MARKET SURVEILLANCE ADMINISTRATOR

Confidential Advice to Executive Council and the Minister of Affordability and Utilities

Advice to support more effective competition in the electricity market:

Interim action and an Enhanced Energy Market for Alberta

December 21, 2023

Taking action to promote effective competition and a culture of compliance and accountability in Alberta's electricity and retail natural gas markets

www.albertamsa.ca

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Overview

In a letter dated August 31, the Minister of Affordability and Utilities requested, among other things, the MSA's advice regarding "whether any … legislative or regulatory reforms are required to support more effective competition in our electricity market in order to support affordability and other outcomes in the consumer interest" by December 24. This report provides the MSA's advice.

The MSA is of the view that change to the Alberta electricity market is required, some changes immediately and some over time. While the existing market framework functioned well, changes in the generation fleet have led to significant and widespread challenges. With a much higher proportion of intermittent renewable generation, pool price variability has increased substantially. In periods where intermittent renewable generation is unavailable, sustained periods of high prices have been observed, leading to higher average prices.

In addition, a marked increase in the extent of economic withholding — exacerbated by physical withholding that is permitted by the ISO rule related to generators that take more than an hour to start — has led to very high pool prices, forward prices, and RRO prices. The MSA's main recommendations are to:

- moderate the extent of economic withholding and reform the approach to unit commitment to eliminate physical withholding through the implementation of two interim measures by July 1, 2024: (i) a Monthly Net Revenue Secondary Offer Price Cap and (ii) a Start-up Cost Guarantee Program; and

- develop an Enhanced Energy Market (EEM) for Alberta.

The MSA's approach to its recommendations

The MSA's recommendations have been developed around several organizing concepts:

- No regrets: Based on the issues that have been identified, the market needs to evolve in a variety of ways. The MSA's recommendations focus on changes the MSA believes need to occur for future success, irrespective of what happens in the broader environment. These are what the MSA regards as "no regrets" changes.

- Implementation timing: The MSA's assumption is that the government intends to make a set of policy decisions in early 2024 that will direct the future evolution of the electricity industry in Alberta and that it recognises that some of these decisions may take longer to implement than others. Presuming that economic and physical withholding are issues the government intends to deal with in the near-term, the MSA will make interim recommendations that can be acted on immediately and long-term recommendations that can replace these as new market mechanisms are developed.

It would be ideal for policy decisions made in 2024 to not focus exclusively on near term change; rather, they should set up the industry for success over time, without repeated reconsideration of the electricity policy framework.

Recommendation 1: Immediately implement interim measures to moderate economic withholding and reform the approach to unit commitment to eliminate physical withholding

To immediately moderate the extent of economic withholding and reform the approach to unit commitment to eliminate physical withholding, the MSA recommends the implementation of two interim measures by July 1, 2024: (i) a Monthly Net Revenue Secondary Offer Price Cap and (ii) a Start-up Cost Guarantee Program.

Developing and implementing an EEM for Alberta will take a number of years and will be considerably more complex an undertaking than the capacity market was. Based on this experience, and experience elsewhere, the MSA estimates it will take at least five years to fully develop and implement an EEM. As discussed in recommendation 2, the MSA strongly recommends the government make the decision to develop and implement an EEM.

However, the MSA understands that acting on economic withholding is a near-term priority to support affordability and other outcomes in the consumer interest, and its recommendations were developed with this in mind. The current market design and rules remain in place until something else is implemented; a policy decision changes nothing in and of itself. Therefore, recommendation 1 is that the government immediately implement interim measures to moderate economic withholding, reform the approach to unit commitment to eliminate physical withholding and create a reliability unit commitment mechanism. These measures would be replaced by the EEM.

The MSA recommends the interim measures set out in recommendation 1 be implemented effective July 1, 2024, and the decision to implement them communicated as soon as possible.

Economic withholding

Economic withholding is an exercise of market power that occurs when offers to the power pool are made at prices sufficiently above marginal cost that the generator is not dispatched, and the pool price is increased as a result. A generation firm benefits from economic withholding to the extent that it receives the higher pool price for the electricity it does sell (the incentive to exercise market power). As such, only relatively large firms have an incentive to economically withhold. Economic withholding is one of two ways that a generation firm can exercise market power.

The simplest way to moderate economic withholding is to place limits on how far above marginal cost offers are allowed to be. In recommendation 1.1, the MSA proposes a feasible method to do this on an interim basis. For clarity, this is not the economically optimal way to deal with this issue, which would be to induce greater forward contracting that would remove the incentive for generation firms to exercise market power in the first place.

Physical withholding and unit commitment

The other way that a generation firm can exercise market power through their offer strategy is by physical withholding. Physical withholding occurs when generation capacity that is capable of producing electricity is not made available to the market at any price. In simple terms, this is when a generator that can operate is not turned on. The incentive and ability to physically withhold is similar to economic withholding: large generation firms can benefit from causing higher prices. Because economic and physical withholding are components of the same offer strategy, they amplify the effect of each other.

Under Alberta's current market rules, a generator that requires more than one hour to start is allowed to go on long lead time (LLT) status if it goes offline. Once on LLT status, the generation firm is allowed to physically withhold the generator in compliance with applicable rules; that is, the generation firm decides for itself when to start (commit) the generator again. The LLT rule was not intended to be used to facilitate the exercise of market power and the MSA has previously recommended changes to it in its Quarterly Reports.

Another reason physical withholding / unit commitment issues should be considered in conjunction with moderating economic withholding is that implementing restrictions on economic withholding will make generation firms more likely to physically withhold as part of their offer strategies. In the extreme, generation firms may have the incentive to cause reliability issues to drive pool prices higher and compel the AESO to direct generators on LLT status online.

A more appropriate market mechanism regarding unit commitment would consider all available generating units and apply a cost minimization criterion over a rolling forward-looking period such as one day. In recommendation 1.2, the MSA proposes changes to the LLT rule framework that would limit the ability of generation firms to physically withhold. The MSA recommends developing a unit commitment mechanism as part of the EEM where the AESO would consider, on a continuous rolling basis, whether to direct generators on LLT status online according to a cost minimization criterion. This interim measure will ensure that economic withholding is not replaced with physical withholding and that the AESO has clear authority to direct for reliability reasons.

Recommendation 1.1

- Effective July 1, 2024, enact a Market Power Mitigation Regulation under the *Electric Utilities Act* (EUA) and the *Alberta Utilities Commission Act* (the same legal basis as the *Fair, Efficient and Open Competition Regulation*) that sets out a clear legislative intent to limit the exercise of market power by electricity market participants in the power pool.

- In the regulation:

    - Create a Monthly Net Revenue Secondary Offer Price Cap (Secondary Offer Price Cap) that limits offers for natural gas-fired generators for the largest firms to the greater of (i) 25 times the day-ahead natural gas price (approximately 3 times marginal cost) or (ii) $100/MWh, for the balance of any month in which the net revenue (contribution to covering fixed cost) associated with a hypothetical combined cycle natural gas-fired generator exceeds two-twelfths of the annualized capital cost of the hypothetical generator. The explanation for these particular parameter selections is set out in the main body of the report.

- Require the AESO to develop an ISO rule that implements the Secondary Offer Price Cap and addresses all technical considerations, including definitions of terms, estimation of generator variable and capital costs, calculation of net revenue, and when the limitation would be imposed (for the balance of the calendar month) after the threshold is reached (e.g., 6 hours to allow calculation time).

- Require the AESO to file the Secondary Offer Price Cap ISO rule as an expedited ISO rule under EUA, section 20.6. If the general intent and parameters are set out in the regulation and the ISO rule only implements the regulation, there will be minimal scope for the ISO rule to be challenged under EUA, section 25(1)(b). Allow for any amendments to the ISO rule following the existing process.

- Require the AESO to develop the necessary data systems to implement the Secondary Offer Price Cap on an automated basis as of July 1. This is critically important so that the impact of any contraventions of the Secondary Offer Price Cap do not automatically flow though to the setting of the pool price, the impact of which cannot be reversed in an enforcement proceeding.

- Provide for a process by which electricity market participants may seek exemptions from the Secondary Offer Price Cap. Exemptions should be transparent and subject to approval by the Alberta Utilities Commission (Commission). The expectation should be that exemptions are rare.

- State that the regulation expires upon the implementation of the EEM.

Recommendation 1.2

- Direct the AESO to develop an ISO rule that implements the unit commitment mechanism and Start-up Cost Guarantee Program whereby the AESO would evaluate, on a continuous rolling basis, whether to direct generators on LLT status online if the generator is considered economic or is needed for reliability. In the event a directed generator does not breakeven, it would receive an out-of-market reliability payment so that it does breakeven. Only dispatchable generators would be eligible for these payments.

- Direct the AESO to file these ISO rules as expedited ISO rules under EUA, section 20.6, effective July 1, 2024. Allow for any amendments to the ISO rule following the existing process. These changes can be achieved through a written direction to the AESO and would not require legislative or regulatory change.

Recommendation 2: Develop an Enhanced Energy Market (EEM) for Alberta

While the existing market framework functioned well, changes in the generation fleet have led to significant and widespread challenges. With a much higher proportion of intermittent renewable generation, pool price variability has increased substantially. In periods where intermittent renewable generation is unavailable, sustained periods of high prices have been observed, leading to higher average prices.

Compared to the volatility of the current spot market, a day-ahead market would likely enhance the returns to generation capacity that is dispatchable (such as hydro with reservoirs and natural gas) and lower returns to generation capacity that is not dispatchable (such as wind and solar). In the MSA's view, improving returns to dispatchable generation and creating an imbalance market and incentives would improve the market design and outcomes for Alberta consumers.

Numerous other features are common to modern electricity markets and are worth adopting for Alberta simultaneously. Notable among these design features is locational marginal pricing (LMP). While some have related LMP to the transmission planning standard, it is the MSA's view that the transmission congestion is a fact of power systems that exists independent of the planning standard; therefore, the EEM should include LMP even if the transmission planning standard is unchanged. Whether consumers in different parts of Alberta would be charged different prices is a decision that can be deferred.

In recommendation 2, the MSA recommends adopting a suite of design elements for the EEM. If an EEM could be implemented expeditiously, the MSA would not have recommended interim measures. As indicated above, the MSA is of the view that these changes would take a number of years to implement.

Recommendation 2

- Recognizing that it will take a number of years to complete, direct the development and implementation of an EEM for Alberta to replace the current energy-only market. The EEM would rely on competition to the maximum extent possible to ensure an efficient allocation of resources over time, both with respect to investment incentives for new supply and consumption incentives.

- The EEM should include the following features:

    - day-ahead market;

    - replace the recommended interim Market Power Mitigation Regulation with a market power mitigation framework tailored to the day-ahead market (that is, suited for multiple part offers) and run with the day ahead market;

    - load obligations to forward contract for generation;

- negative price floor and administrative scarcity pricing / operating reserve demand curve;
- congestion management through locational marginal pricing, security constrained economic dispatch, and system tools;
- extended unit commitment market with co-optimization of energy and ancillary services;
- five-minute real-time settlement intervals;
- enhanced role for demand response; and
- new technical standards for intermittent generation and energy storage.

1 INTRODUCTION AND OVERVIEW

In a letter dated August 31, the Minister of Affordability and Utilities requested, among other things, the MSA's advice regarding "whether any … legislative or regulatory reforms are required to support more effective competition in our electricity market in order to support affordability and other outcomes in the consumer interest" by December 24. This report provides the MSA's advice.

The MSA is of the view that change to the Alberta electricity market is required, some changes immediately and some over time. While the existing market framework functioned well, changes in the generation fleet have led to significant and widespread challenges. With a much higher proportion of intermittent renewable generation, pool price variability has increased substantially. In periods where intermittent renewable generation is unavailable, sustained periods of high prices have been observed, leading to higher average prices.

In addition, a marked increase in the extent of economic withholding — exacerbated by physical withholding that is permitted by the ISO rule related to generators that take more than an hour to start — has led to very high pool prices, forward prices, and RRO prices.

This report is focused on the wholesale energy market. Section 2 discusses Alberta's energy-only market, including the nature of competition and the obligations of suppliers, pricing trends and affordability in recent years, the accumulation of operational challenges, the impact on reliability, and the growth of transmission costs. The need for change is discussed in section 3, including how the MSA has approached the development of its recommendations, interim recommendations (which are needed because more substantial change will require time), and finally the development of an Enhanced Energy Market (EEM) for Alberta. Related to the development of an EEM, clarity about the approach to congestion in the transmission policy and out-of-market payments for environmental attributes would be helpful.

2 THE ENERGY-ONLY MARKET: DEREGULATION TO PRESENT

2.1 The existing market: Competition and the obligations of suppliers

The existing wholesale energy-only market (EOM) intends to use competition to result in an economically efficient allocation of resources. The key features of the market design are:

- The real time merit order is dispatched in an orderly fashion and the system marginal price is set by the offer of the marginal unit needed to meet demand. A single pool price is calculated every hour for energy delivered to the market. Separate prices for ancillary services (AS) products are derived in the AS markets; these are mainly indexed to the pool price to ensure the correct incentives for delivery of AS products.

- Generation assets 'must offer' their physically available capacity, with the exception of assets which require greater than one hour to start (long lead time assets, LLT). While all generation assets are subject to "self-commitment," an LLT owner has additional discretion and can decide whether and when to start them unless they are issued a directive by the ISO.

- Energy may be priced above marginal cost (economic withholding), meaning that it may not be dispatched to produce at some prices above marginal cost. Generation firms that offer this way are exercising market power; hence only the largest market participants do this.

- Absent a capacity market or other forms of out-of-market revenues for generators (other than intermittent generators), economic withholding is a fundamental element of the EOM to allow generators to recover the cost of investment over the business cycle. The resulting corporate returns are intended to drive efficient investment and disinvestment (retirement) at reasonable prices for consumers. Certain rules related to LLT assets or mothballing allow physical withholding, reducing supply adequacy and potentially providing greater opportunity to economically withhold.

- The only intended "capacity" market was to ensure sufficient AS were available: these are capacity reserves held to address contingencies on the system due to a loss of generation or transmission or security needs on the grid. AS markets are used to procure operating reserves (regulation, spinning, and supplemental reserves), as well as blackstart and other bespoke services to support the operation of the Alberta interconnected electric system (AIES).

- Transmission is centrally planned by the AESO, with direction to transmission facility operators (TFOs) to build as required to meet the zero-congestion standard set out in the *Transmission Regulation*. Transmission plans reflect the need to meet load and generation in advance of need to ensure "reasonable access." The current transmission planning standard requires that 100% of in merit generation can access the grid when no transmission is out-of-service and 95% of in merit generation can access the grid when one transmission element is out-of-service.

- The market design is intended to be fuel neutral. This neutrality has eroded in recent years due to out-of-market subsidies for intermittent generation and direct incentives to build intermittent generation.

- Historical investment in transmission capacity, including 500 kV lines, expanded the system backbone to resolve significant congestion and reduce the use of transmission must run (TMR).

- While specific rules have evolved in the market framework, the framework has remained largely an EOM despite evaluations to change the framework to a capacity market framework first in 2005 and more recently in 2016. The capacity market proposed in 2016 would not have solved the current issues in the electricity system.

The MSA's recommendations address issues with the current market design, as well as affordability challenges, with a focus on timely policy changes, regulation amendments, and ISO rule modifications (or new ISO rules) to address the immediate issues. In the MSA's view, while change is needed, broad movement away from a competitive market framework is not called for at present. There are feasible solutions to the problems Alberta faces, and many of these changes should be made even if broader change is ultimately decided.

2.2 Pricing trends and affordability: Context for pricing cycles

2.2.1 Market fundamentals

The generation fleet has evolved since market opening, with significant impacts on competition and pricing. In the first ten years, the market saw significant changes in buyers and sellers interested in participating in the markets. This included:

- 3,000 MW of industrial system co-generation that entered the market at start up;

- new sellers with the introduction of the Power Purchase Arrangements (PPAs) between original utility owners and new buyers;

- the participation of industrial customers in the market in response to wholesale prices and then their entry into the ancillary services market providing reserve products; and

- the evolution of renewable assets at the wholesale level.

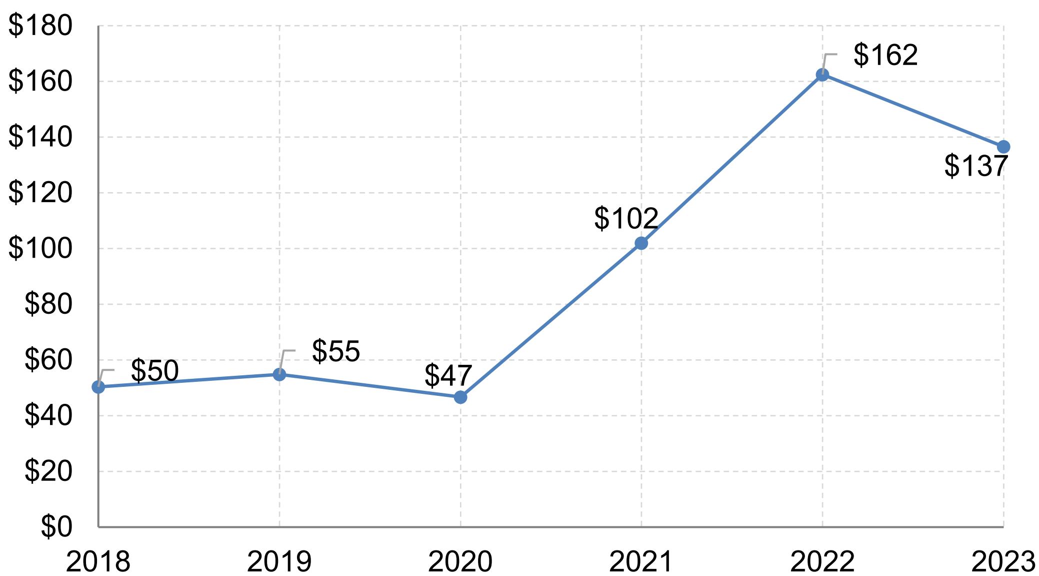
Over the last several years, the most significant impacts on wholesale prices were due to (i) the expiration of the PPAs before and at the end of 2020 and (ii) the phase out of coal, which was replaced by natural gas and intermittent generation. The displacement of natural gas during the daily cycle has contributed to system operation challenges.

A key element of the EOM is the single pool price, which provides operational as well as investment signals. Without additional out-of-market remuneration for generators, the pool price must be sufficient to recover fuel, environmental, and capital costs, including a return on capital. The current electricity framework permits and anticipated some degree of economic withholding (i.e., offering supply at prices above cost so that the generator is not dispatched, and the pool price is increased as a result). This approach has traditionally worked well for Alberta as the market has been competitive and sustained high average prices were not common until recently. For example, a 2012 analysis by the MSA indicated that static efficiency losses in the market amounted to less than 1% of costs.[1] However, recent analysis this year by the MSA (as shown in this report) indicates that, with the changing generation fleet and generation firm offer strategies, static efficiency losses have increased significantly.[2]

Further, consumers not only face cost increases associated with changes in the wholesale energy market, but also face cost increases from the capital pay back on recent transmission build and increases in AS procurement for contingencies (as has been the case historically) and recently for increased system needs.

Average pool prices increased from $47/MWh in 2020 to $162/MWh in 2022, an increase of 247%. Pool prices in 2023 have also been high; the average price this year is expected to be about $137/MWh (Figure 1).

Figure 1: Average pool price by year (2018 to 2023)



Higher pool prices have coincided with lower supply adequacy. Starting in 2020, there has been a trend of increasing Energy Emergency Alert (EEA) events, indicating that the grid is approaching

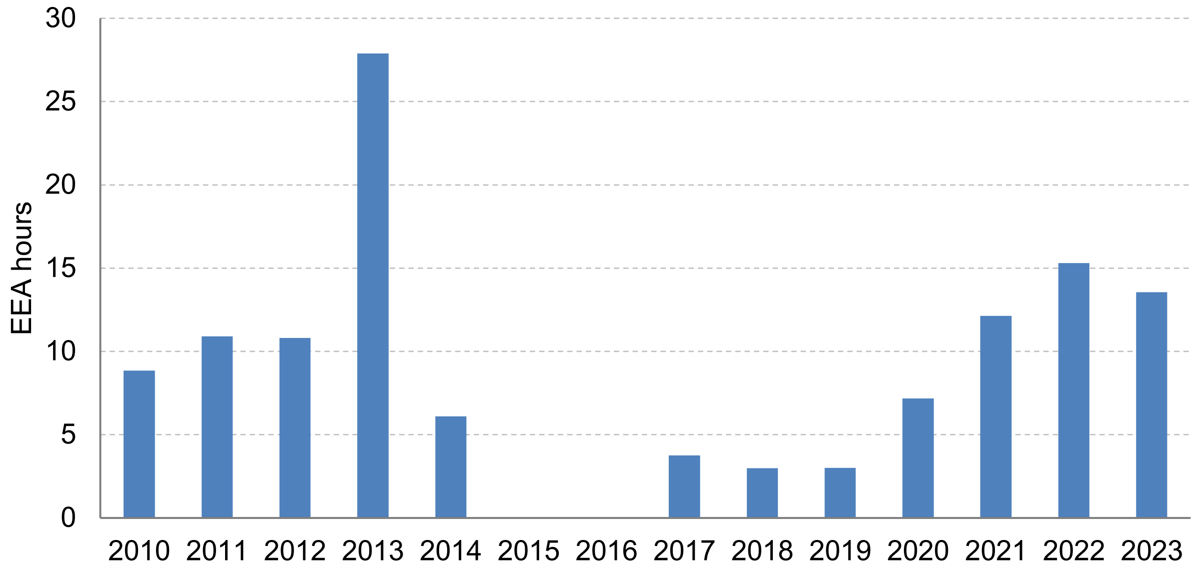
[1] See the MSA's State of the Market Report 2012 (December 10, 2012), pages 12 and 64. (https://www.albertamsa.ca/assets/Documents/State-of-the-Market-Report-2012-2012-12-10.pdf)

[2] See the MSA's Quarterly Report for Q2 2023 (August 15, 2023), page 17.

supply shortfall conditions more often (Figure 2). In Q3 this year, EEA events occurred when the grid was stressed due high demand, low wind generation, thermal generation outages, and reduced import capability.

The higher pool prices in recent years have been caused in part by market fundamentals, but more so by increased market power exercised through economic and physical withholding.

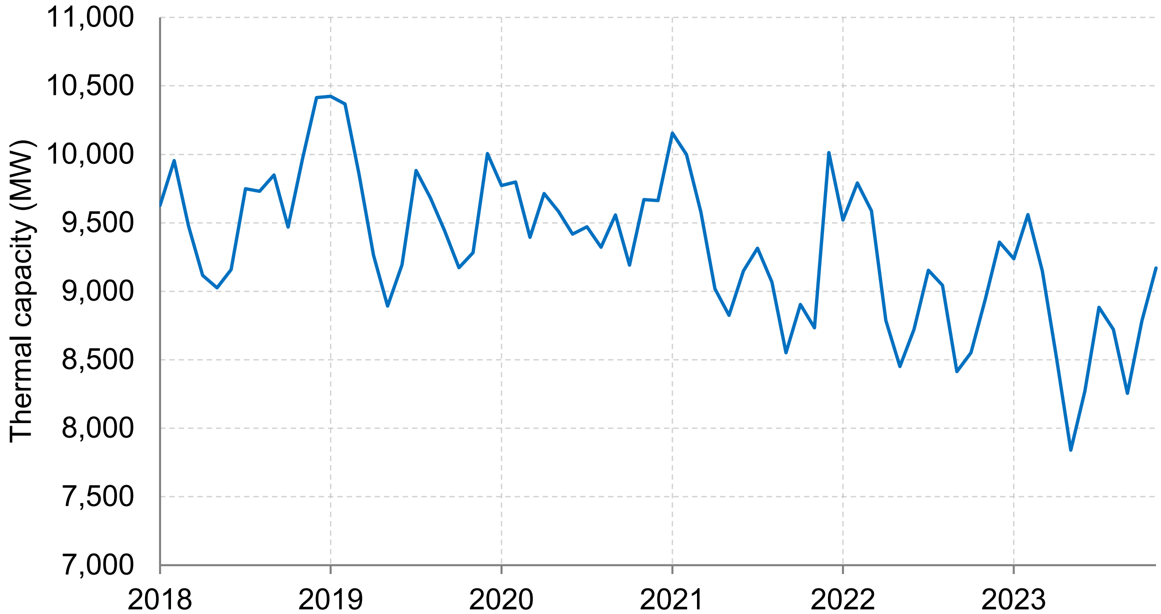
Figure 2: Time under an Energy Emergency Alert, by year (2010 to 2023)



In response to the higher carbon price and because of more intermittent capacity, available thermal capacity has declined in recent years as thermal generation assets have been mothballed and retired (Figure 3). Since 2018, seven coal assets totaling 2,300 MW of capacity have been retired.

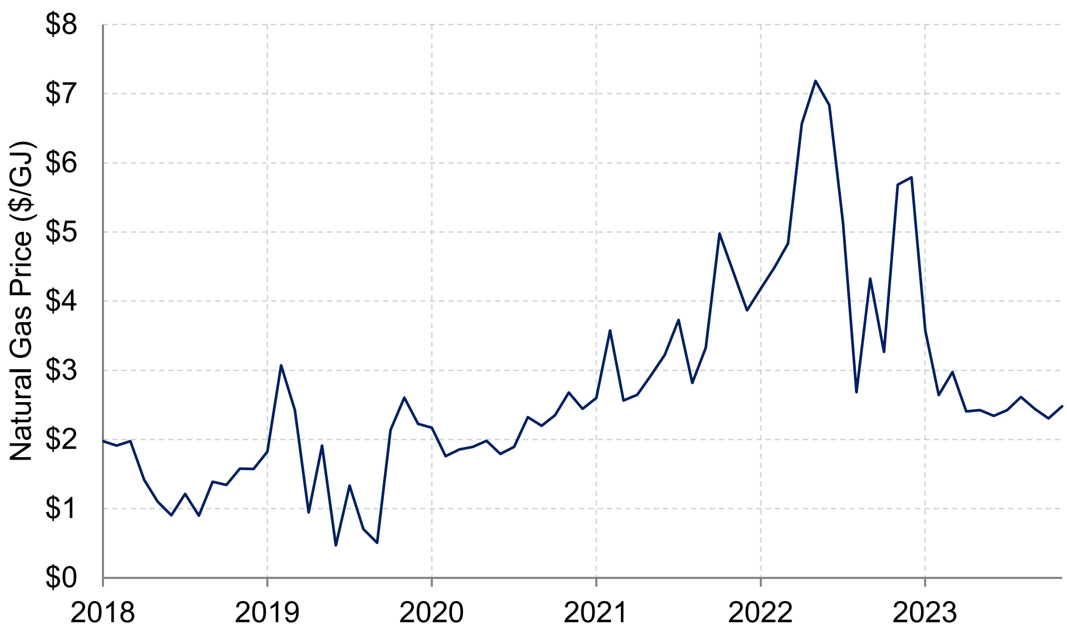
In addition to the retirements, nine coal assets totaling 3,400 MW of capacity were converted to natural gas. The average rate of carbon emissions from electricity generation in Alberta has fallen by almost half over the past decade. To convert these assets, the generators were taken offline for months at a time, which reduced thermal supply and put upward pressure on prices.

Figure 3: Monthly average of available thermal capacity (January 2018 to November 2023)



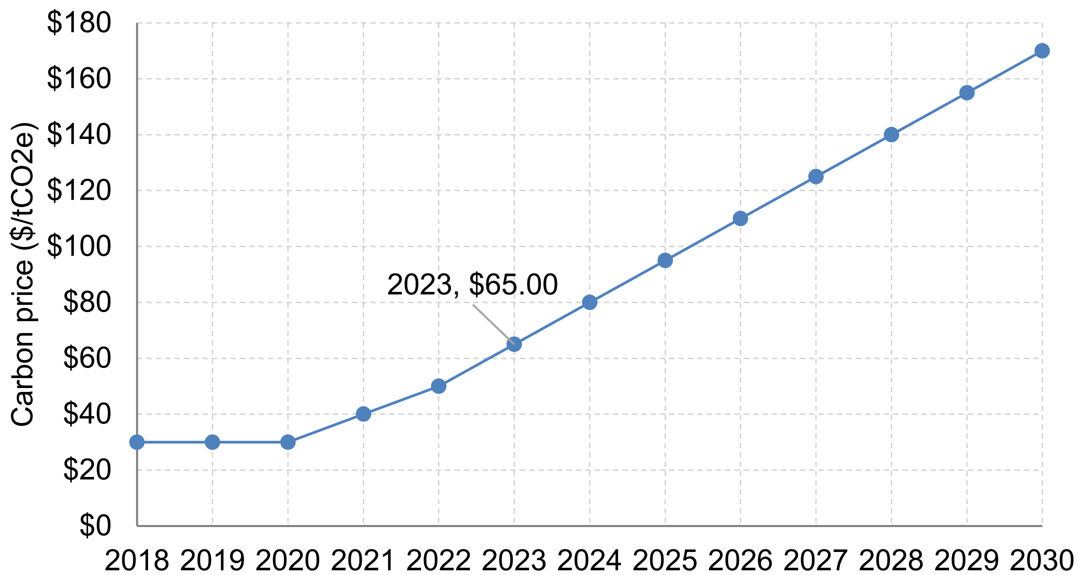
Since 2022, natural gas assets have set the pool price around 90% of the time in the Alberta energy market. The price of natural gas is the major input cost for these assets, and therefore has a significant impact on the pool price. Natural gas prices increased through 2020 and 2021 to a peak of over $7/GJ in early 2022 (Figure 4). The higher cost of natural gas put upward pressure on pool prices during these periods.

Figure 4: Average price of natural gas (AB-NIT) by month (January 2018 to November 2023)



Another significant variable cost for these assets is the carbon price. As shown in Figure 5, the price of carbon increased from \$30/tCO2e in 2020 to \$65/tCO2e in 2023. Going forward, the price will escalate by \$15 annually until it reaches \$170/tCO2e in 2030. For reference, the carbon price increase from 2020 to 2023 increased the variable cost of a converted coal asset by approximately \$8/MWh.[3]

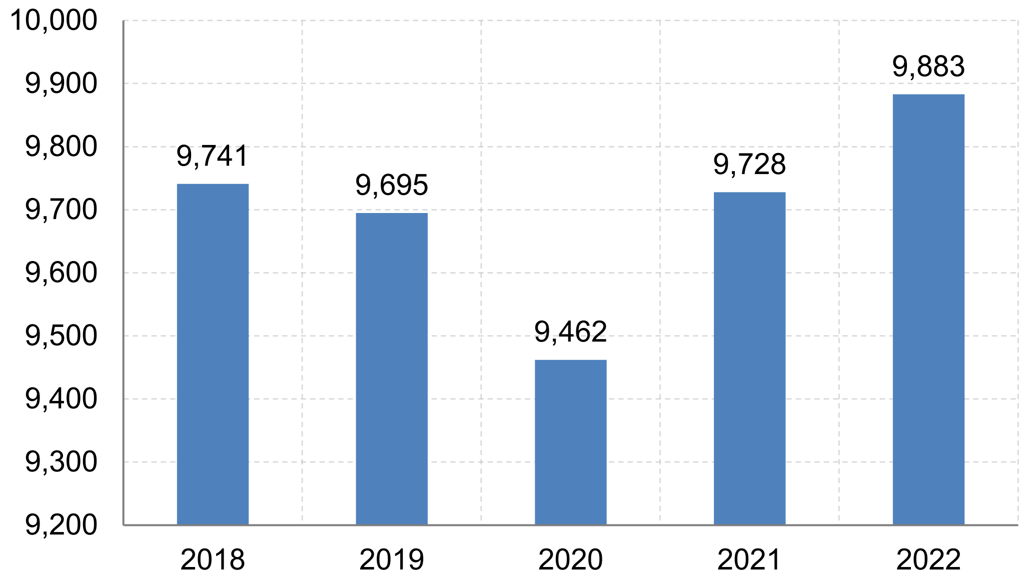
Figure 5: Price of carbon by year (2018 to 2030, forecast from 2024 onward)



The demand for electricity in Alberta fell during the COVID-19 pandemic but has since recovered and surpassed previous levels (Figure 6). Higher demand tends to increase pool prices as the AESO dispatches more expensive supply offers to meet demand. This demand growth will likely continue, and potentially accelerate, with the electrification of the economy.

[3] A difference of \$8.18/MWh follows from the 2023 and 2020 carbon prices, the approximate emissions intensity of a converted coal asset of 0.59 tCO2e/MWh, and the 2020 and 2023 TIER output-based allocations.

Figure 6: Average Alberta Internal Load (AIL) by year (2018 to 2022)

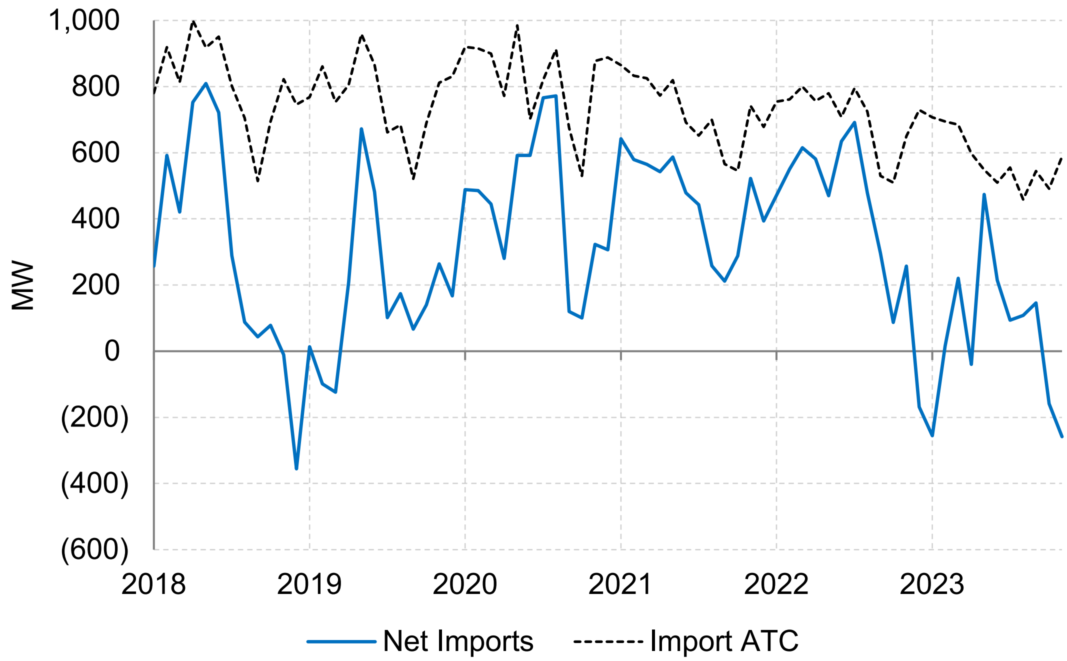


The flow of power over Alberta's interties varies in accordance with prevailing power prices in Alberta and other jurisdictions. In most periods, Alberta is a net importer of electricity because prices tend to be higher here than in other markets, such as Mid-Columbia (Figure 7). However, there have been notable exceptions to this. In late 2022, Alberta was a net exporter of power despite high pool prices. In December 2022 Alberta exported 168 MW on average even as pool prices for the month averaged $312/MWh, the highest on record.

Beginning on March 15, 2023, the available transmission capacity (ATC) for imports was reduced because the AESO increased the requirements for Load Shed Service for imports (LSSi).[4] This reduced import supply into Alberta, and put upward pressure on pool prices.

[4] LSSi is a reliability product in which load providers arm their consumption to be tripped off if the BC/MATL intertie trips.

Figure 7: Average net imports and import ATC by month (January 2018 to November 2023)



2.2.2 Increased exercise of market power

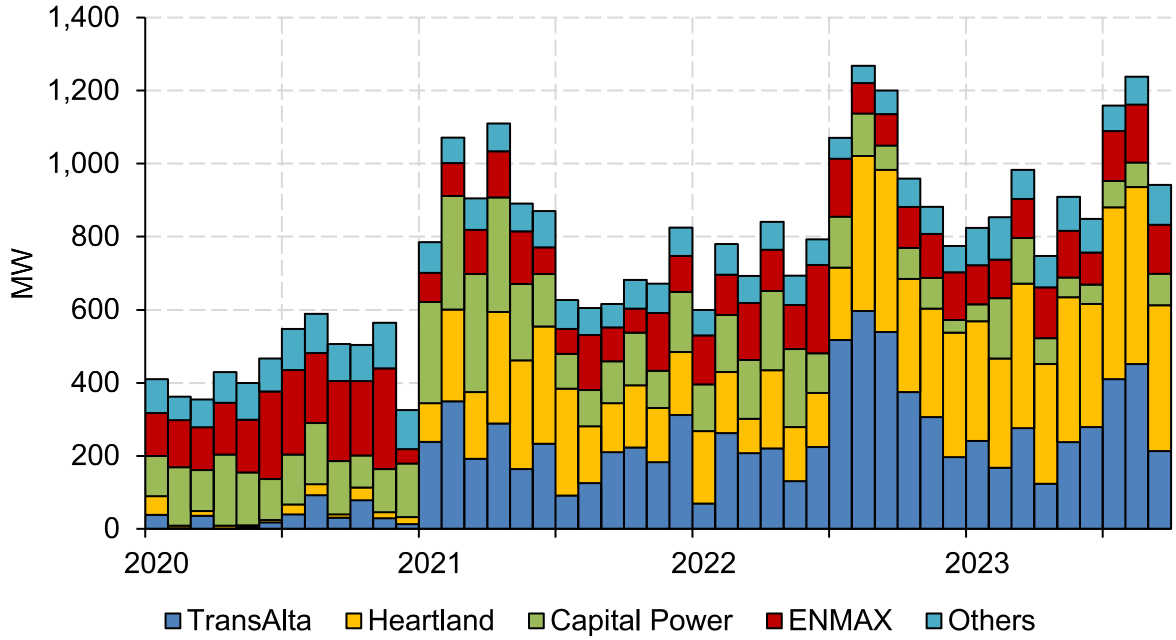
In 2021, the Alberta energy market became more concentrated as the remaining Power Purchase Arrangements (PPAs) expired. This transferred the offer control for six large thermal assets from the Balancing Pool to private companies with existing generation capacity in Alberta (Table 1). Subsequently, some of these assets were offered into the market at higher prices putting upward pressure on pool prices.

Table 1: PPA expirations on December 31, 2020

Assets	Total PPA Capacity (MW)	Offer control transferred from	Offer control transferred to
Genesee 1 and 2	762	Balancing Pool	Capital Power
Keephills 1 and 2	766		TransAlta
Sheerness 1 and 2	756		TransAlta (50%) Heartland (50%)

Figure 8 shows the amount of non-hydro generation capacity offered at or above $250/MWh. Hydro generation is excluded because there are operational constraints and opportunity cost characteristics that are unique to hydro assets. Typically, in the Alberta energy market, most offers are either at or near short-run marginal cost or between $700/MWh and the offer cap of $999.99/MWh. The price of $250/MWh was chosen as a threshold to approximately distinguish between cost-based offers and economic withholding. The figure shows that economic withholding increased significantly after the expiry of the PPAs in 2021. A second significant increase, particularly from TransAlta and Heartland, occurred in mid-2022.

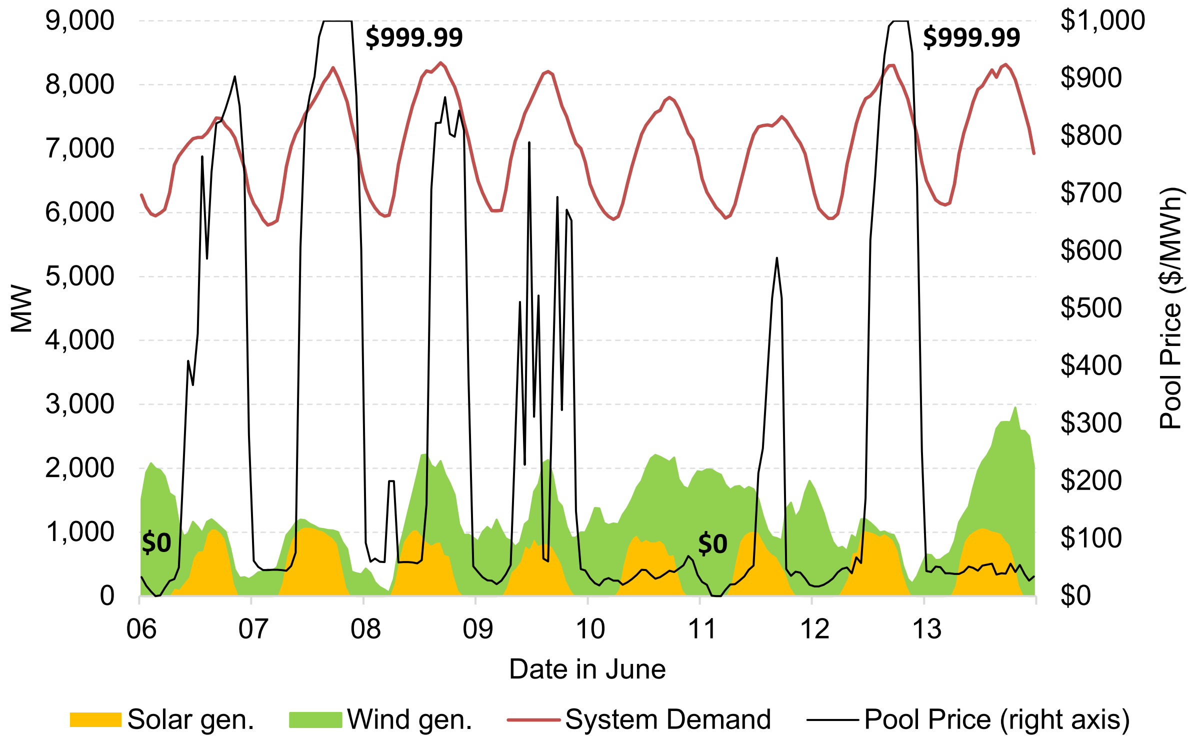
Figure 8: Average amount of non-hydro generation capacity offered at or above $250/MWh by month and company (January 2020 to September 2023)



As discussed above, in recent years the market has seen several coal plants retiring as the build out of intermittent generation capacity has increased. These intermittent generators depend on the sun shining or the wind blowing, and their variable nature has implications for pool prices and competition in the energy market (Figure 9). In particular, the market power of large incumbent generators is higher when intermittent generation is low.

Figure 9 also provides an example of the price volatility caused by intermittent generation supply. In the early morning hours of June 6, 2023, pool prices were at the floor of $0/MWh reflecting high wind generation and low overnight demand. During peak hours on the following day, prices reached the market cap of $999.99/MWh and the AESO declared a supply shortfall partly because of low wind generation and high demand caused by hot weather.

Figure 9: System demand, wind and solar generation, and pool price by hour (June 6 to 13, 2023)



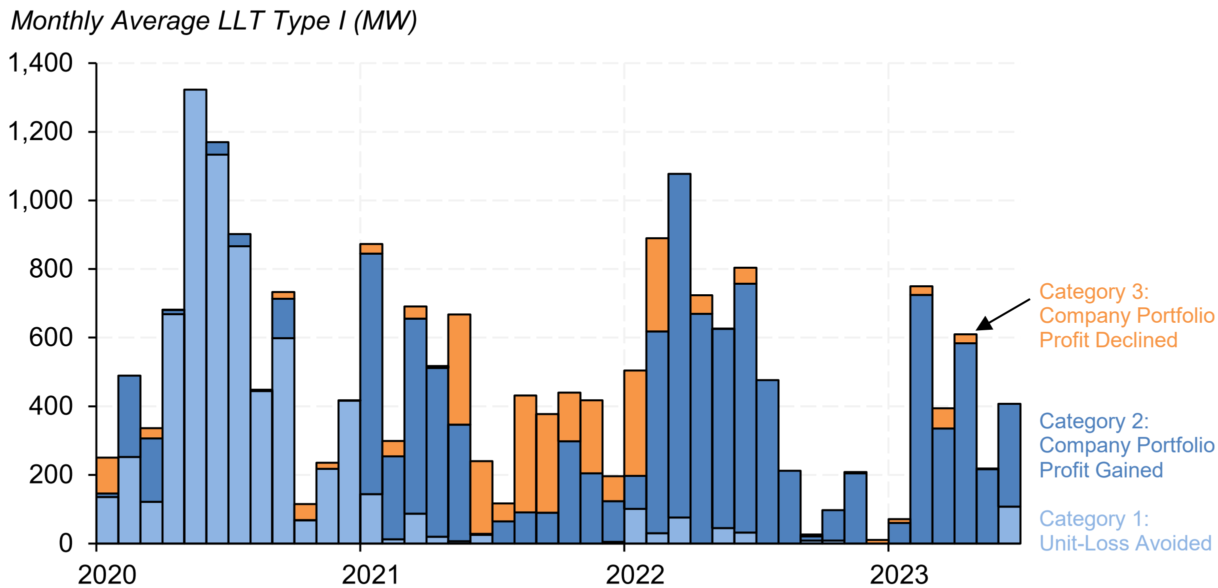
When intermittent generation decreases rapidly, online controllable supply must ramp up to meet demand. These ramp events create windows of opportunity for large suppliers to exercise market power. The AESO does not procure a ramping product, so they must dispatch energy offers until supply and demand are in balance. As a result, large suppliers can offer their generation at high prices and still receive a dispatch.

This increased operational volatility also imposes added costs on suppliers. These costs include fuel used for cycling, extra fuel from operating assets outside their most efficient dispatch range, and increased operations and maintenance costs.

Some market participants have responded to these market conditions with unprecedented use of ISO Rule 202.4, *Managing Long Lead Time Assets* (the LLT rule). The LLT rule allows market participants that operate assets with long start-up times to take these assets offline and leave them offline until they choose to make them available.

MSA analysis suggests that, starting in 2021, there was a marked shift in long lead time asset operation (Figure 10). Before this point, the LLT rule was primarily used to cycle off unprofitable assets to mitigate losses during periods of high intermittent generation or low demand (denoted by Category 1 in the figure). Starting in 2021, aligned with expiry of the PPAs, these assets were left offline during periods of high prices and low supply cushion to exercise market power (denoted by Category 2 in the figure).

Figure 10: Monthly average capacity on LLT type I by category (January 2020 to June 2023)



Exercise of market power through the LLT rule raises concerns when compared with economic withholding. First, economically withheld supply is still available to meet demand once the price becomes sufficiently high. In contrast, assets that are offline through the LLT rule have long start-up times that prevent them from reacting quickly to a reliability event.

Second, the LLT rule may sustain market power over longer durations than would be enabled through economic withholding alone. Market participants can adjust their offers up to two hours before delivery, which allows them to react to high prices and compete for dispatch. This competitive pressure limits the exercise of market power. If an asset is offline through the LLT rule, it cannot be returned quickly, so market participants can offer at high prices with less pressure from their competitor. With recent patterns of renewable energy, economic withholding is less at risk and profit is easier to sustain.

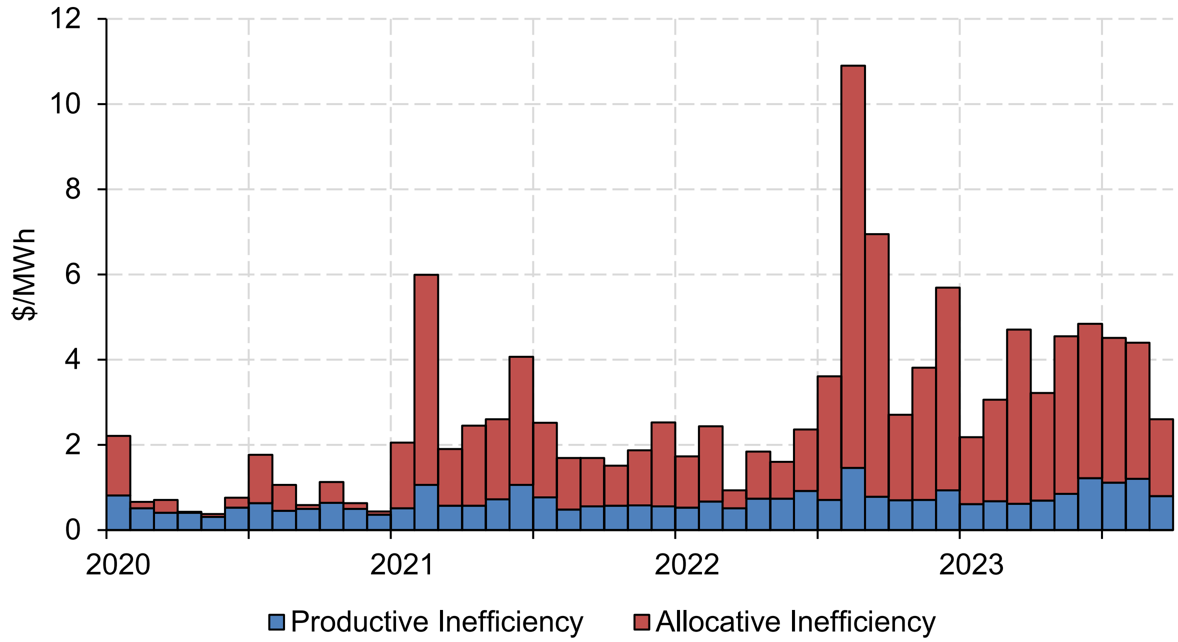
2.2.3 Increased exercise of market power has reduced economic efficiency

Static efficiency is the measure of combined consumer and producer welfare at a given point in time. The exercise of market power tends to result in static efficiency loss, or "inefficiency."[5] The MSA routinely monitors static inefficiency in the Alberta energy market to assess the impact of market power.

[5] The exercise of market power generates two types of inefficiencies: allocative inefficiency and productive inefficiency. Allocative inefficiency represents the lost value of foregone demand to consumers and marginal generators which occurs when price exceeds short-run marginal cost. Productive inefficiency measures the cost inefficiency that occurs when generators with higher costs are dispatched instead of generators with lower costs, which occurs when less costly generating units are economically withheld.

The MSA calculates static inefficiency by comparing realized market outcomes to those that would have occurred if all offers were made at short-run marginal cost. As shown in Figure 11, there was a material increase in static inefficiency in August and September of 2022, driven by the market participant offer behaviour described previously. These inefficiencies fell in recent months but remain higher than historical levels as market participants continued to exercise market power.

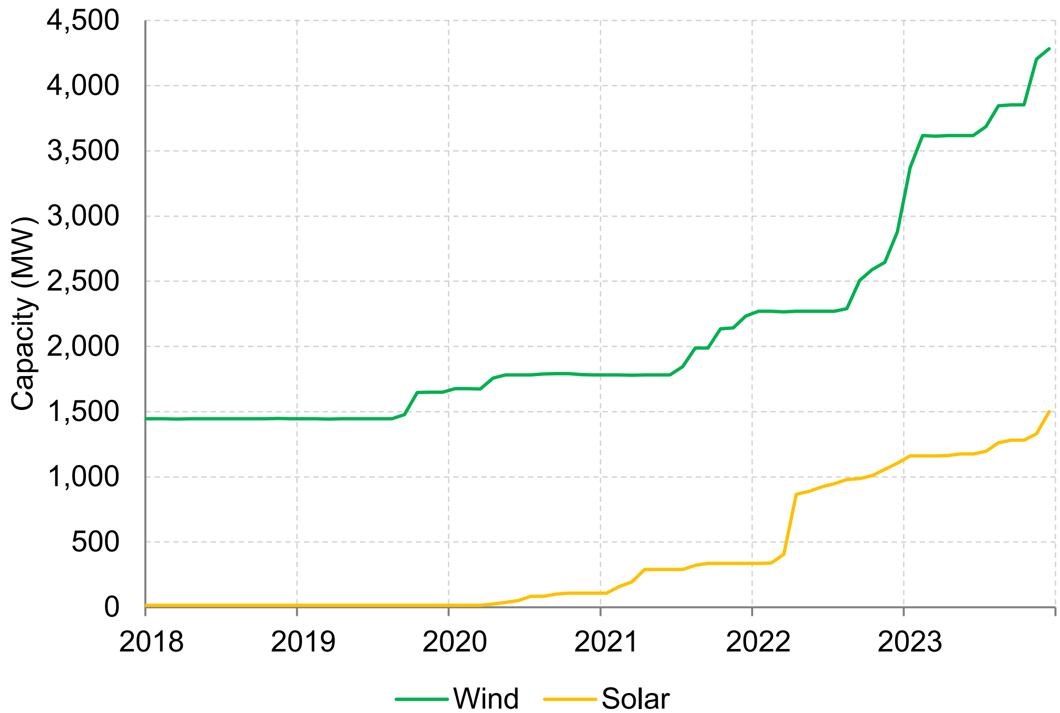
Figure 11: Average static inefficiency by month (January 2020 to September 2023)



2.3 Operational changes: The change in the supply mix has had an impact on reliability and customer costs

The supply mix in the wholesale electricity market has evolved substantially over the last ten years, moving from a traditional system organized around a small number of large coal generators and a combination of co-generation, simple cycle, and combined cycle natural gas plants. The first wind generators connected to the grid in small increments, with little direct impact on prices or system operations. However, the supply mix changed substantially as coal was phased out, and the wind generation capacity grew to over 4,000 MW. As of December 2023, the total wind and solar installed capacity is approximately 6,000 MW (Figure 12).

Figure 12: Wind and solar capacity over time (January 2018 to December 2023)



The overall impact of the change in the fleet on customer costs has been significant. The significant addition of wind and solar to the system has changed the overall attributes and energy value of the fleet impacting both reliability and customer costs. Some of the operational challenges include:

- Wind and solar generation are intermittent and requires additional system support to ensure reliable operations. When dispatched, these variable suppliers require more AS purchases to ensure reliability. The AESO has recently increased their purchases of regulating reserves to provide system support.

- The thermal fleet that supports reliability was at the margin and has recently been displaced when renewables are online. This impacts the capacity factor for some gas units and has recently meant that gas units have been offline when needed for reliability, leaving the system short of both energy and attributes to support system strength. Accordingly, the daily supply curve is deeper throughout the day, but as wind and solar taper off the residual supply to address that system change may have cycled off and be unavailable.

- There is increased congestion in renewable zones that requires additional system tools to manage.

2.3.1 Impact on AS costs

The overall impact of the change in the fleet on customer costs has been significant as energy prices have increased (as noted in section 2.2) but also there has been an impact on ancillary services to address additional issues related to frequency. Alberta's fleet with a large proportion of variable resources is difficult to operate in real-time, as no assets are committed to ensure reliability and security. However, recent events have led to the AESO procuring more regulating reserves to manage the significant variability of renewables on the system. With these costs currently assigned to loads, the tendency of renewables to reduce energy prices is partially offset by the increase in AS costs.

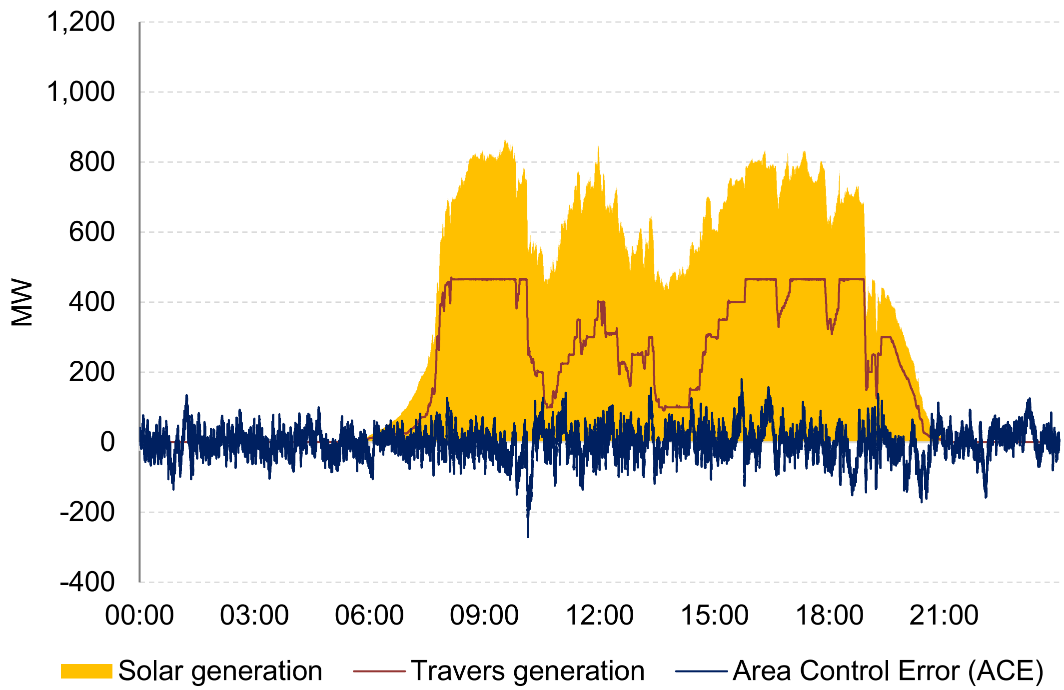
Operating a grid with significant intermittent resources creates more reliability risk. Over the course of Q3 2023, for example, the hourly generation of intermittent generators ranged from 14 MW to 3,305 MW. The increase in intermittent capacity means there are more ramping requirements for the AESO.[6] While wind power provides low-cost energy with low emissions when it has fuel (wind), additional capacity needs to be committed to provide reliable energy in all hours. For example, on the evening of July 17, intermittent generation decreased from 3,000 MW at 18:30 to 1,300 MW at 20:34, a decline of 1,700 MW.[7] This decline in intermittent generation caused the system marginal price to increase from $33 to $801/MWh. A comparable decline in intermittent generation occurred the following evening on July 18.

In addition to the ramp up of solar generation in the morning and the ramp down of solar generation in the evening, there have also been substantial changes to solar generation during day light hours. These changes may be caused by cloud cover or strong gusts of wind (strong winds can require pivoting the solar panels to a different angle). On the morning of July 17, for example, solar generation at Travers decreased by 214 MW over 3 minutes. These changes in solar output are challenging to predict, and this event resulted in a decline in Area Control Error (ACE) to negative 271 MW (Figure 13) indicating that Alberta was importing more than scheduled.

[6] See the MSA's Quarterly Report for Q3 2023 (November 15, 2023), page 16.

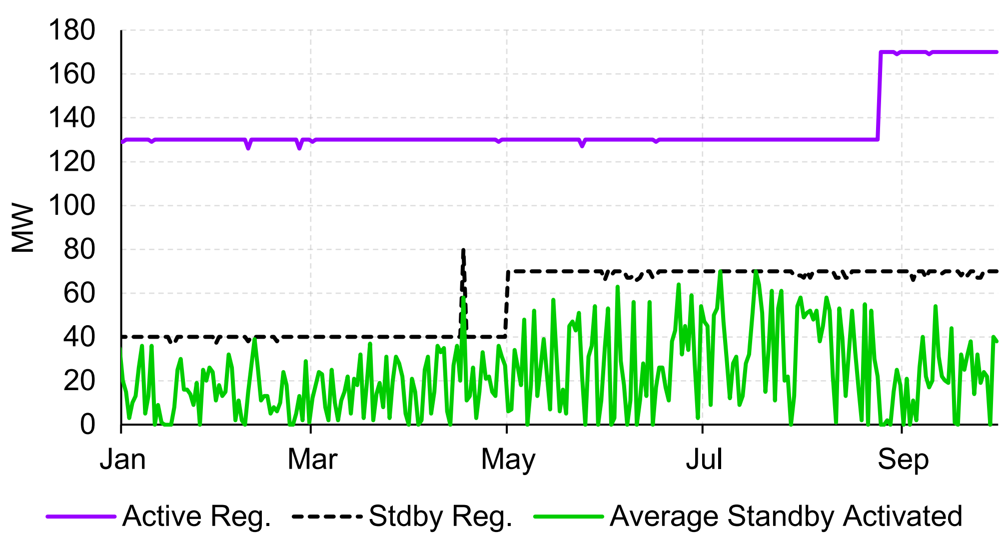
[7] See the MSA's Quarterly Report for Q3 2023 (November 15, 2023), figure 14.

Figure 13: Total solar generation, Travers generation, and ACE (July 17, 2023)



The AESO increased the procurement of on-peak active regulating reserve volumes from 130 MW to 170 MW on August 25. This increase was due to the volatility of intermittent generation, particularly solar, and systematic transmission constraints which restrict the output of a natural gas asset that often provides active regulating reserves. Figure 14 illustrates the daily volume of on-peak active regulating reserves, standby regulating reserves, and the average amount of standby regulating reserves that were activated from January to September 2023.

Figure 14: Active, standby, and activated standby regulating volumes (January to September 2023)



2.3.2 Transmission and operations

The supply mix has impacted the way the grid is operated. The growth of intermittent generation has led to increasingly variable daily dispatch and increasing congestion in wind zones when wind capacity factors are high.

The physical transmission system routinely experiences congestion which the AESO's system management tools are inadequate to address. The AIES is managed as an integrated system, although it is individual lines or zones that may become congested during periods of localized high demand or supply. System management tools need to analyze congestion by zones; much of this congestion created in wind zones as large wind generators are connected to the system. Not only is it expensive to build transmission for these generators, but even when built the transmission tends to be insufficient for the energy production that results when local wind capacity factors are high. Transmission standards to ensure IBR resources can support their own variability are also part of the solution to ensure reliable operations.[8]

To manage the operational risk that occurs in real-time, the AESO needs new tools, in addition to ISO rules that support the forward assessment and commitment of resources to meet system conditions that vary substantially daily.

2.4 Transmission costs: The transmission build out has created new bill impacts to customers

Transmission that has been added over the last twenty years has supported grid integration and relieved constraints. While the transmission expansion has supported Alberta load growth, the capital costs were substantial and lumpy. In concert with increasing energy prices, these costs have been a shock to households, businesses, and industrial operations.

Following the extensive build out of the 240 kV system and the North-South HVDC system, generator connections to the lower voltage system may add to customer costs. Present and future transmission expansions are different than historic expansions needed to connect generators to meet load growth in the context of a zero-congestion transmission policy. Much of the forecasted incremental transmission cost is for intermittent generation that runs at substantially lower capacity factors than historic suppliers and whose investment is at least somewhat dependent on out-of-market payments for environmental attributes. This reduces the average usage and value of transmission expansions.

The current zero-congestion policy, as well as the way it is implemented by the AESO, does not address the full cost, value, or cost causation of incremental customer connections, nor does it allow for much consideration of public interest impacts such as timing for connections, economic tests, and the use of non-wires assets as substitutes or additions to increase the operational capability of the system.

---

[8] See FERC Order 901, *Reliability Standards to Address Inverter-Based Resources*, issued October 19, 2023.

Significant expansion of intermittent generation has led to incremental demand for localized transmission to wind zones, which may strand recent bulk system expansions. Intermittent generators locate where their fuel sources are plentiful, regardless of location siting signals related to the transmission system. Customer connections evaluated based on “sufficient certainty” but not on energy capacity values may result in a net cost to consumers, notwithstanding the value in the energy market when available for dispatch.

There is no practical role for economic tests to play considering the zero-congestion policy, which results in substantial waste of society’s resources. The *Transmission Regulation* also limits the ability to assign incremental costs for ancillary services on cost-causation principles, meaning that new assets are built without fully internalizing their implied operational costs.

3 GOING FORWARD: THE NEED FOR CHANGE

3.1 The MSA's approach to its recommendations

The MSA works to promote effective competition in Alberta's electricity markets. At their core, these markets exist to solve resource allocation and coordination problems. This is done by providing effective price signals, undistorted by the inappropriate exercise of market power, and governed by appropriate rules. While market outcomes may be imperfect, they are best compared against the outcomes under imperfect regulation.

The MSA's recommendations are based on these principles. The changes in supply in concert with the changes in participant behaviour have created affordability issues for consumers as well as reliability risks as system operators face increased uncertainty without the rules and tools to manage these risks.

The shortcomings of the existing electricity market have been exposed by the pace of renewable expansion in concert with the quick removal of fossil fuel assets. There are several efficiency gains that can be made by amending the current structure to address the root causes of these issues and resolve issues related to affordability and reliability.

The MSA's recommendations have been developed around several organizing concepts:

- No regrets: Based on the issues that have been identified, the market needs to evolve in a variety of ways. The MSA's recommendations focus on changes the MSA believes need to occur for future success, irrespective of what happens in the broader environment. These are what the MSA regards as "no regrets" changes.

- Implementation timing: The MSA's assumption is that the government intends to make a set of policy decisions in early 2024 that will direct the future evolution of the electricity industry in Alberta and that it recognises that some of these decisions may take longer to implement than others. Presuming that economic and physical withholding are issues the government intends to deal with in the near-term, the MSA will make interim recommendations that can be acted on immediately and long-term recommendations that can replace these as new market mechanisms are developed.

It would be ideal for policy decisions made in 2024 to not focus exclusively on near term change; rather, they should set up the industry for success over time no matter what happens later without the government having to repeatedly reopen the electricity policy framework.

3.2 Direction and organization of recommended change

The changing supply mix has resulted in issues across the market, reflected in new transmission costs and challenges in system operations, which both impact pricing and customer bills directly. The market framework was designed for a different generation fleet – one with baseload coal, dispatchable natural gas that was synchronized to the grid, and sophisticated industrial loads. The market framework must now adjust for the new and forecasted supply mix, one with an increasing fraction of intermittent generation and risk of reduced dispatchable supply that can respond to system variability as it occurs.

The shortcomings of the existing electricity market should be fixed before Alberta contemplates an expensive and risky reform of the broader electricity market. There are many immediate rule change options available to support affordability for consumers and more effective competition and operation in the market, starting with a focus on efficient pricing and unit commitment.

The objective of a properly functioning market is price formation that reflects competition and an efficient allocation of resources. Addressing price distortions or exercises of market power can be done directly through rules that either moderate the ability to exercise market power and its impact on prices or through market design that changes the unit commitment process in advance (as an example) and therefore set prices while ensuring sufficient capacity is available for the conditions, leaving the real time market for imbalances. In addition, ensuring an active demand side through products or process creates a counterbalance to volatility in the wholesale market.

Change to the energy market should consider the evolving physical nature of the grid, as well as address affordability. The MSA's recommendations can be organized in three categories: **price formation, operations, and transmission**. Table 2 partially summarizes the recommendations. While there are some options in each category, the recommendations should be viewed as a complete set with some trade-offs between the categories to achieve efficient dispatch and pricing. Affordability is a result of a competitive market with prices over a business cycle reflecting marginal costs with some return on capital.

Table 2: Direction and organization of change

Market category to address inefficient pricing	***Rule changes / immediate resolution***	***Market evolution to Enhanced Energy Market***
Price formation	- Moderate economic withholding - Address physical withholding and unit commitment	- Imbalance incentives - Day ahead market (DAM), forward market power mitigation, load obligations - Shorter settlement periods
Operations	- Unit commitment - Dispatch tools	- Expanded unit commitment with energy-AS co-optimization
Transmission	- Cost allocation for new AS / new technical standards	- Congestion management through locational marginal prices (LMP) and security constrained economic dispatch (SCED)

Developing and implementing an EEM for Alberta will take a number of years, and will be considerably more complex an undertaking than the capacity market was. Based on this experience, and experience elsewhere, the MSA estimates it will take at least five years to fully develop and implement an EEM. This is why the MSA recommends that interim action be taken in the meantime.

3.3 Interim recommendations

The MSA understands that acting on economic withholding is a near-term priority to support affordability and other outcomes in the consumer interest, and its recommendations were developed with this in mind. The current market design and rules remain in place until something else is implemented; a policy decision changes nothing in and of itself. Therefore, recommendation 1 is that the government immediately implement interim measures to moderate economic withholding, reform the approach to unit commitment to eliminate physical withholding, and create a reliability unit commitment mechanism.

In recent years, natural gas generators have been displaced by incremental renewables and dispatched less frequently, notwithstanding the value of these generators for flexibility to meet dispatch when intermittent resources are not available. The MSA has observed that natural gas generators use economic withholding and ISO rules relating to LLT assets (e.g., assets that require more than one hour to start)[9] to physically withhold while complying with the rules.[10]

While the MSA has expressed its concern over these rules and resulting offer behaviour,[11] the AESO has taken no action to amend them. Physical withholding is not only inconsistent with the *Fair, Efficient and Open Competition Regulation* but it leads to excessive prices and undermines both reliability and affordability.

The MSA recommends the interim measures set out in recommendation 1 be implemented effective July 1, 2024, and the decision to implement them be communicated as soon as possible.

3.3.1 Moderation of economic withholding

Concerns about the exercise of market power through economic withholding can be addressed by ex-ante (i.e., before the fact) or ex-post (i.e., after the fact) rules and mitigation. An ex-ante approach moderates the exercise market power by design: a set of rules define acceptable limits and deal with situations (offer prices) that exceed these limits. Examples in the Alberta market are the offer price cap, rules related to offering capacity, restatement rules limited to outside of two hours before delivery, rules related to sharing information, and market share offer control limits. An ex-post approach focuses on surveillance and enforcement. While surveillance can be (and is) general in nature, enforcement requires clarity about what is prohibited. Further, because there is no direct intervention before the pool price is set, ex-post mitigation cannot guarantee

---

[9] ISO rule 202.4, *Managing long lead time rules*

[10] See section 1.5 of the MSA's Quarterly Report for Q2 2023 (August 15, 2023).

[11] See section 1.5 of the MSA's Quarterly Report for Q2 2023 (August 15, 2023).

that pool price will not be impacted by undesirable offer behaviour. Importantly, in an enforcement proceeding, only the prosecuted party's ill-obtained profit may be disgorged (i.e., third parties that profited in the form of higher settlement prices are not at risk of disgorgement).

Excessive and persistent exercises of market power that cause harm to efficiency and consumer prices should be addressed sooner than later, i.e., on an ex-ante basis. Further, if certain offer behaviours are considered undesirable, it is feasible to write regulations and ISO rules that prevent them from impacting pool price in the first instance. Beyond this, ex-post mitigation is often time-consuming and costly.

For these reasons, the MSA recommends, to the extent it is desirable to moderate economic withholding, that this be done on an ex-ante basis. The simplest way to moderate economic withholding is to place limits on how far above marginal cost offers are allowed to be. In recommendation 1.1, the MSA proposes a feasible method to do this on an interim basis. For clarity, this is not the economically optimal way to deal with this issue, which would be to induce greater forward contracting that would remove the incentive for generation firms to exercise market power in the first place.

Recommendation 1.1

- Effective July 1, 2024, enact a Market Power Mitigation Regulation under the *Electric Utilities Act* (EUA) and the *Alberta Utilities Commission Act* (the same legal basis as the *Fair, Efficient and Open Competition Regulation*) that sets out a clear legislative intent to limit the exercise of market power by electricity market participants in the power pool.

- In the regulation:

  - Create a Monthly Net Revenue Secondary Offer Price Cap (Secondary Offer Price Cap) that limits offers for natural gas-fired generators for the largest firms to the greater of (i) 25 times the day-ahead natural gas price (approximately 3 times marginal cost) or (ii) $100/MWh, for the balance of any month in which the net revenue (contribution to covering fixed cost) associated with a hypothetical combined cycle natural gas-fired generator exceeds two-twelfths of the annualized capital cost of the hypothetical generator.

  - Require the AESO to develop an ISO rule that implements the Secondary Offer Price Cap and addresses all technical considerations, including definitions of terms, estimation of generator variable and capital costs, calculation of net revenue, and when the limitation would be imposed (for the balance of the calendar month) after the threshold is reached (e.g., 6 hours to allow calculation time).

  - Require the AESO to file the Secondary Offer Price Cap ISO rule as an expedited ISO rule under EUA, section 20.6. If the general intent and parameters are set out in the regulation and the ISO rule only implements the regulation, there will be minimal scope for the ISO rule to be challenged under EUA, section 25(1)(b). Allow for any amendments to the ISO rule following the existing process.

- Require the AESO to develop the necessary data systems to implement the Secondary Offer Price Cap on an automated basis as of July 1. This is critically important so that the impact of contraventions of the Secondary Offer Price Cap do not automatically flow though to the setting of the pool price, the impact of which cannot be reversed in an enforcement proceeding.

- Provide for a process by which electricity market participants may seek exemptions from the Secondary Offer Price Cap. Exemptions should be transparent and subject to approval by the Alberta Utilities Commission (Commission). The expectation should be that exemptions are rare.

- State that the regulation expires upon the implementation of the EEM.

Analysis underpinning recommendation 1.1

The MSA has conducted a backward-looking assessment of the following options to moderate economic withholding through the imposition of limitations on offer prices:

a. Lower offer price cap

b. Limit offer prices for pivotal firms with greater than 250 MW capacity

c. Limit natural gas offers by the largest five firms to 25 times the prevailing natural gas price

d. Secondary Offer Price Cap: Triggered limit on natural gas offers once monthly net revenue threshold is reached. This is the MSA's recommended interim option.

<u>Mitigation option a</u>: The current offer price cap of $999.99/MWh would be lowered to $417.20/MWh. This is the level of the price cap that would result in an identical January 2020 to September 2023 average price as in option d; to facilitate comparison, the specific price cap level was selected for this reason. An offer price cap level of about $400 would significantly moderate economic withholding while providing scope for the recovery of fuel costs, a return on capital, and continue to price for scarcity, although to a far more limited extent than today. Because pool price could not rise as high as today, there would be systematically reduced incentives for demand to respond (and be ready to respond) to price changes and interjurisdictional trading would be significantly impeded, e.g., the maximum Alberta could pay to attract imports when they are needed would be extremely low. Additionally, the ability to reward flexible assets would be removed. This would result in economic inefficiency and potentially load-shedding. For these reasons, lowering the offer price cap is a useful benchmark for comparison but the MSA **strongly recommends against lowering the offer price cap**.

The remaining three options will be discussed briefly together after each has been described.

Mitigation option b: Limiting offer prices for pivotal firms[12] is designed to limit the exercise of market power in hours where firms have market power and scarcity conditions do not exist. Under this option, offers of pivotal firms with at least 250 MW of installed capacity are limited to asset specific reference prices if supply cushion[13] is at least 250 MW:

- When the supply cushion is between 250 MW and 1,000 MW, asset specific reference prices are set at six times the short-run marginal cost of each generating unit.

- When the supply cushion is at least 1,000 MW, asset specific reference prices are set at three times the short-run marginal cost of each generating unit.

Mitigation option c: Limiting the offer cap for the natural gas generating units for the largest five firms by installed capacity acts as an offer price cap for these firms, limiting offers from their natural gas generators to 25 times the daily natural gas price, or $100/MWh, whichever is greater. Since it is usually natural gas units that price higher in the curve to reflect scarcity, this would limit excessive economic withholding, while providing a reasonable cap in the case that natural gas prices are low. All other offers would not be capped.

Mitigation option d: Secondary Offer Price Cap. The revenue threshold option is identical to mitigation option c, except the natural gas offer price limit only takes effect in a given month if a representative combined cycle unit would have earned net revenues necessary to pay off two twelfths of its annualized capital costs.

Estimated annual average pool prices under each mitigation option are presented in Table 3. The effect of offer price mitigation on pool prices was lowest under mitigation options a and d, and greatest under mitigation option c (Table 4). Offer price mitigation had little impact in 2020 when prices were low, but was more impactful in summer 2022 and most 2023 months where economic withholding was relatively high and scarcity conditions were not present (Figure 15).

[12] A firm is said to be pivotal if all other firms cannot meet demand. Conversely, a firm is said to be not pivotal if all other firms can meet demand.

[13] The supply cushion is defined to be the amount of available but not dispatched offers in the energy market merit order.

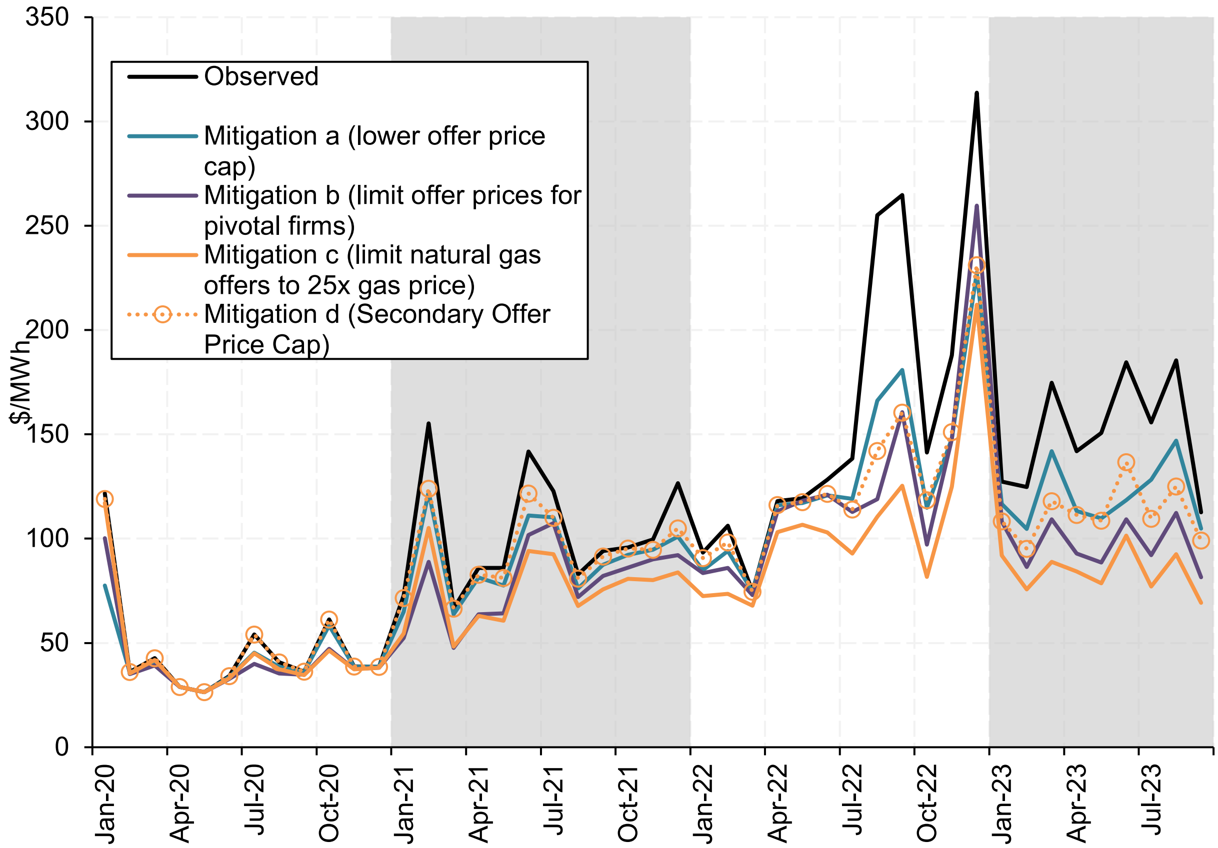
Table 3: Estimated annual average pool prices ($/MWh), observed & price mitigation options

Year	Observed	Mitigation a (lower offer price cap)	Mitigation b (limit offer prices for pivotal firms)	Mitigation c (limit natural gas offers to 25x gas price)	Mitigation d (Secondary Offer Price Cap)
2020	46.72	41.68	41.43	43.61	46.61
2021	101.93	89.92	78.88	75.25	93.46
2022	162.46	130.51	124.51	106.34	128.15
2023 (Jan to Sep)	151.21	120.77	98.00	84.49	112.58
Avg.	*113.13*	*94.00*	*84.84*	*76.92*	*94.00*

Table 4: Change in estimated annual average pool prices under price mitigation options

Year	Mitigation a (lower offer price cap)	Mitigation b (limit offer prices for pivotal firms)	Mitigation c (limit natural gas offers to 25x gas price)	Mitigation d (Secondary Offer Price Cap)
2020	- 11%	- 11%	- 7%	0%
2021	- 12%	- 23%	- 26%	- 8%
2022	- 20%	- 23%	- 35%	- 21%
2023 (Jan to Sep)	- 20%	- 35%	- 44%	- 26%
Avg.	*- 17%*	*- 25%*	*- 32%*	*- 17%*

Figure 15: Monthly average estimated pool prices, observed & price mitigation options



Pool prices are only impacted by mitigation options in less than half of hours, with mitigation c being the most frequently impactful (Table 5).

Table 5: Percentage of hours where pool prices are mitigated by price mitigation option

Year	Mitigation a (lower offer price cap)	Mitigation b (limit offer prices for pivotal firms)	Mitigation c (limit natural gas offers to 25x gas price)	Mitigation d (Secondary Offer Price Cap)
2020	2%	3%	3%	0%
2021	6%	13%	16%	5%
2022	11%	17%	23%	12%
2023 (Jan to Sep)	12%	23%	26%	14%
Avg.	*7%*	*13%*	*16%*	*8%*

Consumers benefit under each mitigation option, measured as consumer surplus, with incremental benefits varying depending on the degree of mitigation in each year (Table 6).

Table 6: Average benefit ($/MWh) to consumers by price mitigation option

Year	Mitigation a (lower offer price cap)	Mitigation b (limit offer prices for pivotal firms)	Mitigation c (limit natural gas offers to 25x gas price)	Mitigation d (Secondary Offer Price Cap)
2020	6.09	6.33	3.65	0.26
2021	14.08	26.55	30.52	10.11
2022	35.88	42.01	62.11	38.03
2023 (Jan to Sep)	32.33	56.05	70.34	41.02
Avg.	*21.80*	*31.79*	*40.60*	*21.68*

Each mitigation option (b, c, and d) has advantages and disadvantages. Some would have had a relatively large price lowering impact and others a relatively small effect. In the MSA's view, the purpose of moderating economic withholding is not to minimize pool prices as this is inconsistent with the fundamental tenets of relying on competition to drive economic efficiency (there are easier ways to do this if it was the objective). Rather, moderating economic withholding must still result in market prices generally being determined by competitive forces, with the most extreme excursions from this being what is targeted by the mitigation option.

Given this assessment, the MSA recommends implementation mitigation option d – the Secondary Offer Price Cap – which strikes a reasonable balance of linking offer limits to input costs and further restricting offers once net revenue thresholds have been met. This mitigation option provides for significant moderation of economic withholding, while not impacting offers during periods with lower prevailing prices. Further, the monthly nature of the Secondary Offer Price Cap means that if a month is subject to being capped part way through, it will be removed at the beginning of the next month. In the MSA's view, this is a highly desirable feature as it would limit the distortionary implications of moderating economic withholding on forward market prices.

3.3.2 Physical withholding and unit commitment

With the changing generation fleet, the self-commitment model results in substantial risk regarding real time capacity availability and unlimited offer price restatements up to two hours before the delivery hour allows significant exercise of market power. A forward unit commitment model of some sort would provide greater certainty to the AESO that assets are available for dispatch of both energy and ancillary services including assets with a start-up time greater than one hour. A range of options can be implemented, some through immediate rule changes. In addition, the grid needs an updated set of system tools to evaluate reliability needs to meet demand in real time while managing congestion, variability, stability, and LLT assets.

The MSA has commented on issues with the LLT rule over the last year.[14] The LLT rule was not intended to provide an opportunity to physically withhold as a strategic offer strategy, but there is a lack of clarity in the rule language that provides participants more discretion than warranted. In addition, without this clarity, the MSA cannot enforce this rule. This results in units that are not available when required and, equally problematic, economic withholding that can be excessive without assets online to compete.

The MSA recommends an immediate and complete evolution to forward commitment markets to ensure that reliability can be secured, that prices to consumers are established in these forward markets, and that the real time market becomes an imbalance market. The steps to an evolution to a full forward market is discussed below. These recommended changes are outlined in section 3.4 as part of the EEM framework where all assets can be committed after a full evaluation through the day ahead timeframe of both energy offers and asset characteristics as part of a co-optimization model.

As an immediate priority, while the design and implementation of the new market structure are underway, the current ISO rules should be amended to align the self-commitment of flexible assets with an evaluation of the need for assets with a lead time greater than one hour to ensure that the market is competitive, free of physical withholding, and able to meet reliability needs.

Physical withholding and unit commitment issues should be considered in conjunction with moderating economic withholding to ensure that generation firms that would be more likely to physically withhold as part of their offer strategies are prevented from doing so. In the extreme, generation firms may have the incentive to cause reliability issues to drive pool prices higher and compel the AESO to direct generators on LLT status online. Minor and immediate changes to the current ISO rules will provide direct and clear authority to the system controller to commit long lead time assets if economic and as required for reliability.

The MSA proposes new and immediate changes to the LLT rule framework that limit the ability of generation firms to physically withhold. This should be combined with the development of a unit commitment mechanism to provide authority to the AESO to consider, on a continuous rolling basis, whether to direct generators on LLT status online according to an economic or reliability criterion. The reason to add this unit commitment mechanism as an interim measure is to ensure that economic withholding is not replaced with physical withholding following the moderation of economic withholding.

These changes will be well aligned with EEM structure changes to create requirements for forward hedging and commitment of assets consistent with market power mitigation and reliability

[14] See section 1.5 of the MSA's Quarterly Report for Q2 2023 (August 15, 2023).

priorities. In this evolution, the real time market truly becomes the imbalance market where volumes are expected to clear.

Recommendation 1.2

- Direct the AESO to develop an ISO rule that implements the unit commitment mechanism and Start-up Cost Guarantee Program whereby the AESO would evaluate, on a continuous rolling basis, whether to direct generators on LLT status online if the generator is likely considered economic or is needed for reliability. In the event a directed generator does not breakeven, it would receive an out-of-market reliability payment so that it does breakeven. Only dispatchable generators would be eligible for these payments.

- Direct the AESO to file these ISO rules as expedited ISO rules under EUA, section 20.6, effective July 1, 2024. Allow for any amendments to the ISO rule following the existing process. These changes can be achieved through a written direction to the AESO and would not require legislative or regulatory change.

Analysis underpinning recommendation 1.2

Long lead time generator obligations

One reason for recent high pool prices is that some assets have been placed on LLT status, effectively removing them from the merit order. This can occur when wind generation is high, meaning that these LLT assets have cycled off and are not available if needed to produce energy and provide related system support services. As noted in the MSA quarterly reports,[15] the MSA recommended ISO rule changes to address the gaps in the rule that allow market participants to offer in a way that was not intended under FEOC, resulting in consumer harm. In a case like this, ex-post mitigation through surveillance is insufficient to address the matter; a clear ISO rule is required.

The MSA has traditionally considered economic withholding through offers to be the primary means by which market participants exercise market power. However, market participants can exercise market power in other ways, including taking an LLT asset offline. Unlike economic withholding, where non-minimum stable generation offers are raised to very high offer prices, putting an asset on LLT removes these offers from the market altogether and the minimum stable generation block that would otherwise be offered at $0/MWh with them.

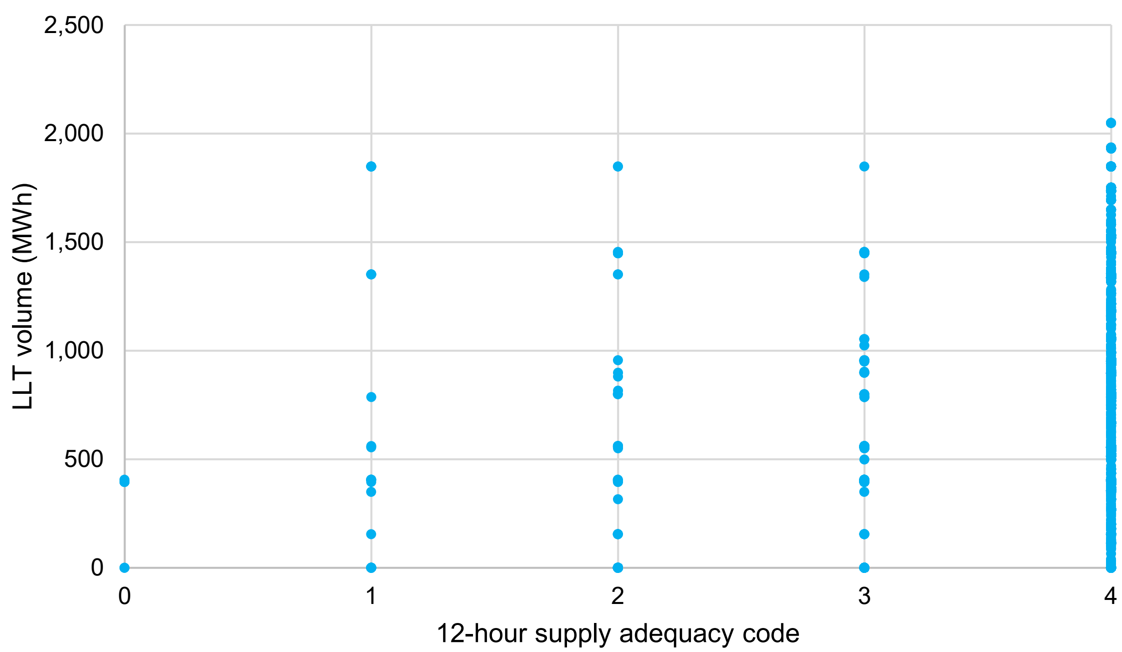
In Alberta's electricity market, where the production capacity of various market participants is well understood, taking offline an asset that is known to require a substantial number of hours to start can be seen as a credible and public commitment to exercise market power in future hours. This commitment may not be feasible through economic withholding alone.

[15] See the MSA's Quarterly Report for Q2 2023 (August 15, 2023), page 36.

A market participant may also put a unit on LLT if it expects that the unit would / may generate at a loss over a period. This could occur if a unit with minimum stable generation had a short-run marginal cost greater than the expected pool price. Placing such a unit on LLT could enhance efficiency by lowering the overall cost of generation.

As noted in Figure 16, the relationship between LLT volumes and the short-term adequacy (STA) code[16] 12 hours ahead of real time can vary. Observations of significant LLT volume at low STA codes indicate that LLT assets do not always respond to scarcity signals sent by the STA report. And there is an imperfect correlation between STA codes and EEA levels.

Figure 16: LLT volume vs. 12-hour ahead supply adequacy code



There were several high price periods with assets commercially offline during specific hours analyzed by the MSA.[17] However, a significant portion of these events had a relatively high supply cushion, with high prices driven by economic withholding. These examples are focused on periods when LLT assets were a contributor to supply tightness, with high prices often coinciding. Even within this category, there were several examples within the sample period. However, in most events intermittent generation forecast errors were a major factor. The examples noted focused on events when the wind and solar forecast errors were not sufficient to explain the observed behaviour. These examples are not exhaustive and were selected to illustrate the patterns of behaviour.

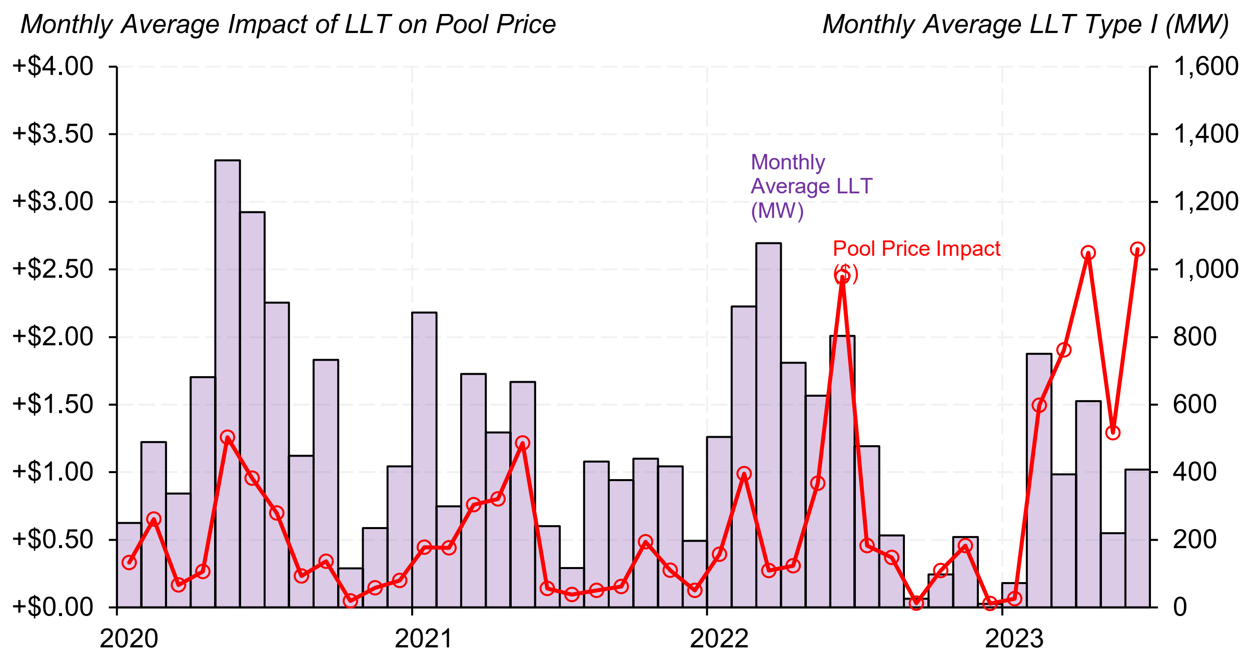
---

[16] STA Codes are determined using forecasts of several adequacy indicators and range from 0 to 4 to show the state of the market supply cushion. See the ISO rule 202.6, *Adequacy of Supply* and ID#2012-006R, *Adequacy, Supply Shortfall and Energy Emergency Alerts*.

[17] See section 1.5.5 of the MSA's [Quarterly Report for Q2 2023] (August 15, 2023).

In at least 90% of hours where units have been on LLT between Q2 2022 and Q2 2023, the average impact of LLT capacity on pool price has been less than $6/MWh (Figure 17). However, in a few hours the placement of assets on LLT can have a significant effect on pool price. For example, in Q2 2023 units on LLT caused the pool price to be at least $50/MWh higher than it would have been if that capacity had been economically withheld in the merit order in 1% of such hours (15 hours).[18]

Figure 17: Monthly average pool price impact of LLT Type I (January 2020 to June 2023)



For these reasons, the MSA recommends immediate rules changes to ensure alignment of the "must-offer" rules as intended for LLT assets. While the rules recognize the misalignment of these assets with an hourly market, the rules should not provide additional discretion that is unavailable to other assets that "must offer" into the merit order. The AESO must always know the state of these assets, including their availability, start time, start-up time, and hot and cold capacity. The rules require adjustment to ensure that when an asset is dispatched off or faces an acceptable operating reason to go off, that they immediately communicate through the Energy Management System their intention to return to the merit order. This information is critical for system management and is used for forward assessments and unit commitment as required. Further, rule clarification is required to support ex-post enforcement of these rules.

Rule changes are required to provide clarity on (i) offer obligations of LLT market participants regarding the asset's technical characteristics and their self commitment intentions and (ii) directives issued by the AESO.

---

[18] See the MSA's [Quarterly Report for Q2 2023] (August 15, 2023), page 49.

Unit commitment and long lead time assets

The amendments to the LLT offer obligations above ensure that the information available to the AESO is timely and correct so that it can be used in any forward assessment for directives as required. Further, immediate amendments to the LLT rule can support a unit commitment mechanism designed to ensure the market can remain competitive and reliable.

While the current approach to self commitment has been relied upon for many years, the recent combination of cycling of LLT assets and gaps in the LLT rule have prevented the AESO from effectively committing assets as required. The MSA recommends an adoption of a full unit commitment market model that aligns with further evolution to an EEM, including the adoption of a day-ahead market and co-optimization of energy and AS (see section 3.4).

However, in the interim, the current rules can be straightforwardly amended to commit units that have not already self committed and are likely to be economic and necessary for reliability to be online. **The change is required as an interim measure to ensure that economic withholding is not replaced with physical withholding following the moderation of economic withholding.**

An evolution of incremental improvements as part of the EEM can be incorporated as system changes can be made; this immediate step can be run with the current merit orders for energy and AS ensuring that any long lead time asset will not be able to physically withhold if required for dispatch. In the EEM, the assessment would include the ability to co-optimize across assets to commit units for energy and ancillary services to meet a least cost algorithm.

3.4 Development of an Enhanced Energy Market (EEM) for Alberta

The interim recommendations outlined in section 3.3 would ensure that the market can operate efficiently immediately by introducing bid mitigation to limit excessive returns to capital and by committing sufficient generation to meet forecast energy needs and overall reliability in concert with the current AS market commitments. However, as the supply mix will continue to evolve, additional changes are required to ensure the energy market is sustainable over the long term.

Efficiency in the market through proper price formation and mitigation of market power will continue to require attention. Many markets have moved to a forward markets structure with centralized day-ahead markets and a robust unit commitment model, committing assets using an optimization of energy and ancillary services. As grid reliability becomes more complex with the need to ensure stability, flexibility, and frequency, as examples, allowing the market visibility of asset attributes and associated cost structures becomes of key importance. Markets will need to move to three-part bids (start-up, no-load, and incremental energy costs) and ensure attributes like ramping capability and inertia are submitted and can be evaluated to ensure reliability. Efficiency in this dynamic market requires that prices are set in a centralized forward market where energy obligations are submitted, unit commitment with a co-optimization function occurs next to ensure that scheduled assets can be dispatched and are not constrained, and a real time delivery or imbalance market for instantaneous dispatch to meet ever changing net demand variability.

The day-ahead energy market (DAM) is a financial market where market participants purchase and sell electric energy at financially binding prices for the following day. This market determines the financially binding schedule of commitments for the purchase and sale of energy the ISO develops each day according to the bid and offer data that market participants submit to the market. The DAM allows buyers and sellers to hedge against price volatility in the real time energy market by locking in energy prices before the operating day.

Recognizing that it will take a number of years to complete, early adoption of the structural direction is important to provide endorsement for the development and implementation of an EEM for Alberta to enhance the current energy market. The new forward markets will incorporate market power mitigation rules at that stage that can replace the temporary bid mitigation in the delivery market. And the expanded unit commitment model should align nicely with the revised rules related to directives for LLT. The new structures will ensure competitive outcomes and support reliability.

Recommendation 2

- Recognizing that it will take a number of years to complete, direct the development and implementation of an EEM for Alberta to replace the current energy-only market. The EEM would rely on competition to the maximum extent possible to ensure an efficient allocation of resources over time, both with respect to investment incentives for new supply and consumption incentives.

- The EEM should include the following features:

    - day-ahead market;

    - replace the recommended interim Market Power Mitigation Regulation with a market power mitigation framework tailored to the day-ahead market (that is, suited for multiple part offers) and run with the day ahead market;

    - load obligations to forward contract for generation;

    - negative price floor and administrative scarcity pricing / operating reserve demand curve;

    - congestion management through locational marginal pricing, security constrained economic dispatch, and system tools;

    - extended unit commitment market with co-optimization of energy and ancillary services;

    - five-minute real-time settlement intervals;

    - enhanced role for demand response; and

- new technical standards for intermittent generation and energy storage.

3.4.1 Day-ahead market: An imbalance market and its incentives

The DAM is a financial market where market participants purchase and sell electric energy at financially binding day-ahead prices for the following day. This market creates the financially binding schedule of commitments for the purchase and sale of energy that the ISO develops into a schedule used for evaluation of unit commitments. The day-ahead market allows buyers and sellers to hedge against price volatility in the real time energy market by locking in energy prices before the operating day and it allows suppliers time to prepare for their supply obligations the next day. A DAM is a standard component of many electricity markets in North America and around the world. In most FERC-regulated markets in the US, load serving entities (LSEs) have an obligation to deliver or nominate supply to cover from 90-110% of their next day load requirement. With the DAM and unit commitment, the RTM market becomes an imbalance market to scheduled energy and deviations in demand.

The DAM is a pre-market to the residual unit commitment process which designates additional power plants that will be needed for the next day to serve specific local needs, or system reliability dispatches for frequency or voltage; the DAM also decommits assets that have expected congestion and cannot deliver. In all cases, assets must be ready to generate electricity as committed through a reliability unit commitment mechanism (RUC). Market prices set are based on bids in the DAM.

The DAM allows market participants to commit to buy or sell wholesale electricity one day before the operating day, to help avoid price volatility. This market produces one financial settlement. This model would set prices based on day-ahead offers dispatched to meet forecast load and contingency reserves. Equilibrium prices would reflect market dynamics based on competitive asset offers including a fleet that meets technical reserves. The DAM creates the proper incentives for the imbalance or delivery market. Suppliers that sell day-ahead and face outages must “buy back” from the real time market. Loads that do not procure in the DAM and secure a forward price for the energy needs must buy at real time prices which often reflect scarcity.

The DAM and unit commitment work on a full network model, which analyzes the active transmission and generation resources to find the least cost energy to serve demand. The model produces prices that show the cost of producing and delivering energy from individual nodes, or locations on the grid where transmission lines and generation interconnect.

When the DAM schedules are further evaluated using co-optimization and security constrained economic dispatch algorithms (as proposed and further discussed below), the resulting committed and dispatched assets reflect the capacity required to meet both system energy and system reserves at the lowest overall cost, noting all constraints. In combination with the use of locational marginal prices in real time, the consumer faces the lowest overall price and the incentives in the market reflect the value of energy and scarcity.

3.4.2 Moderation of economic withholding in a day-ahead market

Most DAM models include an ex-ante market power mitigation test to assess offers. Offers that fail the test are revised to predetermined reference levels that are used for market clearing. The predetermined reference levels are based on fuel and other variable costs (including carbon costs). The choice of mitigation tests will require some evaluation, but the MSA recommends this type of feature be part of the EEM to provide ex-ante moderation of any incentive to exercise market power.

A conduct and impact (C&I) assessment or some other test is conducted to determine if any supplier in the DAM has made an offer sufficiently more than their marginal cost to reflect an exercise of market power that raises the market price. If so, the offers are adjusted prior to running the market clearing mechanism.

Assessments of the pivotality of the firm, that is, how much structural market power a firm possesses and the degree to which it is necessary to satisfy demand, are a common element of market power mitigation frameworks. In situations with significant local constraints, this is considered in the assessment of market power. Structural and C&I approaches can work together, with structural tests determining if market conditions are likely to support the exercise of market power and C&I mitigating price where market power has been exercised.

Assuming the integration of a forward market power mitigation assessment into the DAM, the restrictions on real time market offer obligations can be relaxed, thereby allowing the real time market to price scarcity in the context of consumers having been protected against the exercise of market power in the DAM.

For example, the CAISO markets employ a dynamic local market power mitigation process that identifies local areas, identifies when the local area is not competitive, and mitigates local suppliers' offers to the greater of a pre-established estimate of marginal costs or the broader system competitive energy price.

3.4.3 Load obligations

In an evolution to a DAM, there must be consideration of who / what will act for loads. The two main options are for the (i) the system operator or other central agency act as the central agency committing the energy resources, be they supply or demand reduction, and (ii) load customers, LSEs, or retailers. The LSE model is the market model in FERC ISOs and this is worth considering for Alberta, possibly with amendments to allow large customers to act as their own LSE if they want. Among other reasons, decentralized agents can have stronger incentives to minimize cost and system interventions compared to ISOs. The concept of LSEs would be new to Alberta and some load customers may object to having an agent act for them.

With the introduction of a DAM, it is important to decide whether to clear supply schedules and set prices using a centralized demand curve or whether to create load obligations that would require forward trading and nomination of their positions into the DAM. Load obligations could be set at any level, leaving the imbalance market to handle the rest.

Load obligations or required forward contracting also ensures that trade for load requirements is met in a liquid market where prices can reflect the value of the commodity and avoid the price volatility or scarcity that can be found in real-time markets. The Alberta market has historically had very healthy capacity reserve levels, so setting prices with sufficient supply in a market structure that includes forward market power mitigation and competitive offers ensures that cleared prices reflect the underlying market fundamentals and not extreme operational conditions.

3.4.4 Negative price floor and administrative scarcity pricing / operating reserve demand curve

Negative price floor

The offer price floor (the lowest price to offer or to be paid) is currently zero dollars. The price floor can be reached when there is a supply surplus event, resulting in pro rata dispatches (with some additional rules to keep assets at minimum stable generation levels) until the surplus is relieved. Such events are likely to become more common in the future than they have been in the past because of substantial investment in zero marginal cost intermittent generation. With negative pricing, this surplus could be resolved as some assets would be dispatched off at lower prices. Generation firms are induced to offer at negative prices either to avoid being dispatched off (therefore reflecting the costs saved from not cycling a generator) or because the generator receives an out-of-market payment associated with its production. The result is a more orderly and efficient dispatch of the market.

Of consideration in developing a specific price floor value is the level of out-of-market payment to intermittent generation for their environmental attributes. This means that even at a price below zero, some assets still have a financial incentive to produce energy.

Price cap and administrative scarcity pricing / operating reserve demand curve

When a market has a price cap lower than the value of lost load (VOLL), prices may not reflect the correct value and incentives for scarcity conditions or the provision of quick ramp resources. This condition can be managed in many ways; however, many FERC markets have introduced an administrative shortage pricing mechanism. Through this mechanism, a demand curve sets the price of ancillary services or specific products based on the value of these products during scarce conditions. The pricing mechanism is only used during shortages and only directed to the provision of these scarce products, like ramping, but the administrative mechanism provides a calculated method for increasing energy and ancillary services market prices. A "full" variable demand curve for reserves, also known as an Operating Reserve Demand Curve, reflects a gradually increasing willingness-to-pay for reserves, typically ending in some measure of the VOLL.[19] These options should be examined as part of the holistic introduction of unit commitment,

[19] See Chang, Judy et.al, "Shortage Pricing in North American Wholesale Electricity Markets," (January 26, 2018) available at https://www.aeso.ca/assets/Uploads/4.3-Brattle-Paper-Shortage-Pricing.pdf

co-optimization and bid mitigation to ensure that pricing can reflect scare conditions and increasing value.

3.4.5 Congestion management through locational marginal pricing, security constrained economic dispatch, and system tools

Alberta's market is experiencing real time congestion more frequently, as lines are stressed due to flow limits and when all wind assets produce at the same time. An overhaul is required in operational systems and rules to support a more efficient dispatch of the grid. These changes including better pricing signals to reflect congestion on the grid (LMP), better dispatch algorithms to optimize dispatch in light of these constraints (SCED), as well as a replacement or expansion of current system operational tools to address an increasingly complex grid (system management tools).

Locational marginal pricing

Locational marginal price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received and is based on forecasted system conditions and the latest approved real-time security constrained economic dispatch program solution. LMP is expressed in dollars per megawatt-hour ($/MWh). LMP is a way for wholesale electric energy prices to reflect the value of electric energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. The three components of a LMP are the prices for congestion, energy, and losses.

Given twenty years of investment in the transmission system, the large dispatchable thermal generators face little practical risk of being curtailed due to congestion. Congestion is commonly observed today in areas with high concentrations of intermittent generation. With LMP, the average energy prices received by low value electricity generators are lowered, resulting in reduced incentives for entry. If the market moves to a LMP model, financial transmission rights are usually developed to ensure participants can hedge their congestion risk. The application of LMP in Alberta can be examined. To maintain postage stamp energy prices inside Alberta, LMP could be used exclusively at the border for imports and exports.

Security constrained economic dispatch

In nearly all modern electricity markets, security constrained economic dispatch (SCED)[20] is the basic algorithm for generation dispatch. It determines the most economic dispatch, i.e., the lowest overall system production cost, for all generators, to serve forecasted load, meet system reserve requirements, and other capacity requirements while satisfying all applicable generation and transmission limitations. In light of increasing congestion on the system, an optimization tool like this would ensure the most efficient dispatch and is needed as the complexity and demands of system management moves beyond direct human capabilities.

---

[20] See Hong, Chen (2018), "*Security Constrained Economic Dispatch (SCED) Overview,*" available at https://www.aeso.ca/assets/Uploads/3.3-SCED-Overview-by-PJM.pdf

The look-ahead time ranges from 5 minutes to a full day. SCED can be used in a DAM to determine 24 hours' generation dispatch. In DAM, the cleared energy becomes financially binding and the prices out of SCED are DAM clearing prices. SCED can also be used in other look-ahead periods to determine the future hours' generation dispatch and forecast future prices. In this case, the dispatch and prices for future intervals are usually nonbinding, mainly for advisory purposes such as for operations planning. In real time operation, SCED is often used to determine dispatch signals for the next time interval, which is generally five minutes in duration.

There are two main types of constraints: system wide operation related constraints and resource level constraints. System wide constraints include power balance constraints, reserve requirement constraints, and transmission security constraints. Resource level constraints include capacity constraints, ramp up/down constraints, power generation limit constraints (minimum and maximum), and ramping capability constraints.

Dispatch and operational tools

Market participants use the AESO's ETS to make offer or bid submissions to the market. The Energy Management System (EMS) is the system used by the AESO to create merit orders and dispatch assets in real time, for both the energy and ancillary services markets. These systems were both built for the original market and although there have been some incremental improvements, the systems are antiquated and unable to adjust to evolving system management challenges.

While there are some outstanding TMR contracts that can be dispatched with the EMS, the systems are unable to appropriately measure, manage, and dispatch given current levels of observed congestion. The merit order identifies when a block is ineffective to relieve a constraint, but with increasing congestion, on occasion, a block may be effective for one defined congestion event (an outflow constraint for example), but not be effective for another congestion event. The AESO has addressed these issues as they evolve on an ad hoc basis with side programs or procedures, an approach which is not sustainable as the market evolves, creating risks related to operating limits and emergency alerts.

Continued investment in intermittent generation means that systems must be able to measure, monitor, and support the management of an increasingly complex grid. To manage the risk of these operational challenges, evolution to the EEM requires new dispatch and operational tools.

3.4.6 Extended unit commitment market with co-optimization of energy and ancillary services

The interim unit commitment model recommended in section 3.3 is a simple model that would allow the AESO to non-arbitrarily direct LLT assets when certain forecasts indicate a need for these assets to be online. An extended version of this unit commitment process is recommended to be developed as part of the EEM. The extended unit commitment mechanism would also ensure that any forward schedule can be delivered; if units need to be "decommitted" due to transmission constraints, this positioning for dispatch would occur in the forward unit commitment market.

Co-optimization

Co-optimization is the simultaneous optimization of two or more different yet related resources within one optimization function; in this case, capacity for both energy and ancillary services requirements. The evaluation of additional constraints like ramping may also be accounted for in SCED. In the DAM, the attributes associated with offers are evaluated to provide either energy or AS products based on their specific offers and attributes using a cost minimization algorithm that considers all services. Instead of using a separate market for the procurement of AS products, the co-optimization model allocates available resources to their most efficient use. Some generation assets will be off-loaded for energy so that the capacity may be held in reserve to meet AS demand, with other assets dispatched to provide the energy.

Alberta developed a separate market for AS because (i) the hydro PPA contemplated a market price to settle their AS obligations against and (ii) market participants argued that the development of specific product requirements and pricing would be most efficient for the pricing of these attributes. It was argued that a co-optimized model, like used in most FERC jurisdictions, was a black box and it did not provide clarity of pricing. Now that the Alberta market has experience with specific AS products, moving to a cost minimization model would be sensible and increase economic efficiency.

The AESO conducted some preliminary analysis on the value of co-optimization during the development of the capacity market. Despite the indexed pricing design that provides some level of optimization, co-optimization of energy and ancillary services generated production savings in the study.[21] The benefits may be larger with the growth of intermittent generation and the presence of less dispatchable generation capacity. A summary of the results follows:

- The AESO uses sequential selection where ancillary services offers are selected first to meet the reserve requirement and then remaining MW are selected from the energy market to meet demand. Due to the nature of the clearing price mechanism, the gains from co-optimization are limited compared to how other jurisdictions price, based on the analysis refinement to comparison between sequential selection and co-optimization between energy and ancillary service markets.

- Other jurisdictions that have implemented co-optimization have done so on the premise of positively priced offers.

[21] See "Alberta Capacity Market, Comprehensive Market Design (CMD1) Design Rationale Document, Section 10 Roadmap for Confirming Changes to the Energy and Ancillary Services Markets," (January 26, 2018) page 9, available at https://aeso.ca/assets/Uploads/Rationale-section-10.pdf

- The analysis concludes that in years that exhibit relatively lower system marginal prices, benefits from co-optimization ranged from 1% to 2% of total energy and AS revenue, under the assumptions stated in the paper.

- Priced imports and capacity committed loads are no different than generation assets currently in the merit order.

Unit commitment

Submissions into the energy market are mandatory, though an asset can change its offer prices up to two hours ahead of the beginning of the delivery hour (which may change its place in the merit order) for any reason it likes, including to engage in economic withholding. An asset may also submit an acceptable operating reason (AOR) to withdraw its capacity at any time. In addition, as discussed at length above, the rules related to LLT energy allow assets that have cycled off-line to resubmit a start time more than two hours ahead of the delivery period. In comparison, participation in the AS market is voluntary but assets that clear in that market are committed to make their capacity available for the term of the contract, as procured. An important difference is that assets that clear in the AS market must pay liquidated damages if they do not deliver energy. A unit commitment model would achieve the same firmness to a contracted unit: they must make arrangements to be ready for and fulfil the dispatch or they must “buy back” from the pool to meet any shortfall.

The unit commitment proposal outlined in section 3.3.2 addressed issues with the commitment of LLT assets. An extended unit commitment model would allow analysis of capacity requirements for energy and AS based on their offers and asset characteristics in a coordinated fashion before individual merit orders are developed. The unit commitment algorithm may choose to offload an asset submitted for energy and use it for AS if the overall result is a reduction in costs. The unit commitment considers all costs of producing energy, including no-load costs and start-up costs. At the same time, it respects each resource’s characteristics, such as minimum run time and minimum down time. The appropriate forward period would need to be determined based on the characteristics of the generation fleet. For the immediate rule changes, the MSA recommends that a noon day-ahead commitment process be established to align with the timing for the submission of bids by the same timeline. Immediately following the submission of energy and AS merit orders, the System Controllers can commence their assessment of the next day.

3.4.7 Increasing frequency of settlement: Five-minute real-time settlement intervals

The current settlement interval is hourly in Alberta. Shortening the settlement interval to five minutes will improve price fidelity as the settlement price will be closer to the value of the energy at the time when it is produced and provide financial incentives for market participants to respond more quickly to dispatches.

The pool price is an hourly value charged to all load and paid to all suppliers for energy consumed / supplied to the grid on a metered basis. The 60-minute value is the simple average of 60 one-minute system marginal prices and it is finalized and posted after each settlement hour, ex post.

Since the real time market is dispatched minute-by-minute and the need for energy can vary significantly in each minute, the need for quick ramping assets is significant and increasing. Other markets dispatch their market based on a five-minute interval basis. This creates a stronger incentive for fast ramping units to respond immediately to price changes if they knew they would be paid a higher price and not some lower average of the rest of the hour.

The AESO compared the outcomes associated with a 15-minute settlement interval relative to the status quo during the development of the capacity market.[22] The analysis explains some of the benefits of moving to shorter settlement intervals. The AESO study analysis concluded that:

- Moving to a shorter settlement interval improves the pricing signals in the market.
- Total revenue paid reflects the price at shorter intervals instead of averages across the hours for all energy. The overall revenue is higher under hourly settlement intervals than 15-minute settlement intervals because lower priced energy blocks are paid at a higher hourly average pool price as compared to being paid a lower 15-minute price.
- Payment to Supplier on the Margin is significantly smaller under 15-minute settlement intervals than hourly settlement intervals since the energy settlement price is closer to the offer price.
- A slower ramping generator gets less revenue under either hourly settlement intervals or 15-minute settlement intervals; however, the impact is slightly more under the 15-minute settlement interval (-5%) as compared to the hourly settlement interval (-4%).
- 15-minute settlement intervals minimize the perverse benefit from higher hourly price for the asset that experienced a loss of supply which results in higher priced energy blocks being dispatched and a higher pool price.

Some markets develop a load following or quick ramp product that is capacity that is paid separately and dispatched to meet the ramp as it occurs either due to load increase or supply falling off, like wind. Economically, the value of the ramping contract should approximate the instantaneous value for ramping as set by the system marginal price. It would be more efficient in the long term to change the length of the settlement interval than to forecast capacity needed for ramping through the AS market. Further, prices in the energy market should reflect the value of energy in response to the variability caused by new assets on the grid.

Due to the critical need to ensure price signals for investment in flexible assets as well as dispatch and reward their response in real time, a shorter dispatch and settlement interval is critical.

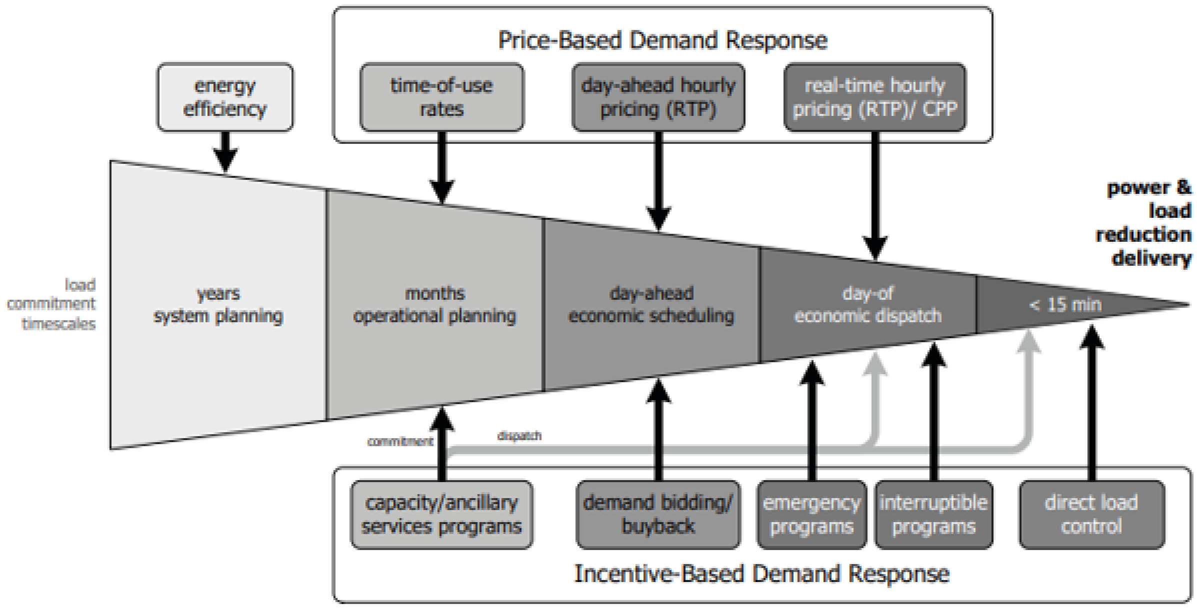
---

[22] AESO evaluation during 2016 CMD "Comparison of 15 minute settlement interval, hourly settlement interval and Payments to Suppliers on the Margin (PSM) impacts," (February 14, 2018) available at https://aeso.ca/assets/Uploads/3.4-Shorter-Settlement-word-doc.pdf

3.4.8 Enhanced role for demand response

Many jurisdictions are increasingly turning to demand response as an integral tool necessary to manage increasingly complex system dynamics. Demand response can be (i) an organized wholesale market product, (ii) latent price responsiveness of large loads, or (iii) arranged by retailers exerting some degree of control over the consumption of the customers they have under contract (Figure 18).

Figure 18: Demand response and energy efficiency in electric system planning[23]



Effective demand response can help reduce electric price volatility, mitigate generation market power, and enhance reliability. Alberta's industrial loads have participated in the wholesale market in a number of ways including provision of ancillary services and responding to real time prices directly. During peak times, effective response by load customers can reduce overall prices in the market substantially.

With enhanced electrification goals, the value of demand response is more important than ever as demand growth will be seen across the grid – from residential consumers connected to distribution grids to commercial customers at all levels across the AIES. Demand response can offset the need to build distribution wires to supply increasing load from electrification and changes to load shape.

There are three categories of demand response programs: curtailing, shifting, or on-site generation (or net-demand management). The learning from many FERC rule making proceedings has identified a range of programs across an entire spectrum that warrant further

---

[23] See "Demand Response Programs in FERC Energy Primer: A Handbook of Energy Market Basics," (April 2020), page 44, available at https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020.pdf

consideration.[24] The AESO indicated in its Reliability Requirements Roadmap that further study will be required on these products.[25]

3.4.9 New technical standards for intermittent generation and energy storage

The market rules have always included technical standards for participation in both the energy and ancillary services markets. These standards were developed when the generation fleet was primarily synchronous and therefore the assets provided system support services such as inertia and frequency. With the increasing proportion of IBR and especially the displacement of synchronous assets, system operations are increasingly challenging.

Due to the expected volume of intermittent generation connected to the grid and the possibility that dispatchable thermal assets will not be managed to address stability issues, NERC has developed technical standards for IBR to ensure that their operations reflect the need to support grid operations.[26] Technical standards can require that market participants provide system inertia or frequency either directly by their assets or through new reliability products, procured by the ISO, with the costs allocated to those assets that did not provide their own services.[27]

Noting system events in 2023 as evidence for an increasing priority on system strength, the AESO has commenced stakeholder processes indicating that they intend to follow industry best practises and move towards technical standards for IBR. It is unclear whether new technical standards will be developed by the AESO, but the MSA recommends that they are. Alberta should learn from best practices elsewhere in North America rather than start anew.

---

[24] See FERC Order 719 on Wholesale Competition in Regions with Organized Electric Market (October 17, 2008) available at https://www.ferc.gov/media/order-no-719

[25] AESO 2023 Reliability Requirements Roadmap, March 2023, Section 3

[26] See FERC 901, Reliability Standards to Address Inverter Based Resources (October 19, 2023) available at https://www.ferc.gov/media/e-1-rm22-12-000

[27] See ID #2013-005R for the technical standards for the OR market as an example of other technical standards. See also AESO consultations on System Strength in Grid Reliability Update (November 23, 2023) available at https://www.aesoengage.aeso.ca/grid-reliability-update