MPA Morrison Park Advisors

Investor Perspectives on the Attractiveness of Alberta's Electricity Generation Market

Prepared by Morrison Park Advisors
For
Alberta's Market Surveillance Administrator

August 2012

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17 August 2012

Mr. Harry Chandler
Alberta's Market Surveillance Administrator
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Dear Mr. Chandler:

MPA Morrison Park Advisors Inc. submits the attached report in fulfilment of the assignment given to us to gather investor feedback on the Alberta electricity generation market.

The report gathers the views of a number of representatives of debt and equity providers, as well as developer/owner/operators of electricity generation projects. All participants in this review process were approached under strictest confidentiality, and every effort has been made to ensure that no confidences have been breached.

In addition, we have provided observations and analysis of the perspectives we gathered, in hopes that these will be of use to the MSA in its work.

Best regards,

Pelino Colaiacovo
Managing Director

Morrison Park Advisors

Morrison Park Advisors is an independent, partner-owned, Canadian investment bank providing financial advisory services to corporations and governments. We provide independent expert advice to clients involved in debt and/or equity capital raising or mergers, acquisitions and divestitures. Our ability to deliver top tier financial advisory services is based on decades of combined experience and expertise developed at some of Canada's leading investment banks, while serving many of Canada's largest and most sophisticated corporate clients as well as federal, provincial and municipal governments and quasi-government entities.

Our areas of specialty include utilities, infrastructure and power; mining; real estate and technology. In the power sector, MPA has direct and recent experience on a number of transactions as financial advisor involving power assets and has detailed knowledge and experience with this market, its participants and how they operate.

For more information on MPA, please visit our website at www.morrisonpark.com.

Executive Summary

Morrison Park Advisors interviewed twenty-two potential capital providers and investors in the Alberta electricity generation market in order to better understand their views on the attractiveness of new investment opportunities in the industry. This was undertaken in the context of an expected need for more than 6,000 MW of new electricity generation capacity in the province over the next ten years.

Participants indicated that they were generally aware of the opportunities that exist in Alberta, and they were knowledgeable about the nature and structure of the electricity market. Practically all of the investors interviewed, including those with significant assets in Alberta, are active investors in electricity markets in multiple jurisdictions in North America and in many cases worldwide. They are therefore able to allocate their investment dollars based on opportunities having the most attractive risk-adjusted return profile, and should be expected to have provided comments to us from this perspective.

Electricity projects are typically funded either on a non-recourse basis, where capital is repaid only through project revenues (also known as "project financing"), or they are funded with recourse to the whole balance sheet of the owner or developer of the facility.

Most of the investors interviewed that typically provide or make use of non-recourse financing indicated that they would not likely invest in Alberta projects at this time. Alberta's energy-only competitive electricity market provides less certainty of future revenues than do other types of markets, where long-term contracts or regulated prices are the norm, and these investors prefer to invest in those types of environments. On the other hand, investors interviewed that tend to finance projects through their own financial resources (on their balance sheet) were much more positive about the Alberta market's attractiveness. Most recent projects that have been built in Alberta or are in advanced stages of development have been financed in this manner.

Some participants provided comments on certain specific issues that might be perceived as barriers to entry into the Alberta electricity generation market, including price caps, contract market liquidity and the regulated rate option, transmission interconnections with other jurisdictions, and size-related issues. However, none of these was unambiguously positive or negative for all potential investors.

On the subject of electricity generation fuels and technologies, investors demonstrated a clear consensus in favour of natural gas-fired generation. Uncertainty related to the regulatory future of coal-fired generation, the challenging economics of most other fuels based on current prevailing prices, and the long development lead times for many of them, have resulted in a strong focus on natural gas, particularly since it has become abundant in recent years. This, coupled with the expected retirement of a number of existing coal-fired plants in Alberta, suggests that the province's fleet will become very much dominated by natural gas as a fuel over the coming decade.

With some notable exceptions, few investors indicated that they believe current prices and economic conditions are conducive to construction of new facilities in the short term. As existing facilities age and are retired, and as electricity demand continues to grow, this picture may change, leading to more investment activity.

A particularly notable issue is the pending expiry of PPAs in 2020. More than 5,000 MW of coal-fired generation will be fully exposed to the market at that time (though some of this capacity may be retired with the expiry of the PPAs). This will have important financial and other impacts on the owners of those facilities, and therefore potentially on the overall electricity generation market.

Currently, a handful of large and diversified companies own or control a significant portion of the Alberta electricity generation market. These companies will potentially continue to fill this role for the foreseeable future, given the structure of the Alberta electricity market and its relative attractiveness to potential investors in the North American market. To the extent that this is the case, the financial health of these companies will largely determine the cost and availability of capital facing the Alberta electricity generation market. It would be worthwhile, in our view, to monitor these circumstances, particularly as the expiry of the PPAs approaches in 2020.

Preparation of the Report

The Market Surveillance Administrator of Alberta (MSA) wished to better understand the perceptions of investors and potential investors in the Alberta electricity generation market. To this end, the MSA undertook a competitive tender process for a consultant who would undertake confidential interviews with a selection of such investors that would seek the following types of information:

- Feedback from investors and potential investors about the attractiveness of the Alberta electricity generation market;
- Feedback from investors and potential investors on barriers to investment in Alberta electricity generation;
- In the context of this feedback, identify and prioritize the advantages and disadvantages of the Alberta electricity generation market as a destination for investment

MPA was selected in May, 2012, and undertook the following program in order to fulfil the mandate provided by the MSA:

1. Background preparation
    - Review of the structure of the market, including records on existing generation plants, plants built or decommissioned in the last 10 years, waiting list for connection of new plants, etc.;
    - Review of recent reports on the Alberta electricity market prepared by other organizations, including the Alberta Electricity System Operator and the Brattle Group;
    - Review publicly available information regarding the current major players in the Alberta electricity generation market, including their financial statements, credit ratings, stock market information (if applicable), and other information; and
    - Review of developments in comparable markets in North America, of particular note being the Texas market, which shares certain characteristics with Alberta in the organization of its electricity market and the rules applicable to it.
2. Interviews with existing and potential investors in the Alberta electricity generation market
    - MPA contacted leading equity and debt providers with a history of investments in electricity generation across North America. Ten institutions participated in the interviews, seven of which provide debt capital, and five of which provide equity capital;
    - MPA contacted companies that are active in developing, owning and operating electricity generation facilities across North America. Twelve companies in total participated in the interviews. Six of the companies that participated currently have generation assets in

Alberta, and six do not. These companies have collectively developed and built natural gas-fired plants, coal-fired plants, and wind, solar and hydropower plants.

- Each of the interviews involved senior executives from the companies in question who are direct decision-makers for investments in electricity generation, and all interviews were conducted on a confidential basis so as to ensure a frank expression of perspectives and opinions.

Investment in Electricity Generation

Electricity generation plants are typically large industrial facilities costing hundreds of millions to billions of dollars, and in many cases requiring years of planning, development and construction. They are long-lived infrastructure with lifespans of 25 to over 100 years, depending on the particular type and design employed. In most cases, the initial cost of development and construction is a very large percentage of the full lifetime cost of the facility, and usually dwarfs all other types of inputs, such as labour and maintenance. As a result, the decision to invest in electricity generation is critically important. Investors will only proceed if they have a firm expectation that they will be able to recoup their investment, including an appropriate rate of return on the capital employed, during the lifetime operation of the plant.

Project Finance vs. Balance Sheet Financing

Electricity generation plants can be financed in two ways: through "project financing" (sometimes referred to as "non-recourse" financing), or through "balance sheet financing".

An electricity generation facility is project financed when capital providers rely exclusively on the financial performance of the facility for their returns over time. In the event that the project does not perform according to expectations, they have no recourse to any other assets or entity, and must satisfy their demands from the project itself, if they are able to. This is analogous to a real estate mortgage, where a loan is secured by a specific parcel of land or a building, without recourse to any other asset or source of value.

Many generation facilities are built, owned and operated by large companies based on their own financial resources, or balance sheet. Unlike project financing, no specific financial obligation attaches to any one facility. All of the facilities owned by the company are part of its portfolio of assets, and together they form the basis for the company's business. Such companies may raise capital by issuing debt or equity securities from time to time, but not necessarily simultaneous with the development of any specific generation project.

	Project Financing	**Balance Sheet Financing**
Developer/owner/ operator	Can be any developer, regardless of size or means	Typically larger companies with substantial financial assets and capacity
Source of Debt	Typically institutional lenders, such as banks, insurance companies or pension funds	The developer/owner/operator provides all of the capital required for development and construction of the

	Project Financing	**Balance Sheet Financing**
Source of Equity	The developer/owner/operator will typically self-fund the initial equity during development of the project, and then may or may not bring in additional equity investors to fund construction, depending on the extent of their financial resources	generation facility. Depending on its financial resources, it may choose to issue debt and/or equity securities in the capital markets to raise additional capital from time to time
Credit Tests	The project must satisfy lenders' credit tests on its own, since loans will be "non-recourse" to any other party or asset. Lenders consider the project budget and risks of cost overruns, the certainty and volatility of expected revenue, expected operating costs, the ratio of expected cash flow to debt service requirements, the expected value of the asset in the event that the project defaults on its debt payments, etc.	Large developer/owner/operators are usually rated by credit rating agencies using a long list of financial criteria and tests. The overall mix of assets in the developer/owner/operator's portfolio will be considered when assessing the ability of the company to satisfy the expectations of its lenders and investors. Any one project or asset may or may not be large enough or important enough to change the views of rating agencies and the capital markets, so developer/ owner/operators carefully consider each investment they add to their portfolio
Equity Considerations	Similar tests as lenders, bearing in mind that creditors rank higher in payment priority, but do not participate in any enhancement in economic value	

Developer/owner/operator: Electricity generation developers can range from small companies working on a single project opportunity in one market, to global corporations owning and managing many facilities around the world. Typically, smaller companies rely on project financing to raise the money required to build projects, while larger companies may choose whether to rely on project financing or balance sheet financing. Some large developer/owner/operators insist that each project must stand on its own economic terms as a project, while others deliberately pursue a portfolio model, and treat all of their assets as a pool. A range of developer/owner/operators were interviewed as part of this study, and several of each type participated.

Sources of Capital: There are a wide variety of debt and equity providers that focus on new construction in the electric power industry. They are capable of assessing the economic potential of proposed electricity generation projects, and providing capital to those projects that meet their standards. All of the debt and equity providers interviewed for this report are in this category. Large developer/owner/operators that finance their new projects from their balance sheet rely on the capital markets to provide them with capital from time to time as required. Such companies typically are subject to constant scrutiny by credit rating agencies and equity research analysts, so that each of the company's new investment announcements is scrutinized to determine its impact, if any, on the overall financial portfolio and expected performance of the company. Several of the developer/owner/operators that were interviewed for this report are in this category.

Economics: The expected financial performance of a proposed electricity generation facility is critical to the decision to proceed with it. Each facility represents a large capital expenditure that, once built, is trapped in its location and cannot be moved. Financial failure of a generation plant can be catastrophic for its owners and capital providers, so estimating future profitability, and understanding risks to that profitability, is a critical part of the development of any facility. All parties interviewed for this report are deeply involved in understanding the risks and return potential of electricity generation projects.

Revenue Certainty: Defining Markets

One of the critical considerations for investment in electricity generation facilities is the certainty of revenues in the future. After a plant is built and is producing electricity, who will purchase that output and under what terms? The answer to the question is largely defined by the characteristics of the market in which the plant is located.

In some jurisdictions, electricity generation is part of a regulated industry, where electricity prices are set by a government-appointed regulator, and facility owners are highly certain that they will receive revenues sufficient to justify their investment during the lifetime of the facility. In other jurisdictions, facility owners operate under long-term contracts with governments or government-appointed bodies, where the price for the electricity they produce is known in advance, and output of the facility is governed by the terms and conditions of the contracts. In still other jurisdictions, electricity is sold in an open market, and facility owners are paid whatever the market price may be at the time, if there is demand for the electricity they can produce.

Alberta is one of the latter types of markets: an energy-only competitive electricity market.

Competitive: Multiple generators compete to provide electricity in Alberta. Ownership of generation is in the hands of private-sector firms and some municipally-owned entities. The provincial government does not own generators. The province does not provide long-term contracts to generators, nor does it regulate the prices offered into the market. Competition incentivizes generators to offer the lowest possible prices at any given time so that their output will be purchased in the market, and they will not sit idle. Generators are free to contract with buyers for fixed prices over periods of their own choosing, if they can find a buyer for their output. Consumers (or their agents in the form of retail electricity marketers that aggregate the electricity demand of many consumers together) are in a similar position, in that they must pay the market price for power at any given time, unless they privately contract with a generator to provide power at a specific price for a certain period of time.

Energy-only: Generators are paid only for the electricity they provide to the market, when it is provided.[1] Unlike in some markets, where generators might be paid for being available to produce

[1] Note that some generators may be able to provide "ancillary services" to the grid such as voltage support, which would be another source of revenue, but these sums would not typically be central to decision-making about plant investment.

power on demand (a "capacity payment"), and paid for the electricity they actually produce (the "energy payment"), Alberta's market is exclusively focused on electricity output.

Alberta's current electricity market structure has been in place since the late 1990s. It is relatively unique in North America, as only one other jurisdiction, Texas, operates an energy-only competitive electricity market. Around the world, several other markets are operated similarly, including in New Zealand and in several states in Australia.

The market is operated by the Alberta Electricity System Operator (AESO), which also performs a variety of other functions, including managing the provincial transmission grid, forecasting the future need for power, and managing several other "ancillary services" markets that are related to the smooth functioning of the electricity system, such as voltage support for the grid.

All of the potential investors interviewed for this report were very familiar with the Alberta electricity market, and in particular its structure as an energy-only competitive electricity market. The nature of this market is a critical part of any investor's consideration of Alberta as a potential venue for electricity generation investment.

Attractiveness of and Perceived Barriers to Investment

Overall Interest of Potential Investors

Each of the four classes of potential investors reacted differently to the general question of whether they found the Alberta electricity generation market to be an attractive opportunity.

Investor Class	Project Financed Facility	Balance Sheet Financed Facility
Debt provider	Energy-only market in Alberta generally does not provide sufficient revenue security at this time, with some exceptions. Long-term contracts are required	Already provide debt to many incumbents and will consider new opportunities for investment
Equity provider	Currently do not believe that market conditions are sufficient to support construction, with some exceptions	Incremental impact of a proposed project is considered by equity investors in balance sheet-based developers
Project-based Developer	Currently do not believe that market conditions are sufficient to support construction, with some exceptions	Not applicable
Balance Sheet-based Developer	Not applicable	Alberta's energy-only market is attractive and new projects are being built, are in advanced stages of development, or are being considered

Debt Providers

Debt providers expressed starkly different views depending on the type of financing proposed for Alberta electricity generation, and the technology used. All debt providers stated that they would not provide project debt to new generation projects relying exclusively for revenues on the energy-only market. It is notable that this has not always been the case over the past 10 years, as some of the debt providers have outstanding debts to project-financed facilities in Alberta. However, there was unanimity in the current view of debt providers for project-financed projects in the province.

Debt providers made clear that if projects have firm long-term contracts with credit-worthy counterparties, then they would consider providing debt coincident with the length of the contract term. There are certain projects in development in the province which benefit from a long-term contract of 20 years or more with a specific consumer, and hence these would have the option of seeking debt on a project-finance basis.[2] Also, co-generation projects which derive a substantial portion of their revenue from the steam host, both for heat provided and electricity delivered, also have strong access to project debt, in proportion to the level of revenue that is contracted with the steam host. These co-generation projects are, in essence, a special case of long-term contracts, with the special feature that they are for a combination of products, rather than just for electricity.

However, other than co-generation facilities, most proposed electricity generation projects currently under development in Alberta – whether for combined cycle or single cycle natural gas plants, coal plants or renewable energy plants – do not benefit from a long-term contract. Relatively few contracts with consumers are available for a period longer than five years, which means that project debt is not practical given the current views of lenders.

Projects pursued by balance sheet-based developers face very different prospects. Debt providers unanimously stated that they view such developers as they would any other corporate credit, and consider them on the basis of their whole portfolio of assets, the stability of their revenues and cash flow, their ratio of debt to equity, and other typical financial measures. Investment by such a company in an Alberta electricity generation project would only be a concern if it undermined the company's overall credit-worthiness. Multiple large companies currently operate in Alberta, have built and are planning to build electricity generation facilities in the province, and regularly raise capital by issuing new debt securities.

Equity Providers

Equity providers mirrored the concern of debt providers with respect to the project financing of proposed Alberta electricity generation projects. In general, they prefer to consider project investments in markets where long-term contracts or regulated prices support new projects. However, equity providers were not as uniform in their views as debt providers. Some equity providers expressed willingness to invest in a generation project in Alberta without a supporting long-term contract, however, the expected return on the project would have to be commensurate with this higher level of risk. Given the generally low prices for electricity in Alberta over the past several years, and the expectation of relatively low prices for some time to come, these potential investors stated that their calculations of expected return are not currently high enough to support investment.

Project-based Developers

Project-based developers reiterated the positions of debt and equity providers with respect to project financing: the lack of long-term contracts in Alberta, with some exceptions, makes project financing extremely difficult, and hence limits their opportunities to develop new projects. This community of developers is largely focused on other jurisdictions, where long-term contracts are more readily available. Several expressed a willingness to consider projects in Alberta if the return expectations were

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[2] One such project is BluEarth Renewables' Bull Creek Wind Project, which has a long-term contract with a number of Alberta School Boards. For more information on this project, please see the BlueEarth Renewables website, at www.bluearthrenewables.com.

high enough to allow the financing of a facility exclusively based on equity, but pointed out that this is not currently the case.

Balance Sheet-based Developers

This class of developers was in general attracted to the Alberta electricity generation market, as it is currently configured, and many are actively considering future investment. They expressed the position that the market offers a return on investment largely commensurate with the risk taken. Several of these investors stated that they manage their portfolios carefully to ensure an appropriate balance between assets that are exposed to the uncertainty of a market such as Alberta's, and other assets that are contracted in various ways.[3] As a result, their overall portfolios are secure enough to be credit-worthy, while still providing attractive returns to their investors.

Comments on Generation Fuels and Facility Types

The Alberta electricity system currently includes a variety of facilities using different fuels and technologies, each of which could be built again. Investors were asked to comment on the variety of investment options available in Alberta, and whether they preferred some over others at the current time, and why.

Fuels

Fuel Type	**General View**
Natural Gas	Preferred fuel, because of its current low price, abundant and growing supply, and the typically lower construction cost of gas-fired facilities
Coal	Not attractive at this time, largely because of uncertainty related to environmental regulations
Wind	Not generally attractive at this time because expected medium-term Alberta electricity prices are on average lower than the full cost of the facilities
Biomass	Not generally attractive on a standalone basis because of limited fuel availability and high cost of facility construction, but may be combined with natural gas

[3] Note that these alternative assets could be located in Alberta, or located in other jurisdictions.

Fuel Type	**General View**
Hydropower	Not generally attractive because of the very high cost of construction, extremely long lead times required for development, lack of transmission to potential sites, and lack of other supporting infrastructure to those sites, which further increases expected costs
Solar	Not generally attractive at this time because expected medium-term Alberta electricity prices are on average much lower than the full cost of the facilities

Natural gas: All respondents commented favourably on the current attractiveness of natural gas-fired facilities. Natural gas prices have been extremely low for the last few years, and are expected to continue to be competitive because of the increasing availability of shale gas, coal bed methane, and other non-traditional sources in North America. At the same time, natural gas-fired facilities are often cheaper to construct than facilities based on other fuels, therefore putting less capital at risk in any one facility, and are often more flexible than facilities using other fuels, therefore better able to follow swings in market prices. Finally, compared to some fuels, such as coal and oil, natural gas emits less carbon and less of controlled emissions such as metals, sulphur and particulates, making it somewhat more attractive than alternatives from an environmental perspective.

Coal: All investors commented on the current lack of clarity with respect to environmental regulations concerning coal-fired electricity plants. The Government of Canada has proposed restrictions on coal plant emissions which would require all new plants to achieve carbon emissions similar to natural gas. If this or a similar proposal were to be instituted, it would mean that any new coal plant would be required to include some form of carbon capture and sequestration process in order to meet this standard. Doing so would make coal-fired plants, which are already more expensive to construct than natural gas-fired plants, uncompetitive with other options. While coal itself is abundant in Alberta, and continues to be relatively inexpensive as a fuel, high capital costs and the uncertainty of these proposed regulations has resulted in investor skepticism about new plants based on this fuel. In this light, it is notable that the proposed 460 megawatt (MW) H.R. Milner coal plant received all required regulatory approvals and permits some time ago, but has not yet proceeded to construction.[4]

Wind: Investors commented that in general, they are not supportive of wind projects at this time, because prices in the Alberta electricity market have been and are expected to continue to be too low to provide a sufficient level of return on investment in a new project, if the only source of revenue were to be the hourly electricity market. There is no fuel cost in wind power facilities, and operating costs tend to be relatively low. The majority of the long-term cost of wind power is the cost of the capital employed

[4] For more information on this project, please see the Maxim Power website, at www.maximpowercorp.com.

in constructing them. Even with the historically low interest rate environment of the last few years, the full cost of new wind projects, with a reasonable return on equity capital included, is higher than the average price of electricity in the Alberta market. Only wind projects which have either contracts or substantial ancillary revenues will be considered for financing by any debt, equity or balance sheet investors. In the event that a wind project is given a contract by a consumer of electricity, that consumer is essentially taking on the risk that the average electricity price will rise above the wind break-even point over the long-term, therefore making the contract a sensible one. Wind projects also sometimes qualify for alternative revenue streams, such as carbon credits or other green financial attributes. If these are sizeable enough, then they could make a positive difference on investor views. At the time of writing of this report, there are more than 1,000 MW of wind projects that have received all required regulatory approvals and permits, but are not currently proceeding to construction.[5] One exception is Capital Power's Halkirk wind project, which according to the company's publicly available information benefits from a long-term renewable energy credit arrangement which will provide approximately 40% of expected revenues over the life of the project.[6]

Biomass: Unlike natural gas, coal or wind, biomass is not an abundant generation fuel (on the scale required for large electricity plants). Facilities capable of using biomass are generally smaller versions of coal plants (using biomass instead of coal in a steam boiler), or natural gas plants (biomass is first converted to a synthetic gas using one of several gasification technologies, or methane is extracted from the biomass using an anaerobic digestion technology, and then in either case the resulting gas is burned as in a natural gas-fired plant). In the former case, the smaller size leads to the loss of economies of scale, and in the latter case the need for additional technology (gasification, digestion, etc.) makes biomass plants more expensive than pure natural gas alternatives. On the other hand, biomass plants often qualify for ancillary revenues, such as carbon credits of various kinds, which can make the projects economic. Investor comments on biomass plants were generally limited, because of the scarcity and size of the opportunities. Where comments were made, however, they were generally negative, because of the higher construction costs involved, unless the biomass was being used in conjunction with another fuel such as natural gas, and explicitly to take advantage of ancillary revenue opportunities. It should be noted that over the past ten years four facilities were built, three of which co-fire biomass and natural gas. Currently, a 41 MW biomass facility is under construction by Mustus Energy. The company recently announced that the facility had reached a 10-year agreement with Shell Energy for the sale to Shell of all electricity output of the plant as well as the right to all carbon offsets and other environmental attributes.[7]

Hydropower: Hydropower is extremely capital intensive, being one of the most expensive types of electricity generation facility to build. Individual site opportunities often also take many years to develop, because of complex environmental impact studies and other required permits and approvals. However, it is the longest lasting technology (many facilities in use across Canada have already passed

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[5] Please refer to the most recent AESO Long Term Adequacy Metrics report for further information on the state of project developments in Alberta, available on the AESO website at www.aeso.ca.

[6] For more information, please see Capital Power's website at www.capitalpower.com. For the specific reference to the expected revenue of the Halkirk project, please refer to page 31 of the May 2012 Investor Presentation posted on the site.

[7] For more information on this project, please see the Mustus Energy website at www.mustusenergy.ca.

100 years of operation), and requires relatively little labour and maintenance to operate. Financing hydropower projects is a specialty of Canadian financial institutions, and there is a relatively high comfort with this fuel source and its associated technologies. Several debt and equity providers commented positively on the possibility of financing hydropower projects, if they were practically available and economic. However, Alberta does not have an abundance of potential locations for hydropower facilities. The largest and best of these sites are typically very far away from the existing transmission system, and are not well-served by existing infrastructure such as roads or public services. Constructing plants in such locations would result in even higher than normal costs for hydropower facilities. Notwithstanding the current low interest rate environment, the extremely high cost of constructing such facilities means that no capital provider indicated a willingness to support Alberta's specific hydropower opportunities at this time in the absence of a long-term contract.

Solar: Solar power generated through photovoltaic panels has become increasingly common around the world, as many governments have supported the growth and expansion of the technology and its application. The price of panels has declined dramatically over the past few years, but even at current, lower than ever prices, electricity generated by solar panels still costs much more to produce than the price of electricity on the Alberta electricity market. No debt or equity provider expressed any interest in supporting investment in solar power facilities in Alberta, unless there was a long-term contract offered by a credit-worthy counterparty for the output of such a facility at a sufficiently high price.

Generation Types

There are five types of electricity generation plants that are in use in Alberta. Investors were asked to comment on the attractiveness of these types of facilities in the current environment.

Type of Plant	General View
Baseload	Recent prices in the Alberta electricity market have not been sufficiently high to support investment
Co-generation	Investment depends on the terms of the contract with the steam host, more than it does on the Alberta electricity market
Mid-merit	Recent prices in the Alberta electricity market have not been sufficiently high to support investment
Peaking	Prices, and the volatility of prices in the market, have been sufficiently high to allow several investors to consider construction
Intermittent	Recent prices in the Alberta electricity market have not been sufficiently high to support investment

Baseload: Baseload facilities are intended to run 24/7, perhaps with some flexibility in terms of total electrical output at any time. Historically, these facilities have used coal as fuel (or in some jurisdictions run-of-river hydro or nuclear power), but they have also used natural gas-fired combined cycle technologies in some jurisdictions. Investing in such facilities requires an investor to believe that the long-term average price of power in the market will be sufficiently high to cover all operating and capital costs for the full life of the project. Investors indicated that at this time the expected prices in the market are not sufficiently high to support investment. However, as Alberta's existing stock of generation facilities ages and retirements become imminent, these views may change.

Co-generation: Co-generation facilities produce two outputs – heat and electricity – with revenue streams associated with each. They are typically located on the property of or close to the intended buyer of the heat output of the facility (called the "steam host", because traditionally the heat is in the form of steam, though occasionally also hot water). Moreover, the steam host that requires the heat will also typically require a certain amount of the electricity production in addition to all of the heat, which means the steam host represents a significant portion of the total revenue of the plant. This amounts to a long-term contract for a substantial portion of the output of the facility, and all capital providers expressed willingness to provide capital to facilities that have such long-term contracts, provided that the steam host is sufficiently credit-worthy in its own right.

Mid-merit: Mid-merit generally refers to electricity generation facilities that operate five days per week for 12 to 16 hours per day. These facilities ensure that an electricity system has sufficient capacity to meet its normal daily and weekly variation in power demand, without having to produce excess power in the late hours of the night or on the weekend when demand is typically lower and only baseload generation is required. In recent years, natural gas-fired combined cycle facilities have been used for this purpose, but also certain coal plants have fulfilled this function. In the context of Alberta's electricity market, investors commented that recent prices for power filling these needs, and future expectations for these prices, do not support new construction. Several projects that could potentially fall into this category have received all required regulatory approvals and permits but have not proceeded, including the proposed 350 MW Saddlebrook natural gas-fired facility, which has been at this stage for some time. Again, investor willingness to proceed may change as existing facilities in Alberta age.

Peaking: Peaking facilities are designed to run very infrequently, sometimes amounting to only a few days per year. Typically, they are required to supply power when the electricity system is most stressed, for example on the hottest and coldest days of the year, or when other electricity facilities are offline due to breakdowns. Since they run so infrequently, and are required to start up very quickly when they are needed, these facilities are typically single-cycle natural gas facilities (older versions may have been oil-fired steam boilers, some of which still exist). They suffer from high fuel consumption, but have the advantage of quick-starting flexibility. This allows them to be available at those times when power prices are very high because system supply availability is stressed. A number of potential investors expressed their concern about the risks inherent in depending on only a few days of operation per year to generate revenue from the market. They stated that they preferred to invest in peaking facilities in jurisdictions that offer some sort of capacity payment or long-term contract to provide greater certainty of revenue. Some equity providers and balance sheet developers indicated that they believe that the frequency of expected peaking needs in Alberta, coupled with the very high prices paid for power in those situations, are sufficient to incent some new peaking generation plant construction in the near to medium term. Several developers have begun the process of receiving permits and approvals for smaller natural gas-fired facilities that would fit the peaking category.

Intermittent: Generation whose running is dependent on a variable outside of the electricity system – such as the shining of the sun, blowing of the wind, or flowing of water – is intermittent. It is forced to accept whatever prices may be available in the electricity market at the time of power production, unless it is operating under a contract with a specific consumer. All investors indicated that absent long-term contracts, they would not finance intermittent generation at this time, because of the outlook for electricity prices. There are currently several thousand MW of intermittent renewable energy projects that are in various stages of permits and approvals in Alberta, including more than 1,000 MW of wind projects that have achieved all required approvals, as mentioned above, which do not appear to be proceeding at this time.

Comments on Other Barriers to Entry

Price Caps

The Alberta electricity market's rules require that the price of electricity be between $0 per megawatthour (MWh) and $1000 per MWh. Participants in the market are not allowed to bid negative amounts into the market, nor are they allowed to bid prices higher than $1000. Investors were asked whether this arrangement affects their investment decisions, positively or negatively.

Debt providers commented universally that changing the price cap regime would not affect their views of project finance opportunities in the Alberta electricity generation market: a wider range of prices, whether higher or lower, would only accentuate the revenue volatility and risks that are already unacceptable to project lenders. Developers dependant on project finance largely expressed the same view, however, some did point out that an increase in the price cap would potentially make peaking generation more valuable, improving the conditions for investment.

Balance sheet-based developers unanimously pointed to the possibility of a higher price cap as an incentive to build new generation. In their view, increasing the price cap would increase the average cost of electricity in the province, which would potentially improve the economic viability of new construction. At the same time, however, there were few comments on the possibility of lowering the price cap below $0. Doing so would most likely affect intermittent generators negatively, and in particular wind generators, as these are most likely to be bidding into the electricity market at a time when there are surplus resources available.[8] Several investors did comment on the direct correlation between price caps and the total cost of power to consumers: raising the cap above $1000 would put

[8] The AESO has reported that in 2011, the average price received by all windpower generators in Alberta was $50.26 per MWh. This compares unfavourably with coal at over $76, imports at over $85, Hydro at almost $95 and natural gas at over $100. The explanation typically given for this variation is that wind power is most often generating at night, when demand is low and supply is easily available, while the other fuels either have flexibility over when to supply, or are simply more fortunate in the timing of their availability. Please see the AESO's 2011 Annual Market Statistics, available at www.aeso.ca.

upward pressure on costs, and lowering the floor below $0 would put downward pressure on costs. However, both of these impacts would be near term, and presumably subsequent decisions and adjustments to operating practices by investors and plant operators would change these dynamics.

Regulated Rate Option and Market Liquidity

The Regulated Rate Option (RRO) in Alberta allows consumers to buy power without having to choose a retail electricity provider. The RRO is managed on the basis of one-month forward contracts for power, the cost of which is then passed on to consumers that have selected this option. As a result of this structure, the RRO largely follows the average price of power in the market, adjusted for the fact that consumers choosing the RRO tend to buy more power at specific times of the day rather than on a baseload basis.

All incumbent developer/owner/operators in Alberta, and several other investors, commented negatively on this system. The remaining investors had no comment on it.

Incumbent developers stated their view that the RRO as it is currently structured diverts electricity consumers from supporting longer-term contracts, and therefore reduces liquidity in the forward market for power. Comments on what to do about this issue divided into two groups: those who argued that the RRO should simply be abolished, and those that argued it should be restructured into a product that includes forward contracts. The former group suggested that there are already a number of retail electricity suppliers offering a variety of pricing arrangements, and that consumers could simply be required to select one if the RRO was abolished. These alternative arrangements could range from true spot prices for power, to medium-term contracts up to five years or more in length. The latter group commented that abolishment of the RRO could lead to very negative consumer reaction, and instead suggested that it should be left in place, but restructured. They suggested that the RRO become a hybrid product, consisting of a variety of contracts of differing lengths, such as one month, six months, and one, three and five years. In this way, the RRO managers would become counterparties for a range of electricity contracts that would ultimately reduce price volatility for consumers, and provide liquidity in the forward contracting market for generators. An increase in contracting on behalf of consumers would assist generators by providing them with increased revenue certainty, perhaps ultimately leading to easier availability of capital.

Interties with Other Electricity Jurisdictions

A number of investors commented on the issue of transmission interties with surrounding jurisdictions. Currently, Alberta has a 750 MW intertie with neighbouring British Columbia, and a 150 MW intertie with Saskatchewan. Given the size of Alberta's electricity system, this is a relatively small level of interconnection with surrounding jurisdictions. Currently, there is a third, privately owned intertie being built that would connect across the United States border to Montana.

Investors divided into two groups: incumbent developer/owner/operators expressed concern about the management of the interties, with some even suggesting that because of the differences between markets in Alberta and surrounding jurisdictions, Alberta electricity producers are disadvantaged by the interties. Investors not currently located in Alberta took the opposite view, that the lack of interties and the resulting characterization of Alberta as an "electricity island" reduced the liquidity and attractiveness of the Alberta electricity market.

Interties are effectively a source of electricity capacity outside a jurisdiction, or an outlet for power produced but not needed domestically. In situations of system stress, whether because of insufficient or excess electricity production, interties can be crucial to the safe management of an electricity system. In Alberta's case, however, the province is surrounded by jurisdictions which have very different internal arrangements for electricity: neither BC nor Saskatchewan operates an energy-only competitive electricity market like Alberta. In both cases, provincially-owned regulated entities control the electricity system, and manage the intertie with Alberta. This difference, and the different motivations and behaviours applicable to electricity entities in these other markets, was pointed to by incumbent developers as being the source of their concern with the interties. Alternatively, non-incumbent investors suggested that lack of access to other jurisdictions is closing off the opportunity to export power from Alberta, which further reduces the attractiveness of investment in Alberta generation facilities.

Scale of Electricity Operations in Alberta

Several potential investors commented on the need for developer/owner/operators in Alberta to have a certain scale of operations in the province in order to compete effectively. Most incumbent developers remarked on this issue, but several non-incumbents did as well.

Given the competitive, energy-only nature of Alberta's electricity market, developers suggested that trading, hedging and supply operations need to be tightly integrated. Detailed understanding of the functioning of the electricity market, and participation in it on a daily basis, were suggested as prerequisites for success. Moreover, the ability to call upon more than one supply facility in the management of daily electricity trades was claimed to be advantageous.

This suggests that a certain scale of operations is required for successful market entry into Alberta electricity generation. According to the suggested line of reasoning, a smaller developer building and operating a single plant would be at a disadvantage compared to larger, more diversified market participants. Similarly, for a new entrant, this suggests that developing and building a plant would alone not be a wise investment. Instead, a more significant investment with additional operations would be the minimum cost of entry. For larger companies, this may not be a significant barrier to entry, but for smaller companies with more limited financial flexibility, this market pressure for diversification may be prohibitive.

Several investors also commented on scale issues from the opposite perspective: that the Alberta market might not be expanding quickly enough to attract larger global competitors in electricity generation. As will be discussed in the next section, Alberta requires new electricity generation capacity, but not necessarily in large increments. Larger companies currently focused on other markets with substantial needs may not be interested in entering the Alberta market only to develop relatively small facilities.

Observations

Alberta's Existing and Expected Electricity Supply Needs

A number of investors commented that their views about investment opportunities in Alberta might change as the fleet of existing electricity generation facilities in the province ages and nears retirement.

Alberta Electricity Supply, December 31, 2011

Generation Source	**Nameplate Capacity (MW)**
Coal	6,242
Co-generation	3782
Natural gas combined cycle	750
Natural gas single cycle	827
Hydro	879
Wind	865
Other[9]	314
Subtotal	*13,659*
Interconnection with British Columbia	750
Interconnection with Saskatchewan	150
Subtotal	*900*
Total Capacity	**14,559**

Source: Alberta Electricity System Operator

During the ten years 2002 to 2011 inclusive, a number of older generation facilities were removed from service, and a number of new facilities were added, demonstrating the constantly changing circumstances of the electricity generation market.

[9] Includes generation facilities fired by fuel oil, waste heat, and biomass.

Generation Removals and Additions, 2002 to 2011

Generation Source	Removals (MW)	Additions (MW)	Net Change (MW)
Coal	547	1,065	462
Natural Gas Co-generation		1,764	1764
Natural Gas Single/Combined Cycle	877	1,049	172
Hydro		39	39
Wind		795	795
Biomass Co-generation/Biogas		104	104
Waste Heat		20	20
Fuel Oil			
Totals	*1,424*	*4,836*	*3,412*

Source: Alberta Electricity System Operator

Electricity generation plants typically have useful lives ranging from 25 to 50 years (with the exception of hydropower facilities that often last for more than a century). Alberta is expected to face the retirement of a significant portion of its existing generation fleet over the next 20 years.

Expected Removals, 2012 to 2032

Generation Source	December 31, 2012 (MW)	Removals to 2022 (MW)	Removals 2023 to 2032 (MW)	Remaining Fleet (MW)
Coal	6,242	1,796	2,756	1,690
Natural Gas Single/Combined Cycle	1,577	106		1,471
All other	5,840			5,840
Totals	*13,659*	*1,902*	*2,756*	*9,001*

Source: Alberta Electricity System Operator

The relative decline of coal-fired generation is particularly notable, as these plants typically operate baseload, and provide a substantial amount of the total power consumed in Alberta today.

The other side of the electricity equation is demand.

The all-time peak electricity demand experienced in Alberta was 10,609 MW, on January 15, 2012. The summer peak, at 9,885 MW, was also experienced this year, on July 9, 2012. While it may appear that Alberta's total capacity of nearly 15,000 MW of supply should give a sufficient comfort margin over this level of demand, it is not always the case. It is notable that on July 9 the province was suffering from the simultaneous failure of several coal and gas-fired generation units, while wind units in the province were operating at very low levels for lack of wind, hence giving rise to brownouts in some parts of the province. [10]

The AESO has estimated that peak demand will grow by 3.1 percent per year for the next 10 years, and by 2.4 percent per year for the following 10 years. Peak demand is expected to grow to 14,801 MW by 2022, and 17,281 MW by 2032.[11]

Total power consumption in Alberta is also expected to rise significantly over the next 20 years, from approximately 74 terrawatthours (TWh) in 2011, to 106 TWh in 2022, and 122 TWh in 2032.[12] The oilsands are expected to lead this growth, increasing their power consumption by more than 250% between 2011 and 2032. Other sectors will also consume more, growing by 50% to 100% from current levels. This distinction is important for two reasons: oilsands facilities often require both electricity and heat, and hence may drive the construction of more co-generation facilities in the province, and the growing predominance of oilsands and other industrial users of electricity means that Alberta will have a greater need for relatively stable electricity supplies that run continuously to serve these large consumers.[13]

Based on expected generation plant retirements and growth in electricity demand, the AESO has forecasted that more than 6,000 MW of new generation capacity will be required by 2022, and almost 12,000 MW of new capacity will be required by 2032.[14]

This new capacity will need to be a mix of baseload, mid-merit and peaking facilities in order to address consumer needs. The AESO estimates that based on the growing needs of oilsands producers and other large industrial companies, approximately 2,000 MW of the new capacity required in the next ten years will be co-generation, with approximately another 600 MW required in the following ten years.[15]

As can be seen from the comments of potential investors reported above, co-generation facilities are financed based on the specific arrangement made with the steam host for the facility, and do not generally depend on the Alberta electricity market to justify investment. As a result, financing of these facilities can be assumed to be feasible.

Given the AESO's forecasts for plant retirements, demand growth, and the need for co-generation in the province, investors will be considering whether to invest in approximately 4,000 MW of electricity generation facilities which will need to be supported by revenues generated in the Alberta electricity

[10] See AESO media release on July 10, 2012.
[11] AESO 2012 Long-term Outlook.
[12] Ibid. Note that 1 TWh is equal to 1 billion KWh.
[13] Industrial users tend to operate on a 24/7 or shift basis, with relatively less consumption volatility than the residential sector, for example, which tends to consume significant amounts of electricity in the morning and evening, but relatively little at other times.
[14] AESO 2012 Long-term Outlook.
[15] Ibid.

market. On average, this amounts to 400 MW of new capacity per year for the next ten years, noting of course that there is no necessity for capacity to be added in these increments, or on an annual basis.

Alberta Generation Needs in the Context of North America

Alberta currently has approximately 13,500 MW of generation capacity. Canada as a whole has more than 130,000 MW of generation capacity, while the United States has over 1,000,000 MW of total capacity. Alberta is a very small fraction of this total existing generation plant in North America.

Alberta faces a need for 6,000 MW of new generation capacity over the next ten years because of new demand growth and expected retirements of existing facilities. Across North America, a similar dynamic is unfolding, driven more in some places by the retirement of ageing facilities, and in others by increased demand. In the United States, for example, there have been more than 5,000 MW of *annual* generation capacity retirements in five of the past ten years, all of which needed to be replaced, dwarfing the demands of Alberta.[16]

This massive need for new construction of electricity generating facilities has resulted in the interest and participation of enormous capital pools, of all types. Debt providers, equity providers and developers of all kinds are focused on opportunities to participate in this ongoing activity. At the same time, however, the variety of markets and economic arrangements across North America means that capital providers have the scope to choose which types of markets they prefer, and have significant opportunities in their chosen subset of the total market without the need to compromise on their preferences.

As was noted above from the participants in this report, many investors have a stated preference to provide project financing in jurisdictions with long-term contracts or regulated markets. Since there are opportunities to provide such financing across the continent, these investors are not easily pressured to modify their preferences in order to invest in a market such as Alberta that does not offer this certainty of revenue.

In this context, it is notable that Alberta, as small a fraction of the total market as it is, already has five large companies owning or controlling a substantial part of its electricity generation market (in alphabetical order: ATCO, Capital Power, Enmax, TransAlta, and TransCanada), as well as many other companies that have a smaller level of participation. Alberta has been an attractive enough market to sustain this level of involvement by multiple companies. Maintaining this level of competition and variety of participants over the longer term would in itself be a sign of success for Alberta's energy-only competitive market. Given the degree of interest shown in potential generation projects in Alberta, as evidenced by applications for regulatory permits or AESO interconnection approvals,[17] there appears to be the potential for new market entrants and expanded participation by others.

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[16] See the United States Electricity Information Administration for detailed information (www.eia.gov/electricity/) .

[17] As of February 2012, more than 16,000 MW of generation capacity additions had applied for or received various regulatory and interconnection approvals. While this is not determinative of what will actually be built in the province, it is an indicator of interest.

Having said that, smaller developer/owner/operators did comment on the fact that Alberta's electricity market appears to be more conducive to larger companies, and particularly challenging to smaller market participants. The difficulty in securing project financing, which most smaller developers rely on, and the lack of available contracts were the key stumbling blocks. Persistence of these conditions, and the greater financial tools at the disposal of larger companies, could lead to fewer developments by smaller companies over time in Alberta, with more of them seeking future opportunities in other jurisdictions across North America. Alberta could eventually be characterized by a relatively small number of large players, without much competition from smaller developer/owner/operators. Smaller developers were firm in questioning whether such an outcome would be desirable.

At the same time, Alberta's need for approximately 4,000 MW of new generation capacity (not including expected co-generation facilities) over 10 years will not necessarily be enough of a pull to attract major new market entrants who have the financial strength and talent pool to compete with the larger existing incumbents. If Alberta generation is added in relatively small increments over time, then larger developer/owner/operators may not be willing to devote the time, effort and management attention required to slowly build up a critical mass of operations in Alberta, especially when they are focused on larger opportunities in other jurisdictions.

It is apparent that in a North American context, only a fraction of capital providers and developer/owner/operators are interested in and attracted to the Alberta electricity generation market. However, it is not clear what impact this reality will have on the cost of capital for Alberta electricity generation projects over the next ten years, and subsequently on the cost of electricity. If it is the case that a number of large and diversified incumbent market participants will continue to be critical to new development projects, then it will be the cost of capital faced by these companies which will largely determine the cost of capital for the Alberta market as a whole. Given that all of these large market participants have assets outside the province, and in many cases have assets in categories other than electricity generation, their cost of capital is only partly determined by what occurs in the Alberta electricity generation market.

The Impending Challenge of PPA Expiry

In 2000, as part of electricity industry restructuring, financial rights to a substantial portion of then-existing generation capacity was auctioned in the form of Power Purchase Arrangements (PPAs). These contracts required that the owners of the facilities continue to run them on specified terms in exchange for largely fixed revenues, while the purchasers of the PPAs were allowed to sell the output of the plants in the competitive market.

This step was taken for the two-fold reason of creating additional competition in the previously regulated electricity sector, while still fairly compensating the owners of (and capital providers to) those facilities for the investments that they had made in the anticipation that the regulated system would persist. The facilities in question were owned by TransAlta, ATCO, and the company now known as Capital Power (formerly a part of EPCOR, at the time known as Edmonton Power). Each of these companies had built the facilities under a traditional regulatory regime, expecting that they would be compensated for their investment over the full life of the facilities. The PPAs, with terms set through a regulatory process, were intended to mimic the returns to capital that the facilities would otherwise have generated for the owners, while still allowing the facilities themselves to be subject to prices in the new competitive market.

In financial terms, the owners of the facilities converted from being regulated entities to owning facilities under long-term contracts. From the perspective of the capital markets, these contracts provide important stability and support to the companies in question, contributing to their credit ratings and their ability to deploy their capital into other opportunities which are not contracted.

In terms of Alberta's generation fleet, this means that the capital employed in the 5,000 MW of current generation capacity that is covered by PPAs is effectively protected by long-term contracts. Given that approximately another 3700 MW of co-generation facilities are also supported by long-term contracts, this means that well over half of the capital employed in the construction of Alberta electricity generation facilities is supported by long-term contracts. This despite the fact that the Alberta energy-only competitive market has not itself generated very many long-term contracts over the past 10 years.

The PPAs expire in 2020, which will have a variety of important impacts. First, some of the facilities in question may be deemed to reach the end of their useful lives, and be taken out of service.[18] To the extent that this results in a significant withdrawal of capacity from the market, it represents a one-time need for an abnormally large amount of new development and construction, which creates a variety of practical challenges (e.g., stretching the availability of specialized construction companies). Second, it will change the financial profiles of the facility owners, since they will no longer be holders of contracts, but instead will be owner/operators of facilities in the energy-only competitive market. Third, it will mean that a much larger portion of the overall Alberta electricity generation market will be totally dependent for its returns to capital on the energy-only market.

The overall impact of these changes on the availability and cost of capital for Alberta electricity generation projects cannot be known today. However, as the expiry of the PPAs comes closer, a variety of decisions by the stakeholders involved will have important impacts on the market as a whole.

Generation Diversity

The province of Alberta is in the fortunate circumstance of containing an abundance of energy resources: massive supplies of coal and natural gas, favourable natural windpower conditions, some of the best solar irradiance locations in Canada, and some remaining sites that are technically exploitable for significant hydropower facilities. Notwithstanding this variety of options, one fuel source, natural gas, appears to be enjoying considerably more support from potential investors than all others.

The current mix of electricity generation facilities predominately relies on coal and natural gas fuels, but also includes wind, hydro and a small amount of biomass. A substantial portion of the coal-fired fleet

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[18] Facility owners may be incented to declare the end of life of the plants because doing so prior to PPA expiry will make them eligible for decommissioning funding from the Alberta Balancing Pool.

will reach retirement age over the next 20 years, however, so without replacement this element of the fleet will dwindle. Given the current uncertainty around environmental regulations and the high capital cost of constructing coal facilities, it would appear that replacement coal facilities are unlikely to be supported by investors. Over the past 10 years, approximately one sixth of capacity additions have been windpower facilities, as is observable from the table above. However, investor sentiment at the current time appears not to support substantial additions to this fleet without either a change in the market, or the fortuitous availability of long-term contracts for power or other substantial ancillary revenues.

Investor support for natural gas-fired facilities, whether co-generation, peaking, or otherwise, suggests that this fuel will be used in most facilities successfully constructed in the near to mid-term. Since Alberta has its own supplies, and the supply picture for natural gas across North America is increasingly positive, this does not appear to constitute a threat to security of electricity generation supply. However, electricity generation facilities have a life usually not less than 25 years, and often substantially more. Over such a time period, the advantages associated with natural gas could shift, as they have over the past 20 years on several occasions. Were the advantage of natural gas relative to other fuels to decline for whatever reason, the electricity market in Alberta could find itself wedded to a less than optimal form of generation for an extended period of time.

In the context of the energy-only competitive market, however, there does not appear to be any incentive driving investors to adopt an alternative perspective. Short of some direct incentives or arrangements to exploit alternative resources by an out of market actor, the current economics of the electricity market suggest that investors will continue to opt for natural gas-fired generation projects, and hence drive the province's fuel mix increasingly toward greater gas dependence.

Conclusions

Feedback from potential investors in the Alberta electricity generation market has provided insights into the expected sources of capital for the foreseeable future, the types of facilities likely to be supported, and some of the potential issues to watch for over the medium term.

It was very clear from interviews that investor appetite for non-recourse debt and equity financing for electricity generation projects in Alberta is very limited. Investors that prefer to invest on this basis are largely not comfortable with the lack of revenue certainty associated with Alberta's energy-only competitive electricity market. They stated that they would consider project financing for new developments if they benefit from long-term contracts, but few of these appear to be available in Alberta. Some equity investors stated that they would consider project financing in the Alberta market, but only if expected returns were high enough to compensate them for the perceived revenue risk, which is not currently the case.

Balance sheet financing appears to be much more readily available, largely driven by the participation in the Alberta market of a number of large, diversified incumbents. In addition, there appears to be some possibility that other large balance sheet-based developers could enter the market to fulfill some of the expected new electricity generation requirements of the next ten years.

The likelihood that new construction will continue to be dominated by existing market participants suggests that the financial health of the Alberta electricity generation sector is at least somewhat dependant on the continued health of these particular companies. In that context, the expiry of the existing PPAs in 2020 should be carefully monitored, as it will perforce represent a significant change in the structure of Alberta electricity generation facility ownership arrangements. Moreover, given that these companies are diversified into other electricity generation markets and other businesses, their cost of capital, and hence the cost of capital facing the Alberta electricity generation market, will be at least partly determined by factors outside Alberta.

Finally, the strength of investor support for natural gas-fired generation, coupled with the ongoing uncertainty of environmental regulations for coal-fired generation and the lack of strong incentives to pursue other forms of generation, suggest that the provincial generation fleet will become increasingly reliant on a single fuel.

Appendix

Interview Participants:

Capital Providers

Banks	3
Insurance Companies	2
Pension and Equity Funds	5
Canadian	8
Non-Canadian	2

Developer/Owner/Operators

Assets in Alberta	6
No Assets in Alberta	6
Have developed Coal assets	4
Have developed Gas assets	9
Have developed Renewable Assets	10
Prefer Balance Sheet Financing	7
Prefer Project Financing	5