Pricing Framework Recommendation to the Minister

RECOMMENDATION TO THE MINISTER | JULY 31, 2020

Contents

1.0 Context

On July 25, 2019, the Minister of Energy (Minister) requested that the Alberta Electric System Operator (AESO) conduct a review of the pricing framework in Alberta and provide a recommendation to the Government of Alberta on whether changes are needed to the price cap and floor, or if shortage pricing should be introduced in Alberta's energy-only market framework. A copy of the letter is attached as Appendix A.

The AESO undertook a thorough review of the existing pricing framework design and its ability to sustainably ensure reliable electricity into the future. This work was completed in consultation with Alberta Energy and with significant input from industry stakeholders.

To review the existing pricing framework, the AESO completed a jurisdictional review and thorough analysis. The analysis focused on the ability of the Alberta energy-only market-pricing framework to continue to send efficient short-term dispatch signals in real time, while also sending effective long-term investment signals to encourage new generation to be built when it is needed. When functioning as they should, these short- and long-term signals work together to ensure electricity supply adequacy: the appropriate level of supply to reliably and affordably meet demand (or electricity consumption) needs in the province.

This *Pricing Framework Recommendation to the Minister* report reflects the AESO's view that ensuring certainty and stability in the market is essential to achieve the appropriate level of investment to meet future electricity needs, while ensuring reliability. Any efficiency benefits that could be obtained from changes to the pricing framework should be evaluated in context.

2.0 Pricing framework objectives

Alberta's energy-only pricing framework consists of an administrative price cap set at $1,000/megawatt hour (MWh), an offer cap set at $999.99/MWh and an offer and price floor at $0/MWh. The pricing framework is intended to achieve a variety of short- and long-term objectives.

In the long term, the pricing framework should ensure clear and transparent signals on the need for capacity to promote long-term adequacy of supply to reliably meet demand. An important part of this signal is revenue sufficiency for generation to support competitive investment decisions needed to meet the long-term adequacy objectives. The signals the pricing framework provides to market participants in the short term enable generating unit self-commitment, facilitate load consumption or reduction decisions and encourage imports or exports. All of these responses are critical to ensure the pool price creates the right signals to encourage flexible and dynamic market participant responses. These market dynamics are critical in ensuring short-term supply adequacy.

The administrative price levels, the offer cap, price cap and price floor are intended to work together to allow the market to clear in a competitive fashion, while not hindering price signals and market response. The AESO worked with stakeholders to articulate the following key objectives of the administrative price levels.

OFFER CAP

The offer cap is intended as a form of market power mitigation. It should protect consumers from unreasonable costs and help mitigate potential market power issues resulting from the concentration of generation ownership and relatively inelastic demand for electricity. The offer cap should also provide a reasonable opportunity for the marginal generating asset to recover its fixed costs over the long term and its variable costs in the short term.

PRICE CAP

The price cap should indicate that the market is in a shortage condition and incent both demand and supply response during shortage situations. The price cap should also limit excessive wealth transfer from consumers to producers.

PRICE FLOOR

The price floor should allow for efficient pricing during supply surplus events. It should also help to mitigate the risk to producers of sustained negative pricing.

The AESO's assessment of the existing administrative price levels involved (1) a forward-looking analysis of the ability of the existing framework to provide sufficient revenue and adequate generation investment to meet Alberta's resource adequacy requirements in the long term and (2) the ability of the existing framework to incent efficient market response during scarcity and shortage situations. The AESO's review concluded that the current framework will continue to meet the short- and long-term objectives above. While there may be some incremental efficiency gains from a change to the price cap and price floor, at this time there is no pressing need for change and the need for stability and certainty of the market is of greater importance at this time than the improvements any change would be expected to provide.

3.0 Recommendation

The AESO recommends no change to the existing pricing framework in Alberta at this time.

The current framework has successfully attracted investment through time and is anticipated to continue to be effective in providing signals to the market for investments that meet Alberta's future resource adequacy and load growth requirements. The Alberta market-pricing framework has provided for a straightforward and effective market design that has stood the test of time, attracting generation when required while providing a high level of reliability. With this recommendation, the AESO also affirms the guidance provided in the AESO's November 2019 *Market Power Mitigation Advice to Minister* report.

The market has experienced substantial instability and uncertainty over the past number of years, and in the absence of a pressing need for change, the AESO believes that at this time the existing framework can successfully meet the short- and long-term pricing framework objectives while ensuring a stable and well-functioning market. As done historically, the AESO will continue to monitor the efficiency and effectiveness of the pricing framework and will identify if circumstances change that require a modification to any of the pricing framework elements. These changes would be undertaken through the AESO's existing rule-making process, with the adjudication of rule changes by the Alberta Utilities Commission (AUC).

4.0 Analysis

The AESO performed comprehensive analysis of the ability of the current pricing framework to satisfy key objectives. This work included the following analysis:

- A review of long-term adequacy and the ability for the market to provide revenue sufficiency to project developers.
- A review to determine whether the existing framework provides efficient short-term market response during supply-surplus and supply-shortage conditions.
- An assessment of whether the existing framework would ensure a robust market that provides competitive pricing signals needed for efficient market clearing as both supply and demand assets evolve in the future.

The following sections provide further background on the methodology, observations and conclusions from the analysis. Additional details can be found in the appendices to this report.

4.1 LONG-TERM ADEQUACY ASSESSMENT

To develop the recommendation provided in this report, the AESO reviewed the ability of the current pricing framework to promote long-term adequacy through revenue sufficiency. Revenue sufficiency is defined as the reasonable expectation that sources of supply will earn enough revenue to recover their capital and operating costs and earn a return on their investments. This is an important element of the energy-only market framework, where signals for market entry and exit occur solely through the energy price signal. This review was important to determine whether the offer cap is a barrier to achieving revenue sufficiency over the long term. In evaluating whether the offer cap is appropriate, the AESO completed modelling of the electricity market between 2021 and 2040.

The AESO conducted simulations that projected the construction and operation of future power generation facilities and then analyzed the expected resource adequacy from the resulting supply mix.

To test the pricing framework's ability to sustain resource adequacy through the energy-only market, the AESO utilized a simulation model to evaluate the sequential economic construction of new generation facilities throughout the next 20 years. The model was configured to select from simple-cycle, combined-cycle, wind, and solar facilities as such facilities became economic. Several future-build scenarios were modeled with the simulation software, and the results were subsequently tested for revenue sufficiency and resource adequacy. The revenue, capital cost, and operating costs for each new facility were combined to approximate the cash flow that the new asset would recover from the market. Internal rate of return (IRR) and payback period were measured as investment project metrics, which were compared to a benchmark weighted average cost of capital (WACC). When projects achieved IRRs equal to or greater than the WACC, they were deemed to have sufficient revenue.

To test for resource adequacy, the AESO used its probabilistic Resource Adequacy Model (RAM), to measure the expected unserved energy (EUE) that resulted from thousands of iterations of each forecast supply mix, considering different weather projections, load modifications, power plant outages and de-rates, intertie capabilities, and demand response sensitivities. The EUE results from the Monte Carlo simulation were then compared to the reliability threshold outlined in Alberta market rules to determine whether the modeled supply mix was adequate.

The AESO's Reference Case scenario resulted in new generation projects that were both revenue-sufficient and provided long-term resource adequacy. The other scenarios, which were considered to capture potential future uncertainties, are described as follows:

- **Reduced coal-to-gas conversions:** a scenario where two coal facilities retire instead of converting to natural gas operation.
- **Lower renewable capital costs:** a scenario with a 20 per cent reduction in renewable capital costs prior to 2026, and a 40 per cent reduction in renewable capital costs thereafter.
- **Increased Carbon Costs:** a scenario with carbon prices rising to $100/tonne by 2030 and natural gas costs increasing by $0.45/gigajoule (GJ) in 2023, $1.20/GJ in 2030, and $2.00/GJ in 2040.
- **Higher Coal-to-Gas Offers:** a scenario with different offering behavior for coal-to-gas conversion units, where variable offers were increased to 1.8X the variable cost of each coal-to-gas conversion unit, from 1.45X.

Each of these scenarios was able to demonstrate revenue sufficiency for the majority of new investments and resource adequacy for the grid.

The analysis showed that projects could be economically added under a wide array of scenarios, demonstrating that the existing market framework does not impede either the recovery of costs or the ability to earn a return on investment. The scenarios also demonstrated the ability to meet the AESO's Long Term Adequacy Threshold. This analysis is the basis for the AESO's conclusion that the current offer cap is expected to be sufficient to incent the level of generation investment needed to reliably meet demand.

4.2 SHORT-TERM EFFICIENCY ASSESSMENT

The AESO reviewed the existing price cap and price floor levels to determine the degree to which they promote efficient outcomes in the short term during supply-shortage and supply-surplus situations.

4.2.1 Price cap assessment

Efficient pricing during scarcity events is important to ensure that adequate signals are provided for short-term supply increases including response over the interties, load reductions and to a lesser extent long-term resource adequacy. Alberta's current price cap is administratively set at $1,000/MWh and is triggered upon the occurrence of firm load shed in the province due to a supply shortage. The AESO's review of the price cap involved determining whether the current level is sufficient to incent response from both supply and demand as the system approaches scarcity and shortage conditions. Scarcity and shortage conditions are defined as follows:

Supply scarcity versus supply shortage

- A **supply-scarcity** situation occurs when available energy in the energy market merit order is greatly reduced or zero.
- A **supply-shortage** situation occurs when there is insufficient energy supply available to meet demand and maintain required reserve levels.
  - Supply-shortage procedures are enacted per ISO rule 202.2.
  - In these situations the system controller may use operating reserve to balance the system, or if required, shed firm load.

To assess the response from supply to the price cap, the supply of energy from long lead time (LLT) assets and imports was analyzed. LLT assets have a start time of greater than one hour and the market participant has discretion to commit their units (unless they are directed on by a system controller). If the price cap is a barrier to incenting supply response, these LLT assets may remain offline during supply scarcity and supply shortage events due to insufficient revenues to cover the costs and risk of starting.

The AESO found that from 2015–2019 LLT assets had an average annual availability of 61 per cent during hours when the pool price was greater than or equal to $999.99/MWh. In all instances, unit unavailability was due to operational reasons rather than economic reasons. This suggests that the current price cap has been sufficient to incent response from LLT assets.

To assess the response from imports during supply scarcity and supply shortage events, the utilization of import available transfer capability (ATC) was analyzed in hours when the pool price exceeded $900/MWh. This analysis found very high utilization rates, greater than 90 per cent for the British Columbia and Montana interconnections in 2018 and 2019, with slightly lower utilization of the Saskatchewan interconnection. The AESO found lower utilization in the years 2016 and 2017 and concluded that response to be partially attributable to the relatively low-priced environment during those years. From this work the AESO concluded that the price cap is not a barrier to incenting response from imports. Intertie utilization during scarcity and shortage conditions will be monitored on an ongoing basis as the supply/demand balance evolves in the Western Interconnection.

To assess the response from demand during supply scarcity and supply shortage events, the AESO performed an analysis to estimate the potential for demand response at prices above the current price cap. As a proxy for higher pool prices, the AESO analyzed the response from load to the coincident metered demand (CMD) charge in the ISO tariff. During the sample period, the CMD charge was approximately $10,000/MW/month.

A regression was used to isolate the load that responds to the CMD charge but not the current pool price, suggesting that their willingness to pay for electricity falls between the price cap of $1,000/MWh and the CMD charge of approximately $10,000/MW/month. This analysis identified approximately 40 MW of load at 10 sites that exhibit this type of behaviour. This suggests that currently a small amount of demand response may be incented to respond if the price cap were increased above $1,000/MWh.

4.2.2 Price floor assessment

The price floor is the minimum price at which generation assets can offer supply to the market and is currently set at $0/MWh. Many jurisdictions employ negative pricing to promote a market-based approach to clearing during supply surplus events. The purpose of the price floor review was to determine if the current floor of $0/MWh was a barrier to efficient clearing during supply surplus events and if the AESO should consider implementing negative pricing in the pricing framework.

Supply surplus events occur when there is excess supply relative to demand. As supply and demand in an electricity system must always remain in balance, supply surplus can introduce an operational challenge where AESO system controllers must impose administrative curtailment rules to direct involuntary reductions of imports or generation. Negative pricing would enable market participants to signal their willingness to incur a cost to avoid curtailment during supply surplus conditions rather than through involuntary curtailment by the AESO.

The AESO has calculated the efficiency gains associated with a transition from a $0/MWh price floor to a negative price floor by reviewing how the price floor impacts generation curtailment during supply surplus hours. Under the current framework, as detailed in Section 202.5 of the ISO Rules, curtailments during supply surplus events are first applied to imported energy and then applied to in-province supply on a pro rata basis. To determine the efficiency gains of negative pricing, a model was created which allowed for negative prices to be incorporated into the merit order. Introducing a negative price floor would allow market participants to determine when to economically curtail their assets, which may result in different curtailments than the current administrative process. The AESO calculated the cost of curtailment associated with 67 supply surplus events between 2015–2019 and determined that negative pricing during this time period would have provided minimal efficiency gains to market outcomes.

5.0 Pricing alternatives and recommendation rationale

5.1 DESCRIPTION OF ALTERNATIVES

In determining whether changes should be made to the pricing framework, the AESO prepared three possible change scenarios and tested the scenarios against the pricing framework objectives. While the AESO's work indicated the existing pricing framework sends the appropriate signals to the market to ensure long-term adequacy of supply under a variety of scenarios, the AESO considered whether changes to the framework may provide an opportunity to implement more market-based rather than administrative response during shortage and surplus conditions to further incent system flexibility and support the efficient transformation of the electricity system. The three scenarios tested were:

- **Option A:** Implement an increased price cap and negative price floor now to incent market-based responses during supply-shortage and supply-surplus situations.
- **Option B:** Implement Option A in the future, delaying implementation due to current economic challenges from low commodity prices and the administrative challenges that have affected market participants as a result of the COVID-19 pandemic.
- **Option C:** Maintain the current pricing framework. The AESO will continue to monitor the state of the market for signs of system inefficiency and reduced long-term adequacy.

Appendix 8.4 describes the AESO's review of each of the options and the rationale the AESO used to arrive at the determination that, at this time, no change is required to the existing pricing framework. Although some efficiencies could be gained, they do not outweigh the cost of implementation and the disruption to market stability and certainty. The existing pricing framework has been effective through time and is expected to continue to achieve the objectives of reliability, adequacy and affordability of the energy-only market in Alberta.

6.0 Stakeholder feedback

The AESO conducted a collaborative stakeholder engagement process on the pricing framework from February to May 2020. The process included three separate sessions and the receipt of both verbal and written feedback from stakeholders. Stakeholders provided input and perspectives on the objectives of the pricing framework in Alberta, the AESO's approach to its review and the findings and conclusions from the review. A total of 19 different stakeholders participated, covering a broad range of market participants, agencies and various associations.

Through the stakeholder process the AESO presented its analysis of the ability of the pricing framework to promote both short- and long-term outcomes and assessed the efficiencies that could be gained by modifying the existing pricing framework. The AESO tested with stakeholders its draft recommendation to maintain the existing pricing framework. The majority of stakeholders were in agreement with the AESO's draft recommendation, indicating that the existing framework has been highly successful in Alberta and the decision to maintain the framework would minimize uncertainty and ensure stability.

A few stakeholders did suggest changes. One stakeholder agreed with the draft recommendation to maintain the existing framework, however, suggested a periodic increase in the price cap, i.e., adjusting it in accordance with inflation. Another stakeholder suggested that the AESO amend its draft recommendation to include a gradual, proactive and transparent increase of Alberta's price and offer cap to ensure: improved resiliency with increased renewables; greater efficiency; and, more effective competition.

The majority of stakeholders were in support of maintaining the status quo. A few also suggested that the AESO should consider periodic reviews of the pricing framework and noted that these reviews may or may not result in a change to the pricing framework in Alberta.

7.0 Concluding remarks

The pricing framework review has been a valuable exercise to confirm the intent of the pricing framework in Alberta and to validate the ability of the existing framework to send efficient signals that support reliability and an efficient market in both the short- and long-term. Alberta's electricity system is undergoing significant transformation:

- Coal generators are being phased out.
- Renewable generation is increasing.
- Distributed generation sources are continuing to be built, providing increased volumes of supply to the grid.
- New loads are emerging with differing responses to energy price signals than have been observed in prior years.

As part of the AESO's mandate to provide for the safe, reliable and economic operation of Alberta's electricity system while facilitating a fair, efficient, and openly competitive (FEOC) market, the AESO will continue to monitor the efficiency and effectiveness of the pricing framework.

In the future, should the AESO determine that efficiency losses warrant a further review of the pricing framework, the AESO will consult with stakeholders on its findings. If through that process changes are determined to be beneficial, the AESO will draft appropriate market rule changes and present the changes to the AUC for adjudication.

Appendix A:

Letter from the Minister of Energy dated July 25, 2019

ALBERTA
ENERGY

Office of the Minister
Deputy Government House Leader
MLA, Calgary-North West

July 25, 2019

AR33195

Mr. Will Bridge
Board Chair
Alberta Electric System Operator
330-5 Avenue SW
Calgary AB T2P 0L4
will.d.bridge@gmail.com

Dear Mr. Bridge:

Over the past several weeks, I have met with both senior officials of the Alberta Electric System Operator (AESO) and stakeholders representing broad interests across the sector on the subject of Alberta's market design.

After careful consideration, the Government of Alberta has decided it is in the public interest to return to the existing energy-only market. Alberta's energy-only market is a proven system that has successfully attracted investment into the province and supported a high quality of life for Albertans. Government believes the existing energy-only market will continue to provide Albertans with a reliable supply of electricity at affordable prices.

We understand that timely implementation of this decision is key to providing policy clarity to agencies. Government intends to introduce legislation as quickly as possible to halt implementation of a capacity market and return to an energy-only market.

During the consultations, I heard concerns about a lack of clarity regarding mandates and roles of Alberta's electricity agencies. I have directed Alberta Energy to examine and propose options to address these concerns.

In addition, I heard repeatedly that certainty and stability in electricity market design are critical to secure future investment in our electricity system and our province. I also heard a range of views on whether the existing energy-only market requires design changes to remain successful in the future. Because of the clear need for certainty and stability, I am

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directing the AESO to take a measured and thoughtful pace to examining if any changes to the existing energy-only market are needed, and to work in consultation with Alberta Energy. By July 31, 2020, the AESO must provide me with analyses and recommendations on whether changes are needed to the price floor/ceiling and shortage pricing in Alberta's energy-only market. I ask require a status update on this work on or before February 1, 2020.

I also heard repeated references to concerns with market power and market power mitigation. In response to those concerns, I have asked Alberta Energy to complete a policy review of this particular issue for both the energy-only and ancillary services markets. I ask the AESO to submit its advice on this topic to me by November 29, 2019.

Please accept my sincerest gratitude for the AESO's availability and advice during the 90-day review and your significant and high-quality efforts to date. The government of Alberta continues to value and rely on the AESO to support our outcomes regarding the implementation and operation of Alberta's energy-only market, which supports our broader economy and benefits all Albertans. I know I can count on the AESO's full support as we implement this decision and seek to restore predictability and certainty to Alberta's electricity market design.

Sincerely,

Sonya Savage

Sonya Savage
Minister

cc: Mike Law, President and Chief Executive Officer, AESO
Grant D. Sprague, Q.C., Deputy Minister of Energy
Doug Lammie, Assistant Deputy Minister of Electricity and Sustainable Energy

Appendix B:

Long-term adequacy assessment

Revenue sufficiency and resource adequacy analysis

The AESO reviewed the existing pricing framework to determine if the existing market structure could continue to deliver an adequate supply of electricity, through incenting investment in generation capacity. In order to review the market resource adequacy and revenue sufficiency, the AESO developed a range of scenarios to account for future uncertainty and then developed simulations and commensurate economic evaluations.

The simulations employed the Aurora Electric Modeling Forecasting and Analysis Software (Aurora) and the Resource Adequacy Model (RAM) that employs the Strategic Energy & Risk Valuation Model (SERVM) software. The Aurora model was used to simulate economic generation builds and operation in several different scenarios. The RAM was used to test the resource adequacy of the resulting generation fleet in each Aurora scenario. The RAM determined the resource adequacy metric which was measured as expected unserved energy (EUE), or the annual average unserved energy from 7,500 simulations of each scenario.

For each scenario the AESO analyzed revenue sufficiency by estimating the cash flow of every new generation facility added to the model. The internal rates of return (IRRs) and payback periods were calculated to approximate investment return metrics demonstrated by each new generation project. The IRRs were compared to the expected weighted-average-cost-of-capital (WACC) which was used to approximate an investment hurdle rate for new generation. If the simulated generation additions were able to meet or exceed the WACC they were deemed to be prudent economic investments.

Separately from the economic investment metrics, the AESO analyzed the resource adequacy of the simulated generation fleet at future dates. For each scenario the AESO ran 7,500 simulations, randomizing generation facility outages, economic conditions, and weather conditions. This simulated fluctuations in the supply of generation available (wind generation, solar generation, hydroelectric generation, and thermal plant output) and the demand for electricity in the Province of Alberta and in interconnected neighboring jurisdictions.

The amount of unserved energy measured in each scenario was recorded and an annual average EUE was calculated. The amount of average EUE in the scenarios was compared to the AESO’s supply adequacy standard, defined in Rule 202.6. The rule implies a maximum expected unserved energy amount equal to 0.00114 per cent of the energy delivered. When the simulations provide an average EUE below this threshold the resource adequacy requirement has been achieved, Conversely, when the simulations indicate average EUE above this threshold there may be additional monitoring and interventions required in order to maintain the reliability of the system.

Methods of analysis

The analysis of the market revenue sufficiency and resource adequacy assessments rely on certain key assumptions that drive the Alberta electricity demand forecast, the expected generation supply additions, cost and operating parameters for new generation facilities, and macroeconomic assumptions.

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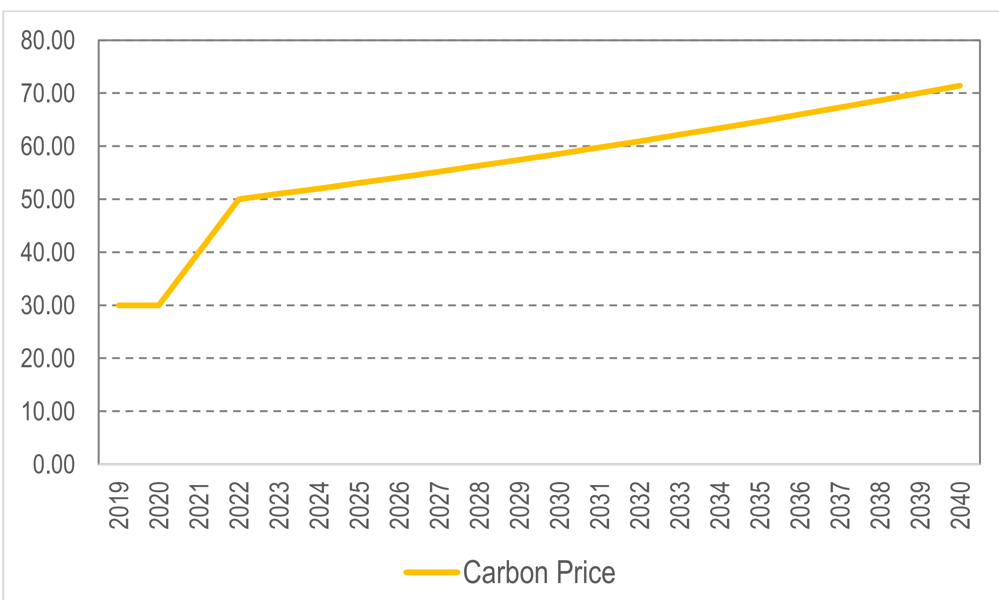
Key economic assumptions

The key economic assumptions included a weighted average cost of capital (WACC) of 10.5 per cent, pretax. This weighted average cost of capital reflected a 15 per cent cost of equity and a 6 per cent cost of debt, with a 50 per cent debt and 50 per cent equity capital structure. The WACC created a hurdle rate that investments would be expected to achieve in order to be considered viable and financially prudent. The WACC was used as an input to the Aurora XMP forecasting model to calibrate the return expectations for new generation facility additions. When reviewing the investment IRRs, the AESO compared the results to the WACC in order to confirm that revenue sufficiency could be met by the generation additions selected by the Aurora XMP forecasting model in each scenario.

Carbon price assumptions have a meaningful impact on existing and future generation fleet operations. Existing facilities' operations can change based on the costs associated with carbon policy. Future generation additions can also change depending on the carbon regulations that they expect to face during their economic life. The carbon policy modeled in the AESO's reference case scenario relied on $30/tonne carbon price in 2020, $40/tonne carbon price in 2021, and $50/tonne carbon price in 2022. Thereafter, the carbon price was increased at an inflationary rate of 2 per cent per annum.

The carbon policy that the AESO assumed relies on the Technology Innovation and Emissions Reduction Regulation (TIER) framework. Carbon policy impacts fossil fuel powered thermal facilities that may need to pay additional variable costs, but it can also impact the revenues that renewables facilities can monetize for the value of carbon offsets or emissions performance credits. The estimated cost for fossil fuel powered thermal facilities was estimated as the difference between the emissions intensity of the generator (tonnes/MWh) less the high-performance benchmark of 0.37 tonnes/megawatt hour (MWh), multiplied by the carbon price. In the case of renewables generation, a carbon credit was calculated and applied to the revenues that a facility would receive based on the expected future grid intensity.

Figure 1: Carbon price assumptions ,$/tonne

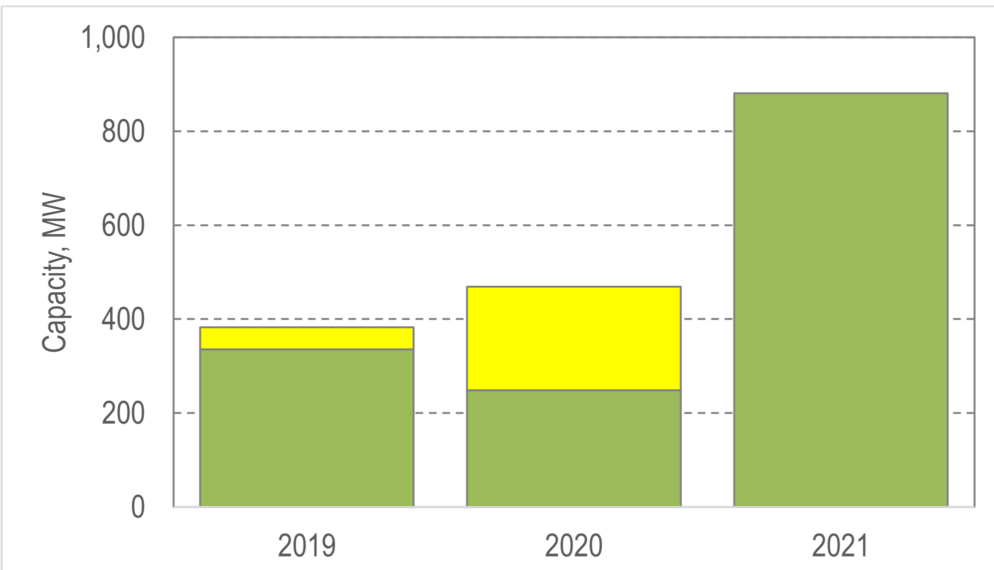


Generation supply assumptions

The modeled scenarios rely on several near-term generation supply additions that are reasonably expected to commercialize in the next several years. Renewables generation additions, including 1,465 MW of wind development and 268 MW of solar development were included in each scenario prior to 2021. The renewables additions included all of the Renewable Electricity Program generation projects, as well as recently announced contracted wind and solar projects.

Thermal generation additions included conversion of 4,890 MW of coal generation to natural gas-fired generation by 2030 and 495 MW of cogeneration additions by 2030. The forecast also included 50 MW of storage in 2031. With these baseline assumptions the Aurora model was programmed to select the economic generation additions throughout the 2021 to 2040 timeframe in each scenario.

Figure 2: Renewables generation additions



In each scenario the Aurora model selected economic generation additions from a set of potential technologies including combined-cycle natural gas, simple-cycle natural gas, solar photovoltaic, and wind generation. These technologies represent the most likely generation additions in the foreseeable future and coincide with numerous announced and planned generation facilities in Alberta. The characteristics of the generation technologies and their costs are exhibited in Table 1.

Table 1: Generation technology characteristics and costs

Facility Type	Overnight Capital Cost ($/kW)	Fixed O&M ($ / kW-year)	Variable O&M ($/MWh)	Carbon Price ($/MWh)	Generator Capacity (MW)	Heat Rate (GJ/MWh)
Combined-Cycle Natural Gas	1,667	$49.71	$2.49	0.0235 t/MWh x carbon price	479	7.03
Simple-Cycle Natural Gas – Aeroderivative	1,159	$52.83	$4.24	0.1719 t/MWh x carbon price	46.5	9.68
Solar Photovoltaic – 2021-2025	1,643	$31.85	-	Credit: grid intensity x carbon price	50	N/A
Solar Photovoltaic – 2026-2030	1,388	$31.85	-	Credit: grid intensity x carbon price	50	N/A
Wind Generation - 2021-2025	1,586	$32.50	-	Credit: grid intensity x carbon price	50	N/A
Wind Generation - 2026-2030	1,105	$29.25	-	Credit: grid intensity x carbon price	50	N/A

Supply additions were selected by the Aurora model through an iterative process, whereby the economic viability of developing each new facility was simulated with consideration of the existing generation fleet at that time. The model would then iterate subsequent generation additions using a similar process to review which additions were most economic and determine a final set of generation additions for the scenario. The process was run until 2045 and the terminal year of the AESO's revenue sufficiency analysis was 2040. All cash flow estimates subsequent to 2040 were based on the terminal year of 2040 until the end of the useful life of the asset.

Load forecast assumption

The provincial load forecast assumed in the analysis reflects the AESO's expectations published in the *AESO 2019 Long-term Outlook* Reference Case[1] under average weather conditions. This Alberta internal load (AIL) forecast is markedly lower than the *AESO 2016 Long-term Outlook* Reference Case load forecast and reflects lower GDP growth than was anticipated at that time. As a result, fewer new generation facilities are required to meet generation demand than previously anticipated.

[1] https://www.aeso.ca/assets/Uploads/AESO-2019-LTO-updated-10-17-19.pdf

Aurora forecasting program

The Aurora program was configured to simulate electricity market conditions in Alberta. The existing fleet of generation assets and near-term anticipated additions were input into the software including operating characteristics for each facility. The AESO also programmed the load forecast based on the most recent *AESO 2019 Long-term Outlook* Reference Case scenario. The Aurora software was allowed to select long-term generation additions as the algorithm deemed them to be economic. The generation fleet, generation output, unit revenue, and unit operating costs were extracted for all units in each scenario, and the AESO used this information to approximate the cash flow of each new generation facility.

Resource adequacy assessment

The generation fleet resulting from the Aurora simulations was subsequently programmed into the RAM, and market conditions were reviewed at five-year intervals in 2021, 2026, and 2031. Each year's generation supply and market demand was simulated using 7,500 iterations, incorporating variability in weather patterns, and generation plant availability. A sensitivity on demand response was performed whereby 200 MW of additional demand response was emulated in each scenario. This demand response sensitivity would emulate known voluntary load reduction in situations where price was very high. From each iteration the unserved energy in the scenario was recorded and the average amount of unserved energy from all iterations determined the EUE. In all scenarios the EUE was compared to the resource adequacy standard from rule 202.6. When EUE was less than the resource adequacy standard supply adequacy was deemed to have been met.

Revenue sufficiency

The Aurora simulation model produced individual plant capital and operational simulations. The cash flows from these individual plant decisions were recorded and analyzed as a stream of cash inflows (revenues) and outflows (costs). The associated IRRs and payback period calculations were recorded for each new generation facility and then compared to the WACC to determine if revenue sufficiency could be met under the simulated market conditions.

Scenario modeling and results

Reference case

The AESO Revenue Sufficiency and Resource Adequacy Modeling reference case included the carbon, growth, and economic assumptions outlined above. In this scenario, coal facilities were phased out by 2029 and replaced with coal-to-gas conversions. As coal to gas facilities retired in the 2030 to 2037 timeframe, combined cycle and simple cycle facilities replaced the void in capacity. Throughout the forecast period economic renewables additions augmented the dispatchable generation additions.

Figure 3: Reference case - generation additions & retirements

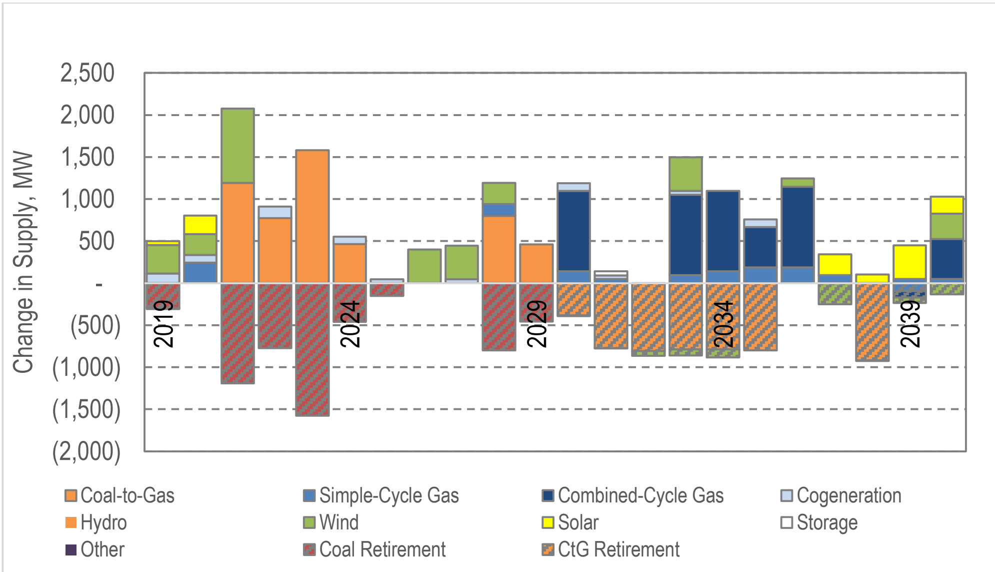
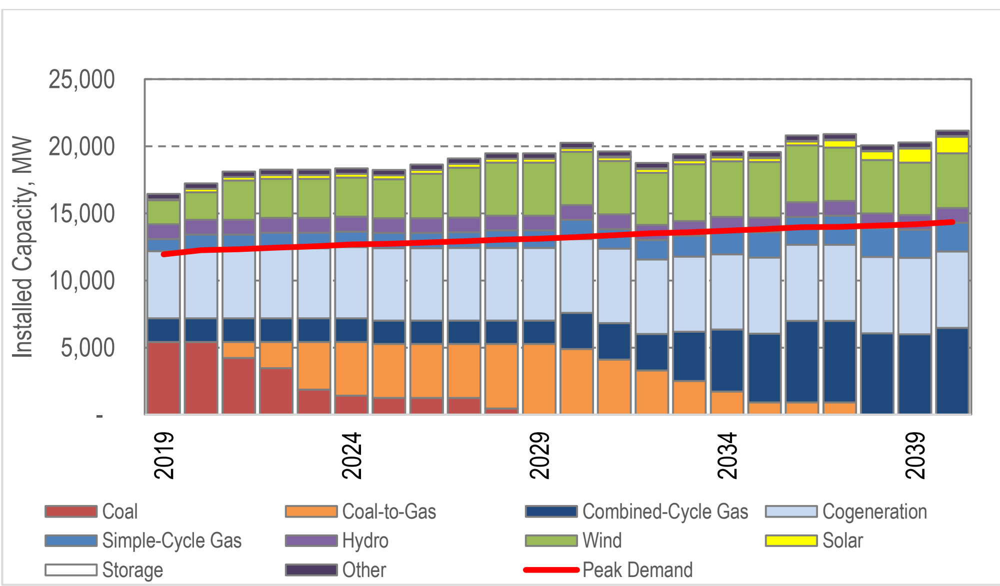


Figure 4: Reference case – generation supply mix



The AESO measured the cash flow for each new generation facility that the Aurora model emulated. By measuring the cash flow, the AESO was able to calculate the IRR and payback period investment metrics that the project proponents could expect to receive. Combined cycle, simple cycle, and wind assets were able to produce IRRs that exceeded the WACC. Payback metrics also exhibited return of capital in seven or less years for these assets.

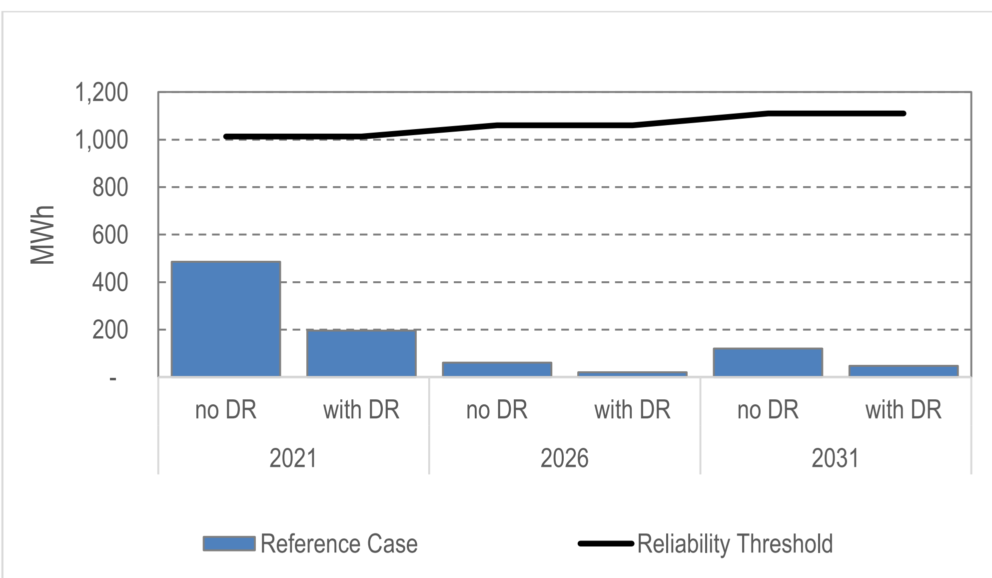
Solar assets were added by the Aurora model towards the end of the forecast, near 2040. However, due to limitations within the model, results beyond 2040 were not reported, and as such, 2040 was treated as a terminal year: The cash flow for 2040 was repeated until the end of the useful life of each asset. As such, the return results for builds in the later part of the forecast should be considered approximate only. Coal-to-gas conversion financial metrics indicated that these were attractive investments for the majority of the projects.

Table 2: Investment return metrics by generation facility type

Facility Type	Average Return (%)	Average Equity Return (%)	Average Unlevered Payback Period (years)	Average Levered Payback Period (years)
Combined Cycle	15%	22%	6	4
Simple Cycle	13%	21%	7	4
Wind	21%	33%	5	4
Solar	7%	7%	12	12

In the Reference Case scenario the reliability metric demonstrated elevated levels of EUE in 2021. That scenario simulated 486 MWh of average unserved energy in the sensitivity with no demand response. When 200 MW of demand response was added the average unserved energy was reduced to 196 MWh. In both cases the EUE was below the resource adequacy threshold. The years 2026 and 2031 did not demonstrate concerning levels of EUE, in cases with or without additional demand response.

Figure 5: Reference case - expected unserved energy



Reduced coal-to-gas conversions

The reduced coal-to-gas conversion scenario simulated a potential future scenario where two coal units retired in 2021 instead of converting to natural gas operation. The omission of these two units led to a reduced supply cushion in the early 2020s, and new combined cycle generation filled the void in 2024 and 2025. This scenario also resulted in more solar photovoltaic installations throughout the 2030s than the reference case. The financial returns for new facilities were very similar to those exhibited in the reference case despite the change in generation mix.

EUE results were below the reliability threshold with one exception: In 2021, the sensitivity with no demand response resulted in an exceedance of the reliability threshold. The scenario demonstrates an extreme case since the facilities that are omitted from conversion would likely be economic as development projects. Furthermore, the 2021 timeframe does not provide sufficient lead-time to develop new generation facilities. The AESO produces regular reporting on supply adequacy in the two to five-year timeframe through its quarterly long-term adequacy (LTA) reporting. Recent reports have not indicated concerns regarding 2021 and the AESO will continue to monitor the situation.

Figure 6: Reduced coal-to-gas conversions: generation additions & retirements

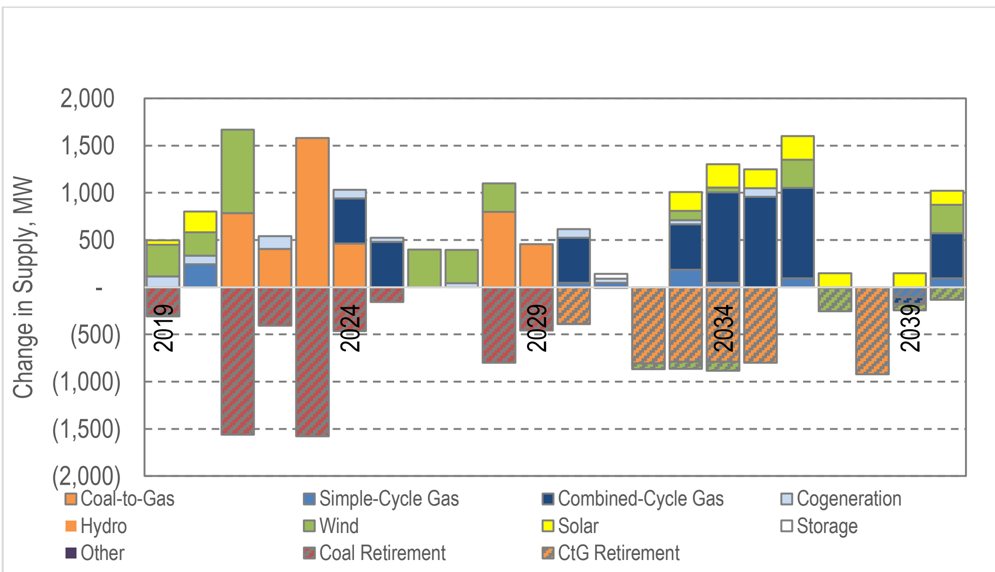
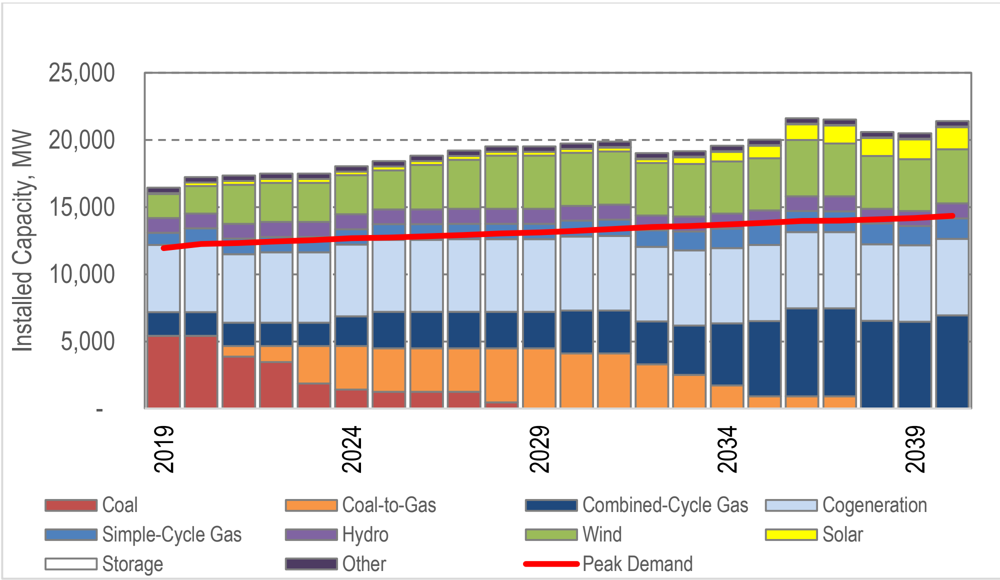


Figure 7: Reduced coal-to-gas conversions: generation supply mix



Reduced renewables capital costs

The AESO reviewed a scenario that incorporated significantly lower renewable generation capital costs than the reference case. In this scenario the capital costs of wind and solar facilities were reduced from the reference case by 20 per cent in the near term, between 2019 and 2025, and by 40 per cent in the longer term, beyond 2025. This scenario resulted in stronger financial returns to renewables facilities due to reduced cash out-flows, and enabled almost 1,500 MW of incremental renewable capacity by 2030. A substantial portion of the incremental renewables capacity was solar photovoltaic. The reduced renewables cost scenario provided similar investment returns for natural gas and renewables asset types and EUE was consistently below the resource adequacy threshold in all years, with and without demand response.

Figure 8: Reduced renewables costs: generation additions & retirements

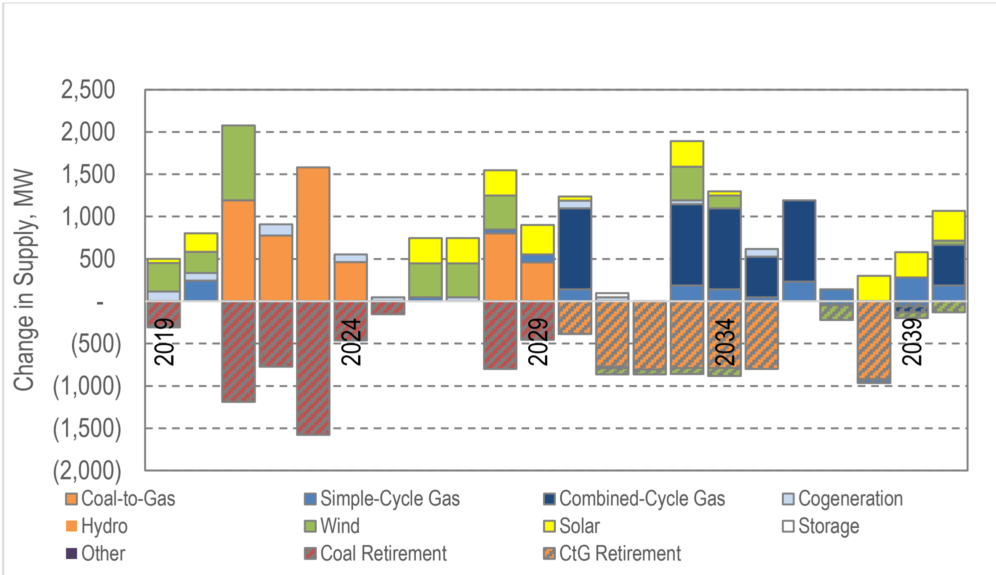
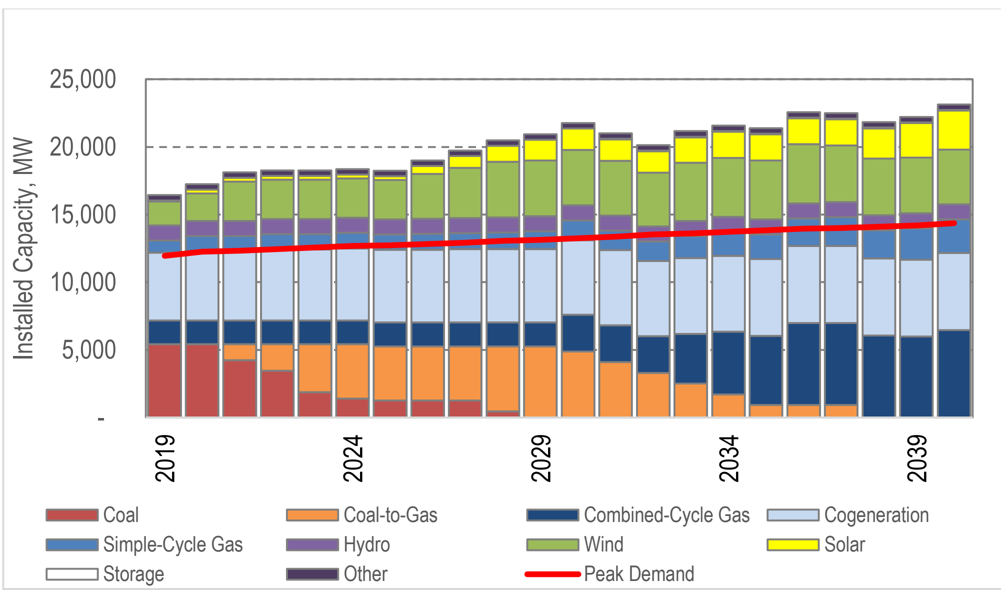


Figure 9: Reduced renewables costs: generation supply mix



Increased carbon costs

The AESO reviewed a scenario where carbon prices were increased, both on emissions and on input fuels. In this scenario the carbon cost was increased to $40/tonne in 2021, then to $50/tonne in 2022, and then incrementally to $100/tonne by 2030. Thereafter, the carbon price was increased at an inflationary rate of 2 per cent. This scenario also included a tax on the cost of natural gas of $0.45/GJ starting in 2023, $1.20/GJ starting in 2030, and $2.00/GJ starting in 2040. The tax on natural gas was intended to reflect a clean-fuel standard. The impact on fossil fuel-fired generation was a significant increase to the variable cost of operation, whereas renewables generation benefitted from the increased revenue associated with the higher value of carbon offsets and higher pool prices.

In this scenario, significantly more wind and solar generation was installed than in the reference case. Over 1,000 MW of additional wind and solar was installed by 2030 and additional renewables capacity was added in the late 2030s. Less efficient simple-cycle natural gas units experienced much higher variable costs and fewer simple cycle facilities were built in the 2030s as a result. The returns for new simple cycle, wind, and solar facilities increased significantly, since coal-to gas units experienced the largest variable cost increase and set marginal price frequently.

The average unlevered IRR for wind facilities was 29 per cent, well above the WACC. The average unlevered IRR for solar facilities was 11 per cent, which also exceeded the WACC. Returns on natural gas-fired generation also increased, although fewer facilities were constructed. In terms of resource adequacy, the threshold was not exceeded in any of the years that were simulated (2021, 2026, and 2031), neither with nor without demand response sensitivities.

Figure 10: Carbon price assumption, $/tonne

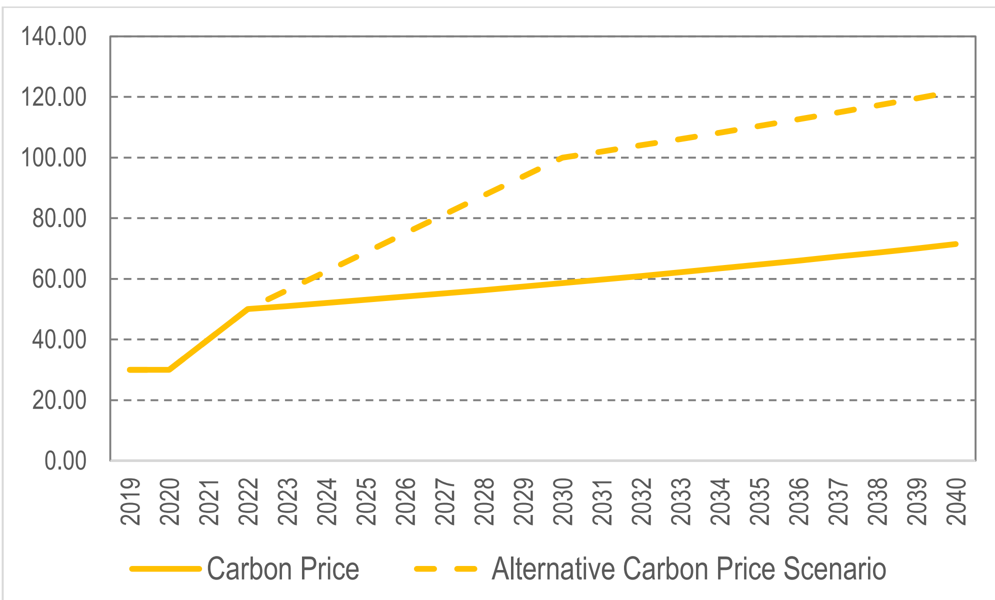


Figure 11: Increased carbon costs – generation additions and retirements

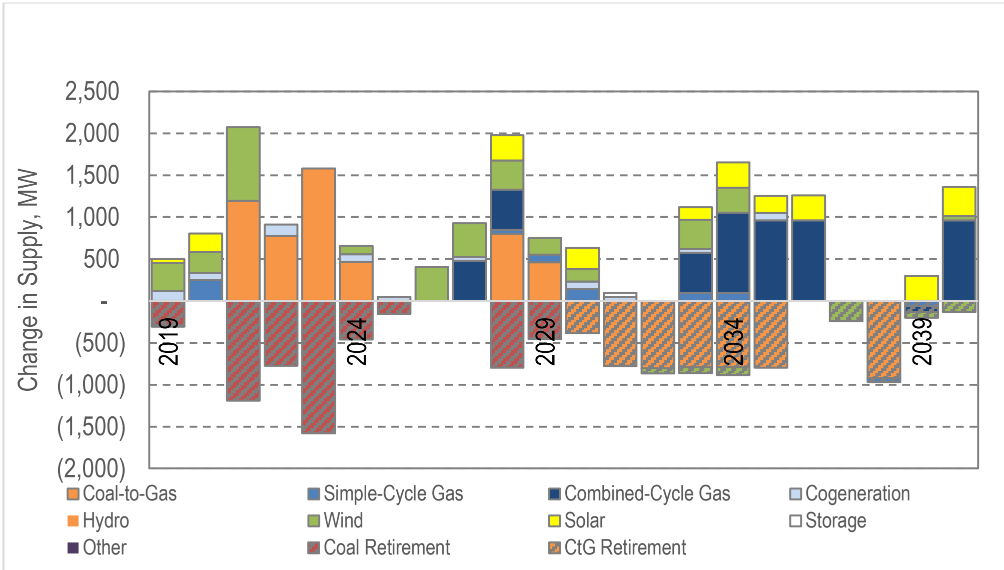
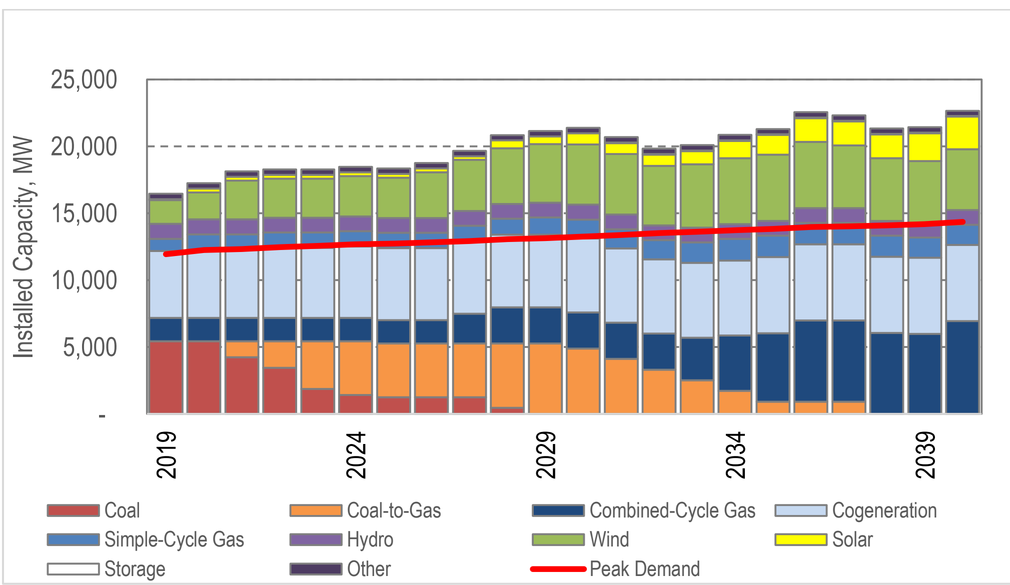


Figure 12: Increased carbon costs – generation supply mix



Higher priced coal-to-gas offers

As an alternative to the reference case scenario, the AESO simulated a scenario whereby the reference case's asset fleet was maintained but the offering behavior for coal-to-gas conversion units was altered. This scenario was intended to emulate changed offering behavior for assets that may operate less frequently as a result of the switch to natural gas operation. Increased operational flexibility may change the offering behavior for coal-to-gas converted units. This scenario also tests the possibility that coal-to-gas converted units may contribute less to reliability due to more frequent cycling of long lead-time assets.

In this "high coal-to-gas offers" scenario, the energy market offers for all generation above a coal-to-gas conversion facility's minimum stable generation level were made at higher prices than the reference case. Specifically, the offer blocks were priced at 1.8 X the variable cost of the unit, as opposed to 1.45 X the variable cost of the unit in the reference case. As a result, this scenario resulted in lower capacity factors and output from coal-to-gas units. Simple-cycle gas facilities, combined-cycle gas facilities and renewables facilities were built years earlier than the reference case. Internal rates of return for new generation facilities were modestly higher than the reference case for all generation types. This scenario resulted in similar resource adequacy results to the reference case as well, with no exceedances of the threshold.

Figure 13: High coal-to-gas offers: generation additions and retirements

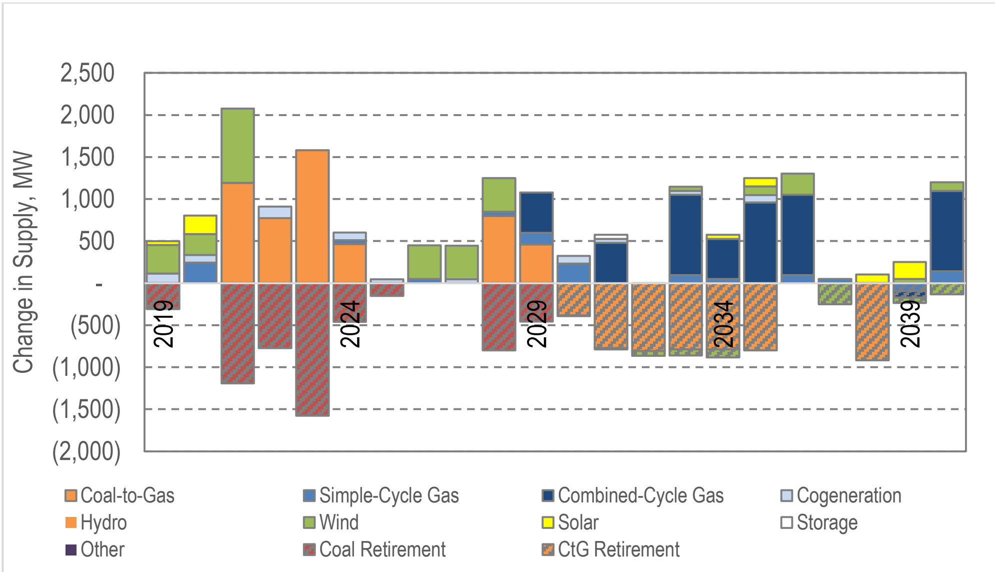
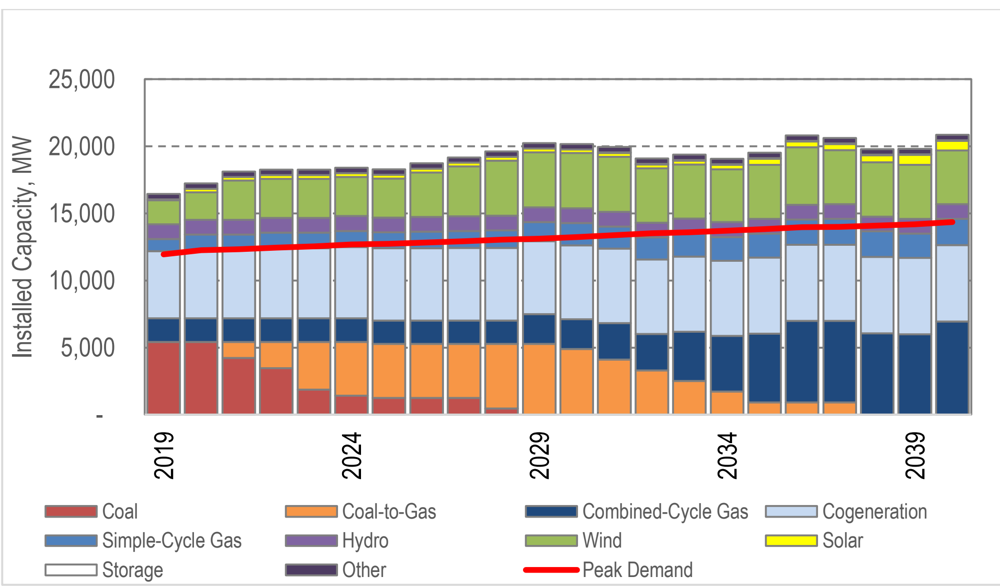


Figure 14: High coal-to-gas offers: generation supply mix



Revenue sufficiency results

In all of the scenarios that the AESO reviewed revenue sufficiency was expected to be achieved for most new generation assets. Timing of new generation assets was important in maximizing cash flow and return metrics, and not all assets were able to achieve returns equal to, or in excess of, the WACC.

However, the average return for new natural gas and renewables assets was attractive in most scenarios. Individual scenarios based on technological outcomes, government policy, and plant operations did result in changes to the generation economics and resulting generation fleets. This dynamic is considered to be a healthy outcome in the energy-only market: The most economic generation projects are expected to develop, while more marginal projects are likely to fail.

Table 3: Investment return metrics by technology and scenario

Facility Type	Average Unlevered Internal Rate of Return (%)	Average Levered Internal Rate of Return (%)	Average Unlevered Payback Period (years)	Average Levered Payback Period (years)
Combined Cycle				
Reduced Coal-to-Gas	14%	21%	7	5
Reduced Renewable Costs	15%	22%	6	4
Policy Driven Renewables	17%	26%	6	4
High Coal-to-Gas Offers	15%	23%	6	4
Simple Cycle				
Reduced Coal-to-Gas	14%	24%	7	5
Reduced Renewable Costs	13%	21%	7	4
Policy Driven Renewables	19%	33%	5	3
High Coal-to-Gas Offers	16%	27%	6	5
Wind				
Reduced Coal-to-Gas	21%	32%	5	4
Reduced Renewable Costs	21%	33%	5	4
Policy Driven Renewables	29%	49%	4	3
High Coal-to-Gas Offers	22%	35%	5	3
Solar				
Reduced Coal-to-Gas	6%	6%	13	13
Reduced Renewable Costs	7%	7%	12	12
Policy Driven Renewables	11%	15%	9	7
High Coal-to-Gas Offers	9%	11%	10	8

Resource adequacy results

In the scenarios that the AESO reviewed, resource adequacy was achieved in each of the five-year intervals considered, 2021, 2026, and 2031. One scenario, reduced coal-to-gas conversions, resulted in a potential resource adequacy issue in 2021. This scenario represents a near-term possible exceedance of the resource adequacy threshold, and the AESO will continue to monitor resource adequacy via quarterly Long Term Adequacy reports, and with information regarding generation development, refurbishment, and retirement from market participants. Overall, the AESO has concluded that the pricing framework can continue to supply the electricity needs of Albertans, while enabling revenue sufficiency.

Conclusions

The AESO does not recommend change to the existing offer cap.

The AESO's long-term adequacy assessment demonstrated several plausible future scenarios where resource adequacy and revenue sufficiency can be achieved by the existing pricing framework. This analysis lends support to the level of the existing offer cap. Through offer strategies based within the current offer cap and within the competitive boundaries set out in the Fair Efficient and Openly Competitive (FEOC) Regulation, asset competitiveness and reasonable economic returns for assets can be achieved.

The existing offer cap is expected to enable diverse generation investment while ensuring the resource adequacy requirements of the Alberta Interconnected Electrical System (AIES) are met. The following sections describe the AESO's assessment of the shorter-term efficiency benefits that were identified when considering changes to the price cap and the price floor.

Appendix C:

Short-term efficiency assessment

Appendix C: Short-term efficiency assessment

A key step in the pricing framework review was to assess the framework's efficiency and effectiveness in incenting market response and supply adequacy in the short term. This involved analyzing historical market response during supply shortage and supply surplus situations to examine the effectiveness of the current price cap and floor levels. The following sections outline the analysis on the price cap and price floor and summarize the AESO's findings on each framework component.

Price cap assessment

The price cap assessment involved reviewing whether the current administrative level is a barrier to providing efficient price signals to the market during supply scarcity and shortage situations. Specifically, the review was focused on determining whether the existing price cap provides signals for:

- Generators to commit or respond to shortage situations
- Flexible demand to economically curtail
- Sufficient supply of power over the interties during scarcity and shortage situations

Frequency and magnitude of historical and forecast supply-shortage situations

In the Alberta market, the current price cap is set at $1,000/megawatt hour (MWh) and the offer cap is set at $999.99/MWh. Supply-scarcity situations are characterized by reduced offers available for dispatch in the supply curve; this situation is often characterized by escalating energy prices as a result of the dispatch of higher-priced supply offers from market participants. A supply-shortage situation occurs when there is insufficient energy supply available to meet demand and maintain required contingency reserve levels.

In daily operation, the AESO assesses short-term supply adequacy to determine the likelihood of a supply-shortage event in upcoming settlement periods. If a supply-shortage situation is imminent, the AESO's system controllers follow a set of procedures to maintain regulating reserves and avoid shedding firm load per ISO rule 202.2. Energy emergency alerts (EEA) are a way for the AESO to communicate scarcity and shortage conditions to the market, to intra-provincial transmission and distribution system operators, and to extra-provincial balancing authorities. Following are summaries of the four EEA stages of ISO rule 202.2.

Energy Emergency Alert 1

- EEA1 is declared after all available resources in the energy market have been used to meet AIES firm load
- Sufficient operating reserves are intact – the ISO is still carrying about 500 MW of contingency reserves
- Energy is imported through the interconnections with BC and Saskatchewan as per schedules
- Energy exports are reduced to zero
- The AESO issues a directive to customers who have Demand Opportunity Service (DOS) contracts to lower their demand on the AIES
- Any transmission maintenance that results in generation constraints is cancelled
- System marginal price (SMP) is set at last offered MW, often $999.99/MWh

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Energy Emergency Alert 2

- All steps under Alert 1 have been taken
- Power service is maintained for all firm load customers
- Contingency reserve are being used to supply energy requirements, regulating reserve requirements are maintained
- Load management procedures have been implemented, which may include voltage reduction by distribution facility owners
- A public communication may have been issued to request customers to voluntarily reduce demand
- Emergency energy has been requested of neighbouring control areas
- System marginal price (SMP) is set at last-offered MW, often $999.99/MWh

Energy Emergency Alert 3

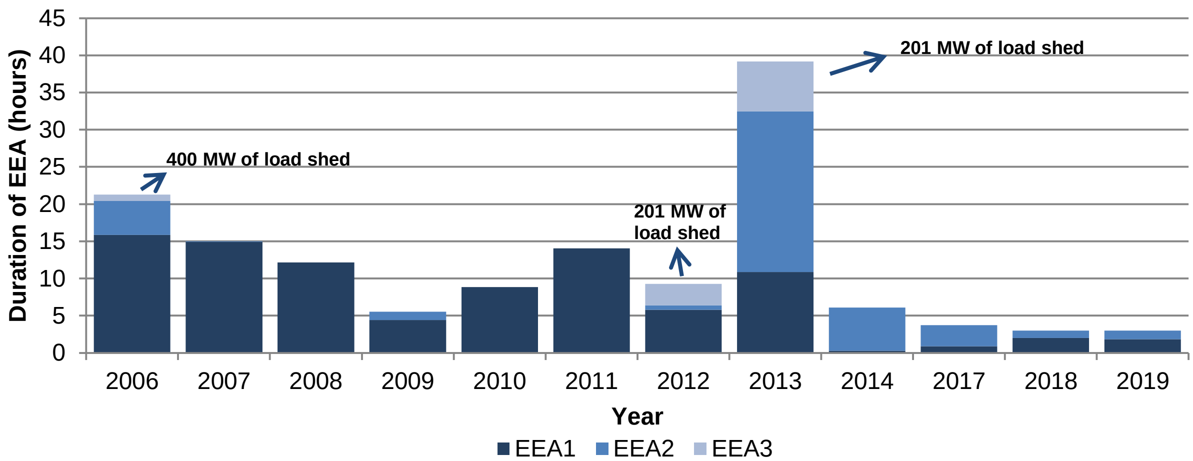
- All steps under Alerts 1 and 2 have been taken
- After receiving directives from the AESO system controllers, the transmission facility owners work with the distribution facility owners to curtail the directed amount of firm load
- Power service to some customers are temporarily interrupted to maintain the minimum required regulating reserve and the integrity of the overall system
- System marginal price (SMP) is set to $1,000/MW

Energy Emergency Alert 0

- Termination of previous energy emergency alerts
- Energy supply is sufficient to meet AIES load and reserve requirements

From 2006 to 2019, there have been a total of 53 instances where EEA procedures were enacted. Of these events, three saw firm load shed of between 200 to 400 MW. The following chart (Figure 1) depicts the historical EEAs broken down by category. As seen in Figure 1, the annual hours with EEA events ranged from below 5 to nearly 40 hours. Note that there were no events in 2015 and 2016. The key observation on a historical basis is that EEA events have been limited, apart from 2013 which saw the largest number of EEA hours in the period analyzed. Following 2013 there were a number of capacity additions that increased installed capacity by approximately 11 per cent. This resulted in strong reserve margins and lower EEA values in subsequent years.

Figure 1: Historical EEA duration – 2006 to 2019



On a forward-looking basis, the frequency of future EEA events was analyzed using the results of the resource adequacy model. Table (1) describes the supply shortage expectations of the reference case, which was the AESO's outlook of the most likely future load growth and generation mix. Three representative years were evaluated: 2021, 2026 and 2031. These results were then compared against the AESO's resource adequacy threshold outlined in ISO rule 202.6. The average outcomes over 7,500 model runs, with modeling outcomes including additional demand response (DR) and without additional DR are presented in Table 1[1]. Included fields in the table are:

- **Expected unserved energy (EUE):** magnitude in MWh of expected load shed
- **Loss of load hours (LOLH):** expected number of hours within the simulation where firm load shed has been observed
- **Threshold MWh:** the maximum allowed unserved energy as outlined in ISO Rule 202.6
- **Count of EEA hours:** expected number of EEA hours, may not always correspond to firm load shed; hours with firm load shed are a subset of this field

[1] A more comprehensive description of these scenarios are included in Appendix B.

Table 1: Reference case supply shortage expectations

	EUE (MWh)	LOLH	Threshold MWh	Count of EEA Hours
2021 with DR	196	0.83	1,013	9.5
2021	486	2.01	1,013	19
2026 with DR	21	0.10	1,060	1.5
2026	61	0.27	1,060	3.8
2031 with DR	47	0.21	1,110	3
2031	120	0.55	1,110	6.7

Overall, historical supply shortage situations have been minimal and on a forward-looking basis are expected to continue to be minimal.

Response from supply

The AESO reviewed whether the current price cap of $1,000/MWh is sufficient to incent response from supply resources during times of scarcity and shortage. The historical responses from long lead-time (LLT) assets and from imports were examined to make this assessment.

Long lead time asset availability

The AESO assessed whether the current offer and price cap provided sufficient incentive for LLT assets to be fully available during periods of supply scarcity and shortage. LLT assets have a start time of greater than one hour and the market participant has discretion whether to make these assets available to the market unless the asset is directed on by a system controller. The AESO hypothesized that if the price cap was a barrier to incenting supply response, the LLT assets may remain offline due to insufficient revenues to cover the costs associated with starting[2].

To assess the historical response of LLT assets, the AESO analyzed hours from 2015–2019 when the pool price was greater than or equal to the offer cap of $999.99/MWh or when EEA events occurred. The available capability (AC) for each LLT asset was examined in each of these hours (T) and compared to the preceding hour (T-1). Each hour was given one of four classifications depending on the comparison of the T and T-1 AC:

- **Online:** The unit decided to run prior to the event and was available both before and during the event
- **Responded:** The unit made its LLT energy available within one hour prior to or during the event
- **Did not respond:** The unit was offline without an operational reason.
- **Unavailable:** The unit was offline for maintenance or other operational reason.

[2] The AESO's must offer rule (ISO rule 203.1) requires offers to be submitted for the asset's maximum capability (MC) of each asset greater than 5 MW. Therefore, supply response to scarcity and shortage events cannot be measured using the submission of offers of long lead time assets. The historical responses from LLT assets are examined to make this assessment

From 2015–2019, there were 17 hours in which the pool price was greater than or equal to $999.99/MWh or an EEA event occurred. During these events, the average availability of LLT assets was approximately 61 per cent. In each instance, all LLT assets were classified as either “online” or “unavailable”; there were no circumstances that met the criteria as “responded” or “did not respond.” Therefore, all LLT assets were available during these hours except those that had an operational reason.

This analysis suggests that the current price cap is not a barrier to incenting response from LLT assets. This is consistent with the fact that the AESO has never needed to issue a directive to a LLT asset.

Import supply availability

While the price cap appears to incent response from internal generators, it is also important to assess whether the price cap allows Alberta to attract import supply from other jurisdictions. The utilization of import available transfer capability (ATC) was analyzed for each tie line (British Columbia, Montana, and Saskatchewan) in all hours from 2015–2019 in which the pool price was greater than or equal to $900/MWh. The following Table (2) shows the result of this analysis.

Table 2: Import supply availability

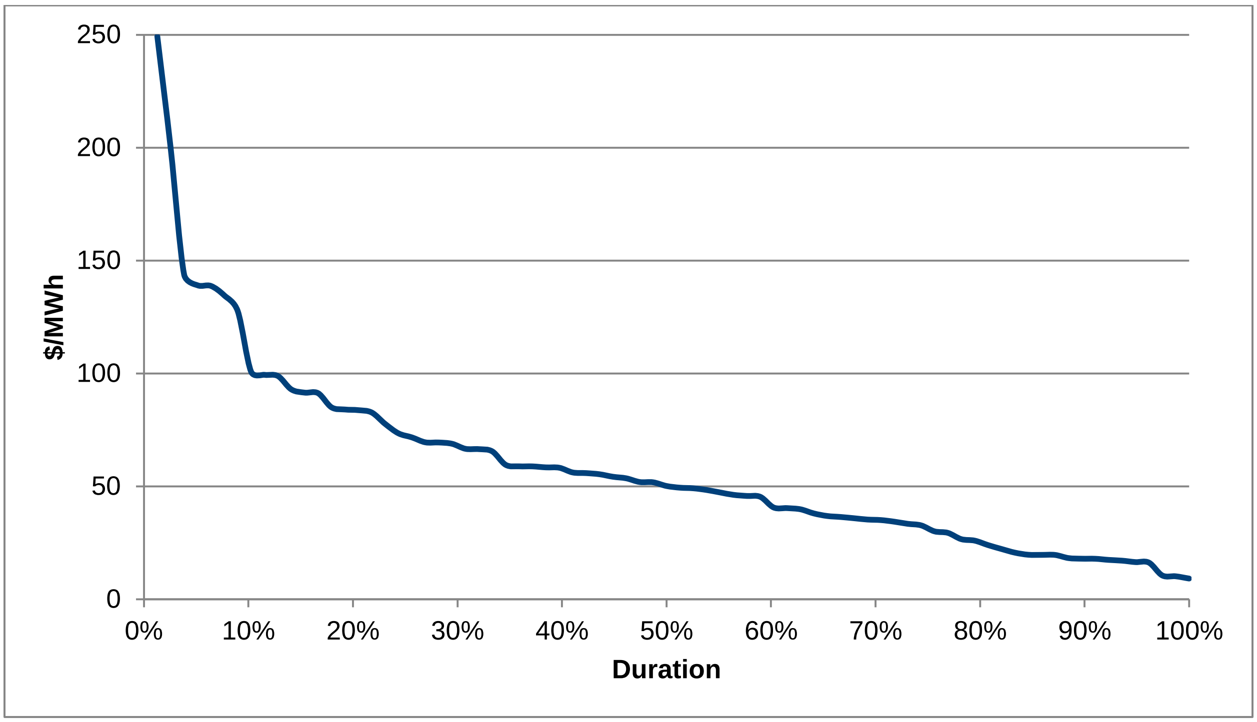
Year	# of Hours		BC Average Utilization (%)		BC Import ATC (MW)		MATL Average Utilization (%)		MATL Import ATC (MW)	
	Total	w/ PP >= $900	w/ PP < $900	w/ PP >= $900	Max	Mean	w/ PP < $900	w/ PP >= $900	Max	Mean
2015	8760	28	20%	**95%**	780	667	24%	**98%**	295	258
2016	8784	0	10%	**N/A**	750	701	14%	**N/A**	295	268
2017	8760	4	23%	**72%**	750	691	21%	**25%**	295	258
2018	8760	29	44%	**97%**	750	656	56%	**92%**	295	238
2019	8760	17	23%	**99%**	750	697	40%	**100%**	295	272

Year	# of Hours		SK Average Utilization (%)		SK Import ATC (MW)	
	Total	w/ PP >= $900	w/ PP < $900	w/ PP >= $900	Max	Mean
2015	8760	28	23%	**79%**	153	124
2016	8784	0	6%	**N/A**	153	146
2017	8760	4	8%	**37%**	153	144
2018	8760	29	23%	**49%**	153	147
2019	8760	17	40%	**88%**	153	120

Table 2 shows that intertie utilization has typically been very high when the Alberta pool price is above $900/MWh. This suggests that the current price cap is sufficient to incent supply response from importers during scarcity and shortage events. Lower utilization rates in 2017 may be partially attributed to the lack of high prices during that year; only four hours exceeded $900/MWh. This relatively low-priced environment may have meant that the high prices were less anticipated and that power marketers focused their attention on other jurisdictions.

To better understand the margin available for importers, the following Figure (2) shows a duration curve of hourly prices at the Mid-Columbia (Mid-C) trading hub in the northwest US during the hours identified in the previous analysis. The prices have been converted from US to Canadian dollars. This figure shows that the Mid-C hourly price index did not exceed $250/MWh when the Alberta pool price was high, and the index was under $100/MWh approximately 90 per cent of the time. This indicates that there was typically a substantial margin to be earned when importing into Alberta during these hours. This also suggests that the observed intertie utilization rates may not be reflective of the utilization that would occur during times of coincident scarcity in both Alberta and neighbouring jurisdictions. Therefore, while this analysis supports the conclusion that the current price cap incents imports, it should be noted that ongoing monitoring is required to assess whether this conclusion continues to hold as the supply and demand mix evolves in the Western Interconnection.

Figure 2: Mid–C price during AB prices above $900/MWh (2015-2019)

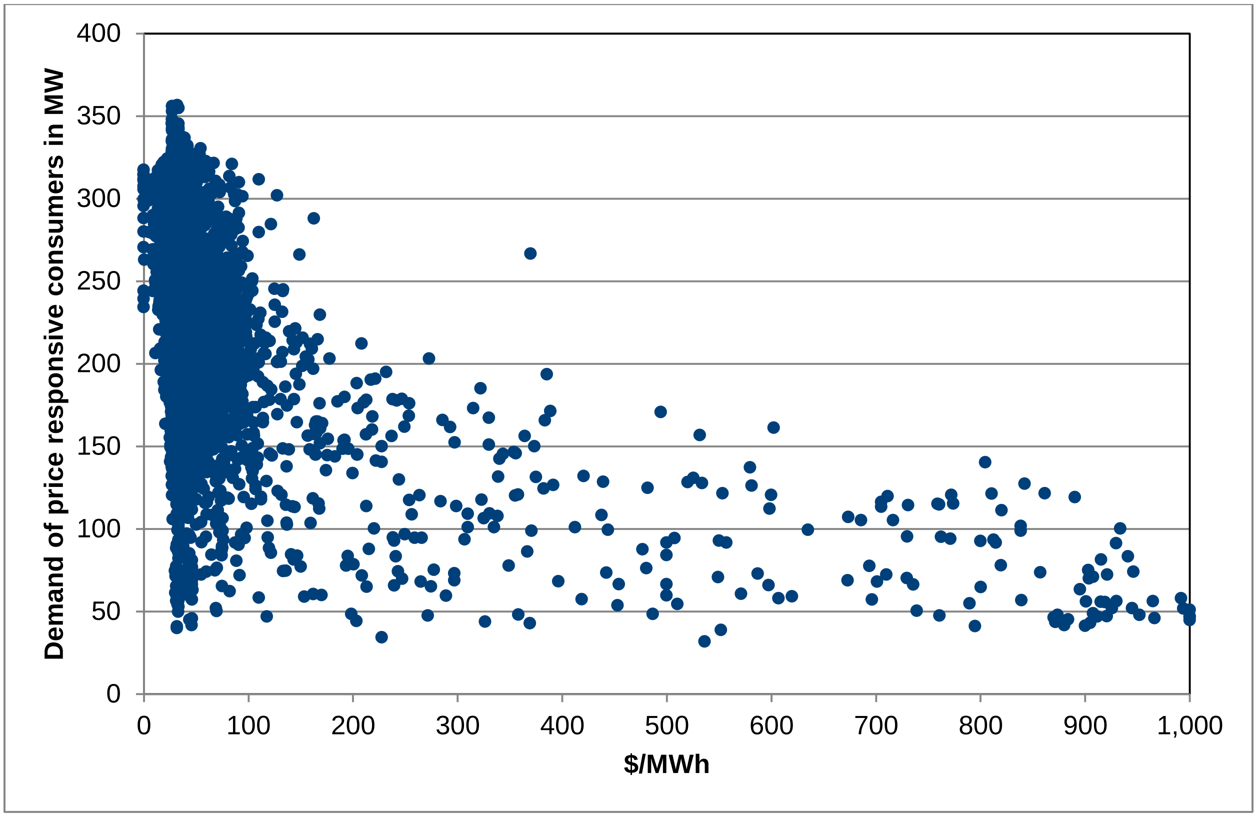


Response from demand

The AESO assessed whether the current price cap of $1,000/MWh is sufficient to incent response from consumers during times of scarcity and shortage.

There are approximately 300 MW of load at eight sites that actively curtail consumption within the existing pricing framework. During periods of lower prices these sites were observed to consume approximately 350 MW of power. As prices increased, the demand of these sites was generally reduced to approximately 50 MW. This relationship is shown in the following Figure (3).

Figure 3: 2018 price responsive loads



The fundamental driver for response from loads is their willingness to pay, sometimes referred to as the value of lost load (VOLL). This VOLL will vary between loads, depending on the value that they receive by consuming electricity. Some loads, as demonstrated by Figure 3, find it worthwhile to respond to prices within the current price cap. There may be others that place a higher value on electricity consumption and would only respond to prices above the current price cap. The observed relationship between pool price and demand cannot be extrapolated to prices above the current cap; a different approach is necessary to estimate this response.

Loads ultimately respond to the delivered cost of energy that they face. This includes the cost of wholesale energy, as well as other charges, including the ISO tariff. A portion of ISO tariff costs are recovered through a coincident metered demand (CMD) charge. The CMD charge - currently $10,814/MW/month[3] - is allocated to each load based on their consumption during a 15-minute interval that represents the time of monthly system peak. The AESO analyzed the response to this charge as a proxy for how loads may respond to a pool price greater than the current price cap of $1,000/MWh.

This analysis used 2018 and 2019 consumption data from approximately 450 sites that had an annual average load of over 1 MW. A regression was used to isolate the load that responded to the pool price and the load that responded to the CMD charge. By isolating the quantity of load that responded to the CMD charge but not the pool price, this analysis identified those loads that likely have a willingness to pay

[3] The CMD charge during the sample period was $10,177/MW/month in 2018 and $10,524/MW/month in 2019

between the current price cap of $1,000/MWh and a hypothetical cap equivalent to the CMD charge. This analysis identified approximately 40 MW of load at 10 sites that exhibited this behaviour.

There are reasons that response to tariff signals may not fully reflect response to energy prices. Firstly, the interval during which CMD will be determined is uncertain until the end of the month. Therefore, loads may need to respond in multiple intervals to avoid this charge, resulting in the expected value of their savings being below the nominal value of the CMD charge. This would suggest that the above analysis may underestimate the potential response. Secondly, loads have the ability to hedge the energy price; they do not have the ability to hedge the tariff costs. This would suggest that the above analysis may overestimate the potential response. With these factors in mind, the identified 40 MW of load should be viewed as an approximation, and that further analysis, such as a Value of Lost Load study, would be required to make a more accurate assessment of prices at which these loads would curtail their energy consumption.

Conclusions

The AESO does not recommend a change to the price cap.

Historically, supply response has been fairly optimized during supply shortage situations with strong import utilization and response from LLT assets. The AESO's analysis has shown that there may be some additional, limited demand response above the existing price cap; however, further work would need to be done to determine the price at which loads would respond to prices above $1,000/MWh. The AESO's analysis demonstrates that the market has been quite efficient during previous supply shortage situations and although there may be efficiency gains with an increase to the cap, those gains are minimal at this time.

Price Floor Assessment

The objective of the price floor assessment was to determine whether the current administrative price floor is a barrier to efficient market clearing during supply-surplus events and if the AESO should consider negative pricing as a more efficient option. Supply-surplus events occur when there are more suppliers wishing to deliver power than there is load in the system. As supply and demand must always remain in balance, supply surplus events can introduce an operational challenge where AESO system controllers must impose administrative curtailment rules to direct involuntary reductions of imports or generation.

Negative pricing is a market-based alternative to clear supply-surplus situations and relies on economic offers from resources that reflect their minimum acceptable sale price for generation. Assets have differing costs associated with reducing output below minimum stable generation levels. They may also have non-electricity market revenues that result in positive economics at electricity market prices less than $0/MWh. When negative prices do occur, power producers would pay consumers to take electricity. The approach is widely used in other jurisdictions to promote a market-based clearing of supply surplus situations.

The AESO reviewed the curtailment economics of various resources to determine the levels at which resources would be expected to offer if a lower price floor existed in the energy market. An efficiency analysis was then conducted to quantify the historical benefit of a move to negative pricing.

Frequency and magnitude of historical and forecast supply surplus situations

A supply-surplus event occurs when the supply of energy available at $0/MWh exceeds the system demand and the AESO must take administrative actions to bring the system back into balance. These actions may include the curtailment of imports over the intertie or curtailment of internal Alberta generation. The series of steps the AESO follows during a supply surplus situation are outlined in Section 202.5 of the ISO rules. Supply surplus procedures are summarized below.

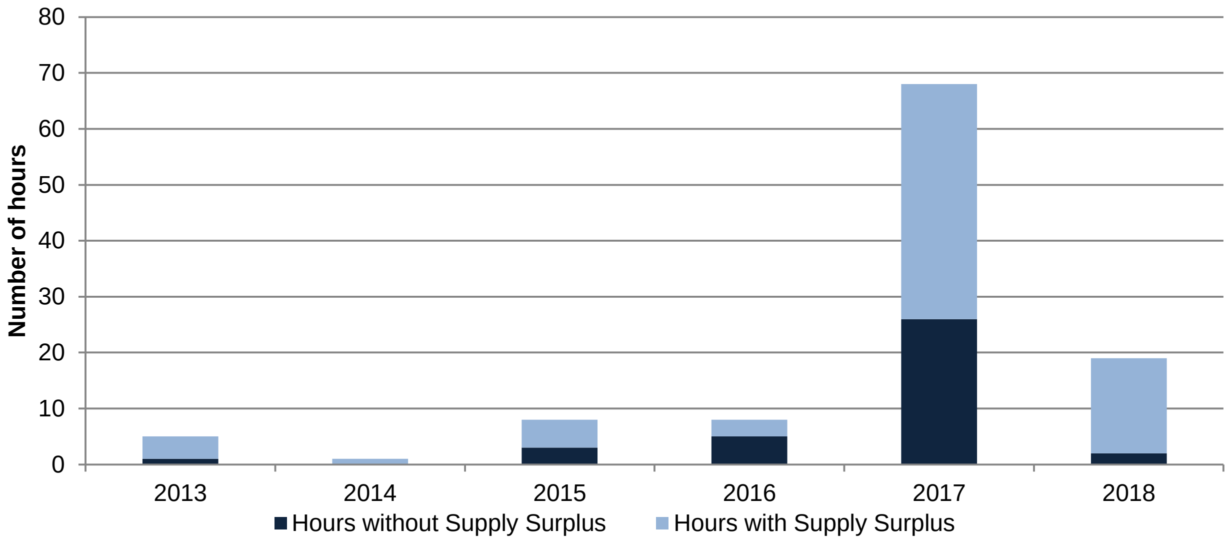
Supply-surplus procedures

If the AESO determines that a supply surplus event is imminent, the AESO will take the following successive steps until the supply surplus situation is mitigated:

- Initiate the curtailment of imports and allow participants to submit offers to decrease imports within T-2
- Allow participants to submit bids to export within T-2
- Permit participants to restate and reduce generating output within T-2
- Issue, on a pro-rata basis, dispatches to generating units and aggregated generating facilities (AGF) for partial dispatch reductions of flexible blocks on $0/MWh offers
- If there are generating units and AGF with $0/MWh offers greater than their minimum stable generation (MSG) level, issue directives to curtail down to MSG, starting within units with the greatest difference between their current dispatch level and their MSG
- Direct any other necessary actions including shutting down generating units and AGF to ensure system reliability

From 2013 to 2019, there have been a total of 109 hours where the system marginal price (SMP) settled at $0/MW. Of these instances there were 72 hours where supply surplus procedures were implemented to curtail imports or generation and bring the system back into balance. There were no supply surplus hours in 2019. The following Figure (4) illustrates the number hours during this time period where SMP was at $0/MW and hours where there were supply surplus.

Figure 4: Number of hours where SMP was $0/MW

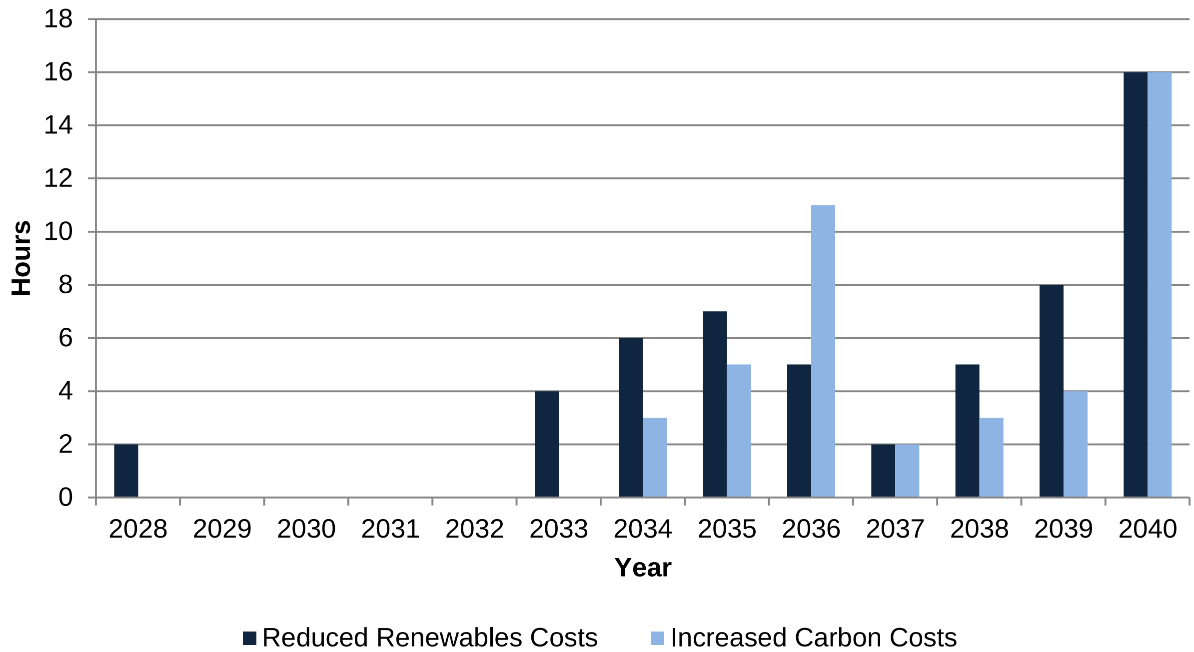


Based on the AESO's forecast scenarios, expected supply-surplus events are anticipated to be minimal[4] and occurred in only two of the scenarios the AESO tested[5]: the reduced renewables costs scenario and the increased carbon cost scenario. Both of these scenarios are described in Appendix B of this report and the supply surplus expectations are reflected in Figure 5 below. The frequency of anticipated supply-surplus events elicits a sense of the urgency for change; if supply- surplus events were anticipated to increase in the future and if there were clear efficiency losses with the current price floor, negative pricing may be an option to promote increased efficiency during supply- surplus situations. Given that supply surplus events are anticipated to be infrequent, there are no forecast surplus events prior to 2028, the urgency for change is low.

[4] Relatively frequent supply surplus events in 2020 are largely attributed to low demand as a result of the COVID-19 pandemic and low oil prices and are not anticipated to be reflective of ongoing market conditions.

[5] In neither scenario were supply surplus hours forecasted prior to 2028.

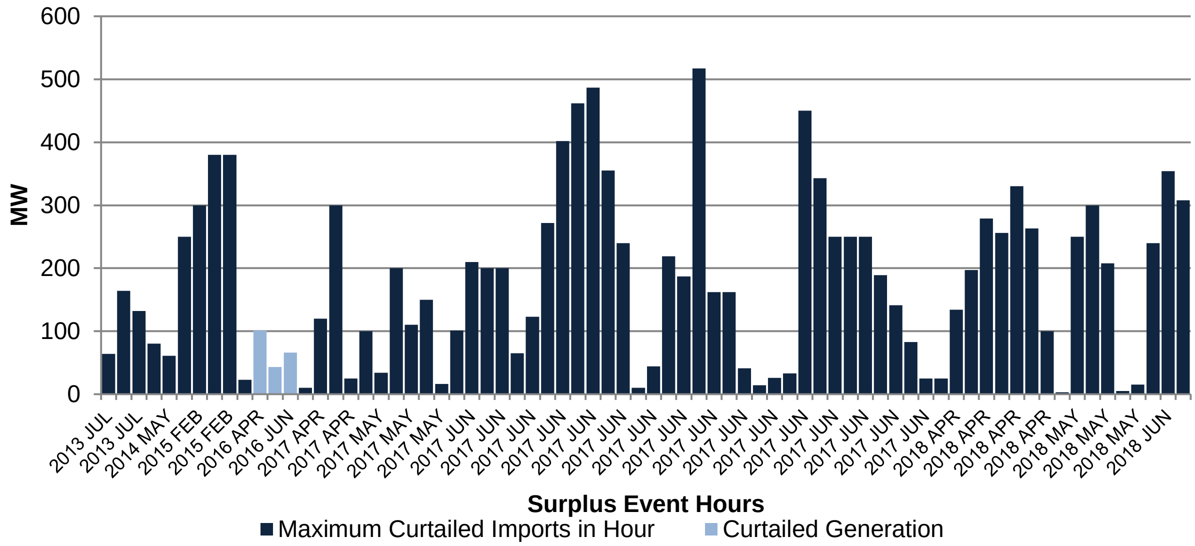
Figure 5: Scenarios with expected supply-surplus hours from 2021-2040



Measuring efficiency losses during past supply surplus events

To mitigate historical supply-surplus events, the AESO system controllers curtailed imports first, followed by internal generation when required in accordance with ISO Rule 202.5. The following Figure (6) illustrates the historical curtailments from 2013 to 2019. As seen in Figure 6, the vast majority of events were mitigated through the curtailment of imports alone. There were only three events that were mitigated by a curtailment of internal Alberta generation. In these three instances, there were no imports flowing into the province. The maximum import curtailment from 2013 to 2019 was approximately 500 MW and, on average historical supply surplus situations, were resolved with approximately 180 MW of either import or generation curtailment.

Figure 6: Volume of imports & generation curtailment during supply surplus events 2013 to 2019



As noted previously, a concern with the current administrative protocol for managing supply-surplus situations is that it does not allow for market participants to express their willingness to curtail. To test the magnitude of the efficiency loss with the current administrative rule the AESO examined the curtailment economics of various resource types that have remained online during supply surplus situations. The AESO then estimated how negative-priced offers from these assets may be developed to compare efficiencies under the current rule to that of negative pricing.

In determining a generation unit's willingness to pay to avoid curtailment the AESO evaluated the curtailment economics of various asset types. The analysis assumed assets would be willing to generate in a negative price environment so long as the cost to the asset from continued generation was less than the costs associated with shutting down the asset and later returning to the market when prices were higher.

For coal and combined-cycle assets, the cost of shutting down and restarting are called cycling costs and are, in part, determined by the duration of the shutdown. For the purposes of the analysis, the AESO used costs associated with a shorter duration shutdown, called a warm start, for coal and combined-cycle assets in order to estimate the cycling cost during negative pricing periods[6]. Simple cycle gas facilities were assumed to have no cost associated with cycling the asset.

In order to calculate a wind asset's willingness to curtail production the AESO estimated the value received by these generating facilities from the sale of renewables attributes such as carbon offsets. The value of the sale of renewables attributes vary from year to year. The carbon-offset values are derived by multiplying a wind asset's grid intensity factor by the carbon price.

[6] Source of cycling costs: APTECH study, Power Plant Cycling Costs, PDF page 12, all values converted to CAD and inflated to 2020 dollars https://www.nrel.gov/docs/fy12osti/55433.pdf

Import prices were calculated using the delivered cost of power into Alberta from the northwest United States. Inputs into the delivered cost of power included the hourly Mid-Columbia trading price, transmission costs, line loss, foreign exchange rates and other miscellaneous charges, including the AESO trading charge.

The following Table (3) describes the AESO's cost assumptions for all assets.

Table 3: Curtailment economics by technology type ($/MWh)

Curtailment Economics by Technology Type ($/MWh)					
Asset Type	2015	2016	2017	2018	2019
Coal	$94.94	$94.94	$94.94	$94.94	$94.94
Combined Cycle	$81.59	$81.59	$81.59	$81.59	$81.59
Simple Cycle	$0.00	$0.00	$0.00	$0.00	$0.00
Wind	$8.85	$11.80	$17.70	$17.70	$17.70

For the purpose of this analysis, the AESO evaluated the 67 supply-surplus events between 2015 to 2019, as noted above. The goal of the approach was to determine whether the historical curtailment approach was efficient by testing whether the highest cost supply was curtailed first.

The following Tables (4 and 5) compare curtailment volumes under the current import reduction/pro-rata methodology and the approach that economically curtails supply based on deemed offer prices less than $0/MWh but greater than a floor price of -$100/MWh. Tables 4 and 5 also show that in a negative price environment, imports would have remained the most efficient supply source to curtail in most instances. In 2015 and 2018 there would have been no change to the clearing of supply surplus hours. In 2016, imports were unavailable for curtailment and therefore generation was curtailed.

As seen in Table 4, under the current framework, 2016 curtailments were divided among all asset types. However, with a negative price floor in Table 5, generation curtailment in 2016 would have been concentrated in simple cycle and wind, due to their lower willingness to pay to avoid operating at a loss. In 2017**,** under a $0/MWh price floor in Table 4, curtailments consisted only of imports. However, with a negative price floor, curtailment of simple-cycle units during hours when Mid-Columbia prices were negative would have been more economic. This is shown in Table 5, where curtailing 564 MW of simple-cycle generation and 7,014 MW of imports would have been more efficient.

Table 4: Generation curtailed under current framework (MW)

Generation Curtailed Under Current Framework (MW)				
Asset Type	2015	2016	2017	2018
Imports	1333	0	7578	3267
Wind	0	50	0	0
Simple Cycle	0	17	0	0
Combined Cycle	0	10	0	0
Coal	0	52	0	0
Hydro	0	5	0	0
Cogeneration	0	75	0	0
Biomass & Other	0	1	0	0
Total	1333	210	7578	3267

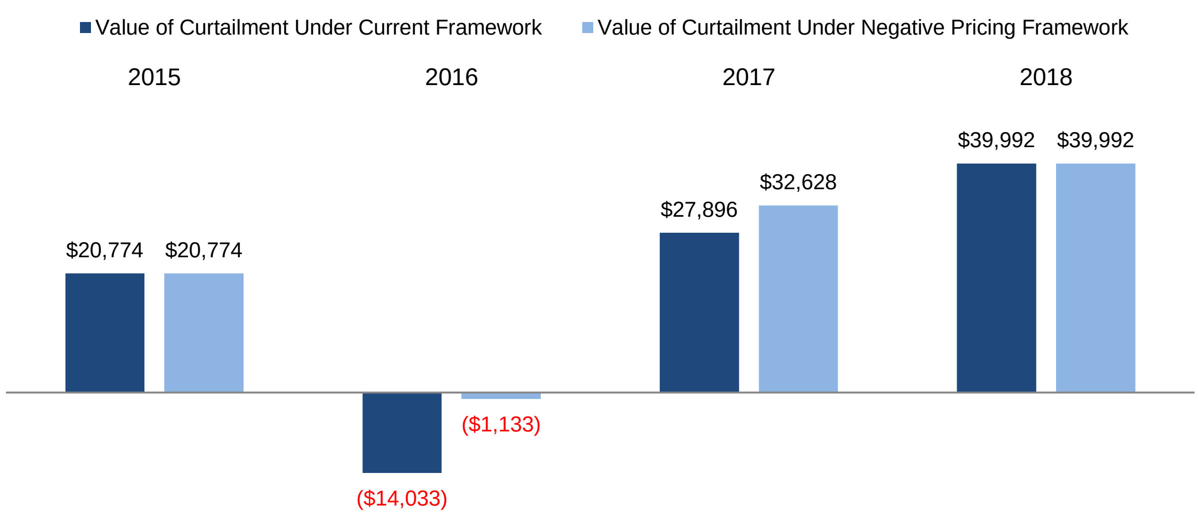
Table 5: Hypothetical generation curtailments under a negative pricing framework (MW)

Generation Curtailed Under Negative Pricing Framework (MW)				
Asset Type	2015	2016	2017	2018
Imports	1333	0	7014	3267
Wind	0	96	0	0
Simple Cycle	0	114	564	0
Combined Cycle	0	0	0	0
Coal	0	0	0	0
Hydro	0	0	0	0
Cogeneration	0	0	0	0
Biomass & Other	0	0	0	0
Total	1333	210	7578	3267

The AESO estimated the value of curtailment for each supply-surplus event using the curtailment cost assumptions and curtailed generation volumes as previously detailed. Assets were assumed to have a marginal cost equivalent to their willingness to pay to avoid curtailment[7]. The number of curtailed MW for each technology type was multiplied by the marginal cost to determine the total value of curtailment for each hour. Therefore, in instances when the AESO curtailed supply with a positive marginal cost, the value of curtailment is positive.

In instances when the AESO curtailed supply with a negative marginal cost, indicating that the asset would have been willing to pay to continue producing, the value of curtailment is negative. This historical value was then compared to the market-based curtailment expected with negative pricing, achieved by curtailing supply from highest to lowest marginal cost. Therefore, an increase in the value of curtailment in the following Figure (7) represents an enhancement in efficiency for a given year.

Figure 7: Comparison of curtailment economics



[7] E.g. for coal assets, the cycling cost of $94.94/MWh is converted to a marginal cost of -$94.94/MWh

The model estimated that, in 2015 and 2018, administrative curtailments with a price floor of $0/MWh were identical to expected market-based curtailments with a negative price floor of -$100/MWh. In 2016, the negative price floor scenario resulted in a more efficient curtailment of supply and a system-wide gain of approximately $13,000. In 2017, negative pricing would have resulted in efficiency gains of approximately $5,000. This demonstrates that the current framework and curtailment practices do not always result in curtailments that reflect the underlying economics of different types of supply. Implementing negative pricing would allow for each asset to reflect its willingness to curtail in its offers and therefore result in a more efficient curtailment in some circumstances.

However, the aggregate efficiency gains through this study period with the introduction of a negative price floor were $18,000. Overall, these efficiency gains are quite small compared to the annual cost of electricity consumption in the AIES which ranged from $4 billion in 2015 to $7 billion in 2019.

Conclusions

The AESO does not recommend a change to the price floor.

This recommendation is made based on the very low number of supply surplus events forecasted in the AESO's reference case and scenario outlooks and the immaterial historical efficiency gains that would have been realized from a negative price floor.

Appendix D:

Pricing framework alternatives and final recommendation

While no change to the pricing framework is being suggested, in assessing whether to recommend a change to the pricing framework, the AESO identified various approaches to establishing a changed price cap as well as the level of a revised negative price floor. The alternatives were selected after a comprehensive jurisdictional review[1] and assessed against Alberta market fundamentals. This section describes the alternatives; the AESO's assessment of the alternatives; the pricing framework approaches the AESO shortlisted; and, the rationale for the final recommendation. The following summarizes each alternative that was assessed:

Price Cap Alternatives

1. Administrative shortage pricing: loss of load probability method
2. Administrative shortage pricing: stepped shortage pricing linked to energy emergency alert (EEA) levels
3. Increase in the price and offer cap through the implementation of a scarcity pricing approach
4. A variant of the current pricing framework, with the AESO accepting offers above the current offer cap if verified costs exceed the offer cap

Price Floor Alternative

1. Negative pricing

Price Cap Alternatives

1. Administrative shortage pricing: loss of load probability method

One implementation option for administrative shortage pricing is the loss of load probability (LOLP) method. This method uses a continuous curve that represents the probability of experiencing a supply shortage given the remaining supply on the system at any given time. Because this curve represents a probability, it is bounded at all times between 0 and 1. To determine a resulting price using this LOLP curve, the probability would be multiplied by some scalar, typically the value of lost load (VOLL), which would be determined through a separate process.

This curve would always be in effect, as opposed to being triggered by some characteristic of the system. The value of the expectation of loss of load is added to the electricity price. The sum of the LOLP value and the electricity value represents the real time price of electricity for consumers and producers. In most cases, the probability of experiencing a supply shortage is very small, approximately 0 but the value gradually increases when remaining supply in the market is reduced. The resulting price adders are generally imperceptible until the system experiences a meaningful risk of supply shortage.

[1] Please see Appendix E for the detailed jurisdictional review.

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Two approaches were explored for estimating the LOLP curve: the forecast error method and the supply cushion method. Both approaches use the data underlying the AESO's short-term supply adequacy report[2], shown in Figure 1. This report uses a measure of supply cushion to determine whether there is a forecasted supply adequacy concern over the next week.[3]

Figure 1: Supply adequacy report

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
05/06/20 Wed	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
05/07/20 Thu	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
05/08/20 Fri	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
05/09/20 Sat	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
05/10/20 Sun	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
05/11/20 Mon	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
05/12/20 Tue	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

Report updates = Every five minutes for the current trading day,
every hour for the six remaining days following the current trading day

4 = greater than 400 MW of supply available in the merit order
3 = 200 to 400 MW of supply available in the merit order
2 = 0 to 200 MW of supply available in the merit order
1 = not enough supply available to maintain 6% reserve requirements
0 = not enough supply available to maintain 3% reserve requirements.

Both the forecast error and supply cushion methods are similar in the sense that they use the same data to determine the probability of supply shortage. The two methods differ in the calculation used to determine this probability.

The forecast error method measures the amount of forecast error experienced within one hour. For an hour T, this means that the T-1 forecast of supply cushion at T is subtracted from the actual realized supply cushion in hour T. A numerical example would be as follows:

- In hour ending (HE) 16, the AESO forecasts 1,000 megawatts (MW) of supply cushion for HE 17
- The actual supply cushion in HE 17 is 700 MW
- The forecast error is 700 - 1,000 = -300 MW

This forecast error method is similar to the approach currently used in Electric Reliability Council of Texas (ERCOT). The ERCOT LOLP curve is calculated using the hour-ahead supply cushion error of their centralized unit commitment optimization process.

The supply cushion method uses the actual differences in supply cushion between hours. So, for hour T, the T-1 actual supply cushion is subtracted from the actual supply cushion in hour T. A numerical example of this method:

- In HE 16, the actual supply cushion is 1,100 MW

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[2] http://ets.aeso.ca/ets_web/ip/Market/Reports/SupplyAdequacyReportServlet

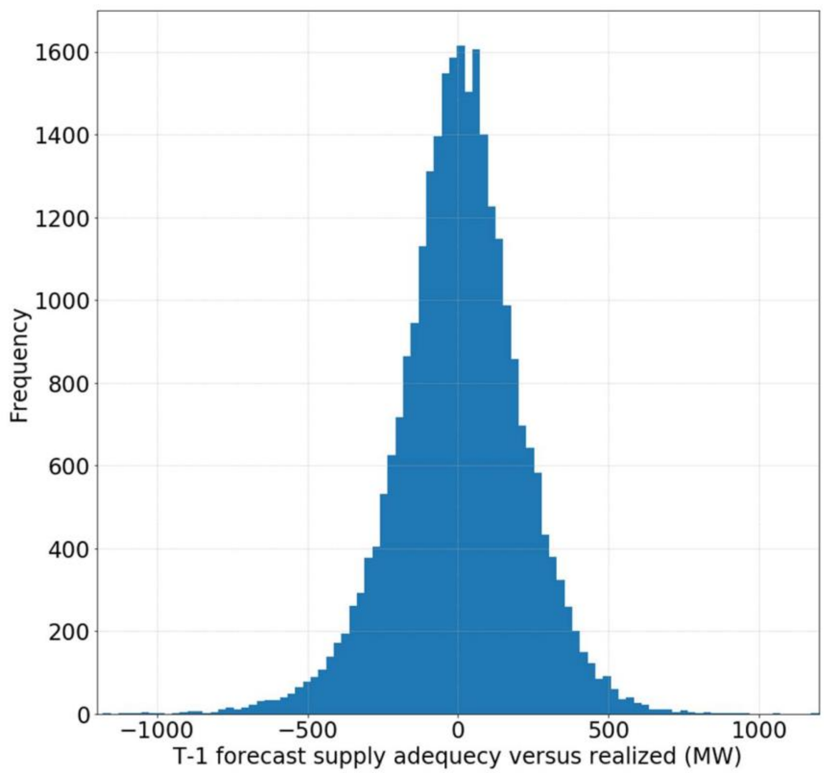
[3] If the LOLP curve shortage pricing method were to be pursued further, the underlying assumptions of this data (e.g. for behind-the-fence load and generation, intermittent renewables, and intertie capability) would need to be tested more thoroughly for their appropriateness in this application.

- In HE 17, the actual supply cushion is 700 MW
- The difference in supply cushion is 700 - 1,100 = -400 MW

While the forecast error method determines how much the *expectation* of supply cushion can change within one hour, the supply cushion method determines how much *actual* supply cushion can change within one hour. If an LOLP price cap change was to be implemented, the AESO would recommend the forecast error method over the supply cushion method. It better differentiates events that happen gradually and provides the market and operators the opportunity to respond to unanticipated events such as a loss of a large generating unit, which are more likely to lead to scarcity and shortage conditions. The following analysis continues to describe how the LOLP curve using the forecast error method could be established.

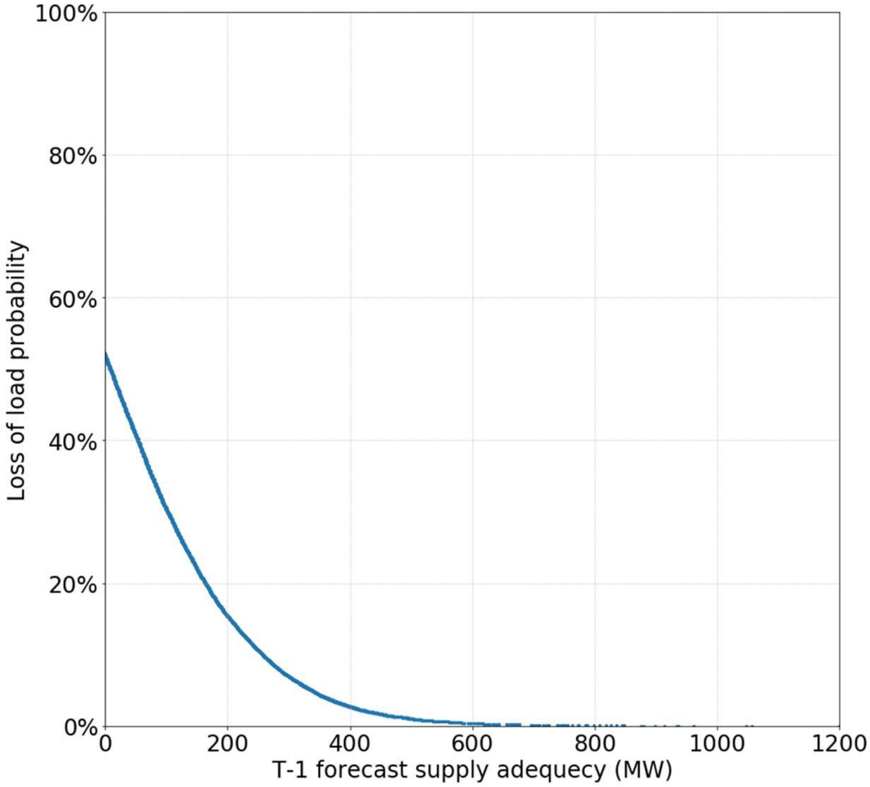
Figure 2 shows the distribution of hour-ahead supply adequacy forecast errors from January 2017 to May 2020. This distribution is approximately normally distributed around 0 MW, with a small positive skew resulting in a mean of 5.39 MW.

Figure 2: Distribution of hour-ahead supply adequacy forecast errors January 2017 – May 2020



To determine the probability of supply shortage with a given supply cushion, the cumulative density of this distribution is used. This cumulative density is the probability that the actual supply cushion in the next hour will be less than 0, given the forecasted supply cushion. This cumulative density curve - the LOLP curve - is shown in Figure 3.

Figure 3: Loss of load probability curve

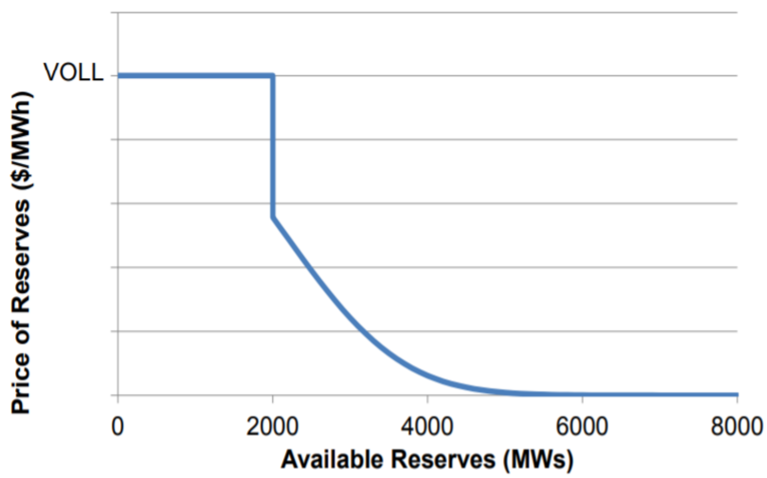


Of note, the LOLP for a forecast supply cushion of 0 MW is approximately 50 per cent. This is consistent with the finding that forecast errors are approximately symmetric around 0 MW. When the AESO forecasts a supply cushion of 0 MW, there is approximately a 50 per cent chance that the realized supply cushion will be below 0 MW - resulting in supply shortage - and a 50 per cent chance that the supply cushion will be above 0 MW.

If the AESO is forecasting a negative supply cushion, the LOLP is not necessarily 100 per cent, as the AESO's forecast may be too low. However, for the purposes of determining the shortage price, LOLP would be set at 100 per cent to incentivize the maximum demand and supply response.

The LOLP curve as shown in Figure 3 is a true representation of the probability of experiencing negative supply cushion. However, in shortage situations, the AESO will exhaust all contingency reserve before shedding firm load. Therefore, it makes sense for this curve to be shifted, so that it no longer represents the probability of negative supply cushion, but rather the probability of falling below a certain level of reserves. This level would likely be the requirements for contingency reserves: spinning and supplemental reserves. This shift is employed by the shortage-pricing curve in ERCOT based on their minimum contingency level of 2,000 MW. To illustrate the approach, the ERCOT shortage-pricing curve is shown in Figure 4.

Figure 4: ERCOT shortage-pricing curve



2. Administrative shortage pricing: stepped shortage pricing linked to EEA levels

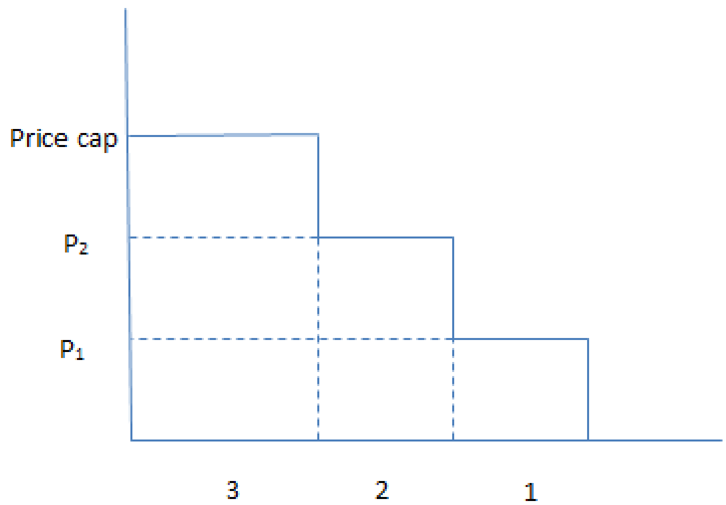
In Alberta's current market structure there is little pricing distinction between varying degrees of scarcity, as the offer cap is set at $999.99/MWh and the price cap is set at $1,000/MWh. The concept behind a more graduated administrative pricing mechanism is that it would reflect different levels of scarcity and have the potential to improve price signals and market participant response during scarcity conditions. Alternative 2 involves establishing price adders to reflect these varying degrees of scarcity anchored against the existing energy emergency alert (EEA) levels detailed in ISO Rule 202.2.

The AESO identified 3 existing EEA steps within the current procedure that could trigger price increases above the current price cap level to incent market response.

1. Curtailment of opportunity service contracts (exports and demand opportunity service)
2. Increase the available transfer capability (ATC) on the interconnections with British Columbia (B.C.), Montana and Saskatchewan
3. Direct internal spinning and supplemental reserves to meet Alberta load requirements

The following is a visual of how the price increases would be triggered at the above EEA actions.

Figure 5: Price increases triggered at specific EEA actions



At step 1, the system controller has curtailed non-firm load or opportunity service customers. A step here would indicate to the market that the system is approaching scarcity conditions and the AESO is unable to serve non-firm load.

At step 2, the system controller has increased the ATC of the interconnections, permitting additional flow over the B.C., Montana and Saskatchewan tie lines. A price increase here may incent additional response from other jurisdictions over the interties. A consideration here is that the price increase would need to be comparable to competing jurisdictions to ensure that Alberta is an attractive market during shortage situations.

At step 3, the system is nearing the highest level of risk as Alberta is relying on contingency reserve to meet its load requirements. Price should be raised to the highest level to incent the maximum amount of response from supply and demand market participants prior to curtailing firm load.

3. Increase in the price and offer cap and implementation of a scarcity pricing mechanism

The Alberta market's primary scarcity mechanism is to allow generators to submit high-price supply offers in the energy market. In the event of firm load shed, prices are set at 1 cent higher than the offer cap. Through this framework, competitive forces will drive prices toward marginal cost in normal conditions because supply exceeds demand by an amount sufficient to force suppliers to compete with each other. During scarcity conditions however suppliers have the ability to increase their offer prices well above their marginal costs. This is an important feature of the energy-only market that allows for fixed cost recovery over time.

Alternative 3 is a variant of the current framework that would involve an increase in both the price and offer cap. This is similar to the approach used in Australia, where price has been increased to the Value of Lost Load (VOLL), and acts to incent response in both the short-term and long-term.

In Australia, the price and offer cap is set at AUD14,700/MWh. The framework also includes a price limiter which is a form of mitigation. If the sum of settlement prices for the previous 7 days exceeds a cumulative price threshold, the entire trading day will have an administered price of AUD300/MWh applied. The cumulative price threshold is set to approximate the revenues required by a hypothetical peaking plant, the implied marginal unit, to remain economic for 1 year. The current value of the cumulative price threshold is AUD221,100/MW.

There are challenges with this alternative. This approach would require additional market monitoring and market mitigation as it would involve an increase in the offer cap. Additionally, as noted in Appendix B revenue sufficiency is not anticipated to be an issue, meaning that no change in the offer cap is required. Another challenge with this approach is that it relies on scarcity prices being driven by supplier offers rather than by the severity of the scarcity or shortage situation. This may result in a distortion to the price signal, where high prices are not directly linked to shortages but rather suppliers' forecast of tight conditions and possibly the exercise or market power.

4. Offers with verified cost recovery

In the Alberta market, offers are capped at $999.99/MWh. From the AESO's jurisdictional review, various FERC regulated jurisdictions historically have had similar offer caps in place; California ISO for example has an offer cap of USD1,000/MWh. In 2016, through Order 831[4], FERC amended its regulations to require FERC regulated ISOs and RTOs to allow resources to submit verified cost-based offers above USD1,000/MWh to a maximum of USD2,000/MWh. The verification process for cost-based incremental offers above USD1,000/MWh ensures that the offers reflect a resource's actual or expected costs and reduce the risk of suppliers operating at a loss if actual costs are greater than the offer cap.

Alternative 4 would be a variant of the current framework, with the same administrative price levels in place with the exception that costs above $999.99/MWh would be eligible for recovery if a resource could verify that its costs exceed the current offer cap. The benefit to this approach is that it would keep resources with costs greater than the offer cap whole, encouraging the needed supply response during tight conditions. This approach would most likely only apply to intertie resources when market prices in neighbouring jurisdictions were at prices higher than the Alberta offer or price cap. This approach would help to ensure that the Alberta market remains competitively priced with other markets.

The challenge with this approach is that it would not be transparent. One of the principles the AESO established for the pricing framework was that the framework should improve the efficiency of short-term response. This approach would provide benefits to limited suppliers and because the pricing would not be reflected in the market the approach would not have the effect of encouraging additional demand response in real-time.

Comparison of Price Cap Alternatives

Of the four price cap alternatives presented, the AESO believes Alternative 2, administrative pricing through a stepped curve, would be the most applicable for the Alberta market should a change to the price cap be warranted. This assessment is guided by the following: This design provides the opportunity for better signals during shortage events as this approach would provide the market with price signals that reflect different levels of scarcity. Implementation would also be less complex than that of Alternative 1, the LOLP approach. The approach also aligns well within the major aspects of the existing market framework as the offer cap and market power mitigation framework would likely require no change.

[4] https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf

Price Floor Alternative

1. Negative pricing

The alternative identified to the current $0/MWh price floor is to lower the price floor such that market participants can submit offers and set price at negative prices. This would mitigate the need for administrative curtailments during supply surplus events by allowing market participants to compete for dispatch during these circumstances. The AESO estimates that a price floor of -$100/MWh would capture the willingness to curtail of many different generation technologies with volumes of over 2,000 MW participating in some form of economic offering before the cap of -$100/MWh was reached.

Revenue sufficiency impact of a higher price cap or negative price floor

Annual average price impact

The AESO estimated the impact on historical annual average prices from a change in the price floor and price cap. For illustrative purposes, the AESO changed historical $0/MWh prices to -$100/MWh and adjusted the price cap by moving prices in EEA1 and EEA2 to $1,500/MWh and prices in EEA3 to $3,000/MWh. The resulting prices are shown below in Table 1.

Table 1: Change in price floor and price cap – impact on historical annual average prices

Year	Actual Average Annual Price	w/ -$100/MWh floor	w/ $1,500/MWh EEA1/2 and $3,000/MWh EEA3	w/ Price Cap & Price Floor Change	Difference w/ Price Cap & Price Floor Change
2012	64.32	63.87	65.65	65.20	0.88
2013	80.19	80.15	83.99	83.95	3.77
2014	49.42	49.42	49.82	49.82	0.40
2015	33.34	33.30	33.34	33.30	-0.03
2016	18.28	18.23	18.28	18.23	-0.05
2017	22.19	21.72	22.46	21.99	-0.20
2018	50.35	50.22	50.75	50.62	0.28
2019	54.88	54.88	55.00	55.00	0.12

Table 1 shows that the largest difference in annual average pool price from the illustrative change in the price cap and price floor was an increase of $3.77/MWh in 2013. All other years saw changes of less than $1/MWh. Five years showed a net increase in price, while three years showed a net decrease.

In the following sections, the AESO analyzes the expected impact to future revenue sufficiency from changes to the price cap and price floor.

Price cap analysis

For illustrative purposes, the AESO tested the impact that increasing the price cap to $3,000/MWh would have on power project cash flow[5]. The AESO reviewed the number of hours from the Aurora simulations that were forecast to settle at the existing cap and replaced power project cash flows with the counterfactual cash flows earned at a price cap of $3,000/MWh.

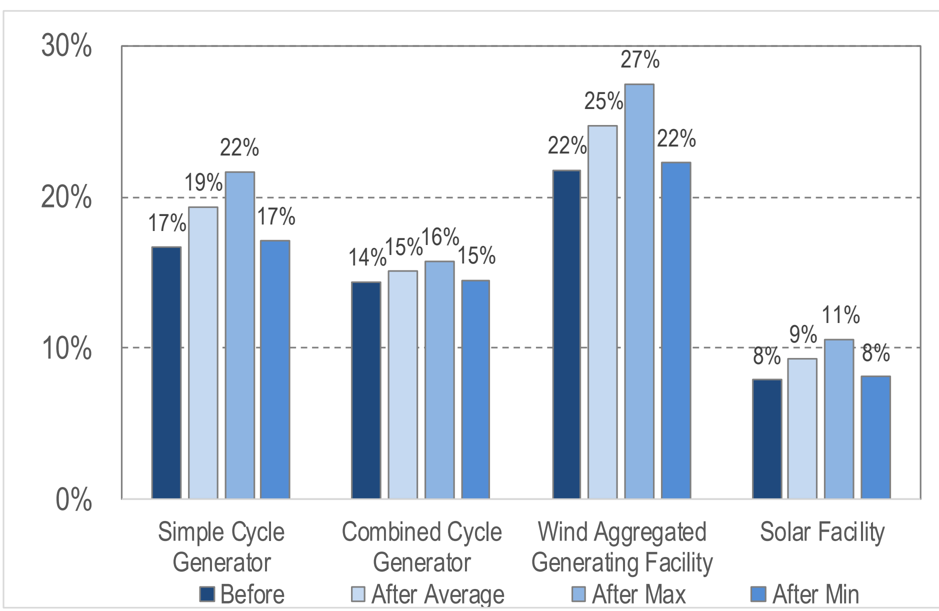
[5] If a change to the price cap was to be established the actual price cap would need to be determined through additional analysis.

The AESO tested three scenarios, where the number of annual hours at the price cap was represented by the minimum, average, and maximum number of hours from the years within the scenarios. The AESO tested the minimum, average, and maximum number of hours at the price cap by replacing each year's project cash flow with the counterfactual cash flow for each project type. Wind facilities, solar facilities, simple cycle natural gas, and combined cycle natural gas facility cash flows were augmented with the additional cash flow in each case. Cash flow from the first built unit of each new generation type was used to analyze the impact of a change in price cap to the plant IRR.

When the minimum number of price-cap hours was augmented, the impact on project IRR was less than 1 per cent for all project types. When the maximum number of price-cap hours was augmented, the IRRs increased by 5 per cent for simple cycle generators and wind generators, by 3 per cent for solar facilities and by 2 per cent for combined cycle generators. When the average number of price-cap hours was augmented, the IRRs increased by 3 per cent for wind generators, 2 per cent for simple cycle generators, and 1 per cent for solar and combined cycle generators.

The price cap increase demonstrated a large increase to price in a small amount of hours, which yielded meaningful increases in project returns. Notably, returns for these generation project types were already expected to achieve returns consistent with the WACC and the level of investment was expected to be sufficient to meet the AESO's minimum reliability requirements. Therefore, the incremental revenue associated with increasing the price cap may not be necessary to enable investment in generation projects. Although additional revenue opportunities may incent additional generation, the increase in cost to consumers must be considered as well.

Figure 6: AESO Reference case outlook: project internal rate of return with incremental revenue due to a change in price cap from $1,000 to $3,000/MWh

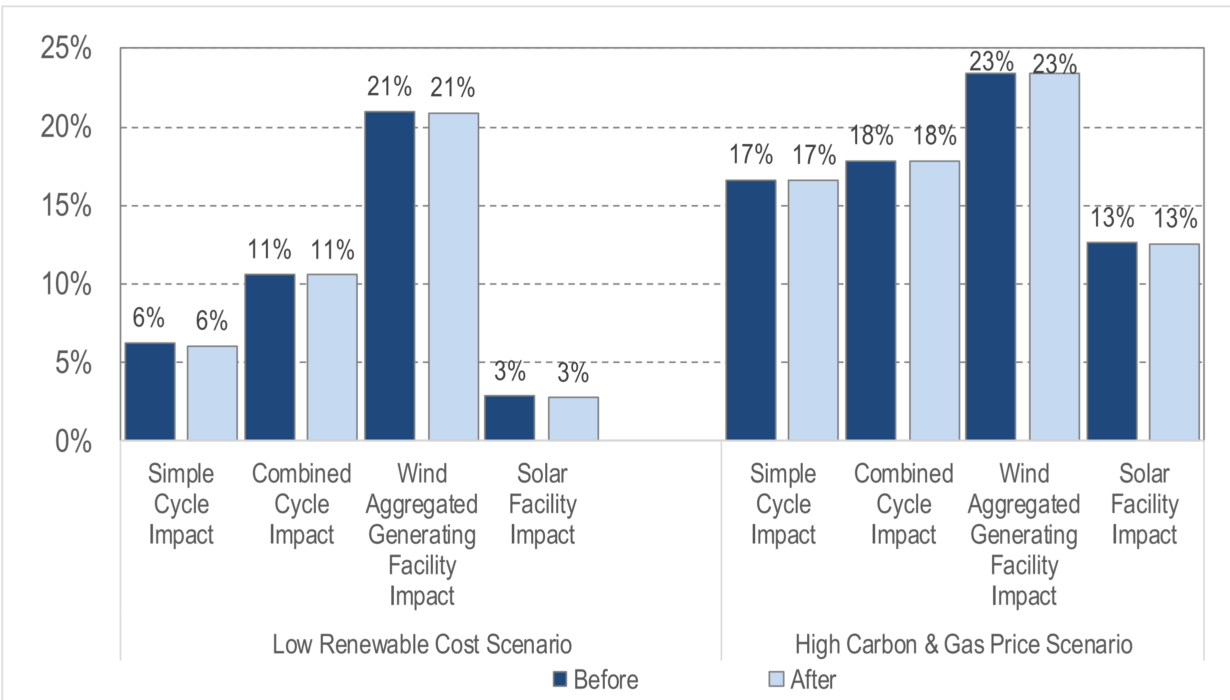


Price floor analysis

The AESO tested the impact that reducing the price floor to -$100/MWh would have on power project cash flow. In order to estimate the maximum impact that could be expected, the AESO reviewed the number of hours where the price floor was reached and replaced the revenue in these hours with the counterfactual price floor of -$100/MWh. The AESO then analyzed the revenue impact to the first generation facility constructed for each fuel type, assuming that each project was generating at full capacity during these events. The change in cash flow was measured as an impact to each project's IRR.

Since the number of hours in each year that prices settled at the price floor was relatively low, the impact on the cash flow for projects was very small and had a negligible impact on IRRs. The analysis did not incorporate operational mitigation, such as reduced output, that generators may practice in order to mitigate losses during negative pricing events.

Figure 7: Project internal rate of return with incremental revenue due to a change in price floor from $0 to -$100/MWh



Comparison of Alternatives and Recommendation Rationale

The AESO considered two approaches to change the pricing framework in Alberta. The options are noted below and were compared against the current framework.

Option A: Implement changes to the pricing framework now to incent market based response during supply shortage and supply surplus situations. In this option, the AESO would implement a stepped price cap, with the steps outlined in the preceding section Price cap alternatives, option 2. The price floor would be set at a level of -$100/MWh.

Option B: Implement Option A in the future, delaying implementation due to the pandemic and negative oil and economic fundamentals that are currently stressing the provincial economy. These events would limit the ability of the stakeholder workforce to effectively prepare for price change implementation. In this option, over the next 18 to 24 months the AESO would re-assess the provincial economic situation and the ability for the stakeholder community to effectively participate in the rule change process. Concurrent with the pandemic and the economic stressors, there are also other events within the electricity industry that are competing for stakeholder time such as the ISO tariff engagements and AUC proceedings. These competing events also require active stakeholder community support. Delaying the implementation of the pricing framework changes reduces one stressor on the stakeholder community.

Option C: Maintain the current pricing framework. The AESO will continue to monitor the state of the market for signs of system inefficiency and long-term adequacy.

The AESO assessed these options against the following criteria:

Long-term adequacy: The intent of the pricing framework is to provide clear and transparent signals on the need for capacity. Prices should rise over time when reserve margins are low and decrease when reserve margins are high. Over the longer term the pricing framework is meant to ensure revenue sufficiency for the marginal assets needed to meet the resource adequacy objectives of the power system.

Efficient short-term market response and adequacy: The pricing framework should also ensure that the pool price creates the right signals for the market to respond appropriately and efficiently to system conditions. The required responses from market participants, both suppliers and consumers, is to increase production or reduce consumption when the price signal indicates the system is in scarcity or shortage conditions and, conversely, to reduce production or increase consumption when the supply demand balance indicates the system is in or approaching surplus conditions. The effectiveness of the market price to provide signals that encourage participant flexibility are important to ensure the overall short-term robustness of the power system.

Robustness over time: The AESO is of the opinion that the pricing framework is meant to be robust over time. Market conditions, or the externalities that influence markets, change in ways that participants do not often expect and these changes can occur at a pace faster than expected. A robust pricing framework is able to accommodate unexpected changes that influence the power sector while meeting the longer term and short-term adequacy needs of the AESO and market participants.

Provides for a stable market: The pricing framework should also provide for a stable market. The framework should not require ongoing change and adjustment in order to meet the needs of the AESO and market participants. Frequent change creates uncertainty as to what the future state of the market might be. This uncertainty erodes confidence in the power market for developers and operators of generation facilities, existing and new load customers and other market participants such as retail, commercial and industrial hedge and service providers.

Implementation complexity: Any change to an existing element of the market design will require rule changes and system changes for both the AESO and market participants. While this consideration on its own should not prevent change, any change alternative proposal should appropriately consider the cost and complexity of change and the impacts that change will have on the AESO's and market participants' operations and systems.

As part of the AESO's final pricing framework stakeholder presentation, the following graphic (Figure 8) was presented to stakeholders to guide the discussion related to the AESO's decision rationale. The AESO discussed the rankings of each of the options described below.

Figure 8: Options and related rankings

Criteria	Change now	Delay	Maint-ain
Long-term adequacy, transparent signals, revenue sufficiency	⊕	⊕	⊕
Short-term efficiency: signals to encourage flexibility	⊕	⊕	△
Short-term efficiency: self commitment signals	⊕	⊕	⊕
Short-term efficiency: signals aligned with external markets	⊕	⊕	△
Relies on market rather than administrative mechanisms	⊕	⊕	△
Robust over time, meets the need of uncertain load & generation types, other market changes	⊕	⊕	⊕
Creates/ maintains a stable market	△	⊘	⊕
Implementation complexity and cost	△	△	⊕

Long-term adequacy: The AESO's revenue sufficiency study work demonstrated that the existing offer cap of $999.99/MWh was expected to be sufficient to provide for revenue adequacy while meeting the reliability objectives of the electrical system. None of the options presented considered a change to the offer cap and as such they all were considered to favourably meet the long-term adequacy objective.

Short-term efficiency – signals to encourage flexibility: In developing alternatives to the price cap, the AESO demonstrated that a higher price cap may provide incentive for a small amount of load, approximately 40 MW, to actively curtail based on prices above the current price cap of $1,000/MWh. The AESO also provided analysis that indicated a price floor of -$100/MWh would provide an economic incentive for upwards of 2,000 MW of supply to self-curtail production during supply surplus events. The AESO was of the opinion that changes to the existing price cap and floor may provide improved short-term signals to encourage flexibility.

Short-term efficiency – self-commitment signals: To test the effectiveness of the existing pricing framework, the AESO demonstrated that the current price cap has provided very robust signals for the availability of long lead-time assets, as well as for nearly full intertie utilization during scarcity and shortage events. Both of the change alternatives would also provide this signal.

Short-term efficiency – aligned with external markets: The AESO reviewed the pricing framework of neighbouring markets and found that external mid and northwest US markets had pricing frameworks with higher price caps than Alberta. In periods of coincidently high price events the existing price cap of $1,000/MWh in Alberta may not be sufficient to economically attract imports to Alberta.

Relies on market rather than administrative mechanisms: As described above in the signals to encourage flexibility, the AESO is of the opinion that a higher price cap and lower price floor may remove the need for administrative actions to balance the market in scarcity, shortage and surplus periods.

Robust over time: The AESO is of the opinion that all the alternatives presented, including the existing framework, would provide for a robust market over time. Changes to the price cap and the price floor would help to ensure the market was able to accommodate the needs of the future grid, regardless of the changes and pace of change that might be experienced. The AESO also believes the existing framework is robust. The existing framework has provided the environment for the development of thousands of MW of new and diverse supply to meet the needs of a substantially increasing load base. The existing framework is straightforward and well understood by market participants.

Creates and maintains a stable environment: The AESO believes the current design best meets this criteria; the existing framework is well known and understood by load and generation market participants. While changes to the price cap may provide signals to enhance flexibility, the AESO's analysis demonstrated that the efficiency gains from a higher price cap would currently apply to approximately only 40 MW of load. While the amount of load may increase in the future, those volumes are uncertain and the efficiency benefit to the market for a price cap change is deemed very marginal. Similarly the AESO considered changes to the price floor as favourable in that they would provide more market based, rather than administrative, approaches to clearing supply surplus events however our analysis demonstrated that the aggregate efficiency gains over the last five years amounted to only $18,000. The gains from an immediate change to the price cap and floor were deemed not sufficient to warrant the uncertainty and instability to the market that would ensue. Likewise, Option B, implementing price cap and floor changes but waiting until the current pandemic and oil fundamental uncertainty and other elements of tariff and regulatory activity abated would introduce far more uncertainty to the market than the small efficiency benefits identified with a price cap and floor change. The Alberta power market has undergone significant change over the last three years. Changes to the pricing framework are not expected to provide sufficient benefit to compensate for continued uncertainty.

Implementation cost and complexity: Any change to the framework will require work and expenditure to implement the change. A decision to maintain the current pricing framework allows the AESO and market participants to focus on initiatives that provide higher amounts of efficiency benefits for the electricity system.

Appendix E:

Jurisdictional review

The AESO has reviewed the mitigation and pricing approaches used by other electricity markets within the United States (US), Australia and New Zealand. The review was conducted to better understand the approaches used in other jurisdictions, and determine whether there are elements of these frameworks that could be considered for inclusion in Alberta's energy-only market. Capacity markets are included but are not directly comparable to energy-only markets due to the way the capacity payment is meant to provide fixed-cost recovery.

Jurisdiction	Mitigation Framework	Energy Market Pricing
Energy-only Market – Ex Post Mitigation		
New Zealand[1]	***Discretion to investigate*** The Electricity Authority (EA) code provides discretion for the [MSA] to declare 'undesirable trading situations'. ***Time limitation*** The EA cannot initiate an investigation after more than 10 business days after the situation occurred. ***Retroactive pricing*** EA may retroactively impose administered pricing. ***Safe harbor for pivotal suppliers*** EA code defines 'pivotal' and provides a safe harbor for pivotal suppliers, which are generalized as: - offers are deemed okay if a supplier's offers do not result in a price increase inconsistent with prices in an immediately preceding trading period or other comparable trading period or - the generator's offers are generally consistent with offers it has made when it has not been pivotal; or - the generator does not benefit financially	***Offer cap*** No offer cap ***Price cap with stop loss*** A price cap based on the value of lost load with a stop loss. If scarcity pricing is triggered, a generation weighted average spot price (GWAP) will first be calculated for the regions. If the GWAP is lower than $10,000 NZD/MWh, all prices within the affected region(s) will be scaled up to NZ$10,000 /MWh. If the GWAP based is more than NZ$20,000/MWh, all prices will be scaled down so that GWAP is NZ$20,000/MWh. A pricing mitigating mechanism will halt the application of scarcity pricing if the average price over any rolling seven-day period is greater than NZ$1,000/MWh. ***Price floor*** NZ$0/MWh

[1] https://www.ea.govt.nz/code-and-compliance/the-code/

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Jurisdiction	Mitigation Framework	Energy Market Pricing
Australia National Energy Market	***Defined terms*** Distinguish ‘substantial market power’ and ‘transient pricing power’. Define *substantial market power* as the ability of a generator or group of generators to increase annual average wholesale prices to a level that exceeds long run marginal cost (LRMC), and sustain prices at that level due to the presence of significant barriers to entry. Define *transient pricing power* as the ability to increase prices above estimates of costs for short periods of time. Transient pricing power, manifested through occasional price spikes, is an inherent feature of a workable competitive wholesale market and is only a concern if it occurs frequently enough to lead to average annual wholesale prices above LRMC of generation.[2] ***Reporting*** National Electricity Law requires the Australian Energy Regulator (AER) to monitor the wholesale market and report on its performance at least every two years, including whether there is ‘effective competition’. The 2018 AER report concludes that while participants exercise market power, often it is only transient. AER does not have conclusive results of the exercise of substantial market power, but will closely monitor offer behaviour, fuel costs, changes to generation mix, and physical issues in states where electricity dispatch offers have increased.[3]	***Price cap with stop loss*** EUE based price cap of AUS$14,700/MWh (2019-2020)[4] Price cap lowered to AUS$300/MWh if Cumulative Price Threshold (CPT) of AUS $221,100 (2019-2020) is reached. That is – if the sum of spot prices for the previous seven days reaches the CPT, the market has provided the fixed cost recovery required for a peaker plant, and the price cap is lowered to AUS$300/MWh.[5] ***Price floor*** AUS-$1,000/MWh[6]

[2] https://www.aemc.gov.au/sites/default/files/content/b0feca33-0630-45e8-9bfc-54dfa262acd0/Final-Determination.PDF

[3] https://www.aer.gov.au/wholesale-markets/market-performance/aer-wholesale-electricity-market-performance-report-2018

[4] https://www.aemo.com.au/-/media/Files/Electricity/NEM/National-Electricity-Market-Fact-Sheet.pdf

[5] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Operation-of-the-administered-price-provisions-in-the-national-electricity-market.pdf

[6] Section 3.9.6. https://www.aemc.gov.au/sites/default/files/2020-03/NER%20-%20v136%20-%20Chapter%203.pdf

Jurisdiction	Mitigation Framework	Energy Market Pricing
Energy-only Market – Ex Ante Mitigation		
Texas ERCOT[7]	***Defined terms*** 'Market power abuse' and 'withholding of production' are defined in Texas Public Utility Code and are unacceptable behaviours ***Exceptions to market power*** Market power mitigation does not apply to 'small fish' - suppliers controlling less than 5% of installed capacity[8] ***Control limitations*** Installed capacity ownership limit is 20% ***Mitigation plan*** Allows voluntary mitigation plan which when approved by the Public Utilities Commission provides an absolute defense against allegations of market power abuse.[9]	***Offer cap*** High system wide-offer cap (HCAP): $9,000 USD/MWh Low system-wide offer cap (LCAP)– greater of $2,000 USD/MWh and 50 times the natural gas price index[10] ***Price cap*** An operating reserve demand curve with the cap set at the value of lost load: $9000 USD/MWh ***Price floor*** -$251 USD/MWh[11]
Contracts for long term adequacy		
California CAISO[12]	***Three pivotal supplier test*** Local market power mitigation based on assessment and designation of transmission constraints as competitive or non-competitive. Suppliers choose method of calculating default energy bid – variable cost option, negotiated rate option, or locational marginal price (LMP) option. Pivotal supplier's incremental bids that relieve a binding transmission constraint are subject to mitigation.[13] CAISO market design assumes there are competitive conditions in the CAISO balancing area at the system level.[14]	***Offer cap*** $1,000 USD/MWh[15] ***Price cap*** None, but highest shortage price is $1,000 USD/MWh[16] ***Price floor*** -$150 USD/MWh[17]

[7] TPUC code, chapter 25., https://statutes.capitol.texas.gov/Docs/UT/htm/UT.39.htm

[8] https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.504/25.504.pdf

[9] https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf

[10] System-wide offer cap set at HCAP at beginning of each calendar year and maintained at this level until the peaker net margin during a calendar year exceeds a threshold of three times the cost of new entry of new generation plants. https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf

[11] Section 4: Day-Ahead Operations, Current Protocols. http://www.ercot.com/mktrules/nprotocols/current

[12] CAISO Tariff Section 39 updated Sep 28, 2019, retrieved from: http://www.caiso.com/Documents/Conformed-Tariff-asof-Sep28-2019.pdf

[13] Section VII.A, http://files.brattle.com/files/13751_market_power_screens_and_mitigation_options_for_aeso_energy_and_ancillary_service_markets.pdf

[14] http://www.caiso.com/Documents/SystemMarketPowerAnalysis-May6-2019.pdf

[15] Section III, http://files.brattle.com/files/14169_4_3-brattle-paper-shortage-pricing.pdf

[16] Section III, http://files.brattle.com/files/14169_4_3-brattle-paper-shortage-pricing.pdf

Jurisdiction	Mitigation Framework	Energy Market Pricing
Capacity and Energy Markets		
PJM Inter-connection LLC	***Three pivotal supplier test*** Uses a 3 pivotal supplier (TPS) test to identify pivotal suppliers ***Pivotal supplier mitigation*** Suppliers that fail the TPS test are subject to offers to a maximum reference price, i.e. an offer price level that includes only verifiable resource marginal costs. The independent market monitor is allowed to verify these costs[18] PJM imposes mitigation on entire generating unit of pivotal supplier's incremental offer.[19] Day-Ahead Market - offer caps are applied at the time of commitment and apply for the length of time the unit is scheduled in the Day-Ahead Market at the schedule that results in the lowest overall system Real Time Market – offer caps are applied at the time of commitment and apply at the schedule that results in the lowest dispatch cost[20]	***Offer cap*** Offer cap $1,000 USD/MWh, or cost-based incremental energy offer capped at $2,000 USD/MWh for purpose of dispatch and calculating locational marginal price.[21] ***Price cap*** Shortage pricing capped at $3,700 USD/MWh [22] ***Price floor*** None

[17]Stranded Flexible Ramp Capacity, http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

[18] https://www.pjm.com/~/media/documents/manuals/m15.ashx

[19] https://www.aeso.ca/assets/Uploads/4.2-Brattle-Paper-Mitigation.pdf

[20] https://www.pjm.com/~/media/documents/manuals/m11.ashx

[21] If verified cost-based incremental energy offer exceeds $2,000/MWh, a resource may be eligible for a make-whole payment. https://www.pjm.com/markets-and-operations/energy/energy-offer-verification.aspx

[22] https://www.pjm.com/~/media/documents/manuals/m11.ashx

Jurisdiction	Mitigation Framework	Energy Market Pricing
ISONE	***RSI combined with conduct and impact tests*** Conduct and impact tests apply to a market participant that is determined to be a pivotal supplier ***Conduct test*** Non-constrained areas: suppliers must offer at the lower of 400% of their reference price or $100/MWh above their reference price Constrained areas: suppliers must offer at the lower of 150% of their reference price or $25/MWh above their reference price otherwise they fail conduct test ***Impact test*** Non-constrained areas: the supply offer cannot raise the clearing price by more than the lower of 200% or $100/MWh Constrained areas: the supply offer cannot raise the clearing price by more than the lower of 50% or $25/MWh[23] Failing both the conduct test and the impact test results in the resource's offer being replaced by its reference price.[24]	***Offer cap*** Offer cap currently $1,000 USD/MWh, March 2020 implementation of verified cost-based incremental energy offers up to $2,000 USD/MWh[25] ***Price cap*** Fixed penalty factors for depletion of each type of reserve[26] ***Price floor*** -$150 USD/MWh [27]

[23] https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

[24] Reference price calculated by IMM, based on the following order: The lower of the mean and median of a resource's accepted offers in the last 90 days. This can be adjusted by fuel price if it is relevant. 25th percentile LMP at the resource's node during which the resource was dispatched at in the last 90 days. This can also be adjusted by fuel price if it is relevant. A fundamental ground-up calculation based upon plant characteristics, verifiable costs, and opportunity costs

[25]Per FERC Order 831 https://www.iso-ne.com/participate/support/customer-readiness-outlook/

[26]Section III.2.7A: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

[27] https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf

Jurisdiction	Mitigation Framework	Energy Market Pricing
NYISO	***Conduct and impact tests*** ***Conduct test*** Non-constrained area: the resources' offers cannot exceed its reference price by the lower of 300% of the reference price or $100/MWh more than the reference price. Constrained area: conduct test based on the lower of non-constrained area thresholds and a formula where higher historical market prices increase the threshold and higher historical constrained hours decrease the threshold.[28] ***Impact test*** Non-constrained area: the resource's offer price may not raise the clearing price by the lower of 200% or $100/MWh more than the reference price. Constrained area: threshold determined in accordance with formula specified in the conduct test. Failing both the conduct test and the impact test results in the resource's offer being replaced by its reference price.[29]	***Offer cap*** Offer cap $1,000 USD/MWh, with no more than $100 USD/MWh adder. If supported by cost the offer can be no more than $2,000 USD/MWh ***Price cap*** No price cap, but prices are limited by shortage costs. Operating Reserve Demand Curve for each operating reserve requirement[30] ***Price floor*** -$1,000 USD/MWh [31]

[28] Section 23.3.1.2.2.1 https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf

[29]Reference price calculated by NYISO based on the following order: The lower of the mean and median of a resource's accepted offers in the last 90 days for hours between 7 am and 10 pm on working weekdays. This can be adjusted by fuel price if it is relevant. 50th percentile LMP at the resource's node during which the resource was dispatched at in the last 90 days. This can also be adjusted by fuel price if it is relevant. A fundamental ground-up calculation based upon plant characteristics, verifiable costs, and opportunity costs.

[30] https://www.nyiso.com/documents/20142/2923301/ancserv.pdf/df83ac75-c616-8c89-c664-99dfea06fe2f

[31] Section 21.4. https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariff.pdf

Jurisdiction	Mitigation Framework	Energy Market Pricing
MISO	***Conduct and impact tests*** ***Conduct test:*** Broad Constrained Area: threshold is the lower of 400% of the reference price or $100/MWh above each generating unit's reference level. Offers below $25/MWh are not considered economic withholding. Narrow Constrained Area: threshold is net annual fixed costs of a new peaking generator divided by the total number of hours over the prior 12 months during which a binding transmission constrained occurred in the constrained area ***Impact test:*** Broad Constrained Area: threshold is the lower of an increase of 200% or $100/MWh in applied to the energy LMP. Narrow Constrained Area: threshold is the net annual fixed costs of a new peaking generator divided by the total number of hours over the prior 12 months during which a binding transmission constraint occurred in the constrained area applied to the energy LMP. Failing both the conduct test and the impact test results in the failing offers being replaced by the reference level price.[32]	***Offer cap*** Offer cap currently $1,000 USD/MWh. Effective December 1, 2019, subject to FERC approval, implementation of verified cost-based energy offers up to $2,000 USD/MWh.[33] ***Price cap*** Operating reserve demand curve with cap set at VOLL $3,500 USD/MWh[34] ***Price floor*** -$500 USD/MWh[35]

[32] Reference levels selected in order of precedence as: Offer-Based, LMP-Based, Cost–Based, Estimated, or Averaged. See MISO Market Monitoring and Mitigation Business Practices Manual, BPM-009-r15, Effective Date: July 9, 2019

[33] https://www.misoenergy.org/stakeholder-engagement/issue-tracking/increase-the-energy-offer-cap/

[34] https://www.potomaceconomics.com/wp-content/uploads/2018/07/2017-MISO-SOM_Report_6-26_Final.pdf

[35] Common Tariff Provisions: https://cdn.misoenergy.org/Module%20A108022.pdf

Appendix F:

Stakeholder feedback

Introduction

On July 25, 2019 the AESO received direction from the Alberta Minister of Energy (Minister) to submit a recommendation on whether changes are required to the existing pricing framework in Alberta's energy-only market by July 31, 2020.

In providing its recommendation to the Minister, the AESO's focus has been to ensure it considers the perspectives of market participants, agencies and other interested parties (stakeholders). The AESO conducted stakeholder sessions on three occasions and solicited and received both verbal and written feedback.

The AESO thanks the stakeholders who participated in the pricing framework engagement sessions for their valuable input, both verbal and written. Each response was reviewed thoroughly and the information received has helped inform the AESO's recommendation to the Minister on whether changes are required to the pricing framework in Alberta's energy-only market.

The presentations made to stakeholders and feedback received, is available on the AESO website:

https://www.aeso.ca/stakeholder-engagement/aeso-initiatives/market-related-initiatives/market-efficiency-pricing-framework/

Summary of stakeholder feedback: pricing framework sessions 1-3

A total of 19 stakeholders submitted written feedback through the comment matrices.

Respondents/Participants

- 10 market participants
- 6 industry associations/organizations
- 1 independent consultant
- 2 agencies

The AESO's stakeholder feedback matrices were posted after each of the three stakeholder sessions and solicited input on key subject areas. The feedback has been summarized into the following sections:

1. Objectives of the pricing framework and intent of the administrative price levels
2. The ability of the current pricing framework to ensure long-term adequacy
3. The ability of the current pricing framework in ensuring efficient short-term market response
4. The need or urgency for change

1. Objectives of the pricing framework and intent of the administrative price levels

The majority of stakeholders were generally aligned with the objectives of the pricing framework. The AESO outlined the objectives of the pricing framework at the first stakeholder session, which included ensuring both long-term adequacy and efficient short-term market outcomes. While many stakeholders were supportive of the objectives, some also noted items the AESO should consider in its review:

- AESO should develop a longer-term vision, or end state, for the energy-only market
- Ensure that the market sends the right signals for flexibility

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- This consultation may determine that these objectives can be achieved without any changes to the pricing framework
- Consider aligning the pricing framework with other jurisdictions

The AESO also presented information on the intent of the price cap, offer cap and price/offer floor.

Stakeholders overall were generally aligned with the descriptions of the offer cap, price cap and price floor. Some stakeholders also indicated that the existing price levels are appropriate to incent both long-term and short-term response from the market. In their feedback, some of the additional concerns that stakeholders noted included:

- The AESO should identify an objective metric and avoid arbitrary administrative levels
- Revenue sufficiency may be a concern with negative pricing
- The AESO should consider the impact these price levels have on forward-market liquidity as well as financing costs of new projects

2. The ability of the current pricing framework to ensure long-term adequacy

The majority of stakeholders agreed with the AESO's conclusions regarding long-term adequacy, that the current offer cap allows sufficient recovery of costs both historically and on a forecast basis, and agreed that resource adequacy requirements were expected to be met in all scenarios. Issues noted by stakeholders included:

- Input assumptions used in the modeling, including the volume of future renewables and emerging technologies
- Requests for more transparency on modeling details
- Uncertainty around whether import response will remain strong in the future
- Agreement with AESO's conclusion; however, comments that certain aspects of the pricing framework could be enhanced

One stakeholder noted that historically the energy-only market has been effective in providing efficient and timely price signals, and a strong factor in this is the simplicity of the market design.

3. The ability of the current pricing framework in ensuring efficient short-term market response

The majority of stakeholders opposed change to the current pricing framework, and requested the AESO to commit to market stability and certainty in the absence of pressing concerns. There were also concerns that the anticipated efficiency gains from changing the pricing framework would be minimal relative to the need for market stability. There were suggestions to optimize current demand response in the fleet, rather than increasing the price cap to incent additional demand response as a first step.

In terms of a price floor change, stakeholders noted that efficiencies could be gained; however, the urgency was not immediate, and noted that the AESO's existing supply-surplus procedures have been effective historically, and are anticipated to remain effective in the future. Stakeholders also raised concerns around impacts to revenue sufficiency with a price floor change that could impact long-term investment decisions.

4. The need or urgency for change

In the third and final stakeholder session, the AESO presented various pricing alternatives and discussed the need for change. The AESO presented a draft recommendation to maintain the existing pricing framework. The majority of stakeholders were in agreement with the draft recommendation, indicating that the existing framework has been highly successful in Alberta and the decision to maintain the framework would minimize uncertainty and ensure stability.

A few stakeholders made suggestions for change. One stakeholder agreed with the recommendation to maintain the existing framework; however, suggested a periodic increase in the price cap, such as by inflation. Another stakeholder suggested that the AESO amend its recommendation for a gradual, proactive and transparent increase of Alberta's price and offer cap to ensure:

- Improved resiliency with increased renewables
- Greater efficiency
- More effective competition

Overall, stakeholders were in support of no change to the framework. A few suggested that the AESO should undertake periodic reviews of the framework to ensure the design continues to meet the needs of the evolving electricity market.

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