Glacier Power Limited
Dunvegan Hydroelectric Project

An Assessment of the “Need” for a Renewable Power Project in Northwest Alberta

prepared for
Glacier Power Limited

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EXECUTIVE SUMMARY

In Alberta, replacing generating capacity that will reach retirement age in the next 15 to 25 years, plus the need to meet rising new demand will be a formidable challenge. It will be complicated by potential opposing forces of competition to reduce cost and environmental pressures to reduce emissions associated with energy use and production—particularly Green House Gases (GHG). Planning for capacity, even in a competitive environment, is further complicated by uncertainties associated with forecasting the demand for electricity. These uncertainties tend to forestall decisions as long as possible. To avoid being wrong in a prediction of demand the tendency would be to wait until the last possible minute for the future to reveal itself.1

In Alberta today, the decision to develop a power project lies solely with the investor once all approvals and permits have been obtained, which contrasts to development in the past under the previous regulated environment. Even in a competitive environment the decision to develop one project over another requires a comprehensive cost-benefit analysis to assess the better investment. Any project that provides a substantial net-benefit should be considered in the public interest and is therefore “needed”. In addition to the direct project, economic, social, and environmental cost-benefits, the “need” for any electric generating facility can also be supported by other or indirect benefits (externalities) associated with any positive impact on:

1. market fundamentals relating to electricity supply, demand and price;
2. electrical system benefits relating to technical interconnection and delivery; and
3. other factors such as government policy relating to environmental objectives and standards.

The growth in the Alberta economy as measured by real gross domestic product (RGDP), and almost every other developed economy, is very much dependant on a reliable source of competitively-priced electricity. From 1960 to 1980, Alberta’s consumption of electric energy per dollar of Real GDP doubled by growing an average of 7% per year. Currently, Alberta generates approximately $1.85 million in Real GDP (1992 dollars) for every GWh of electric energy consumed—a relationship that has been relatively constant since the early 1980’s. Canada in general and Alberta more specifically have two of the most electric-intensive economies in the world as measured by electric energy per capita.

A substantial portion of Alberta’s electric generating capacity will reach the end of its useful life in the foreseeable future. At the end of 2004, Alberta’s total gross installed generating capacity will be approximately 13,000 MW (10,500 MW net-to-grid) of

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1 Repowering Alberta: Options for Electrical Generating Units; Economic and Emissions Impacts, Canadian Energy Research Institute, Study No 73, September 1996.
which almost 25% will reach retirement age in the next 15 years and just under 40% will reach retirement age in the next 25 years.

Alberta total electric energy sales, as measured by Alberta Internal Load (AIL), have grown by an Annual Compound Growth Rate (ACGR) of 3.4% per year over the last 15 years (1987-2003) and is anticipated to grow by 2.7% ACGR per year over the next 15 years (2004-2018). This level of demand growth coupled with retirements would necessitate the need to develop almost 4,500 MW of new net-to-grid generating capacity plus an additional 1,425 MW of on-site capacity bringing the total new generating capacity needed to just under 6,000 MW over the next 15-years or approximately 50% of today’s total capacity.

The Alberta electricity market price has been and will continue to be defined by the cost structure of the mix of supply technology that is added over time to meet rising demand and to replace older less efficient units as they exit the market. Historically the bulk of Alberta’s electric energy supply has been developed under a cost-of-service regulatory regime. The abundance of thermal coal in Alberta coupled with a very high electrical system load factor—driven by a large share of industrial load on the Alberta grid—has favoured the development of high capital cost mine-mouth coal fired facilities. Ironically, these large-scale high capital projects were developed during a time of relatively high cost of financing, notwithstanding the low cost of competing fuels such as natural gas. More ironically still, high fuel cost and relatively low capital cost projects are now being built in an environment of much lower cost of capital and soaring marginal natural gas fuel prices.

It should be noted that the significant advances made in lower capital cost and higher fuel efficiency of natural gas-based technologies over the last couple of decades have fostered a greater level of natural gas fired generation development. The other obvious change in the Alberta electricity market which supports this new trend in generation development has been the implementation of a competitive market in place of the previous cost-of-service regulatory regime. The new market places the risk of capital investment squarely with the investor and passes the fuel cost to the consumer through the marginal price of the energy spot market. This new risk profile in the market clearly supports the development of smaller more efficient relatively lower capital cost projects at the expense of high fuel costs. Finally, the uncertain future regarding environmental policy only serves to support the new trend, particularly in the absence of competitive low environmental impact options.

Current large-scale base load generating options in Alberta are capable of producing long-term power on an all-in life-cycle basis in the $45 to $50/MWh range, whereas some newer technologies with a relatively low utilization rate would be expected to produce power for just over $80/MWh. The all-in cost structure for the median generation technology deployed in Alberta appears to be approximately $60/MWh—at today’s expected natural gas price. The Dunvegan Hydroelectric project’s expected all-in cost compares favorably with mainstream technologies from a cost perspective however, it does not carry the same risks associated with fuel and airborne environmental considerations, and would be expected to provide power over a much longer useful life—almost 2 to 3 times or 50 to 100 years.
It is estimated that the market impact of the development of the Dunvegan Hydroelectric project could be a reduction in the all-hour average pool price by approximately $1 to $2/MWh in the first one or two years of service relative to the price that might be expected without the Dunvegan project—all other things being equal. Assuming pool prices were reduced on average by $1 to $2/MWh, then the potential benefit to Alberta electricity consumers would be about $30.5 to $61 million dollars in 2009 and 2010 for a total market benefit of $91.5 million if 50% of all consumers were exposed to spot prices.

In some cases in Alberta, generation development can provide benefit to the regional transmission system by reducing system losses and by providing voltage support as an interim measure prior to other transmission development. In addition, some generation can provide benefit to the overall transmission system by providing various ancillary services, which are needed to maintain system reliability. Currently the AESO expends approximately $40 to $50 million per year on Transmission Must Run (TMR) payments the majority of which are in northwest Alberta. The Dunvegan Hydroelectric project, because of the expected nature of its operations, could reduce northwest Alberta area transmission losses and TMR requirements by approximately $5 million dollars per year, which would result in a direct reduction in AESO transmission costs by 11 percent.

On a global scale, the Kyoto Accord has been the impetus for the adaptation and implementation of environmental stewardship principals in Canada and around the world. In Canada, governments at all levels have been working with industry and stakeholders to develop guiding principles that will define future policy with respect to Green House Gas (GHG) emissions. In addition, the Federal and most Provincial Governments have made commitments to buy a large percentage of their power needs from green energy sources which has led to an increased development of wind, run of river hydro and biomass facilities across Canada and around the world. The Dunvegan Hydroelectric project given its expected operating characteristics would provide a significant reduction in green house gas emissions in Alberta in the order of 500,000 Tonnes annually (assuming 0.8 Tonnes per MWh) by displacing other thermal generation sources. This reduction is anticipated to save the electric industry approximately $5 million dollars per year in potential CO₂ offset costs assuming a cost of $10/Tonne.

As a result of the foregoing facts, reasonable capital cost projects—particularly those with lower operating costs, such as the Dunvegan Hydroelectric project—are in the best interest of electricity consumers in Alberta. In addition, further diversification of the power sectors fuel supply in Alberta can only provide additional value to the electricity consumer by mitigating long term fuel supply risk. Direct and indirect technical benefits potentially arise from the interconnection of Dunvegan Hydroelectric facility in the northwest Alberta transmission grid that will benefit both regional and system wide consumers. Finally, the environmental attributes of the Dunvegan Hydroelectric project will provide a long lasting benefit with respect to the issue of global warming through reduced GHG emissions in Alberta, which is clearly in the public interest.
### Table 1 - Estimated Monetary Benefits of the Dunvegan Project

<table>
<thead>
<tr>
<th>Estimated Monetary Benefits of the Dunvegan Project</th>
<th>Millions of Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004 dollars assuming a 10% discount rate</td>
<td>2009</td>
</tr>
<tr>
<td>Pool Price Effect</td>
<td>$55.1</td>
</tr>
<tr>
<td>Transmission Losses and TMR</td>
<td>$33.4</td>
</tr>
<tr>
<td>Green House Gas Emissions</td>
<td>$33.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$121.9</strong></td>
</tr>
</tbody>
</table>

Note: Present values were calculated assuming 40 years of project life.
PROJECT BACKGROUND & SCOPE

Project Background

Glacier Power anticipates the submission of an application, in respect of the development of its Dunvegan Hydroelectric Project (Project) located near Fairview in northwest Alberta, to a joint review panel formed by the AEUB and NRCB. While the AEUB and the NRCB have at the core of their mandates to assess the project in the context of Public Interest relating to social, economic and environmental effects, the AEUB currently has no mandate to review the "need" of a power project in Alberta by virtue of changes to the Electric Utilities Act in 1995. The NRCB on the other hand is not legislatively constrained from the consideration of “need” and cost in its deliberations in respect of Public Interest.

As a result, EDC was retained by Glacier Power to provide an assessment of the “need” for a renewable power project in northwest Alberta such as the Dunvegan Hydroelectric Project.

Scope of Work

This report details, from a qualitative perspective, the “need” for a renewable energy, run-of-river hydroelectric project in northern Alberta. The question of “need” is addressed from several perspectives including market fundamentals (supply-demand and price), electric system benefits, and government policy regarding renewable energy. Quantitative assessments or qualifications are provided where possible.

- Market Fundamentals section presents a look at Alberta’s current and future demand for electricity as well as the make up of the current supply portfolio and its typical cost structure. The section also presents the potential market benefits associated with the development of the Dunvegan Hydroelectric project.

- Electrical System Benefits section looks at generation from the perspective if it is situated in an area where transmission is congested and heavily loaded it may provide significant benefits to regional or system-wide electricity consumers through voltage support and reduced system losses. The section also attempts to assess the market value of the loss savings.

- The Government Policy sections looks at current and potential environmental regulations regarding air emissions, particularly green house gases (GHG) that may be mitigated in part by increased utilization of renewable energy resources.
The ebb and flow of supply-demand fundamentals typically underpin longer term price cycles associated with commodity markets, notwithstanding other speculative and psychological effects. In electricity markets, the timing of new supply additions or exit of old capacity relative to demand growth can be a dominant source of price volatility given the limited storage capacity. This fact is further compounded in the short term by the volatile nature of real-time electricity supply and the need for significant spare capacity to facilitate operating reserve requirements and plant maintenance. Slow development of supply relative to robust demand growth will almost certainly lead to higher market based prices and price volatility. While the converse is also true, neither outcome—very high or very low prices—is palatable to one side of the market. The most efficient outcome in any commodity priced market will result with the least amount of imbalance given an orderly development of new supply added just sufficient to meet rising demand expectations.

**Electricity Underpins Economic Growth**

Historically vertically integrated electric utility companies have been the agent for economic development. Growth in the electric system infrastructure and low cost power were the implements used to foster higher economic growth. The global expanse and commoditization of many industries has increased the pressure to optimize energy cost inputs to maintain a competitive edge. Figure 1 illustrates the strong relationship between economic growth in Alberta and electric energy consumption.

Alberta’s consumption of electric energy per million dollars of Real Gross Domestic Product (RGDP) doubled from 0.22 GWh/million $RGDP during the 1960’s to 0.53 GWh/million $RGDP during the 1980’s by growing an average of 7% per year. Currently, Alberta generates approximately $1.85 million in Real GDP (1992 constant dollars) for every GWh of electric energy consumed—a relationship that has been relatively constant since the early 1980’s.
Alberta’s resource based economy has prospered for many years given the growth experienced within its trading partner economies with growth in RGDP averaging 4% over the last decade. The economic outlook for Alberta has strengthened with high energy and commodity prices that have resulted from economic activity in other parts of the world, particularly in China. This is a positive sign for resource industries including oil and gas, forest products and mining, all of which have a major presence in Alberta. Strong economic growth has given Alberta the healthiest job market in Canada resulting in the lowest unemployment rate, where the employment participation rate has been steadily increasing, exceeding the national average. Commensurate to the favorable business environment, the Alberta economy is expected to post very strong growth in the short term adding from 3% to 4% for the next two years. In the long term Alberta could post an average compound growth rate in real GDP of just over 3% over the next 15-years.

Historically, electricity demand has been very strongly correlated with RGDP growth as a key economic driver. While improvements in economic efficiency have occurred in the past, with respect to energy consumption, the trend is expected to continue. This relationship supports the assertion that Alberta relies on electric energy as a key input to continued economic growth where low cost power projects are an essential element to support that growth.

**Electric Energy Demand & Future Supply Needs**

Alberta total electric energy sales, as measured by Alberta Internal Load (AIL), have grown by an Annual Compound Growth Rate (ACGR) of 3.4% per year over the last 15 years (1988-2003), while energy sales over the most recent 5 years (1998-2003) have been moderately less averaging 2.2% ACGR per year. Alberta Integrated Electric System (AIES) energy sales on the other hand, have grown by an annual
compound growth rate of 3.2% per year over the last 15 years (1988-2003), while AIES energy sales over the most recent 5 years (1998-2003) have been moderately less averaging 1.3% ACGR per year.

AIL is anticipated to grow by 2.7% ACGR per year over the next 15 years (2004-2018), while AIES energy sales are expected to grow between 1.8% and 2.0% ACGR per year. AIL energy sales represent a more accurate representation of the need for total Alberta electricity requirements whereas AIES energy sales are representative of commodity price grid served energy—net of on-site energy supply, particularly at large industrial sites where cogeneration exists.

While electricity demand is consistent with economic growth and is somewhat more predictable, electricity supply in Alberta is now developed in the hands of a competitive market. Supply will be added when participants in the market perceive that price signals are expected to fully compensate for the costs and risks associated with any particular venture. Having said this, the full risk of any venture in a competitive environment lies squarely with the investor. This contrasts with the “obligation to serve” requirement of utility companies under a cost-of-service regulatory regime that ensures a somewhat orderly development of generation capacity, albeit not entirely without risk to the consumer.

A substantial portion of Alberta’s electric generating capacity will reach the end of its useful life in the foreseeable future. At the end of 2004, Alberta’s total gross installed generating capacity will be approximately 13,000 MW (10,500 MW net-to-grid) of which almost 25% will reach retirement age in the next 15 years and just under 40% will reach retirement age in the next 25 years. These capacity retirement estimates include the assumption that all large thermal power plants in Alberta will be life-extended by at least 5 to 10 years. Figure 2 illustrates the expected retirement of net-to-grid generating capacity over the next 15 years.

Figure 2 also illustrates the rapid rise of generation capacity over the last 10 years in Alberta, particularly since 1998 as over 3,100 MW of gross generation capacity has been added to the system yielding approximately 2,300 MW of net-to-grid supply from on-site industrial and other generation sources. Onsite generation development has resulted in lower AIES energy sales relative to total Alberta electricity requirements, as measured by Alberta Internal Load (AIL), due to the behind the fence load now being served by the on-site generation. This fact is apparent in Figure 2 particularly in the years from 2000 to 2002 where AIES peak demand actually declined although AIES energy sales did not.
Combining future load growth and expected generation retirements, as presented in Figure 2, further illustrates that there will be a “need” to develop almost 4,500 MW of net-to-grid generating capacity over the next 15-years. This deficit is shown by the difference between the thick blue line that represents existing supply if no more development occurred with only retirements and the dashed red line representing the expected rise in demand plus a reserve margin requirement—assuming long term equilibrium of 17% to 18%. The additional on-site capacity also assumed to be developed would add another 1,425 MW of new capacity to meet Alberta Internal Load bringing the total generating capacity needed to just under 6,000 MW or approximately 50% of today’s total capacity.

**Potential Fuel Supply Constraints**

While generation unit retirements have a degree of uncertainty, the exact timing will for the most part be driven by market signals that predominantly relate to the wholesale price of power relative to the operating cost of the unit. Other constraints relating to fuel supply, environmental or operational licensing may also influence the exact date of retirement.

As outlined in Table 2 there are 6 thermal coal mines in Alberta where 5 of the 6 have electric generating plants located at the mine-mouth. Highvale coal mine supports both Sundance and Keephills power plants, while Battle River is supported by two coal mines, Vesta and Paintearth. HR Milner imports fuel by train from the Coal Valley mine, which is over 200 km south.

In total there is almost 6,000 MW of coal-fired generation capacity in Alberta, including Genesee 3, which is on-line as of the 4th quarter of 2004 (November 4th). The following points highlight some of the potential fuel supply constraints associated
with Alberta’s dominant coal based generation supply facilities that may increase the certainty of capacity retirements assuming a typical operating life of 40 years ².

- By the end of 2012, there is a total of 553 MW (Wabamun 1, 2 & 4, plus HR Milner) of installed coal-fired generating capacity scheduled for shutdown that could represent a net loss of 9% of installed coal capacity.

- By the end of 2019, Alberta faces the potential shutdown of Sundance 1-5 (1,619 MW) plus Battle River 3&4 (296 MW). As a result, Alberta could experience a further net loss of 32% of coal capacity.

- By the end of 2019, Genesee, Keechills and Sheerness (total 2,736 MW) will be the only coal-fired power plants in Alberta that are fully operational. Sundance and Battle River are expected to each have one unit still operating within their 40 year life cycle (total 767 MW).

- TransAlta has an AEUB permit for the 900 MW Centennial project (Keechills 3&4) that will be located at the Highvale mine, which seemingly has sufficient coal reserves to supports its operation.

- In 1992, Fording received an Approval-in-Principal to develop the Brooks thermal coal-mine. This project was to include development of a 900 MW coal-fired generating plant, which would use the Kitsim irrigation reservoir for cooling. After Enmax declined further participating and citing environmental concerns as an issue, along with grid congestion, Fording expensed $8 million for the project in 2002. The project is now in the hands of Luscar having acquired the Fording property.

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² It should be noted that the Clean Air Strategic Alliance (CASA) assumed an average operating life of 50 years for all Alberta coal-fired generating stations in its report and recommendations on air emissions submitted to the government in November 2003. This assumption was based on consultation with all generation owners.
Table 2 - Alberta Coal Reserves vs. Coal Fired Generation Plant Life Cycle

<table>
<thead>
<tr>
<th>Mine</th>
<th>Remaining Reserves (kt)</th>
<th>Annual Production (kt)</th>
<th>Mine Life (Years)</th>
<th>Generating Station Served</th>
<th>Coal-Fired Generating Facility</th>
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</thead>
<tbody>
<tr>
<td>Highvale</td>
<td>476,000</td>
<td>12,700</td>
<td>37.5</td>
<td>Sundance &amp; Keephills</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Sundance 1</td>
<td>280</td>
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<td>Sundance 2</td>
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<td>Sundance 6</td>
<td>399</td>
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<tr>
<td></td>
<td></td>
<td></td>
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<td>Keephills 1</td>
<td>381</td>
</tr>
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<td></td>
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<td></td>
<td>Keephills 2</td>
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<tr>
<td>Genesee</td>
<td>136,000</td>
<td>3,600</td>
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<td>(+G3) 2,100</td>
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<td>Vesta &amp;</td>
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<td>1,400</td>
<td>12.8</td>
<td>Battle River</td>
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<td>Paintearth</td>
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<td>Wabamun 1</td>
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<td>Wabamun 2</td>
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<td>Wabamun 4</td>
<td>279</td>
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<tr>
<td>Coal Valley (export mine)</td>
<td>68,000</td>
<td>1,800</td>
<td>37.7</td>
<td>HR Milner (over 200 km away)</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>HR Milner</td>
<td>144</td>
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</table>

Source: Table 5.2 and Table 5.4 EUB Statistical Series 2003-98
Alberta’s Coal Reserves 2002 and Supply Demand Outlook

While it is likely that many of the above noted facilities will be able to continue operations beyond a typical 40 year life cycle, it is apparent that Alberta will inevitably face the issue of some base load coal capacity retirement within the next 15 to 25 years. Coupled with demand growth this will necessitate the development of new supply sources.

**Future Generation Supply Options**

Fortunately the province of Alberta, having significant hydrocarbon based energy resources, also has many electricity supply options at its disposal for development. Alberta has in the past opted to develop a variety of supply technologies and fuel sources to meet the unique characteristics of the load present on the integrated electric system and its reliability criterion. Figure 3 illustrates the breakdown of the current AIES (net-to-grid) generation capacity by fuel type.
While Figure 3 shows Alberta’s strong reliance on coal based electric energy with an installed net-to-grid capacity of approximately 56%, the incremental development of natural gas fired and wind supply additions, now standing at 32% and 3% respectively, have eroded the coal capacities dominant share. Alberta’s water resources also fuel just under 10% of total AIES capacity.

From an energy production perspective, as shown in Figure 4, coal remains the dominant fuel source of electric energy at 79%, while natural gas based energy represents 17% and hydro / wind resources make up the remaining 4% of electric energy delivered to the AIES.
As noted above, Alberta is able to develop a variety of electric energy supply resources using a number of mainstream technologies—each offering a diverse array of operating benefits, characteristics, constraints and cost structure. Each generating technology whether it is mainstream, proven or in development has a unique development life cycle and presents the developer with a specific risk profile. Correspondingly, each mainstream generating technology and fuel source combine to produce a unique cost structure that is part derived by the technology operating criteria. Many high capital cost technologies such as large-scale nuclear, coal, and reservoir based hydro projects typically provide significant benefit through low operating costs that result in a competitive all-in life cycle cost. Whereas lower capital technologies such as natural gas based projects, may come at the expense of higher long-term operating costs.

Notwithstanding the capital, all-in cost or operating differences, the risks associated with the development of large-scale or shorter lead time projects are clearly different and both will have a different impact on the system. The combination of these factors necessitates the development of a balanced portfolio of supply options to mitigate the risks and constraints associated with any one technology, fuel source or geographic location.

An array of differing risk profiles and cost structures almost automatically results in the development of a variety of technology and fuel sources. Further, it should be recognized that not all projects are exactly the same, where the capital structure, financing costs, tax position and operating characteristics may differ from one developer to the next. However, using a common set of assumptions for simplicity,
Figure 5 illustrates the relative cost structure of the generally accepted mainstream electric generation supply options in Alberta.

**Figure 5 - Comparative Electricity Supply Costs by Technology**

![Generation Comparative Levelized Costs](image)

Assumptions: (Natural Gas Cost of $5.00/GJ, Capital Structure of 60/40 D/E with Debt and Equity costs of 7.0% and 15.0%)

Source: EDC Associates Ltd.

Figure 5 serves to show that certain large-scale base load generating options may produce power in the $45 to $50/MWh range, whereas some newer technologies with a relatively low utilization rate would be expected to produce power for just over $80/MWh. The all-in cost structure for the median generation technology deployed in Alberta appears to be approximately $60/MWh—at today’s expected natural gas price. Each project’s cost structure in the figure is calculated assuming consistent assumptions regarding capital structure and in-service date coupled with estimated operating capacity factors (CF) and financial life\(^3\) that is typical for each generating technology. One notable exception is the Dunvegan Hydroelectric project that will have a physical plant life well in excess of the 40 years used to estimate the comparable all-in cost. Major components of the facility may have a useful life in the range of 50 to 100 years, while other technologies’ major components do not have a useful life in that range without significant capital expenditures.

Figure 5 also illustrates that on a purely economic basis, natural gas and coal based technologies appear to offer the lowest all-in life cycle cost options for electricity supply in Alberta. However, as noted above the capital versus operating cost differences pose different risks to the system in addition to potential environmental concerns with respect to emissions that are not quantified in the cost structure as shown. Historically, transmission development has also been a significant factor.

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\(^3\) Financial life is used as a conservative proxy for operational plant life, while some technologies may have longer physical lives with some amount of capital investment.
consideration in generation development and may present additional risks to some particular projects. This is true with respect to incremental coal based developments in the Lake Wabamum area that is currently transmission constrained.

The Dunvegan Hydroelectric project, as presented in Figure 5, compares favorably with other mainstream technologies on a pure all-in cost perspective and does not carry the same risks or costs associated with fuel and terrain or airborne environmental considerations as some of the other technologies—which in many cases are significant. In addition, the Dunvegan Hydroelectric project would be expected to produce power over a much more sustainable and longer life—almost 2 to 3 times the typical life of a thermal based unit.

Table 3 compares the key attributes of the aforementioned Alberta based generation, noting specific advantages and disadvantages of each technology. As the table illustrates, all mainstream generation technologies utilized in Alberta and elsewhere have unique advantages and disadvantages that in many cases are complimentary or offsetting. A robust generation sector would include some amount of all forms of generation to take advantage of the positive characteristics of each generation source while at the same time mitigate the impact of the negative influences of any one technology. A decision to implement a particular technology today will predetermine to some degree Alberta’s dependence on that specific technology into the future, as most technologies have fairly long service lives.4

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4 Repowering Alberta: Options for Electrical Generating Units; Economic and Emissions Impacts, Canadian Energy Research Institute, Study No 73, September 1996.
<table>
<thead>
<tr>
<th>Technology</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
</table>
| Coal (40 to 50 year asset life) | • long term low fuel cost not subject to commodity price risks  
• base load low full life-cycle cost  
• high availability and capacity factor typically >90%  
• regulating reserve resource | • high capital cost  
• long development lead time  
• large-scale capacity additions  
• typically low efficiency  
• slow ramp rates, high start-up and shut-down costs  
• potentially high emissions costs  
• most projects are currently transmission constrained |
| Natural Gas (30 to 40 year asset life) | • lower capital cost  
• short development lead time  
• “packaged” generation configuration in variety of economic sizes and efficiencies  
• cost effective ancillary service provider | • market based and currently very high fuel price  
• total cost is largely variable cost contingent  
• higher efficiency w/ cogeneration  
• typically marginal supply subject to dispatch risk |
| Wind (25 to 30 year asset life) | • low variable cost  
• fixed levelized cost over life of the asset  
• emission free resource | • intermittent supply source and low capacity utilization  
• new developing technology  
• operating reserve impact  
• transmission constrained |
| Hydro (50 to 100 year asset life) | • system black start capability  
• rapid ramp-rate capability  
• typically low capacity factor (20% to 30% - Dunvegan 50% to 70%)  
• very long asset life  
• good standby reserve provider  
• emission free resource | • resource and energy constrained  
• water, land and fishery environmental issues |
| Biomass (20 to 25 year asset life) | • provide environmental alternative for waste products  
• low emissions | • high operating cost  
• lower efficiency  
• limited fuel resources at plant site |
Wholesale Market Price

The implementation of a competitive market for electric energy supply in Alberta has largely been designed to facilitate and encourage the development of the most economic electric energy supply source where the risk of any projects development remains with the project owners and not with the consumer—as had previously been the case with the cost-of-service regulation. In the absence of any long term power sale agreement, the long term wholesale market price for electricity is the key determinant used by developers to assess the financial viability of any incremental generation project. Quite clearly, to meet the test of financial viability the expected forward price of electricity must be equal to or greater than the all-in life cycle cost of the selected generation supply source technology. In a competitive market, a forecast electricity price in excess of this level for the least cost technology would tend to attract significant supply additions to capture any economic rent available at the time—a value less than this would tend to forestall development. In the longer term, well timed and balanced capacity additions to the supply portfolio would tend to neutralize any economic rent. Future market price expectations would typically incorporate any transparent information regarding the size, timing and cost structure of potential supply additions and any market participant’s decisions would react accordingly.

Having said this however, and as noted above, not all generation is the same. Different technologies have different operating characteristics and constraints as well as a different fixed and variable cost structure. As a result, a 100 MW base load low variable cost project would have a different impact to the wholesale market price expectations than would a 100 MW high variable cost project—all other things being equal. Similarly, the expected market price would be different with and without one specific project assuming everything else was constant. It is estimated that the market impact of the development of the Dunvegan Hydroelectric project could be a reduction in the all-hour average pool price by approximately $1 to $2/MWh in the first one or two years of service relative to the price that might be expected without the Dunvegan project—all other things being equal. This wholesale power price reduction is illustrated in Figure 6 and would provide a substantial benefit to the overall market through lower overall energy costs.
Assuming pool prices were reduced on average by $2/MWh as a result of the addition of the Dunvegan Hydroelectric project—all other things being equal, then the potential benefit to Alberta electricity consumers would be about $122 million dollars per year starting in 2009 if all consumers were exposed to spot prices. Assuming a more realistic spot market exposure such as 50% then the incremental market benefit to Alberta electricity consumers would be about $61 million dollars in 2009. If the wholesale price reduction was in the order of $1/MWh in 2010 then the market benefit would be $30.5 million dollars assuming the same wholesale price exposure. It is assumed that the price reduction would not be permanent as the supply market would react in such a way that would mitigate the benefit. The total market benefit over the two year period would be $91.5 million dollars.
ELECTRICAL SYSTEM BENEFITS

The interaction between generation and transmission development has historically been seamless with the least cost approach used by vertically integrated utilities under the cost-of-service regulatory regime. However, in today’s competitive environment there is a greater need to co-optimize the development of each segment of the market in a way that recognizes any mutual benefit that ultimately results in a safe and reliable electric system at the lowest possible or most economic cost. The TA’s Invitation to Bid on Credit (IBOC) and Location based Credit-Standing Offer (LBC-SO) programs are clear past examples of collaboration between generation and transmission development in a competitive environment with an objective to provide a least cost solution.

Generation development can provide benefit to the regional transmission system by reducing system losses and by providing voltage support as an interim measure prior to transmission development. In addition, generation can provide benefit to the overall transmission system by providing various ancillary services that are required to facilitate a safe and reliable electric system. The Dunvegan generation project has the potential to provide benefit to the Alberta electric system in all of the aforementioned ways.

Northwest Regional Transmission Area

In the Transmission Administrator’s (TA⁵) most recent 10 year Transmission Development Plan (2002-2011), issued March 2002, a discussion of each broad area of the transmission network is presented. Each area discussion includes a brief description, a detailed load forecast, details of existing and new generation plants, a description of the main transmission reinforcements required for the next 10 years, along with the driving factor in each case. In the case of the northwest Alberta transmission grid, the TA provides the following discussion⁶;

The electric system in northwest Alberta (specifically Rainbow Lake and High Level areas) is characterized by long 144 kV and 240 kV transmission lines connecting loads to generation. The system is generally radial with a low degree of redundancy of transmission paths. Some 144 kV transmission lines are heavily loaded and consequently have high transmission losses. The outage of a single transmission line or a local generator can result in voltage depressions outside of acceptable limits.

Because of the area’s remoteness from any major source of generation and limited transmission capacity into the area, system security is maintained by ensuring certain local generation is running at all time, i.e. Transmission Must Run (“TMR”). The

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⁵ The TA was at the time ESBI Alberta Limited and now is the Alberta Electric System Operator (AESO).
exact amount of generation required is generally determined by local load level at that time.

While immediate security issues have been addressed by the installation of Rainbow #5 unit, there is a need to provide a more robust long-term solution. While there is no significant increase in forecast load, the future of a number of other generation units at Rainbow is in doubt as they reach the end of their useful life.

The generation in the Grande Prairie Area that was procured under the LBC-SO program also provides system security in the short to medium term depending on load growth. However there is also a need to develop a more long-term solution and to recognize the increased uncertainty over the viability of the HR Milner power plant. A reduction in system losses must also be factored into the analysis.

This part of the system continued to pose operational challenges in 2001 as transmission maintenance required careful coordination with the generation available in the area. The Rainbow Lake area in particular experienced a number of forced outages including a major equipment failure of a 14.4 kV circuit breaker on October 7, 2001, rendering Rainbow 2 unavailable for TMR until mid-December. This incident rendered the Rainbow area vulnerable to loss of load had any remaining generation become unavailable.

Based on informal discussions with the Alberta Electric System Operator (AESO), now the TA, the northwest transmission area typically imports approximately 500 to 600 MW of power in addition to requiring significant amount of Transmission Must-Run generation to maintain the system integrity. The AESO has noted that any additional generation in the northwest area of the province would help mitigate current TMR requirements.

**TMR & Other Ancillary Services**

In Alberta the AESO is responsible for the procurement and provision of all ancillary services including Transmission Must-Run (TMR) requirements. Currently the AESO procures approximately $45 to $50 million dollars per year in TMR services from existing generators. The addition of base load generation in the northwest area would effectively reduce region area electricity imports and hence TMR requirements. The Dunvegan Hydroelectric project, because of its expected operations, could reduce AESO TMR costs by $5 million per year or 11 percent of total TMR costs.

Another very important ancillary service is Black Start capability to re-energize the system in the event of a system wide black out. Once again the nature of the Dunvegan Hydroelectric project and its ability to self generate its own electrical needs gives the project the ability to provide Black Start capability to the northwest region. The AESO currently spends approximately $1 to $2 million per year in Black Start ancillary service payments to various generators in Alberta.

**Regional/System Losses**

As noted above by the TA, the northwest Alberta transmission grid experiences heavy loading and as a result high thermal losses, particularly during peak demand
periods. Additional generation in the area would serve to reduce transmission load levels and would therefore serve to reduce line losses. Given that, on an AC system, line losses are a function of the square of the resistance on that line, meaning that a doubling of the load results in losses that are four times, any reduction on a heavily loaded system would provide a significant marginal loss saving. Given that the regional heavy load periods would typically coincide with the system wide heavy load periods, when electricity prices tend to be the highest, the monetary savings of lower losses would also represent a direct and potentially large benefit through the transmission tariff.

In addition, lower system wide losses tend to provide an overall lower level of system demand and therefore would also tend to lower the overall system pool price. This indirect effect, while somewhat difficult to assess with a high degree of accuracy given the small size of the change, would at least on a directional basis provide benefit to all consumers of Alberta through lower energy costs. The AESO currently spends approximately $160 to $180 million per year to cover the cost of transmission losses.

Overall, the Dunvegan Hydroelectric power project will potentially provide significant benefit to all Alberta electricity consumers through an otherwise lower transmission tariff resulting from lower losses, reduced ancillary service costs and an overall lower cost-of-service due to possible delay in transmission development and the associated capital investment. While the foregoing assertion is somewhat subjective and reliant on assessments about the future (or forecasts) any project that can reasonably be expected to provide any of these benefits is clearly needed and in the best interest of Alberta consumers.
GOVERNMENT POLICY – RENEWABLE ENERGY TARGETS

The Kyoto Accord has been the impetus for the adaptation and implementation of environmental stewardship principals in Canada and around the world. Governments at all levels have been working with industry and stakeholders to develop guiding principals that will define future policy with respect to greenhouse gas emissions (GHGs). In addition, both federal and most provincial governments have made commitments to buy a large percentage of their power needs from green energy sources. This has lead to an increased development of wind, hydro and biomass facilities across Canada. The Alberta provincial government currently procures 90% of its electric energy needs from green sources (typically wind and biomass). The United States has adopted a Renewable Portfolio Standard approach to support renewable energy project development directly.

Federal Government

Natural Resources Canada (NRCan)

On a federal level, the Government of Canada recognizes the valuable role that small-scale hydroelectric facilities can play in meeting Canada’s energy requirements, particularly those of rural regions, in a sustainable and environmental friendly manner. The federal Government, through Natural Resources Canada supports the development of small hydroelectric facilities in Canada through activities such as: Renewable Energy Technologies (RET) R&D Program and Renewable Energy Policy and Market Development.

In 1994 Natural Resources Canada (NRCan) studied the feasibility of having the federal government buys some of its electricity from Emerging Renewable Energy Sources (ERES). After consulting with electrical utilities and the renewable energy industry, NRCan announced its intention to start pilot projects to purchase electricity from renewable sources. ERES means wind power, sun, water, biomass and the earth where the electricity is generated from emerging and innovative applications. In 1997, NRCan began purchasing electricity through ERES from Various utilities across the country.

Wind Production Incentive Program (WPPI)

In April 2002 the Federal Government followed up with details surrounding the Wind Power Production Incentive (WPPI). This program is to provide an incentive to encourage the development of 1,000 MW of new wind power in Canada.

The final document from the Federal Government outlines: the eligibility criteria for the wind credit, the approval process, terms of the incentive, and the administrative requirements for the program.7 The Canadian Wind Energy Association (CanWEA)

7 NRCAN website and document entitled: “Wind Power Production Credit, 1,000 MW over five years”.

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along with others requested that the Federal Government make several changes to the WPPI program in the 2004 federal budget. The requested changes are as follows:

- increase the size of the WPPI program to 4,000 MW,
- extend the WPPI program deadline to 2010,
- remove all project, corporate and provincial caps under WPPI and
- allow all projects that qualify for the Canadian Renewable and Conservation Expense (CRCE) to also be eligible for WPPI.

These activities are clear signals that renewable energy sources are desirable and in the public interest to pursue.

**Provincial Government**

The Alberta Government, through Alberta Environment (AENV), establishes policies, legislation, plans, guidelines, and standards for environmental management and protection of the province's air, land, and water. Alberta Environment has been working with Alberta's Clean Air Strategic Alliance (CASA) to develop a framework to reduce emissions of several priority airborne substances from the province's thermal electricity generating sector. The government has recently (spring 2004) accepted the recommendations from CASA regarding the emissions management framework. One such recommendation calls for 3.5% of all electricity traded through the AIES to be sourced from renewable or green energy sources by 2008. This target requires that approximately 800 MW of incremental green power capacity be developed. As a result of this proposed target the Dunvegan Hydroelectric project is essentially needed to help meet this target and is therefore in the best interest of the power sector, the environment and all Alberta electricity consumers.

**Alberta Infrastructure RFP for Green Power**

Other forms of an “RPS like” standard have been initiated in Alberta. Alberta Government department of Infrastructure has stated that by 2005, more than 90% of the electricity used in government-owned facilities will come from green power sources. Alberta Infrastructure has entered into long-term agreements with both Enmax and Canadian Hydro Developers to procure this power. This will result in the purchase of approximately 210,000 MWh annually which will be split equally between Enmax and Canadian Hydro. Enmax is providing their share of the power from the McBride Lake wind power farm near Pincher Creek. Likewise, Canadian Hydro will be providing power from their biomass combustion facility near Grande Prairie.

Alberta Infrastructure has stated that as it will be reducing its portfolio of energy consuming assets (i.e. buildings) over the next few years, such that the 90% energy procured today will ultimately equate to 100% of its future load. Initiatives like this have created the opportunities to develop renewable energy projects in Alberta.
Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) is a policy instrument that aims to increase the production of higher cost energy sources that are characterized by desirable social and environmental benefits. RPS dictates that a market participant derives a percentage of its electricity from specific fuels and/or technologies (typically wind, biomass and hydro). As such RPS is becoming a popular mechanism among policy makers in North America to bring more renewable energy to the market place.

In the United States, as of July 1st, 2001 24 states and the District of Columbia already have an RPS\(^8\). This means that generators and retailers are required to have a percentage of renewable green power in the energy portfolio that is offered to their consumers. Currently there are not any federally or provincially mandated Renewable Portfolio Standards in Canada.

Table 4 - Canadian Renewable Portfolio Standards (RPS) by province

<table>
<thead>
<tr>
<th>Province</th>
<th>Initiative</th>
<th>Potential Wind Energy Production</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>British Columbia</td>
<td>50% of new generation portfolio standard</td>
<td>Minimum 50 MW</td>
<td>Voluntary, includes high efficiency natural gas generation</td>
</tr>
<tr>
<td>Alberta</td>
<td>3.5% Renewable Portfolio Standard (RPS) by 2008</td>
<td>Up to 560 MW</td>
<td>Under consideration</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>150 MW of wind energy project</td>
<td>150 MW</td>
<td>Voluntary</td>
</tr>
<tr>
<td>Manitoba</td>
<td>100 MW of Wind Energy Project</td>
<td>100 MW</td>
<td>Under consideration</td>
</tr>
<tr>
<td>Ontario</td>
<td>10% RPS by 2010</td>
<td>Approximately 1,500 - 3,000 MW</td>
<td>Under consideration</td>
</tr>
<tr>
<td>Quebec</td>
<td>1,000 MW RFP by 2012</td>
<td>1,000 MW</td>
<td>Implementation not guaranteed with new government</td>
</tr>
<tr>
<td>New Brunswick</td>
<td>NB Power Target of 100 MW by 2010</td>
<td>100 MW</td>
<td>Voluntary</td>
</tr>
<tr>
<td>Nova Scotia</td>
<td>3.75% RPS by 21011</td>
<td>Up to 145 MW</td>
<td>Under consideration</td>
</tr>
<tr>
<td>Prince Edward Island</td>
<td>10% RPS by 2010</td>
<td>Up to 40 MW</td>
<td>Under consideration</td>
</tr>
<tr>
<td>Newfoundland</td>
<td>25 MW wind energy project</td>
<td>25 MW</td>
<td>Under consideration</td>
</tr>
</tbody>
</table>

Source: CanWEA

A legislated RPS would create demand for renewable power from utilities and retailers. This would insure that renewables, such as wind, could find market penetration in each region. Although there is not a legislated RPS in any province or territory in Canada, there is momentum building in various regions. Table 4 outlines the RPS momentum in Canada as of December 31\(^{st}\), 2003. If these initiatives become legislative mandates they could help stimulate the demand for renewable and wind powered generators.

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\(^8\) Department of Energy “Annual Energy Outlook 2002”
SUMMARY & CONCLUSIONS

Notwithstanding direct economic, social, and environmental benefits, the “need” for the Dunvegan Hydroelectric power project is demonstrated by the following facts.

- Alberta’s consumption of electric energy per million dollars of Real GDP doubled from 0.22 GWh/million $RGDP during the 1960’s to 0.53 GWh/million $RGDP during the 1980’s by growing an average of 7% per year. Alberta’s economy is dependant on electric energy and produces $1.85 million real GDP (1992 dollars) for every GWh of energy consumed—a relationship that has been relatively constant since the early 1980’s.

- Alberta total electric energy sales, as measured by Alberta Internal Load (AIL), have grown by an annual compound growth rate of 3.4% per year over the last 15 years (1987-2003) and is anticipated to grow by 2.7% ACGR per year over the next 15 years (2004-2018). This level of demand growth coupled with retirements would necessitate the need to develop almost 4,500 MW of new net-to-grid generating capacity plus an additional 1,425 MW of on-site capacity over the next 15-years bringing the total generating capacity needed to just under 6,000 MW or approximately 50% of today’s total capacity.

- A substantial portion of Alberta’s electric generating capacity will reach the end of its useful life in the foreseeable future. At the end of 2004, Alberta’s total gross installed generating capacity will be approximately 13,000 MW (10,500 MW net-to-grid) of which almost 25% will reach retirement age in the next 15 years and just under 40% will reach retirement age in the next 25 years.

- Alberta’s has strong reliance on coal based electric energy with an installed net-to-grid capacity that represents approximately 56% of all capacity and provides almost 80% of total AIES energy supply. Within the next 15 to 25 years many of Alberta’s coal fired facilities will reach their expected useful life and coupled with reduced coal resource availability will face retirement decisions. This decision may also be affected by the potential costs associated with a more stringent environmental emissions policy. These factors combined, almost necessitates the development of a balanced portfolio of supply options for Alberta to mitigate the risks and constraints associated with any one technology, fuel source or geographic location.

- Current large-scale base load generating options in Alberta are capable of producing long-term power on an all-in life-cycle basis in the $45 to $50/MWh range, whereas some newer technologies with a relatively low utilization rate would be expected to produce power for just over $80/MWh. The all-in cost structure for the median generation technology deployed in Alberta appears to be approximately $60/MWh—at today’s expected natural gas price. The Dunvegan Hydroelectric project’s expected all-in cost compares favorably with other mainstream technologies and does not carry the same risks associated with fuel
and airborne environmental considerations and would be expected to provide power over a much longer useful life—almost 2 to 3 times.

- It is estimated that the market impact of the development of the Dunvegan Hydroelectric project could be a reduction in the all-hour average pool price by approximately $1 to $2/MWh in the first one or two years of service relative to the price that might be expected without the Dunvegan project—all other things being equal. Assuming pool prices were reduced on average by $1 to $2/MWh, then the potential benefit to Alberta electricity consumers would be about $30.5 to $61 million dollars in 2009 and 2010 for a total market benefit of $91.5 million dollars if 50% of all consumers were exposed to spot prices.

- The Dunvegan Hydroelectric project, because of its expected operations, could reduce northwest Alberta area transmission losses and Transmission Must-Run requirements that would result in a reduction in AESO transmission costs by as much as $5 million per year or 11 percent.

- The Dunvegan Hydroelectric project given its expected operating characteristics would provide a significant reduction in green house gas emissions in Alberta in the order of 500,000 Tonnes annually (assuming 0.8 Tonnes per MWh) by displacing other thermal generation sources. This reduction is anticipated to save the electric industry approximately $5 million dollars per year in potential CO₂ offset costs.

### Table 5 - Estimated Monetary Benefits of the Dunvegan Project

<table>
<thead>
<tr>
<th>Estimated Monetary Benefits of the Dunvegan Project</th>
<th>Millions of Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004 dollars assuming a 10% discount rate</td>
<td>2009</td>
</tr>
<tr>
<td>Pool Price Effect</td>
<td>$55.1</td>
</tr>
<tr>
<td>Transmission Losses and TMR</td>
<td>$33.4</td>
</tr>
<tr>
<td>Green House Gas Emissions</td>
<td>$33.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$121.9</strong></td>
</tr>
</tbody>
</table>

Note: Present values were calculated assuming 40 years of project life.