IN THE MATTER OF the *Public Utilities Act*
Revised Statutes of Yukon, 2002, c. 186,
as amended

and

An Application by Yukon Energy Corporation
for review of its
20-Year Resource Plan: 2006-2025

YUKON UTILITIES BOARD

RECOMMENDATIONS

Yukon Utilities Board Report on

Yukon Energy Corporation
20-Year Resource Plan

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1. Introduction

This report is submitted to the Commissioner in Executive Council as requested by the Minister of Justice in a letter of June 5, 2006, the deadline for which was extended by the Minister of Justice in a letter of August 29, 2006.

On June 1, 2006, Yukon Energy Corporation (YEC) filed with the Yukon Utilities Board (YUB, the Board) its 20-Year Resource Plan (the Plan) for the years 2006 to 2025 inclusive. YEC's Plan contains the following: Resource Planning for Yukon Power Systems; Proposed New Capacity-planning Criteria; Proposed Near-Term Actions; and Proposed Actions Relating to Industrial Development Scenarios and Opportunities.

Within the Plan, YEC "committed to seek YUB review, prior to construction, of any new capital projects costing $3 million or more." Further, in its December 2004 application regarding 2005 Required Revenues and Related Matters, YEC committed to bring before the Board new or revised capacity-planning criteria. This requirement is to be in advance of any capital investment in new generation for capacity reasons.

YEC sought review of its Plan including use of its new capacity-planning criteria, the planning process, the criteria for longer term development opportunities, and the four near-term projects identified as: the Aishihik Third Turbine Project, the Marsh Lake Fall/Winter Storage Project, the Carmacks-Stewart Transmission Project and the Mirrlees Life Extension Project.

The Minister of Justice's June 5, 2006, letter directed the Board to review and hold a hearing on the Plan. Specifically, the Board was requested to:

1. Review YEC's plan with emphasis on:
    a) those projects related to the 20-Year Resource Plan which require commitments by YEC before the year 2009 for major investments with anticipated costs of $3 million or more for feasibility assessment and engineering, environmental licensing, or construction; and
    b) planning activities related to the 20-Year Resource Plan which YEC may be required to carry out in order to commence construction on other projects before the year 2016 to meet the needs of potential major industrial customers or other potential developments in Yukon.

2. The YUB review is to consider:
    a) significant utility spending commitments related to the generation and transmission of power in the Yukon that would affect long-term utility costs and rates;
    b) the effect of the proposed spending commitments on electricity rates to be charged to Yukon consumers;
    c) with regard to generation or transmission projects, the necessity for the proposed spending commitments and, to the extent currently known,

their physical and engineering characteristics and their economic consequences with emphasis on:

i. effects relating to electrical load forecast requirements, including requirements related to potential new major industrial customers or other major potential developments in Yukon, and the need for spending commitments to meet such load forecast requirements;
ii. the capability of existing generation and transmission facilities to provide reliable electrical power generation to meet the load requirements in (i), taking into consideration capacity-planning criteria appropriate and adequate to establish requirements for such electrical power generation capacity in accordance with principles established in Canada by regulatory authorities of the Government of Canada or of a province or of a territory regulating hydro and non-hydro electric utilities;
iii. evidence that all reasonable alternative options have been considered and that the proposed spending commitments have been selected on reasonable grounds, i.e. technical feasibility, cost efficiency, and reliability; and
iv. the analysis by YEC of potential risks form all causes, including but not limited to economic and financial risks, and including possible modifications to design or schedule resulting from environmental review and related regulatory approvals.

The Board was further instructed to hear submissions from any persons or groups or classes of persons who have an interest in the matter and to forward a report on its findings to the Commissioner in Executive Council, and make it public not later than October 31, 2006. This deadline was extended to January 15, 2007, in the Minister's August 29, 2006, letter.

From the direction of the Minister, the Board established a process to review the Plan. Notices were originally published in the *Yukon News* June 30, 2006, and July 5, 2006, and in the *Whitehorse Star* on June 29, 2006. However, due to schedule changes, revised and final notices were published in the *Whitehorse Star* on September 14, 2006, and in the *Yukon News* on September 15, 2006. The process included preliminary Board Information Requests to YEC on July 7, 2006, with responses received July 21, 2006, a Public Workshop on July 25, 2006, and a Pre-Hearing Conference on August 30, 2006.

Based on submissions from interested parties at the Public Workshop, the Board submitted a letter, dated July 26, 2006, to the Minister of Justice to extend the deadline for completion of the review to January 15, 2007.

In the Minister's letter agreeing to requested change in the deadline for the reports the Minister also stated:

> It is our government's understanding that no final decision has been made to implement any of the proposed projects. However, the Resource Plan and the input received as a result of your review will be valuable in assisting YEC in planning and decision making in future. Of course, any specific projects to be implemented by YEC will be subject to various regulatory approvals and reviews. In addition, we would like to note that prior to the implementation of any proposed significant energy projects by YEC (e.g. construction of the Carmacks-Stewart transmission line), it is the government's intention to refer the details of such projects to the YUB for review and recommendation under provisions of Part 3 of the *Public Utilities Act*.

At the Pre-Hearing Conference on August 30, 2006, Parties were requested to provide feedback on the Minister's letter, the role of the Yukon Environmental and Socio-Economic Assessment Board (YESAB), and comments on the Issues List.

In Board Order 2006-8, the Board ruled that none of the projects identified in the Plan have been designated under Part 3 of the *Public Utilities Act*, that environmental considerations are within scope of the review, and provided the final Issues List for the oral public hearing.

On November 9, 2006, YEC provided an update to its Plan wherein it:
- Withdrew the Marsh Lake Fall/Winter Storage project;
- Concluded that the Mirrlees Life Extension Project was technically feasible and introduced a Faro unit for further rehabilitation; and
- Provided an update on the Carmacks-Stewart Transmission Project.

The oral hearing took place in Whitehorse from November 14 to16, 2006, inclusive. Final argument was submitted on November 24, 2006, and reply on December 1, 2006. Registered Intervenors were the City of Whitehorse, the Utilities Consumers' Group (UCG), Yukon Conservation Society (YCS), Peter Percival, and the Marsh Lake Local Advisory Council. Registered Observers were John Maissan, Gary McRobb, Samson Hartland, and Government of Yukon's Department of Energy, Mines and Resources.

All Intervenors were provided the opportunity to make Information Requests, file evidence, cross-examine the YEC witnesses, and provide final argument and reply. The evening of November 15, 2006, was set aside to allow Registered Observers and the public to make presentations to the Board.

On December 21, 2006, the Board received correspondence from YEC regarding the negotiation of a purchase power agreement (PPA) between YEC and Minto Exploration Ltd. (Minto) for YEC service to the Minto Mine. The Board, while recognizing that formal agreement has not been finalized, issued a letter December 27, 2006, setting out a process to allow submissions from Intervenors on this new information. Intervenors could provide submissions by January 4, 2007, with reply for YEC by January 8, 2007.

2. Load Forecast, Accuracy, and Methodology

YEC outlined the basis for its load forecast within Section 4.2 of the Plan. Within this section, YEC pointed out that under the new proposed capacity-planning criteria there is a winter peak capacity shortfall on the Whitehorse-Aishihik-Faro (WAF) system and a surplus winter peak capacity on the Mayo-Dawson (MD) system. For the City of Whitehorse non-industrial loads, YEC provided load forecasts ranging from 0.9-percent increases per annum (low) to 3.0-percent increases per annum (high). The midpoint forecast was 1.85 percent. YEC supported this growth projection based on Whitehorse population growth rates in excess of 1 percent per year, based on the period 2001-2004, and increases in energy usage per customer of 0.5 percent per year. YEC forecast similar growth for commercial customers. This method provided the base-case load forecast of 1.5-percent to 2.2-percent growth per year with the midpoint being 1.85 percent.

From the above, YEC developed 4 sensitivities:

1. Base Case: 1.85-percent growth, no new industrial loads.
2. Low Sensitivity Case: 0.9-percent growth, no new industrial loads.
3. Base Case including Mines: 1.85-percent growth plus 9 MW growth from mines.
4. High Sensitivity Case including Mines: 3-percent growth plus 9 MW growth from mines.

The forecast was undertaken by YEC using Yukon Bureau of Statistics information, information from consulting with potential industrial loads, and reviewing wholesale sales to Yukon Electrical Company Ltd. (YECL), the largest electrical distribution company in Yukon. Input was not directly received from YECL.

In its argument, YEC stated that non-industrial load forecasts have a negligible effect on any of the projects or actions proposed in the Plan[1]. In a footnote to UCG-YEC-2-43, YEC qualified that the proposals in the Plan would not be materially affected by any changes in forecast information if provided by YECL. The near-term capacity shortfalls relate to the planned retirements of the Mirrlees units, the new planning-capacity criteria, and the potential for new industrial loads. YEC also indicated that the forecast for the non-industrial load had no bearing on the justification for the Mirrlees Life Extension Project nor the Carmacks-Stewart transmission line. At most, the non-industrial load forecast has the greatest impact on the need for the Aishihik third turbine, and then only the timing of this project would be affected.

In its argument, UCG commented that the YEC load forecast was deficient due to lack of involvement by YECL, Government of Yukon, the Energy Solutions Centre, and other stakeholders. UCG further stated that, contrary to the Board recommendations from the

[1] YEC Argument, page 14.

1992 Resource Plan, YEC has not accounted for up-to-date use per customer and that YECL is the utility most likely to have this data. This notion was supported by YCS in the customer-use patterns section of its argument. UCG continued that the forecast risk for the non-industrial load was not one carried by YEC but largely by YECL customers. Presumably, this is since YECL provides distribution service to most Yukoners.

Although the non-industrial forecast is important in final rate design and cost-of-service issues, UCG concluded that the thrust of the Plan was not to address load increases due to non-industrial customers, but that any capital expansion to meet industrial load growth could bring economic risk to non-industrial customers.

2.1 Recommendations of the Board

The Board considers that the purpose of the Plan is to outline the future direction for the company, the potential growth in transmission and generation assets, capitalize on economic opportunities in the Yukon, align with government policy and objectives, and be responsive to Yukon ratepayers. The Board also notes the methods used by YEC in developing its forecast for non-industrial customers.

For this type of planning process, a macro-view is appropriate. The Board agrees with both YEC and UCG. The thrust of the Plan is not to address load increases due to non-industrial customers, but to test if the load growth assumptions support the projects promoted by YEC.

At an aggregate level, the forecast is satisfactory; however, for a general rate application (GRA) more rigor would be applied to testing the load forecast at the rate-class level. Where cost-of-service and rate design issues apply, the shortcomings of not including YECL load forecast information needs to be addressed at the next GRA.

In order to properly test the veracity of the load forecasts and to assist in the testing of adjustments to revenue requirements, the Board suggests that YEC and YECL jointly prepare and file, for information purposes, 2-, 5-, 10-, and 15-year load forecasts by rate class every two years. For rate design and cost-of-service purposes, applications cannot properly proceed without load forecasts, jointly prepared by YEC and YECL, documented at the rate-class level. With YECL providing distribution service to most Yukon residential and commercial customers, YECL input in use patterns and customer growth is essential. The utilities are to solicit input from stakeholders and document within the forecasts all assumptions and consultations used in developing these forecasts. Further, the forecasts should include a narrative discussing the sensitivity of the forecast to alternative fuel supplies (for example, growth in home heating options) and the probabilities of those alternatives proceeding).

2.2 Industrial Load Forecast

Within its Plan, YEC has a need to consider the potential development of major industrial loads in the long term. Page 1-10 of the Plan states:

> Beyond near-term needs and opportunities, current planning issues must be addressed regarding other potential future industrial loads and developments during the next 10 to 20 years, including the Alaska Highway Natural Gas Pipeline project. Potential industrial loads need to be considered, and the identification, definition and "protection" of appropriate resource options is required to ensure that YEC is able to meet new loads when relevant on a timely basis if and when they develop.
>
> Supply side options potentially relevant for a construction start within the next 10 years vary widely depending on the potential industrial developments considered, and include a range of different hydro possibilities as well as coal fired generation and potentially natural gas-fired generation.
>
> Lead times required to plan, approve and develop major new power supply projects, as well as the material planning costs associated with pre-construction activities required to keep these options available on a timely basis, underline the relevance of the current Resource Plan review.

Figure 1.2 on page 1-12 of the Plan lists the potential load situations in the long term. Industrial development scenarios and opportunities are described further in Chapter 5 of the Plan.

YEC faces many challenges when forecasting future industrial developments. Some of the risks for this type of forecast include:

1. Inability to forecast which industrial development will proceed;
2. Limited value to current information;
3. Limited time to respond to new developments once it is decided that the developments should proceed;
4. YEC faces long lead times to develop new bulk power supply options;
5. Lag time for regulatory approvals;
6. Long-term rate impacts for assets constructed to serve industrial loads;
7. Isolation of the Yukon electric system; and
8. Scale of projects that can be undertaken by YEC.

The benefit of Section 5 (Industrial Development Scenarios and Opportunities) of the Plan is that it provides a long-term perspective and allows more time to evaluate potential loads and options. For the long term, YEC has developed four scenarios of potential future industrial loads.

1. Development of 10 MW WAF industrial (2 small mines);
2. Development of 25 MW WF industrial (3 mines);
3. Development of 40 MW WAF industrial (4 mines); and

4. Development of 120 to 360 MW WAF industrial (Alaska Highway Natural Gas Pipeline).

In each scenario, YEC outlined the planning requirements necessary to meet the potential loads.

In argument, YEC noted that only limited attention was given to the longer term elements of the Plan[2]. YEC also stated that:

> In the past industrial developments have proven to support development of long-term cost-effective electrical infrastructure in Northern Canada[3].

In its argument, UCG proposed that similar to the Government of the Northwest Territories (GNWT), stakeholders have the opportunity to provide input to the development of a policy framework for a comprehensive energy plan for the territory. The use of multiple resource portfolios similar to those in the British Columbia Utilities Commission (BCUC) Resource Planning Guidelines were advocated by UCG. A 'go-slow' approach was recommended by UCG in regard to planning for industrial loads until the probability of proceeding could be more fully assessed.

UCG further cautioned in its argument that:

> Planning for such loads within the load planning for the rest of YEC's non-industrial customers can result in excessive capital expenditures to account for temporary mine loads, expenditures which could then be left to non-industrial customers to bear. A prime example could be the proposed Carmacks-Stewart transmission line proposal which, if not strictly segregated from the planning for the rest of the load, could result in the costs of this expensive project being borne by ratepayers who do not need the expansion if the mine fails prematurely[4].

In reply, YEC stated that the balanced approach to new industrial developments as outlined in Section 5.1.1 of the Plan is the path to address issues around industrial development.

2.3 Recommendations of the Board

The Board is cognizant of the risks within this type of forecast and yet sees benefits to all ratepayers when infrastructure is constructed for industrial developments. The Board recognizes the efforts of YEC in investigating future potential industrial loads and the planning guidelines it follows when assessing these potential developments and agrees with the balanced approach that YEC utilizes. It is recommended that YEC continue to monitor these potential material load additions and, when warranted, make a filing with the Board when new facilities are required to meet these increased loads. Within the filing, YEC should outline the risk of proceeding, the benefits to existing ratepayers, and

[2] YEC Final Argument, page 27.
[3] Ibid, page 27.
[4] UCG Argument, page 8.

sensitivities to existing ratepayers if the economic life of the project is shorter than forecast. Further, YEC should outline how its contribution policy is being applied and what contributions it will receive from the industrial customer for the infrastructure created to satisfy the load.

3. Assessment of New Planning Criteria

The previous planning criteria used by YEC was a so-called deterministic criteria that was outlined and reviewed in the 1992 Resource Plan proceeding, resulting in the 1992 Resource Plan Report by the Board.[5] There was one planning criterion specific to isolated communities served by diesel plants and one specific to the WAF grid. In particular:

- For the isolated communities, the criterion required each system to have installed generation capacity sufficient to meet 110 percent of the forecast peak load with the largest generation unit out of service.
- For the WAF, the criterion stated that the WAF grid should carry sufficient generating capacity to meet 100 percent of the forecast system peak with the loss of the single largest winter unit (one of the Aishihik units at 15 MW) and the loss of 10 percent of its diesel capacity.

There were no criteria specific to the MD grid or specific to individual communities connected to the WAF grid.

Subsequent to a study conducted by reliability experts, Rajesh Karki and Roy Billinton from the University of Saskatchewan in 2004 (Karki-Billinton report) [6], YEC adopted new planning criteria as follows:

- Each system (WAF and MD) should not exceed a Loss of Load Expectation (LOLE) of two hours per year;
- Each system (WAF and MD) should be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as N-1);
- For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more should be considered as a preferred location for new diesel units if that community does not already have backup from another source (e.g., having an existing diesel unit); and
- No change for isolated diesel communities, i.e., the previous criteria, namely 110 percent of the community peak with the largest unit out of service is maintained[7].

The Board deals with the merits of each of the above individual criterion in the following paragraphs.

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[5] Review of Capital Resource Plans of YEC and YECL, December 7, 1992 – Attachment 1 to UCG-YEC-2-1
[6] Reliability Evaluation of the Whitehorse-Aishihik-Faro System – YUB-YEC-1-1, Attachment 1, Exhibit B-6.
[7] Exhibit B-1: YEC 20-Year Resource Plan: 2006-2025, January 2006, page 3-21.

3.1 The LOLE Criterion

The LOLE is a probabilistic criterion and is computed by calculating, for each hour during the year, the probability that the load would exceed the available generating capacity (due to unplanned outages of generating units) and adding them all throughout the year. This summation of hourly probabilities becomes the annual LOLE, i.e. the expected number of hours per year when the generating sources may not be able to supply the load.

In comparison, the previous deterministic criterion was easy to calculate, as it entailed a simple addition of available winter capacity (excluding the largest unit and 10 percent of the diesel capacity) and comparing it with one single load level – the annual peak.

While easy to calculate, deterministic criteria suffer from significant shortcomings when compared to probabilistic criteria such as the LOLE. These shortcomings can easily be understood by comparing the way deterministic and probabilistic criteria are calculated. For example:

- The LOLE is calculated over all hourly loads during the year, while the deterministic criterion is calculated over one single hour, the annual peak. This makes the LOLE sensitive to the shape of the load, relative to the annual peak, as it would produce higher or lower values depending on how high or low the rest of the hourly loads are, given the same annual peak.
- Calculating the hourly probability of the load exceeding the available generating capacity due to unplanned outages of generating units, which is needed to compute the annual LOLE, requires use of each individual generator's probability of being unavailable, which is represented by the unit's Forced Outage Rate (FOR). Therefore, the LOLE is also sensitive to the FOR of each generator in the system. In addition, when the FOR of a transmission element is included in the calculation of LOLE, it also becomes sensitive to the unavailability of that transmission element. However, deterministic criteria are insensitive to the probabilities of failure of generators and transmission elements in the system.

The above are just two examples that show some of the many advantages of probabilistic criteria, such as the LOLE, over deterministic criteria. By the 1970s and 1980s, the advantages of probabilistic criteria over the shortcomings of deterministic criteria had been recognized by many electric utilities and provincial regulators in Canada. Since then, the majority of the Canadian utilities have adopted probabilistic criteria with the LOLE, and in particular LOLE values of 1 to 2 hours per year were the most widely used[8].

The Board is of the view that YEC's move from the previous deterministic criterion to the new LOLE probabilistic criterion is a positive step, given the advantages of the LOLE over the previous criterion as explained above. Further, this places YEC at par with the utilities in the majority of other jurisdictions in Canada. Moreover, adoption of the 2 hours per year LOLE value, which was derived from analyses conducted by Billinton

[8] Karki-Billinton

and Karki, is also consistent with similar LOLE values used by other utilities in Canada[9]. Therefore, the Board recommends the use of the 2 hours per year LOLE, for the WAF and MD grids, provided it is calculated using the same technique as in the Karki-Billinton report included in Exhibit B-6. The Board is satisfied that maintaining a minimum 2 hours per year LOLE will ensure that the generating resources are adequate to meet the load requirements on the MD and WAF grids.

The Board notes that YEC's initial LOLE calculations were made using industry-average FORs, specifically 10 percent for all diesel plants and 3 percent for all hydro plants, instead of individual generators' FORs. YEC indicated that, although it did have historical output records from all its generators, it could not compute FORs accurately because the records did not differentiate between planned outages (for maintenance purposes) and unplanned outages (due to failures). Also, industry-average data was used to obtain the 0.66-percent FOR for Line L171, as there were no failure records for this transmission line. However, following Dr. Billinton's recommendations, YEC has undertaken a data collection program to compile outage statistics so that the FORs for individual YEC resources can be computed and used in the future. Nevertheless, the use of industry averages for this resource plan was an appropriate proxy given insufficient YEC-specific outage data. Therefore, the Board accepts the use of industry-average data for this Plan but expects that, after sufficient YEC-specific data is collected, actual FORs derived from YEC data will be used in future plans.

YEC indicated that new generating capacity will not be planned or added to the system for the purpose of ensuring reliable supply to major industrial loads. This has been properly captured in the definition of the N-1 criterion, which is addressed in more detail below, as the definition explicitly indicates "excluding major industrial loads." However, the definition of the LOLE criterion does not mention exclusion of major industrial loads explicitly and it appears that YEC included the major industrial loads in the calculations of LOLE[10] under certain load forecast scenarios. If this is the case, the Board considers it to be an inconsistent approach, as inclusion of major industrial loads in the LOLE calculation will produce higher LOLE values, possibly above 2 hours per year, that would signal a need for new capacity. Therefore, the Board recommends that, in order to ensure that no new generating capacity is added for the purpose of ensuring reliable supply to major industrial customers and to ensure consistency with the N-1 criterion, major industrial loads should not be included in the LOLE calculation.

3.2 The Single-Contingency (N-1) Criterion

YEC's N-1 criterion states that each system (WAF and MD) should be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency, i.e. the removal of a single element which could be either a transmission line or a generating unit, or any other element that causes the worst possible situation in the power system.

[9] Karki-Billinton report
[10] Transcript, pages 446-447

Normally, utilities throughout North America use contingency analysis such as the N-1 criterion, which consists of removing elements from a power system, to identify weaknesses in the transmission system. This is typically done by removing a transmission element at the worst possible time, which is usually at the time of the annual peak, and conducting steady-state (load-flow) analyses to identify buses with over/under voltages and branching elements (transmission lines, transformers, etc.) that would be reaching or exceeding their power transfer limits.

The above-mentioned steady-state analysis, which is necessary in power systems that have redundant transmission lines, i.e. there is usually more than one path for the electric energy to flow between two points in the grid, is not necessary in power systems such as the WAF or the MD, which are basically radial systems with no transmission line redundancy. Consequently, a contingency situation in the WAF or the MD systems, such as the loss of a transmission line, could immediately translate into a loss-of-load situation. Therefore, the Board agrees with the way the N-1 criterion has been postulated, namely that the system should be able to carry the annual peak load under the largest single contingency.

YEC's use of the N-1 criterion in parallel with a generation adequacy criterion, such as the LOLE, is somewhat unique in the sense that the N-1 criterion is being used to assess not only weaknesses in the transmission system but also the adequacy of the generation sources. However, the WAF system is also unique in the sense that its major generating sources and load are separated by long distances, they are connected via single transmission lines, and there are no interconnections with neighbouring power systems. Therefore, these unique characteristics warrant the use of "generation" solutions to transmission deficiencies, and vice versa and the Board recommends the use of the LOLE and N-1 planning criteria as proposed by YEC.

The Board also notes that major industrial loads are to be excluded when the N-1 criterion is to be used. This is specified in the definition of the N-1 criterion, which states: Each system (WAF and MD) should be able to carry the forecast peak winter loads (**excluding major industrial loads**) under the largest single contingency [emphasis added]. This is consistent with YEC's testimony that new generating capacity will not be planned, or added to the system, for the purpose of ensuring reliable supply to major industrial loads[11]. The Board expects that the same consistency would be applied under the LOLE criterion, as addressed above.

3.3 Connected and Isolated Community Criteria

YEC's criterion respecting communities connected to the WAF or MD grids, which states that any location with a load large enough to justify a diesel unit of about 1 MW or more should be considered as a preferred location for new diesel units, is a criterion for deciding where to locate new units rather than a planning criterion to decide if new units

[11] Exhibit B-1, page 3-12, states than no capacity is planned to supply secondary energy sales. At Transcript, pages 86–87, YEC testified that, for capacity planning, industrial customers are treated as if they were secondary sales customers.

are needed or not. Therefore, the Board has no concerns with YEC's adopting this criterion.

The Board agrees with YEC continuing to use the previous criteria for isolated diesel communities, i.e. to maintain generating capacity at no less than 110 percent of the community peak with the largest unit out of service.

4. Capability of Existing Facilities and Resources to Supply Forecast Loads

YEC's assessment of the need for new resources under the new planning criteria is summarized in Table 3.5 of the resource plan[12]. As no Intervenors verified YEC's assessment of need, the Board carried out calculations of need, under the N-1 and LOLE criteria, to replicate and verify YEC's assessment. The Board's assessment is presented in Table 4-1.

In comparing YEC's assessment with the Board's assessment, the Board is satisfied that both assessments have produced practically the same results. The same Load Carrying Capacity (LCC) was obtained for the N-1 calculation, except for an insignificant difference due to rounding of the second decimal place. Under the LOLE calculation, the Board's results produced consistently slightly lower values of LCC than YEC's. For comparison purposes, YEC computed LOLE surplus values have been included on the right-most column of Table 4-1. These differences between YEC's and the Board's LOLE calculations are small, ranging between 0.2 to 0.6 MW, and are to be expected due to the extent and complexity of the LOLE calculations. Therefore, the Board considers these differences to be immaterial for the purpose of this exercise.

Table 4-1: YUB Need Assessment Under New Planning Criteria

			YUB	YUB		YUB	YUB	YEC
		N-1	N-1	N-1	LOLE	LOLE	LOLE	LOLE
Year	Resources	Peak	LCC	Surplus	Peak	LCC	Surplus	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3	6.5
2006		56.4	55.7	(0.7)	57.4	62.7	5.3	5.5
2007	WD3-Retired.	57.5	51.5	(6.0)	58.5	58.3	(0.2)	0.2
2008	.	58.6	51.5	(7.1)	59.6	58.4	(1.2)	(0.9)
2009	WD2-Retired	59.7	47.3	(12.4)	60.6	54.0	(6.6)	(6.1)
2010		60.8	47.3	(13.5)	61.7	54.1	(7.6)	(7.2)
2011	WD1-Retired	62.0	44.3	(17.7)	63.0	50.9	(12.0)	(11.4)
2012		63.1	44.3	(18.8)	64.1	50.9	(13.1)	(12.5)

[12] Exhibit B-1, page 3-24.

Using its own analysis, the Board has verified YEC's N-1 and LOLE calculations presented in Exhibit B-1. Therefore, the Board concurs with YEC's submission that based on the new planning criteria, and given the expected retirement of the Mirrlees units (if there is no refurbishment), the WAF system has been in a resource shortfall situation since 2006, according to the N-1 criterion.

According to YEC's LOLE calculation, existing YEC generation sources are adequate to supply the forecast base-case load until 2007, even when the Mirrlees diesel Unit WD3 is retired in that year. In 2008, the LOLE indicates a small generation deficiency of 0.9 MW. The LOLE provides a clear indication that new generating capacity would be needed in 2009 when Unit WD2 is retired.

However, the N-1 indicates a minor deficiency (0.7 MW) in 2006 and larger deficiencies (6 MW and more) starting in 2007, when Unit WD3 is retired. This indicates that there has been a transmission deficiency since 2006 rather than indicating that the generation resources are inadequate, as the LOLE criterion indicates adequate generation resources until 2007. This can be seen if one simply adds a transmission element, specifically a second transmission line connecting the Aishihik plant to Whitehorse, to the WAF grid. Adding this second transmission line turns the 2006-2010 deficiencies into surpluses, as this line would contribute with 15 MW of LCC, and pushes the need for new resources to 2011 under the N-1 criterion. However, it should be emphasized that adding this transmission element in 2006 is only an example to illustrate how the N-1 criterion is demonstrating a transmission deficiency in the WAF system, as YEC indicated that this line could not be installed until 2010.

Applying the LOLE and N-1 criteria leads to the conclusion that the WAF system currently has a transmission deficiency but the generation resources are still adequate for a few more years. This conclusion can be inferred, without applying any criteria, by simply analyzing the topology of the WAF grid, which shows that the largest source of generation, the Aishihik plant, is connected to the largest load, the Whitehorse area, via a single transmission line.

Currently, the winter capacity of the WAF system in 2006 is 87 MW. An outage of one single transmission element, namely the Aishihik-to-Whitehorse line, would bring down the entire Aishihik plant (30 MW), which is more than 34 percent of the total winter capacity of the WAF. This is another indication that the WAF has a serious transmission deficiency, which the N-1 criterion is indicating.

In summary, the Board's view is that, based on the new N-1 criterion, the WAF system is currently affected by insufficient transmission capacity, and based on the LOLE criterion, it would face inadequate generation resources as early as 2008, assuming the base-case load forecast materializes. However, as stated in the preceding section, the Board considers it appropriate to investigate and pursue generation options to address transmission deficiencies and vice versa, given the unique characteristics of the Yukon electric systems. These options are addressed in detail in the following sections.

5. Selection of an Expansion Plan

A number of projects have been suggested as possible near-term options, and they are discussed in greater detail in Section 6. In Section 5.1 below, the Board deals with the merits of YEC's proposed expansion plan, i.e. different near-term projects in certain years, and other possible expansion plans, and how well it would satisfy the need for new resources according to the new planning criteria. Later, in Section 5.2, the Board addresses the economic aspects of YEC's expansion plan and compares them with an alternative plan.

The Board's assessment of the merits of different expansion plans (in Sections 5.1 and 5.2 below) is made only for the base-case load forecast. Clearly, higher or lower growth forecasts would result in the timing of new required resources moving earlier or later in time. This would affect all expansion plans equally, but the relative merits of one plan over another plan should be preserved, irrespective of the load forecast used. Therefore, the Board expects that whichever expansion plan is found to be the best plan would remain the best even if different load forecast scenarios are assumed.

5.1 Expansion Plans According to New Planning Criteria

YEC proposes a mainly diesel-based expansion plan. The plan calls for the refurbishment of old diesel plants that are currently scheduled for retirement (the Mirrlees Life Extension project), the refurbishment of a previously retired diesel unit at Faro (the Faro Rehab Project), and a transmission line from Carmacks to Stewart, which would provide access to excess capacity on the MD grid.

YEC's scenario meets the planning criteria up to 2016, as can be seen in Table 5-1.

Table 5-1: YEC's Plan: Faro Rehab, Mirrlees Life Extension, and Carmacks-Stewart Line – Base-Case Load Forecast

	Expansion Plan	N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC[13]	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	Faro Rehab	57.5	60.7	3.2	58.5	67.8	9.3
2008	WD3-Refurb	58.6	61.5	2.9	59.6	68.5	8.9
2009	WD2-Refurb CS-Line	59.7	68.3	8.6	60.6	75.0	14.4
2010	WD1-Refurb	60.8	69.2	8.4	61.7	76.0	14.3
2011		62.0	69.1	7.1	63.0	76.0	11.9
2012		63.1	69.0	5.9	64.1	76.0	10.7
2013		64.3	68.9	4.6	65.3	76.0	9.5
2014		65.5	68.8	3.3	66.5	76.0	8.3
2015		66.7	68.7	2.0	67.7	76.0	7.0
2016		68.0	68.6	0.6	69.0	76.0	5.7
2017		69.3	68.5	(0.8)	70.3	76.0	4.4

One variant to YEC's proposed expansion plan arises from YEC's intentions to proceed with the Carmacks-Stewart line in two stages. In the first stage, the line would be built from Carmacks to Pelly Crossing in the 2009-2010 timeframe to supply the Minto Mine. The second stage, from Pelly Crossing to Stewart Crossing, would be undertaken later. Under this scenario and according to the new planning criteria, the first stage (Carmacks to Pelly Crossing) would contribute no new capacity to the WAF system but neither would it impose a need for new capacity. This is because the load of the Minto Mine is not included in the N-1 and LOLE calculations, as no new capacity is planned for large industrial loads[14]. The WAF system would receive capacity contribution from the MD grid only after the second stage (Pelly Crossing to Stewart Crossing) is completed, which should occur no later than 2013, according to the N-1 criterion, as illustrated in Table 5-1A.

[13] For simplicity of the LOLE calculation, capacity assistance from the MD grid is assumed to remain the same, rather than slowly decrease due to load increases in the MD system, which is in the order of 0.1 MW per year.
[14] There is an implicit assumption here that, under a potential capacity shortfall situation, the load of the Minto Mine would be either interrupted or supplied by Minto's own backup generators.

Table 5-1A: YEC's Plan: Assuming Timing of the Pelly-Stewart Line Installed to Satisfy N-1 Criterion – Base-Case Load Forecast

		N-1	N-1	N-1		N-1	N-1
Year	Project	Peak	LCC	Surplus	Project	LCC	Surplus
2005		55.4	55.7	0.3			
2006		56.4	55.7	(0.7)			
2007	Faro Rehab	57.5	60.7	3.2			
2008	WD3-Refurb.	58.6	61.5	2.9			
2009	WD2-Refurb. C-PC Line	59.7	62.3	2.6			
2010	WD1-Refurb.	60.8	63.3	2.5			
2011		62.0	63.3	1.3			
2012		63.1	63.3	0.2			
2013		64.3	63.3	(1.0)	PC-S Line	68.9	4.6
2014		65.5	63.3	(2.2)		68.8	3.3
2015		66.7	63.3	(3.4)		68.7	2.0
2016		68.0	63.3	(4.7)		68.6	0.6
2017		69.3	63.3	(6.0)		68.5	(0.8)

Although in an Information Request the Board asked YEC to provide alternative expansion plans[15], only one expansion plan was provided. Therefore, the Board faced the challenge of there being only one plan before it to consider and no alternative plans with which to compare it. Since YEC did not provide analyses of other expansion plans to arrive at what YEC believes is the best plan, the Board had to envision alternative plans and test them against YEC's proposed plan in order to make an informed recommendation in this report. These alternative plans are discussed below.

YEC's proposed expansion plan solves WAF's transmission deficiency using a "generation" solution. However, YEC's solution does not solve the root problem, namely that the largest source of generation, the Aishihik plant, is connected to the largest load, the Whitehorse area, via a single transmission line. Therefore, if a second transmission line between the Aishihik plant and Whitehorse (Aishihik second line) were pursued instead of the Carmacks-Stewart Lline, the WAF system would meet the planning criteria until the year 2022, which is 6 years longer than YEC's proposed plan. (See Table 5-2).

[15] One plan was proposed in YUB-YEC-1-10. After YEC decided not to pursue the Marsh Lake Winter Storage Project, YEC filed a revised plan proposing the same expansion plant but including the Faro Rehab Project as a replacement to the Marsh Lake Winter Storage project.

Table 5-2: Faro Rehab, Mirrlees Life Extension, and Aishihik second line in 2010 – Base-Case Load Forecast

	Expansion Plan	N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	Faro Rehab	57.5	60.7	3.2	58.5	67.8	9.3
2008	WD3-Refurb	58.6	61.5	2.9	59.6	68.5	8.9
2009	WD2-Refurb	59.7	68.3	8.6	60.6	69.2	8.6
2010	WD1-Refurb Aish. second Line	61.8	79.6	17.8	61.7	77.5	15.8
2011		63.0	79.6	16.6	63.0	77.5	14.4
2012		64.1	79.6	15.5	64.1	77.5	13.4
2013		65.3	79.6	14.3	65.3	77.5	12.2
2014		66.5	79.6	13.1	66.5	77.5	10.9
2015		67.7	79.6	11.9	67.7	77.5	9.7
2016		69.0	79.6	10.6	69.0	77.5	8.5
2017		70.3	79.6	9.3	70.3	77.5	7.1
2018		71.6	79.6	8.0	71.6	77.5	5.9
2019		72.9	79.6	6.7	72.9	77.5	4.6
2020		74.2	79.6	5.4	74.2	77.5	3.3
2021		75.6	79.6	4.0	75.6	77.5	1.9
2022		77.0	79.6	2.6	77.0	77.5	0.4
2023		78.4	79.6	1.2	78.4	77.5	(0.9)

With the Aishihik second line, the old Mirrlees diesel unit WD1 could be retired in 2010, and not refurbished, and the WAF would still meet the planning criteria until 2019. Moreover, if the Mirrlees unit WD2 is also retired and not refurbished, the WAF would still meet the planning criteria until 2016.

Table 5-3 shows an expansion sequence that meets the planning criteria until 2016, which is the same year as YEC's proposal, but swaps the Carmacks-Stewart line with the Aishihik second line and does not require refurbishment of the Mirrlees units WD1 and WD2.

Table 5-3: Faro Rehab, Only Mirrlees WD3 Refurbished, and Aishihik second line in 2010 – Base-Case Load Forecast

	Expansion Plan	N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	Faro Rehab	57.5	60.7	3.2	58.5	67.8	9.3
2008	WD3-Refurb.	58.6	61.5	2.9	59.6	68.5	8.9
2009	WD2-Retired	59.7	63.3	3.6	60.6	64.2	3.6
2010	WD1- Retired. Aish. second Line	61.8	70.6	8.8	61.7	68.9	7.2
2011		63.0	70.6	7.6	63.0	68.9	6.0
2012		64.1	70.6	6.5	64.1	68.9	4.8
2013		65.3	70.6	5.3	65.3	68.9	3.6
2014		66.5	70.6	4.1	66.5	68.9	2.4
2015		67.7	70.6	2.9	67.7	68.9	1.2
2016		69.0	70.6	1.6	69.0	68.9	0.0
2017		70.3	70.6	0.3	70.3	68.9	(1.4)

Another possibility would be to implement the Faro Rehab Project and retire the three Mirrlees units WD1, WD2, and WD3 in 2010, the same year the Aishihik second transmission line is commissioned. This scenario is presented in Table 5-4 and shows that the WAF system would meet the planning criteria until 2012.

Table 5-4: Only Faro Rehab, Mirrlees Units Retired in 2010, and Aishihik second line in 2010 – Base-Case Load Forecast

	Expansion Plan	N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	Faro Rehab	57.5	60.7	3.2	58.5	67.8	9.3
2008		58.6	60.7	2.1	59.6	67.8	8.2
2009		59.7	60.7	1.0	60.6	67.8	7.2
2010	WD1, WD2, WD3- Retired. Aish. second Line	61.8	65.6	3.8	61.7	64.3	2.6
2011		63.0	65.6	2.6	63.0	64.3	1.3
2012		64.1	65.6	1.5	64.1	64.3	0.2
2013		65.3	65.6	0.3	65.3	64.3	(1.0)

Installation of the Aishihik second line also opens up the full potential of the Aishihik third turbine, as this removes the transmission constraints on the Aishihik plant. For example, if the third turbine was installed in 2013, to address the capacity shortage identified by the LOLE for this year under the scenario presented in Table 5-4 above, the WAF system would meet the planning criteria until 2018. This is illustrated in Table 5-5.

Table 5-5: Only Faro Rehab. Mirrlees Units Retired in 2010, Aishihik second line in 2010, and Aishihik third turbine in 2013 – Base-Case Load Forecast

	Expansion Plan	N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	Faro Rehab	57.5	60.7	3.2	58.5	67.8	9.3
2008		58.6	60.7	2.1	59.6	67.8	8.2
2009		59.7	60.7	1.0	60.6	67.8	7.2
2010	WD1, WD2, WD3- Retired. Aish. second Line	61.8	65.6	3.8	61.7	64.3	2.6
2011		63.0	65.6	2.6	63.0	64.3	1.3
2012		64.1	65.6	1.5	64.1	64.3	0.2
2013	Aish. third turbine	65.3	72.6	7.3	65.3	71.6	6.3
2014		66.5	72.6	6.1	66.5	71.6	5.1
2015		67.7	72.6	4.9	67.7	71.6	4.0
2016		69.0	72.6	3.6	69.0	71.6	2.6
2017		70.3	72.6	2.3	70.3	71.6	1.4
2018		71.6	72.6	1.0	71.6	71.6	0.0
2019		72.9	72.6	(0.3)	72.9	71.6	(1.3)

YEC's plan to pursue the Carmacks-Stewart line appears to be motivated by the potential for significant electric energy sales to new mines. This line, if built, would provide some capacity to the WAF system but its contribution is limited. This is illustrated in Tables 5-6 and 5-7. Table 5-6 shows the WAF surplus if only the Mirrlees Life Extension Project is pursued. Table 5-7 shows the same scenario but the Carmacks-Stewart line has been added in 2009. Comparing the WAF surplus under these two scenarios shows that the Carmacks-Stewart line produces a positive surplus for only four years.

Table 5-6: Mirrlees Life Extension – Base-Case Load Forecast

		N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	WD3-Refurb.	57.5	56.5	(1.0)	58.5	63.5	5.0
2008	WD2-Refurb.	58.6	57.3	(1.3)	59.6	64.2	4.6
2009	WD1-Refurb.	59.7	58.3	(1.4)	60.6	65.2	4.6
2010		60.8	58.3	(2.5)	61.7	65.2	3.5
2011		62.0	58.3	(3.7)	63.0	65.2	2.2
2012		63.1	58.3	(4.8)	64.1	65.2	1.1
2013		64.3	58.3	(6.0)	65.3	65.2	(0.1)

Table 5-7: Mirrlees Life Extension and Carmacks-Stewart line in 2009 – Base-Case Load Forecast

		N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	WD3-Refurb.	57.5	56.5	(1.0)	58.5	63.5	5.0
2008	WD2-Refurb.	58.6	57.3	(1.3)	59.6	64.2	4.6
2009	WD1-Refurb. CS-Line	59.7	64.3	4.6	60.6	71.0	10.4
2010		60.8	64.2	3.4	61.7	71.0	9.2
2011		62.0	64.1	2.1	63.0	71.0	8.0
2012		63.1	64.0	0.9	64.1	71.0	6.8
2013		64.3	63.9	(0.4)	65.3	71.0	5.7

If the Carmacks-Stewart line could not be on-line until 2010, which YEC indicated during the hearing was a real possibility, then the capacity contribution from this project would produce positive surpluses for only three years in this scenario, as illustrated in Table 5-8.

In summary, the Carmacks-Stewart line contribution to WAF capacity (under the N-1 criterion) is only 6 MW in 2009, which corresponds to the reserve capacity in the MD grid that can be used to assist the WAF. Also, the capacity assistance decreases every year as the load grows in the MD grid.

Table 5-8: Mirrlees Life Extension and Carmacks-Stewart line in 2010 – Base-Case Load Forecast

		N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	WD3-Refurb.	57.5	56.5	(1.0)	58.5	63.5	5.0
2008	WD2-Refurb.	58.6	57.3	(1.3)	59.6	64.2	4.6
2009	WD1-Refurb.	59.7	58.3	(1.4)	60.6	65.2	4.6
2010	CS-Line	60.8	64.2	3.4	61.7	71.0	9.3
2011		62.0	64.1	2.1	63.0	71.0	8.0
2012		63.1	64.0	0.9	64.1	71.0	6.8
2013		64.3	63.9	(0.4)	65.3	71.0	5.7

To illustrate the effect of the Aishihik second line and to compare it with the effects of the Carmacks-Stewart line, the same scenario presented in Table 5-8 has been reproduced in Table 5-9 but with the Aishihik second line instead of the Carmacks-Stewart line in 2010.

Table 5-9: Mirrlees Life Extension and Aishihik second line in 2010 – Base-Case Load Forecast

		N-1	N-1	N-1	LOLE	LOLE	LOLE
Year	Project	Peak	LCC	Surplus	Peak	LCC	Surplus
2005		55.4	55.7	0.3	56.4	62.7	6.3
2006		56.4	55.7	(0.7)	57.4	62.7	5.3
2007	WD3-Refurb.	57.5	56.5	(1.0)	58.5	63.5	5.0
2008	WD2-Refurb.	58.6	57.3	(1.3)	59.6	64.2	4.6
2009	WD1-Refurb.	59.7	58.3	(1.4)	60.6	65.2	4.6
2010	Aish. second Line	61.8	74.6	12.8	61.7	72.8	11.1
2011		63.0	74.6	11.6	63.0	72.8	9.8
2012		64.1	74.6	10.5	64.1	72.8	8.7
2013		65.3	74.6	9.3	65.3	72.8	7.5
2014		66.5	74.6	8.1	66.5	72.8	6.3
2015		67.7	74.6	6.9	67.7	72.8	5.1
2016		69.0	74.6	5.6	69.0	72.8	3.8
2017		70.3	74.6	4.3	70.3	72.8	2.5
2018		71.6	74.6	3.0	71.6	72.8	1.2
2019		72.9	74.6	1.7	72.9	72.8	(0.1)

From Table 5-9, one can see the superior contribution from the Aishihik second line compared to the Carmacks-Stewart line. In this scenario, the addition of the Aishihik second line turns the shortfalls (negative surpluses) into positive surpluses for nine years after its installation.

In summary, capacity contribution from the Aishihik second line is 15 MW, under the N-1 criterion, and 8 MW under the LOLE criterion. Such a large "capacity" contribution from a single transmission line, which is a passive element (i.e. it does not generate capacity by itself), is due to the fact that this is the only project that addresses the root cause of the WAF's transmission deficiency. This project relieves the existing transmission weakness in the WAF system, as it turns the N-1 event from a loss of 30 MW to a more manageable loss of 15 MW. This project also increases by 8 MW the contribution of the Aishihik plant to the overall adequacy of the generating system (measured by the LOLE), as it eliminates the constraint caused by the unavailability of the single transmission line.

In conclusion, the Board recognizes that YEC's proposed expansion plan would satisfy the need for new resources until the year 2016 for the base-case load forecast. However, the Board notes that YEC's is not the only possible expansion plan, as there are alternative expansion plans that would also satisfy the need for new resources. For example, the expansion plan shown in Table 5-5 above satisfies the need until 2018 and takes a different approach from that proposed by YEC. In particular, it addresses the WAF's transmission deficiency with a true transmission solution, namely the addition of the Aishihik second line, and relies on more hydro resources and less diesel resources, as it calls for the retirement of the Mirrlees Whitehorse diesel units in 2010 and the addition of the Aishihik third turbine in 2013.

In this section, the Board has shown the adequacy of YEC's proposed expansion plan and other alternative expansion plans to meet the new planning criteria. In order to make a recommendation on which plan should be pursued, the Board must determine which is the least-cost plan. To this end, a longer-term economic comparison is required to assess if YEC's proposed expansion plan is indeed less costly than other alternatives.

5.2 Economic Aspects of Expansion Plans

In this section, the Board will assess which plan, of those plans that meet the planning criteria, would be the least-cost plan. To simplify the economic assessment, the Board has selected YEC's plan and one alternative plan, the one presented in Table 5-5 above, for comparison. This alternative plan is, in the Board's opinion, the best alternative plan (of all those presented in Section 5.1) that could challenge YEC's plan as the least-cost plan.

A proper economic comparison would require a cash-flow analysis that would include annual production costs, such as fuel requirements and O&M costs[16], as well as capital costs, properly escalated to the year that each new project is placed in-service under

[16] O&M was not accounted for in the economic comparison as it was assumed it would be similar under both plans.

each expansion plan. Then, for each plan, the annual cash-flows have to be present-valued, using appropriate economic parameters, to a reference year for comparison.

The Board will first compare the annual production costs, with an aim at determining if the alternative plan would produce significant fuel-related savings over YEC's plan, and then it will compare the capital additions required by each plan.

5.3 Production Cost (Fuel Savings)

The first step in evaluating annual production costs under the different expansion plans selected entails calculation of electric energy generation from the different sources that make up each plan. In this particular case, the only significant electric energy sources are either hydro or diesel plants. Therefore, for the purpose of this analysis, one needs only to focus on the generation from diesel plants under both expansion plans and the potential fuel savings that would intuitively result from plans that requires less diesel generation.

YEC asserted that diesel plants on the WAF system are used mainly as backup or for peaking generation[17]. Therefore, generation from existing and new diesel plants would be very small as diesel plants would operate for only short periods of time. This means there would be no significant fuel savings under a different plan requiring less diesel plants.

To verify YEC's assertion and further simplify the assessment, the Board will first estimate the potential diesel fuel savings that are expected under the alternative plan, as it requires less diesel plants than YEC's plan. If the fuel savings are significant, they will be carried further into the economic analysis. However, if they are not significant, as asserted by YEC, only the second step of the economic analysis, i.e. a comparison based only on the capital costs required under each plan, would be sufficient to determine the less costly plan.

The following Table 5-10 shows annual diesel generation for YEC's and the alternative expansion plan. These diesel generation figures were obtained using an energy generation model in which all generating units, existing and new units under each expansion plan, were "dispatched" to supply the load according to a simplified stacking order, where all diesel units were dispatched after all hydro units in no particular order. However, it should be emphasized that, due to many assumptions made and several modeling limitations, these generation figures[18] are only adequate for the purpose of comparing the relative merits of one plan over the other and to verify YEC's assertion.

[17] Exhibit B-23: Undertaking 11 WAF Generation Staking Order.

[18] The Board used an energy generation model that "dispatches" generating units to supply the load, which was represented by the same load duration curves (LDC) used in the LOLE calculation. This model also accounts for random outages of generating units using the equivalent load method, i.e. the LDCs are modified using the FOR of each generator after dispatched, so that the next generator in the staking order would face a slightly higher load that accounts for the outages of generators already dispatched. Only units connected to the WAF were used in the analysis and there was no consideration of must-run units and/or units that run for emergency standby or voltage support purposes. Also, hydro generation in the MD grid was not assumed to supply WAF loads due to line losses.

Table 5-10: Diesel Generation under YEC's Plan and the Alternative Expansion Plan – Base-Case Load Forecast

	YEC Expansion Plan	Diesel Generation GWh	Alternative Expansion Plan	Diesel Generation GWh	Diesel Generation Difference GWh
2005		1.4		1.4	0
2006		1.5		1.5	0
2007	Faro Rehab	1.6	Faro Rehab	1.6	0
2008	WD3-Refurb	1.9		1.9	0
2009	WD2-Refurb. Carmacks-Line	2		2	0
2010	WD1-Refurb.	2.3	WD1, WD2, WD3 Retired. Aish second line.	2.2	0.1
2011		2.7		2.5	0.2
2012		3.1		2.9	0.2
2013		3.6	Aishihik third turbine	1.2	2.4
2014		4.9		1.6	3
2015		5.2		1.7	3.5
2016		6.7		2.3	4.4
2017		7		2.3	4.7
2018		9.2		3.2	6
2019		9.2		3.1	6.1
2020		12.3		4.4	7.9
2021		12.7		4.5	8.2
2022		14.3		5.2	9.1

The right-most column on Table 5-10, labeled "diesel generation difference", shows the annual diesel-energy savings of the alternative expansion plan over YEC's plan. As can be seen, there are no diesel fuel savings until 2012, which is expected given that diesel plants are used only as "peaking" units, there are no hydro resources added up to that year under either plan, and the load is still relatively low. However, beginning in 2013, diesel fuel savings start to grow steadily as the load continues to grow, diesel units are called to operate more often under YEC's plan, but less often under the alternative plan due to the addition of the Aishihik third turbine.

YEC stated that its plan with respect to the Aishihik third turbine was to install this unit post 2011–2012 provided that the load grew sufficiently high to justify this project purely on the basis of potential diesel fuel savings. This approach is justified given that the Aishihik third turbine would not contribute to capacity under YEC's proposed expansion plan, as measured by the N-1 criterion. This approach is further supported by the diesel generation figures presented in Table 5-10, as they show significant savings starting in 2013 and due to the addition of the Aishihik third turbine. Therefore, if YEC proceeds with this project as planed and installs the third turbine in 2013, which is the same year as the alternative plan, there would be no significant diesel fuel savings attributable to the alternative plan over YEC's plan. This is illustrated in Table 5-11:

Table 5-11: Diesel Generation under YEC's Plan Including Aishihik third turbine and Alternative Expansion Plan – Base-Case Load Forecast

	YEC Expansion Plan	Diesel Generation GWh	Alternative Expansion Plan	Diesel Generation GWh	Diesel Generation Difference GWh
2005		**1.4**		**1.4**	**0**
2006		**1.5**		**1.5**	**0**
2007	Faro Rehab	**1.6**	Faro Rehab	**1.6**	**0**
2008	WD3-Refurb	**1.9**		**1.9**	**0**
2009	WD2-Refurb. Carmacks-Line	**2**		**2**	**0**
2010	WD1-Refurb.	**2.3**	WD1, WD2, WD3 Retired. Aish second line.	**2.2**	**0.1**
2011		**2.7**		**2.5**	**0.2**
2012		**3.1**		**2.9**	**0.2**
2013	Aishihik third turbine	**1.3**	Aishihik third turbine	**1.2**	**0.1**
2014		**1.8**		**1.6**	**0.2**
2015		**1.8**		**1.7**	**0.1**
2016		**2.4**		**2.3**	**0.1**
2017		**2.4**		**2.3**	**0.1**
2018		**3.3**		**3.2**	**0.1**
2019		**3.3**		**3.1**	**0.2**
2020		**4.7**		**4.4**	**0.3**
2021		**4.7**		**4.5**	**0.2**
2022		**5.5**		**5.2**	**0.3**

Although the right-most column on Table 5-11 above does show some diesel fuel savings in the 0.1–0.3 GWh per year range in the alternative plan over YEC's plan, these would be offset by other diesel fuel savings under YEC's plan which are not accounted for in this table. In particular, the first stage of the Carmacks-Stewart line project would result in additional diesel fuel savings due to the connection of the isolated community of Pelly Crossing, which is currently supplied by diesel generation, to the WAF System[19].

In conclusion, the Board considers it unnecessary to include diesel fuel savings in the rest of the economic comparison as the calculated savings appear to be insignificant and most likely offset by diesel fuel savings due to the connection of Pelly Crossing to the WAF system. This conclusion is based on the assumption that the Aishihik third turbine would be installed around 2013under both expansion plans. Therefore, the remainder of the economic comparison focuses strictly on the capital costs required under each plan.

[19] Pelly Crossing is currently served by a 0.7 MW diesel plant. The extent of diesel fuel savings due to the connection of Pelly Crossing to the WAF is unknown. However, a crude estimate can be obtained assuming that the installed capacity at the isolated community is "at criterion", the plant has at least 2 units of equal capacity, and the load factor is 50 percent. Using these assumptions, the diesel fuel savings could be as high as 1.3 GWh/year. If this is the case, then there would be a slight diesel-saving advantage of YEC's plan over the alternative plan.

5.4 Capital Cost Comparison

As stated earlier, a proper economic comparison would require a cash-flow analysis of capital costs, properly escalated to the year when each new project is placed in-service under each expansion plan, and then a present-value analysis, using appropriate economic parameters, to bring all costs to the same reference year for comparison. However, for this exercise it is sufficient to simply compare the total capital costs without a present-value analysis, given that all capital cost additions would take place in a relatively narrow expanse of time. To this end, Table 5-12 shows all capital additions under YEC's and the alternative plan.

Table 5-12: Capital Cost Comparison - YEC's and Alternative Expansion Plan under Base-Case Load Forecast

	YEC Expansion Plan	Capital Cost millions	Alternative Expansion Plan	Capital Cost millions
2006				
2007	Faro Rehab	**2.3**	Faro Rehab	**2.3**
2008	WD3-Refurb	**2.3**		
2009	WD2-Refurb. Carmacks-Pelly Crossing Line	**2.3** **0.0**		
2010	WD1-Refurb.	**1.8**	WD1, WD2, WD3 Retired. Aishihik second line.	**16 – 19**[20]
2011				
2012				
2013	Aishihik third turbine Pelly Crossing-Stewart Line	**7.0** **0.0**	Aishihik third turbine	**7.0**
2014				
2015				
2016				
2017	New Capacity Required	**??**		
2018				
2019			New Capacity Required	**??**
2020				
	TOTAL	**15.7**	**TOTAL**	**25.3 - 28.3**

[20] Preliminary estimate, likely understated based on current escalation factors. This would follow the analysis in YEC's November 9, 2006, update on page 10 where capital costs for the Carmacks-Stewart line are discussed with escalations in the 17 percent-34 percent range.

In reaching a conclusion, the Board makes the following observations:

- The above table is intended to show only capital costs that would increase electric rates. Therefore, the capital costs associated with the first stage of the Carmacks-Stewart line, namely the portion of line from Carmacks to Pelly Crossing in 2009, is shown as no cost to ratepayers, as YEC would pursue this project only if it results in no rate increases.[21] YEC's preliminary filing of a PPA with the mine owner supports this position (see Section 6.7 for discussion on the PPA).
- The capital costs associated with the second stage of the Carmacks-Stewart line (Pelly Crossing to Stewart Crossing) is treated the same as the first stage since YEC will only commit to this project if there is no adverse impact to ratepayers.[22]
- During the 2007–2009 time period, the Faro Rehab Project occurs the same years under both plans, which means equal rate increases under both plans. Modest rate increases are expected under YEC's plan in 2008 and 2009 due to refurbishment of two Mirrlees units, while no additional rate increases occur under the alternative plan.
- The 2010–2013 time period would see rate increases of $8.8 million under YEC's plan and $24.5 million under the alternative plan. Therefore, the latter plan would result in significantly higher rate increases as capital additions are larger and occur earlier in the period.
- In the post-2014 period, new capacity is needed in 2017 under YEC's plan and in 2019 under the alternative plan. This means that a rate increase would happen two years earlier under YEC's plan than the alternative plan. However, the effect of this two-year difference is not expected to be significant given that it occurs later in time.

In light of these observations, it becomes evident that YEC's plan would result in lower capital costs than the alternative plan.

In summary, the Board is satisfied that YEC's plan is acceptable, both in terms of its ability to satisfy the new planning criteria and its required capital additions. The Board could not find an alternative plan that is superior to YEC's Plan. It is important to note that the Board's recommendation to accept YEC's expansion plan is based on the premise that the Aishihik third turbine is installed and that the first stage of the Carmacks-Stewart line will result in no rate increase to ratepayers (which assurance was provided by YEC). This equally applies to the second stage of that line.[23]

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[21] Exhibit B-1: YEC's 20-Year Resource Plan: 2006-2025, January 2006, page 4-23.
[22] YEC Update November 9, 2006, page 9.
[23] YEC Update, November 9, 2006, at page 9 where YEC states: "Stage 2 will proceed thereafter only when conditions will permit its development without any adverse impact on ratepayers; in this regard, firm commitment to connect the Carmacks Copper mine is currently assumed to be a precondition for Stage 2 development."

6. Assessment of Near-Term Projects (need and timing)

6.1 $3-million capital spending threshold

Within the Plan, YEC committed to bring all projects with anticipated costs of $3 million or more before the Board for review[24]. UCG argued that the threshold should be lower. UCG suggested that that the threshold should be determined by a twofold criterion such as project value (for example, $500,000 or more) and impact on rates.

6.2 Recommendations of the Board

The June 5, 2006, letter from the Minister in point 1a) directs the Board to review:

> those projects related to the 20-Year Resource Plan which require commitments by YEC before the year 2009 for major investments with anticipated costs of $3 million or more…

YEC's commitment to bring capital projects of $3 million or more to the Board for this review, however, appears to stem from the Auditor General's *Mayo-Dawson City Transmission System Project Report*, dated February 2005.[25] Recommendation No. 35 of the Auditor General's report, and YEC's response to this states:

> The Yukon Energy Corporation should request that the responsible minister seek an order from the Commissioner of the Executive Council to designate future major capital projects as regulated projects, in accordance with the *Public Utilities Act*, so that such projects are reviewed by the Yukon Utilities Board and public hearings are held, if necessary, before the projects proceed. The minister may wish to consider proposing legislative amendments to require that all major capital projects be reviewed by the Yukon Utilities Board prior to approval.
>
> **Management's response.** The Corporation is proposing to establish a process that would require projects greater than $3 million to receive prior approval by the Yukon Utilities Board.

The Board interprets the letter from the Minister as referencing, for this review, the threshold as proposed by YEC. While this is the threshold for review in this proceeding, the Board is persuaded by the argument of UCG that a lower threshold should be used. Given the smaller rate-base in the Yukon compared to many Canadian utilities, and given the relatively small number of ratepayers in Yukon, the Board considers that a lower threshold would be more appropriate in the future. The Board recommends that the threshold for capital expenditures to be reviewed by the Board be set at $1 million. The Board agrees with Recommendation 35 and encourages the Minister to consider its implementation.

[24] Overview of Yukon Energy and Resource Plan submission, page 1.
[25] Exhibit C3-13.

6.3 Aishihik Third Turbine

In Chapter 4 of the Plan, YEC listed the Aishihik third turbine as a major near-term opportunity project. This project would provide 7 MW of capacity and energy of 5.4 GW.h/year. YEC recognized that under the N-1 planning criterion, this project would provide no reliable peak capacity value. The project cost was estimated at $7 million. Among the benefits listed for the project was the ability to displace peaking diesel generation. YEC indicated that the turbine was not needed before 2009.

In its argument[26], YEC confirmed the economic feasibility of the project and, based on the November 2006 update, stated that it expects to start construction in 2007 for a 2009 in-service date.

UCG disagreed with the position of YEC. UCG submitted that with 10 MWs of mine load added to the system, ratepayers would not see any benefit for two or three years; without mine loads, ratepayers would not see a benefit until the eighth year of operation. UCG also argued that this project would not assist YEC in meeting any of the planning criteria and, therefore, the project should be evaluated under Part 3 of the *Public Utilities Act*.

The City of Whitehorse and YCS were generally supportive of the Aishihik third turbine.

In reply, UCG submitted that this project is a mine-promoted opportunity as well as an opportunity for secondary sales, causing a negative impact on rates for a two- to eight-year period. UCG further stated that if the project were to proceed, those customers driving the need for the project should fund the negative rate impacts.

YEC, in its reply, addressed the environmental concerns of the City of Whitehorse and YCS. With respect to the comments of UCG, YEC disagreed that further review of the project is necessary, as the project was reviewed in detail in the 1992 Resource Plan and later by the Yukon Water Board.

6.4 Recommendations of the Board

Recommendation No. 37 from the 1992 Resource Plan Report stated:

> The Board recommends that the Companies pursue YTWB approval for the construction of Aishihik #3, assess the environmental costs after giving due consideration to the findings of the environmental reviews, and report back to the Board before commencing construction. The companies should pursue installation of the maximum capacity that is economically, technically and environmentally feasible.[27]

[26] YEC Argument, page 7.
[27] 1992 Resource Plan Report, page 136.

The Board recognizes that since 1992, YEC has obtained the necessary licences and environmental approvals for the Aishihik third turbine. The views expressed in 1992 are similarly held today. The question is: When should this project proceed?

The Board's analysis in Sections 4 and 5 above, which was conducted assuming the base-case load forecast, has shown that YEC's proposed expansion plan would be more economic than the alternative plan provided that the Aishihik third turbine is installed in 2013. It should be noted, however, that the addition of the third turbine under YEC's plan is not a capacity requirement determined by the planning criteria, but rather a requirement driven strictly by economic reasons, namely to offset future diesel generation that is expected to increase under the base-case load forecast. However, should the actual loads turn out higher or lower that the loads under the base-case forecast, the optimal timing of the third turbine would move earlier or later than 2013. Therefore, to minimize the uncertainty around timing of the third turbine, the final decision to proceed with this project should be made closer to the date when economic reasons indicate that the turbine is needed. Therefore, the Board recommends that this project not proceed until that time unless YEC can justify an earlier in-service date.

6.5 Marsh Lake Fall/Winter Storage Licence Revision

In its Plan[28], YEC proposed this project to increase the capacity at the Whitehorse Rapids hydro facility by approximately 1.6 MW with a concomitant energy increase of about 7.7 GW.h/year. YEC's approach was to amend the Whitehorse Rapids water licence by August of 2007. The estimated cost of this project was to be no more that $1 million.

In the Resource Plan Update filed November 9, 2006, YEC withdrew this project. Shoreline erosion, high fall water-level impacts in low lying areas, and related impacts to the built environment were reasons given for the withdrawal[29]. During the hearing, YEC elaborated that resistance to the project from residents of Marsh Lake was another reason to suspend the project. YEC felt that these concerns could not be addressed in the near term, thus losing the main appeal of the project.

UCG commented that YEC abandoned the project without assessing and evaluating the facts and recommended the project be retained as a potential future capacity enhancement. The City of Whitehorse and YCS held similar views

In reply, YEC stated that it would continue to study the Southern Lakes watershed but that from a resource perspective YEC was at its limit and would prefer to focus on projects with higher success probabilities. [30] YEC was not opposed to looking at this project again in the future.

[28] Overview of Yukon Energy's Resource Plan Submission, page 28.
[29] YEC Resource Plan Update November, 2006, page 2.
[30] YEC Reply, page 24.

6.6 Recommendations of the Board

The Board is of the view that this project is not likely to be completed in the near term, given the argument by YEC regarding local opposition to the project. However, the Board sees some viability to this project in terms of either displacing diesel generation or delaying future capacity additions. Therefore, the Board recommends that this project be retained in the Plan but be removed as a near-term project. YEC should update the status of this project when it files its next resource plan. The timing for YEC's next resource plan is discussed in Section 13.

6.7 Carmacks-Stewart Transmission Project

YEC has undertaken a number of planning activities with respect to this project. YEC indicated that, following consultations with First Nations and others, it had already filed an application with the YESAB for the Carmacks-Stewart line. In addition, subsequent to this hearing, YEC advised it had reached agreement on key terms of the PPA with the Minto Mine owners, who have now received sufficient financing to complete the mine that is currently under construction and is scheduled to be completed in the second quarter of 2007.

YEC also indicated that Western Copper had reconfirmed its interest in reaching agreement with YEC for supply of grid power to the proposed Carmacks Copper Mine and negotiations were expected to begin shortly. However, YEC indicated that, although Western Copper had recently made applications to the Government of Yukon and the YESAB for approval of this mine, Western Copper was not prepared to enter into formal commitments until approval was received.

In light of the above, YEC proposed developing the Carmacks-Stewart line in two stages. In the first stage, the 138-kV transmission line would be built from Carmacks to Pelly Crossing, including a 35-kV spur line to connect and supply the Minto Mine, and would cost $14.8 million. However, YEC submitted that the Minto PPA would result in material benefits, over and above the cost of the line, so that ratepayers will not be adversely affected by the expenditures required to implement this project.

While the PPA has not been finalized, by letter of December 31, 2006, YEC outlined the key terms of the PPA agreed to with the Minto Mine owner. These include a $7.2-million customer contribution, a $24-million minimum take or pay power purchase provision within the first eight years of YEC service, and security to be provided by the mine owner for these commitments. YEC indicated it would be filing an application with the Board for approval once the PPA is finalized, prior to the end of January 2007.

Intervenors expressed numerous concerns regarding the PPA which included:

- The timing of the filing and the process for review of this, and YUB approval of new rates;
- What happens if the Minto Mine closes earlier than anticipated;
- Terms of payment of the customer contribution; and
- YEC purchase of Minto Mine diesel units.

The second stage, a 138-kV transmission line from Pelly Crossing to Stewart Crossing, would be undertaken later, only when conditions would allow this development to occur without adverse effect on ratepayers. YEC indicated that a firm commitment to connect the Carmacks Copper Mine was a precondition for the development of the second stage, which would cost an estimated $15.2 million to complete.

6.8 Recommendations of the Board

The finalized PPA must still be submitted to the Board for review and approval. The Board assures Parties that a full review, including Information Requests to YEC, will take place once YEC files its application. For the purpose of this report, while the timing was tight given the date of YEC's letter and the deadline for this report, the Board considered it appropriate to seek comments from Intervenors. The Board recognizes that this filing of YEC has not been tested; however, the Board must proceed with making a recommendation on the Carmacks-Stewart line based on the information it has before it from this proceeding.

In the absence of an approved PPA, the Board cannot make a firm recommendation on the Carmacks-Stewart line. However, based on the information before it, the Board is of the view that YEC's proposed first stage of the Carmacks-Stewart line should proceed as applied for by YEC. This view is based on the fact that the Minto Mine is under construction, the mine owners have secured financing to complete the mine, key terms of a PPA have been agreed to by YEC and the mine owners, and YEC has asserted that ratepayers would not be adversely affected by the expenditures required to implement this project. The latter was an instrumental premise applied by the Board in the economic comparison, presented in Section 5.2, and used by the Board to favour YEC's plan over the alternative plan.

The Board notes that the Minister's August 29, 2006, letter suggests that the Government of Yukon may direct the Board to hold a project-specific hearing on the Carmacks-Stewart line. If the government chooses to direct such a hearing, the Board recommends this be done as soon as possible, given YEC's timing constraints for this project. If such a hearing takes place, its outcome may impact the Board's views on whether this project should proceed. Likewise, the outcome of YEC's forthcoming application to the Board regarding the PPA may also affect the Board's recommendation here to proceed with the Carmacks-Stewart line.

With respect to the second stage of the Carmacks-Stewart line, the Board concurs with YEC's strategy not to pursue this project unless there is a firm commitment to connect the Carmacks Copper Mine, if and when this mine is built, and under the same condition that ratepayers would not be adversely affected.

It is worth noting that in its economic comparison in Section 5.2, the Board assumed that the Pelly-Stewart line would be commissioned in 2013, to satisfy a need for new capacity in that year, and with its costs having no effect on ratepayers. Under this assumption, the Board found that YEC's plan was superior to the alternative plan.

On the other hand, if the Carmacks Copper Mine does not proceed, the Board does not recommend the Pelly-Stewart line as a project to satisfy a need for capacity in the WAF system, as the cost of this line ($15.2 million) does not justify the limited capacity contribution of 6 MW (and decreasing as the load on the MD grid increases).

6.9 Mirrlees Life Extension Project

YEC indicated it has continued to assess this project, including the scope of work, expected parts requirements, scheduling overhaul activities, etc., and confirms that it would be capable of completing the project by the proposed dates. Specifically, YEC proposes to complete refurbishment of the Mirrlees units WD3, WD2, and WD1 in 2008, 2009, and 2010, respectively. The total cost of refurbishing these three units is estimated to be $6.4 million.

YEC's continued investigation has led it to propose a fourth refurbishment, that of another previously retired Mirrlees unit currently situated at the Faro plant, to be completed in 2007.

YEC submits that there would be two benefits to proceeding with the refurbishment of the Faro unit first, followed by the Whitehorse Mirrlees units:

- The Faro unit would bring 5 MW to the current available capacity, while overhauling and refurbishing WD3 in 2007 would only secure less than 1 MW of new capacity. Therefore, the Faro Project in 2007 would more than compensate for the decision not to pursue the Marsh Lake Fall/Winter Storage Project, which would have provided 1.6 MW in 2007, and provides the WAF system with some added near-term capacity cushion; and
- The Faro Project can be started at any time, including during winter, without impacting on the amount of backup capacity available on the system. In contrast, plans for overhauling WD3 were focused on the need to start the work only after winter peak loads had subsided, and ensure completion by the time fall loads begin to grow to cold weather levels.

YEC also indicates that the cost for the rehabilitation of the Faro Mirrlees unit is expected to be similar to the cost of refurbishing the other Mirrlees units at Whitehorse, i.e. at about $0.457 million/MW, or a total of about $2.3 million.

YEC mentioned that it may consider other used diesel plant alternatives if they are found to be cost competitive and offer other advantages. YEC made reference to two EMD 645F4B 2.8 MW units with a comparable or better economic life and at a comparable total project cost, as an alternative to refurbishing Mirrlees units. However, for the purpose of evaluating this resource plan, YEC considered that these alternative units were equivalent to the Mirrlees refurbishments.

The City of Whitehorse submitted that extending the life of the existing diesel units or possibly replacing them with new larger units would have significant environmental impacts relating to air pollution, noise pollution, and greenhouse gas production, and recommended that the use of these diesel units not only be discouraged, but that their relocation out of downtown Whitehorse be considered. Further, it submitted that diesel units located in downtown Whitehorse should be specified for use only in the case of emergencies, and should not be used to offset power supply when sufficient hydro generation capacity is not available.

UCG supported this project on condition that the refurbished units are restricted in hours used such that they only be used to meet the highest peak load and not to provide capacity on an ongoing basis.

6.10 Recommendations of the Board

The Board notes that the WAF system already had a capacity shortfall of 0.7 MW in 2006, according to the adopted N-1 criterion, and is expected to grow to 1.8 MW in 2007, assuming the load growth as per the base-case forecast. Therefore, new capacity should be added to the WAF system as soon as possible.

The Board is of the view that, of all the projects that have been discussed in this proceeding, refurbishments of existing diesel units are the only options that could be implemented in a relatively short period of time to alleviate the current shortfall situation in the WAF system. Furthermore, the Board concurs with YEC that the previously retired Mirrlees unit, currently situated at the Faro plant, should be the one to proceed first, as it would contribute 5 MW of capacity and could be started at any time without impacting the rest of the existing capacity. Therefore, the Board recommends that YEC proceed with refurbishing the Faro unit as expeditiously as possible.

Once the Faro unit is operational in 2007, the winter LCC of the WAF system would be 60.7 MW under the N-1 criterion and this should ensure adequate capacity until 2009, provided that the Mirrlees units WD1, WD2, and WD3 are not retired and the load increases as per the base-case forecast. If the load increases less than the base-case forecast, the 60.7 MW LCC would be adequate for a few more years but it is unknown how much longer the Mirrlees units WD1, WD2, and WD3 could be counted on if they are not refurbished. On the other hand, if the load increases more than the base-case forecast, then the annual peak would reach the 60.7 MW LCC sooner than 2009. Therefore, irrespective of load growth, it is evident that the WAF system would need additional capacity in the 2008–2010 time period, soon after the Faro unit is commissioned. This supports YEC’s proposal to complete the refurbishment of units WD1, WD2, and WD3 within these years according to its expansion plan, which the Board found to be acceptable. Based on the foregoing, the Board recommends that YEC proceed with the Mirrlees units WD1, WD2, and WD3, as planned.

With respect to YEC’s future consideration of other used diesel plants, such as the EMD 645F4B units, as an alternative to refurbishing the Mirrlees units, YEC should obtain Board approval before it decides to pursue this option, and file an update to its resource plan if exercising this option materially changes the approved plan.

The Board, by way of conducting its own analysis, confirmed YEC's submission that generation from diesel plants is indeed very small, as all diesel plants operate as peaking units, and is not expected to increase in the near term. Furthermore, the addition of the Aishihik third turbine would ensure that diesel generation remains minimal in the mid to long term as well. This should alleviate concerns of increased air and noise emissions from these units.

6.11 Alternatives to proposed projects (provisions for independent power producers (IPP) of renewable energy)

YEC acknowledged that IPPs can offer specific skill, knowledge or experience for certain supply options which can be beneficial to Yukon ratepayers. However, YEC also reiterated several outstanding issues from 1992 that still remain unresolved. Determining the value of the energy provided by the IPP has not progressed. The isolation of the Yukon power system gives IPPs no external alternatives for their production and creates a scenario of take-or-pay contracts. YEC also questioned reliability issues and the potential for financial guarantees.

In argument, YEC reaffirmed that it does not have an IPP policy in place and, until the new capacity-planning criteria was implemented, there was surplus capacity and energy on the system. As the Yukon electrical system grows, YEC is prepared to look into developing an IPP policy.

The City of Whitehorse noted that, with new technologies, government grants, and the implementation of net metering, IPP opportunities should be increasing and should be addressed in the Plan. It also pointed out changes to the BC *Utilities Commission Act* that incorporated an IPP clause into the BCUC Resource Planning Guidelines. The City of Whitehorse requested that the 1992 YUB recommendations respecting IPPs be implemented.

YCS echoed that there should be an IPP policy to ensure fair treatment of all potential IPPs and that the policy should include a renewable energy preference.

In reply, YEC responded that neither the Board nor YEC can implement a recommendation directed toward the Minister. YEC further stated:

> In any event, YEC sees no practical benefit to this type of recommendation at this time in advance of its expectation that such a policy will be developed by YEC as needed in the next few years[31].

[31] Transcript, page 91; YEC Reply, page 33.

6.12 Recommendations of the Board

The Board is of the view that developing an IPP policy has merit. Given that YEC is looking at capacity additions and energy for diesel displacement, the Board is of the view that this is an appropriate time to develop a policy. The Board agrees with the views of UCG, YCS and the City of Whitehorse, and recommends that YEC, in consultation with stakeholders, begin the process to develop an IPP policy.

6.13 Aishihik Second Transmission Line

On page 4-27 the Plan states:

> As discussed in detail in Section 3.3, the largest single factor influencing the reliability and risk profile of the WAF system today is the non-redundant nature of the Aishihik transmission line. A major rationale for maintaining substantial "stand-by" diesel in Whitehorse is to address the risks of an Aishihik line failure[32].

The option to twin the Aishihik transmission line would bring a 15 MW benefit to the LCC of the system and an 8 MW benefit under the LOLE criterion. Additional firm capacity benefits would be derived from re-runnering and third turbine enhancements. The effect future capacity requirements have are shown in Section 5 of this report.

YEC further stated on page 4-36:

> In addition to ensuring existing Aishihik capacity can remain substantially more reliable to the system, the Aishihik 2nd Transmission Line Project also has the benefit of enhancing the opportunity provided by two projects to provide additional capacity at Aishihik:
>
> 1. The 7 MW Aishihik 3rd turbine.
> 2. A re-runnering of the existing Aishihik turbines for potentially up to 6 MW of added capacity.
>
> The Aishihik 3rd Turbine is discussed in detail in Section 4.3.2. At this time, there is insufficient definition on the potential Aishihik re-runnering project to determine likely costs and practical full capabilities; however, re-runnering projects in other jurisdictions are frequently pursued as cost-effective sources of new capacity and/or energy.

In argument, YEC said that this project was not the lowest cost option for securing needed capacity when compared to either a new diesel plant in Whitehorse or the Mirrlees life extension projects. No other parties commented on this project.

[32] YEC 20-Year Resource Plan, page 4-27.

6.14 Recommendations of the Board

Using the base-case scenario without mines, the Board agrees with YEC that other options are more cost effective in securing capacity than building the Aishihik second transmission line. As the Aishihik hydro facility is enhanced (third turbine, re-runnering), it would appear the risks of not proceeding with this project materially increase. If diesel displacement is truly a goal of YEC and Yukon ratepayers, then perhaps this project should move up in priority and the purchase/refurbishment of diesel generation should drop. Based on the economics as currently presented in the Plan, not proceeding with this project is the prudent course of action. However, based on the Minto PPA and updated load projections, if the scheduling of the Aishihik third turbine becomes viable at an earlier date, then YEC should reassess this.

6.15 Aishihik Rewind

YEC indicated that it had completed the rewinding of the existing generators at the Aishihik plant, which resulted in an electric-capacity increase of the generators, but the actual capacity increase from the plant had yet to be ascertained. YEC explained that the capacity increase could not be counted on until testing of other components was completed. Specifically, YEC needed to ensure that bearings and other mechanical parts of each turbine could handle the increased output as well as the ability of the penstock and wicket gates to handle increased water flows.

The Board is of the view that, given that the rewinding of both turbines has been completed, the required testing needed to ascertain the new capacity of these turbines should be carried out in due course. However, there is no urgency on completing the testing since the increased capacity of the existing turbines would not contribute to load carrying capacity of the WAF system under YEC's expansion plan[33]. Therefore, the Board recommends YEC conduct the testing when it considers it appropriate.

6.16 Wind Energy

Intervenors submitted that wind power should be considered and included in the Plan. However, Intervenors did not elaborate on how much, and when, wind power capacity should be installed, nor did they elaborate on the conditions that would be required to justify wind power plants in the WAF. Without the benefit of Intervenor evidence, the Board must consider only YEC's testimony and the Board's own analysis to reach any conclusions respecting the prospects for wind power in the Plan.

[33] YEC's plan does not call for the twinning of the Aishihik-Whitehorse transmission line, which means that under the N-1 planning criterion the entire Aishihik Plant is removed from the calculation of load carrying capacity. Therefore, any increased capacity of the Aishihik Plant would have no effect.

The Board will address the following two questions in its analysis of wind power as a potential resource:

1. Can wind power capacity replace, or defer, the need for other resources?
2. Can wind power plants be justified on economic grounds as a resource that would displace other more expansive generation?

To address the first question, i.e. whether or not wind power capacity can replace or defer the need for other resources, wind power capacity has to be put through the planning-criteria test, which in this case requires an assessment of the capacity contribution that could be expected from wind plants under the LOLE and the N-1 criterion.

Wind-power capacity should be included in the LOLE calculation, as the LOLE is computed over all the hours in the year and wind power plants would contribute to lowering the LOLE in those hours when the wind allows them to generate. However, since these hours cannot be predicted, wind power capacity is normally de-rated throughout the year to simulate the unavailability of wind. The most common de-rating factor used on a wind plant is the capacity factor achieved by that plant in previous years or, in case of new plants, typical capacity factors achieved by other plants located in the same wind regime. YEC indicated that the capacity factor of the Haeckel wind plant was in the order of 20 percent. The Board agrees with YCS that a privately owned wind plant may perform better. Therefore, it may be possible for wind plants to achieve a better capacity factor, perhaps in the order of 30 percent. In summary, the contribution to capacity, as defined by the LOLE criterion, from a wind power plant would normally be in the order of 30 percent of the installed capacity of the wind plant.

Wind energy is an intermittent resource outside the control of the wind power plant operator. Therefore, for capacity planning purposes, wind cannot be counted on to be available during an N-1 contingency situation and it should be assumed to be zero at the time of the annual peak when calculating load carrying capacity under the N-1 criterion. This is consistent with the approach used by YEC, as it also assumed to be zero capacity for the existing Haeckel wind plant in its N-1 calculations. Therefore, the Board concurs that wind power would have no capacity contribution under the N-1 criterion. Consequently, since the N-1 criterion is the driving force behind the need for new resources under YEC's expansion plan, the Board concludes that wind plants would have had no effect on either replacing or deferring the need for other resources, had wind power been included in the expansion plan.

The Board will address the second question, namely, Can wind power plants be justified on economic grounds as a resource that would displace other more expansive generation, by analyzing and extrapolating the results obtained in the economic comparison conducted earlier in Section 5?

As it was found in Section 5, there was no opportunity for diesel fuel savings until 2012, given that diesel plants were used only as "peaking" units and the load was still relatively low. Therefore, it can be easily inferred that any generation from wind plants added in that time frame, i.e. before 2012, would have displaced mainly hydro generation and very little diesel generation, if any. Therefore, wind power cannot be justified in this time period.

The economic comparison of Section 5 also found that beginning in 2013, there was potential for diesel fuel savings as the load continued to grow and diesel units were called on to operate more often under YEC's plan. This was the reason the addition of the Aishihik third turbine in 2013 is instrumental in achieving significant diesel savings and turning YEC's expansion plan more economic than the alternative plan. So, in order to assess if wind power can be justified on economic grounds during this time period, one needs to assume that a wind power plant would be installed instead of the Aishihik third turbine in 2013, and to demonstrate that the installation of the wind power plant would be more economic than, or at least as economic as, installing the Aishihik third turbine in that same year. Furthermore, one also has to assume that the wind power plant would displace the same diesel generation as the Aishihik third turbine, if the former is to produce similar diesel energy savings as the latter.

In reviewing the results of energy-generation modeling conducted to arrive at the diesel savings presented in Table 5-11 (Section 5), the Board finds that generation volumes from the Aishihik third turbine start at 14 GWh in 2013 and steadily increase to 22 GWh in 2022[34], which was the end of the simulation year. Had the simulation been carried further into the future, generation from the Aishihik third turbine would have continued to increase, possibly up to its full potential (55 GWh[35]) or up to a level determined by water flows. Therefore, if a wind power plant is installed instead of the third turbine, it would have to generate similar energy volumes (i.e. 14 GWh–22 GWh and increasing) if it is to produce the same diesel energy savings as the third turbine. Such generation levels equate to wind power capacities of 6MW - 8MW[36] and increasing, which would cost[37] an estimated $6 million to $8 million and more to install. In comparison, the capital cost of the third turbine is $7 million. Moreover, the estimated wind power plant cost does not include the cost of connecting to the grid, which may require a new dedicated transmission line depending on location, nor does it include wind power's known higher maintenance costs and less longevity, when compared to a hydro plant. In conclusion, a wind power plant that would produce similar diesel fuel savings would cost more to install, more to maintain, and would have a shorter life than the Aishihik third turbine. Therefore, the Board cannot justify wind power generation on economic grounds, i.e. as a resource that would displace other more expansive generation, for this expansion plan.

[34] The Aishihik third turbine was dispatched fourth in the stacking order, after the Whitehorse unit WD4, and the Aishihik units 1 and 2.
[35] Assuming 90-percent capacity factor.
[36] Assuming a base-loaded plant, i.e. first in the stacking order, and achieving a 30-percent annual capacity factor.
[37] Assumes $1 million per installed MW. Does not include the cost of connecting to the grid.

In summary, the Board finds that for this Plan, wind power would neither replace nor defer the need for other resources, nor can it be justified on the basis of potential diesel fuel savings. Therefore, the Board recommends that utility-scale wind power plants should not be included in the current resource plan.

6.17 Rate Impacts and Risks

Schedule 1, attached hereto as Appendix A, provides a high level assessment of YEC's proposed projects. It is intended to show the effects in an order of magnitude, considering the general assumptions utilized, and not imply a specific rate impact to any particular rate class. The purpose is to provide a directional impact of the projects and serve as a guide in the understanding of how these projects affect ratepayers.

Schedule 1 assumes a base-case load-growth scenario (no mine loads), no increases in secondary sales, approximates revenue requirement increases based on the Aishihik second transmission line, and from there derives rate increments. Each project is mutually exclusive to show the individual rate impact.

Aishihik re-runnering is not considered, as cost information is not available. The Whitehorse Diesel Replacement Project is shown but will not be considered when compared to the Mirrlees Life Extension Project, as the latter is clearly the best option. The options are compared in present value terms and thus the timing of the benefits are skewed forward when in reality the rate impacts would be higher in the short-term and decreasing in the long term. Further, the rate increments do not reflect a compounding effect, they are treated as additive to the currently assumed ratebase.

If a project proceeds, the rate impact is reflected in Schedule 1. These impacts can be mitigated by such events as increased load (for example, mine additions), capital contributions, and potential further diesel displacement.

Each project presents risk to Yukon ratepayers. Foremost, all projects face forecast risks. The risks associated with each project will be briefly discussed.

Mirrlees Life Extension – Regulatory and environmental risks are considered minimal for this project. Cost overruns provide the largest economic risk, but the project is feasible when compared to the diesel replacement option. If the Aishihik second transmission line moves forward within the next three years, then this project would be redundant.

Aishihik third turbine - Regulatory and environmental risks are considered minimal for this project. Cost overruns present one risk, and quantity of diesel displacement presents another risk. If the Aishihik second transmission line does not proceed, then based on the N-1 criterion, there is an operational risk.

Carmacks-Stewart transmission line - Regulatory and environmental risks are considered significant for this project. There is regulatory risk on project approval, PPA approval, and rate-design approval. YESAB approval is necessary and any regulatory delays can nullify this project (scheduling risk). Additional risk relates to the economic volatility of the mining industry (credit risk), and related load forecast. Mine loads greatly enhance the economics of this project. The size and timing of the project could face cost overruns and, as mentioned by YEC, there is some project agreement risk.[38]

Aishihik second transmission line – There are regulatory and environmental risks with this project as regulatory and environmental approvals are required. Similar to all the projects, there is risk of cost overruns. This project has not received the level of planning review as has the Carmacks-Stewart line; therefore, the cost estimates are not as refined. As this is a project to satisfy the N-1 criterion it is not directly related to load growth but its viability increases with each expansion at Aishihik. The benefits of this project reduce if Mirrlees proceeds.

Overall, the risks with these projects are standard for the utility industry, and in the case of the Minto Mine, are standard for Yukon. The Mirrlees Project presents the least risk and should proceed. The Aishihik third turbine project is driven by economics and YEC has pledged not to proceed with this unit until it is demonstrably needed. The Carmacks-Stewart transmission line has been split into two stages which in itself is a risk reduction. The security measures obtained by YEC from Minto reduce risks further. Aishihik's second transmission line is not being promoted by YEC. This inevitably reduces the potential forecast risk for costs on this project.

Potential risks can be mitigated further by the following:

1. YUB review of the Minto-YEC PPA;
2. YUB review of the second stage of the Carmacks-Stewart transmission line; and
3. YUB review of the timing of the Aishihik third turbine.

A regulatory review of the PPA and the second stage of the Carmacks-Stewart line, would provide Yukon ratepayers a full opportunity to test the deemed benefits of those projects. The Aishihik third turbine only needs to be tested for timing. A lengthy proceeding would not be necessary for the Aishihik third turbine project, as it would be limited to the consideration of the economics of the project.

7. Demand-Side Management (DSM)

Intervenors submitted that DSM initiatives should be considered as alternatives, or in addition, to the resources that would be required by any expansion plan to comply with the new planning criteria. Unfortunately, Intervenors did not provide information respecting the types of DSM programs, the expected amounts of load reduction or load shifting that could be expected from DSM, their implementation costs, or who should be responsible for their implementation and continued administration.

[38] A project agreement is needed with NTFN; YEC Argument, page 18.

DSM programs can generally be grouped into two main categories, namely programs intended to reduce electric load and programs intended to shift load. Reducing electric load has a direct effect on the N-1 and LOLE criteria, as any load reduction would translate into less required resources. DSM programs usually accomplish load reductions through incentive programs. For example, cash-rebate programs and/or tax exemptions are offered to convince consumers to reduce their use of electric energy by purchasing more efficient appliances and/or to switch from electricity to an alternative fuel[39]. The effectiveness of these kinds of programs depends on how many customers actually purchase new more efficient appliances (or switch to a different fuel), which normally would depend on how large the cash rebate or tax exemptions are.

Load shifting programs are normally aimed at reducing the annual peak by influencing consumers' load behaviour so that they would shift consumption from peaking hours to non peaking hours. Load shifting has significant effect on the need for new resources under the N-1 criterion, as the annual peak is reduced, but less effect on the LOLE criterion, as load is not actually reduced but moved to off-peak hours. Load shifting is normally accomplished by implementing time-differentiated electric rates, so that the electricity price is higher during peaking hours and lower during off-peak hours, in conjunction with the installation of time-differentiated electric meters at the customers' connection points. The effectiveness of these kinds of programs depends on how many customers would be willing to purchase the more expensive time-differentiated electric meter, if the program is voluntary, or how many meters are actually installed under a non-voluntary government-sponsored program, or how many are installed if cash rebates or tax exemptions are offered.

In whichever case, load reduction or load shifting, the cost of implementing a DSM program has to be carefully assessed against the expected benefit of the DSM program itself. Therefore, the Board is of the view that, although conceptually DSM initiatives should always be encouraged and, ideally, actively pursued as they promote conservation (through load reduction) and efficient use of resources (through load shifting and/or peak shaving), their implementation comes with significant associated costs. The challenge is to accurately assess weather the costs of a DSM program would be less than the benefits that would be realized by its implementation. Making this assessment is not a trivial matter and there is definitely insufficient information in the evidence submitted at this proceeding to attempt an assessment.

Another important issue respecting DSM programs is to determine who should be responsible for implementation and continued administration. Traditionally, regulators have imposed DSM programs on the electric utility companies they regulate. However, this has resulted in less than expected benefits from DSM programs due to conflicting objectives, i.e. electric utilities are in the business of producing and selling electric

[39] Intervenors at the hearing mentioned new housing developments in Whitehorse using electric space heating. This is a typical example of electric load suitable for fuel switching. It is presumed that the developers selected electric space heating based on economics reasons, i.e. it was probably less expensive than installing a different type of space heater. Therefore, a well designed DSM program would create an economic incentive for developers to install non-electric space heaters in new housing developments and for owners of existing dwellings to switch to an alternative fuel.

energy to customers while DSM programs are intended to influence consumers to reduce their electric energy use. Therefore, the question of who should be in charge of implementing and administering DSM needs to be addressed.

In summary, given the insufficient information and the unknown benefits and costs of possible DSM programs in this proceeding, the Board recommends that the Government of Yukon consider commissioning an independent group to study the potential for DSM initiatives in the Yukon and make recommendations. The types of DSM programs, the expected amounts of load reduction or load shifting that could be expected from DSM in the YEC and YECL systems, the implementation costs, and who should be responsible for implementation and continued administration of DSM programs should be part of this study. The Board is aware of a DSM report that Parties may wish to review which was prepared for the Canadian Association of Members of Public Utility Tribunals and is publicly available[40].

8. Environmental and Other Issues

This section addresses the environmental and other issues that were identified earlier in this proceeding and that were subsequently reviewed and revised with input received from those who participated at the Pre-Hearing Conference.

The Board recognizes the mandate of the YESAB in its role to assess environmental and socio-economic impacts of projects in the Yukon. The Board assumes that the Parties also recognized the YESAB's role and mandate, and this explains the limited attention that many of these issues received during the proceeding.

With the YESAB's role and mandate in mind, the Board is of the view that its responsibility to consider environmental issues is limited to assessing how environmental issues would affect the economic analysis of projects and the impact that these issues would have on Yukon ratepayers and YEC rates. Therefore, what follows is the Board's assessment of the effects of environmental issues on the economic merits of YEC's proposed expansion plan as well as other related issues.

8.1 Water levels at Marsh Lake and Aishihik Lake

Imposing less stringent winter peak generation limits at the Whitehorse Hydro Plant and/or achieving higher output at the Aishihik plant may result in environmental impacts as a result of different water levels at Marsh Lake and Aishihik Lake, respectively.

As explained in Section 6.15 above, YEC completed rewinding of the existing generators at the Aishihik plant. This could potentially result in a capacity increase provided that future testing proves this is mechanically feasible. However, if this capacity increase cannot be implemented due to environmental reasons, such as water level or icing issues on Aishihik Lake, the Board considers that this would not affect the proposed expansion plan. This is because increased output at the Aishihik plant would

[40]*Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Tests*; Summit Blue Consulting, LLC

neither contribute to capacity, as per the N-1 criterion, nor would it displace any significant diesel-fuel generation elsewhere on the WAF system.

Currently, the maximum winter output of the Whitehorse Hydro Plant is restricted to 24 MW. The potential for lessening this restriction was discussed during the hearing. YEC submitted that a study by Acres Engineering, which had been conducted previously to study the plant's winter peaking output, indicated that the maximum winter peaking capacity could be increased above the 24-MW level, possibly as much as 29 MW, provided that this level of output was maintained for a limited number of hours and followed by a period of lower output to compensate and to maintain an ice hinge to shore ice[41]. YEC indicated that, before this winter operation could be implemented, it needed to assess the risks and constraints posed by such operational requirements. To this end, YEC was in the process of retaining ice experts who would be asked to assess this potential for higher winter output at the Whitehorse Hydro Plant.

The Board considers that a 5-MW lessening of the Whitehorse Hydro Plant winter peaking restriction would have a significant effect on the proposed Plan, as a 5-MW winter capacity increase will raise the LCC of the WAF system by 5 MW under the N-1 criterion, and to a lesser degree under the LOLE criterion. Such an increase could replace the need to refurbish one of the Mirrlees diesel units, provided that associated icing issues and possible environmental effect can be mitigated.

Therefore, the Board recommends that the icing studies, which YEC plans to undertake to assess potential for less stringent winter constraints on the Whitehorse Hydro Plant, be conducted as soon as possible. Should these studies demonstrate that higher winter capacity is possible, the effect on the timing of new capacity additions should be re-evaluated and an updated resource plan should be submitted to the Board.

8.2 Diesel generation issues related to greenhouse gas emissions, fuel efficiencies, and impact of pollutants in urban centres

In the absence of federal or territorial legislation restricting or taxing carbon dioxide (CO_2) emissions, no economic penalties can be imposed on diesel generation that may favour one expansion plan over another. Therefore, CO_2 emissions do not affect the economic analysis of projects and/or the impact on Yukon ratepayers.

Diesel plant fuel efficiency becomes relevant only when diesel plants are operated for extended periods of time. However, this would not be the case under the YEC proposed expansion plan. The Board found (in Section 5) that in the 2007–2012 time period, diesel plants operate mainly as "peaking" units, i.e. they operate very few hours during each year and, with the addition of the Aishihik third turbine in 2013, they would continue operating as peaking units for several more years into the future. Therefore, diesel plant fuel efficiency would not affect the plan.

[41] YUB-YEC-2-8

With respect to the impact of pollutants (in general) from diesel generation, the Board points out that, unless the cost associated with pollution can be ascertained and included in the economics of each project, the Board is unable to impose pollution-related penalties that may favour one plan over another.

8.3 Proposed Carmacks-Stewart transmission line and issues related to right-of-way clearing, timber salvage, and connection of communities along the line

While this was raised as an issue by Intervenors, there was no discussion of this issue at the hearing. The Board considers that right-of-way clearing and timber salvage are site-specific issues that fall under the YESAB mandate and can only be addressed once a proposed line routing has been applied for. In general, any transmission right-of-way would require constant vegetation control as part of ongoing maintenance and to maintain reliability. Therefore, good engineering practice and common sense dictate that a low-maintenance cost right-of-way should be preferred.

Connection of communities along the line should be pursued, provided that the connection costs, which may include a step-down substation and additional lower-voltage power lines, are offset by diesel-fuel savings and increased reliability of supply. The Board is satisfied that YEC's first stage of the Carmacks-Stewart transmission line contemplates connection of the community of Pelly Crossing to the WAF system and that other communities may be connected in the future, if and when the second stage is constructed.

8.4 Ability for independent power providers to access the proposed line and the possibility of this project being used to indirectly subsidize mines

There are two different issues formulated above. The first issue, i.e. the ability for independent power providers to access the proposed transmission line, is an issue related to the connection of IPP plants to the grid. Therefore, this issue belongs in a future IPP policy, which the Board addressed earlier in Sections 6.11 and 6.12. Any IPP policy should address all matters related to access and connection of IPPs to the grid. Wheatear the policy itself would favour IPPs using renewable resources over those using non-renewable resources is a different matter, but this would have to be part of an IPP policy.

The second issue, i.e. the possibility of this project being used to indirectly subsidize mines, can be addressed by answering the following question: Why should new mines benefit from generation from electric facilities already built and paid for by Yukon ratepayers?

In finding YEC's proposed expansion plan appropriate, the Board considered the following points as it addressed the issued posed by the question above. The Board notes that currently, there is surplus hydro-electric energy available from existing electric facilities in the WAF system. This surplus energy should not be confused with the capacity shortfall that could be expected during the winter peak and under an N-1 situation. The proposed transmission line would afford an opportunity to sell surplus hydro-electric energy to these mines, which would bring economic benefits expected to be more than the cost of building the line. Furthermore, there would be additional economic and environmental benefits as the line would allow the connection of isolated communities (currently supplied by diesel generation) to the predominately hydro WAF grid. On the other hand, if this line was not allowed, the opportunity to sell surplus energy would be lost, isolated communities would continue their diesel-fuel dependency, and moreover, the mines would have to install their own generation, which would operate base-loaded and would most likely be generated by fossil-fuels such as diesel. Therefore, the Board is convinced that the Carmacks-Stewart transmission line would result in net benefits to ratepayers. The mines should also bring additional socio-economic benefits as a result of increased economic activity and employment opportunities.

8.5 Provisions to limit the use of non-renewable fuels such as coal, gas and oil to their current levels

It is unclear if the energy sources enunciated in the above issue refer exclusively to their use in electricity generation or if the intention was to consider their other potential broader use in residential, commercial, and industrial uses. The Board can only address the former, as the latter is outside the scope of this proceeding. Therefore, the following paragraph addresses the effect of limiting non-renewable fuels (coal, gas, oil, etc) in the resource plan.

When it comes to assessing the economic benefits of any expansion plan intended to ensure a reliable power supply in the near and long term, the Board considers it unwise to limit the potential energy sources that could be considered in the Plan, as excluding some of the options would most likely result in a less-than-optimal plan, possibly resulting in higher costs. However, the Board recognizes that this issue results from a genuine concern for the perceived negative environmental effects of resources such as coal, gas and oil. Therefore, the ideal approach to finding the best expansion plan would consider not only all possible energy sources but also their associated environmental costs in the economic analysis. Unfortunately, these environmental costs are unknown. However, the only new fossil-fuel resources in the Plan are diesel plants which would operate only as emergency or peaking units; therefore, they would be called to operate only for few hours each year. Further, the addition of the Aishihik third turbine in 2013 or thereabouts would ensure that diesel plants continue to operate in their emergency/peaking mode, and diesel generation is not expected to increase significantly from current levels.

8.6 Integration of resource extraction industries and power generation, such as the timber industry and the development of bio-fuels

The Board is of the view that this matter should be left up to the forestry industry to decide. In general, if the price of electric energy is too high, some industries may prefer to generate their own electricity, especially if they have some sort of waste product, such as biomass, that can be used as fuel. This is, of course, a decision based purely on economic grounds. Therefore, the Board has no further comments on this issue.

9. Secondary Energy

The City of Whitehorse in argument stated:

> YEC's resource plan speaks to the advantages gained by YEC making secondary power sales available at a cost-effective rate. Secondary Power sale was a program offered by Energy Solutions Centre and YEC to promote the use of excess hydro power while reducing GHGs at the same time[42].

The City of Whitehorse went on to recommend that YEC use the surplus funds being received from secondary power sales to implement DSM programs that reduce power usage.

YCS noted the YEC's reference to growth in secondary sales from 3.917 GW.h in 2000 to a forecast of 20.613 GW.h for 2005 and pointed out that if the Minto Mine and Carmacks Copper Mine go forward, secondary sales will significantly curtail. YCS asked the Board to see that secondary sales continue on a seasonal basis and that such revenue is included in the evaluation (economic) of capacity and energy supply options[43].

In reply, YEC had two comments[44]:

1. Secondary Sales are offered as a means to use otherwise surplus hydro to make the best use of assets that ratepayers are paying for and generate revenues that help keep firm rates lower than they would be if this power was wasted. It is not primarily offered as a "green house reduction initiative" although it does offer this benefit as well.
2. The secondary power sales on WAF now exceed 20GW.h per year, and customers indicate no plans to end their use of the rate. In short, the rate remains viable for all customers who have made the investment to access the power.

YEC further stated that firm ratepayers benefit as secondary sales contribute to YEC's revenue requirement.

The Board agrees that secondary sales are a beneficial use of YEC assets and shares the view that capacity and energy supply additions should not be undertaken simply to satisfy demand for secondary sales.

[42] City of Whitehorse Argument, page 5
[43] YCS Argument, pages 10 and 11.
[44] YEC Reply, page 40.

10. Assessment of Long-Term Planning

As stated in the Load Forecast section of this report (Section 2), YEC must look ahead to the potential development of major industrial loads. Although growth in the residential and commercial sectors needs to be considered, the potential for variability in the non-industrial forecast, which is the only component affected by YECL load data, is at most a small component of the shortfalls being assessed and the resulting proposed projects[45]. Page 1-10 of the Plan states:

> Beyond near-term needs and opportunities, current planning issues must be addressed regarding other potential future industrial loads and developments during the next 10 to 20 years, including the Alaska Highway Natural Gas Pipeline Project. Potential industrial loads need to be considered, and the identification, definition and "protection" of appropriate resource options is required to ensure that YEC is able to meet new loads when relevant on a timely basis if and when they develop.
>
> Supply-side options potentially relevant for a construction start within the next 10 years vary widely depending on the potential industrial developments considered, and include a range of different hydro possibilities as well as coal-fired generation and potentially natural gas-fired generation.
>
> Lead times required to plan, approve and develop major new power supply projects, as well as the material planning costs associated with pre-construction activities required to keep these options available on a timely basis, underline the relevance of the current resource plan review.

Chapter 5 of the Plan describes the challenges faced by YEC in its long-term planning. The demographics of Yukon are such that there is significant volatility in the industrial forecast and the potential impacts on generation and transmission assets. The benefit of the long-term planning is that it allows more time to evaluate potential loads and options.

Some of the risks with planning long term for industrial loads were described by UCG:

> Planning for such loads within the load planning for the rest of YEC's non-industrial customers can result in excessive capital expenditures to account for temporary mine loads, expenditures which could then be left to non-industrial customers to bear. A prime example could be the proposed Carmacks-Stewart transmission line proposal which, if not strictly segregated from the planning for the rest of the load, could result in the costs of this expensive project being borne by ratepayers who do not need the expansion if the mine fails prematurely[46].

[45] UCG-YEC-2-43, Footnote 1.
[46] UCG Argument, page 8.

Section 5.1.1 of the Plan outlined the consideration given by YEC in terms of long-term planning and new industrial loads. YEC needs to assess its readiness and timing in its ability to provide service to new industrial loads. It must also review the costs it invests and risks associated with projects that potentially may not materialize.

10.1 Recommendations of the Board

The Board agrees with the long-term planning approach utilized by YEC in the Plan. The approach by YEC in assessing the industrial development factors versus the Yukon energy factors[47] is balanced. On a go-forward basis, YEC should attach probabilities to the industrial development scenarios. This would assist the Board in comparative analysis when future resource plans are filed or when applications under Part 3 of the *Public Utilities Act* are submitted. As recommended in the Load Forecast section, when YEC proposes a new facility, YEC is to outline the risk of proceeding, the benefits to existing ratepayers, and sensitivities to existing ratepayers if the economic life of the project is shorter than forecast.

11. Industrial Contributions

Little was said about the contribution policy of YEC in this proceeding until comments were received from Intervenors on the Term Sheet for Power Purchase Agreement between YEC and Minto Exploration Ltd. on January 4, 2007. Until then, the only comments were from UCG, which largely related to the utilities' obligation to serve. UCG referenced OIC 1995/90 indicating that the costs of supplying major industrial customers and isolated customers will be either through a special rate class or through specific contracts with the industrial customer isolated from other ratepayers[48] UCG also referenced Section 33 of the *Public Utilities Act* which prohibits the Board or the Commissioner in Executive Council from requiring the utility to build an extension of service if the costs are not justified, unless the Commissioner agrees to pay any costs that are not justified and underwrite any expenditure that is not reasonably warranted under the section[49].

11.1 Recommendations of the Board

Normally, a discussion on industrial contributions would not be a part of a resource plan review but would instead form part of a Phase II GRA. In evaluating the Carmacks-Stewart line, the company investment is germane to the analysis.

Paragraph 3 from Schedule B (Maximum Company Investment) of YEC's Electrical Service Regulations state:

> The Maximum Company Investment for an extension of service not specified in paragraph 2, and the Maximum Company Investment in any extension of service, whether or not specified in paragraph 2, the Load characteristics of which are expected to vary materially from the average for that type of service, shall be

[47] See pages 5-4 to 5-6 of the Plan for a listing of the factors.
[48] UCG Reply, page 18.
[49] UCG Reply, page 18.

> determined on the basis of a detailed analysis of the **Annual Cost** of such extension and the revenue expected to be derived therefrom. If the **Annual Cost** of serving a customer is higher than the revenue expected to be received from such service, then the Maximum Company Investment shall be the **Cost** of the extension less the present value of the annual amounts over the expected life of the service by which the **Annual Cost** is expected to exceed the revenue [emphasis added].

Based on the information presented, the Board cannot verify that this is being adhered to. Further, given the length of time since the last review of Phase II matters, there is some uncertainty whether the policy is still applicable.

The Term Sheet filed on December 21, 2006, provides a contribution amount, a new firm mine rate, and a low grade ore secondary energy rate. None of these rates have been approved as YEC has yet to file an application with the Board.

Now is an appropriate time for YEC and YECL to have a complete review of all GRA Phase I and Phase II matters. The Board recommends that YEC and YECL file a full GRA application before October 31, 2007. The application should include a full cost of service, rate design and an update of the Electric Service Regulations. The Board also suggests that YEC and YECL consider a performance-based regulation mechanism. As well, the Board recommends that evidence be provided as to what other utilities provide for Maximum Company Investment and model theirs accordingly.

12. YEC contracting policies and project management

UCG introduced the Auditor General's report[50] on the MD line and submitted that the Board must review major projects undertaken by YEC until YEC has fully responded to the points outlined in the Auditor General's report, has the appropriate resources to undertake major projects, and has established appropriate procedures and controls.

UCG acknowledged that YEC has updated its contracting procedures since the MD project, but stated that the Board must review the application of those procedures in the context of a large project.

In response, YEC indicated that while its commitment to undertake an audit of project management policies had not been carried out, this was still a commitment of the YEC Board of Directors. Further, in reply, YEC stated[51]:

> The Board maintains full control to ensure that all aspects of every project undertaken by YEC are fully assessed and analyzed before they will ever be included in the rates charged to ratepayers in Yukon [also see Section 4.6.5 of this reply]. In this regard the Board has all controls required to ensure ratepayers are protected from any form of issues on any project, be they related to

[50] In argument, YEC responded to Exhibit C3-13 (*Mayo-Dawson City Transmission System Project*, February 2005; Office of the Auditor General of Canada).
[51] YEC Argument, page 31.

management, contracting, or any other area that UCG may care to cite. Beyond this, it is a well accepted regulatory principle that a regulator has neither the role nor responsibility to be involved in management of the utility[52].

12.1 Recommendations of the Board

The Board recommends that YEC adhere to all outstanding recommendation as outlined in the Auditor General's *Mayo-Dawson City Transmission System Project Report*. In addition, in any subsequent major project, YEC should detail how it has adhered to the direction in the Auditor General's report.

13. Summary and Conclusions

Arriving at a well thought-out electric resource expansion plan is typically the result of undertaking the following major tasks:

- **Load Forecasting**. Forecasting electric use is what normally triggers the development of an expansion plan. Therefore, producing a reasonable load forecast is essential.
- **Planning Criteria**. Having planning criteria is also essential, as it ensures that any plan would assure a pre-determined desired level of reliability of supply.
- **Expansion Projects.** A menu of technically feasible projects that could be implemented to supply the load forecast must be compiled.
- **Generation of Expansion Plans.** Many expansion plans that satisfy the load growth forecast and meet the planning criteria are formulated by placing different projects in different years.
- **Selection of a Plan.** Finally, the best plan, of those generated above, is selected based on pre-determined criteria. Typically, the selection is made on the economic merits of each plan and with aim at minimizing electric rate increases.

Therefore, the following paragraphs summarize the Board's position respecting the merits of YEC's Plan and, to the extent possible, adhering to the same sequence of tasks mentioned above.

13.1 Load Forecasting

With respect to the load forecast, the Board concluded that YEC's macro-view approach for this type of planning process was appropriate. Therefore, at an aggregate level, the forecast is satisfactory. Furthermore, the Board selected the base-case forecast to conduct its own testing to determine if the load growth assumptions support the projects promoted by YEC.

[52] YEC Reply, page 32.

13.2 Planning Criteria

YEC adopted the following new planning criteria for the WAF and MD systems:

- An LOLE of two hours/year criterion.
- A single contingency (N-1) criterion requiring sufficient resources to carry the forecast peak winter loads with the worst-case loss of one element (transmission or generation) in the system.

The Board accepted the use of the 2 hours/year LOLE, provided it is calculated using the same technique as in the Karki-Billinton report included in Exhibit B-6. The Board is satisfied that maintaining a minimum 2 hours/year LOLE will ensure that the generating resources are adequate to meet the load requirements on the MD and WAF grids.

Although contingency criteria (such as the N-1) are typically used to identify weaknesses in the transmission system, the Board considers YEC's use of the N-1 criterion in parallel with the LOLE to be somewhat unique. However, given that the electric systems in the Yukon are also unique in the sense that major generating sources and load are separated by long distances, they are connected via single transmission lines, and there are no interconnections with neighbouring power systems, the Board accepted the use of the N-1 and LOLE planning criteria as proposed by YEC.

Applying the new planning criteria to the base-case load forecast in conjunction with the planned retirements of the existing diesel units WD1, WD2, and WD3, indicates that the WAF system is currently affected by insufficient transmission capacity (based on the N-1 criterion) and would face inadequate generation resources as early as 2008 (based on the LOLE criterion).

If the new planning criteria are applied to a lower load growth forecast, the LOLE would indicate adequate generation resources for a few more years than the base-case forecast but the N-1 criterion would still indicate a transmission deficiency in 2006. Therefore, it is imperative that new resources be added to the WAF system as soon as possible.

13.3 Expansion Projects

A number of projects have been suggested as possible near-term options. YEC's proposed plan included the refurbishment of old diesel plants that are currently scheduled for retirement (the Mirrlees Life Extension Project), the refurbishment of a previously retired diesel unit at Faro (the Faro Rehab Project), and a transmission line from Carmacks to Stewart Crossing. In addition, the Board considered it appropriate to include the Aishihik third turbine and the Aishihik second transmission line as suitable candidate projects for the purpose of generating other expansion options. The Board agreed not to include the Marsh Lake Fall/Winter Storage Licence Revision Project as a near-term option, as YEC withdrew the project.

13.4 Generation of Expansion Plans

The Board notes that, although YEC produced an expansion plan, it did not provide evaluations of alternative expansion options to support its proposed plan. Instead, YEC appeared to have focused on a single preconceived plan motivated primarily by the potential for significant electric energy sales to new mines. Consequently, the Board had to envision alternative plans and test them against YEC's proposed plan in order to make an informed recommendation in this report.

The Board decided to produce alternative expansion sequences taking a different approach than YEC, with the purpose of investigating the merits of those projects not included in YEC's plan. Specifically, the Board included the Aishihik third turbine and the Aishihik second transmission line in a number of expansion sequences presented in Section 5.

From this work, the superior contribution from the Aishihik second line, compared to the Carmacks-Stewart line, became evident, as the capacity contribution from the Aishihik second line is 15 MW, under the N-1 criterion, and 8 MW under the LOLE criterion. Such a large capacity contribution from a single transmission line is due to the fact that this is the only project that addresses the root cause of the WAF's transmission deficiency. This project relieves the existing transmission weakness in the WAF system, as it turns the N-1 event from a loss of 30 MW to a more manageable loss of 15 MW. This project also increases by 8 MW the contribution of the Aishihik plant to the overall adequacy of the generating system (measured by the LOLE), as it eliminates the constraint caused by the unavailability of the single transmission line.

In an ideal situation, several expansion plans should be produced and evaluated. Due to resource constraints and time limitations, the Board selected only one alternative expansion option to compare against YEC's plan. Therefore, the Board selected the expansion plan shown in Table 5-5 (Section 5), as it satisfies the planning criteria until 2018 and takes a different approach from that proposed by YEC. In particular, it addresses the WAF's transmission deficiency with a true transmission solution, namely the addition of the Aishihik second transmission line, and relies on more hydro resources and less diesel resources, as it calls for the retirement of the Mirrlees Whitehorse diesel units in 2010 and the addition of the Aishihik third turbine in 2013.

13.5 Selection of a Plan

The criteria the Board used in selecting a plan stemmed from the Minister of Justice's June 5, 2006, letter, which directed the Board to consider reliability, capacity planning, alternatives, and effect on rates, among other things.

The Board is satisfied that it has addressed reliability, through the adoption of new planning criteria, capacity planning, through the application of the new planning criteria on a forecast of load growth and on different near-term projects, and considered alternatives, through development of an alternative expansion plan to compare with YEC's plan. Therefore, the final selection of a plan is based on ensuring that the selected plan would result in the lowest possible rate increases.

However, not having access to YEC's revenue requirement model, or the benefit of a similar model to assess rate impact, the Board had to base its selection purely on the basis of total costs. Nevertheless, the Board considers that this is still a valid approach as the least-cost plan should result in least revenue requirements, hence the least rate increases.

The Board's assessment of total costs was conducted in two steps. Firstly, the Board evaluated annual production costs with a focus on the generation from diesel plants under both expansion plans and the potential fuel savings that would intuitively result from the alternative plans, which requires less diesel generation. Secondly, the Board compared the capital cost requirements under both plans, with consideration to benefits that would offset rate increases for the Carmacks-Stewart project.

The expected diesel-fuel savings attributed to the alternative plan over YEC's plan were found to be insignificant and most likely offset by diesel fuel savings due to the connection of Pelly Crossing to the WAF system under YEC's plan, which is not accounted for in the results shown in Table 5-11. However, this finding is based on the assumption that the Aishihik third turbine would be installed in 2013, or thereabouts, under both expansion plans.

The capital cost comparison demonstrated that YEC's plan would result in less costs than the alternative plan due to lower capital cost requirements. However, this conclusion is based on the important assumption that the capital costs associated with both stages of the line would result in no net rate increase to ratepayers.

In conclusion, the Board found that YEC's plan is the least-cost plan. Therefore, YEC's plan should result in the least revenue requirements, hence the least rate increases, and it satisfies the new planning criteria unit 2017 under the base-case load forecast.

13.6 What-if Considerations

YEC's Plan does carry some risk, as does any plan, for that matter. Therefore, the following paragraphs have been included to address how well the plan would cope with potential unexpected outcomes.

The Board concluded that, since the WAF system is already short of capacity (according to the adopted N-1 criterion), it is imperative that new capacity be added to the WAF system as soon as possible and the Faro Rehab Project should be the first to proceed.

With the Faro unit operational in 2007, the WAF system would have adequate capacity until 2009, provided that the Mirrlees units WD1, WD2, and WD3 are not retired and the load increases as per the base-case forecast. If the load increases less than the base-case forecast, the capacity would be adequate for a few more years but it is unknown how much longer the Mirrlees units WD1, WD2, and WD3 could be counted on if they are not refurbished. On the other hand, if the load increases more than the base-case forecast, additional capacity will be required sooner than 2009. Therefore, irrespective of load growth, it is evident that the WAF system would need additional capacity in the 2008–2010 time period, soon after the Faro unit is commissioned. Since refurbishments of existing diesel units are the only options that could be implemented in a relatively short period of time, the Board recommends that YEC proceed with the Mirrlees units WD1, WD2, and WD3, as planned.

With the Faro unit operational and the Mirrlees units WD1, WD2, and WD3 refurbished as planned, the WAF system would have adequate capacity until 2012.

The first stage of the Carmacks-Stewart Project would have no effect on the adequacy of generating capacity as this line would contribute no new capacity to the WAF, but neither would it impose a need for new capacity as the load of the Minto Mine is not included in the N-1 and LOLE calculations. There is a risk that if the Minto Mine does not proceed, there would be no benefits from energy sales to the mine, which could result in potential stranded investment if the line is built. However, this would not be a complete loss as this line would still be used to supply the community of Pelly Crossing, which would result in diesel-fuel savings possibly in the order of 1.3 GWh per year and perhaps be sufficient to pay for the cost of the line, albeit over a long period of time.

If the Carmacks-Stewart Project does not proceed, the Board considers it appropriate that YEC's efforts be focused on bringing the Aishihik second transmission line into reality by 2010–2012, or whenever needed to satisfy the need for additional capacity. This could be followed by the Aishihik third turbine, which would contribute its full potential after the second line is operational. With the addition of these resources, the WAF capacity should be adequate to approximately the year 2020.

To conclude, the Board recommends YEC's Plan on the basis of it being the plan that would result in the least cost to consumers. Furthermore, the Board is satisfied that if the Carmacks-Stewart line fails, there are other options available that would allow the expansion plan to take a new direction and still ensure reliability of supply.

13.7 Resource Plan Updates

The Board recommends that YEC file an update to its resource plan in five years, at the latest. The Board expects that YEC will consult with stakeholders in preparation of its next resource plan.