diesel generation. This will benefit all Yukon ratepayers, the mines, governments and others. The line will allow Pelly Crossing, a community relying on diesel generation, to have access to hydro power. Connecting the two existing power grids will provide long-term benefits. The project will encourage economic development along the corridor and enhance overall system reliability and flexibility.

Project Overview

No decisions have been made at this time to proceed with the project. Any decision to proceed will occur only after meaningful consultation occurs with the affected First Nations, all environmental and other permits and approvals are obtained, and arrangements are concluded with major mine customers and the Yukon government as required to ensure that Yukon ratepayers are protected against adverse rate impacts.



Proposed Carmacks-Stewart Transmission Project

The Carmacks-Stewart Transmission Project is currently expected to be developed in two stages:

Stage 1: Carmacks to Pelly Crossing, including the Carmacks substation and the Pelly Crossing substation and approximately 108 kilometres of line. Ancillary transmission projects related to this stage are currently anticipated to include:

Minto Mine Spur: A 30 kilometre line at 25 or 35 kV, funded entirely by the mine, connecting the Minto mine currently under development west of the Yukon River with the project in the vicinity of Minto Landing.

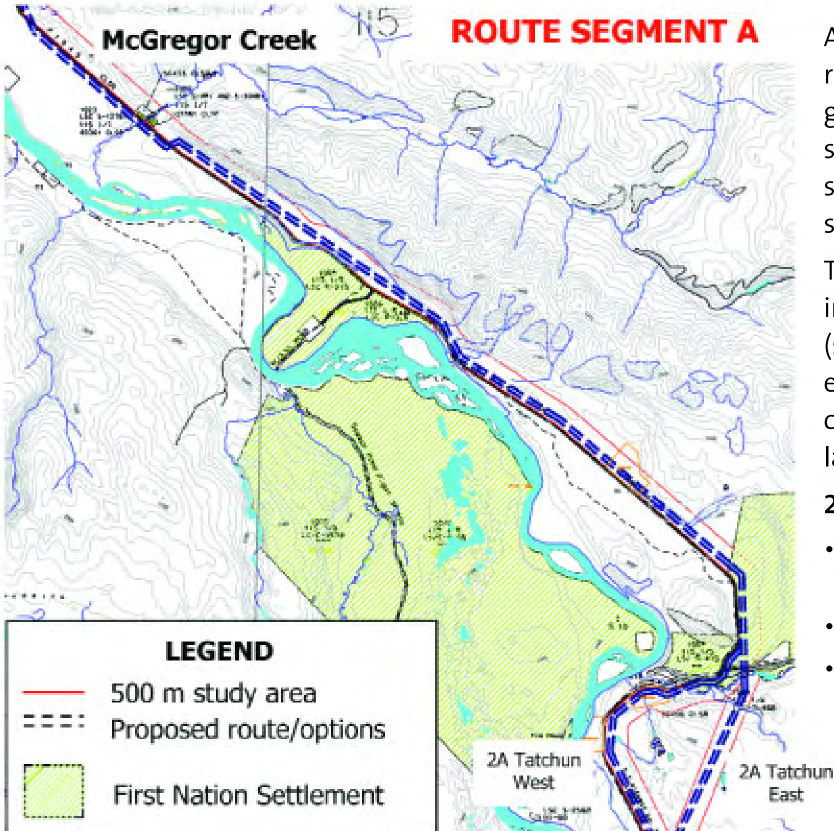
Carmacks Copper Spur: A 11 kilometre line at 138 kV, funded entirely by the mine if it is developed (it is currently in permitting/environmental assessment process), connecting the Carmacks Copper mine site west of the Yukon River with the project in the vicinity of McGregor Creek.

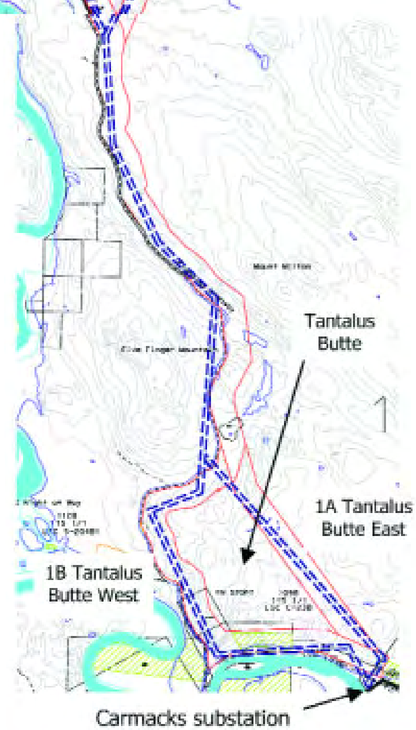
Local distribution facilities: Connections at 25 or 35 kV to local distribution systems at Carmacks and Pelly Crossing will be developed by the local distributor, Yukon Electrical—consideration also to connection to local distribution at Minto Landing.

Stage 2: Pelly Crossing to Stewart Crossing, including changes to the Stewart substation and approximately 72 kilometres of line.

Routing for the project, which generally is expected to follow the Klondike Highway, will in certain areas be adjacent to or cross settlement lands for three Northern Tutchone First Nations (Little Salmon/Carmacks First Nation, Selkirk First Nation, and the First Nation of Nacho Nyak Dun). Yukon Energy has had initial discussions with these First Nations to inform them of the project and inquire as to their respective interests and concerns. A Memorandum of Understanding (MOU) has recently been concluded between Yukon Energy and these three First Nations addressing consultation on route selection, impacts, mitigation, benefits and other matters.

Route Options from Carmacks to McGregor Creek





Yukon Energy has obtained land for a new transmission substation at Carmacks, located north of the Yukon River and adjacent to the Carmacks airport and west of the existing 138 kV transmission line from Carmacks to Ross River.

Two route alternatives have been currently identified moving west from the new Carmacks substation around Tantalus Butte (separate 500 metre study areas identified for each option):

1A: east option at Tantalus Butte

- Route is straighter, shorter and less costly.
- Avoids both privately owned lands and Little Salmon/Carmacks settlement lands.
- Avoids viewpoints of the Yukon River.

1B: highway option at Tantalus Butte

- Route is longer, adjacent to the Klondike Hwy, and more costly.
- Crosses privately owned land as well as Little Salmon/Carmacks settlement land.
- Will likely be aesthetic concerns from people who use the Yukon River.

After Tantalus Butte, the currently identified route to Five Finger Rapids/Tatchun Creek will generally follow the study area along the east side of the Klondike Highway, avoiding or spanning poor drainage locations and any steep slopes.

Two route alternatives have been identified in the Five Finger Rapids/Tatchun Creek area (separate 500 metre study areas identified for each option – each option at its northern end crosses Little Salmon/Carmacks settlement land):

2A: east option at Tatchun Creek

- Avoids prime recreational viewing site of Five Finger Rapids.
- Avoids crossing gravel pits.
- Is east of Tatchun Creek campground, as recommended by the Dept. of Environment.
- Route is straighter, shorter and less costly.

2B: highway option at Tatchun Creek

- Close proximity to Five Finger Rapids and Tatchun Creek Campground.
- Potentially crosses gravel pits.
- Route is longer, adjacent to the Klondike Highway and more costly.

After Tatchun Creek the proposed route to McGregor Creek follows generally the east side of the Klondike Highway to reduce aesthetic impacts and crosses Little Salmon/Carmacks settle-ment land north of the Tatchun Creek area. Shortly before McGregor Creek, the proposed route crosses to the west of the highway to avoid two small Little Salmon/Carmacks First Nation settlement land parcels and to be in an optimum area for any tap connection to the proposed Carmacks Copper Mine.

Route Options from McGregor Creek to Pelly Crossing

North of McGregor Creek, the proposed route soon crosses back to the east side of the Klondike Highway and generally remains there on Crown land until McCabe Creek to minimize impact on views. The proposed route crosses to the west side of the highway about three kilometres prior to McCabe Creek due to very steep slopes squeezing the transmission line right-of-way to overlap the highway right-of-way.

The proposed route must cross Selkirk First Nation settlement lands throughout much of the remaining area from about McCabe Creek until close to Pelly Crossing.

Route and tap/substation location alternatives will be identified in the Minto Landing area in consultation with the Selkirk First Nation and the Minto Mine, taking into consideration:

- Location of additional step-down station (138 kV to lower voltage) for servicing the Minto Mine, and possibly the community of Minto Landing.
- Potential options range between the Minto Landing community area (on Crown land) and the new barge landing site south of Minto Landing (on First Nation settlement land) for road access from the highway to the Minto Mine.

In order to avoid poor drainage, lakes and the Lhutsaw Wetland Protected Habitat on the east side of the highway between Minto Landing and Pelly Crossing, the proposed route north of Minto Landing to Pelly Crossing is generally located on the west side of the Klondike Highway, proceeding north along as straight a line as possible.

Three route options have been identified in the Pelly Crossing area for discussion with the Selkirk First Nation and others. These options typically (particularly Options 3A and 3C) go outside the 500 metre study area along the highway and cross Selkirk First Nation settlement lands.

3A: east option at Pelly Crossing

- Avoids privately owned land and existing infrastructure within the community, as well as campground, road pull-out, airport and the more scenic Pelly River crossing areas.
- Longer line length than going through the community. Option is straighter and has fewer corner towers.
- Substation tap located south of community. Additional distribution line required to service the community.

3B: option through community at Pelly Crossing

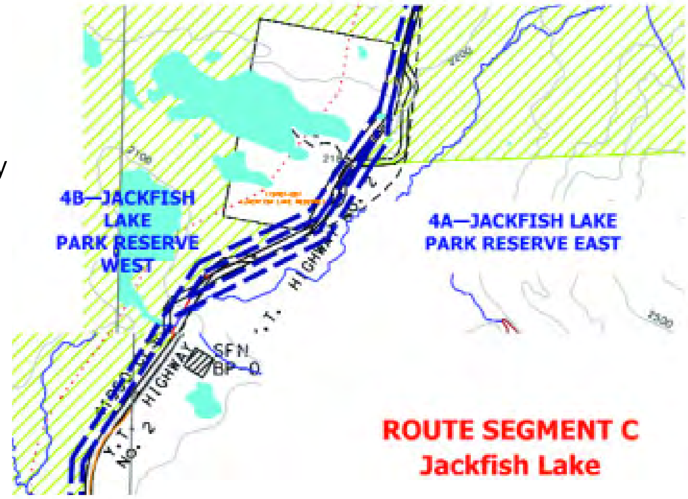
- Shorter line length than option 3A, steeper terrain, more corner towers.
- Various infrastructure constraints within the community, including housing development on north side of Pelly River and airstrip, as well as certain geographic constraints.
- Substation tap can be closer to the community; minimize additional distribution line to service the community.

3C: west option at Pelly Crossing

- Avoids privately owned land and existing infrastructure within the community.
- Constraints include steep slopes, a creek and the airstrip on north side of Pelly River.
- Further engineering feasibility is still required.
- Substation tap located south of community. Additional distribution line required to service the community.

Route Options Pelly Crossing to Stewart Crossing

From Pelly Crossing to Jackfish Lake terrain constraints and cost efficiency of long tangent lines result in the proposed route currently being located on the west side of the Klondike Highway across Selkirk First Nation settlement lands. Options on the east side of the highway might be considered, if so desired, to avoid some of these settlement lands.



At Jackfish Lake two options have been identified:

4A: Option east of Jackfish Lake

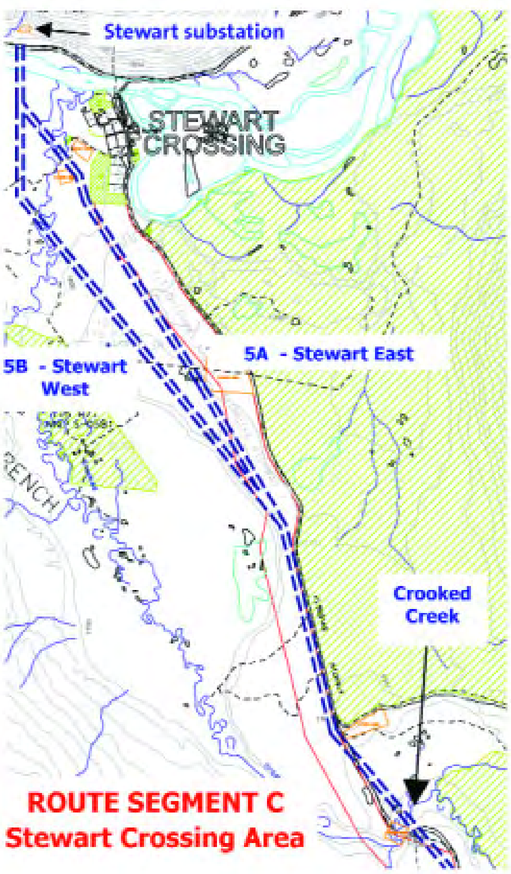
- East side of highway, away from Jackfish Lake Park Reserve.
- Requires crossing the highway before the park to avoid aesthetic and recreation concerns (preferred route from Yukon Renewable Resources' perspective).

4B: Option through Jackfish Lake Park Reserve

- Slightly straighter/shorter line route; avoids crossing highway; goes though park reserve.
- Potential for recreation and aesthetic concerns with this option.

North of Jackfish Lake, after about five kilometres the proposed route falls within crown lands all the way to the Stewart Crossing substation.

From Jackfish Lake to Crooked Lake, the currently identified route follows along the east side of the Klondike Highway before crossing to the west side. There are a few sections where steep slopes squeeze the transmission right-of-way very close to or within the highway right-of-way.



At Crooked Creek, the proposed route crosses the highway well to the south-east of the roadside pull-out and bridge over Crooked Creek, and crosses the North Crooked Creek to avoid conflict with views. The proposed route then crosses back to the west side of the highway to avoid settlement lands of the First Nation of Nacho Nyak Dun (NND), and stays very close to the highway to avoid a section of poor drainage/bog.

At Stewart Crossing, the proposed route is sited directly into the existing transmission substation, avoiding built-up areas of the community and keeping the Stewart River crossing for the route away from the community, bridge and highway. Two alternatives have been identified west of the highway for this last segment of the route:

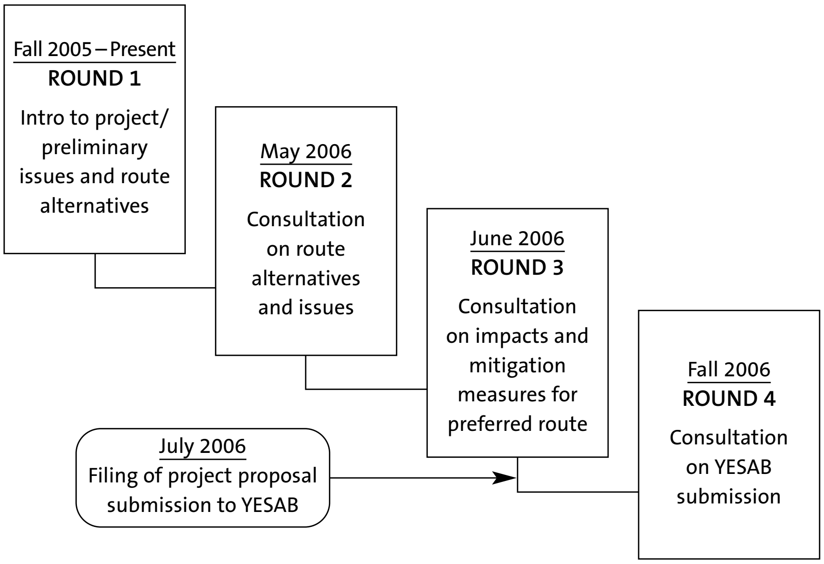
5A: East option at Stewart:

- Route adjacent to west side of 500 metre study area; in close proximity to existing housing and NND settlement lands.
- Slightly shorter line length.

5B: West option at Stewart:

- Route is further west than 5A and outside the 500 metre study area; avoids conflict with community and NND settlement land parcels.
- Encounters poorly drained soils and boggy conditions.
- Requires additional terrain analysis and engineering feasibility.

Public Involvement Stages – Carmacks-Stewart Transmission Project



The second round of public involvement is aimed at all interested publics. It provides information on the project and identifies options and issues regarding routing of the proposed transmission line.

A specific route has not yet been chosen – consultation is a key factor in selecting the final route.

Route Selection Consultation Principles

1. Opportunities for early involvement – BEFORE route decisions are made.

2. Opportunities for involvement at all stages providing real options and alternatives for route selection, and an opportunity for First Nation and public involvement after filing.

3. Unique status of Northern Tutchone First Nations as a Decision Body of proposed routes crossing settlement land, and as an interested party or expert on proposed routes through First Nations traditional territory.

Comments? Questions?

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YUKON ENERGY

Anticipated Time Line	
2002/2003	Studies to define 500 m project study area completed
2005 Fall/Winter	Information to First Nations, general public and YESAB.
2006 March	Letter of Intent signed with Minto Mine
March/April	Waste stripping construction begins at Minto Mine site
	MOU discussions with Northern Tutchone First Nations
May/June	Consultation on route alternatives & issues (May) and on impacts and mitigation (June)
July	Project proposal submission filed with YESAB
Late Fall	Project agreements with Northern Tutchone First Nations finalized
December	Recommendations from YESAB
2007 First Quarter	Decision Body approves on project; Stage 1 construction to Pelly Crossing begins
March/April	Minto Mine production set to begin (use diesel)
2008 Summer/Fall	Carmacks Copper Mine production target start
	Stage 1 of transmission line complete to Pelly
2009 Summer/Fall	Construction of Stage 2 of transmission line to Stewart complete

REFERENCE:

QUESTION:

What consultation has taken place with YECL in the formulation of this plan? If there has not been any consultation with YECL, why not? Have you accounted for any potential expansion of YECL production?

ANSWER:

In regards to potential expansion of YECL production, see YUB-YEC-1-15(c) and YUB-YEC-1-4.

The Resource Plan relates directly to the Yukon Energy WAF and Mayo Dawson generation and transmission systems and not to the YECL distribution or isolated diesel systems.

While developing the Resource Plan, Yukon Energy informed YECL on a number of occasions that it was preparing internal infrastructure plans and more recently a full Resource Plan for the bulk power supply to the integrated systems, particularly WAF. During Yukon Energy's regular meetings with YECL at both the senior levels and operational levels, YECL did not indicate at any time any relevant capital projects planned for their parts of the system served by Yukon Energy.

At the outset of the Resource Plan preparation, Yukon Energy also sought from YECL support in the form of load and generation data (in July 2005), and had planned on further discussing with YECL the capacity criteria and the long-term plans to meet YEC's requirement to service those WAF loads at the bulk power level. However, Yukon Energy was informed by YECL in August 2005 that YECL viewed their load data as commercially sensitive and sharing such data with YEC would put YECL at a competitive disadvantage in Yukon (although such data was routinely shared in preparing the 1992 Resource Plan[1] and in all Yukon General Rate Applications). YECL did ultimately offer to

[1] In particular, the 1992 Resource Plan similarly reflected YEC's primary role as the main generator and transmitter of power on the interconnected systems in Yukon, where YEC incurred hearing related costs of $0.508 million in regulatory and preparation costs compared to YECL's $0.015 million. In addition, the underlying planning and study costs for hydro investigations, DSM programming and transmission studies approximated $2 million for YEC, as compared to approximately $0.6 million for YECL comprising almost solely McIntyre III hydro plant studies and DSM programming in about equal proportions (where DSM costs include spending in isolated communities).

provide some data in December 2005 and suggested a meeting to discuss the requirements, however, this was too late in the process for this detail to be incorporated into the January 2006 Resource Plan.

Since January, Yukon Energy's focus has been on the topics noted in the Supplemental Filings (the feasibility of Mirrlees Life Extension, the planning of the Carmacks-Stewart project and measures to serve proposed new industrial loads) and is engaging Yukon Electrical where required on these topics (such as the requirements for service to YECL's distribution system at Carmacks and at Pelly Crossing from a new Carmacks-Stewart transmission line).