APPENDIX A:
POWER RESOURCE TECHNOLOGY OPTIONS

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APPENDIX A:
POWER RESOURCE TECHNOLOGY OPTIONS

A.1 POWER RESOURCE TECHNOLOGY OPTIONS

This Appendix provides a brief overview of technology options for providing power resources, either through new generation (supply side) or through Demand Side Management.

A substantial review of power resource options and technologies was provided in the 1992 Yukon Resource Plan. More recent power resource technology overviews have been prepared for northern conditions, most notably the Alaska Power Association overview titled *New Energy for Alaska* published in March 2004 (available online at http://www.areca.org/areca/energy_sys.htm) and a more site-specific review[1] "*Galena Electric power – A Situational Analysis (*pre-publication draft)" (available online at http://www.iser.uaa.alaska.edu/Publications/ Galena_power_draftfinal_15Dec2004.pdf) .

For each technology option reviewed, the scope of consideration from the 1992 Resource Plan is noted, as well as more recent information from either the Alaska studies, or other Yukon specific information compared to 1992.

A.1.1 DIESEL

The 1992 Resource Plan was directed, as per OIC 1992/92 to consider "contracts and commitments for non-diesel fuel generation". At the time, diesel generation was being used for a substantial part of the WAF supply. As such, diesel was not reviewed as a supply option, but was reviewed as the "base case" for comparison of non-diesel alternatives.

Diesel generating units have relatively low capital costs (approximately $1 million per MW), and high operating costs. Consequently, diesel units are typically well-suited to meeting reserve capacity requirements and short-term capacity needs during system peaks. Diesel is also well suited to isolated regions where loads are small (such as the Yukon isolated communities), where loads do not have very long lives (such as temporary applications or short lived mines) or where the heat from the operation of the diesels is of economic value (such as in certain industrial operations). Since diesel units can be turned off when they are not needed (and because of the relatively low capital costs), diesel units provide a relatively lower risk source of supply if loads are uncertain (as load decreases can be met with cost increases from putting the unit on standby).

[1] The draft was published in December of 2004, and provides an overview of generation options for an Alaskan community of 800 people. The options considered for Galena included: diesel, coal, nuclear, and a grid connection.

Diesel is expensive for utility operations running to provide sustained energy on a regular basis throughout the year.

Since 1992, efficiencies of new diesel units have occurred. The 1992 resource plan was based on efficiency of 3.7 kW.h/year and the most efficient units now in service on WAF are cited at 3.9 kW.h/litre (installed in early 1990s). However, the more recent Alaska studies cite potential efficiencies in the 4.18 kW.h/litre range for the most efficient new units (15.8 kW.h/gallon) at maximum efficiency. This maximum may be unattainable over any sustained operating period with normal start-up, shut-down, load variations, and other factors, but does reflect improvements since the 1992 review.

A.1.2 HYDRO

Hydro options were studied extensively as part of the 1992 Resource Plan Submission. In addition to the information provided in the main Resource Plan document in 1992, a separate binder (Supply Side: Binder A), contained detailed information on hydro options evaluated by the utilities.

Hydro generating plants have relatively high capital costs and very low operating costs; as a result, sustained operation of such facilities over an extended time period in a year can often yield lower unit costs for energy generation than would occur with diesel generation units. Hydro options have the potential to meet the needs of the Yukon under industrial development scenarios.

Hydro options for the Yukon are identified in detail in *Chapter 5: Industrial Developments and Opportunities*, and significant specific characteristics and issues related to hydro are discussed in particular in *Section 5.3: Options*., and *Appendix B: Hydro Project Options*.

A.1.3 WIND

At the time of the 1992 Resource Plan, the Yukon utilities had no wind generation in operation, but wind power was identified as a potential future supply option. Since that time, Yukon Energy, with the support of Yukon Development and the Government of Yukon, has gained considerable experience with wind generation for utility supply. This includes operation of two turbines on Haeckel Hill on WAF (a Bonus 150 of 150 kW installed in 1993 and a Vestas V47 of 660 kW installed in 2000) as well as numerous wind monitoring projects throughout Yukon[2]. At this time, Yukon is consistently cited as a leader in assessing the commercial potential and technical considerations of wind generation in northern climates.

Key issues with respect to wind generation are capital costs (particularly for smaller units), capacity limitations and wind availability. Capital costs for wind generation have been declining in recent years, but remain quite high for installation in Yukon, where major new support systems can be required (transmission and roads are typically required to install wind generation in new sites, which are typically high elevations sites in Yukon). Wind is also not a form of reliable capacity to utility systems, as it is not dispatchable and is an intermittent resource, consequently wind does not make a contribution towards planning for meeting the peak commitments of a utility. Wind is well suited, however, to larger hydro-based systems that have material storage (such as WAF) once material expensive diesel generation begins to be dispatched.

More important to wind economics, the feasibility of wind is very sensitive to wind regime and availability. Utility industry experience indicates that wind economics essentially require a capacity factor of 30%[3] while high grade commercial installations may be higher. By comparison, wind turbines installed in Yukon have only been able to achieve an average capacity factor of 22% given the wind regime and other operational factors (such as rime icing, which can substantially reduce wind output) and a Community Wind Resource Assessment program run by YDC has surveyed a number of sites in Yukon (focused on potential customer wind installations) with capacity factors of 2% to a little over 10%. Two utility focused projects were investigated at Destruction Bay and Old Crow. Each was found to have an uneconomic wind regime compared to project costs.

Wind generators can be installed reasonably quickly (outside of the time to order new units, which today have significant lead times due to market demand). Capital costs risks related to wind primarily relate to associated infrastructure (such as roads and transmission lines needed to access the proposed site).

Capital costs for new wind generators continue to reduce in price fairly substantially. However, the scale of new wind turbine models is also growing, and is now approaching a range that would not be able to be easily integrated into Yukon systems other than WAF (1.5 MW or more per unit). On WAF, future industrial loads that push the system onto material diesel generation may enable commercial

[2] Sites at Mt. Sumanik, Destruction Bay, Haines Junction, Tagish, Whitehorse, Dawson City, and Ferry Hill have been undertaken since the early 1980s. Three locations suitable for wind generation were identified in the WAF area: Haeckel Hill, Mount Sumanik and Flat Mountain. Monitoring of potential commercial wind sites continues, including under the Yukon Development Community Wind Resource Assessment Program.

[3] p. 8, Yukon Energy Resources: Wind. March 1997.

development of wind as a complement to other resources reviewed in this plan. Given the rapid evolution of the wind industry and technology, updated assessment of the potential for wind will need to made once potential industrial loads become further defined.

In the north, the Northwest Territories Power Corporation has excluded wind generation from their resource planning for the current time, as a result of the challenges of operating wind turbines. In Alaska a number of remote communities have developed wind generation to supplement isolated diesel, but there are not utility wind turbines on the major interconnected systems. Also, the challenges associated with wind regime (capacity factor), as well as infrastructure costs (including transmission, as well as installation costs requiring major cranes) are noted to be a barrier.

A.1.4 BIOMASS

As of the 1992 Resource Plan, biomass had been studied for the generation of power in the Watson Lake region[4].

Biomass use for thermal generation is subject to the economic constraints related to the fixed costs (including fixed operating and maintenance costs). These costs do not fall dramatically for smaller scale operations or loads. In these circumstances, economic viability hinges on large and constantly running facilities.

As a general principle, biomass generation does not typically become economic unless three key conditions are met. These same conclusions have also recently been cited as preconditions for biomass electricity generation by the Alaska Energy Authority and in some cases the Yukon Cabinet Commission on Energy[5].

1. The fuel (typically wood) must be available from a source that would otherwise have to pay to dispose of it. Economic biomass generation is not typically possible with a wood product that has a cost to harvest, or even (in at least some cases) that can be delivered to the plant for free; there has to be savings from avoided disposal costs.

[4] A 6 MW steam-fired turbine had been assessed (assuming the Watson Lake sawmill was in operation) and determined to have too long a pay back period. See in particular the Yukon Cabinet Commission on Energy publication entitled "Wood", September 1997.

[5] Wood-Fired Boilers for Rural Communities, Online: http://www.uaf.edu/aetdl/presentationsre02.html. Also the 1998 Yukon Cabinet Commission on Energy "Principles of Supply Options for the Yukon" noted "Although abundant in supply, wood is not generally seen as a cost effective way to generate electrical power unless it has little or no cost as a fuel source".

2. The wood-fired power displaces diesel power.
3. There is a substantial market for power and heat.

To date, proposals discussed in Yukon do not meet these three key criteria.

In the Yukon, one biomass proposal received to date involves a waste wood generation facility at Haines Junction. However, that proposal was largely focused on burning wood that was previously killed by beetle infestation which will likely not be useable by the time the loads develop. A 2002 Canadian Forest Service annual Forest Health Survey found that the infestation was slowing. Standing wood tends to start to lose its heating value within three years of dying, and the bulk of the deadfall is now more than three years old.

Further information on biomass can be found in *Chapter 5: Industrial Development Scenarios and Opportunities.*

A.1.5 COAL

Coal-fired generation was examined in detail in the 1992 Resource Plan.

The economics of coal generation are very sensitive to various factors, such as the quality of the coal and emissions standards, which can materially impact the capital costs required for the plant (for example, ash handling and dealing with sulphur in the coal). The practical minimum size coal development considered for Yukon has been 20 MW which roughly equates to 144 GW.h/year.

Technologies for use of coal have been advancing at a rapid pace, particularly in regards to reducing emissions. Recent studies in Alaska have also summarized and assessed the potential for small coal developments, including Atmospheric Fluidized Bed Combustion[6]. Although a number of studies were cited, no successful small scale (1-10 MW) electrical utility coal projects are known to be in service in the north.

Key to development of environmentally sound coal generation in Yukon is the development of indigenous coal deposits independently of power generation requirements.

[6] "Galena Electric Power – a Situational Analysis" as noted above.

Further information on coal can be found in *Chapter 5: Industrial Development Scenarios and Opportunities.*

A.1.6 COAL-BED METHANE

Coal-bed methane generation was not studied in the 1992 Resource Plan.

Coal-bed methane generation produces electricity by using a methane gas from coal seams and fractures in coal beds, to produce electricity with conventional turbines. In order for coal-bed methane to be economic, the site must be close to a population base. In Yukon, no developed resources for coal-bed methane are available.

The Alaska resource study considered the potential for coal bed methane. No utility generation from coal bed methane is in service in Alaska today. The Alaska summary document identified high exploration and drilling costs, and the disposal of water as the main challenges associated with coal-bed methane generation.

A.1.7 NATURAL GAS

Natural gas was not reviewed in 1992.

Natural gas as a source for power is only available where commercial sources of gas can be delivered. Currently gas in not available in Yukon for utility purposes. Natural gas is in use in Inuvik, NWT for both domestic use (home heating) and power generation via reciprocating engines.

The availability of gas in Yukon would provide opportunities for a dramatic shift in the power resource framework for Yukon. Gas is a flexible resource that easily allows for "scalable" generation (from small 30 kW micro-turbines through massive turbines of hundred of MW, and including reciprocating engines of the size range is use in Inuvik of 2-3 MW).

However, given the limitations of gas availability in Yukon today, there is no option for gas generation to meet near-term requirements (Chapter 4) but serious investigation is required of opportunities to use gas (or maintain the option to use gas when it arrives) under Chapter 5 scenarios. If in the near-term Yukon Energy pursues new diesel generating units, consideration will be given to the potential to secure units that can later be converted to natural gas or can be run as dual fuel units.

Alaska has devoted considerable time and energy to natural gas generation given the availability of gas in many key communities. This information and experience will be of significant value to Yukon should gas become available during the period covered by the Resource Plan.

A.1.8 GEOTHERMAL

Geothermal generation was not studied in the 1992 Resource Plan.

Using heat energy from a geothermal resource is practical only if the geothermal occurrence and the energy need are located in close proximity. Thus, the development of geothermal applications in the Yukon will first occur where geothermal resources are found close to populated areas. A major well registry, mapping and resource analysis project is presently underway which will assemble the existing and available information on the groundwater and ground-source heat potential in all Yukon communities.

Known geothermal resources in the Yukon are too low in temperature to produce steam that could be used to generate electricity on a cost-competitive basis. While geothermal temperatures in the range of 100°C to 180°C are required, Yukon geothermal resources have so far been identified in only the 15°C to 55°C range. As a result, the Yukon's geothermal resources are best suited for heat energy applications such as space or district heating.

The recent reviews from Alaska noted similar concerns with respect to location of geothermal resources in relation to loads, and high capital costs of installing geothermal generation.

A.1.9 HYDROGEN

Hydrogen generation was not studied in the 1992 Resource Plan.

Yukon Energy has assessed hydrogen as an option for energy storage for electrical power. Given current hydro surpluses, the potential exists for electrolysis during off-peak or summer seasons for storage and use during peak times (or for isolated system generation or other non-utility purposes). However, given the technical complexity including issues related to storage and transportation, and the capital costs of hydrogen systems, hydrogen has not been considered a feasible resource option at this time.

Similar conclusions from Alaska indicate "feasibility is unknown, and the prospects without further advances in technology and market development are poor"[7].

A.1.10 SOLAR

Solar generation was not studied in the 1992 Resource Plan.

Given the angle of the sun, the intensity of the sunlight received closer to the Arctic Circle is less than in southern jurisdictions. Solar radiation is greater in the summer time, when there is currently a hydro surplus in the Yukon. As such, solar power does not provide any potential value to the Yukon in the near term, but has the potential to provide value in future if it is used to offset diesel generation.

Solar power is characterized by high initial or capital costs, and potentially low operating and maintenance costs. In isolated areas where grid power is not an option, residential and small commercial applications for mining camps, lodges, especially those with higher or solely summertime use, solar power may be considered a viable option.

The recent work in Alaska similarly concluded in respect of solar generation that "this technology is generally not cost-competitive for utility use when other alternatives are available"[8].

A.1.11 NUCLEAR

Nuclear generation was not studied in the 1992 Resource Plan.

Nuclear generation was studied for the Alaskan community of Galena based on a 10 MW Toshiba 4S reactor, which was to be provided for free from the manufacturer as a North American "Reference Case". Nuclear power was found to have the potential to be cost-competitive compared to diesel or coal, assuming that diesel and coal costs result in higher operating costs. The rising cost of diesel fuel has the potential to increase the economic attractiveness of nuclear generation.

The primary uncertainties with respect to nuclear power in Alaska are security and technical feasibility. In Galena, it was estimated that a minimum of four, and a maximum of 34 guards would be required. The proposed reactor is also a new technology for North America and will likely not available on a commercial basis for many years.

[7] "New Energy for Alaska" Alaska Power Association. March 2004.
[8] "New Energy for Alaska" Alaska Power Association. March 2004.

For Yukon, there is no commercial availability for the type of nuclear generation studied for Galena, and its future commercial availability is unknown. However many characteristics (size, life, efficiency, cost) of the project considered for Galena could be very attractive for consideration in Yukon. Other relevant considerations (including security and waste disposal) will clearly need substantial further attention before the true potential for nuclear in Yukon can be assessed.

A.1.12 DEMAND SIDE MANAGEMENT

DSM options were studied extensively as part of the 1992 Resource Plan Submission. In addition to the information provided in the main document, a separate binder (Demand Side: Binder B), contained detailed information on DSM options evaluated by the Utilities. The approach to DSM in 1992 reflected the situation that existed at that time; the Faro Mine was still in operation. A summary of the approach to DSM was outline at page 8 of the Demand Side Management binder, "In the Yukon, significant opportunities exist for Energy (GWh) savings because of the high cost of diesel generation. However, savings opportunities through reduction in peak Demand (MW) are relatively small due to the low capital cost for installing new diesel generation facilities. The priority, therefore, for DSM programs in the Yukon at this time relates to strategic reduction in energy use." Given the closure of the Faro Mine, there is no longer an incentive to decrease annual energy use. Consequently, the focus of the 1992 DSM plan does not correspond with Yukon Energy's current needs.

Yukon has been actively and aggressively engaged in DSM activities of various types since 1992, and in particular since 2000. Major emphasis from entities such as ESC, YDC and Natural Resources Canada has focused on reducing loads on isolated diesel systems, reducing non-electrical energy consumption (such as oil heating) as well as major efforts by Yukon Energy to grow the WAF loads via Secondary Sales (with surplus hydro, the most pertinent WAF DSM programs focus on selling this renewable resource that would otherwise be wasted, rather than reducing consumption).

In the near-term in Yukon, the electrical system requirements are almost entirely related to peak capacity (Chapter 4). Most non-industrial DSM programming is generally more successful at energy reductions than capacity reductions. As such, DSM has limited potential to address utility requirements in the near-term. In addition, DSM activities in the near-term that lower peak demand levels, but reduce utility sales which are currently being made from surplus hydro will be an adverse rate driver in Yukon (as lost revenue from reduced sales will outweigh cost savings from reduced system peaks).

Over the longer term, and under the various industrial scenarios (Chapter 5), DSM activities have the potential to contribute to savings from diesel fuel generation. As such, DSM activities will in all likelihood become an important utility focus should such scenarios arise. However, as a major supply option, there are limits to the scale of savings available from DSM. For example, under the 25 MW scenario diesel consumption on WAF proceeds rapidly to more than 100 GW.h per year – given a current firm non-industrial WAF sales of 250 GW.h/year, it is not possible for DSM to provide the resources needed to address this scenario, and therefore major displacement of diesel must come from supply-side resources (such as new hydro generation).

Information on Yukon DSM is provided in greater detail in *Section 2.4.5: Demand Side Management and the Energy Solutions Centre.*

A.2 LITERATURE REVIEWED

A.2.1 HYDRO

BC Hydro's 2002 Small Hydro Assessment in Yukon and northern BC.

Yukon Economic Development. Yukon Energy Resources: Hydro. March 1997.
The article provided an overview of hydro generation in Yukon, and issues affecting development. The article indicated that facilities smaller than 20 MW as the most likely to succeed.

A.2.2 WIND

Yukon Development Corporation & Yukon Energy Corporation. The Winds of Change: The Story of Wind . Generation in the Yukon. March 2001.
The report summarizes the history of wind generation in the Yukon and the history of Yukon Energy's experimental turbines at Haeckel Hill. YEC installed Bonus 150 kW MARK III in 1993 at Haeckel Hill in 1993. However, the report indicates that even with the special modifications that had been made to the Bonus before it was installed, there are still some problems, especially the lower temperatures and rime icing. The capacity factor of the turbine is 21%. The Vestas V47-660 kW was installed in 2000. YEC forecast a capacity factor of 23% for the Vestas.

Yukon Economic Development. Yukon Energy Resources: Wind. March 1997.

The article provides an overview of wind development in Yukon, and factors affecting development. The report indicates that wind velocities are greater at higher elevations; and that wind has the greatest velocities in the winter months, correlating with the period of peak electrical demand. However, rime icing is a significant factor impacting reliability and production levels during the winter peak.

A.2.3 BIOMASS

Wood-Fired Boilers for Rural Communities, Online: http://www.uaf.edu/aetdl/presentationsre02.html

Yukon Economic Development. Yukon Energy Resources: Wood. March 1997.

The article provided an overview of Yukon's wood fuel resources and the factors affecting development. The report indicated that wood fuel is a source of residential heating fuel, and supports existing small industries in sawmilling and firewood cutting. Further potential for wood fuel, including limited export and as a means of producing electricity were also identified.

A.2.4 COAL

Yukon Economic Development. Yukon Energy Resources: Coal. March 1997.

The article provides an overview of Yukon's coal resources, and the factors impacting development. The local markets identified for coal, included power generation and industrial heating.

A.2.5 LITERATURE REVIEWED ASSESSING MULTIPLE GENERATION TECHNOLOGIES

A number of publications were reviewed that provided an overview of generation and/or demand side management options for the Territory. These publications are outlined below.

New Energy for Alaska. Alaska Power Association. March 2004.

The publication includes an examination of a number of alternative energy sources, including: battery energy storage systems; biomass power; clean coal; coal bed methane; cogeneration; diesel engine efficiency; fuel cells; geothermal; hydroelectric power; hydrogen; microturbines; solar; tidal energy; and wind turbines. Given the similarities between Alaska and the Yukon, the analysis provided relevant comparisons for the Yukon.

Galena Electric Power – a Situational Analysis (Draft Final Report). Prepared for the U.S. Department of Energy. December 2004.

The economics of electrical power generation options for the City of Galena, Alaska were identified. Given the similarities between Alaska and the Yukon, the analysis provided relevant comparisons for the Yukon.

Economic Development from Renewable Energy: Yukon Opportunities. Provided by Pembina Institute. October 1999.

The report summarizes the energy conservation and efficiency, key renewable energy resources, and their application in the Yukon. The economic benefits, environmental and social aspects of renewable energy, and strategic direction for renewable energy in the Yukon were examined.

Yukon Government Cabinet Commission on Energy. Energy Efficiency for the Yukon, 1998.

The report provided an overview of the potential for greater energy efficiency in the Yukon.

Yukon Government Cabinet Commission on Energy. Green Power Fund. 1998.

The report provided an overview of a Green Power Fund for the Yukon.

Yukon Government Cabinet Commission on Energy. Principles of Supply Options for the Yukon, 1998.

The report provided an overview of principles of supply options for the Yukon.

Yukon Economic Development. Yukon Energy Resources: Alternatives. March 1997.

Generation resources were identified and examined, including: solar energy, geothermal energy and refuse-derived energy.

Yukon Economic Development. Yukon Energy Resources: Oil & Gas. March 1997.

The article provides an overview of oil and gas generation in the Yukon, and the factors affecting their development. The article explored development activities, and environmental issues.

APPENDIX B:
HYDRO PROJECT OPTIONS

B.1 HYDRO PROJECT OPTIONS

Yukon Energy has developed an inventory of many potential hydro sites in Yukon and in northern BC that have been studied in the past (primarily by NCPC or Government of Canada, and reviewed from time to time by Yukon Energy). Based on the inventory of sites studied in the past, Appendix B reviews specific potential hydro sites over a range of sizes.

The projects in this chapter reflect the primary alternatives identified to date based on review of the numerous studies conducted in Yukon. In selecting the projects noted in this chapter, location was used as a key screening factor, as well as information available on the relative attractiveness of the various sites (as reflected in part in the rough qualitative and quantitative factors considered in the various Level 1 work on the projects, including potential integrated system benefits).

Rough assumptions to date are that hydro projects in the 1-4 MW range cannot support any material transmission costs beyond simple connection (i.e., must be basically on the established transmission, preferably 138 kV) while 5-10 MW projects may be able to support transmission of 50 km (to perhaps as high as 100 km at a maximum). Projects in the 10-30 MW range may be able to allow for transmission somewhat over 100 km.

For the large to very large projects (30-60 MW and 60+ MW) there has not been any serious effort to screen based on incremental transmission costs, as this can only likely be usefully considered once loads have been identified and required upgrades or additional circuits to existing transmission can be incorporated into the assessment – such planning is not possible in the absence of further information about potential loads.

No screening is applied in this section based on environmental or socio-economic considerations. Such considerations would become key considerations for projects that can progress through an initial "technical" screening of the type outlined in this Appendix and Chapter 5.

The hydro sites reviewed in this Appendix are summarized in Table B-1 and shown on the map in Figure B-1.

Table B-1:
Potential Hydro Sites

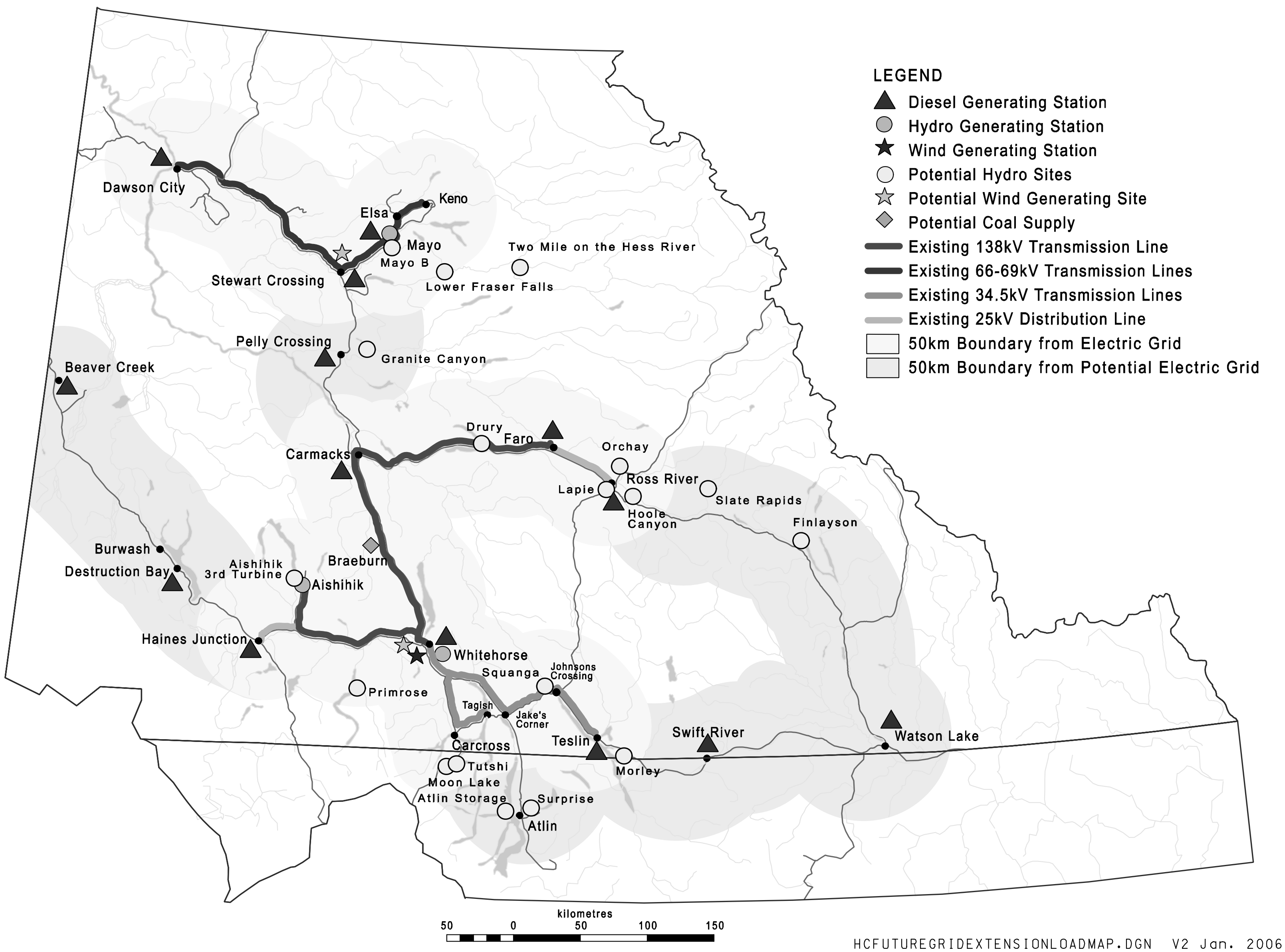
	Grid	Installed MW	GWh	Capital Cost (2005$millions) (excl. trans.)	Trans. Distance (km)	Protected under Yukon land claims	In BC	Capital Cost LCOE (cents/KWh) excl. trans (2005$ real)
Existing Hydro Enhancements								
Aishihik Diversions	WAF	0	total of 24	n/a	0	X		n/a
Atlin Storage	WAF	2	9	n/a	0		X	n/a
Very Small Hydro Projects (1-4 MW)								
Drury	WAF	2.6	23	31	0	X		7.2
Squanga	WAF	1.75	8.3	12	5			7.7
Orchay	WAF	4.2	27	47	15			9.2
Morley	WAF	4	22	31	30	X		7.5
Lapie	WAF	2	10	14	8			7.4
Small Hydro Projects (5-10 MW)								
Moon	WAF	8.5	50	51	66		X	5.4
Surprise	WAF	8.5	50	50	100		X	5.3
Tutshi	WAF	7.5	50	79	25		X	8.4
Mayo B	MD	10	48	101	0			11.2
Medium Hydro Projects (10-30 MW)								
Primrose	WAF	28	141	191	100			7.2
Finlayson	WAF	17	129	179	230			7.4
Large Hydro Projects (30-60 MW)								
Hoole	WAF	40	275	412	100			8.0
Slate	WAF	42	252	422	172			8.9
Two Mile Canyon on the Hess	MD	53	280	380	n/a	X		7.2
Very Large Hydro Sites (60+ MW)								
Granite	WAF	80 (up to 250)	660	706	125	X		5.7
Fraser Falls	MD	100 (up to 450)	613	555	n/a			4.8
Yukon River *(such as Rink Rapid, Eagles Nest, Five Fingers)*	WAF	various 75-240	n/a	n/a	n/a			n/a

Many of the above hydro projects arise from studies carried out by NCPC prior to 1987. In many cases these projects have not been subsequently reviewed in sufficient detail to confirm technical, economic or environmental acceptability for Yukon Energy to pursue today.

The above table also notes that some of the potential hydro projects identified here are "protected" under the Yukon First Nations land claims. Protection under the land claims agreements does not preclude the requirement to consult and work with local First Nations should Yukon Energy determine a need to develop these projects to supply load requirements. Furthermore, the extent to which such "protection" in each case may or may not extend to the elevations required to reach the maximum outputs noted in this Appendix has not yet been confirmed (because, as noted, further work has not yet been carried out since the initial studies).

Figure B-1:
Map of Potential Supply Options

EXISTING TERRITORIAL POWER INFRASTRUCTURE AND POTENTIAL SUPPLY OPTIONS



B.1.1 LEVELIZED COST OF ENERGY

A primary consideration in screening potential new projects is the basic generation cost of energy supplied by output from any new resource (with typical focus on overall unit cost per kW.h as opposed to cost per MW of capacity). For the purposes of initial screening, “levelized costs of energy” (“LCOE”) can be used to determine the unit costs/kW.h at the project site of energy produced. Levelized costs reflect the costs of the plant amortized over its life (all kW.h units available to be produced by the plant) assessed on real dollar (2005$) economic terms (i.e., assuming the levelized unit cost after 2005 increases with inflation each year).

- LCOE focuses only on key generation cost components for a resource option as needed to screen or compare alternative resource options during preliminary assessment stages[1].
- LCOE for hydro supply projects accordingly focuses in most instances only on capital costs, as these tend to establish the primary overall generation cost for this option[2]. Operating and maintenance costs for large projects can be quite modest (0.5% of capital cost based on BC Hydro estimates) which would tend to increase the LCOE by about 9.4%. Smaller hydro project operating and maintenance costs may vary up to 1.0% to 1.5% of capital cost, which can increase LCOE by 18.8% to 28.3% over the levels quoted in Table B-1.
- In the case of other resource options which involve material fuel operating costs (e.g., diesel generation, or thermal generation using coal, wood biomass or natural gas) it is also necessary that the LCOE reflect fuel as well as capital costs (if the capital costs are also likely to be a key part of the option’s overall costs).
- LCOE automatically takes into consideration variations in the economic lives of alternative resource options.
- LCOE implicitly assumes that all energy generated over the economic life of a resource option is sold at rates that fully recover the LCOE costs, i.e., this screening tool does not address the extent to which a resource option may be oversized to meet forecast loads, or otherwise mismatched with forecast loads (in terms of, say, seasonal consideration).

[1] In BC, transmission costs to interconnect a project are considered in the levelized costing, but not overall transmission system upgrades required outside of the simple connection to the generation. In Yukon, screening of hydro projects is intended to be a quick and relatively simple process, so transmission costs to interconnect stations are not specifically estimated but are approximated in the screening process by focusing, for each scale of project, on only those projects a reasonable distance from developed transmission systems.

[2] Hydro project operating costs are modest compared to capital costs (outside of special charges such as BC water rentals, which need to be separately considered).

Levelized cost of energy as it is used in this Resource Plan for hydro focuses exclusively on hydro capital costs (excluding transmission and excluding O&M), estimated in 2005$ (includes 25% for owner's costs and contingency). Levelized costs are calculated by dividing the 2005$ capital cost of the project by a 65 year energy output (kW.h) of the project, discounted each year at a real discount rate of 5.41%. The real discount rate is determined by a nominal discount rate of 7.52% (based on YEC's costs of capital – 40% equity at 9.05% and 60$ debt at 6.5%) and inflation of 2%[3].

B.2 EXISTING HYDRO ENHANCEMENTS

Opportunities to enhance existing hydro in Yukon include items identified in Chapter 4 (such as re-runnering, Aishihik 3rd Turbine, Marsh Lake Top Storage and other potential opportunities in the Southern Lakes) as well as the Aishihik Diversions projects.

B.2.1 AISHIHIK DIVERSIONS

One set of projects that Yukon Energy has protected under the First Nations land claims (Champagne and Aishihik First Nation and Kluane First Nation as required) is the potential diversion of Long Lake (maximum 4.6 GW.h), Hutshi Creek (maximum 1.8 GW.h) and Gladstone Lake (maximum 17.7 GW.h) into the Aishihik Lake and Canyon Lake systems (total maximum potential energy of 24.0 GW.h per year). These projects have the potential to add energy with no new capacity Considerable further work would be required on these project before their respective feasibility can be assessed, including work to update capabilities and considerations with respect to licencing.

B.2.2 ATLIN STORAGE

NCPC studied and assessed the potential to optimize the water regime on Atlin Lake (an important upstream source of water for the existing Whitehorse Rapids hydro plant) to allow improved winter flows on the Yukon River. Although various potential scales exist, one option involves managing the lake within the natural range. This variant is expected to be able to provide 2.0 MW of enhanced Whitehorse Rapids firm capacity, plus 9 GW.h of additional energy (depending on loads). No reliable updated cost estimates

[3] This is generally consistent with major utilities considering long-term generation options. Other LCOE approaches have been used at times by other utilities when comparing to IPP projects, which attempt to address disparities in the length of IPP contracts compared to project service lives, the availability of low-cost financing to Crown utilities compared to IPPs, before-tax versus after-tax costs of Crown utilities versus IPPs, and elimination of federal government subsidies that may distort economic choices and fail to recognize that subsidies are a cost to taxpayers (see, for example, the 2005 BC Hydro Resource Options Report, section 4), The intent of such processes is to incorporate "societal perspectives" rather than focus on ratepayer perspectives. The Yukon Energy Resource Plan focuses primarily on utility and ratepayer perspectives.

are available, and significant complications are expected with respect to required interprovincial licencing processes should the project be advanced.

B.3 VERY SMALL PROJECTS (1-4 MW)

Very small hydro projects in the range of 1-4 MW may be candidates for development under Chapter 5 forecasts under the 10 MW industrial scenario or larger (at the very maximum that the 10 MW scenario can handle).

B.3.1 DRURY

Drury is a proposed 2.6 MW, 23 GW.h project that capitalizes on the head between Drury Lake and the confluence of Drury Creek with Little Salmon Lake. Drury was assessed in 1992, and remains the preferred candidate for scenarios with capacity and energy requirements consistent with Drury's output. The project has a capital cost of $31 million (2005$).

On a simple LCOE basis the costs of Drury are about 7.2 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes.

The 2.6 MW is a firm winter capacity number based on the assumption that the plant would be developed to operate at a very high load factor throughout the year (e.g., include all necessary storage to allow firm winter supplies). If a more variable and flexible operating regime were to be considered for Drury, additional capacity above 2.6 MW could be installed (larger capacity configurations up to 5.2 MW and 29 GW.h have also been recently considered, at a cost of $37 million – a gain of 2.6 MW and about 6 GW.h). Alternate project layouts and sizes must be evaluated to determine the optimum scheme.

The plant would interconnect with the 138 kV line which follows the highway from Carmacks to Faro and would give rise to very little transmission costs.

Yukon Energy has the Drury site protected under the Yukon First Nation land claims agreements.

B.3.2 SQUANGA

A small potential site at Squanga Creek, at 1.75 MW and 8.3 GW.h at a rough capital cost of $12 million for a run-of-river version (2005$). This creek is near Johnson's Crossing with a steep final drop into the Teslin River, where the project would be located. Yukon Energy did work on Squanga as part of the 1992

Resource Plan, focusing on a run-of-river design with primarily summer supply (only 500 kW of firm winter capacity). In 1992 the potential for year-round storage was also noted, but little recent study of the potential for this variation had taken place.

The simple LCOE of Squanga is about 7.7 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes.

In 1996 during the call for Expressions of Interest, Yukon Energy received an IPP proposal to develop Squanga at a similar run-of-the-river (limited winter capacity) configuration. Since that time, Yukon Energy/Yukon Development have been approached by private IPP developers interested in developing the Squanga site and YDC worked with one private outfit (via the Green Power Fund) with respect to further work. Continuing issues with Squanga relate to its limited ability as studied to provide winter capacity, and its location on a weak transmission link (the 34.5 kV system towards Teslin).

B.3.3 MORLEY, LAPIE AND ORCHAY

Three other sites in this size range that were recommended by the YUB for further water monitoring in 1992 (but not further assessment work) were Morley (past Teslin, 4 MW, 22 GW.h, $31 million (2005$)), Lapie (near Ross river, 2 MW, 10 GW.h, $14 million (2005$)) and Orchay (near Ross River, 4.2 MW, 27 GW.h, $47 million (2005$)). In each case, YEC has conducted water monitoring, but not undertaken the additional work required to advance the projects to the level of Drury in terms of technical assessment. In each case, projects may be limited by transmission, as they are not located on or near the 138 kV system.

Simple LCOE for these projects (excluding transmission, incremental operating and maintenance costs and taxes) varies from 7.4 cents/kW.h (Lapie) to 7.5 cents/kW.h (Morley) to 9.2 cents/kW.h (Orchay) (2005$, real).

Yukon Energy has the Morley site protected under the Yukon First Nation land claims agreements.

B.4 SMALL PROJECTS (5-10 MW)

Small hydro projects in the range of 5-10 MW may be candidates for development under Chapter 5 forecasts under the 25 MW industrial scenario or larger. These projects may also be part of a development plan under the larger 40 MW scenario.

B.4.1 MOON HYDRO SITE

The proposed Moon Lake project would have a capacity of 8.5 MW with 50 GW.h of annual generation at an estimated capital cost of $51 million (2005$). Potential exists for increasing the energy capability by the diversions of other small watersheds into Moon Lake. Additionally, the capacity could be increased to take greater advantage of the seasonal storage capability (other versions of Moon have been cited at as large as 14.6 MW for primarily winter peaking operation).

The simple LCOE of Moon is about 5.4 cents/kW.h (2005$, real). This includes all capital costs of the generating project including interest, depreciation and return on equity, but excludes transmission, incremental operating and maintenance costs and taxes (also excludes water rentals – see below).

Moon Lake is located in northern BC on the east shore of Tutshi Lake, approximately 45 km south of Carcross, Yukon. Moon Lake provides the opportunity for seasonal storage of water (like Aishihik) focused on allowing summer flows to be stored for use during the winter. Due to the distance from the 138 kV transmission grid (about 66 km), a reasonably substantial amount of new transmission would be required[4].

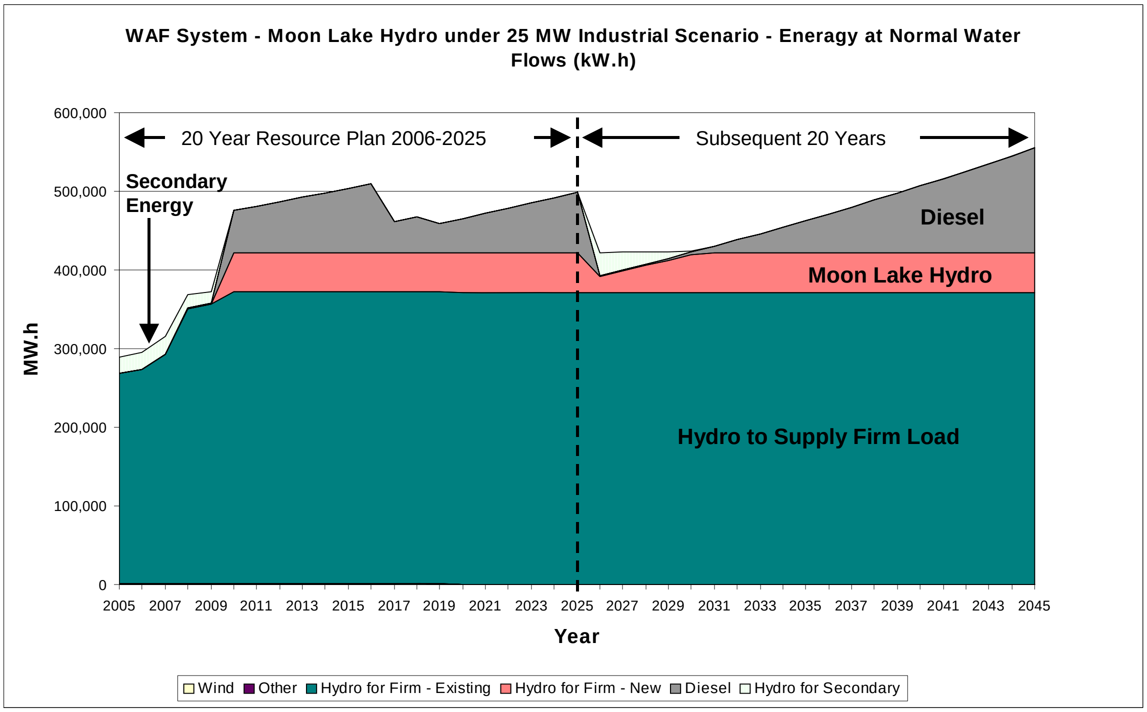
Because the Moon Lake project is located in BC, it would be subject to economic disadvantages due to material "water rental" payments and potentially property and school taxes that would be due to the BC government, as well as potentially more complicated licencing and regulations. The economic feasibility of operating in BC would need to be thoroughly assessed before proceeding with this project. Water rental payments to the BC government, for example, can likely add in the range of 0.5 cents/kW.h to the LCOE of the project.

In 1996, during the call for Expressions of Interest, Yukon Energy received a proposal from a local developer to either develop Moon Lake for Yukon Energy, or to develop the project as an IPP.
If developed in response to the 25 MW Industrial Development Scenario 2 (see Chapter 5: Section 5.2.2), it will become relevant to consider in detail the load fit of Moon to the loads to be developed. Under the 25 MW scenario loads, Moon would see full use of its energy output through 2045, with the exception of the 2026-2029 period (when surplus Moon hydro would arise, from 22 GW.h in 2026 reducing to 6 GW.h

[4] Although this transmission connection has not been priced, at a standard pricing of about $130,000 per km, plus substations, the rough capital cost could equate to $10 million. If this transmission line is solely providing a connection to Moon, the extra costs could increase the LCOE by 1.1 cents/kW.h

in 2029) as noted in Figure B-2. The impact of this 4 year surplus energy period is an increase in the LCOE of Moon over 65 years from 5.4 cents/kW.h (if all output could be used) to 5.6 cents/kW.h[5].

Figure B-2:
WAF Energy Requirements under 25 MW Scenario with Moon Lake Hydro



B.4.2 SURPRISE LAKE HYDRO SITE

In 1992, Surprise Lake was considered one of the key options for Yukon Energy in this size range. It was studied extensively in the early 1990's and a joint venture was contemplated with YEC, YECL and Synex to develop the project. It is an 8.5 MW project (50 GW.h) in two powerhouses estimated at $50 million (2005$).

In earlier review, significant concerns arose with respect to transmission requirements (more than 100 km from Jake's Corner to the site near Atlin, plus issues related to the 34.5 kV connection to Jake's Corner), regulatory requirements (due to location in BC), and economics due to material "water rental" payments and property and school taxes that would be due to the BC government as well as the local community.

[5] Full screening of Moon under a 25 MW scenario could therefore result in LCOE of 5.6 cents/kW.h for hydro capital costs reflecting "load fit", plus about 18.8% for hydro O&M based on 1% of capital cost (reflecting small projects, about $500,000 per year (2005$)), plus 1.1 cents/kW.h for transmission, plus 0.5 cents/kW.h for BC water rentals (ignoring taxes) for a total LCOE of 8.25 cents/kW.h (2005$, real).

More recently, the local community has indicated they are proceeding with a much smaller variant of the project to supply power solely to BC Hydro at Atlin. This development would likely preclude any future development of the full project as contemplated by Yukon Energy, and the project has been discarded by Yukon Energy as a likely development for Yukon needs.

B.4.3 TUTSHI AND OTHER HYDRO SITES IN THE SOUTHERN LAKES

There are a number of sites in the southern lakes that may provide opportunities for new generation, such as on the Tutshi River (7.5 MW installed, 50 GW.h, $79 million (2005$), LCOE of 8.4 cents/kW.h[6] plus water rentals to BC government). These projects serve to provide new generation as well as potentially enhance management of flow to the existing Whitehorse Rapids plant which provides added generation benefits (both capacity and energy). Yukon Energy is currently undertaking a hydrology study of this area along with site identification of potential water management structures or generating stations. Until that work is complete, all potential generation projects remain at the very initial stages of study.

Similar to Moon, a development of Tutshi under the 25 MW scenario would give rise to at least four years of surplus energy from 2026-2029. However, the actual annual flow patterns, flexibility and storage potential of Tutshi (and its associated impacts on Whitehorse Rapids) have not been recently assessed, and it is possible that surplus hydro would arise for more than four years if the plant output is not as able to be tailored to fit WAF loads as a Moon or other existing flexible resources such as Aishihik. The impact on LCOE from this surplus hydro under optimum conditions (a very flexible output from Tutshi) is an increase from 8.4 to 8.6 cents/kW.h; however the impact could be considerably more under a less flexible output.

B.4.4 MAYO B

The existing hydro site at Mayo has the potential to be enhanced by various changes in configuration, either to develop further head below the existing reservoir or an expansion of capacity utilizing the same head. This leads to multiple potential alternatives. However, as a supply option to WAF, these various projects are only of relevance if the Carmacks-Stewart transmission line is previously in service. The full capability of various potential Mayo enhancements to supply an interconnected WAF and MD system (as opposed to MD on its own) has not been fully studied, and should be re-examined in the event that the interconnection proceeds.

[6] As above, excludes transmission, incremental operating and maintenance costs and taxes.

One configuration alternative considered is a 10 MW, 48 GW.h, $101 million (2005$) variation based on a separate conveyance route from the existing reservoir to a new plant lower in elevation than the existing plant, which would be able to operate in parallel with the existing plant. This concept has an initial LCOE of 11.2 cents/kW.h. Various other concepts require further study. However, although work is still in preliminary stages, it must be recognized that it is possible no credible facility enhancements of this type exist at Mayo.

B.4.5 LACK OF OTHER YUKON-BASED HYDRO PROJECTS

There are very limited other potential hydro projects in the broad 5-15 MW size range identified in Yukon (as opposed to BC). One is near Faro, involving a diversion of the Anvil Creek and Rose Creek (9 MW, 70 GW.h, no reliable recent cost estimates available). Other identified projects are in the vicinity of Ross River (Prevost Canyon) or Pelly Crossing (Mica Creek) but have little to no reliable updated assessment of capital costs, transmission constraints and other key feasibility variables. Given the economic disadvantages of projects in BC (due to water rentals and taxes), it would be beneficial to secure generating station options in Yukon.

B.5 MEDIUM PROJECTS (10-30 MW)

Medium sized hydro projects have potential fit to the 40 MW industrial development scenario. However, key limitations arise with respect to the requirement for projects of this size once the mines close, as well as the risks of premature mine closures.

B.5.1 PRIMROSE/KUSAWA/TAKHINI HYDRO SITE

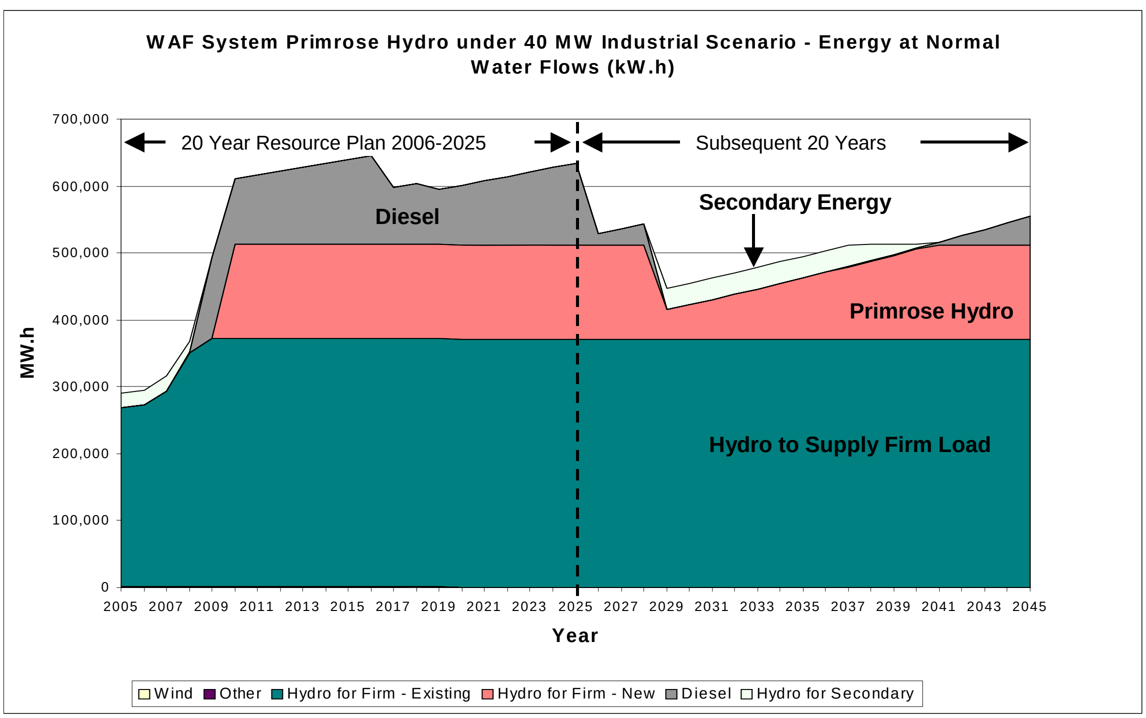
The potential Primrose generating station involves a number of potential concepts that were studied as alternatives to the Aishihik GS when it was constructed (studied in 1962, 1968, 1975, some more recent reviews). In general terms, the project involves developing hydro generation to capture the head between the high elevation Primrose Lake or Rose Lake and either Kusawa Lake or Takhini Lake.
Variations considered to date extend from about 19 MW to 30 MW and 100 to 180 GW.h. The primary concept reviewed to date is 28 MW, 141 GW.h/year estimated at $191 million (2005$). The LCOE under this scenario, consistent with the approaches used above, is about 7.2 cents/kW.h (2005$, real).

The site has reasonable access to developed transmission (less than 100 km, potential impact on LCOE of about 0.5 cents/kW.h). However, the site is located within an area that may be encompassed by a Park or special conservation area (subject to ongoing discussions with Yukon Government and the Kwanlin Dun, Champagne and Aishihik, and Carcross Tagish First Nations), which may limit development opportunities. Primrose is not "protected" by notation under the Yukon First Nations land claim agreements. In addition, the Primrose River is glacial fed and carries large amounts of silt, which may pose technical problems for a generating station.

The project is located in Yukon, so would not be subject to economic disadvantages of BC locations due to "water rental" payments or property and school taxes, as well as the potentially more complicated interprovincial licencing regulations.

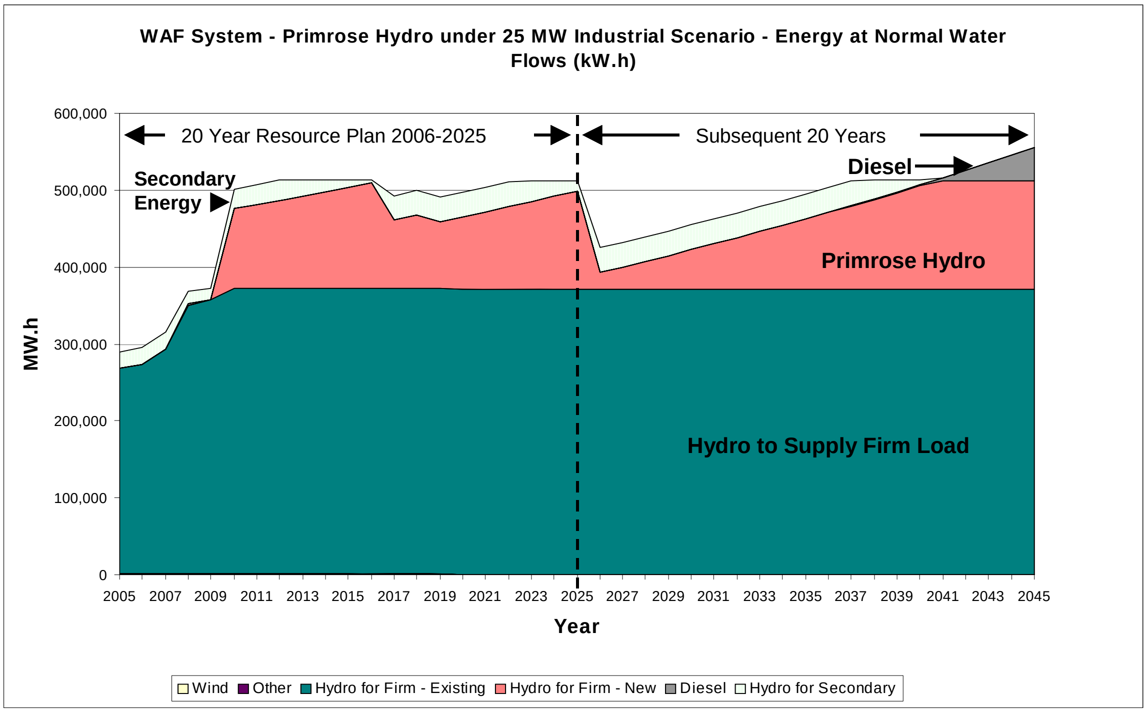
The key issues with Primrose or other hydro sites under the 40 MW scenario is the lack of load following closure of the mines, and the resulting potential for material surplus energy at that time (and potential consequent adverse rate impacts) as noted in Figure B3. In particular, were Primrose to be developed to service the 40 MW Industrial Scenario 3 (see Chapter 5: Section 5.2.3), its output would be fully utilized from the date of in-service to 2028. Starting in 2029 the facility would be in excess of WAF needs (about 2/3 of its output would be surplus), and the hydro surplus would extend through 2040. The consequent impact on project LCOE over 65 years is an increase from 7.2 to 7.7 cents/kW.h.

Figure B-3:
WAF Energy Requirements under 40 MW Scenario with Primrose Hydro



In contrast, were Primrose to be brought into service under the 25 MW industrial scenario, as noted in Figure B-4, the size would be well in excess of the system requirements in many years, and the consequent impact on LCOE would be an increase from about 7.2 cents/kW.h to over 9.0 cents/kW.h.

Figure B-4:
WAF Energy Requirements under 25 MW Scenario with Primrose Hydro



B.5.2 FINLAYSON HYDRO SITE

This potential project is on the Finlayson River, at Frances Lake well past Ross River near the Robert Campbell highway. It is potentially a 17 MW generating station (very high load factor, at 129 GW.h/year), and has a substantial transmission requirement (about 230 km). No recent reviews have been done of the potential costs of the station, but simple escalations from earlier capital cost estimates indicate potentially \$179 million (2005\$) (equivalent to an LCOE of 7.4 cents/kW.h in 2005\$, real).

Finlayson is located in the Kaska area which has not signed a final agreement, so the status of any protection is not available.

Other larger hydro generating sites also exist in this area, along with significant future mining potential (Wolverine, Kudz Ze Kayah, others) which may enable a major system development along the Robert

Campbell highway at some point in the future. However, as a lone supply option, Finlayson is unlikely to be economic due to the substantial transmission requirements (which could add more than 1.2 cents/kW.h to the above LCOE).

B.6 LARGE PROJECTS (30-60 MW)

Large sized hydro projects have limited potential under any of the industrial load scenarios, with the exception of potential service to a limited number of compressors under the Alaska highway pipeline case.

B.6.1 HOOLE

Hoole is located on the Pelly River east of Ross River and is in the Kaska First Nations area which does not have final agreement on any protection for potential hydro sites. The project is a 40 MW, 275 GW.h/year facility at an estimated $412 million capital cost (2005$). Resulting LCOE is 8.0 cents/kW.h (2005$, real).

B.6.2 SLATE

Slate is similarly on the Pelly River east of Ross River, and is also in the area without final agreements as yet on protected sites (Kaska). The project is a 42 MW, 252 GW.h/year facility at an estimated $422 million capital cost (2005$). The resulting LCOE is 8.9 cents/kW.h (2005$, real))

B.6.3 HESS

Two Mile Canyon on the Hess is located east of Mayo and is protected in the Yukon land claims agreements. It is only of value to WAF if Stewart-Carmacks interconnection in place. The project is a 53 MW, 280 GW.h/year with an estimated $380 million capital cost (2005$). The resulting LCOE is 7.2 cents/kW.h (2005$, real)).

B.7 VERY LARGE PROJECTS (60 MW+)

Very large hydro projects have the potential to service most or all of the potential Alaska highway pipeline loads.

B.7.1 GRANITE CANYON

On the Pelly River (east of Pelly Crossing), Granite Canyon is a site that was studied by NCPC under a number of different concepts and sizes. Although the site is protected under the Yukon final agreements, the extent to which development of the site can be accommodated within the “protection” areas has not yet been determined. Possible development concepts previously studied range from 80 MW (660 GW.h/year and $706 million capital cost (2005$)) or up to 250 MW or more. The LCOE is about 5.7 cents per kW.h (2005$, real) for the 80 MW version excluding transmission.

B.7.2 FRASER FALLS

On the Stewart River east of Mayo, possible concepts range from 100 MW up to 450 MW; the smallest version (100 MW, 613 GWh/year) has been estimated (2005$) to cost about $555 million, with LCOE for generation at about 4.8 cents per kW.h (2005$, real), excluding transmission costs.

B.7.3 VARIOUS OTHER LARGE YUKON RIVER SITES

Other sites have been identified on the Yukon River, well downstream of Whitehorse, ranging from 100 MW to 500 MW. No costs are available at this time for these options.

APPENDIX C:
AISHIHIK 3RD TURBINE ASSESSMENT

C.1 AISHIHIK 3RD TURBINE ASSESSMENT

Yukon Energy has reviewed the economics of a potential Aishihik 3rd turbine project under various assumptions, focused on a 65 year life. The assessment reviews five cases, as summarized in Chapter 4:

- **Section C-2:** Aishihik 3rd Turbine at 2009 under Base Case Loads

- **Section C-3:** Aishihik 3rd Turbine at 2009 under Base Case with 10 MW Mine Loads

- **Section C-4:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case Loads

- **Section C-5:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case with 10 MW Mine Loads

- **Section C-6:** Aishihik 3rd Turbine at 2011 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage under Base Case Loads

- **Section C-7:** Aishihik 3rd Turbine at 2009 assuming earlier in-service (2007) of Marsh Lake Fall/Winter Storage and (2008) of Carmacks-Stewart (CS) under Base Case with 10 MW Mine Loads

In each case, there are two sets of tables presented:

- **Overall Project Economics (IRR based on cash flows):** The first indicates an overall cash flow analysis of the project, focused on determining the Internal Rate of Return (IRR) of the project (e.g., focused on one-time capital costs rather than "accounting" costs of depreciation or return on rate base used for ratemaking). This is basically the equivalent of the analysis of the Mayo-Dawson Transmission Line project provided in Table 5.4 of the YEC 2005 Required Revenues and Related Matters Application.
- **Ratepayer Impacts (NPV based on annual impacts on ratepayers):** The second table indicates the overall project lifetime NPV, the project NPV during the period of the current Resource Plan (2006-2025) and the annual impacts on ratepayers.

In each case, the economics do not include assessment of the expected beneficial impacts on secondary sales, particularly in the early years of the project[1].

A summary of the cases is provided in Table C1.

[1] Once the WAF system grows to the point of having "diesel on the margin" and no annual surplus hydro, all secondary sales will be interrupted, so no further impacts on secondary sales will occur as a result of the project; for a few years prior to the point of diesel on the margin, the 3rd Turbine project may also reduce the availability of secondary sales, as there will be less "surplus" hydro due to the 3rd Turbine allowing more of the water to be used to avoid peaking diesel.

Table C-1:
Summary of Aishihik 3rd Turbine Assessment Cases (2005$, $000s)

	IRR lifetime (%)	Ratepayer Costs/(Savings) (NPV) lifetime	Ratepayer Costs/(Savings) (NPV) 20 years	Years until beneficial rate impact
Section C2: Turbine in 2009 – Base Case Loads	10.81%	(4,075)	57	8
Section C3: Turbine 2009 – Base Loads with 10 MW Mines	16.31%	(7,854)	(3,722)	2
Section C4: Turbine 2009 – Base Loads – Marsh Lake Storage in service	9.95%	(3,104)	1,028	9
Section C5: Turbine 2009 – Base Loads with 10 MW Mines – Marsh Lake Storage in service	14.44%	(6,726)	(2,594)	3
Section C6: Turbine 2011 – Base Loads – Marsh Lake Storage in service	10.96%	(3,779)	291	7
Section C7: Turbine 2009 – Base Loads with 10 MW Mines – Marsh Lake Storage and Carmacks-Stewart in service	14.91%	(7,258)	(3,126)	3

C.2 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE LOAD

Table C-2A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forcast

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	177	177	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	279	279	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	399	-	(399)	3.48	115	115	81	7	not assessed	87	7,577	76	7,653	7,565
2010	-	-	-	3.9	-	547	-	(547)	3.48	157	157	113	10	not assessed	122	-	77	77	(45)
2011	-	-	-	3.9	-	741	0	(741)	3.48	213	213	156	13	not assessed	169	-	79	79	(90)
2012	-	-	-	3.9	-	999	42	(957)	3.48	275	275	205	18	not assessed	223	-	80	80	(143)
2013	-	-	-	3.9	-	1,341	126	(1,215)	3.48	349	349	266	23	not assessed	289	-	82	82	(207)
2014	-	-	-	3.9	-	1,786	230	(1,556)	3.48	447	447	347	30	not assessed	377	-	84	84	(293)
2015	-	-	-	3.9	-	2,352	351	(2,002)	3.48	575	575	456	39	not assessed	495	-	85	85	(409)
2016	-	-	-	3.9	-	3,055	493	(2,562)	3.48	736	736	595	51	not assessed	646	-	87	87	(559)
2017	-	-	-	3.9	-	3,909	674	(3,236)	3.48	930	930	766	66	not assessed	832	-	89	89	(743)
2018	-	-	-	3.9	-	4,926	911	(4,015)	3.48	1,154	1,154	970	83	not assessed	1,053	-	91	91	(963)
2019	-	-	-	3.9	-	6,116	1,228	(4,889)	3.48	1,405	1,405	1,205	103	not assessed	1,308	-	92	92	(1,216)
2020	-	-	-	3.9	-	7,488	1,646	(5,843)	3.48	1,679	1,679	1,469	126	not assessed	1,595	-	94	94	(1,500)
2021	722	-	(722)	3.9	185	8,327	2,186	(6,141)	3.48	1,765	1,950	1,740	151	-	1,891	-	96	96	(1,794)
2022	7,299	1,899	(5,400)	3.9	1,385	3,506	970	(2,537)	3.48	729	2,114	1,924	178	-	2,101	-	98	98	(2,003)
2023	13,997	8,597	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	-	1,409	-	100	100	(1,309)
2024	20,819	15,419	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	27,768	22,368	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	34,845	29,445	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	42,053	36,653	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	49,394	43,994	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	56,871	51,471	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	64,486	59,086	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	72,242	66,842	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	80,142	74,742	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	88,188	82,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	96,383	90,983	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,729	99,329	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,230	107,830	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	121,888	116,488	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	130,706	125,306	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	139,687	134,287	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	148,835	143,435	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	158,151	152,751	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	167,640	162,240	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	177,305	171,905	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	187,148	181,748	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	197,174	191,774	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											10,246	947		11,193	5,669	1,068	6,738	(4,455)
																Internal Rate of Return			**10.81%**

Table C-2B: Aishihik 3rd Turbine Economics (65 years) - NPV based on annual impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	115	81	7	not assessed	87	117	565	76	758	670
2010	157	113	10	not assessed	122	117	557	77	750	628
2011	213	156	13	not assessed	169	117	548	79	743	574
2012	275	205	18	not assessed	223	117	539	80	736	513
2013	349	266	23	not assessed	289	117	530	82	729	440
2014	447	347	30	not assessed	377	117	522	84	722	345
2015	575	456	39	not assessed	495	117	513	85	715	220
2016	736	595	51	not assessed	646	117	504	87	708	62
2017	930	766	66	not assessed	832	117	495	89	701	(131)
2018	1,154	970	83	not assessed	1,053	117	487	91	694	(360)
2019	1,405	1,205	103	not assessed	1,308	117	478	92	687	(621)
2020	1,679	1,469	126	not assessed	1,595	117	469	94	680	(915)
2021	1,950	1,740	151	-	1,891	117	460	96	673	(1,218)
2022	2,114	1,924	178	-	2,101	117	451	98	666	(1,435)
2023	1,385	1,285	123	-	1,409	117	443	100	659	(750)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		10,246	947		11,193	1,236	4,813	1,068	7,118	(4,075)
7.52%								20 year NPV (2006-2025)		57

C.3 AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-3A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits															**Project Costs**			**Net Costs**
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	380	380	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	2,874	2,874	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	3,574	601	(2,973)	3.48	854	854	601	51	not assessed	653	7,577	76	7,653	7,000
2010	3,834	-	(3,834)	3.9	983	563	784	221	3.48	(64)	919	660	64	-	724	-	77	77	(646)
2011	9,209	3,809	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,014	97	-	1,111	-	79	79	(1,032)
2012	14,684	9,284	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	-	1,133	-	80	80	(1,053)
2013	20,428	15,028	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	-	1,156	-	82	82	(1,074)
2014	26,107	20,707	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	31,892	26,492	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	37,784	32,384	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	5,558	1,074	(4,484)	3.48	1,289	1,289	1,062	91	-	1,153	-	89	89	(1,064)
2018	-	-	-	3.9	-	6,809	1,432	(5,377)	3.48	1,545	1,545	1,299	111	-	1,411	-	91	91	(1,320)
2019	-	-	-	3.9	-	6,116	1,228	(4,889)	3.48	1,405	1,405	1,205	103	-	1,308	-	92	92	(1,216)
2020	-	-	-	3.9	-	7,488	1,646	(5,843)	3.48	1,679	1,679	1,469	126	-	1,595	-	94	94	(1,500)
2021	722	-	(722)	3.9	185	8,327	2,186	(6,141)	3.48	1,765	1,950	1,740	151	-	1,891	-	96	96	(1,794)
2022	7,299	1,899	(5,400)	3.9	1,385	3,506	970	(2,537)	3.48	729	2,114	1,924	178	-	2,101	-	98	98	(2,003)
2023	13,997	8,597	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	-	1,409	-	100	100	(1,309)
2024	20,819	15,419	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	27,768	22,368	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	34,845	29,445	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	42,053	36,653	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	49,394	43,994	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	56,871	51,471	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	64,486	59,086	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	72,242	66,842	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	80,142	74,742	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	88,188	82,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	96,383	90,983	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,729	99,329	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,230	107,830	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	121,888	116,488	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	130,706	125,306	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	139,687	134,287	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	148,835	143,435	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	158,151	152,751	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	167,640	162,240	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	177,305	171,905	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	187,148	181,748	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	197,174	191,774	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											13,689	1,283		14,972	5,669	1,068	6,738	(8,234)
																Internal Rate of Return			**16.31%**

Table C-3B: Aishihik 3rd Turbine Economics (65 years) - NPV based on annual impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					**Project Costs (Ratepayer Impacts)**				**Net Impacts**
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	854	601	51	not assessed	653	117	565	76	758	105
2010	919	660	64	-	724	117	557	77	750	27
2011	1,385	1,014	97	-	1,111	117	548	79	743	(368)
2012	1,385	1,034	99	-	1,133	117	539	80	736	(397)
2013	1,385	1,054	101	-	1,156	117	530	82	729	(427)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	1,289	1,062	91	-	1,153	117	495	89	701	(453)
2018	1,545	1,299	111	-	1,411	117	487	91	694	(717)
2019	1,405	1,205	103	-	1,308	117	478	92	687	(621)
2020	1,679	1,469	126	-	1,595	117	469	94	680	(915)
2021	1,950	1,740	151	-	1,891	117	460	96	673	(1,218)
2022	2,114	1,924	178	-	2,101	117	451	98	666	(1,435)
2023	1,385	1,285	123	-	1,409	117	443	100	659	(750)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		13,689	1,283		14,972	1,236	4,813	1,068	7,118	(7,854)
7.52%								20 year NPV (2006-2025)		(3,722)

C.4 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS

Table C-4A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	45	45	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	125	125	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	221	-	(221)	3.48	64	64	45	4	not assessed	49	7,577	76	7,653	7,604
2010	-	-	-	3.9	-	333	-	(333)	3.48	96	96	69	6	not assessed	74	-	77	77	3
2011	-	-	-	3.9	-	466	-	(466)	3.48	134	134	98	8	not assessed	106	-	79	79	(27)
2012	-	-	-	3.9	-	635	-	(635)	3.48	182	182	136	12	not assessed	148	-	80	80	(67)
2013	-	-	-	3.9	-	858	17	(840)	3.48	241	241	184	16	not assessed	200	-	82	82	(118)
2014	-	-	-	3.9	-	1,155	89	(1,066)	3.48	306	306	238	20	not assessed	258	-	84	84	(175)
2015	-	-	-	3.9	-	1,546	189	(1,357)	3.48	390	390	309	26	not assessed	336	-	85	85	(250)
2016	-	-	-	3.9	-	2,051	305	(1,746)	3.48	502	502	406	35	not assessed	440	-	87	87	(353)
2017	-	-	-	3.9	-	2,687	440	(2,247)	3.48	646	646	532	46	not assessed	578	-	89	89	(489)
2018	-	-	-	3.9	-	3,471	606	(2,864)	3.48	823	823	692	59	not assessed	751	-	91	91	(661)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	not assessed	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	not assessed	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	not assessed	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	not assessed	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											9,355	867		10,222	5,669	1,068	6,738	(3,484)
																Internal Rate of Return			9.95%

Table C-4B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	64	45	4	not assessed	49	117	565	76	758	709
2010	96	69	6	not assessed	74	117	557	77	750	676
2011	134	98	8	not assessed	106	117	548	79	743	637
2012	182	136	12	not assessed	148	117	539	80	736	588
2013	241	184	16	not assessed	200	117	530	82	729	529
2014	306	238	20	not assessed	258	117	522	84	722	463
2015	390	309	26	not assessed	336	117	513	85	715	379
2016	502	406	35	not assessed	440	117	504	87	708	267
2017	646	532	46	not assessed	578	117	495	89	701	123
2018	823	692	59	not assessed	751	117	487	91	694	(58)
2019	1,032	885	76	not assessed	961	117	478	92	687	(274)
2020	1,270	1,111	95	not assessed	1,206	117	469	94	680	(527)
2021	1,534	1,368	117	not assessed	1,486	117	460	96	673	(813)
2022	1,818	1,655	142	not assessed	1,796	117	451	98	666	(1,130)
2023	1,952	1,813	169	-	1,981	117	443	100	659	(1,322)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		9,355	867		10,222	1,236	4,813	1,068	7,118	(3,104)
7.52%								20 year NPV (2006-2025)		1,028

C.5 AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-5A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	207	207	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	1,919	1,919	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	2,435	387	(2,048)	3.48	589	589	414	35	not assessed	450	7,577	76	7,653	7,203
2010	-	-	-	3.9	-	3,060	518	(2,541)	3.48	730	730	524	45	not assessed	569	-	77	77	(492)
2011	1,509	-	(1,509)	3.9	387	2,293	680	(1,613)	3.48	464	851	623	56	-	679	-	79	79	(600)
2012	6,984	1,584	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	-	1,133	-	80	80	(1,053)
2013	12,728	7,328	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	-	1,156	-	82	82	(1,074)
2014	18,407	13,007	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	24,192	18,792	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	30,084	24,684	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	3,969	718	(3,251)	3.48	934	934	770	66	-	836	-	89	89	(747)
2018	-	-	-	3.9	-	4,975	962	(4,012)	3.48	1,153	1,153	969	83	-	1,053	-	91	91	(962)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	-	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	-	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	-	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	-	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											12,663	1,181		13,844	5,669	1,068	6,738	(7,106)
																Internal Rate of Return			**14.44%**

C-5B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)
Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	589	414	35	not assessed	450	117	565	76	758	308
2010	730	524	45	not assessed	569	117	557	77	750	182
2011	851	623	56	-	679	117	548	79	743	64
2012	1,385	1,034	99	-	1,133	117	539	80	736	(397)
2013	1,385	1,054	101	-	1,156	117	530	82	729	(427)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	934	770	66	-	836	117	495	89	701	(135)
2018	1,153	969	83	-	1,053	117	487	91	694	(359)
2019	1,032	885	76	-	961	117	478	92	687	(274)
2020	1,270	1,111	95	-	1,206	117	469	94	680	(527)
2021	1,534	1,368	117	-	1,486	117	460	96	673	(813)
2022	1,818	1,655	142	-	1,796	117	451	98	666	(1,130)
2023	1,952	1,813	169	-	1,981	117	443	100	659	(1,322)
2024	1,385	1,311	126	-	1,437	117	434	102	652	(785)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		12,663	1,181		13,844	1,236	4,813	1,068	7,118	(6,726)
7.52%								20 year NPV (2006-2025)		(2,594)

C.6 AISHIHIK 3RD TURBINE AT 2011 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS

Table C-6A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project and with Marsh Lake (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project and with Marsh Lake (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	45	45	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	125	125	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	221	221	-	3.48	-	-	-	-		-	-	-	-	-
2010	-	-	-	3.9	-	333	333	-	3.48	-	-	-	-		-	-	-	-	-
2011	-	-	-	3.9	-	466	-	(466)	3.48	134	134	98	8	not assessed	106	7,883	79	7,962	7,856
2012	-	-	-	3.9	-	635	-	(635)	3.48	182	182	136	12	not assessed	148	-	80	80	(67)
2013	-	-	-	3.9	-	858	17	(840)	3.48	241	241	184	16	not assessed	200	-	82	82	(118)
2014	-	-	-	3.9	-	1,155	89	(1,066)	3.48	306	306	238	20	not assessed	258	-	84	84	(175)
2015	-	-	-	3.9	-	1,546	189	(1,357)	3.48	390	390	309	26	not assessed	336	-	85	85	(250)
2016	-	-	-	3.9	-	2,051	305	(1,746)	3.48	502	502	406	35	not assessed	440	-	87	87	(353)
2017	-	-	-	3.9	-	2,687	440	(2,247)	3.48	646	646	532	46	not assessed	578	-	89	89	(489)
2018	-	-	-	3.9	-	3,471	606	(2,864)	3.48	823	823	692	59	not assessed	751	-	91	91	(661)
2019	-	-	-	3.9	-	4,415	823	(3,592)	3.48	1,032	1,032	885	76	not assessed	961	-	92	92	(869)
2020	-	-	-	3.9	-	5,531	1,110	(4,421)	3.48	1,270	1,270	1,111	95	not assessed	1,206	-	94	94	(1,112)
2021	-	-	-	3.9	-	6,829	1,492	(5,337)	3.48	1,534	1,534	1,368	117	not assessed	1,486	-	96	96	(1,390)
2022	-	-	-	3.9	-	8,318	1,991	(6,327)	3.48	1,818	1,818	1,655	142	not assessed	1,796	-	98	98	(1,698)
2023	6,297	897	(5,400)	3.9	1,385	3,706	1,730	(1,976)	3.48	568	1,952	1,813	169	-	1,981	-	100	100	(1,881)
2024	13,119	7,719	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	-	1,437	-	102	102	(1,335)
2025	20,068	14,668	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	27,145	21,745	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,353	28,953	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	41,694	36,294	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	49,171	43,771	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	56,786	51,386	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	64,542	59,142	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	72,442	67,042	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	80,488	75,088	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	88,683	83,283	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	97,029	91,629	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	105,530	100,130	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	114,188	108,788	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	123,006	117,606	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	131,987	126,587	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	141,135	135,735	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	150,451	145,051	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	159,940	154,540	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	169,605	164,205	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	179,448	174,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	189,474	184,074	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
2074			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,529	339	-	3,868	-	274	274	(3,593)
2075			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,600	346	-	3,945	-	280	280	(3,665)
PV (2005)	7.52%											9,320	864		10,184	5,102	962	6,064	(4,120)
																Internal Rate of Return			**10.96%**

Table C-6B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage - NPV based on annual impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved (with project compared to without the project and with Marsh Lake)	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	-	-	-		-	-	-	-	-	-
2010	-	-	-		-	-	-	-	-	-
2011	134	98	8	not assessed	106	121	588	79	788	682
2012	182	136	12	not assessed	148	121	579	80	781	633
2013	241	184	16	not assessed	200	121	570	82	773	574
2014	306	238	20	not assessed	258	121	561	84	766	508
2015	390	309	26	not assessed	336	121	552	85	758	423
2016	502	406	35	not assessed	440	121	543	87	751	311
2017	646	532	46	not assessed	578	121	534	89	744	166
2018	823	692	59	not assessed	751	121	524	91	736	(15)
2019	1,032	885	76	not assessed	961	121	515	92	729	(232)
2020	1,270	1,111	95	not assessed	1,206	121	506	94	722	(485)
2021	1,534	1,368	117	not assessed	1,486	121	497	96	714	(771)
2022	1,818	1,655	142	not assessed	1,796	121	488	98	707	(1,089)
2023	1,952	1,813	169	-	1,981	121	479	100	700	(1,281)
2024	1,385	1,311	126	-	1,437	121	470	102	693	(744)
2025	1,385	1,337	128	-	1,466	121	461	104	686	(780)
2026	1,385	1,364	131	-	1,495	121	451	106	679	(816)
2027	1,385	1,391	134	-	1,525	121	442	108	672	(853)
2028	1,385	1,419	136	-	1,555	121	433	110	665	(891)
2029	1,385	1,448	139	-	1,587	121	424	113	658	(929)
2030	1,385	1,477	142	-	1,618	121	415	115	651	(967)
2031	1,385	1,506	145	-	1,651	121	406	117	644	(1,006)
2032	1,385	1,536	147	-	1,684	121	397	119	637	(1,046)
2033	1,385	1,567	150	-	1,717	121	388	122	631	(1,087)
2034	1,385	1,598	153	-	1,752	121	378	124	624	(1,128)
2035	1,385	1,630	157	-	1,787	121	369	127	617	(1,169)
2036	1,385	1,663	160	-	1,822	121	360	129	611	(1,212)
2037	1,385	1,696	163	-	1,859	121	351	132	604	(1,255)
2038	1,385	1,730	166	-	1,896	121	342	135	598	(1,298)
2039	1,385	1,765	169	-	1,934	121	333	137	591	(1,343)
2040	1,385	1,800	173	-	1,973	121	324	140	585	(1,388)
2041	1,385	1,836	176	-	2,012	121	315	143	579	(1,433)
2042	1,385	1,873	180	-	2,052	121	306	146	572	(1,480)
2043	1,385	1,910	183	-	2,093	121	296	149	566	(1,527)
2044	1,385	1,948	187	-	2,135	121	287	152	560	(1,575)
2045	1,385	1,987	191	-	2,178	121	278	155	554	(1,624)
2046	1,385	2,027	195	-	2,222	121	269	158	548	(1,674)
2047	1,385	2,068	198	-	2,266	121	260	161	542	(1,724)
2048	1,385	2,109	202	-	2,311	121	251	164	536	(1,775)
2049	1,385	2,151	207	-	2,358	121	242	167	530	(1,827)
2050	1,385	2,194	211	-	2,405	121	233	171	524	(1,880)
2051	1,385	2,238	215	-	2,453	121	223	174	519	(1,934)
2052	1,385	2,283	219	-	2,502	121	214	178	513	(1,989)
2053	1,385	2,328	224	-	2,552	121	205	181	508	(2,044)
2054	1,385	2,375	228	-	2,603	121	196	185	502	(2,101)
2055	1,385	2,422	233	-	2,655	121	187	188	497	(2,158)
2056	1,385	2,471	237	-	2,708	121	178	192	491	(2,217)
2057	1,385	2,520	242	-	2,762	121	169	196	486	(2,276)
2058	1,385	2,571	247	-	2,817	121	160	200	481	(2,337)
2059	1,385	2,622	252	-	2,874	121	150	204	476	(2,398)
2060	1,385	2,675	257	-	2,931	121	141	208	471	(2,461)
2061	1,385	2,728	262	-	2,990	121	132	212	466	(2,524)
2062	1,385	2,783	267	-	3,050	121	123	216	461	(2,589)
2063	1,385	2,838	272	-	3,111	121	114	221	456	(2,655)
2064	1,385	2,895	278	-	3,173	121	105	225	451	(2,722)
2065	1,385	2,953	283	-	3,236	121	96	230	447	(2,790)
2066	1,385	3,012	289	-	3,301	121	87	234	442	(2,859)
2067	1,385	3,072	295	-	3,367	121	78	239	438	(2,929)
2068	1,385	3,134	301	-	3,435	121	68	244	433	(3,001)
2069	1,385	3,196	307	-	3,503	121	59	249	429	(3,074)
2070	1,385	3,260	313	-	3,573	121	50	254	425	(3,148)
2071	1,385	3,325	319	-	3,645	121	41	259	421	(3,224)
2072	1,385	3,392	326	-	3,718	121	32	264	417	(3,301)
2073	1,385	3,460	332	-	3,792	121	23	269	413	(3,379)
2074	1,385	3,529	339	-	3,868	121	14	274	409	(3,458)
2075	1,385	3,600	346	-	3,945	121	5	280	406	(3,539)
PV (2005)		9,320	864		10,184	1,112	4,332	962	6,406	(3,779)
7.52%								20 year NPV (2006-2025)		291

SECTION C-7: AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE AND (2008) OF CARMACKS-STEWART (CS) UNDER BASE CASE WITH 10 MW MINE LOADS

Table C-7A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & Carmacks-Stewart (CS) S - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits															Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenues Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	89	89	-	3.48	-	-	-	-		-	-	-	-	-
2007	-	-	-	3.9	-	207	207	-	3.48	-	-	-	-		-	-	-	-	-
2008	-	-	-	3.9	-	2,113	2,113	-	3.48	-	-	-	-		-	-	-	-	-
2009	-	-	-	3.9	-	2,685	505	(2,180)	3.48	627	627	441	38	not assess	479	7,577	76	7,653	7,174
2010	-	-	-	3.9	-	3,379	667	(2,711)	3.48	779	779	559	48	not assess	607	-	77	77	(530)
2011	-	-	-	3.9	-	4,204	873	(3,331)	3.48	957	957	701	60	not assess	761	-	79	79	(682)
2012	-	-	-	3.9	-	5,171	1,137	(4,034)	3.48	1,159	1,159	866	74	not assess	940	-	80	80	(859)
2013	5,087	-	(5,087)	3.9	1,304	1,203	1,478	275	3.48	(79)	1,225	933	90	-	1,023	-	82	82	(941)
2014	11,374	5,974	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	-	1,179	-	84	84	(1,095)
2015	17,777	12,377	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	-	1,202	-	85	85	(1,117)
2016	24,298	18,898	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	-	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	4,735	1,014	(3,720)	3.48	1,069	1,069	881	75	-	957	-	89	89	(868)
2018	-	-	-	3.9	-	5,905	1,357	(4,548)	3.48	1,307	1,307	1,099	94	-	1,193	-	91	91	(1,103)
2019	-	-	-	3.9	-	5,365	1,194	(4,171)	3.48	1,199	1,199	1,028	88	-	1,116	-	92	92	(1,024)
2020	-	-	-	3.9	-	6,675	1,604	(5,071)	3.48	1,457	1,457	1,275	109	-	1,384	-	94	94	(1,290)
2021	-	-	-	3.9	-	8,189	2,141	(6,047)	3.48	1,738	1,738	1,551	133	-	1,683	-	96	96	(1,587)
2022	-	-	-	3.9	-	9,913	2,827	(7,087)	3.48	2,036	2,036	1,853	159	-	2,012	-	98	98	(1,914)
2023	3,787	-	(3,787)	3.9	971	8,070	3,681	(4,388)	3.48	1,261	2,232	2,072	187	-	2,259	-	100	100	(2,159)
2024	11,339	5,939	(5,400)	3.9	1,385	2,687	-	(2,687)	3.48	772	2,157	2,042	189	-	2,231	-	102	102	(2,129)
2025	19,030	13,630	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	-	1,466	-	104	104	(1,362)
2026	26,863	21,463	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	-	1,495	-	106	106	(1,389)
2027	34,842	29,442	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	-	1,525	-	108	108	(1,417)
2028	42,968	37,568	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	-	1,555	-	110	110	(1,445)
2029	51,244	45,844	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	-	1,587	-	113	113	(1,474)
2030	59,674	54,274	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	-	1,618	-	115	115	(1,503)
2031	68,259	62,859	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	-	1,651	-	117	117	(1,534)
2032	77,003	71,603	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	-	1,684	-	119	119	(1,564)
2033	85,909	80,509	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	-	1,717	-	122	122	(1,595)
2034	94,980	89,580	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	-	1,752	-	124	124	(1,627)
2035	104,218	98,818	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	-	1,787	-	127	127	(1,660)
2036	113,628	108,228	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	-	1,822	-	129	129	(1,693)
2037	123,211	117,811	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	-	1,859	-	132	132	(1,727)
2038	132,972	127,572	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	-	1,896	-	135	135	(1,762)
2039	142,913	137,513	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	-	1,934	-	137	137	(1,797)
2040	153,039	147,639	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	-	1,973	-	140	140	(1,833)
2041	163,351	157,951	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	-	2,012	-	143	143	(1,869)
2042	173,855	168,455	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	-	2,052	-	146	146	(1,907)
2043	184,552	179,152	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	-	2,093	-	149	149	(1,945)
2044	195,448	190,048	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	-	2,135	-	152	152	(1,984)
2045	206,545	201,145	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	-	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	-	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	-	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	-	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	-	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	-	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	-	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	-	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	-	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	-	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	-	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	-	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	-	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	-	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	-	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	-	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	-	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	-	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	-	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	-	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	-	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	-	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	-	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	-	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	-	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	-	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	-	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	-	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	-	3,792	-	269	269	(3,523)
PV (2005)	7.52%											13,162	1,214		14,376	5,669	1,068	6,738	(7,638)
																Internal Rate of Return			**14.91%**

Table C-7B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage & CS - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - **Base Case load forecast with Mines**

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-		-	-	-	-	-	-
2007	-	-	-		-	-	-	-	-	-
2008	-	-	-		-	-	-	-	-	-
2009	627	441	38	not assessed	479	117	565	76	758	279
2010	779	559	48	not assessed	607	117	557	77	750	144
2011	957	701	60	not assessed	761	117	548	79	743	(17)
2012	1,159	866	74	not assessed	940	117	539	80	736	(204)
2013	1,225	933	90	-	1,023	117	530	82	729	(294)
2014	1,385	1,076	103	-	1,179	117	522	84	722	(457)
2015	1,385	1,097	105	-	1,202	117	513	85	715	(488)
2016	1,385	1,119	107	-	1,226	117	504	87	708	(519)
2017	1,069	881	75	-	957	117	495	89	701	(256)
2018	1,307	1,099	94	-	1,193	117	487	91	694	(499)
2019	1,199	1,028	88	-	1,116	117	478	92	687	(429)
2020	1,457	1,275	109	-	1,384	117	469	94	680	(704)
2021	1,738	1,551	133	-	1,683	117	460	96	673	(1,011)
2022	2,036	1,853	159	-	2,012	117	451	98	666	(1,346)
2023	2,232	2,072	187	-	2,259	117	443	100	659	(1,600)
2024	2,157	2,042	189	-	2,231	117	434	102	652	(1,578)
2025	1,385	1,337	128	-	1,466	117	425	104	646	(820)
2026	1,385	1,364	131	-	1,495	117	416	106	639	(856)
2027	1,385	1,391	134	-	1,525	117	408	108	632	(893)
2028	1,385	1,419	136	-	1,555	117	399	110	626	(930)
2029	1,385	1,448	139	-	1,587	117	390	113	619	(967)
2030	1,385	1,477	142	-	1,618	117	381	115	613	(1,006)
2031	1,385	1,506	145	-	1,651	117	373	117	606	(1,044)
2032	1,385	1,536	147	-	1,684	117	364	119	600	(1,084)
2033	1,385	1,567	150	-	1,717	117	355	122	593	(1,124)
2034	1,385	1,598	153	-	1,752	117	346	124	587	(1,165)
2035	1,385	1,630	157	-	1,787	117	337	127	581	(1,206)
2036	1,385	1,663	160	-	1,822	117	329	129	575	(1,248)
2037	1,385	1,696	163	-	1,859	117	320	132	568	(1,290)
2038	1,385	1,730	166	-	1,896	117	311	135	562	(1,334)
2039	1,385	1,765	169	-	1,934	117	302	137	556	(1,378)
2040	1,385	1,800	173	-	1,973	117	294	140	550	(1,422)
2041	1,385	1,836	176	-	2,012	117	285	143	544	(1,468)
2042	1,385	1,873	180	-	2,052	117	276	146	538	(1,514)
2043	1,385	1,910	183	-	2,093	117	267	149	532	(1,561)
2044	1,385	1,948	187	-	2,135	117	259	152	527	(1,609)
2045	1,385	1,987	191	-	2,178	117	250	155	521	(1,657)
2046	1,385	2,027	195	-	2,222	117	241	158	515	(1,706)
2047	1,385	2,068	198	-	2,266	117	232	161	510	(1,756)
2048	1,385	2,109	202	-	2,311	117	224	164	504	(1,807)
2049	1,385	2,151	207	-	2,358	117	215	167	499	(1,859)
2050	1,385	2,194	211	-	2,405	117	206	171	493	(1,911)
2051	1,385	2,238	215	-	2,453	117	197	174	488	(1,965)
2052	1,385	2,283	219	-	2,502	117	188	178	483	(2,019)
2053	1,385	2,328	224	-	2,552	117	180	181	477	(2,075)
2054	1,385	2,375	228	-	2,603	117	171	185	472	(2,131)
2055	1,385	2,422	233	-	2,655	117	162	188	467	(2,188)
2056	1,385	2,471	237	-	2,708	117	153	192	462	(2,246)
2057	1,385	2,520	242	-	2,762	117	145	196	457	(2,305)
2058	1,385	2,571	247	-	2,817	117	136	200	452	(2,365)
2059	1,385	2,622	252	-	2,874	117	127	204	448	(2,426)
2060	1,385	2,675	257	-	2,931	117	118	208	443	(2,488)
2061	1,385	2,728	262	-	2,990	117	110	212	438	(2,552)
2062	1,385	2,783	267	-	3,050	117	101	216	434	(2,616)
2063	1,385	2,838	272	-	3,111	117	92	221	429	(2,681)
2064	1,385	2,895	278	-	3,173	117	83	225	425	(2,748)
2065	1,385	2,953	283	-	3,236	117	75	230	421	(2,816)
2066	1,385	3,012	289	-	3,301	117	66	234	417	(2,885)
2067	1,385	3,072	295	-	3,367	117	57	239	412	(2,955)
2068	1,385	3,134	301	-	3,435	117	48	244	409	(3,026)
2069	1,385	3,196	307	-	3,503	117	39	249	405	(3,099)
2070	1,385	3,260	313	-	3,573	117	31	254	401	(3,172)
2071	1,385	3,325	319	-	3,645	117	22	259	397	(3,248)
2072	1,385	3,392	326	-	3,718	117	13	264	394	(3,324)
2073	1,385	3,460	332	-	3,792	117	4	269	390	(3,402)
PV (2005)		13,162	1,214		14,376	1,236	4,813	1,068	7,118	(7,258)
7.52%								20 year NPV (2006-2025)		(3,126)

GLOSSARY OF TERMS

BASELOAD DIESEL GENERATION:

Diesel generation operated to provide energy, due to a shortfall in annual energy (kW.h) from hydro (or other low variable cost generating sources).

BULK ELECTRICAL SUPPLY:

The generation and transmission part of an electrical grid that delivers power to the distribution system(s).

CAPACITY:

The load for which a generating unit, generating station or other electrical apparatus is rated either by the user or by the manufacturer.

COST OF SERVICE:

The total cost incurred to provide utility service, including expenses, taxes and return on investment. The cost of service may be thought of as an annual revenue requirement.

DEMAND:

The rate of flow of electricity demanded at one point in time and the maximum size (capacity) of facilities required to serve the demands of electric customers, usually expressed in kilowatts.

ENERGY:

The consumption of electricity over a period of time by customers of an electric system, usually expressed in kilowatt hours.

FIRM CAPACITY:

Capacity which is intended to have assured availability to the customers to meet all or a portion of the load requirements.

FIXED COST:

Those costs that do not vary with the number of kilowatt hours supplied. Examples would be depreciation and return on investment.

GIGAWATT:

One gigawatt equals 1,000 megawatts.

INDUSTRIAL CUSTOMER:

Defined in OIC 1995/90 as:

a) "major industrial customer" means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer;

b) "isolated industrial customer" means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer.

KILOWATT:

One kilowatt equals 1,000 watts, where a watt is an electrical unit of real power or rate of doing work. One kilowatt is equivalent to approximately 1.34 horsepower.

KILOWATT HOUR:

The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt hour equals 1,000 watt hours.

LOAD FACTOR:

The average load of a customer, a group of customers, or the system divided by the maximum load (usually expressed as a percentage). For example, assuming 48 kWh of usage for the day, the average is 48/24 or 2 kW. If the maximum capacity available is 4 kW, the load factor is 2/4 or 50%.

LOAD FORECAST:

The forecast energy and demand requirements of the customers (usually on a monthly or annual basis).

MAXIMUM CONTINUOUS RATING:

The generation output rating in megawatts that a generating unit can sustain on a continuous basis.

MEGAWATT:

One megawatt equals 1,000 kilowatts.

PEAKING DIESEL GENERATION:

Diesel generating operated over short-term periods (hours to days) to aid in meeting the peak demand (MW) for electricity, typically during daytime hours.

RE-RUNNERING:

The replacement of turbines at an existing hydro generating station with a modern, more efficient design.

RESERVE:

Excess generation capacity that is maintained to safeguard against losses of supply due to unexpected equipment failures.

RUN OF RIVER:

Hydro projects that do not have any material storage, and must generate power based on river flows at any given point in time.

SECONDARY ENERGY:

Energy sold on an interruptible basis for service to heating loads.

ACRONYMS

BES: BULK ELECTRICITY SUPPLY

DFO: DEPARTMENT OF FISHERIES AND OCEANS

DSM: DEMAND SIDE MANAGEMENT

ESC: ENERGY SOLUTIONS CENTRE

GRA: GENERAL RATE APPLICATION

IPP: INDEPENDENT POWER PRODUCER

LCOE: LEVELIZED COSTS OF ENERGY

LOEE: LOSS OF ENERGY EXPECTATION

LOLE: LOSS OF LOAD EXPECTATION

LOLH: LOSS OF LOAD HOURS

LOLP: LOSS OF LOAD PROBABILITY

MAPL: MAXIMUM ALLOWABLE PEAK LOAD

MCR: MAXIMUM CONTINUOUS RATING

MD: MAYO-DAWSON

MW: MEGAWATT

NCPC: NORTHERN CANADA POWER COMMISSION

NTPC: NORTHWEST TERRITORIES POWER CORPORATION

NWT: NORTHWEST TERRITORIES

UKHM: UNITED KENO HILL MINE

WAF: WHITEHORSE-AISHIHIK-FARO

YDC: YUKON DEVELOPMENT CORPORATION

YEC: YUKON ENERGY CORPORATION

YECL: YUKON ELECTRICAL COMPANY LIMITED

YTG: YUKON TERRITORIAL GOVERNMENT

YTWB: YUKON TERRITORIAL WATER BOARD

YUB: YUKON UTILITIES BOARD