Alberta’s Wholesale Electricity Market Transition Recommendation

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1.0 Executive summary

The AESO has completed its assessment of the wholesale electricity market and developed a recommendation for ensuring reliability as Alberta transitions to a lower-emission electricity system.

This report provides a summary of the AESO’s analysis, followed by our recommendation that Alberta’s electricity market structure needs to evolve from the current energy-only market (EOM) to include a capacity market.

BACKGROUND

Alberta’s wholesale electricity market structure was designed to deliver safe, reliable, competitively priced electricity. Since Alberta’s transition from a regulated market, the current EOM structure has successfully achieved several outcomes:

- Met growing demand in one of North America’s fastest growing jurisdictions
- Maintained reliability through an adequate supply of electricity
- Incented generation development and investment in a wide range of technologies without incurring public debt
- Provided reasonable electricity prices through a fair, efficient and openly competitive market

The EOM has delivered on the original objectives set for it. More recently, however, an additional objective has emerged for the electricity sector. Achieving a lower-carbon, sustainable electricity system is now policy.

Specific measures to achieve this objective were included in the Climate Leadership Plan (CLP), announced in November 2015. The CLP contained policy measures which will have a substantial impact on Alberta’s mix of generation supply by 2030, as emissions from coal units are eliminated and significant amounts of new renewable generation are added. This changing supply mix has the potential to materially impact electricity market dynamics, and in turn, the ability of the current EOM to continue to deliver on the objectives of reliability and reasonable cost in the long run. To examine this, the AESO has conducted an assessment of the long-term sustainability of the current EOM in a future with a supply mix characterized by a transition off coal and the integration of more renewable and natural gas generation. It should be noted that jurisdictions around the world (with a range of electricity structures) have been grappling with the potential impact that increased amounts of renewable generation may have and the adjustments that may be required. In this regard, Alberta is far from unique.
Executive summary

Alberta’s Wholesale Electricity Market Transition Recommendation

Summary of the AESO’s analysis of the current energy-only market going forward

The AESO’s analysis indicates that there is considerable uncertainty about whether sufficient investment in non-renewable generation, needed to ensure a reliable supply of electricity, will occur in the future. The AESO modelled future economic and financial conditions and determined that adding high volumes of intermittent renewable generation to Alberta’s market through the Renewable Electricity Program will decrease the revenue available for all generators. As a result, revenue sufficiency (i.e. the amount of revenue needed to recoup an investment and earn a profit) for investors and developers will decrease and investment may be deterred.

The AESO commissioned interviews with generation developers, investors and lenders and consulted with expert financial advisors. This effort indicated that interest in investing in energy-only markets has declined across North America, and that the Alberta wholesale electricity market is not attractive to investors. There is far less capital available for investments in merchant power plants which have significant revenue uncertainty. Capital that is available is at much higher cost. A certain amount of revenue certainty is required to attract sufficient investor interest to deliver the generation build that Alberta will require going forward.

The AESO also tested whether raising the price cap from $1,000/MWh to $5,000/MWh would attract sufficient investment to maintain reliability. We concluded that doing so may provide revenue sufficiency, but not revenue certainty and that the volatility that would result from this measure would create unacceptable risk for consumers. While this measure could provide increased revenue, the AESO determined that it was unlikely to be successful in attracting investment due to increased price volatility.

Without investment in new firm generation (or equivalent but alternative sources of firm supply such as demand response, etc.) to replace retiring coal-fired electricity, the market will be unable to support increasing volumes of intermittent renewables and provide a healthy reserve margin to manage through a wide range of system conditions. System reliability will be compromised.

The current EOM structure will not ensure the investment in new generation that Alberta will need in the future. Therefore, the AESO has concluded that Alberta must adopt a different electricity structure to meet its objectives for the electricity system.

Alternatives to the current energy-only market considered

The AESO considered the suitability of four electricity structures for meeting the government’s desired policy outcomes for Alberta’s electricity system.

<table>
<thead>
<tr>
<th>Two market-based structures</th>
<th>Two non-market structures</th>
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</thead>
<tbody>
<tr>
<td>Energy-only market (EOM)</td>
<td>Long-term contract (LTC)</td>
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<tr>
<td>Capacity market (CAP)</td>
<td>Cost of service regulation (COS)</td>
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An assessment of how well each structure is likely to achieve certain policy outcomes is provided below, and described in further detail in this report.

**TABLE 1: Alignment to desired outcomes**

<table>
<thead>
<tr>
<th>Policy outcomes</th>
<th>Energy-only market (EOM)</th>
<th>Capacity market (CAP)</th>
<th>Long-term contract (LTC)</th>
<th>Cost of service regulation (COS)</th>
</tr>
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<tbody>
<tr>
<td>Reliable and resilient system</td>
<td>![Generally positive]</td>
<td>![Generally positive]</td>
<td>![Generally positive]</td>
<td>![Generally positive]</td>
</tr>
<tr>
<td>Improved environmental performance</td>
<td>![Generally negative]</td>
<td>![Generally positive]</td>
<td>![Generally positive]</td>
<td>![Generally positive]</td>
</tr>
<tr>
<td>Reasonable cost to electricity customers</td>
<td>![Generally neutral]</td>
<td>![Generally positive]</td>
<td>![Generally negative]</td>
<td>![Generally neutral]</td>
</tr>
<tr>
<td>Economic development and job creation</td>
<td>![Generally positive]</td>
<td>![Generally positive]</td>
<td>![Generally negative]</td>
<td>![Generally neutral]</td>
</tr>
</tbody>
</table>

* Generally negative  ** Generally positive  $ Generally neutral

**TABLE 2: Orderly transition - costs and risks**

<table>
<thead>
<tr>
<th>Policy outcomes</th>
<th>Energy-only market (EOM)*</th>
<th>Capacity market (CAP)</th>
<th>Long-term contract (LTC)</th>
<th>Cost of service regulation (COS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orderly transition — costs</td>
<td>![High]</td>
<td>![Low]</td>
<td>![Medium]</td>
<td>![High]</td>
</tr>
<tr>
<td>Orderly transition — risks</td>
<td>![Medium]</td>
<td>![High]</td>
<td>![Low]</td>
<td>![Medium]</td>
</tr>
</tbody>
</table>

* EOM represents costs and risks of introducing enhancements

Transitioning to a long-term contract or a cost of service regulation structure would represent fundamental change to the electricity sector with commensurate risks and uncertainties. Transition to either of these structures carries a significant risk of being a time-consuming and contentious process which could extend for several years. Treatment of legacy assets would need to be determined while the details of the new structure were developed and implemented. In addition, both of these structures would likely result in higher long-term costs to consumers as competitive forces are minimized and they are exposed to the risk of poor long-term decisions.

By comparison, transitioning to a capacity market could be accomplished in a more timely manner with significantly less disruption, and legacy issues would be minimized. A capacity market would achieve key policy outcomes for the electricity system. It would ensure continued reliability of the system in a cost-effective manner while enabling the transition to a cleaner, lower-carbon electricity system over the coming years.
CONCLUSION

The AESO has concluded that Alberta would be best served by the adoption of a capacity market. A capacity market would provide the following combination of benefits which no other single electricity structure can:

- Ensure reliability and specifically compensate for firm generation
- Provide suppliers with revenue sufficiency and stability
- Implement key areas of the CLP and be robust to accommodate potential future policy evolution
- Maintain market incentives to preserve efficiency and flexibility
- Compatible with the existing transmission policy or future changes
- Allow a manageable amount of change with a high probability of success

While raising the price cap in the existing energy-only market structure can be introduced relatively quickly, there remains a high degree of risk that this measure would not ensure supply adequacy in the long run. There would be no time to course-correct if changes did not work. Although it is a more significant change, the introduction of a capacity market would materially reduce supply adequacy risks. Lessons learned from other capacity markets can be employed to ease Alberta’s transition. Implementation of a long-term contract or cost of service structure would involve significant change for the current industry. There is a high risk that the process to transition to one of these structures would take longer, be more costly and contentious, and ultimately may jeopardize reliability and make achieving of CLP objectives unlikely.

RECOMMENDATION

The Government of Alberta should adopt a capacity market structure

The AESO recommends that Alberta move to adopt a capacity market structure. Should the government accept our recommendation, the AESO requests ministerial direction as soon as possible to begin the design of a capacity market for Alberta, including engagement of industry stakeholders. Earning their support through robust engagement will be critical to the success of this endeavour.

Because of the complexity, we must emphasize the time that will be required to successfully implement this recommendation. The AESO estimates that design of the market will take two years to complete, with an additional year to finalize legal contracts and set up the procurement process. Therefore, it should be expected that the first capacity contracts will be entered into at least three years after the design process starts. Consequently, the earliest date that capacity procured through the initial auction would be in service is likely 2024, and a bridging mechanism will likely be required to ensure supply adequacy between 2021 and 2024. In addition to the design of the capacity market itself, the impact of a capacity market structure on the existing energy market will need to be addressed.
2.0 Introduction

This report provides the AESO’s analysis and recommendation about how the transition to lower-emission sources of electricity generation can occur while maintaining the necessary level of reliability at reasonable cost.

2.1 BACKGROUND

Alberta’s energy-only wholesale electricity market structure was designed to deliver safe, reliable, competitively priced electricity. Since deregulation, the energy-only market (EOM) has achieved several outcomes successfully:

- Met demand for electricity in one of North America’s fastest growing jurisdictions
- Maintained reliability\(^1\) (i.e. healthy reserve margins)\(^2\)
- Incented generation development and investment in a wide range of technologies without incurring public debt
- Provided reasonable electricity prices through a fair, efficient and openly competitive market

The energy-only market has met its objective of delivering reliable, competitively priced power, but its performance in a future with the additional objective of achieving a lower-carbon, greener electricity system is much less certain.

\(^1\) Throughout this report, the term “reliability” refers to maintaining an adequate supply of electricity in the future.

\(^2\) Electricity systems must always ensure that the amount of electricity being generated is equal to the amount of electricity being consumed. Reserve margin is the amount of supply available above the level of demand, typically measured as expected reliable or “firm” supply relative to expected peak demand levels. A sufficient reserve margin is required to ensure demand can be met despite events, such as unit outages or maintenance, which make some supply unavailable. Insufficient reserve margins significantly increase the risk that system operators may be forced to cut electricity service to some customers to maintain overall system balance.
2.1.1 The relationship between generation investment and reliability

Ensuring that an adequate supply of generation will be available in the future is a key part of the AESO’s reliability mandate. The Alberta Interconnected Electric System (AIES) is dependent on investors and developers to build enough generation to meet future demand and to provide a reserve to help system operators manage through contingencies. The electricity price in Alberta’s wholesale electricity market provides the investment signal that investors consider when making decisions about whether to build new generation facilities. Periods when the price is low can indicate an abundance of generation capacity; periods when the price is high can indicate a tighter supply of generation. These latter circumstances can provide a signal to investors to build new generation. Investors and developers will create an outlook of future electricity prices under a range of conditions, and these forecasts are critical inputs for determining whether to invest in new generation.

2.1.2 The shift to cleaner electricity systems

In recent years there has been a global shift away from higher-emission sources of electricity (such as coal), toward lower-emission sources such as renewables and natural gas. The transition to a cleaner generation mix has taken a variety of forms around the world, but the effort begins with jurisdictions evaluating and adapting their electricity structures to achieve more stringent environmental objectives and integrate new technologies and fuel types. Typically, jurisdictions making this shift encounter similar challenges, such as ensuring coal-fired generation is replaced by other sources of cleaner, firm generation. They must also manage the reliability and market impacts of intermittent renewable sources of generation like wind.

The AESO recognized this trend toward cleaner electricity through its strategic planning efforts for 2014-2018, and considered how a shift toward lower-emission sources would impact Alberta’s electricity system. At the time, perceptions of Alberta as an environmental laggard were growing in media and other public conversations, and were tied to both the oilsands and electricity sectors. These industries are two of the province’s most emissions-intensive sectors and were coming under increasing scrutiny because of their high-carbon emissions and perceived poor environmental performance. Additionally, concerns were being raised within the electricity sector about whether there would be sufficient investment in new generation to meet future needs, as the PPAs (i.e. the transition mechanism from deregulation) ended and legacy coal assets began to retire.
In 2015 the AESO examined the historical performance of the EOM, compared it with other jurisdictions and conducted an impact assessment under a range of possible future conditions. The AESO also considered whether the energy-only market could accommodate more stringent environmental policies and still deliver on its objectives. The AESO concluded that the EOM has served Alberta well: it has delivered on the objectives set when deregulation began (i.e. to provide Albertans with safe, reliable and competitively priced electricity). Looking forward however, as public support for achieving significant reductions in carbon emissions intensifies, doubts about the ability of the EOM to deliver these environmental objectives while maintaining reliability at reasonable cost began to emerge.

This exercise provided the AESO with an opportunity to begin considering the impacts of the inevitable shift toward a lower-emission power system in Alberta before specific details were available. In November 2015, the government’s Climate Leadership Plan (CLP) was announced. Among the suite of policies contained in the CLP, two are specifically focused on Alberta’s electricity sector: the accelerated phase-out of emissions from coal-fired electricity and the replacement of that generation with lower-emission sources such as natural gas and renewables. Shortly after the release of the CLP, the government announced the Renewable Electricity Program (REP), which will be designed to expedite Alberta’s transition to a cleaner electricity system. REP will provide support for new renewable electricity projects to increase the amount of renewable energy produced in the province.

2.1.3 How renewables interact with the market and grid

In Alberta’s electricity industry, trade-offs abound. Renewables are ideally suited to Alberta’s goal of achieving a low-carbon electricity grid, but accommodations must be made to ensure the benefit that this type of generation provides is not undermined by its impacts on the electricity system. When wind power, for example, produces electricity for the Alberta market it reduces the pool price, mostly because the fuel is free (operational costs of wind are also comparatively lower than other types of generation).\(^3\) Lowering the price is an attractive outcome for consumers, but not for other generators who are competing against wind generators. With less revenue available for these generators to earn when wind farms are producing and selling electricity, they become more reliant on higher prices at times when wind farms are producing less or not at all.

Adding even higher volumes of wind can erode the economics of generating electricity in Alberta. All generators will have an increasingly difficult time earning the revenues they need to be economic. The resulting low pool price, if expected to stay low and perhaps drop further, together with increasing amounts of renewables added through the REP, will also deter investors. The intermittency of renewables (i.e. that they produce only when environmental conditions are suitable) will also cause challenges. Due to their intermittency, back-up generation such as gas peaking plants will be needed when the renewable sources are not producing electricity. As there are many times when renewables may not be able to produce any energy, the volume of firm generation required is not reduced as more intermittent generation is added. The result is that intermittent renewable generation development is in addition to the volume of firm generation required to serve load and maintain reliability. As the shift to renewables takes place, the market must incent enough new firm generation to replace retiring coal units, meet growth in demand and satisfy demand for power when the increasing amounts of renewables installed on the grid are not producing. The impact of renewables on the market’s ability to incent new firm generation is a consideration for ensuring the future reliability of Alberta’s electricity system.

\(^3\) The economics of wind technology and, to a lesser extent, solar suggest that these technologies are likely to account for most of the new renewable generation that will be added to Alberta’s supply mix through the Renewable Electricity Program in the near term.
2.2 THE AESO’S ROLE IN IMPLEMENTING THE CLIMATE LEADERSHIP PLAN

The AESO is playing a critical role in helping the government implement elements of the Climate Leadership Plan (CLP) related to electricity. The AESO is providing advice to the government with respect to achieving a reliable transition away from coal-fired electricity, and has been tasked with designing and implementing the REP. Underlying each of these key initiatives is the question of how Alberta’s current electricity market may need to evolve in order to support these new objectives. The AESO’s position within the electricity industry, its work with government on implementing the electricity components of the CLP and its unique understanding of the economic and reliability aspects of the electricity system, allowed it to undertake a detailed assessment of the electricity market structure. The AESO focused on the market’s ability to deliver on the long-term objectives of the CLP while continuing to achieve the original objectives of reliability and reasonable cost.

2.2.1 Ensuring a reliable transition away from coal-fired electricity

The AESO’s work on the coal transition to date has determined that uncertainty about the pace, transparency and transition of coal retirements is likely to deter investment in new generation needed to replace coal. This in turn prompts concerns about system reliability—specifically, whether there will enough new generation to meet demand as coal units leave service. The AESO recommended a publicly announced schedule to provide more certainty to investors about retirements in order to manage the transition in a reliable way. The AESO also advised that its study of the market may yield other options to implement a reliable coal transition.

2.2.2 Developing the Renewable Electricity Program

The AESO submitted recommendations for the REP to the government in May 2016. This advice addresses the design of the program, the generic competitive process for implementing it and key features of the first competition, including a payment mechanism. While the government considers these recommendations, the work to develop the program must continue in parallel. The first REP-supported projects are currently targeted to be in service in 2019.

2.2.3 Understanding the new demands on Alberta’s electricity system

The AESO is uniquely positioned to provide advice about how to achieve the government’s CLP objectives while continuing to maintain reliability of Alberta’s electricity system. Carrying out the AESO’s mandate affords access to data no other entity in the industry has, providing the AESO a rich and layered understanding of how the system performs. The AESO’s professionals apply their expertise in markets, economics, engineering, system operations and law to the tasks of planning and operating the grid, connecting customers and running the energy-only market. In doing so the AESO has gained critical insights for maintaining a reliable system that remains responsive to Alberta’s needs.

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4 Pace: Ensuring that as large volumes of coal capacity retire there will be enough firm generation coming into service to replace it. Transparency: Ensuring that the market is able to send timely signals to incent replacement firm capacity relative to expected coal retirements. Transition: Ensuring that new firm generation is operating reliably before the coal generation it is replacing retires.
The AESO’s work in determining whether the EOM will remain the vehicle best suited to deliver on the original and new objectives for the system (i.e. reliability, reasonable cost and low emissions) drew heavily on the expertise and experience of AESO professionals. This work was supported with additional research and advice from external consultants with recognized expertise in electricity markets and electricity generation investment criteria.5

The AESO’s assessment relies heavily on a comprehensive understanding of:

- Operation of the physical electricity system
- The current energy-only market and other structures for delivering electricity and their respective economics (e.g. how costs are allocated)
- How these structures ensure there will be enough generation to meet future demand for electricity in the future
- Trade-offs involving allocation of risk between stakeholders, certainty of outcomes versus flexibility and innovation, and incentives for cost minimization

A keen understanding of the complex interplay of risks, trade-offs and variables within electricity systems generally, and how these factors and the relationships between them exist in Alberta’s system, is also critical for understanding whether the system in its present form is viable or whether change may be required.

2.3 ABOUT THIS REPORT

This report provides the AESO’s analysis and recommendation about how the transition to lower-emission sources of electricity generation can occur while maintaining the necessary level of reliability at reasonable cost. The report offers analysis of the challenges outlined above, and provides insights about how they can be addressed. It examines how the current energy-only market is likely to perform in the future, when CLP objectives are implemented and reliability must be maintained. The report also includes the AESO’s recommendation, developed through multiple analytical approaches and in consultation with external industry experts, for an electricity structure designed to ensure a cleaner, reliable electricity system at a reasonable cost to Albertans.

Section 3 of this report provides an in-depth discussion of how the AESO approached the question of whether Alberta can rely on the current energy-only market structure to achieve CLP objectives while also maintaining reliability. It describes the analysis the AESO conducted to test the current structure and explains the conclusions reached. Section 4 provides a discussion of alternative structures, including the EOM, and evaluates the suitability of these alternatives for achieving a set of desired policy outcomes. The AESO’s recommendation for adopting one of these structures is provided in Section 5. Section 6 outlines next steps for implementing the recommendation.

5 The Brattle Group and KPMG provided expert input and validated the AESO’s analysis.
3.0 Energy-only market sustainability analysis

Will there be enough revenue in the market to drive an acceptable level of supply adequacy?

Alberta relies on the wholesale electricity market to provide enough generation to meet demand, and to manage through circumstances when there are supply problems. In order to achieve this, there must be opportunity for investors to earn sufficient revenue to cover their initial investment and earn a profit. In the current market, investor revenue is earned primarily through sales of energy, priced either at the pool price or through bilateral or forward contracts. Accordingly, new developers will consider the outlook for pool price as significant in investment decisions. To a lesser extent, depending on plant capability as well as operational plans, investors can also earn revenue from ancillary services sales.

The AESO’s market sustainability analysis focused on the question of whether the energy-only market is expected to deliver an acceptable level of supply adequacy given changes driven by the CLP. The AESO used quantitative (modelling) and qualitative (research, interviews) approaches to study this question.

3.1 QUANTITATIVE ASSESSMENT

Market and financial modelling was used to determine the expected range of economically driven, new non-renewable generation builds and resulting level of reliability. Modelling efforts focused on this question: Will there be enough revenue in the market to drive an acceptable level of supply adequacy?

In particular, the AESO was interested in determining more clearly:

- How coal retirements and renewable additions would impact generation build decisions
- How renewable additions would impact price levels and volatility in the market
- How generation would operate to meet fluctuating load, given flexibility of the system and ability to manage varying supply from renewable sources
- Whether the market would provide sufficient revenue and return on capital to drive non-renewable generation investment to a reliable level

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6 Ancillary services include regulating, spinning and supplemental reserves, transmission-must-run, dispatch-down service and blackstart services.

7 Supply adequacy in this document refers mainly to the ability of the supply assets in an electricity system to cover the load, taking into account uncertainties in supply availability and load level. Note that supply adequacy references can also include the ability of the transmission system to perform; however, transmission aspects of supply adequacy are not focused on in this document.
3.1.1 Description of AESO modelling

Generation developers will examine future expectations for revenue and consider whether the revenue is sufficient to cover fixed and variable costs as well as provide an attractive return on capital. They will also examine the risk associated with uncertainty related to market conditions, construction, financing costs, transmission congestion and changes in policy.

**FIGURE 1: Market supply mix**

Alberta relies on investment in new generation to ensure reliability. Price signal, build decisions and reliability are interrelated. The AESO's modelling was aimed at understanding how and to what extent these factors could impact each other in the future.

The AESO modelled a range of market conditions based on a forecast for changes to Alberta's generation fleet (i.e. retirement of coal and addition of renewables) to understand their impact on market prices. The modelling exercise attempted to mimic the complexity of the power system, with changes to individual assumptions significantly impacting the overall outcome and reliability assessment. Detailed hourly modelling was required to fully understand the implications of future changes in the system. The AESO performed hourly market simulation between 2016 and 2030 under a range of scenarios, varying the key factors that would impact results.

The AESO's modelling used a baseline set of assumptions for:

- Demand growth
- Natural gas price
- Coal retirements
- Renewable additions
- Intertie capability

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8 The fixed costs of power generation are essentially capital costs. Capital costs vary largely as a function of the technology employed. Variable costs, also known as operating costs, include fuel, labour and maintenance costs. Unlike capital costs which are “fixed” (meaning they do not vary with the level of output), a plant’s total operating cost depends on how much electricity the plant produces. Fuel costs dominate the total cost of operation for fossil-fuel power plants. For renewables, fuel is generally free (with the exception of biomass power plants in some scenarios). For these types of power plants, labour and maintenance costs dominate total operating costs.


11 A moderate coal retirement schedule with maximum two retirements per year (December 2018 - December 2029).

12 350 MW of non-dispatchable renewables (wind) added per year beginning in 2018 from the Renewable Electricity Program to total 4,200 MW of additions.

13 Our assumptions considered historical flows while also accounting for anticipated increases in intertie capability resulting from restoration initiatives.
The AESO also modelled two comprehensive sensitivities (scenarios) to determine the impacts of these conditions on the energy-only market’s ability to provide investors with the revenue required to develop new combined-cycle generation:14

- Higher renewable development (7,200 MW added)
- Higher natural gas price (approximately 50 per cent higher than baseline assumption)15

Using these parameters the AESO developed forecasts of:

- Pool prices for electricity and expected timing and volume of generation additions
- Reserve margins (i.e. amount of generation capacity in excess of peak demand levels)
- Unserved energy (i.e. electricity that is needed but not available)
- Supply surplus (i.e. excess electricity that is not required)
- Intertie flows (i.e. the amount of power flowing over transmission lines that connect Alberta to neighbouring jurisdictions)

The AESO employed the pool price forecasts mentioned above in financial models to assess whether investments in non-renewable generation would meet investors’ rate of return requirements.

The reliability of the electricity system was further assessed using “stress” cases that tested plausible, but extreme (i.e. severe and/or rare) conditions on the electricity system including:

- An extended intertie outage
- An extended outage of a major coal generator
- An extreme weather event16
- A major gas generation project development delay

It is important to note that these conditions are not necessarily theoretical; all but one of these conditions has occurred to some degree on the Alberta system in recent years.17

By using a broad range of assumptions, sensitivities and conditions, along with stress cases, the AESO developed a range of outcomes that indicated potential future impacts on investment and reliability.

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14 The analysis looked to evaluate the attractiveness of new firm generation. Natural gas-fired combined-cycle and simple-cycle are the main expected development options. Economic analysis indicated that combined-cycle plants exhibited higher returns and therefore became the generation type of choice. Cogeneration was also included in the assessment, but was added based on oilsands development expectations.

15 Average natural gas prices for 2016-2030 for the base case is forecast at $3.77/GJ and for the high natural gas price case is forecast at $5.55/GJ.

16 An extreme weather event is considered to be a period of sustained hot or cold temperatures that extraordinarily increases demand for electricity and decreases the reliability of generation supply.

17 Examples include:
- An extended outage of a major coal generator: From January 2011 to July 2013 supply from 560 MW of coal capacity at the Sundance 1 & 2 plants was unavailable while boiler issues were repaired. Also in 2013, for over nine months the 395 MW Keephills 1 plant was offline for force majeure generator repairs.
- An extreme weather event: During the summers of 2012 and 2013, hot weather days on July 9, 2012 and July 2, 2013 increased demand to record levels while limiting output from gas-fired generation. This combination limited the ability to manage further system disturbances which occurred, requiring small amounts of demand to be shed around the province.
- A major gas generation project (e.g. 450 MW) development delay: Large generation projects are complex infrastructure developments prone to delays. The most recent gas-fired generation project developed in Alberta, the Shepard Energy Center, was developed on the schedule set out at the start of the construction. Prior to that, the Keephills 3 coal-fired generation facility was commissioned six months behind schedule.
3.1.2 Findings from quantitative market analysis

Figure 2 below shows the forecast reserve margins resulting from the AESO’s modelling of the base case and two sensitivities, as well as historical reserve margins for context. The reserve margins achieved historically (2004–2015) have proven to be adequate. The results indicate that the market will not support generation development at historic reserve levels in the baseline, High Gas or High Renewables views. The reason for this outcome is that price signals do not attract sufficient new generation development.\(^{18}\)

**FIGURE 2: Historical and forecast reserve margin**

![Figure 2: Historical and forecast reserve margin](image)

The AESO determined that the lower level of reserve margins forecast through modelling creates too much risk of electricity shortages (i.e. situations where demand exceeds supply and some demand must be reduced by interrupting electricity delivery to customers to maintain overall system stability). At the forecast reserve margin levels, there is a risk of significantly large outage events on rare occasions. In addition, modelling indicated an increased reliance on imports above historical levels and increased reliance on generator ramping capability\(^{19}\) to balance the market. Reliability would be further jeopardized should these assumptions not hold.

Even though the forecast reserve margin is lower than historical levels, average prices are expected to stay at levels consistent with historical ranges (notwithstanding the recent very low prices in 2015 and 2016).\(^{20}\) Long-term prices are expected to trend toward the cost of new firm generation, expected to be a combined-cycle natural gas unit. Market equilibrium is established here as less investment (resulting in a lower reserve margin) will increase prices and associated profits triggering additional investment and returning to equilibrium, while more investment (resulting in a higher reserve margin) will depress prices and make all investments unprofitable.

While average prices are consistent with historical levels, future hourly prices are expected to have increased variability. While fewer overall high-priced hours are expected, their occurrence will be driven more and more by whether or not renewable generation is producing. This will create greater

\(^{18}\) It should be noted that energy production from renewables and interties are not reflected in reserve margin numbers as they are not firm capacity available to meet system demand at all times, especially in the peak periods of summer heat and winter cold.

\(^{19}\) “Ramping” is the ability of a generating facility to start and stop on command, while the “ramp rate” is the rate at which a power plant can increase or decrease output. This type of flexibility in generating units to ramp up or down quickly is paramount in managing variability in electric loads and grid stability.

\(^{20}\) Prices in 2015 and 2016 have decreased significantly relative to previous years due to a large increase in supply resulting from commissioning of the 860 MW Shepard combined-cycle gas generating station and weaker demand conditions.
uncertainty for investors and consumers. For investors, the volatility in prices makes it more difficult to determine whether they will be able to recoup their investment, as well as manage their cash flows and financial requirements.

The energy-only market will not be able to create enough revenue to cover fixed costs of new non-renewable generation, so investment in firm generation is unlikely to occur. The modelling indicates that a significant portion of revenues for non-renewable generation will be dependent on bidding behaviour and power system scarcity events, leading to higher prices. Reliance on these factors creates unmanageable risk for investors.

The AESO’s quantitative modelling results indicate that the reserve margin achieved by the energy-only market in the future would fall below an acceptable level of reliability.

### 3.2 QUALITATIVE MARKET ANALYSIS

To supplement the AESO’s quantitative analysis and develop a broader understanding of considerations related to investing in new non-renewable electricity generation facilities, the AESO engaged Morrison Park Advisors (MPA), an independent banking advisory firm, to gather the views of generation developers and lenders, as well as JCRA, an independent financial risk management consultancy, for an expert opinion. These qualitative efforts were focused on the following questions:

| What is the willingness and financial capacity of investors to build new generation in Alberta? |
| Is there enough revenue certainty or upside potential to make Alberta an attractive market to invest in? |

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21 In 2012, MPA completed a report for the Market Surveillance Administrator of Alberta’s *State of the Market* examination regarding the perceptions of investors and potential investors related to the Alberta electricity generation market. The work commissioned by the AESO examines similar questions and comparisons can be made between these reports.

22 The full MPA report and JCRA opinion can be found in Appendix A.
3.0 Energy-only market sustainability analysis

3.2.1 Themes

The following key themes emerged from MPA's interviews:

- Too much uncertainty

Participants were unanimous in saying that at present, investment decisions cannot be made in Alberta owing to the significant government policy and market uncertainty that currently affects the sector. This uncertainty makes forecasting future power system characteristics impossible in the near term; there are simply too many variables to manage and make assumptions about. With such a wide range of potential outcomes, making investment decisions in the current environment is viewed as having an unacceptable level of risk.

- Attractiveness of Alberta's energy-only market declining

Many participants indicated that the risks associated with investment in an energy-only market are too high and do not align with their investment philosophy or their ability to gain financial backing for generation developments.23 MPA's findings indicated that large pools of investment capital are available for low-risk investments with revenue certainty, but significantly less is available for riskier investments such as those typical in an energy-only market. The preference for revenue certainty and lack of support for energy-only markets was further validated by JCRA. JCRA emphasized that this is not “just another [capital market] cycle” but rather that there have been fundamental shifts in global capital markets away from the riskier investments characterized by energy-only markets to investments with more predictable earnings. JCRA suggested that developers, investors and lenders will consider revenue certainty far more in the future than they did in the past.

- Attracting new investment

MPA's findings stated that if Alberta wishes to increase the number and variety of potential investors interested in developing new non-renewable electricity facilities in the province, the government may wish to consider an alternate electricity structure which provides more revenue certainty. Interview participants commented on two types of changes: development of a capacity market or the offering of long-term contracts.

The addition of a capacity market will significantly increase the number of potential investors and level of interest compared to the current structure, but the details around a capacity market matter. Size, liquidity, maturity of the capacity market, and the treatment of existing and new generators, will all factor into investment decisions.

Participants also made it clear that if Alberta were to offer contracts for the construction of new facilities, they would participate in procurement processes. This structure would likely result in the broadest possible participation by developers. However, MPA also warns that adopting a contracting structure represents a significant transfer of risk from generators to consumers, and would be a very significant departure for Alberta from its current market structure and risk allocation.

More generally, MPA cautioned that implementing any new structure for electricity in Alberta would add policy uncertainty in the near term and would likely delay investment until the design is definitively resolved. Because of this, MPA stressed the importance of making any transition to a different structure quickly and efficiently.

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23 See MPA report “Investor Perspectives” p. 19 in Appendix A. Some respondents expressed willingness to invest in the current market structure in the future provided that policy uncertainty is decisively settled. Critically, however, the number of these participants supportive of current market arrangements has declined since 2012, when a similar report was prepared by MPA, indicating a loss of confidence with the energy-only market structure through time.
Cost of capital impacts

MPA's analysis indicated that a wider range of financing options which are not typically available in an energy-only market are available to project developers and balance sheet owners in capacity markets. An analysis JCRA performed on two power plant financing deals that recently occurred, one in a capacity market structure and another in an energy-only structure, concluded “the capital structure of the capacity market will be less costly due to lower debt spread and higher debt capacity.” Overall, the MPA and JCRA analysis indicated that relative to an energy-only structure, the cost of capital for investors would be lower under a capacity market structure and lowest under a fully contracted model due to the relative shifting of investment risk onto consumers.

3.3 SUMMARY OF QUANTITATIVE AND QUALITATIVE MARKET ANALYSIS

Increasing the amount of intermittent renewable resources and retiring coal-fired generating units will require additional firm dispatchable generation. Alberta’s electricity market will require a significant amount of investment in this type of generation between now and 2030.

Increasing amounts of renewables in the system will lead to lower prices in more hours going forward, thereby increasing the risk to non-renewable generators that they will earn insufficient revenues to cover their costs and earn a return on capital. Prices in the future are expected to be more volatile, which provides little or no financial certainty of the future revenues that will be required by investors to build new capacity. Revenue certainty has become increasingly important, with many capital providers avoiding energy-only markets. Future investment in energy-only markets is in doubt.

The analysis showed that status quo (i.e. no change to current market rules, products or design) will be unable to attract a sufficient amount of investment in firm, dispatchable generation to ensure an appropriate level of supply adequacy. This problem may be mitigated if power prices are allowed to rise to levels high enough to cover long-run revenue requirements when wind and other intermittent sources are unavailable. To test this, the AESO examined possible enhancements to the energy-only market.

3.4 EVALUATING MODIFICATIONS TO THE CURRENT ENERGY-ONLY MARKET

Increasing the price cap would be the most direct solution to increase generator revenue in the current energy-only market. Raising the price cap has also been used as a strategy in other jurisdictions. Through modelling analysis, the AESO identified that the price cap needs to be increased from $1,000/MWh to approximately $5,000/MWh to ensure a reserve margin that can sufficiently reduce the risk of load shed events. This modelling is for revenue and investment calculations and does not consider whether this level of price cap and associated price levels would be acceptable to loads or generation developers.

Although enhancements to the energy-only market may theoretically achieve a reliable reserve margin, the risks associated with its implementation are very high. In particular, higher or more frequent scarcity prices associated with an increased price cap are necessary to attract new investment to Alberta. However, as shown in Table 3 this will lead to an increased level and volatility of pool price, potentially leading to public pressure to intervene in the market. Even if volatile and higher prices were publicly acceptable, the AESO’s qualitative analysis indicated that they may not be attractive to investors because the risk is still too high (i.e. there is no revenue certainty and no guarantee that investments will be economic; further, investors may still be skeptical that government support of the market will persist).

24 Enhancements to the energy-only market may be attractive given the past successes of the energy-only market structure, stakeholders’ familiarity with it and potentially relatively minor cost of changes.

25 A price cap is the highest price that electricity can trade at in the market.

26 For example, the price cap in ERCOT (Texas) was raised to USD $9,000/MWh in 2014. The price cap in Australia’s National Electricity Market is adjusted annually, with the most recent increase raising it to AUD $14,000/MWh.
TABLE 3: The highest volatility in monthly pool price is observed with $5,000 price cap sensitivity

<table>
<thead>
<tr>
<th>Prices ($/MWh)</th>
<th>2000-2015</th>
<th>Sensitivities 2016-2030</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Historical</td>
<td>Baseline</td>
</tr>
<tr>
<td>Maximum</td>
<td>253.28</td>
<td>211.22</td>
</tr>
<tr>
<td>Minimum</td>
<td>13.63</td>
<td>18.53</td>
</tr>
</tbody>
</table>

Energy price is one of several components of a consumer’s electricity costs. Other charges include administration and delivery charges which are determined outside the energy market.

3.5 CONCLUSION: A MARKET CHANGE IS NEEDED

Quantitative modelling indicates that under anticipated future market conditions, the AESO expects there to be insufficient investment in new firm generation due to reduced revenues available in the energy market. Qualitative analysis indicated that there is reduced interest in investments in energy-only markets due to a lack of revenue certainty. Limited sources of capital are available compared to alternative structures. Taken as a whole, these indicate significant challenges for the energy-only market going forward.

While enhancements to the energy-only market may theoretically address the problem of insufficient revenue, and could lead to a high enough reserve margin, this is not viewed as a practical or viable solution due to high risks of market interference, volatile prices for consumers, and failure to address fundamental concerns of generation investors regarding revenue certainty.

The AESO concluded that neither the current nor an enhanced energy-only market will be able to ensure reliability while achieving CLP objectives. Therefore, AESO broadened its analysis to assess the potential of alternative structures to meet these objectives.

> …MPA stressed the importance of making any transition to a different structure quickly and efficiently.

27 See Footnote regarding the amount of generation used in the AESO’s modelling. It is reasonable to assume that the REP target of 5,000 MW of new renewable generation announced on September 14, 2016 would reduce revenues even further.
4.0 Assessment of different structures

4.1 GENERAL CONSIDERATIONS
An electricity structure is the means by which electricity is generated, delivered and paid for by consumers. Structures are implemented via an interconnected collection of policies, legislation and regulation. Changes to one part can impact the functioning of the whole. Consideration must be made to ensure consistency between pieces to achieve objectives. Electricity structures determine:
- How energy prices are set and their variability
- Who bears costs and the mechanisms for how costs are managed
- How risk and cost are allocated between ratepayers, taxpayers and generation developers
- The degree of flexibility and incentive for innovation
- The degree of certainty in timing and amount of new supply additions

4.2 RANGE OF ELECTRICITY INDUSTRY STRUCTURES
While there is some degree of overlap between structures, they can generally be delineated into the following four high-level structures which are found throughout the world:

<table>
<thead>
<tr>
<th>Two market-based structures</th>
<th>Two non-market structures</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Energy-only market (EOM)</td>
<td>• Long-term contract (LTC)</td>
</tr>
<tr>
<td>• Capacity market (CAP)</td>
<td>• Cost of service regulation (COS)</td>
</tr>
</tbody>
</table>
Energy-only market structure (EOM)\(^{28}\)

An energy-only market is a market-based structure where generation capacity, type, location, and timing are determined by private sector investors based on a single energy price signal. There is no direction or administrative planning for electrical supply by a central agency. Generating facilities are built by investors who primarily rely on selling electricity in a centralized market where they compete with other generators to earn revenue to cover costs and earn a return on invested capital. This structure is found in Alberta, Texas (ERCOT), Australia, Germany, and Nordic and Baltic countries (NORDPOOL).

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple structure</td>
<td>High degree of revenue uncertainty for generators and cost uncertainty for loads</td>
</tr>
<tr>
<td>Fosters innovation and supports low-cost outcomes in electricity generation</td>
<td>Lower certainty of reliability – investment in supply strictly determined by market forces</td>
</tr>
<tr>
<td>Investment risk fully borne by private investors</td>
<td>Volatility of wholesale spot market prices attracts public attention and administrative intervention</td>
</tr>
</tbody>
</table>

Capacity market structure (CAP)

A capacity market is a market-based structure with two separate markets: a market for the provision of capacity, or the ability to produce energy, and a market for the actual production of energy. As such, generators can receive two main revenue streams: capacity payments and energy payments. The volume of capacity purchased is determined by a central authority and is set to ensure reliability is achieved. Capacity is procured in advance of when it will be supplied. Examples of capacity market structures can be found in PJM,\(^{29}\) New England,\(^{30}\) New York, Russia and the UK.

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Provides some revenue certainty for generators while preserving key market characteristics such as incentives to drive innovation, cost discipline and investors bearing investment risk</td>
<td>Increased complexity</td>
</tr>
<tr>
<td>Ensures reliability</td>
<td>Forecasting error may lead to procuring more capacity than required resulting in higher costs than necessary for consumers for short periods of time (3-5 years)</td>
</tr>
<tr>
<td>Reduces month-to-month price volatility</td>
<td>More difficult for consumers to individually manage their own costs</td>
</tr>
<tr>
<td>Allows government to introduce some policy objectives while maintaining a market-based structure</td>
<td></td>
</tr>
</tbody>
</table>

\(^{28}\) An energy-only market structure was included in the following assessment for comparison purposes. Conclusions presented in this section apply to this structure generally, regardless of whether an increased price cap is implemented.

\(^{29}\) PJM Interconnection is a large system operator in the eastern United States.

\(^{30}\) New England states include Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
**Long-term contract structure (LTC)**

A long-term contract structure is a non-market and centrally planned structure where electricity generators enter into multi-year contracts (typically 20-30 years) which cover their costs and provide a profit. The type, amount and location of generation to be contracted is determined as part of an overall central plan. Contracts are awarded through a tendering process. Ontario currently has this structure.

**Advantages**
- Allows government to directly introduce other policy objectives into the electricity sector
- Ensures supply adequacy
- Provides investors with a stable revenue stream, lowering cost of capital

**Disadvantages**
- High risk of locking into high-cost or obsolete technologies
- Cost of poor decisions borne by consumers or the public
- Limited incentives for innovation (loss of opportunity to benefit from the creativity of multiple participants competing with each other)
- Higher long-term costs for consumers
- Costly and lengthy transition to move from the current structure
- Exposed to over-procurement risk for long periods of time (20-plus years)

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**Cost of service regulation structure (COS)**

The cost of service regulation structure is a non-market, centrally planned model where type, size and location of generation are determined as part of an overall plan. Investments are subject to cost of service oversight by a regulator or government, with approved rates of return on investment. British Columbia, Manitoba and Saskatchewan have these structures.\(^\text{31}\)

**Advantages**
- Direct administrative oversight of all cost components
- Ensures supply adequacy
- Allows government to directly introduce other policy objectives into the electricity sector

**Disadvantages**
- High risk of locking into high-cost or obsolete technologies
- Limited incentives for innovation (loss of opportunity to benefit from the creativity of multiple participants competing with each other)
- Incentive to “gold plate” solutions and favour investments that increase rate base
- Higher long-term costs for consumers
- All investment risks are shifted to consumers or public
- Increased costs of regulatory oversight
- Costly and lengthy transition to move from the current structure
- Risk of over-procurement costs (e.g. building new assets)

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\(^\text{31}\) Due to their historic structure, British Columbia, Saskatchewan and Manitoba have crown corporations. Prior to deregulation, Alberta’s form of cost of service regulation involved three vertically integrated utilities. Analysis presented is general and applicable to either form of cost of service regulation.
4.3 GOVERNMENT OF ALBERTA’S DESIRED OUTCOMES

In order to critically assess which of the potential structures would be most suitable for Alberta, it was necessary to have a clear set of criteria against which all of the structures could be assessed. Working with the Alberta Department of Energy, the AESO developed the following list of outcomes and a range of considerations that it believes reflect the objectives of the government for an electricity system that will serve the interests of Albertans.

### Reliable and resilient system

- **Expected unserved energy:** “The lights stay on” and there is sufficient supply adequacy. An acceptable level of firm (dispatchable) generation capacity is added.
- **Variability of reserve margin:** The consistency of the level of supply adequacy, or risk of a load shed event, through time.
- **Compatibility with increased interties:** Market structure resilient to increases in intertie capacity and increased connection to existing or new jurisdictions.
- **Reliable and efficient integration of renewable generation and new technologies:** Reliable operation of the electricity grid is maintained with greater portions of energy consumed coming from low-carbon or renewable sources. Operation of the system is cost effective and economically efficient.
- **Compatibility with managing coal phase-out:** Coal emissions phase-out can be achieved reliably and cost effectively.

### Environmental performance

- **Compatibility with REP objectives and implementation:** Ability of market structure to continue to deliver other key objectives (reliability, reasonable costs) while successfully implementing REP program objectives and target of 5,000 MW of utility-scale generation.
- **Resiliency of market to environmental policy:** Ability of market structure to continue to deliver other key objectives (reliability, reasonable costs) under changing, potentially more stringent environmental policies.
- **Compatibility with increased cogeneration, energy efficiency, micro and distributed generation:** Ability of market structure to continue to deliver other key objectives (reliability, reasonable costs) while potentially supporting increased volumes of cogeneration, energy efficiency programs, and micro and distributed generation volumes.
- **Compatibility with carbon pricing:** Ability of market structure to continue to deliver other key objectives while not counteracting intended price signal from carbon pricing.
- **Compatibility with future expansion of renewable energy and new technology:** Ability of market structure to continue to deliver other key objectives (reliability, reasonable costs) under increased renewable energy targets or the incorporation of new technology supporting low-carbon and low-emission electricity production.
Reasonable cost to consumers

- Reasonable cost of delivered energy: Delivered costs of energy to a variety of load types (industrial, commercial, residential) appropriately compensate providers for cost of services provided and reasonable profit, while keeping overall cost levels and rate of increase in line with other jurisdictions and general inflation.

- Stability of price: Volatile or unpredictable energy prices can significantly increase public attention to the cost of electricity. This may not be acceptable to government or the public. Volatile costs or revenue streams may inhibit business activity, cause negative impacts to various stakeholders or demographic groups and not be attractive to generation investors even if they are sufficient to provide a return.

- Fair, efficient and openly competitive: Fair, efficient and openly competitive market operation is maintained.

- Ability to hedge or manage price or cost exposure: There are mechanisms in place for electricity consumers to take individual action to control their costs, either financially or physically.

- Compatible with changes to Regulated Rate Option (RRO): Options to “smooth” RRO charges for residential consumers can be implemented while maintaining the overall market structure.

- Effective and appropriate regulatory oversight: Regulatory oversight can be effectively employed to manage costs where appropriate. Such oversight is efficient in cost, time and certainty. Regulatory oversight does not interfere with effective functioning of market mechanisms but rather enhances them.

- Impact on transmission costs: Market is compatible with measures to maintain reasonable transmission costs.

- Does not fundamentally alter the market: Investment risks should primarily fall on generators; private investment should be encouraged.

Economic development including job creation

- Ability to incorporate “social” drivers: Electricity system or industry can be used to achieve other social objectives such as support for particular demographics, locations or industrial policy.

- Impact on trade-exposed or key industries: Impact to industries which provide high levels of employment, large tax revenues, compete with external jurisdictions or are strategic in some other way.

- Enables economic growth: Supportive of overall industrial policy to provide a stable, diversified and growing economy.

Orderly transition

- Minimize transition impact: High confidence that the intended end-state structure will be achieved while disruption to industry, magnitude of change and transition costs are minimized.
4.4 DETAILED ASSESSMENT RESULTS – KEY POLICY OUTCOMES

This section provides a detailed assessment of how well each electricity structure achieves the desired policy outcomes. The results of that assessment are summarized in the following table. Orderly transition issues will be examined further in Section 4.5.

TABLE 4: Alignment to policy outcomes

<table>
<thead>
<tr>
<th>Policy outcomes</th>
<th>Energy-only market (EOM)</th>
<th>Capacity market (CAP)</th>
<th>Long-term contract (LTC)</th>
<th>Cost of service regulation (COS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliable and resilient system</td>
<td>⬤</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Improved environmental performance</td>
<td>⬤</td>
<td>✓</td>
<td>✓</td>
<td>⬤</td>
</tr>
<tr>
<td>Reasonable cost to electricity customers</td>
<td>⬤</td>
<td>✓</td>
<td>⬤</td>
<td>⬤</td>
</tr>
<tr>
<td>Economic development and job creation</td>
<td>✓</td>
<td>✓</td>
<td>⬤</td>
<td>⬤</td>
</tr>
</tbody>
</table>

General symbols: ⬤ Generally negative  ✓ Generally positive  ⬤ Generally neutral

Based on this assessment, a capacity market provides the best structure to achieve key government objectives. Detailed rationale for the conclusions summarized in the table are provided in this section.
4.4.1 Energy-only market structure (EOM)

- **Desired outcome: reliable and resilient system**
  - An EOM structure is weak in achieving the desired outcome of a reliable and resilient system. The AESO's qualitative analysis of the EOM indicated that capital markets and most generation developers express little interest in investing in markets where there is too much revenue uncertainty. While increasing the price cap in the current energy-only market could theoretically provide a better opportunity for investors to recoup investments, a high degree of revenue risks would remain. This uncertainty of investment interest makes it unlikely that sufficient generation will be built to ensure future reliability. The volatility and occasional high price levels required to make this structure provide revenue sufficiency to generators may not be acceptable to consumers.

- **Desired outcome: environmental performance**
  - The energy-only market’s alignment to the desired outcome of environmental performance is generally negative. The EOM structure is the least complex but it is also the least flexible in dealing with government policy adjustments and the ability to continue to effectively function with significant “out-of-market” revenue streams. The Renewable Electricity Program (REP) is an out-of-market revenue stream for renewable energy investors which incents that type of generation, but impacts the overall clearing price of the market.

  An energy-only market has a single revenue stream for all energy produced and that single price should reflect the value of all energy traded. In an energy-only market, intermittent renewable energy resources cause variability in the wholesale price and lower prices in many hours. The AESO’s quantitative analysis indicated that volumes of renewables proposed under the CLP will challenge the ability of new non-renewable generators to earn sufficient revenue in an energy-only market. Further, potential future increases in renewable generation targets will be difficult to incorporate into this structure while retaining supply adequacy.

- **Desired outcome: reasonable cost to consumers**
  - Provided the risks are properly mitigated, EOM is an effective structure for achieving the desired outcome of reasonable cost to consumers. There are three key features of an EOM structure that help to generally achieve reasonable costs to consumers in the long run:
    - This structure relies on economic dispatch and competition to ensure the lowest cost generators are dispatched to provide electricity, and the most economically efficient price is offered to consumers.
    - The risk of investment in new supply falls on the generation investor and competition provides a strong incentive for innovation. This structure does not lock the consumer into a generation technology choice that may over time become less competitive and more costly than an alternative.
Electricity consumers are able to hedge their full energy cost exposure in the market through forward financial transactions. Even retail consumers are able to manage price risks by signing contracts with retailers in order to obtain price stability. EOM will also continue to let competition discipline participants and allow regulatory oversight to focus on participant behaviors to ensure that competition leads to reasonable cost to consumers, as opposed to using a lengthy regulatory process to determine the cost of consuming and the price of producing electricity.

The caveat is that price hedges cost money and while efficient, this structure exposes unhedged consumers directly to price swings whenever there is a disruption such as a forced generator outage requiring more expensive replacement energy. The AESO’s modelling results predict much more volatility in prices for electricity in the future under this structure. Volatility for consumers exposed to $5,000/MWh prices, even for short periods of time, may be unacceptable. There is a risk of increased political pressure to manage the unpredictable prices in the market and risk to add reliability products to manage reliability. If this happens it will undermine the necessary price signals in the market, and thereby undermine investor confidence in the market’s stability, hindering generation investment and ultimately resulting in supply shortages and power outages.

Desired outcome: economic development and job creation
- The alignment of the energy-only market to the desired outcome of economic development and job creation is generally positive.

A well-functioning EOM should provide the most competitive electricity prices, which will positively influence Alberta’s competitiveness, supporting economic development and job creation. As market prices are likely to be correlated with business cycles, it will provide a natural hedge on costs to customers with electricity prices decreasing as the economy cools and increasing during strong economic conditions. EOM promotes innovation and cost-minimization, as well as allowing flexibility to respond to a dynamic economic environment.

However, many social objectives cannot effectively be incorporated into the energy price and would require out-of-market actions to achieve them. Out-of-market actions interfere with market signals and bring inefficiencies to EOM. These inefficiencies present a higher reliability risk because generation investors solely rely on an efficient price signal to make build decisions. An inefficient structure would further increase the risk of high price excursions and power outages, compromising economic growth.
4.4.2 Capacity market structure (CAP)

- **Desired outcome: reliable and resilient system**
  
  CAP is an effective structure to achieve the desired outcome of a reliable and resilient system.

In a capacity market structure, a centralized forecast of supply requirements is created to ensure adequacy is achieved and capacity is procured to meet this target. A clear obligation is placed on capacity suppliers to deliver the amount of generation they contracted for when it is needed. As a result, CAP will ensure supply adequacy.

A capacity market is forward-based and provides a degree of revenue certainty to investors before the capacity is committed or built. As indicated through the analysis by Morrison Park Advisors, capital markets have expressed interest in investing in these markets, stating that a capacity market is definitely superior to the energy-only structure from a capital availability and cost of capital perspective. As such, sufficient generation development is expected in a capacity market. In addition, experience from existing capacity markets indicates that they incent additional sources of cost-effective supply such as demand response and uprates or refurbishments of existing generators.\(^{32}\)

- **Desired outcome: environmental performance**
  
  Capacity market’s alignment to the desired outcome of environmental performance is generally positive.

Capacity markets can enable improved environmental performance by ensuring a supply of reliable back-up generation while increased amounts of intermittent renewable generation are added to the system, either internally or via imports from other jurisdictions.

A capacity market solves the energy market price impact problem created by renewable intermittent energy resources by giving value to capacity. This value, in the form of a capacity contract, helps offset the otherwise insufficient prices found in the energy market caused by increased levels of variable generation depressing energy prices. Even in a policy environment with increasing renewable targets, these contracts provide additional revenue certainty.

A capacity market allows for efficient coordination of the coal phase-out and renewable additions through management of all capacity products. There is potential for some renewable support to be eventually transitioned to a capacity market by providing some capacity credit for renewables. Additionally, some technologies such as hydro, and emerging technologies such as storage and price-responsive load, might be able to participate in a capacity market, thus providing reliability certainty while allowing market participation and achieving environmental performance objectives.

A caveat is that while integration of the Renewable Electricity Program into a capacity market would continue to see the REP targets achieved, the REP payment mechanism will likely need to continue to provide a high degree of revenue support outside of the capacity market. A portion of the renewable support may be transitioned into a capacity market by carving out volumes with capacity value. See Section 4.5 for more detail.

For the coal phase-out, a capacity market could smoothly reduce the volume of coal that can depart from service in any given period, which helps to address retirement concerns. See Section 4.5 for more detail.

\(^{32}\) See for example PJM’s *2019/2020 RPM Base Residual Auction Results*, p. 3.
Desired outcome: reasonable cost to consumers

Capacity market’s alignment to the desired outcome of reasonable cost to consumers is generally positive.

CAP is a generally superior structure to EOM in achieving the desired outcome of reasonable cost to consumers. Like EOM, CAP relies on competitive and transparent pricing in the capacity and energy market, rather than regulatory processes, to ensure the cost of electricity delivered to consumers is reasonable and the compensation to suppliers is market-driven and competitive. Market opportunities preserve the incentive for participants to develop innovative and cost-reducing solutions.

Compared with the EOM structure, CAP reduces the price volatility faced by consumers and the investment risks faced by investors. Although reduced compared to an EOM structure, CAP does not completely remove a market participant’s ability to hedge their electricity costs. Energy costs may still be hedged against high prices similar to the EOM structure. In addition, since CAP is a market-based structure, it can be designed to provide the flexibility to transact capacity obligations and adjust for new market and operational conditions.

CAP provides better price stability than an EOM. Prices for energy produced are closer to marginal costs, reducing political and investment risks. A downside of the CAP structure compared to EOM is that higher than necessary volumes of capacity may be purchased due to forecast error. This can be mitigated somewhat by holding rebalancing auctions closer to the contract start period and limiting the length of the contract period.

Capacity markets are implemented in several ISO-run wholesale electricity markets and have demonstrated success in incenting investments to ensure reliability at reasonable costs. For example, the three-year forward capacity markets in both PJM and ISONE have been able to attract sufficient new investments in generating plants, as well as demand response, energy efficiency and import resources every year. In addition, a study conducted by Ontario’s Independent Electric System Operator (IESO) shows that the cost of securing reliability is significantly lower in the US capacity markets than through the Ontario government’s long-term contracting.

Desired outcome: economic development and job creation

The alignment of the capacity market structure to the desired outcome of economic development and job creation is generally positive.

Overall, CAP will promote competition and efficient outcomes and ensure greater certainty of reliability. CAP provides enough flexibility to respond to changing economic environments and makes it easier than EOM to target specific social objectives by creating “carve-outs” or specific criteria in the capacity market. However, CAP may be a less-preferred structure for some industrial consumers, as it can result in overall cost increases due to inability to hedge and to avoid capacity payment surcharges if they are not given the ability to manage it themselves. If industrial consumers are allowed to manage their own obligation, CAP will add a new layer of complexity for those customers. This design decision would need to be resolved through stakeholder consultation.

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33 See for example The Brattle Group’s Response to U.S. Senators’ Capacity Market Questions
4.4.3 Long-term contract structure (LTC)

**Desired outcome: reliable and resilient system**

LTC is an effective structure to achieve the desired outcome of a reliable and resilient system. In a long-term contracting structure, a long-term forecast of supply requirements based on expected demand and other parameters is used to drive the volume of new supply required. As long as demand growth is not underestimated, LTC provides satisfactory levels of supply adequacy as investment is attracted to long-term contracts; however, the structure introduces the risk of poor centralized decision-making and generation planning, saddling consumers with unnecessary costs through time.

**Desired outcome: environmental performance**

LTC is an effective structure to achieve the desired outcome of environmental performance. LTC accommodates environmental performance because it provides certainty to attract renewable generation through the REP program, plus enough non-renewable generation to ensure reliability no matter what environmental performance requirement is implemented. Renewable volume targets and technology types can be revised through time and the remaining long-term plan adjusted to accommodate these. Because of the long-term nature of the contracts, this structure would allow for the development of high capital cost, long-life assets such as hydro, as well as the introduction of emerging but “uneconomic” advanced technologies. The desired supply mix can be explicitly achieved via long-term contracts and there is higher flexibility for implementing a wide range of policies while ensuring reliability.

A centrally determined supply mix might not result in the lowest cost solution for reducing carbon as there are no incentives for lower-cost options to be developed. Further, this structure might prevent carbon-intensive and inflexible power plants from leaving the market because long-term contracts “lock in” the asset and mute carbon price signals. There is a high risk of long-term contracts developing a mismatch of generator capabilities and system need as a result of increased amounts of cogeneration, energy efficiency, micro and distributed generation. There is a potential for higher costs for consumers if the use of cogeneration and efficient microgeneration is not included in the planning process from the beginning or if assumptions regarding potential from these resources are incorrect. In addition, energy efficiency and load reductions over time can result in increasing power prices to remaining load as contract costs must be recovered from a smaller customer base.

**Desired outcome: reasonable cost to consumers**

LTC is not an effective structure for achieving the desired outcome of reasonable cost to consumers. Although LTC provides price stability to consumers as well as revenue stability and access to lower-cost capital for investors, it is not as efficient as a market-based model like CAP over the long term. Competitive forces are reduced and innovative ideas from multiple parties have limited ability to be included. The outcome to consumers is dependent upon a single entity (the central planner) having complete knowledge of future market conditions, competing technologies, cost drivers and consumer requirements. LTC is typically locked in for a long period of time (e.g. 20 years) based

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35 Further discussion comparing the cost advantages of a capacity structure with long-term contract and cost of service structures is provided in Appendix B.
on information known at the time of contracting and there is no mechanism to make adjustments efficiently as new information becomes available. Therefore, the LTC structure reduces the ability of taking advantage of cost reduction caused by technology advancement and causes consumers to pay higher prices than would otherwise be paid. The incentive to develop innovative solutions to capture market opportunities is minimized.

Because of a lack of clear price signal, there is a tendency to take sunk costs into account when making decisions, and to significantly underestimate the risks associated with high capital cost investments. The risks of these investments are borne by consumers or the general public and the regulatory reactions to fix perceived problems tend to be overcompensated as well.

Another finding observed from other jurisdictions is that the centralized resource allocation is often too inflexible and too slow to respond to external stresses and changing market conditions. Jurisdictions (such as Ontario) which have followed this model have started to recognize the long-term costs of this structure and are starting to consider more market-based alternatives.

**Desired outcome: economic development and job creation**

The alignment of the long-term contract structure to the desired outcome of economic development and job creation is generally neutral.

LTC increases the risk that costs will be above market, potentially for significant periods of time. Higher costs take away competitive advantage. There would also be little incentive for generators to innovate and to search for more efficient solutions because of the long-term contract’s limited flexibility to adjust to changing economic conditions.

Social objectives can be incorporated directly by setting specific requirements during the tendering process (e.g. Indigenous Peoples’ involvement, specific location of power plants for jobs creation, etc.). However, this may be unfair and negatively impact broader economic development as the cost of achieving broad societal objectives is then tied to the consumption of electricity and concentrated on electricity ratepayers rather than spread across society as a whole via taxation.

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4.4.4 Cost of service regulation structure (COS)

**Desired outcome: reliable and resilient system**

COS is an effective structure to achieve the desired outcome of a reliable and resilient system. Like LTC, COS also requires centralized forecasting of system resource adequacy requirements and an obligation of ensuring enough capacity is available when needed. New generation capacity can be built if required but the regulatory approval process may introduce additional risk, particularly with respect to the time it may take to get new projects approved.

COS provides satisfactory levels of supply adequacy but as with the LTC structure introduces the risk of poor administrative decision-making and generation planning, potentially saddling consumers with unnecessary costs through time.

**Desired outcome: environmental performance**

The alignment of COS to the desired outcome of environmental performance is generally positive. Under this structure any environmental goal can be implemented through direction and the regulatory process. Reliability can be ensured as renewable volumes increase. In addition, this structure provides the ability to support long-lived and high capital cost assets such as hydro developments and large interties. However, no market signals exist and regulators decide the exit and entrance of old and new technologies. There is a high risk that ratepayers would be locked in to expensive long-term solutions as new technologies evolve. As with a long-term contract structure, there is a high risk of COS developing a mismatch of generator capabilities and needs as a result of increased amounts of cogeneration, energy efficiency, micro and distributed generation. This will lead to higher consumer costs in the long term.

**Desired outcome: reasonable cost to consumers**

The alignment of COS to the desired outcome of reasonable cost to consumers is generally negative. COS is similar to LTC when evaluating cost to consumers. COS shifts the investment risks entirely to consumers or the general public by providing investors with regulated, guaranteed returns and cost recovery. COS has similar benefits and shortcomings as the LTC structure discussed above, but relies on the regulator to determine appropriate rates of return on investment for capital instead of relying on a tendering process. While a public regulatory body aims to ensure reasonable costs, the incentives in this model are to spend as much as possible because generators earn profit on capital deployed. When prices and profit margins are controlled by regulation and based on incurred costs, traditional utilities are rewarded for charging more, not less, and developing a large rate base.

A COS model provides little ability for customers to manage their costs as there is no competitive supplier market and costs are driven by regulatory decisions. The lack of market competition eliminates incentives for innovation and low-cost solutions.
Desired outcome: economic development and job creation

The alignment of COS to the desired outcome of economic development and job creation is generally neutral.

Regulated rates are often above competitive market prices in the long term, taking away a region’s competitive advantage and therefore economic development and jobs. A COS structure is inflexible and slow to respond to a changing business environment.\(^{38}\) The time it takes to propose, approve and then implement a change to rates is typically a two-to-three year cycle, and is not at all related to what is going on in the rest of the economy. The result may be “rate lag” where the burden of increases in electricity system costs are added when businesses are least able to bear them due to changed economic conditions. There are also no alternate service providers available, which removes consumers’ choice to search for more competitive prices or better product offerings.

COS can achieve nearly any social objective through intervention. Additionally, COS might be able to offer preferential or lower rates for businesses to provide a competitive advantage. However, the cost of achieving these objectives, similar to LTC, is more likely to be borne by ratepayers than taxpayers, which may negatively influence Alberta’s competitive advantage. Social objectives would need to be incorporated into regulatory decisions, making it a process and objective of a public utilities commission.

The technology “lock in” problem described in LTC is also found in the COS structure. There is less incentive to keep costs down because there may be other policy objectives at play. There are many examples in the media of cost overruns typical of this structure.\(^{39}\) Project cost overruns flow directly to the consumer and not the investor. The only avenue for consumers to manage these increased costs is reducing consumption.

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38 According to McDermott (2012), “Utilities are required to plan for all future demand, but there are major sources of uncertainty: (1) demand may fail to materialize as anticipated; (2) investment tends to require significant lead time; (3) generally projects require large up-front capital requirements; (4) investment tends to be lumpy and technology tends to be unique rendering the investment inflexible (i.e. invested capital has no other use). Cost of Service Regulation In the Investor-Owned Electric Utility Industry – A History of Adaptation, Karl McDermott, 2012.

39 For example, the Muskrat Falls hydro project in Labrador has repeatedly revised its budget higher with the original budget of $6.2 billion (2012) increasing to $7.65 billion (2015). In April 2016 Ernest and Young conducted a review on the project and identified that some material risks were not reflected in the 2015 budget estimation. Other examples include cost over-runs at Southern Company’s nuclear plant expansion in Georgia State, South Carolina Electric & Gas’s nuclear plant in South Carolina and Southern Company’s combined cycle generating plant in Kemper, Mississippi.
4.5 DESIRED OUTCOME OF ORDERLY TRANSITION – COSTS AND RISKS

In addition to assessing the structures against the first four desired policy outcomes, the AESO also considered the costs and risks associated with transitioning from the current energy-only market to another structure.

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<td>Orderly transition – risks</td>
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* EOM represents costs and risks of introducing enhancements

**Energy-only market structure (EOM)**

The transition from the current market design to an enhanced design is the simplest and least costly transition. Structurally, nothing changes from the current state. However, there are impacts to cost when the price cap is increased. An increased price cap will increase the credit requirements for all market participants who hedge as the range of potential market prices is widened and the risk of higher monthly settlements increases. This will challenge smaller participants who must exclusively rely on bank-issued letters of credit or cash deposits to meet their prudential requirements as they do not qualify for unsecured credit amounts. The costs of this transition are shared by both generators and consumers within this structure. These costs are minor compared to the transition costs required to move to a different electricity structure.

The greatest risk from making enhancements to the energy-only market structure is that the enhancements fail to result in sufficient additional generation investment to achieve an acceptable level of long-term supply adequacy. Given uncertainties regarding future market conditions and the intentions of generators to build new generation, it may take a considerable period of time before it can be definitively determined that the enhancements have not achieved their desired outcome. In this interim period there may need to be heavy reliance on non-market tools to maintain reliability. If the EOM enhancements fail, there is a significant risk that Alberta will run out of time to implement alternative structures, such as CAP or LTC, before significant coal retirements begin. This is likely to result in a default to second-best solutions as ad hoc measures to maintain reliability are implemented.

**Capacity market structure (CAP)**

Transitioning from the current structure to one that includes a capacity market is a significant change. It would create a new market for stakeholders to function within. While overall costs are expected to be similar to, if not lower than, an EOM, consumers would need to be educated on the rationale for a capacity market and its mechanics. Generators would face a similar adjustment process.

The design and implementation process for a capacity market is significant. The AESO estimates that design of the market will take two years with an additional year to finalize legal contracts and establish the procurement process. Therefore, it should be expected that the first capacity contracts will not be entered into until at least three years after the design process starts. In addition to the

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40 For example, cost-based emergency service contracts which can be deployed to mitigate emergency situations and maintain reliability.
design of the capacity market itself, the impact of a capacity market structure on the functioning of the existing energy market will need to be addressed. Existing market rules regarding energy pricing and dispatch will need to be reviewed and adjusted as necessary\(^{41}\) and new rules established to govern the operation of the capacity market.

The support of major market participants is therefore extremely important and significant stakeholder input around the detailed design decisions is needed for success. As market rule changes are currently subject to a regulatory oversight process in which impacted stakeholders can challenge rule provisions, there is material risk that implementation of elements of the capacity market structure could be delayed during the regulatory process. To mitigate this risk, rules with respect to implementing a capacity market may need to be enacted through a more prescriptive approach. Introducing a capacity market adds a new layer of market complexity so an extensive AESO and industry educational initiative is required. A well designed stakeholder engagement plan will be key to minimizing transition risks.

The role of regulatory oversight in the capacity market will need to be established, with a particular focus on clarifying roles, responsibilities and methods to ensure the reasonableness of capacity costs and determine their allocation. This may require minor legislative changes but should not impact the overall role and mandate of existing electricity agencies. In addition, other design decisions must be made early in the design process. Changes to transmission, hydro or intertie policy, as well as treatment of coal generation and renewables, can be incorporated into a capacity market. Design of the capacity market would proceed more efficiently if these policy directions were established up-front, while changes introduced later may result in delays to capacity market implementation.

Unlike the non-market structures there should be fewer claims for compensation with this structure change.

During the transition period while a capacity market is being implemented, it is highly likely that a “bridging mechanism” will be required to ensure reliability before new supply supported by a capacity payment is added to the system (the period from 2021-2024). No investments in new supply are expected until the details of the capacity market are determined. Bridging mechanisms may range from contracts with specific loads to curtail during supply shortages to interim (five year) capacity-like contracts with new generation supply. These contracts would be entered into with the understanding that the new supply will eventually need to compete in the capacity market. In addition to the cost of entering such arrangements, there is some risk that market participants will push to have these contracts extended and continued, thus defaulting to an unintended, alternative market structure (LTC).

### Long-term contract structure (LTC)

Transition to a long-term contract structure is a fundamental change to the electricity sector with commensurate risks and uncertainties. The form and terms of the long-term contracts would need to be developed. The contracts would have to be negotiated not only for new capacity, but for all existing capacity as well, if reliable operations are to continue. There are currently 239 generation assets in the province that will all have unique requirements for their long-term contracts. Changes would likely be required to energy market rules to ensure compatibility with contract structure.

The form of regulatory oversight with respect to the contract procurement mechanism, contract terms and cost oversight and allocation would need to be established and would very likely require legislative changes. Legislative changes would also likely be required to establish the authority of an agency, such as the AESO, to enter into the contracts with suppliers. Additionally, there would be a need for development and regulatory approval of a comprehensive procurement plan, including type, location and timing of new supply resources. This plan would need to accurately predict the next 20 years (the typical term of a long-term contract) as the cost of any errors in forecast, either over or under, would be passed directly to consumers.

\(^{41}\) Jurisdictions with capacity markets typically place greater restrictions on the prices at which supply can be offered into the energy market.
Under this structure, an appropriate regulatory approval process which takes extended time to establish or is challenged may significantly delay implementation of new generation procurement. As with the establishment of a capacity market, no new supply investments would be made until the details of the new long-term contract structure are finalized. Given construction timelines for new generation, this means that bridging mechanisms to ensure reliability during the transition period would likely be required.

A long-term contract structure would be a new and unfamiliar structure in the Alberta industry and would need to address treatment of legacy issues, which can be onerous. In Ontario, for example, developing contracts for legacy assets developed under previous structures was contentious and lengthy, even though the vast majority of generation was owned by one entity. As indicated above, a significant cost and risk of transitioning from the current structure to a long-term contracting structure arises from treatment of existing energy providers who built assets under a deregulated structure. This is somewhat analogous to the transition issues faced when moving from a regulated to a deregulated structure. Investors who built supply under a competitive market structure will likely expect some form of compensation for potential lost revenue or to be offered reasonable contract terms for their existing assets. Contract terms may need to be negotiated on a case-by-case basis involving considerable time and expense. Development of contracts or compensation for existing assets has the potential to become contentious and protracted, and has a high risk of triggering legal challenges, all of which may delay implementation of contracts for new generation. Investor confidence in the electricity sector can be negatively impacted should treatment of existing generation investments not be viewed as reasonable.

**Cost of service regulation structure (COS)**

Transition to COS, or essentially from a deregulated model to a regulated one, involves the highest complexity, cost and risk of any of the structures. The transition would be far greater than the magnitude undertaken in the late 1990s when the industry was deregulated, simply due to the fact that it is easier to break things into smaller parts than to assemble dissimilar parts into a whole. The cost of service regulation structure bears many of the same transition risks as long-term contracts but to an even greater degree. Implementing a cost of service structure would involve a comprehensive overhaul of enabling legislation and regulatory processes to define new roles and responsibilities. The legislation must define the roles of government and the required agencies, and define which is responsible for generation, transmission, distribution and retail.

The impact on businesses that are currently involved in the deregulated structure but no longer have a role under regulation would need to be determined and dealt with. The COS model typically involves companies which are vertically integrated, containing transmission, generation and customer supply components with a service monopoly within a specified geographic service territory. To reinstate this type of model, or even a hybrid version, would require merging or purchasing assets from some or all of multiple different entities including competitive retailers, currently regulated transmission and distribution companies and merchant generation owners. The number of regulated entities would need to be established and winners and losers from amongst existing entities would need to be determined, with the winners continuing to exist as new regulated entities while the losers are forced to exit the Alberta marketplace. Appropriate compensation for impacted assets and entities would need to be determined. It is highly likely that this process would involve legal challenges and take significant time.

Overall, moving to a cost of service model would be a very significant change and would take significant time to develop. It is highly likely that development and transition to this structure will not be accomplished before current excess supply conditions are reduced by coal unit retirements and load growth. Interventions will be required to maintain reliability over the interim period. These interventions would be procured rapidly to prevent black outs and may not be negotiated at least cost given time pressures. As with the long-term contracting model, the costs and risks of transitioning to the cost of service regulated structure makes it an undesirable approach for Alberta.

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4.6 SUMMARY OF DESIRED OUTCOMES ASSESSMENT

Implementing enhancements to the current energy-only market (EOM) is the easiest transition to make, but even after enhancements, this structure will not meet the other desired outcomes of the Government of Alberta, namely improved environmental performance and ensuring a reliable and resilient system. The EOM, with an increased price cap, would still provide significant uncertainty that long-term supply adequacy would be achieved. Investor appetite for purely merchant market risk has declined significantly over the past few years. Should the enhancements prove ineffective in attracting adequate investment, there would be insufficient time to course correct to an alternative structure in an orderly way. Levels of price volatility would be unacceptable when tested against the desired outcome of reasonable cost to electricity consumers. EOM is also not seen as sufficiently robust to withstand continued policy evolution, especially increasingly stringent environmental regulations or significantly increased interties. These results point to a need for a new market structure for Alberta that ensures investment and reliability through some form of revenue certainty beyond the energy price.

The capacity market structure will require some transition time, but should be functional in time for the anticipated market tightening in the early 2020s. Capacity market structures, common in many jurisdictions around the world, value capacity separately from energy prices. This ensures reliability by providing a payment for the important attribute of supply certainty in a future electricity system where energy may be cheap and abundant but only available when permitted by weather conditions. A capacity market will work well with the coal emissions phase-out, ensuring reliability by providing the necessary retirement and new build signals to investors. The capacity market structure is sufficiently robust to ensure reliability while delivering on existing policy objectives, and can continue to produce desired results even with potential future policy evolution related to renewable energy targets or interties. In a capacity market structure, market forces are utilized to ensure reasonable costs to consumers are maintained without the risk of stranding capital or placing too much emphasis on centralized administrative planning approaches.

When comparing the transition from the current market to a capacity market versus a long-term contracting model, the transition to a capacity market will be at a lower cost, and have the least impact to stakeholders. Long-term contracting structures have not proven to be a healthy or stable approach to achieving the objectives that electricity structures are intended for. They have historically been inefficient, prone to political interference and regularly resulted in poor administrative decision-making and generation planning, saddling consumers with unnecessary costs through time. While they provide longer term revenue streams to generators, the costs and risks of transitioning to a long-term contract structure makes it a less desirable approach for Alberta.

While the cost of service regulation option is the most flexible in terms of delivering on improved environment performance and reliability (because through this structure the government has full control of the electric industry), the transition from a deregulated model to a regulated one is by far the most complex and costly. The transition will require a potentially contentious, protracted and expensive process to re-regulate generation assets. Additionally, there is a significant risk of “locking in” with obsolete technologies or at high prices that do not reflect true costs, and also the potential of “gold plating” technologies in this structure. Under this model, market incentives and customer choices which drive innovation and result in lower costs in the long run are eliminated. It is more difficult for consumers to manage costs in this structure other than by reducing consumption. As with the long-term contracting model, the costs and risks of transitioning to a regulated cost of service option makes it an undesirable approach for Alberta.

Given that a capacity market structure provides the best balance for meeting multiple government objectives, the AESO conducted further detailed assessments of the potential impact of moving to a capacity market structure on various stakeholder groups and on the coal emissions phase-out and REP elements of the Climate Leadership Plan.

43 According to IESO data, the annual average energy price experienced consistent increases from 2006 to 2015 regardless of whether excess capacity existed.

4.7 STAKEHOLDER REQUIREMENTS AND IMPACT ASSESSMENTS

The AESO assessed potential stakeholder perspectives on a capacity market structure in Alberta. The intent of this exercise was to represent as closely as possible the requirements of key stakeholders and how these may align with the capacity market structure. Ideally, direct consultation with stakeholders would have been used to gather these perspectives, but this was not practical given the sensitive nature of the topic.

4.7.1 Load requirements and impact assessment

The AESO categorized two types of loads: loads that have to either rely entirely or partially on the market to secure electricity, and loads that own cogeneration they can use to supply their electricity demand. For all loads, the primary requirements were determined to be reasonable cost and reliable supply of electricity. Depending on the nature of electricity consumption, other requirements may include price stability and the flexibility to manage price volatility. For loads that own on-site generation, including cogeneration, the opportunity to generate revenue from an energy or a capacity market to supplement revenue received from their core businesses may also be desirable.

Under the capacity market structure, the volume of capacity purchased is centrally determined. For all types of load, the potential for increased total costs will likely be a concern as a payment for a new service, capacity, is introduced. However, for the same level of reliability, the overall costs in an EOM and capacity market should be of similar magnitude for consumers, except that in a capacity market the costs are split between an energy and capacity payment. Energy prices themselves would be expected to be lower under a capacity market. Unlike an EOM, where loads that rely on the market to secure electricity can manage the price they pay for it, these loads have limited flexibility to avoid the capacity payment when this amount is charged to them. Offsetting this, for industrial and commercial loads that rely on the market to meet electricity demand, the electricity cost of doing business is more stable as volatility is removed from the energy price.

For residential loads, the electricity cost in household spending would be more predictable. Although less price volatility would reduce the incentive for loads to hedge, the capacity market would not eliminate all price volatility and loads would still be able to further reduce price volatility through forward transactions and fixed-price retail contracts.

Loads that have on-site generation able to meet their entire demand do not benefit from more stable pool price as they are already hedged. To the extent that their generation exceeds their load, they may actually prefer the revenue upside offered by a more volatile and higher energy price. Loads that have on-site generation may be able to offset some capacity costs or earn a profit by selling capacity from their generation. These cogenerators would be concerned with how capacity obligations may be applied to them as their operational flexibility may be reduced. This is a design feature that would need to be determined. The capacity market would provide an opportunity for a wide range of industrial and commercial loads to earn capacity revenue by providing supply adequacy in the form of demand response.

In general, from the perspective of loads, a capacity market will add more complexity and make hedging more difficult. There may be a perception that the market will increase overall costs. Offsetting this are new potential revenue opportunities, a less volatile total cost and lower and more stable energy prices. Given these offsetting factors, load will probably view a capacity market as neutral overall, but opinions may be quite diverse.

45 These assessments were conducted with internal industry experts who have extensive historical experience working with all stakeholders. The AESO’s assessments of the EOM, LTC and COS structures can be found in Appendix C.
4.7.2 Generator requirements and impact assessment

The AESO identified two types of generators: generators that rely entirely on the electricity market to earn revenue and generators that have additional “out-of-market” support payments. The first category includes merchant thermal generators and renewable generators that are not eligible for the Renewable Electricity Program (REP). The second category includes renewable generators that are eligible for the REP. Cogenerators owned by loads or under commercial contract with loads to provide steam and/or electricity are discussed in the load section above.

For generators, the primary requirement is to earn an adequate return. Elements within a structure that facilitate adequate returns would be desirable for generators. These elements include long-term regulatory or market design stability, long-term revenue stability and certainty, efficient regulatory process (i.e. limited bureaucracy), level playing field (i.e. equal business opportunity), low barriers to entry (i.e. access to transmission system and market), fair compensation (e.g. compensating the firmness and the green attributes) and information transparency.

The capacity market structure allows generators that rely entirely on the market to earn additional revenue and increase revenue certainty. Developers of new generation would view the capacity market positively as it provides more stable revenues which are known ahead of time. A formally established and consistent capacity market would provide confidence that future revenue opportunities would be available. The views of existing non-renewable generators would greatly depend on their eligibility to participate in the capacity market. This is a design detail that needs to be established but the best practice is to include them. Existing renewable generators would be opposed to a capacity market as it would reduce energy prices and they would not be able to make a material amount of money from selling capacity. If they have already sold their green attributes, they would have no ability to offset decreases in energy revenue. A capacity market would be viewed negatively by incumbent renewable generators.

The impacts of the capacity market structure on renewable generators with REP contracts will depend on the payment mechanism chosen for each competition. If an indexed renewable energy credit (REC) is chosen, then REP generators will be insulated from the market through their contracts. Decreases in energy prices will be offset by increased support payments. If a fixed REC payment mechanism is chosen, then a capacity market structure will impact REP generators negatively as they will be exposed to decreases in energy prices that were not factored in to their offered REC price. To the extent that the payment mechanism for the REP may not completely offset changes in energy prices, renewable generators would want to price in the expectations of lower energy prices before entering into long-term agreements through this program. Eventually intermittent renewables may be able to sell limited volumes of capacity but details will matter.

Design considerations are significant in a move to a capacity market and generators would look to gain comfort that the capacity market design would remain relatively stable. Investment decisions would not be made during the transition period. Overall, however, given the additional revenue stability and certainty that a capacity market provides, generators would generally view a move to this structure as positive.

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46 For example, restrictions may be placed on the amount of coal generation that can participate in the capacity market.
4.8 COORDINATION WITH CLP ELECTRICITY OBJECTIVES

Given advice previously provided to the government by the AESO on implementation of the key CLP elements of the REP and coal emissions phase-out, the AESO conducted further assessments on how a capacity market may impact these elements, as well as the CLP’s objectives related to energy efficiency.

4.8.1 Renewable Electricity Program

The introduction of a capacity market would not jeopardize achieving the renewable targets as set out by the government because the REP was designed to be robust, flexible, sustainable and scalable. With the additional payment stream provided to firm generators under a capacity market, supply adequacy can be assured with higher REP volume targets.

Under a capacity market, an additional payment mechanism for renewable projects will still likely be needed in order to continue to provide a high degree of price certainty and sufficient revenue. A portion of the renewable support may be transitioned into a capacity market by carving out volumes for renewables with capacity value. For renewable competitions launched after the introduction of a capacity market, the design of the renewable attribute payment mechanism can be adjusted to reflect any revenues received from a capacity market. Due to lower energy prices in a capacity market, there would be an increase in REP support payments for renewables that cannot earn sufficient capacity payments.

4.8.2 Coal emissions phase-out

With respect to the coal emissions phase-out, a competitive auction for capacity in concert with a retirement schedule provides transparency, mitigates supply adequacy concerns, and can be used to smoothly reduce the volume of coal that can depart from service in any given period. These outcomes help to address concerns about the pace of coal retirements.

Achieving a fixed schedule through a competitive capacity auction also provides the following additional benefits:

- Achieves government objective of a smooth phase-out of coal by 2030 and meets AESO’s recommendation of using a schedule to manage the transition
- Provides more certainty and visibility of supply in future years, resulting in greater reliability and lower risk premiums in bids
- Reduces reliance on new reliability/ancillary services products
- Reduces year-to-year price volatility and ensures reliability because new entrants will see investment opportunities throughout the transition period despite uncertainty of coal retirements
- Provides flexibility for changing conditions over time
- Allows coal owners to compete for coal capacity, resulting in greater efficiency and allowing the cleanest, most reliable units to stay on longest
- Provides coal owners who win the capacity auctions with an additional revenue stream until their run-to date, providing more certainty and better reliability
- Allows other fuel types to compete for capacity, resulting in lower bid prices and technological innovation
- Eases transition and reduces risk of cost escalation, connection and regulatory delays by incenting new generation to build throughout the entire period, rather than waiting until 2029 or 2030
4.8.3 Energy efficiency

There is no fundamental conflict between energy efficiency initiatives in Alberta and the successful introduction of a capacity market. As a very rough estimate, the total amount of capacity that would need to be purchased is approximately 15 per cent higher than expected peak load. Even under a successful energy efficiency initiative that reduced peak demand in 2030 by 20 per cent over the base expectation, Alberta would retain a sizeable capacity market.\(^{47}\)

In structures such as long-term contracting and cost of service regulation, long-term commitments are entered into based on 20-plus year forecasts. In these structures, higher than expected reductions in demand growth can mean that long-term financial commitments are made for new supply that is not needed. In a capacity market, volumes of capacity procured can be adjusted through time, meaning that procurements reflect the actual impact of energy efficiency initiatives on demand growth.

A capacity market could potentially be an effective tool in achieving Alberta’s energy efficiency goals by providing a method of compensation for efficiency gains.\(^{48}\) Broadening the scope of capacity markets to include energy efficiency and other demand resources should reduce market clearing prices, with potential benefits of lower capacity costs to consumers.

4.9 IMPLICATIONS FOR TRANSMISSION POLICY

Transmission policy refers to the way in which transmission is developed and utilized. Alberta currently has an unconstrained transmission policy. Under this policy, transmission is planned and developed such that all in-merit supply\(^{49}\) is able to deliver energy to load under normal operating conditions on the transmission system.\(^{50}\) Transmission is available to suppliers to deliver energy to loads when they are dispatched. This policy approach means that no specific source of supply holds a standing right to access transmission to the exclusion of others. There are minimal locational price signals to incent supply or demand to locate in certain areas; rather, the transmission grid is developed such that participants have reasonable access to the system regardless of location.

Existing interties are to be enabled to operate at their rated capacity, while development of new interties is driven by merchant developers.

A capacity market is compatible with Alberta’s current transmission policy. Adoption of a capacity market does not imply that current policy with respect to internal or intertie transmission would be required to change. However, alternative transmission approaches could also be applied within a capacity market structure to manage the potential for transmission policies that allow for higher levels of congestion. For example, the granting of transmission rights to utilize the system, increased use of locational price signals to incent participants to locate in certain areas, or other ways in which transmission policy may evolve could work within the market structure. The other electricity structures are also largely compatible with these changes, although the EOM structure functions more effectively under the current unconstrained policy. LTC and COS models can incorporate a wide range of transmission policies by including them as criteria in the long-term planning process, although pricing signals are less useful when choices are primarily made through the planning process.

\(^{47}\) The AESO analyzed the impacts of two possible energy efficiency targets: 0.4 per cent and 1.5 per cent annual compound reduction in demand. They reduce the 2030 forecast peak demand from 15,229 MW to 14,494 MW and 12,270 MW respectively. By comparison, peak demand in 2015 was 11,229 MW. This means that the expected size of the capacity market in 2030 would be between 14,000 and 17,500 MW.

\(^{48}\) For example, capacity created by energy efficiency initiatives is eligible to participate in capacity markets in New England and PJM. Participation of efficiency resources in New England’s capacity market has more than doubled over the past seven years, from 655 MW to 1,538 MW. Participation of efficiency resources in PJM’s capacity market has nearly doubled over the past five years, from 569 MW to 1,117 MW.

\(^{49}\) In-merit supply is supply which has been dispatched, based on offer price, to meet demand. Supply is dispatched from lowest to highest price.

\(^{50}\) See Transmission Regulation section 15(1).
5.0 Recommendation

The AESO recommends that Alberta move to adopt a capacity market

The AESO’s analysis indicates that all structures involve a series of trade-offs. The electricity system is complex with multiple requirements and stakeholder interests. Decisions and their impacts unfold across several years and clear cause-and-effect relationships are not always readily apparent. There is no perfect electricity structure and jurisdictions across the world have taken multiple approaches to transition to a cleaner grid. On balance, however, a form of capacity market provides the best structure to meet Alberta’s current objectives for its wholesale electricity market in light of introduction of the CLP.

The AESO recommends that Alberta move to adopt a capacity market. A capacity market would provide the following combination of benefits which no other single market structure can achieve:

- **Ensure reliability and specifically compensate for firm generation**
  As more and more renewables are added to the supply mix, Alberta is moving into an environment where it will be energy rich but capacity limited, due to the non-dispatchable nature of a significant portion of the generators in its electricity system. With additional intermittent renewable resources the electricity system will have sufficient or even excess energy at times; however, due to the intermittent, low-reliability capacity value of the resource, supply adequacy cannot be guaranteed. The price signal provided by the current energy-only market increasingly will not signal for new investment. In order to ensure that new generation capacity is developed in a timely and orderly manner, Alberta needs to put a specific value on the attribute of “capacity.” A capacity market will accomplish this. A capacity market will ensure reliability by maintaining supply at a targeted level, something which the current energy-only market structure does not do.

- **Provide suppliers with revenue sufficiency and stability**
  As discussed above, as more and more low-dispatch cost, renewable generation is added to the supply mix, revenue available to non-renewable generators is expected to be insufficient to support enough generation to ensure adequacy. By providing an additional source of revenue that recognizes the value of firm capacity, a capacity market will close the gap such that non-renewable supply has sufficient revenue. By procuring capacity contracts ahead of time and for sufficient duration, a capacity market will provide stability to the generator’s income stream. Combined, this will attract a wider range of investment interest to Alberta’s market.
Implement key areas of the CLP and be robust to potential future policy evolution

Capacity market structures are found in many jurisdictions around the world and have delivered capacity additions at reasonable costs under a wide variety of market conditions. A capacity market will work well with coal retirements by providing the necessary retirement and new build signals to investors. The capacity market structure will allow for the integration of renewables according to the REP. The capacity market structure is sufficiently robust to ensure reliability while delivering on existing policy objectives, and can accommodate future policy evolution.

Maintain market incentives to preserve efficiency and flexibility

A capacity market utilizes market forces without unnecessarily adding costs to consumers, stranding capital or placing too much emphasis on centralized administrative planning approaches. Market incentives which drive innovation and cost efficiencies are preserved. The risk of locking ratepayers into costly and obsolete solutions is reduced and flexibility to adjust to technological and economic changes through time is preserved.

Allow a manageable amount of change with a high probability of success

Electricity supply margins are forecast to tighten in the early 2020s, when the next tranche of coal generation is expected to reach end-of-life. This introduces reliability risks if no new supply is built. Investors have indicated that until the policy environment has stabilized and there is certainty in structure, they will be reluctant to make any investment.

While changes to the existing energy-only market structure can be introduced relatively quickly, there remains a high degree of risk that these changes would not ensure supply adequacy in the long term. There would be no time to course correct if changes did not work. Although a more significant change, the introduction of a capacity market would materially reduce supply adequacy risks. Lessons learned from other capacity markets can be employed to ease Alberta’s transition. Implementation of a long-term contract or cost of service structure would involve significant dislocation of the current industry. There is a high risk that this process would take longer and be more costly and contentious than initially thought. Engaging in such a process would jeopardize both reliability and CLP objectives.

The time required to see new natural gas generation built is five to seven years. Given that the market currently has significant excess supply, the time to introduce market changes is now. Even with an expedited decision to move to a capacity market structure, it is likely that an interim bridging mechanism would be required in order to ensure reliability in the 2021 through 2024 timeframe.

Given the above, the AESO recommends that Alberta move to modify its wholesale electricity market by adopting a capacity market structure as quickly as possible.

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51 Most U.S. ISO-run markets (except for ERCOT) have a capacity market structure. A capacity structure is also found in the UK. Ontario is working on moving towards capacity market.

52 More mature forward capacity markets such as PJM and ISONE attracted new capacity additions every year and were able to incorporate capacity from demand response, energy efficiency and imports. In 2014, IESO compared the capacity costs under Ontario’s long-term contracting vs U.S. capacity markets and found the latter were significantly lower.
6.0 Next steps

Should the government accept the AESO’s recommendation, it requests ministerial direction as soon as possible to begin the design of a capacity market for Alberta. Because of the complexity we must emphasize the time that will be required to successfully implement this recommendation. As indicated earlier in this document, the AESO estimates that design of the market will take two years, with an additional year to finalize legal contracts and set up the procurement process. Therefore, it should be expected that the first capacity contracts will not be entered into until at least three years after the design process starts. Therefore, the earliest date that new generation procured through the initial auction would be in service is likely 2024, and a bridging mechanism will likely be required to ensure supply adequacy between 2021 and 2024. In addition to the design of the capacity market itself, the impact of a capacity market structure on the functioning of the existing energy market will need to be addressed. Furthermore, earning the support of industry stakeholders through a robust engagement process will be critical to the success of this endeavour. The Alberta electricity system will remain dependent on their investment to ensure supply adequacy under a capacity structure, and their assistance to uncover and understand market design issues and to limit unintended consequences. A more detailed discussion of the key design elements that must be developed through this process is contained in Appendix D.

While the AESO notes the complexity of moving to a capacity market, it must reiterate that the challenges, complexities, risks and financial implications of moving to a cost of service or long-term contract structure are significantly greater.
7.0 Summary

Alberta’s current energy-only market structure has performed well since deregulation on its original objectives of providing reliable and reasonably priced electricity. However, a clean and low-carbon system has emerged as a new objective. The CLP recommended specific initiatives to achieve this by 2030: phase out coal emissions and increase renewable generation.

Given this new objective and initiatives, the AESO examined how they would impact the ability of the EOM to continue to deliver the original objectives of reliability and reasonably priced power. Our analysis indicates that the combination of increased renewables and a general global trend of investors and capital away from investing in markets with significant revenue uncertainty meant that the EOM is unlikely to deliver an acceptable level of reliability going forward. Even changes to the EOM are unlikely to deliver on the objectives.

As such, the AESO reviewed a number of alternative electricity structures found throughout the world, comparing them to the revised set of objectives for Alberta’s electricity sector. This comparison indicated that a capacity market would strike the best balance between trade-offs and meeting government objectives. Implementing a capacity market would provide assurance going forward that supply adequacy will be delivered while retaining many of the important benefits of a market-based structure. While challenging, transition from the current structure to a capacity market would be achievable at reasonable cost and in a timely manner. The views of most stakeholders would range from neutral to supportive of the change. The change would not negatively impact timelines for current CLP initiatives and could increase their chance of success. For these reasons, the AESO is recommending a move from an energy-only market structure to a capacity market structure.

Given that change is required, the AESO recommends that it be tasked to begin the design process as soon as possible.
Appendix A
Financial and economic analysis
Investor Perspectives on the Attractiveness of Alberta’s Electricity Generation Market

Prepared by Morrison Park Advisors
For Alberta Electricity System Operator

June 2016
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3 June 2016

Mr. Mike Law  
Vice President, Market Services  
Alberta Electric System Operator  
2500, 330 - 5th Avenue SW  
Calgary, AB T2P 0L4

Dear Mr. Law:

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 AESO in its work.

Best regards,

[Signature]

Pelino Colaiacovo  
Managing Director
Morrison Park Advisors

Morrison Park Advisors is an independent, partner owned investment banking advisory firm. We primarily advise clients on mergers and acquisitions, equity and debt capital raises, divestitures and restructurings. In addition, we provide formal valuations, fairness opinions, contract negotiations, advice to special committees of boards of directors, advice on initial credit ratings, expert testimony, policy development, and market analysis. 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

The Alberta electricity sector is undergoing a period of dramatic change, with certainly the most significant developments since the formation of the market in the 1996 to 2001 period. With this backdrop, Morrison Park Advisors was asked to gather the views of current and potential participants in the electricity generation market in Alberta, to gain insight into the perspectives of people who will be making decisions about future investments in new electricity generation facilities.

25 participants in the industry were interviewed, 14 of which were developer/owner/operators of electricity generation facilities, and 11 of which were capital providers. All have deep experience in the industry, and are current on Alberta’s circumstances. Of the developer/owner/operators, approximately half have facilities in the province today.

Participants were unanimous in saying that investment decisions cannot be made in Alberta today, principally owing to the significant policy uncertainty that currently affects the sector. The Government of Alberta has made recent decisions with respect to coal use, renewable energy facilities and carbon taxes that are as of yet still not fully fleshed out. These policy issues make forecasts about the future untenable, as the outcomes to pending decisions will have profound impacts on the course of electricity supply, demand and prices over time. Without confidence in forecasts, there can be no market-based investments.

Beyond policy issues, a significant majority of report participants stated that they would not invest in new electricity generation facilities given the current structure of Alberta’s market. For these participants, future market uncertainty is too great a risk. A minority of developer/owner/operators and capital providers expressed willingness to invest in the future in the current market structure, provided that policy uncertainty is decisively settled. Critically, however, the number of these participants supportive of current market arrangements has declined since 2012, when a similar report was prepared by MPA.

If Alberta wishes to increase the number and variety of potential investors interested in developing new electricity facilities in the province, then it may wish to consider new arrangements. Report participants commented on two types of changes: development of a capacity market, and the offering of contracts. In the first instance, a number of participants claimed existing experience in jurisdictions with functioning capacity markets, and expressed willingness to participate in Alberta should the province choose to go down that road. While close to half of the report participants expressed support for capacity markets – and therefore a significantly greater number than support the existing energy-only market – this support was mitigated by comments about the challenges associated with setting up such markets, the need for time for markets to mature, and many other details.

All participants made clear that if Alberta were to offer contracts for the construction of new facilities, they would participate in procurement processes. Contract structures would ensure the lowest cost of capital for new projects, and the broadest possible participation. However, adopting a contracting structure represents a significant transfer of risk from generators to consumers, and would be a very significant departure for Alberta, from its current arrangements.
1. Preparation of the Report

In 2012, MPA completed a report for the Market Surveillance Administrator of Alberta (MSA) on the perceptions of investors and potential investors related to the Alberta electricity generation market. This exercise was part of a broader process that the MSA undertook in 2012 relating to the “State of the Market”. Information about the MSA State of the Market review, including the MPA report, can be found here: State-of-the-market-2012.

In 2016, after a number of events have occurred which have resulted in significant changes to market dynamics, the Alberta Electric System Operator (AESO) wished to re-examine the issues addressed by the earlier report in 2012. MPA was contracted to perform a very similar exercise to the previous one, and report the results. The objectives included:

- Gathering feedback from investors and potential investors about the attractiveness of the Alberta electricity generation market, particularly with respect to the potential future construction of non-renewable electricity generation facilities;

- Gathering feedback from investors and potential investors on current barriers to investment in Alberta electricity generation;

- In the context of this feedback, identify issues that may, if they were addressed by responsible authorities, improve the perception of the Alberta electricity generation market as a destination for investment.

MPA undertook the following program in order to fulfil the mandate provided by the AESO:

1. Background preparation

   - Review of the structure of the market, including records on existing generation plants, plants built or decommissioned since market opening, waiting list for connection of new plants, etc.;

   - Review recent announcements by the Government of Alberta and its various agencies which are relevant to the electricity generation market;

   - 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 electricity markets in North America, of particular note being the Texas electricity market, which shares certain characteristics with Alberta in the organization of its electricity market and the rules applicable to it, and others including PJM and NEPOOL, which have put in place somewhat more complex electricity market arrangements.
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, as well as leading market analysts participating in the formation of market opinions on the attractiveness of potential capital investments. 11 institutions participated in the interviews;

- MPA contacted companies that are active in developing, owning and operating electricity generation facilities across North America. 14 companies in total participated in the interviews. 8 of the companies that participated currently have generation assets in Alberta, and 6 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.
2. Investment in Electricity Generation

Transmission grid-connected 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. Smaller facilities that qualify as “distributed generation” may be connected to local distribution networks, or may be located directly on the premises of customers “behind the meter”. Regardless of type, all facilities are long-lived infrastructure with lifespans of 20 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 (however, in some cases such as natural gas-fired electricity generation plants, the cost of fuel can be a very substantial part of the full-life cost of the plant). 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 single facility for their returns over time. Their investment is in one facility, and their revenues and returns exclusively come from that facility. 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.

Alternatively, 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.
<table>
<thead>
<tr>
<th>Developer/owner/operator</th>
<th>Project Financing</th>
<th>Balance Sheet Financing</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Can be any developer, regardless of size or means</td>
<td>Typically larger companies with substantial financial assets and capacity</td>
</tr>
<tr>
<td>Source of Debt</td>
<td>Typically institutional lenders, such as banks, insurance companies or pension funds</td>
<td>The developer/owner/operator provides all of the capital required for development and construction of the 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</td>
</tr>
<tr>
<td>Source of Equity</td>
<td>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</td>
<td></td>
</tr>
<tr>
<td>Credit Tests</td>
<td>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.</td>
<td>Large developer/owner/operators are usually rated by credit rating agencies using a long list of financial criteria and tests. Equity analysts may offer opinions to market investors about the expected future value of the company's publicly traded stocks based on its expected future performance. 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</td>
</tr>
<tr>
<td>Equity Considerations</td>
<td>Similar tests as lenders, bearing in mind that creditors rank higher in payment priority, but do not participate in any enhancement in economic value</td>
<td></td>
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</tbody>
</table>

**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 special category of developer/owner/operators consists of companies that pursue electricity generation as a support or add-on to their main business. These would include
large industrial companies that build cogeneration plants (providing both heat and power) on the site of their facilities, or a small “behind the meter” electricity generation facility so that the industrial or commercial facility will not be dependent on the grid for electricity. 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, and several of the financial market participants are such analysts.

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 the risks to that profitability, are 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, public agencies, utilities, very large industrial users of power, or aggregators of small consumer contracts (sometimes referred to as Load Serving Entities or LSEs), where the price for the electricity that will be produced by a facility 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 for electricity at the time of sale, assuming 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. Neither the province nor its agencies 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. Unlike in some markets, where generators might be paid for being available to produce 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 was developed over the period 1996 to 2001, with full deregulation and operation of the competitive market beginning at the end of the period. It is relatively unique in North America, as only one other jurisdiction, Texas, currently 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 Electric System Operator (AESO), which also performs a variety of other functions, including managing the provincial transmission grid, forecasting the future need for transmission, dispatching generation to meet system load and managing several other “ancillary services” markets that are related to the smooth functioning of the electricity system, such as contingency reserves.

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.

*Forward Curves and Forecast Curves*

In any market with fluctuating prices, market participants need to make decisions based on their assumptions about the future. For existing facilities as well as new facility proposals, it is critical to

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1. With the exception, to be discussed further below, of the Power Purchase Arrangements (PPA) provided to certain electricity generation facilities at the time of market opening.

2. Note that some generators may be able to provide “ancillary services” to the grid such as contingency reserve, which would be another source of revenue, but these sums would not typically be central to decision-making about plant investment.
have some sense of what will happen in the future in order to make decisions about fuel supplies, scheduled maintenance and, most critically, investment decisions.

The “forward curve” for a market is what results from the actual market activity that occurs: as buyers and sellers make arrangements to buy and sell electricity in the future, each negotiated price becomes a point on the curve representing the expected price for electricity in the future. In Alberta, where parties may choose to satisfy their power needs, typically for periods in the range of one to three years, there is at any given time an established forward curve that is a few years long.

The “forecast curve” is more relevant to long-term investment decisions. It is essentially the best guess of market analysts on the trend in prices in the future, often extending out ten to twenty years. A series of assumptions about both supply and demand are set out, with a resulting estimation of what electricity prices are expected to look like for many years in the future. In an energy only market like Alberta, where generators are neither regulated nor contracted, faith in the forecast curve and the prices it predicts are fundamental to investment decisions.
3. Developments Since 2012

The current report takes into consideration a very different context than that of 2012, when the previous report was prepared. Some of the highlights of the contrasts are presented below.

*Alberta Government Policy*

The official policies of the Government of Alberta with respect to matters affecting electricity have changed substantially in the past four years, and are continuing to evolve. This is consistent with the change in government that occurred in May 2015.

In particular, the government has announced climate change-related policies which have a significant impact on the electricity sector, including the total phase-out of coal-fired electricity by 2030, targets for the construction of new renewable energy electricity generation facilities, and an increase in carbon taxes applicable to electricity generation. These changes are a very dramatic departure from the relatively laissez faire electricity policies of the government from the period of market opening to 2015.

A critical issue is not only that these policies are different from the past, but that the changes are incomplete. For example, the details and timing of the phase out of coal-fired generation are currently in the process of being developed. Similarly, the government's targets and timelines for future development of renewable energy facilities have yet to be finalized, and the nature of any financial support that may be provided to encourage the construction of those facilities is unspecified at this time. Also, the future application of carbon taxes to the electricity sector, as coal is phased out and hence less taxes are collected based on declining carbon dioxide emissions, is unclear.

Finally, it should be noted that for the first 15 years of the electricity market, government electricity policy was stable, and had the, perhaps unjustified, appearance of permanence. A change in government has resulted in changes to electricity policy, which has broken the illusion of permanence. In many other jurisdictions in Canada and elsewhere, electricity policies have often changed with governments, and Alberta now appears to be following that pattern.

*Alberta Economy*

The collapse in global oil prices which began in July 2014 has affected Alberta’s economy profoundly. The contrast of today’s economy with that of the spring of 2012 could not be more stark: boundless optimism in 2012 about an expected decade of growth has been replaced by the economic challenges of a sharp and painful recession. Widespread job losses in the oil and gas sector and the cancellation of a large number of oil & gas-related construction projects have dramatically changed the prospects for the province’s main growth driver, and continue to have ripple effects through the broader services sector and the economy as a whole.

For Alberta’s electricity sector, the decline in economic activity has meant a significant decline in electricity demand, both immediately, and in terms of future growth forecasts. Prices for electricity have fallen with demand, and are now approximately 40% lower than they were in the spring of
2014, before the price of oil began its collapse. The chart below depicts ten years of the monthly Regulated Rate Option price for residential consumers, which is representative of the trend line of prices over the past number of years.

![Graph of Residential RRO Price (Edmonton)](image)

**Technology Trends**

In 2011, the average bulk price for solar modules was approximately US$1.75 per watt. Already in the spring of 2012 this price was declining, and had breached the $1 barrier, but this was an unfolding story at the time, with much uncertainty about the durability of price trends. Today, bulk solar module prices are consistently below US$0.60 per watt. Moreover, the balance of solar systems costs, including racking, inverters, engineering, permitting and labour, are also declining steadily. Globally, solar has become dramatically more competitive in the past five years, such that in some sunny jurisdictions it is legitimately economically competitive with other electricity generation technologies, on an unsubsidized basis.
Natural gas prices in early 2012 had dropped below US$3 per mmbtu, and briefly touched US$2 which was a price not seen for 10 years. However, in the previous three years since the beginning of the recession in 2008, prices had averaged closer to US$4, and of course prior to the recession had been much, much higher. The fracking revolution had already driven prices downwards, but there was still considerable uncertainty about the future of the industry and the ability of fracking-based natural gas producers to continue to produce gas profitably at lower prices. Today, natural gas prices have been below US$3 for more than a year, and have dropped to levels below US$2 for significant periods of time. Moreover, production volumes in North America are up. Fracking-based natural gas producers have demonstrated that they can continue to sustain and grow their production at these prices through continuous improvements in their technology and processes, coupled with downward pressure on their supply chain costs.

Source: Bloomberg
This systemic decline in natural gas prices has had profound effects on electricity generation, as natural gas-fired electricity costs have declined proportionately. In the United States in particular, natural gas-fired electricity nearly tied coal as the primary electricity fuel in 2015, and so far in 2016 has actually surpassed coal for the first time ever.\(^3\) Older coal facilities are being retired at a record rate, and new coal facilities are not being built, as pressure to improve the environmental performance of the electricity sector is coupled with cost pressures to progressively drive coal out of the electricity industry.

The overall cost of wind power projects has been declining since 2012, but not to the degree of the other advancing technologies. Continuous improvements in turbine efficiency have been coupled with lower prices for critical commodities such as steel and copper to modestly reduce the net price of new facilities.\(^4\)

Larger scale electricity storage technologies appear to be coming closer to mainstream economic viability, with trials and test installations deployed in a number of markets. While battery, compressed air, molten salt and other technologies continue to undergo rapid development, none has yet emerged as a dominant option. However, should any storage technology reach commercial penetration, it is widely believed that there could be significant effects on electricity system dispatch, daily and weekly price variations, and the need for peaking generation facilities. Along the same vein, demand management technologies continue to proliferate in a number of markets, which has created new

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\(^3\) United States Electricity Information Administration, Electric Power Monthly, March 2016.

\(^4\) In the recent Ontario RFP for renewable energy, winning projects in the wind category boasted prices averaging $86/MWh, the lowest inflation-adjusted price since procurement of renewable resources began in the province in 2004. See the IESO announcement on March 10, 2016, available at IESO Media Release
low-cost options for system operators seeking alternatives to peaking generation capacity, as well as a
variety of ancillary services options.

All of these changes to underlying electricity technologies continue to demonstrate that change in the
sector is ongoing, and is unlikely to abate in the near future.

Particular note should be taken of the dramatic differences that these accumulated technologies have
caused over the past ten years. Market outlooks a decade ago did not take into account low natural
gas prices due to fracking, perceived solar as being very, very expensive for years to come, and had
no visibility on economically competitive storage technologies other than traditional pumped hydro.
An investment made in 2006, based on outlooks and forecasts common in the previous few years,
would find itself in 2016 operating in an environment that was well outside the boundaries of what
were then considered “likely” scenarios.5

Alberta Power Purchase Arrangements (PPAs)

Prior to the deregulation of the Alberta electricity system, the province was served by several vertically
integrated regulated utilities. Most of the electricity generated in the province was produced by coal-
fired, gas-fired and hydroelectric facilities that were built before 1996 and owned by the regulated
utilities. As regulated facilities, these generators were built under the expectation that they would earn
a regulated return over the course of their full economic life.

In order to create a meaningfully competitive electricity market, it was imperative that these facilities
participate, and yet in order to maintain fairness for the owners of the facilities, it was critical that
their expectations of a reasonable return on their investment not be disrupted. The solution to this
problem was the development of the Power Purchase Arrangements, wherein the owners of the
facilities would operate them under contract for 20 years6, at a fixed price which would result in a
reasonable return akin to what would have been earned had the regulated system continued. In the
case of the coal and gas-fired facilities the PPAs were sold to buyers in an auction,7 and the
purchasers of the contracts were free to participate in the electricity market on the basis of the
electricity generation capacity that they had secured through the contracts.

In 2012, these contracts had been operating for more than a decade, and had approximately 8 years
of life remaining. The owners of the PPAs were critical participants in the electricity market, while the
facility owners benefited from receiving a stable, contracted revenue stream.

5 A useful historical example is the Supply Mix Advice provided by the Ontario Power Authority to the Government
of Ontario in December 2005. Part 2-6 (Methodologies and Assumptions Adopted) of the report summarizes a vast
quantity of forecasts on electricity related prices that were current at the time in 2005. For example, seven long-term
forecasts for natural gas prices were referenced, which show assumed 2015 prices for natural gas ranging between
$5 and $11/mcf in real 2006 Canadian dollars. Prices are of course now far lower, especially on an inflation-adjusted
basis. The document can be found here.
6 Or a shorter term if the expected end of life of the facility was prior to 2020.
7 Hydroelectric facilities were also given PPAs, but their owner, TransAlta Corporation, retains control of the
facilities. Also note that not all PPAs were successfully auctioned in 2000.
Today, the PPAs are in the hands of the Balancing Pool, since the holders of the PPAs have returned them, based on a contract provision relating to “changes in law”. While these contracts have approximately four years of life remaining, the steep decline in the market price of electricity, coupled with the increase in carbon taxes announced by the government, appears to have rendered the contracts uneconomic (in other words, the expected net revenue from the market over the next four years is less than the cost of the contracts plus the fuel required for electricity production and carbon taxes that might be due).

It is not clear what will be happening with the contracts: will the Balancing Pool simply bid the output from all of the contracts into the market for the next four years (in which case the Balancing Pool will be by far the largest supplier of electricity in Alberta until the contracts expire); will the Balancing Pool cancel the contracts with the facility owners at the cost of a significant penalty (in which case the facility owners will then be free to bid them into the market, or close them); or will the Balancing Pool seek to force the buyers of the PPAs to take them back through legal action, thus recreating the electricity market as it was prior to the return of the PPAs?

In any case, unlike the buyers of the PPAs, the Balancing Pool will not be losing money, since all Balancing Pool costs ultimately are recoverable from ratepayers. The return of the PPAs to the Balancing Pool, assuming the owners of the PPAs are not required to take them back through Balancing Pool legal action, effectively results in an increase in electricity prices for consumers, up to the real cost of the PPAs, plus the fuel and carbon taxes associated with the electricity output.

For the underlying facility owners, the PPAs are critical to their business profile, because they represent a fixed stream of income. If the PPAs themselves are terminated early by the Balancing Pool (and in any case after 2020 when the PPAs expire), the facility owners will be carrying substantially more un-contracted facilities as part of their asset pools than they otherwise would.
4. Investor Feedback

Current Uncertainty

All participants stressed the extreme uncertainty currently facing the Alberta electricity market. There was near total agreement among report participants that investment decisions cannot be made under current conditions.

All classes of potential investors identified two broad categories of uncertainties: market and government policy. In the first case, a variety of factors were mentioned by multiple participants, including:

- the volatility of global oil & gas prices and their uncertain impact on industrial demand for electricity in Alberta;
- the potential impact of economic stimulus measures such as infrastructure spending;
- the uncertainty around whether Alberta will benefit from a new oil pipeline to support its petroleum export industry;
- the future attractiveness of cogeneration projects, as well as “behind-the-meter” electricity projects, based on the avoided cost of electricity transmission and distribution in the future.

Government policy uncertainty was a universal concern. Primary issues mentioned included:

- the schedule for coal plant shutdowns;
- potential compensation for coal plant owners;
- the unknown details of the longer term renewable energy targets (including whether the targets are based on renewable energy production measured in MWh or renewable energy capacity measured in MW), and the timing for their achievement;
- the level of non-market financial support that will be made available to renewable energy projects to incentivize their construction;
- the future of the carbon tax and its applicability to electricity generation facilities other than the coal plants being phased out;
- the degree of future government support for conservation and efficiency measures which would serve to depress market demand for electricity; and
- the potential for non-market inter-provincial electricity arrangements (including the potential for a special arrangement with British Columbia that was reported in the press as a “rumour” while participants were interviewed for this report).

The degree and range of uncertainty afflicting the electricity market is such that report participants described the current environment as having “no forecast curve”. By this it was not meant that forecast curves for the next 20 years are unavailable (a number of such analyses are available from a number of consulting and economic forecasting firms); rather the participants of all stripes claimed the inability to make informed judgements about the forecast because of the number of unknowns prevailing at this time.
In most cases, report participants prioritized the government policy uncertainties. They pointed out that while the sources of market uncertainty primarily focused on a variable fundamentally outside the control of Alberta (i.e., global oil & gas prices), direction and clarity on the outstanding policy issues are very much in the hands of the Alberta government.

It should be stressed that these comments were echoed by virtually all participants, incumbent as well as external developer/owner/operators, debt providers and equity investors and analysts. The entire market for new projects appears to be waiting for government policy direction. The only exception to these circumstances are the developers of very small “behind the meter” projects expressly designed to protect industrial and commercial customers from market instability. One of the main selling points of these types of facilities is that they are a mechanism to avoid or hedge against the uncertainty of the broader electricity market (and the increasing costs of transmission and distribution).

*Non-Recourse Financing is Unavailable to Market-Based Projects*

Lenders, equity providers and developers agreed that there is currently no appetite to finance Alberta electricity projects on a non-recourse basis.

When pressed, capital providers agreed that while they had funded such projects in Alberta in the past, those instances were principally before the recession in 2008, and the decline in natural gas prices. Both debt and equity providers indicated that they see no likelihood of their position changing in the medium term. Note that this sentiment was NOT based on the current uncertainty described in the previous section: even if all outstanding government policy uncertainties are addressed, debt and equity providers do not see market-based projects as viable candidates for non-recourse financing.

Several capital providers and developers mentioned specific cases of past project investments which have suffered poor financial returns based on unexpected technology trends or government policy decisions. For example, past investments were made assuming that natural gas prices would remain high in North America, which would push electricity prices up because of the price-setting role of natural gas plants in the merit order of many electricity markets. Instead, the decline in natural gas prices since 2008 has driven overall electricity prices downwards, below previous forecasts, and to the detriment of many projects. Similarly, government interventions in many jurisdictions to subsidize the building of renewable energy projects has caused excesses of supply, which has driven electricity prices down in local markets, and spilled into neighbouring jurisdictions. Having suffered these types of losses in the past, credit committees and boards are reported to be reluctant to incur these risks again.

A minority of debt and equity providers commented that if Alberta had a more liquid market in electricity contracts (i.e., electricity hedge contracts lasting in the range of five to ten years), they might be more willing to place some value on market-based projects. However, hedge contracts in Alberta are seldom longer than three years, and the large industrial consumers in the oil & gas sector who would be most likely to desire longer term hedge arrangements have been suffering from financial challenges and credit downgrades, making them less attractive counterparties.
The smallest developers, typically of behind the meter and commercial co-generation facilities, indicated some willingness to consider the financing of projects on a pure equity basis. However, these are necessarily small projects in niche situations which do not address the basic investment needs of the Alberta electricity market.

**Balance Sheet Investments Currently Have Limited Support**

Most large balance sheet-based developers indicated little support for building new market-based projects in Alberta in the near future.

A small number of report participants indicated that they would consider future market-based investments, but only if current government policy uncertainties were thoroughly alleviated. These responses came from two groups: large balance sheet-based incumbent developer/owner/operators, and incumbent cogeneration developer/owner/operators. It should be noted that among the first group, only a small minority of report participants indicated support for investments, even assuming clarification of outstanding government policy uncertainty. Most incumbents stated bluntly that they could not foresee making additional investments without significant structural change to the electricity market. Amongst the co-generation group, however, support for investment was higher, albeit with the same caveat about current uncertainty. Non-incumbents do not support investments.

Lenders, equity providers and market analysts were skeptical about additional investments by large balance sheet developers. Several of the more conservative debt providers suggested that they are currently heavily discounting the expected cash flows from market-based projects in their analysis of large developers, and would be inclined to be very negative towards new market-based investments. Equity market analysts similarly expressed skepticism about support in the capital markets for new market-based investments, even for larger companies that have a mix of assets in their portfolios.

Several respondents pointed to the outcome of negotiations between the provincial government and coal plant owners as a critical issue for future investments in the province. They indicated that if facility owners are not fairly compensated for the early closure of their assets, investors of all types would be leery of making any investments unsupported by specific guarantees by and/or contracts with the government. Even balance sheet-based developers would not be able to raise financing for new investments if there was perceived risk that government policy in the future could impair asset values so dramatically without compensation.

A number of participants, across the categories, indicated that there has been both an increase in the market’s perception of risks in the electricity sector, and a declining interest in taking those risks. This is evidenced not by a demand for higher returns for given risks (i.e., changing the so-called “risk-reward ratio”), but by the unwillingness of many market participants to take the described risks at all. Given that balance sheet developers must ultimately raise their capital in the markets in the form of both bonds and equity issues, this ebbing of the markets interest in electricity risk is affecting not only project financed opportunities, but also balance sheet developer considerations. Report participants had a variety of comments with respect to whether this is simply a market cycle or a more permanent
change in the market. However, in most cases it was believed that this state of affairs is likely to persist at least for the medium term.

**Generation Fuels and Facility Types**

The focus of discussion for this report with capital providers and developers was new gas-fired electricity generation facilities. Given the government’s announcement of coal phase out in the province, it was generally assumed by report participants that future electricity will be provided by some mix of natural gas and renewable resources. Moreover, given the announcement that some form of financial incentive will be provided to support new renewable energy resources, only natural gas-based investments are currently facing full market exposure.

Comments summarized above regarding uncertainty and the unwillingness of capital providers and developers to invest on the basis of electricity market revenues applies equally to natural gas-fired facilities and new renewable energy facilities. From a project financing perspective, choice of fuel is subsidiary to the inherent risks in making a market-based investment. No participants other than a select few balance sheet-based developer/owner/operators stated a willingness to even consider a market-based investment of any size, regardless of fuel.

To the extent that renewable energy projects are to be supported by some form of out of market incentive, several participants did make comments about the attractiveness of various energy types.

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>General View</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Wind</strong></td>
<td>Generally viewed as the lowest cost form of renewable energy generation currently available for Alberta. If new renewable energy resources are going to be selected purely on the basis of cost, then most report participants believed that wind would be the result of competitive processes for the foreseeable future.</td>
</tr>
<tr>
<td><strong>Solar</strong></td>
<td>Currently more expensive than wind, however given rapid price declines, and certain very favourable locations for projects in Alberta, several participants commented that there is interest in developing solar projects. These participants pointed out that solar tends to be peak coincident in the summer months, and that it has a very different production profile from wind, both of which may make it an attractive part of the mix of resources available to the grid. Several participants suggested that in the future, price declines and conversion efficiency gains could make solar price competitive with wind, particularly if full system integration costs (including transmission) of new wind is taken into account.</td>
</tr>
<tr>
<td><strong>Biomass</strong></td>
<td>A number of report participants commented that biomass is not generally considered attractive because of the high cost of building facilities, and because of the limited availability and cost of fuel.</td>
</tr>
</tbody>
</table>
Fuel Type | General View
--- | ---
Hydropower | Most participants commented that hydroelectric projects are generally not attractive at this time. Locations that can be developed are far from available transmission capacity, construction costs are very high, and lead times for development are long. Moreover, given the much longer asset life of hydropower facilities than other renewable energy types, several participants commented that a financial incentive structure separate from what applies to wind and/or solar would likely be required in order to allow hydropower to compete economically.

Facility and Resource Types

A typical classification of electricity generation facilities includes five types:

- Baseload (which are intended to run 24/7);
- Mid-merit (which is typically defined as being available to run 5 days per week, 16 hours per day, with some flexibility to follow load during each period);
- Peaking (typically available to provide power on short notice, for up to a few hours at a time);
- Co-generation (typically running 24/7, but not always, and providing both heat and electricity);
- Intermittent (typically renewable energy, such as wind, solar or tidal, and dependent on naturally varying environmental conditions).

A sixth category is “Behind-the-meter”, which are electricity generation facilities that are situated on a customer premises, and which are not directly connected to the electricity grid. Such facilities are usually quite small, as they are designed only to serve the demands of a single industrial or commercial customer. Co-generation facilities and behind-the-meter facilities share many characteristics, in that co-generation facilities could be considered one particular flavour within the behind-the-meter class. However, co-generation facilities are unique in the fact that the heat component of the facility is often more important to the underlying business than the electricity component, and they are often larger, more costly and more complex than other behind-the-meter types. As a result, it is useful to maintain a separation between these categories.

In addition, there are two types of non-generation “resources” that are sometimes discussed in the context of electricity systems; namely,

- Energy storage (which can come in many forms, including batteries, flywheels, compressed air, pumped hydro, heat, etc.), and
- Demand management (the ability to temporarily curtail loads rather than providing additional peaking electricity capacity).

In the current environment, most capital providers and developers were clear and virtually unanimous that they would not invest in market-based projects under any of these categories of generation or resources.
The exceptions to this general view were with respect to co-generation projects, and behind-the-meter projects. In the first instance, if a “steam host” (the purchaser of the heat produced by the facility) was credit worthy, and was responsible for a majority of the cash flow of the proposed project, then market-based exposure for the remainder of the revenues would be considered as an investment opportunity by several of the participants in the report. As will be discussed below with respect to contracting, several participants suggested that if approximately 70% of the total lifetime revenue of the facility was guaranteed by the steam host, then a case could be made for an investment, even under current economic conditions (but notably, not unless issues of government policy uncertainty have been resolved).

A small number of participants indicated an interest in behind-the-meter projects, and claimed they are actively working on developing such opportunities in Alberta. A critical component in the economics of such opportunities is the avoidance of transmission and distribution charges for the proposed customer. In addition, in the event that any additional electricity not used by the customer can be sold into the local distribution grid, such electricity may be eligible for an additional payment from the distributor for the avoidance by the distributor of transmission charges.

While these two categories of projects do demonstrate that some developers are willing to consider investments in the electricity generation market, it should be noted that these are very special cases:

- Co-generation can be considered a special case of a partially-contracted facility, given the economic support of a steam host;
- Behind-the-meter projects rely on distribution and transmission cost avoidance in their economics, which are not generally available to most system resources; they are typically very small in size and therefore do not address the needs of the system as a whole, and cannot be scaled in quantity without undermining their own economic viability (massive use of behind-the-meter resources would dramatically change the economics of the electricity grid, likely resulting in changes to the distribution and transmission cost avoidance calculations that the projects depend on).

A few participants made comments about energy storage and demand management opportunities. In general, both opportunities were not considered viable under current electricity market prices and conditions. To the extent that these opportunities might qualify for inclusion in ancillary services markets, participants claimed to be actively examining them. However, for demand management in particular, which in certain other jurisdictions is considered to be a direct competitor to peaking generation facilities, commenting participants indicated that the energy-only market in its current form would be unlikely to accommodate investment.

**Comments on Market Evolution**

Participants commented on several issues which may affect investment decisions on the margin. In most cases, these issues were also addressed in MPA’s 2012 report. While action on any of these issues may be more or less welcome by various parties, all participants stressed that these issues are
very much subsidiary, and would not substantially alter their overall views on market-based investments.

**Price Caps**

The Alberta electricity market’s rules require that the offer prices for electricity be between $0 per megawatthour (MWh) and $1000 per MWh. Participants in the market are not allowed to bid negative prices into the market, nor are they allowed to bid prices higher than $1000.

In general, report participants commented that potential changes to this regime are largely irrelevant to their investment decisions. A small number of participants, mostly from developer/owner/operators interested in building gas-fired peaking facilities, suggested that increasing the cap above $1000 (as has been done in certain other jurisdictions), might be helpful to generate greater interest in investment.

Several capital providers commented that increasing the price cap would simply increase the volatility of returns from the electricity market, making investment even less attractive. For project based developers, who rely on contractual or otherwise certain revenues to support the financing of their projects, the issue was considered irrelevant, as the current price cap regime is already too volatile.

Several incumbent developers commented that while a higher price cap might in theory be an incentive to additional investment, two issues might make such a change counter-productive:

- The number of annual hours in which very high prices obtain in the Alberta electricity market has been shrinking (presumably due to weak demand and a general excess of supply), and typically have only occurred when some fraction of the generation fleet has been suffering unplanned outages; meaning that the generator(s) suffering the outage do not participate in the extra revenue resulting from the extremely high peak prices, and over time the average benefit to generators will be moderated in any case (on the theory that every generator will suffer a high price-triggering outage at some point);
- Whenever very high prices occur in the electricity market, the media reports the event, which has a negative consequence on the reputation of the industry, undermining general support for the market as a whole.

**Ancillary Services**

Several participants commented on the ancillary services market in Alberta (which includes regulating reserves, contingency reserves, blackstart resources, etc.). Currently, these resources are procured from time to time by the AESO on a short-term basis. In most cases, prices for services are set daily, while in others contracts can extend up to a few years.

To the extent that developer participants expressed interest in ancillary services, it was to point out that while such revenues were helpful to projects, contracts for the services are not long enough to support investments on their own. Moreover, the size of the ancillary services market is such that it is of interest only to a limited number of projects. Extending the length of contracts for ancillary services
might help to incent development of new resources, however given the eligibility of existing resources for contracts, it was not seen as a significant opportunity.

**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. The RRO represents a relatively small fraction of the total electricity sold in the Alberta market, given that it is limited to a subset of small consumers (residential and small business consumers that have not chosen a retail provider).

Only a few incumbent developers commented on RRO related issues. In general, they were all negative comments. In most cases, participants suggested that the RRO simply be scrapped, given the availability of a number of retail electricity providers in the province. Limited interest was evident with respect to reform of the RRO, which was considered likely too complicated and costly a process to be of value. Moreover, participants who commented believed that reforming the RRO to purchase medium term forward power (in the range of three to five year contracts rather than one month) would not have much of a positive benefit on investment opportunities in Alberta. In general, these comments were much more muted and negative than the responses in 2012, when a review of the RRO had made the issue more prominent in the minds of many stakeholders in the Alberta electricity market.

**Interties with Other Electricity Jurisdictions**

The management of interties, particularly with British Columbia, continues to be a contentious issue, as it was in 2012.

Several incumbent developer participants commented that the existing intertie with British Columbia results in substantial value leaving the province of Alberta. The same criticisms were generally not voiced about the smaller interties with Saskatchewan and Montana. From the perspective of these participants, the existence of the interties is a deterrent to further investment in Alberta electricity generation capacity. As was noted above, the potential for additional out-of-market arrangements with British Columbia, as per the news media speculation during the course of the report process, accentuated the degree of uncertainty that is hindering new investment in Alberta electricity projects.

For non-incumbents who commented on the issue, whether developers or capital providers, the relative lack of interties from Alberta to other markets is a hindrance to investment. Given Alberta’s relative electricity isolation, all revenues from a project must come from Alberta load sources (except potentially renewable energy credits revenues, which in a few past cases come from external jurisdictions). This was contrasted to highly interconnected markets in the United States (such as PJM or NEPOOL), where revenues can come from a variety of jurisdictions, making the electricity market in those areas much less dependent on the policies and economy of a single state/province.
Market Alternatives

Given the indications from virtually all participants that they are unwilling to make investments in Alberta at this time on the basis of electricity market revenues, most commented on alternative arrangements that might help to encourage investment.

One market-based alternative would be the development of a “Capacity Market”, in addition to the existing energy only market. PJM (an area including parts or all of 14 US states, in the mid-Atlantic and Midwest) and NEPOOL (the electricity transmission area and market in New England) are examples of electricity jurisdictions currently operating both capacity and energy markets. In those cases, electricity generation capacity is secured three years forward, on a rolling basis. As a result, participating generators know what a portion of their revenue will be in advance, and depend on the energy market for the remaining portion of their revenues. The prices resulting from annual capacity auctions have fluctuated from year to year, and also fluctuate within each of the markets on a nodal basis (depending on localized supply and demand conditions).

Developer Comments

A number of developers, both incumbent and others, stated that they have experience with capacity markets. In general, those that have participated in such markets stated that they might consider investing on the basis of a functioning capacity market in Alberta. However, this position was neither universal, nor without considerable caveats.

Several participants pointed out that many functioning capacity markets are much larger than Alberta (PJM is over 10 times the size of Alberta in terms of electricity capacity, while NEPOOL is more than double), with considerably more market liquidity. Moreover, those markets serve multiple political jurisdictions, making them less exposed to government policy decisions (note that the New York ISO is an exception in that the capacity market exclusively serves one state; moreover, the markets are all susceptible to the impact of national electricity regulations). In addition, the creation and maturing of a functioning capacity market in other jurisdictions did not occur quickly, and required a number of years and the sorting out of countless issues before the capacity market was reliable enough to incent new facility construction.

One critical issue raised by a few participants was the likelihood that capacity markets would incent the construction of facilities with the lowest capital costs. In general, this would suggest single cycle peaking facilities, rather than mid-merit or baseload electricity generators. These would be the easiest to finance based on expected capacity market revenues, regardless of the perceived needs of the market in question.

A few participants pointed out that capacity markets have been successful in supporting investment in demand management initiatives as an alternative to peaking generation, which has put downward pressure on overall electricity costs.

Developers that focus on project-financed opportunities stated that while it may be possible to obtain financing for new facilities being constructed in capacity market jurisdictions, the cost of that
financing is considerably higher than in contracted or regulated jurisdictions, making it much more difficult for them to compete with balance sheet developers. As a result, they generally choose not to focus on those jurisdictions. The result is that a smaller pool of typically larger developers (coupled with demand management providers) are interested in developing projects in a capacity market environment.

**Capital Provider Comments**

Debt providers stated that debt is available to new projects in capacity market jurisdictions, and that in a number of cases they have current debt outstanding to such facilities. In general, however, they echoed comments made by developers that the cost of this debt is higher than in jurisdictions offering contracts or where electricity is provided exclusively by regulated utilities, and that on a per project basis less debt is typically available as a percent of total capital. They also echoed concerns about the time required to establish a capacity market, the need for liquidity, and the ongoing susceptibility of such markets to changes in government policy as a risk factor.

Equity providers were less likely to have any interest in capacity markets, commenting that these markets were of greater interest to large balance sheet-based developers.

**Contract Issues**

All participants were unanimous in expressing a willingness to invest in Alberta electricity generation facilities on the basis of long-term contracts with a credit-worthy counterparty. All developer/owner/operators, whether incumbent or otherwise, currently operate facilities in other jurisdictions that are under contract. All capital providers, both debt and equity, are currently invested in facilities in other jurisdictions that are under contract.

It should be reiterated that a small number of report participants, and in particular drawn from the incumbent developer/owner/operators in the balance sheet and cogeneration class, did not favour pursuing a contract option in Alberta, though they readily admitted that if contracts were offered they would pursue them. Among this minority group, there was a strong opinion that decisive resolution of the government policy uncertainty currently affecting the market would be sufficient, coupled with the passage of time, to allow a return to a healthy level of investment in the Alberta electricity sector.

Given that Alberta does not currently have a regime for contracting of electricity supply, participants were questioned more closely about what exactly could be the nature of such arrangements.

**Counterparty**

All participants stressed that the level of interest in and the cost of capital for any new facilities would be directly related to the credit quality of the contract counterparty. That party must be legally able to recover the cost of the contract from the consumers of the province.

Several participants noted that the existing Balancing Pool could be an entity which holds contracts, given that it currently fulfills that role for the PPAs. Others suggested that a new government sanctioned entity could fill that function, or with appropriate changes, so could the AESO.
Contract Term

Most participants expressed a preference for the term of the contract being coincident with the expected life of the facility (i.e., typically about 25 years). This was universally stated to be the best way to minimize the cost of capital for the projects. However, several developers pointed out that the contract could be shorter than full life, suggested that even at 15 years contracts would still be attractive. Providing a market value “tail” to the contract would be one way to ensure that investments remained sensitive to the market.

Debt providers were split on their reactions to contract term issues. Some suggested that they would value only the revenues covered by the contract terms, while others suggested they would assume some small level of refinancing at termination of the contract. Regardless, all debt providers indicated that shortening the term of contracts would result in a penalty with respect to the total debt that would be made available to projects, with varying views on the size of that penalty.

Energy vs. Capacity

For natural gas-fired plants, a universal preference was expressed for capacity-based contracts (monthly payments for the availability of the plant, which are independent of the actual level of production). Contracts which pay for energy production are seen as higher risk, since any new facility’s production would be exposed to market demand risk, and to future government policies in favour of renewable energy.

Debt providers made clear that an energy contract regime would result in less debt being available for the construction of gas-fired facilities, given the production risk that must be taken into account. For equity providers and balance sheet developers, an energy-based contract would put upward pressure on the hurdle rates that would be assumed in bidding for contracts, resulting in higher overall contract costs.

Fraction of Plant Capacity Contracted

While all report participants stated that contracts would definitely encourage investments in the Alberta electricity market, there were varied opinions about whether those contracts need to cover entire facilities, or just a fraction.

In a capacity contract that covers the entire cost of a facility, the monthly capacity payment typically covers:

- The amortized full cost of constructing the facility;
- Interest on debt borrowed to construct the facility;
- Expected “fixed” maintenance and operation costs (that are independent of the level of production); and
- Profit margin for the equity provider.

The variable costs of fuel and operations is then bid into energy markets as the cost of actual energy production, and are only incurred if those costs meet the market clearing price. Typically, the facility
owner is then constrained by contract from making additional profit margins beyond what was built into their original contract price (there may be certain incentive structures to encourage operational efficiency, but relatively speaking these are often minimal when compared to the contract value itself).

It is possible, however, to construct contract arrangements which do not cover the full cost of the facility, interest, fixed maintenance and profit margin. Most of the developer/owner/operators and debt providers participating in this report indicated that a less than 100% contract regime would still be attractive to some parties, with caveats.

Several balance sheet developers indicated that they would be willing to bid on contract arrangements which they believed would achieve approximately 65% to 75% of the discounted full life expected revenue of the facility. In order to make this calculation, expected contract revenues would be discounted over the life of the contract at a relatively low rate (given the high degree of certainty attached to those revenues), while expected market-based revenues for the life of the facility would be discounted at a much higher discount rate (appropriate to the degree of risk associated with the market).

Debt and equity providers focused on non-recourse financing were more skeptical of this type of arrangement. More conservative debt providers insisted that they would discount expected market revenues to zero when calculating the amount of debt that could be made available to such a project. They would simply depend on contract revenues to calculate whether the plant was a viable business, and then scale their debt according to those cash flows and their debt service coverage ratio requirements. Other debt providers were somewhat more willing to put value on market-based revenues, but only to a small degree. Project equity providers considered this to be a mechanism for putting a floor on expected returns (with market revenues representing all returns above that floor amount), but expressed skepticism that such a regime would ultimately find favour as compared to opportunities in other jurisdictions.

Several debt providers and equity analysts covering the balance sheet market suggested that this kind of arrangement might be considered broadly acceptable to the capital markets if it could be demonstrated that at least approximately 75% of the capacity of a plant was fully covered by the contract. This is actually a somewhat higher burden on the contracts, as it is a calculation made on an undiscounted basis.

All report participants agreed that while offering contracts on less than 100% of capacity would be a mechanism which would ensure the continued relevance of the market to investment decisions, and would represent a sharing of risk as between the contract counterparty and the facility owners/sponsors, it would nonetheless result in higher costs of capital for the projects (both because debt ratios would be lower than fully contracted projects, and the cost of equity would be higher).

**Fairness for Existing Facilities**

A number of report participants expressed concern about any new type of arrangement that would be offered to support new investment in the Alberta electricity market, in respect of the consequences of
those arrangements on existing facilities and facility owners in the market. These comments came from incumbents in the market (universally), but also from equity and debt providers, as well as market analysts.

Existing investments, particularly those that were made after the launch of the market in 2001, were made in good faith and in the expectation that market principles would determine future prices and cash flows. A variety of comments were expressed about the fairness, or lack thereof, of offering support for construction of new facilities, which might serve to depress energy market prices that are the sole means for existing facilities to recover their costs. Several participants suggested extreme caution in designing any new arrangements, given the possibly that a negative market reaction could directly affect the share value (and hence the financial flexibility) of publicly traded incumbents that would potentially be affected.

These concerns applied both to any potential development of a capacity market, as well as development of any sort of contracting regime.
5. Observations

*Contrasts: 2012 vs. 2016*

Given the similarity in the processes undertaken to develop the reports in 2012 and 2016, it was impossible not to remark on the many differences in views observed.

**Overall “Tone” of Market Participants**

In 2012, incumbent developer/owner/operators were by and large comfortable with the market environment, and focused primarily on opportunities to reduce market irritants and continue the slow evolution of the market. Capital providers and market analysts focused on balance sheet developers expressed similar comfort with existing arrangements, while recognizing that the universe of potential investors was somewhat limited by the size and liquidity of the market.

For project-focused investors and developers, the Alberta electricity market was not attractive in 2012, and continues to be unattractive. If anything, however, the number and range of contract-focused market participants has grown and become more competitive, meaning that an incrementally larger number of players believe themselves to be shut out of Alberta, given the current market structure.

The significant shift has come among incumbent developers, non-incumbent balance sheet developers and the debt and equity market participants focused on them: in general, all of these groups appear to be much more negative about investment opportunities under the existing market structure. Several parties who had expressed continued support for the market in 2012 stated bluntly that they now could not foresee investing in the near to medium term (with an unstated “if ever”), unless the investments were supported by a contract. Capital providers were generally much more skeptical of mixed portfolios of contracted and market-based assets, stating that much higher ratios of contracted assets were required before a portfolio was considered a “safe” investment.

In addition to these general reactions, unmistakeable and elevated concern was evident among most report participants about the level of uncertainty currently affecting the Alberta policy environment. The number and potential impact of outstanding policy issues (details of coal phase out and compensation, form and extent of renewable energy support, level of renewable energy targets, future application of carbon taxes, etc.) are undoubtedly weighing heavily on all generators and capital providers exposed to the Alberta electricity market.

**The Economy and Market Prices**

In 2012, electricity market prices were fairly typical given the history of the market: that is to say, they were somewhat volatile, with price spikes sustained for certain periods, but in general not out of line with market experience. On the other hand, 2015 and early 2016 have been the lowest sustained market prices in Alberta electricity market experience.
The oil price collapse and economic downturn, with its marked impact on provincial electrical load and hence downward pressure on electricity prices, is clearly having a significant bottom line impact on generators, and making it difficult for report participants to consider opportunities to invest. This sharply contrasts to 2012, when optimism about the future growth of the Alberta economy was almost boundless, and enthusiasm for new investment opportunities was more evident (at least among the subset of report participants that expressed comfort with the market structure).

**Purpose and Nature of Investments Required**

The primary focus of investment consideration in 2012 was on serving growing load requirements. While some older facilities were expected to reach end of life over the following decade, the primary concern for all parties was supporting the substantial growth occurring in Alberta. In its 2012 Long-Term Outlook, the AESO forecasted load growth of over 3% per year through 2022, with expected Alberta Internal Load reaching over 14,800 MW at the end of that period, and over 17,200 MW by 2032.

Today, a major concern is the commitment to phase out coal. Replacing the entire 6000+ MW of coal fleet by 2030 is a larger challenge than growth. Moreover, the very recent AESO 2016 Long Term Outlook suggests that a “medium” growth expectation is 13,700 MW by 2022, and only 15,230 MW by 2030, a significant decline in expected growth from the scenario presented four years ago.

One consequence of the shift in focus from growth to coal replacement is the nature of the new facilities that will be required: whereas a substantial portion of growth was expected to be industrial load best served by cogeneration plants, coal replacement is most likely to require a combination of renewable energy, single cycle and combined cycle gas facilities. Since, as discussed above, cogeneration facilities are by their nature effectively partially contracted (given the needs and commitment of the steam host), they are much easier to arrange financially in a market environment. On the other hand, the facilities now predominately required are fully exposed to the market.

**Market Skepticism: Cyclic Trend or Fundamental Shift?**

As has been noted above, report participants have clearly become less supportive of electricity markets in general. Many participants referred to specific poor experiences over the last number of years in Alberta and in other market environments in the United States (i.e., comments that amounted to “we lost our shirts on project X, so our Board would never approve another one”). A crucial question is whether this skepticism about the operation of electricity markets, and the ability to recover a reasonable return through market-based electricity investments, is merely a cyclical low that will eventually turn around, or whether it is evidence of a more fundamental shift in the way new projects will be financially structured.

On the basis of a small sample review of the sort undertaken for this report, it is impossible to come to any conclusions about this very important issue. Ongoing experiences in other energy only electricity markets, such as Texas, New Zealand and Australia, will no doubt colour the long-term views about the viability of energy only competitive electricity markets in general.
However, in the near term, it may not matter to Alberta whether declining support for its electricity market can be understood to be cyclical if those cycles are very long in duration. In the near to medium term Alberta requires new investment, and if that investment is not forthcoming under the current market structure, then some new arrangements may have to be considered in any case.

**Alberta and the Broader Market for Electricity Facilities**

Alberta is a relatively small, relatively isolated electricity market. The AESO 2016 Long-Term Outlook predicts a requirement for approximately 10,000 MW of net new electricity generation capacity over the next 20 years. In the United States, much more than this total is constructed annually. The pool of available developers and capital providers is very large and very active across an enormous range of electricity markets and government jurisdictions. There is no shortage of activity in the electricity plant construction sector when considered on a North American or global basis.

The largest, most competitive pool of developers and capital providers appears to be interested in contracted facilities. Alberta need not necessarily choose to offer contracts for the construction of new generation facilities, but if it does not, these players will simply look elsewhere for their opportunities, as they do now. A smaller group of developers and capital providers have traditionally been interested in pursuing opportunities in market-based environments. However, under current conditions this group appears to have shrunk substantially.

Alberta does not have the size, ability or “market power” to shape the electricity plant construction market. Alberta’s decisions on how to proceed will not likely convince any developer or capital provider to change their business approach or preferences. However, depending on its decisions, Alberta will definitely affect the number of parties who will be active and interested in developing new projects in the province, particularly in the near term.

**Uncertainty and Market Pressure**

The degree of policy uncertainty facing the Alberta electricity sector appears to be greater than it has been since deregulation in the late 1990s. At the same time, the economy is under severe strain since the decline in oil prices. It cannot be overstressed how much these two factors are colouring the views of all incumbent participants in the Alberta electricity market.

Even if these two factors are mitigated – i.e., the government resolves a number of outstanding policy questions, and at least moderate economic growth returns to the province – it is not clear whether support for market-based investments will return to previous levels in the near term.

Making market-based investments requires a relatively high level of confidence in long-term projections and forecasts. Short-term volatility is not necessarily fatal, but a solid belief in long-term trend lines is a requirement to make investments on reasonable risk/reward terms. Both government policy fluidity and economic course corrections make such faith in long-term trends much more difficult to sustain. Contracts reduce the risks for developers resulting in “easier” investment decisions, but increase burdens for ratepayers. No choices are without costs and consequences.
6. Conclusions

The climate for investment in Alberta’s electricity generation market appears to have deteriorated significantly since MPA’s last report in 2012. Uncertainty and economic challenges have had negative effects on the confidence of potential investors in market forecasts, and undermined the willingness even of a number of Alberta incumbents to make further market-based investments.

A large pool of developers and capital providers claim the willingness to invest on the basis of contract-based structures. A smaller pool state that they are investing in other jurisdictions that offer more complex market structures involving capacity market features, and that they would consider similar investments if Alberta were to follow that path. No participants in this report process claim willingness to make market-based investments in the current environment, given existing uncertainties. A small number of potential investors, and crucially fewer than in 2012, stated that they would return to a pro-investment stance if current policy uncertainties were definitively addressed.

Alberta is embarking on a process of coal phase out which will require the replacement of a substantial portion of its electricity generation fleet in the next decade. Given this urgency, the question of whether developer and capital provider dissatisfaction with market-based investments will dissipate over time may be moot.
## Appendix

*Interview Participants:*

### Capital Providers

<table>
<thead>
<tr>
<th>Total Participants</th>
<th>11</th>
</tr>
</thead>
<tbody>
<tr>
<td>Of Which:</td>
<td></td>
</tr>
<tr>
<td>(note that several participants are in more than one category)</td>
<td></td>
</tr>
<tr>
<td>Lenders</td>
<td>7</td>
</tr>
<tr>
<td>Equity Providers</td>
<td>5</td>
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<tr>
<td>Market Analysts</td>
<td>3</td>
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</table>

### Developer/Owner/Operators

<table>
<thead>
<tr>
<th>Total Participants</th>
<th>14</th>
</tr>
</thead>
<tbody>
<tr>
<td>Of Which:</td>
<td></td>
</tr>
<tr>
<td>(note that several participants are in more than one category)</td>
<td></td>
</tr>
<tr>
<td>Alberta generation assets</td>
<td>8</td>
</tr>
<tr>
<td>Gas-fired facilities</td>
<td>12</td>
</tr>
<tr>
<td>Coal-fired facilities</td>
<td>6</td>
</tr>
<tr>
<td>Renewable facilities</td>
<td>7</td>
</tr>
<tr>
<td>Cogeneration facilities</td>
<td>3</td>
</tr>
<tr>
<td>Behind the Meter facilities</td>
<td>2</td>
</tr>
</tbody>
</table>
May 12, 2016

Elizabeth Moore  
Alberta Electric System Operator  
2500, 330 5th Avenue SW  
Calgary AB T2P 0L4  
Canada

Dear Elizabeth,

Thank you for the recent inquiry on the status of the financing markets and the implications for Alberta’s energy-only electricity market and its plans to introduce significant renewable electricity generation. We understand that the Alberta Electric System Operator ("AESO") has seen uncertainty surrounding electricity price forecasts and is questioning whether this uncertainty has dampened developer interest in the AESO’s market.

Furthermore, we understand that the AESO is keen to understand the extent to which this dampened interest is caused by increased price uncertainty or whether other factors, such as changes to the underlying financing markets, have had an impact. Specifically, the AESO has asked us to provide answers to the following questions:

1. Do you think that the price uncertainty observed in Alberta’s energy-only market today would dissuade new investment and/or present challenges when it comes to financing new capital expenditure (both in terms of availability of finance and cost)?

2. Generally speaking, when it comes to raising finance for projects that carry merchant price risk, do you think that finance markets today are more or less conservative than in previous years (in terms of both project and corporate finance)? If so, do you consider this to be a fundamental shift in the risk appetite of finance markets or rather the result of typical market cycles?

3. In previous years, projects carrying merchant price risk have been readily financeable in Alberta using corporate finance. Do you think that those same projects would be equally financeable today if the increased price uncertainty evident in the market was absent?

In answering the above questions, we understand that the AESO has not asked us to study the Alberta market or the details of the Alberta’s plans to introduce renewable electricity. Such a review would be needed to provide a more complete answer. Instead, we have focused on the status of the financing markets and whether that status of the financing markets alone could have created dampened developer interest.

The first question addresses whether price uncertainty would dissuade new investment or present challenges when financing new capital expenditure. Price uncertainty is an important issue when developers look to finance their projects. Without any price certainty, projects will have a difficulty in raising debt finance. This situation would create a scenario where projects would likely only be all-equity financed, thereby creating, at the very least, a very expensive capital structure and potentially other challenges.
Following the recent financial crisis, many projects were financed with power purchase agreements. These provided the market with comfort regarding both volume and price. There were numerous projects that were completed in both Canada (eg. Ontario FIT program) and the United States (eg. California and the Alta Wind projects).

As the financial markets became more healthy after the crisis, investors and the banks started taking more risks and developers were able to finance projects without long dated power purchase agreements. Price uncertainty remained a key risk, but many developers found that they are able to finance projects with revenue hedges. Banks provided these hedges with tenors of 5 to 7 years in the United States. Recently, we are aware that Capital Power’s Bloom Wind Farm in Kansas closed a financing with a 10 year proxy revenue swap hedge to provide stability regarding the project’s revenue for a low base amount of power. The hedge provided sufficient certainty to permit the debt financing to close. The hedge was provided in a partnership through Nephila Capital and Allianz and the project is financed by Capital Power on balance sheet using corporate debt and cash flow from operations. The project is not secured by any power purchase agreement. Allianz is rumored to have closed on other financings in the US recently.

As it relates to the second question, our view would be that the financial markets have been willing to take on greater financial risk than in the years immediately following the financial crisis. Immediately after the financial crisis, the most viable projects were those that had power purchase agreements to provide revenue stability following construction completion. As the economies improved, debt investors have taken on increasing risk. In project finance transactions, credit spreads on the projects initially financed in the bank market have been refinanced with lower credit spreads ranging from 150 basis points to 175 basis points. This phenomenon has been evident in both Canada as well as the United States and would be expected given this stage of the economic recovery.

In order to understand the condition of the corporate finance market, we examined the bond market in the Canadian market from 2009 through 2015. In selecting the relevant sample set, we specifically excluded issuances related to the following sectors:

- Governmental issuances
- PPP/availability payment backed bond issues
- Bond issuances reliant on power purchase agreements for revenue and/or repayment
- Financial institution issuances
- Issuances deemed to be backed by relatively stable businesses

We specifically attempted to include issuances in the energy sector where the above factors were not evident. The outcome produced the following results:

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Number of Issuances</strong></td>
<td>31</td>
<td>34</td>
<td>40</td>
<td>61</td>
<td>59</td>
<td>56</td>
<td>42</td>
</tr>
<tr>
<td><strong>Maximum Size</strong></td>
<td>1000 MM</td>
<td>800 MM</td>
<td>1450 MM</td>
<td>1100 MM</td>
<td>1225 MM</td>
<td>1530 MM</td>
<td>2185 MM</td>
</tr>
<tr>
<td><strong>Average Size</strong></td>
<td>520 MM</td>
<td>450 MM</td>
<td>475 MM</td>
<td>625 MM</td>
<td>609 MM</td>
<td>643 MM</td>
<td>728 MM</td>
</tr>
</tbody>
</table>

In our view, we believe that the corporate financing market was very active the last three years for financings that support businesses with price/volume variability.

In the US, we have also seen that institutional investors have also taken greater risk. Last year, the Indiana Toll Road, a toll road that is subject to both price and volume variability, was purchased by IFM out of bankruptcy. The purchase price for the toll road was $5.72 billion, a price that was larger than the original $3.8 billion purchase price in 2006. While the leverage in the capital structure was more conservative, the fact that the acquisition was completed using bank financing followed by a capital markets takeout is proof that the corporate finance market is willing to take risk. Finally, it should be noted that IFM was able to reduce the bank financing amount due to institutional investor
demand that was willing to commit to the financing at a fixed rate prior to the completion of the acquisition conditions precedent.

In the first quarter of 2016, another financing was completed for the acquisition of the Chicago Skyway, another toll road that is subject to both price and demand variability, by Ontario Teachers, OMERS, and Canada Pension Plan Investment Board.

Overall, we believe that the financing market is less conservative than what we have seen coming out of the financial markets. Capital structures tend to have less leverage than prior to the financial crisis; but investors are willing to take more risk structurally. We would expect this to be a normal evolution in the financing markets associated with this stage of the recovery. We would expect that the market may never get to the leverage that existed prior to the financial crisis and all financial institutions have permanently increased risk awareness. If anything, this latter point may be considered a fundamental shift.

As it relates to the third question, the financial markets have gone through a fair amount of volatility. Initially, 2015 represented a year of significant investor demand. This was not evident in the figures above due to the exclusion of the record setting C$2.5 billion PPP bond issuance. During the mid to late summer of 2015, the increased supply of bond issuance combined with global risk factors (eg. Greek governmental issues, Puerto Rican debt difficulties, slower Chinese growth, etc.) caused Canadian bond spreads to increase approximately 40 basis points. The demand tapered off in the last quarter of 2015. While the first quarter of 2016 did not exhibit significant investor demand, we have begun to see much greater demand in the second quarter of 2016. This greater demand has been accompanied with declining credit spreads. Therefore, we believe that the debt capital markets would be receptive to properly structured projects that you refer to if the increased price uncertainty in the market was absent.

The above represents addresses is our view regarding the financial markets relative to your questions taking into consideration both the time and information that we have had our disposal to address your questions. We would be happy to discuss the above with you at your convenience to answer any questions that you may have and/or to provide additional details. As time passes, we would expect that the status of the financial markets will continue to evolve and would be willing to update our analysis accordingly.

Regards,

William Kloehn
August 29, 2016

Nino Vakhtangishvili  
Alberta Electric System Operator  
2500, 330 5th Avenue SW  
Calgary AB T2P 0L4  
Canada

Dear Nino,

Thank you for the recent inquiry on the status of the financing markets and the implications for Alberta’s energy-only electricity market. Specifically, the AESO has asked us to provide opinions on the following:

1. The state of the financial markets as it relates to potentially developing a capacity market in Alberta.

2. The “value” to Alberta of developing a capacity market as compared to the current energy-only market, from the perspective of the capital markets;
   - In considering the nature of the potential "value" from a capital markets perspective, could you consider specifically whether a materially larger pool of investors would be likely to participate in a capacity market vs. the current energy-only market, and whether the cost of capital would likely be materially different?

In answering the above questions, we understand that the AESO has not asked us to do an in-depth study in the markets, but to provide initial opinions on each of the markets. In order to provide a more detailed assessment, further investigation would be required. In addition, this letter has been developed after addressing certain questions that the AESO has asked regarding the development of a renewables market. In this letter, we will focus on additional opinions as they relate to the natural gas market and have incorporated the previous letter on financing renewables by reference.

The first question addresses state of the financing markets as it relates to developing a capacity market in Alberta. ERCOT, one energy-only market, has been undergoing a significant amount of change as a result of the change in commodity pricing and the availability of various sources of energy, thereby creating price uncertainty. Price uncertainty is an important issue when developers look to finance their projects. Without any price certainty, projects will have difficulty in raising project debt finance. This situation could create a scenario where projects could either be high cost debt or all-equity financed, thereby creating, at the very least, a very expensive capital structure and potentially other challenges.

As a result, investors and developers are carefully considering ways to mitigate price uncertainty. Depending on the project/market, the mitigation of price uncertainty has included PPAs, derivative hedges, and other structural items including development of a capacity market. In an effort to bolster further development, PJM in the US announced last year that it was increasing capacity payments by 37.3%, in part to address the development need for gas plants to offset the retirement of coal and oil plants.
Despite the current state of the markets, there is a substantial amount of capital available that could potentially finance a capacity market. As one example, Panda Power last year closed the financing for its Hummel gas fired plant which is considered the largest coal to gas conversion project in the US. The financing consisted of the following:

<table>
<thead>
<tr>
<th>Financing</th>
<th>Term</th>
<th>Rating</th>
<th>Amount</th>
<th>Spread</th>
</tr>
</thead>
<tbody>
<tr>
<td>Term Loan A</td>
<td>6.5 years</td>
<td>NA</td>
<td>$250m</td>
<td>375</td>
</tr>
<tr>
<td>Term Loan B</td>
<td>7.0 years</td>
<td>BB-</td>
<td>$460m</td>
<td>600</td>
</tr>
<tr>
<td>Equity</td>
<td></td>
<td></td>
<td>$400m</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>$1,100m</td>
<td></td>
</tr>
</tbody>
</table>

This financing was completed in a very choppy market (4th quarter 2015) and we would consider the capital markets to be much improved from the time period in which this project closed. This project sells power into the PJM market on a merchant basis with the use of a heat rate call option as a hedge to cover approximately 500MW of the 1,124MW capacity.

In terms of the value to developing a capacity market as opposed to the energy-only market from the perspective of financing additional gas plants, we believe that there is significant value in considering the development of this market. Despite the availability of capital, one of investors’ key concerns relates to the stability of revenues. The capacity market helps to stabilize revenues by lowering price volatility associated with uncontrollable factors especially compared to the energy only market where returns are more dependent on achieving peak pricing.

The capital markets historically have provided a significant amount of capital to ERCOT, an energy only market. At the time the capital was invested, the belief was that there would a significant demand increase for energy in the Texas market. Panda, the developer in the Hummel plant above, also invested in the ERCOT market through the Temple I, Temple II, and Sherman plants. However, these projects have encountered significant financial difficulties as the debt service coverage levels have dropped below 1.00 times. The largest reason for the financial difficulties is due to lower pricing and the inability of the projects to meet their revenue forecasts.

Earlier this year, Panda completed a refinancing of the Sherman plant. Assuming that total capitalization of this plant is the same as the Hummel plant adjusted for size, the capital structure for the Sherman plant would be as follows:

<table>
<thead>
<tr>
<th>Financing</th>
<th>Term</th>
<th>Rating</th>
<th>Amount</th>
<th>Spread</th>
</tr>
</thead>
<tbody>
<tr>
<td>Term Loan</td>
<td>6 years</td>
<td>B-</td>
<td>$360m</td>
<td>900</td>
</tr>
<tr>
<td>Equity</td>
<td></td>
<td></td>
<td>$390m</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>$750m</td>
<td></td>
</tr>
</tbody>
</table>

The rating is based on the rating that was provided by the rating agencies to the Term Loan B financing which was that was refinanced with this facility. The tenor is assumed to be the same as the original Term Loan B. The spread is not known but we have benchmarked it with another energy project that recently went to the market with a B+/B3 rating by S&P and Moodys, respectively. If one were to assume a 15% return on equity, then the cost of capital for the Hummel project is 9.6% compared to the 12.7% refinanced Sherman project. If one uses these examples to assess the value of a capacity market versus the energy only market, one would draw the following conclusions:

- The capital structure of the capacity market will be less costly due to lower debt spread and higher debt capacity.
- The capacity market is a much deeper and broader market. Hummel was financed by banks and institutions. On the other hand, Sherman, which was originally financed in the institutional loan market, could not be refinanced in this market and was instead refinanced by a single investor that tends to invest in distressed assets.

While there are differences between projects and markets, we would expect that equivalent projects in a capacity market would find a deeper pool of investors at a lower cost of capital.
The above represents our view regarding the financial markets relative to your questions taking into consideration both the time and information that we have had our disposal to address your questions. We would be happy to discuss the above with you at your convenience to answer any questions that you may have and/or to provide additional details. As time passes, we would expect that the status of the financial markets will continue to evolve and would be willing to update our analysis accordingly.

Regards,

William Kloehn
Appendix B
Cost analysis
Cost Analysis

Cost advantages of a capacity market vs. long-term contract or cost of service structure

Relative to capacity markets, long-term contract (LTC) and cost of service regulation (COS) structures are expected to enable investors in new natural gas generation to obtain capital at lower cost. However, this reduction of cost is the result of a transfer of risk from generation investors to electricity ratepayers. Due to this transfer of risk, generation developers can use more debt to finance their projects and require a lower return on equity. This may make it appear that an LTC or COS structure can deliver reliability at a lower cost to electricity consumers; however, this is an incorrect conclusion for two reasons.

1. Risk has not been eliminated; it has just become less visible

Higher costs of capital available to generation developers in capacity markets reflect the fact that those projects face uncertainty regarding revenue for the life of the project. This uncertainty can come from changing market prices but also from the risk that changes in technology or market conditions may make the generator unnecessary or expensive relative to competing sources of supply. Under an LTC structure, these risks are transferred from the generation developer to the ratepayer as the ratepayer is entered into a commitment to pay the generator regardless of future conditions. Risk does not diminish, it just changes form. The visible cost of a new generation plant decreases but the risk of the plant becoming obsolete or unprofitable still exists. Direct visibility of the cost of this risk is lost because it is not explicitly priced into the cost of the contract. Rather, it remains hidden until a future point in time where ratepayers may end up paying out contracts for generation which may not be required or could be obtained from much cheaper alternative sources. This risk is very real in a long-term contract as technologies and market conditions can change significantly from assumptions used in long-term plans.

2. Capacity markets provide access to alternative sources of reliability

A sufficient level of capacity, or ability to generate electricity (or willingly reduce consumption), is essential for reliable operation of the electricity system. Capacity markets are intended to provide this necessary volume of capacity at the least possible cost. Different sources compete within the market to sell capacity. Capacity can come from existing generation, upgrades to existing generation, load that is willing and able to curtail, energy efficiency, interties, new generation (from a range of potential technologies) or other sources that meet the technical requirements. From this mix, the cheapest sources of capacity are selected, thus ensuring that a desired level of reliability is maintained at a low cost. Long-term planning processes used to identify capacity additions in LTC and COS structures typically fail to identify this wide range of capacity options as a single organization will always have less information regarding costs and technologies than multiple organizations.

New combined-cycle gas (CCGT) generation is just one of the possible sources of capacity. In organized capacity markets in the northeastern United States, the cost of a new CCGT is used as a benchmark against which capacity market prices are compared. The cost of a new CCGT is calculated and the revenue it would be expected to earn by producing electricity is subtracted from this amount. This amount, known as the net Cost of New Entry (or net-CONE), represents an estimate of the residual payment that a new gas generator would require to earn from the capacity market.
The experience to date in these capacity markets has been that capacity prices have settled significantly below the net-CONE (see graph below). This indicates that capacity in these markets has come from a variety of sources that are cheaper (often significantly so) than a new CCGT unit. Reliability can be maintained at costs below the all-in costs for a new natural gas unit. There is no reason to expect that similar results would not be seen in an Alberta capacity market.

![Capacity Prices vs Net CONE (NE US)](chart)

Given these results, Ontario, which currently utilizes a long-term plan and LTC structure to identify and compensate new supply, has assessed the potential benefits of adopting a capacity market structure. Noting that “markets have proven to be effective in eliciting responses from new resources not necessarily predictable ahead of time through a planning process”\(^1\), the Ontario Independent Electric System Operator (IESO) estimated the potential annual cost savings from adopting a capacity market could range from $250 - $500 million.\(^2\)

Thus, while on the surface it may appear that access to lower cost capital would result in lower costs to consumers in long-term contract or cost of service structures, this is only part of the picture. Lower capital costs are achieved by transferring risks to ratepayers who may then realize higher costs in the future. In addition, while capital costs may be lower for new gas generators under an LTC structure, capacity markets often provide alternative sources of capacity which are significantly cheaper than new gas generation.

**Additional background**

According to an analysis of data from the Energy Information Administration and the Bureau of Labor Statistics, between 1997 and 2013, efficiencies produced by organized markets are keeping prices affordable and saving consumers billions of dollars. This indicates that market structures may avoid

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\(^1\) *Ontario Capacity Auction: Assessment of Expected Benefits*, p. 28, IESO

\(^2\) Ibid, p. 29
problems facing more regulated structures, such as a lack of incentive to increase performance efficiencies and a tendency to spend capital to expand rate bases.

- Retail rates in U.S. states with organized competitive markets increased 0.9% less than the rate of inflation; those in states outside of organized competitive markets increased 6.7% greater than the rate of inflation.
- Rates for residential and commercial customers increased 3.1% and 10.4% less than inflation in states within organized markets but increased 3.2% and 1.8% more than inflation in the other states.
- For industrial customers, rates in Regional Transmission Organization (RTO) states increased 1.7% more than inflation but increased 8.7% more than inflation in non-RTO states.
Appendix C
Stakeholder impact
In addition to assessing the potential stakeholder impacts of transitioning to a capacity market presented in section 4.7, the AESO also examined potential stakeholder impacts from increasing the price cap to $5,000/MWh within the current energy-only market (EOM), or transitioning to a long-term contract (LTC) or cost of service regulation (COS) structure. As in the capacity market assessment, internal AESO experts were utilized to examine how assumed requirements of key stakeholders may align with the various structures. Ideally, direct consultation with stakeholders would have been used to gather these perspectives but this was not practical at this point given the sensitive nature of the topic. The results of the AESO’s assessment are summarized as follows with additional detail provided below.

### Table: Stakeholder Impact Assessment Results

<table>
<thead>
<tr>
<th>Stakeholder Requirements</th>
<th>EOM</th>
<th>CAP</th>
<th>LTC</th>
<th>COS</th>
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</thead>
<tbody>
<tr>
<td>Load</td>
<td></td>
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<td>X</td>
<td>X</td>
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<tr>
<td>Generators</td>
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</table>

The AESO categorized two types of loads: loads that have to either rely entirely or partially on the market to secure electricity, and loads that own cogeneration they can use to supply their electricity demand. For all loads, the primary requirements were determined to be reasonable cost and reliable supply of electricity. Depending on the nature of electricity consumption, other requirements may include price stability and the flexibility to manage price volatility. For loads that own on-site generation, including cogeneration, the opportunity to generate revenue from an energy or a capacity market to supplement revenue received from their core businesses may also be desirable.

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**Energy-only market structure (EOM) impact to load**

Under the EOM structure with an increased price cap, loads with no generation are exposed to the price volatility inherent in an EOM. However, loads with cogeneration or other on-site generation would be indifferent to price volatility as their electricity demand is met by their on-site generation.

While higher price volatility in an EOM incents industrial or commercial loads that have market exposure to participate in demand response and improve energy efficiency, it also increases the uncertainty of electricity costs for their businesses. However, all loads, including industrial, commercial and residential loads, are able to hedge against price volatility – large industrial loads are able to hedge by entering forward contracts with power producers and retail loads are able to hedge by signing fixed price competitive retail contacts with retailers. Although higher price volatility may increase the hedging costs as overall risk is increased, the EOM structure offers both large industrial and retail loads the most flexibility in terms of electricity cost management options (it is likely that evaluating or re-working the regulated rate option (RRO) due to cost implications of this provision may be required).
Under the EOM structure, loads that have on-site generation to meet their entire demand are not exposed to the market. Instead, they have the flexibility to capture energy revenue from the electricity market if electricity revenue is higher than the revenue from their business processes.

**Long-term contracts (LTC) impact to load**

For loads that rely on the market to meet demand, long-term contracts entered by government or government agencies essentially take away the opportunity to individually manage electricity costs. This is because the generators who would otherwise naturally be the counterparties of loads would enter long-term contracts with the government or government agencies. While the electricity price is stable under the long-term contract structure, it may be unreasonably high due to long-term locking in of generation contracts, reducing the incentive for innovation and cost reduction, and the possible inclusion of non-electricity related public policy costs. The lack of ability to manage price risks may incent industrial and commercial loads to build generation and self-supply, hence reducing the market size and liquidity. It also makes it more difficult for retail loads to find retailers who are able to find counterparties in order to provide retail choices and help retailers reduce costs.

For loads that have on-site generation wishing to use the market to earn supplemental revenue, the existence of government-backed, long-term contracts will reduce their opportunity because the LTC structure is expected to lower and stabilize prices in the energy market. If loads use their on-site generation to participate in long-term contracting, the obligation imposed by long-term contracts may interfere with or reduce the flexibility of their business processes.

**Cost of service (COS) impact to load**

Cost of service would entail a regime change by re-regulating the generating sector (and eventually retail sector) of the electricity industry. The process is likely to involve a broad range of changes in legislation and regulatory entities, resulting in high transition costs and risks (which are discussed in Section 4.4) that will be eventually borne by loads.

A COS structure would provide price stability to loads that would otherwise be exposed to market price volatilities. However, since a COS guarantees cost recovery and a reasonable rate of return for generators, the lack of incentive for innovation and cost reduction, as well as possible non-electricity related public policy costs could result in high electricity cost to loads. The COS structure also shifts the risk of investment entirely to loads from whom the cost of service is recovered.

For loads that currently self-supply, the impact of a COS structure is unclear. If their generating capacity is under cost of service recovery, certain obligations will be imposed on the capacity and the obligations may interfere with loads’ business processes. If their generating capacity is not under cost of service recovery, there will be no transparent market for loads to optimize their revenue stream by optimizing power generation and business process. It is particularly unclear how a cost of service model would work with cogeneration in terms of development, ownership and operation of assets.

**Generators**

The AESO identified two types of generators: generators that rely entirely on the electricity market to earn revenue, and generators that have additional “out-of-market” support payments. The first category includes merchant thermal generators and renewable generators that are not eligible for the Renewable Electricity Program (REP). The second category includes renewable generators that are eligible for the REP. Cogenerators, who are owned by loads or under commercial contract with loads to provide steam and/or electricity, are discussed in the load section above.
For generators, the primary requirement is to earn an adequate return. Elements within a structure that facilitate adequate returns would be desirable for generators. These elements include long-term regulatory or market design stability, long-term revenue stability and certainty, efficient regulatory process (i.e. limited bureaucracy), level playing field (i.e. equal business opportunity), low barriers to entry (i.e. access to transmission system and market), fair compensation (e.g. compensating the firmness and the green attributes) and information transparency.

**Energy-only market structure (EOM) impact to generators**

Under an EOM structure with an increased price cap, generators that entirely rely on the energy market to earn adequate revenue will be able to make more revenue during scarcity periods. Generators that do not entirely rely on the market to earn adequate revenue may be able to capture more upside to enhance their revenue through optimizing their business processes. Further, an EOM will not significantly change the current market mechanics, therefore maintaining the ease of entry and information transparency provided by the current market. Compared with other structures, an EOM is likely to provide regulatory efficiency due to the relative simplicity of the structure. However, high price volatility inherent in the EOM and the resulting likelihood of regulatory intervention will negatively impact the ability of generators that entirely rely on the market to make adequate return on investments. In addition, this volatility makes revenue streams harder to predict for generators, increasing risk and reducing investment attractiveness. Further, under the EOM structure, the wholesale market has no direct ability to compensate thermal generators for their “firmness” or renewable generators for their green attributes.

**Long-term contracts (LTC) impact to generators**

Overall, assessed from the perspective of generators and supported by the work performed through investor sounding, generators would generally favour structures that provide more revenue certainty. Generators, especially new developers, would find this the most attractive structure. The LTC structure provides generators that would otherwise face market price volatility with long-term revenue certainty. If the long-term contracting opportunity is open to all generators, the level playing field desired by generators is reasonably maintained. However, there is a high risk that in practice this will not be maintained as the playing field is prone to be unlevelled by non-electricity related government policy and new generation likely to be favoured. Long-term contracting is also able to compensate generating capacities for desired attributes. However, the details of different long-term contracts may make it hard for potential generation investors to decipher the value of the contracts. This would be a barrier for them to participate.

Because long-term contracts will lower and stabilize energy price, generators that do not entirely rely on the energy market to earn an adequate return, but rather use the energy market to earn additional revenue will likely find less upside in the energy market for their power (i.e. surplus supply from generators that have on-site load or generators that provide steam under commercial contracts). For renewable generators under the REP, the impact of a LTC structure is unclear, depending on whether long-term contracting is open to existing renewables and whether renewables under the REP will be combined with other long-term contracting processes.

**Cost of service (COS) impact to generators**

A COS structure only provides adequate return on investment to regulated generators, which do not currently exist in Alberta. For generators, establishing a COS structure is a regime change of the electricity industry which will involve a broad range of changes in legislation and institutions. The COS structure will eliminate all opportunities that currently exist for all generators who do not end up being designated as regulated entities. A transition to this structure would involve establishing a reduced
number of regulated entities from amongst the existing generators. Some companies would continue to exist as new regulated entities while others would be forced to exit the Alberta marketplace. Appropriate compensation for impacted assets and entities would need to be determined. It is highly likely that this process would involve legal challenges and take significant time. Given this uncertainty, most generators would find transition to a COS model undesirable.
Appendix D
Capacity market design considerations
Capacity markets can take a number of different forms depending on design elements chosen. There are several key components and numerous details which can be implemented in different ways. Design choices will impact how effectively the capacity market achieves the desired outcomes set for it. These choices determine the degree of various incentives, allocation of risk and impact to stakeholder groups. Several of the key design decisions which must be made are discussed below.

**Method for determining volume of capacity required**

A reliability target must be established and translated into a volume of capacity to be purchased. Typically, the volume required is established to meet reliability criteria and is expressed as a percentage of forecast peak load. The resource requirement is calculated to establish the amount of installed capacity resources that will provide an acceptable level of reliability. Key considerations are:

- Clarification of reliability standards that are utilized to specify reliability targets for the system; and
- The modelling methodology that calculates installed capacity or reserve margin required.

**Who holds the obligation to procure capacity?**

It must be determined who is responsible for procuring the required capacity. This establishes which parties must purchase contracts for capacity and demonstrate that the required volume of capacity has been secured. Procurement obligations are typically placed on:

- Independent System Operators who centrally procure capacity on behalf of all load; or
- Load Serving Entities who are responsible for procuring sufficient capacity for their customer base.

The eligibility of self-supply or bi-lateral transactions to offset capacity obligations or costs must also be established.

**Contract term, delivery period, and frequency of procurements**

The term (or length) of the capacity obligation must be established and whether the contract term should be the same for all resource types such as existing and new capacity resources or various technologies. Typically, capacity contracts are between one and five years in duration but other durations are possible. New resources often receive longer contract terms than existing resources. In addition to contract duration, it must be determined how far ahead of time before the contract start date the contract should be procured. Typically, procurement is done one to four years ahead of the contract start date but other options are possible. The potential and timing of subsequent procurements after the initial procurement for rebalancing of volume procured must also be established. How often a procurement process is held and how many procurements are conducted for a delivery period must be established.
Resource eligibility

Criteria must be established to specify the resource types and volumes which qualify to provide capacity. Considerations include:

- Whether existing or only new resources will be eligible;
- The “firmness” of the resource, or degree of certainty that the resource would be able to provide energy if required, and the proportion of the resource which would be eligible to provide capacity; and
- Treatment and requirements for resources such as energy efficiency, price responsive load, cogeneration, intermittent renewable resources and interties.

Delivery requirements and performance incentives

The criteria for determining whether contracted supply has been delivered and the consequences of contract non-performance must be established. The method of determining any penalties and their potential amount must be determined. Whether or not additional incentives will be provided for capacity suppliers is another consideration. Consequences for not procuring sufficient capacity to meet obligations must also be established.

Market mechanics

Details about how the market works need to be determined, including:

- Segmentation, if any, of the market by location or technology types and size of market segments;
- Level of any price caps or floors;
- Market power mitigation and compliance monitoring process;
- Provision of data to market participants;
- Shape of capacity demand curve; and
- Role of secondary market

Allocation of costs

While not a market design detail per se, implementation of a capacity market would also require determination of how capacity costs would be allocated amongst load and how required funds would be collected. Any secondary process to assess reasonableness of capacity costs would need to be established.