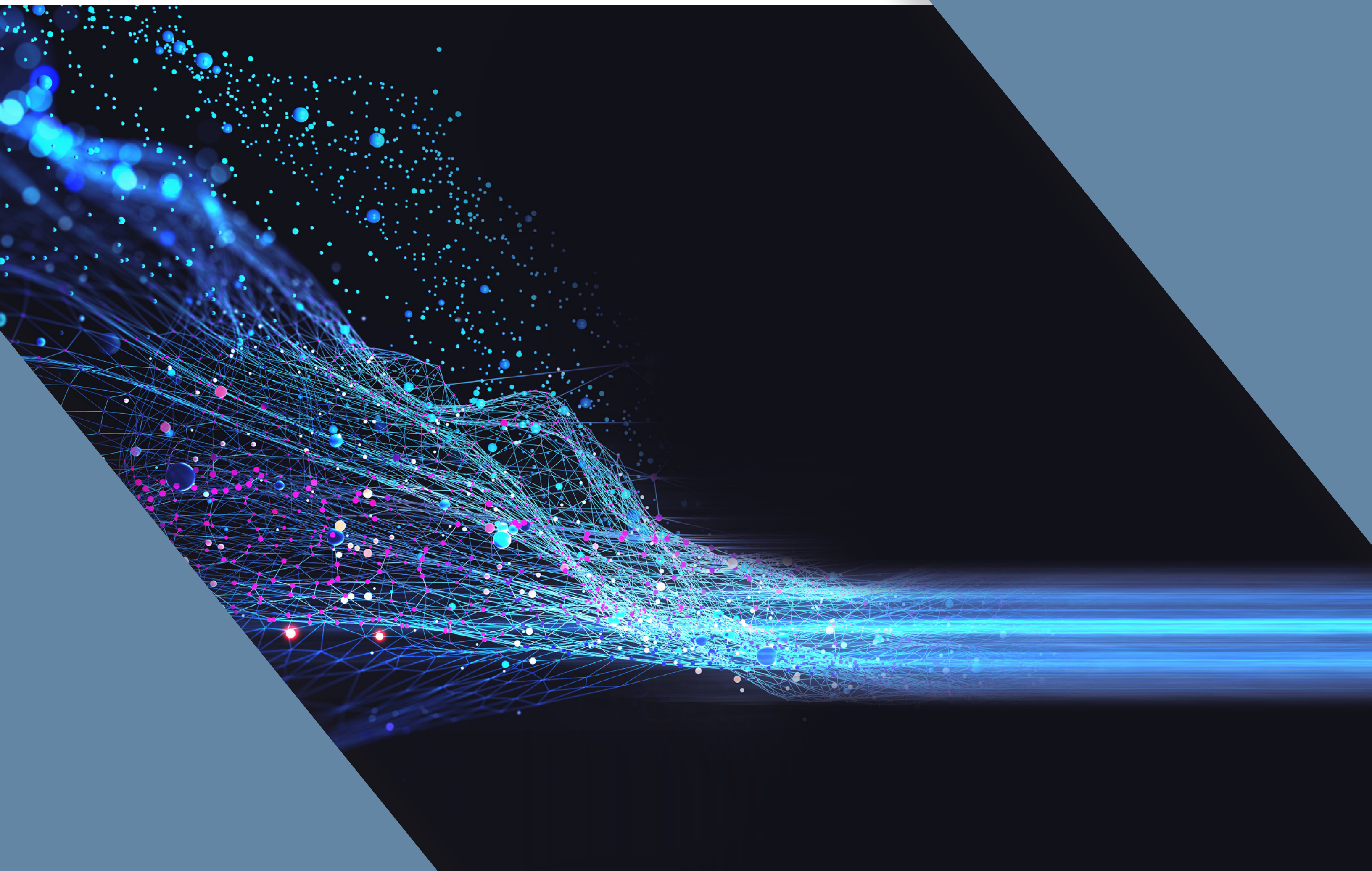


Restructured Energy Market
High-Level Design

DECEMBER 13, 2024

Contents

1. Overview

The AESO has been working extensively with industry stakeholders and market participants, partner agencies and government to ensure the Restructured Energy Market (REM) design provides a strong foundation for the Alberta electricity system, ensuring it's affordable, reliable, investable and sustainable for generations to come.

The purpose of this document is to outline the progress made on the REM design. It shows the current state of the working high-level market design as a whole package for further stakeholder feedback.

Significant Progress

The high-level REM design has progressed significantly from the original recommendations made by the AESO in February 2024. We took an iterative approach to progress each design element, striving for alignment on key priorities. This document:

- Details the current state of the high-level REM design
- Provides stakeholders with an overview of the proposed design following extensive engagement
- Serves as a platform to gather additional feedback to refine the elements of the design further
- The REM modernizes the Alberta electricity market for the future. This design is a major shift to address reliability and affordability challenges. The REM will provide:
- Investment incentives to attract the supply mix needed for the reliable operation of the Alberta Interconnected Electricity System (AIES) now and into the future
- Continued competition to drive affordable outcomes
- Strong investment signals while preserving the ability to use strategic offers in the Alberta electricity market
- Appropriate guardrails to protect consumers against the excessive exercise of market power

Next Steps

Upcoming engagements through early 2025 will aid in finalizing the design, developing corresponding ISO rules and identifying the associated information system requirements. Consultation activities to progress the design and implementation will include:

- Continued in-person design engagements
- Incorporate clear decision points for the REM design
- Engagement with existing stakeholder leadership groups (i.e., executive working group, CEO roundtable) for further input
- External expert assessments

The AESO will continue to steward REM engagements that are inclusive and transparent for producers, consumers, and transmission and distribution facility owners. Their expertise and knowledge are critical in finalizing a market design and framework that ensures a reliable and affordable grid, provides investment confidence for industry and supports government requirements.

2. Policy Direction

The REM is compatible with government policy direction provided by the Minister of Affordability and Utilities (MAU) in July 2024[1] to:

- Move forward with the introduction of a mandatory day-ahead market;
- Allow the price of energy to be determined by the strategic offers of market participants, while using market mitigation to limit the potential for excessive exercise of market power;
- Maintain a province-wide uniform price for electricity; and
- Maintain the following components of REM:
  - Security-constrained economic dispatch (SCED)
  - Shorter settlement intervals
  - Review of the price floor and ceiling
  - Co-optimization of energy and ancillary services.

In December 2024,[2] government provided further policy direction to the AESO to address the following:

- The AESO will develop a market-based congestion management mechanism that recognizes incumbency, provides impacted generators with a means of managing the dispatch risk arising from congestion constraints, and considers the participation of controllable load and energy storage
  - Any revenue generated from this mechanism will be applied towards the cost of transmission projects prioritizing congested areas of the province
  - The AESO will collaborate in an Alberta Utilities Commission (AUC) led initiative to implement a 5-minute settlement for transmission-connected loads, generators and interties by 2032 and for all loads by 2040
- Require the AESO to file a needs identification document for the Alberta Intertie Restoration project by December 31, 2026, to restore the Alberta—British Columbia (BC) Intertie to or near 950 megawatts
- Require the AESO to procure and maintain sufficient levels of availability ancillary services to support full import flows on the Alberta—BC Intertie and the Montana—Alberta Tie Line (MATL)
- Require the AESO to increase the path rating of the Alberta—Saskatchewan Intertie as part of the McNeill Converter's end-of-life replacement to leverage the use of the existing transmission capacity in the region

[1] MAU Direction Letter - July 3, 2024: www.aesoengage.aeso.ca/42905/widgets/185854/documents/134459
[2] MAU Direction Letter - December 10, 2024: www.aesoengage.aeso.ca/42905/widgets/185854/documents/144696

Additionally, in December 2024:

- The Government of Alberta is directing the AESO to continue developing the detailed design of the REM in consultation with stakeholders, with a view to finalizing the detailed REM design before the end of 2025.
- Government will bring forward the necessary policy and legislative tools to allow the initial set of ISO rules required for the REM to be enacted via legislation. Under this approach, the initial REM rules will be enacted via legislation but not brought into effect before the end of 2025 for an interim period. At the end of the interim period and beyond, any proposed amendments to the REM rules will require AUC approval in accordance with the established process for ISO rules.

3. REM Design Objectives

The REM design is structured to meet four objectives:

Reliability: Market incentives and design support reliable power delivery. A sufficient range of reliability attributes and supply technologies are available to keep the lights on during the various system conditions.

Affordability: Achieve the lowest overall delivered cost of electricity by promoting competitive and efficient outcomes, creating safeguards from excessive use of market power and incenting optimal use of existing infrastructure.

Decarbonization by 2050: Better market integration of technology and innovation that facilitates decarbonization to reach the goal of net-zero emissions by 2050.

Reasonable implementation: Implemented expeditiously to minimize investment and reliability risks. The AESO strives to minimize negative impacts on existing asset investment during REM implementation.

4. REM Design Highlights

The key REM design features are:

- **Financial day-ahead markets:** Allows participants to firm up pricing a day in advance to inform operation decisions, with day-ahead commitment (DAC) to ensure adequate resources are available and deliverable in real time.
- **New ancillary services:** Meets reliability requirements, including a DAC product and ramping products to ensure sufficient resources are available for real-time needs.
- **New market tools and co-optimization of energy and ancillary services:** Enhances ability to operate a system with transmission congestion and great variability and ensures the lowest cost solution is dispatched to meet system needs.
- **Updated pricing:** Sends appropriate signals to resources in times of supply scarcity and supply surplus through an increase in the price cap, lowering of the price floor, including price signals for energy and required ancillary services to compensate resources in advance of supply scarcity situations.

- **Appropriate guardrails:** Provides protection for consumers against excessive exercise of market power without interfering with investment signals.
- **Shorter settlement Interval:** Encourages quicker response to variability on the Alberta Interconnected Electric System (AIES).

The progression of the high-level design and recent policy direction will require reassessment of congestion management, and how interties are treated in the day-ahead, real-time and ancillary service markets. Consultation on intertie participation will continue in 2025.

5. High-Level Design Purpose

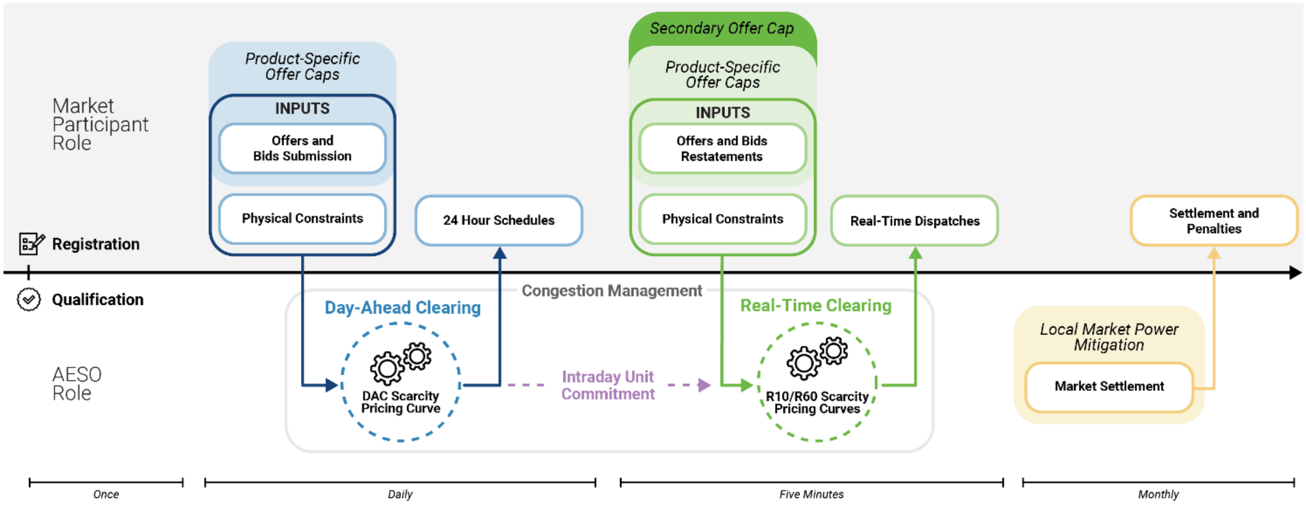
This document shares the current state of the working market design. It will be relied on to progress finalizing a complete and thoughtful design that that best fits for Alberta's purposes and reaches the REM objectives. It transitions the six REM workstreams into a consolidated REM working design.[3] The workstreams served their purpose of providing a framework to consult on interrelated aspects of the REM design effectively. Based on design sprints and the stakeholder feedback received, the design progressed and the breadth of options being considered were narrowed. Moving forward, consultation will be focused on refining the REM design using this high-level design.

The layout of the high-level design reflects relevant time periods for the REM, along with topics that occur during multiple time periods. See below for a visual overview of the sequence of processes found in the main sections of this document.

- Pre-Market
  - Registration Section: Can involve matters that would be settled prior to direct participation in the market
- Market Operations
  - Day-Ahead Markets (DAM) Section: the first phase of the market, which involves the input submission, clearing and scheduling of day-ahead products
  - Intraday Unit Commitment Market Section: when decisions outside of the DAM and the real-time market will occur
  - Real-time Market Section: the prompt phase of the market, which involves input submission, clearing, and dispatching of real-time products
- Post-Market
  - Market Settlement Section: involves the operations and processes occurring after market operations, like compliance and payment/collection of market products

[3] Previously indicated to be Day-Ahead Market, Market Clearing, Pricing and Reserve Market, Market Power Mitigation, Intertie Participation, and Shorter Settlement. The initial options papers, published on July 18 and August 16, 2024, reflect the six interrelated REM workstreams.

Figure 1: Overview of the REM Processes



Topics that occur over multiple phases of the REM are covered in separate sections: Congestion Management Section, Market Power Mitigation Section and Scarcity Pricing Curve Section.

Within each section, an element of the REM design is explored through four common subsections:

- **Purpose:** briefly describes what the design element is trying to achieve and how it relates to the overall objectives of the REM design
- **Detailed Design:** provides the proposed design and, where appropriate, references to other documents and Sprint materials used
- **Stakeholder Feedback Summary:** shares key themes from the Sprints and stakeholder submissions on the design elements. Some of the stakeholder feedback received has been incorporated in the high-level design. There is also feedback that requires further consultation or consideration as we continue to progress the design and some of the feedback listed in these sections may not be incorporated in the high-level design if the outcome did not support the overall objectives.
- **Outstanding Items:** lists the focus areas for the next iteration of the REM design

This high-level design relies heavily on the preceding consultation record. References to select topics from earlier materials are provided to ease the transition from workstreams to the overall high-level REM design. The AESO will be seeking feedback and working with stakeholders to iterate this high-level design, building on the feedback and design decisions that have already been made.

6. Registration

6.1 Purpose

The registration process formalizes participation in the Alberta wholesale electricity market. Market participants must register with the AESO as a participant to exchange electric energy or to provide ancillary services. Registration comprises two key elements: eligibility to participate and qualification for various products.

6.2 Design Details

6.2.1 Eligibility to Participate

The registration process will adopt existing processes.[4] These rules outline criteria to assess eligibility on a product-by-product basis. Additional consultation is planned to refine the eligibility criteria for the new reserve products (i.e., R10, R60, and DAC).

Initially, the REM does not allow virtual participation. Market participants must have physical assets tied to real-time delivery or consumption. The degree to which virtual participation may be permitted will be explored post-implementation.

6.2.2 Qualification of Reserve Products

The general eligibility and qualification process for reserves was outlined in Sprint 4.[5] The eligibility criteria describe the requirements to be eligible to provide different types of reserves. Market participants apply to qualify volumes for each eligible asset for each type of reserve. Qualified assets have a must-offer obligation for each specific reserve.[6] Assets must manage their offers and operational constraints to reflect physical resource capabilities accurately.

Load (sink) assets are qualified as either "Down By" or "Down To." Information on these concepts was provided in Sprint 6.[7] Using DAC as an example, a qualifying load needs to show that the specified volume is dispatchable/controllable such that there is a guaranteed load reduction ("Down By") or that consumption is reduced to a firm consumption level lower than observed historic levels ("Down To"). Similar qualification criteria for load participation will apply to the ramping products (R10/R60). The AESO is determining the qualification process for load participation in DAC and the new ramping products. Demand resources may offer their qualified volumes into the relevant products, but do not have a "must offer" obligation.[8]

A market participant can submit an available capability (AC) restatement with an accompanying Acceptable Operational Reason (AOR) in the day-ahead timeframe to reflect the asset's operations. The AOR relieves the participant of its obligation to offer the indicated volume in the day-ahead market. The specific AOR to reflect day to day operations in the day-ahead markets requires further development. The option to reflect day-to-day operations through a specific AOR process was discussed in Sprint 3.[9]

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[4] ISO Rule Section 201.1, *Pool Participant Registration*.
[5] REM Design Sprint 4 Presentation, posted on AESO Engage November 1, 2024, slides 65-66.
[6] This was further clarified with an example in REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slide 32.
[7] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slides 84-94.
[8] For more information on input obligations see the relevant subsection in the Day-Ahead Market and Real-Time Market sections.
[9] REM Design Sprint 3 Presentation, posted on AESO Engage October 4, 2024, slides 49-50.

Energy storage qualification will have similar requirements. For example, the qualified volume is dependent on an energy storage's charging and discharging capacity. The AESO prefers market participants to remain responsible for managing the energy storage asset's state of charge. This requires a clear way to communicate and measure performance relative to the state of charge and expectation for each qualifying product criteria. To the extent possible, and where appropriate, the qualification requirements from other source and sink assets will apply.

Existing Reserve Products (Regulating Reserves and Contingency Reserves)

The current technical requirements for regulating reserves[10] and contingency reserves, including spinning reserves[11] and supplemental reserves will continue to apply.[12] The current product definition and qualification requirements for existing reserve products will remain; however, the method and timeframes for procuring these products will change. Regulating Reserves and Contingency Reserves will be procured in the day-ahead and real-time markets.

New Ramping/Uncertainty Reserve Products

The qualification for R10 and R60 reserve products relies on a resource's controllable ramp rate. Specifically, R10 uses the 10-minute controllable ramp range/volume, while R60 uses the 60-minute controllable ramp range/volume. For offline units, start-up time is included in the calculation of the controllable ramp range/volume. The R10 and R60 products are only procured in the real-time market, so a day-ahead AOR is unnecessary; however, an AOR may be required for assets that are unable to provide headroom by backing off generation due to onsite requirements to deliver energy.

Day-Ahead Commitment Product

The DAC reserve qualification includes two primary criteria:

- **Asset specificity:** ensures the commitment of availability is assessed for physical feasibility based on location. Asset-specific requirements prevent asset substitution and may limit participation from some resource types
- **Four-hour duration capability:** Requires the resource to provide controllable capacity during peak net demand periods. The 4-hour requirement may be adjusted based on a historical assessment or forecasted peak net demand. The qualified volume of an asset is determined based on a 4-hour delivery rate[13]

DAC-qualified assets have a must-offer obligation for their qualified volumes in the DAC market, with compliance assessed in real-time against AC. See Market Settlement for further details.

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[10] ISO Rule 205.4, *Regulating Reserve Technical Requirements and Performance Standards*.

[11] ISO Rule 205.5, *Spinning Reserve Technical Requirements and Performance Standards*.

[12] ISO Rule 205.6, *Supplemental Reserve Technical Requirements and Performance Standards*.

[13] For example, a one MW, 4-hour battery would be allowed to sell one MW of DAC for four consecutive hours. However, a one MW, 1-hour battery would be derated to a qualified capacity of 0.25 MW of DAC, eligible to sell over four hours.

6.3 Stakeholder Feedback Summary

Stakeholders made no direct comments on the registration process of REM but provided feedback on the participation requirements for new reserve products.

- R10 and R60 lack differentiation from existing products
- Integration of these reserve products may require significant additional megawatts, which are perceived as unnecessary in the status quo market
- DAC should not be co-optimized with the other day-ahead products
- Concerns that DAC will allow certain resources to profit rather than focusing on cost recovery
- DAC over-procurement could negatively impact the real-time market and not participating in DAC when eligible could lead to physical withholding
- Concerns with must-offer requirements for batteries, storage and cogeneration for reserve products
- Concerns around must-offer requirements in the DAC market if the asset qualifies
- Further details on how the must-offer requirement for reserves would apply to the intertie participants
- Stakeholders identified two design changes for DAC: a price adder in the real-time market and a payment for Minimum Stable Generation (MSG)

6.4 Outstanding Items

- Finalize eligibility criteria for all products, focusing on R10, R60, and DAC. This includes the submission and determination of an asset's 10-minute and 60-minute controllable ramp range/volume, asset specificity, and other requirements.
- Refine the qualification process for each reserve product, particularly whether the qualification for DAC should be voluntary or more strict requirements should apply to limit physical withholding
- Translated DAC qualification criteria, such as the 4-hour delivery requirement, into the day-ahead market clearing mechanism
- Work with stakeholders to develop REM eligibility criteria for load participation in DAC and ramping products (R10/R60). Expand the definitions of “Down To” and “Down By” load participation categories to align with availability-based product requirements

7. Day-Ahead Market

7.1 Purpose

7.1.1 Day-Ahead Energy and Operating Reserves

The day-ahead energy market allows participants to buy and sell energy in advance, reducing or eliminating exposure to real-time prices. By enabling price discovery and risk management through hedging, the DAM serves as a central, transparent market for forming expectations about the operating day. The day-ahead market is primarily a financial hedging market, but it will incorporate resources' physical capability to meet system reliability by clearing physically feasible energy and reserve schedules. Participation will initially be limited to entities with physical assets within or connected to the AESO. Participants without physical assets or participants wanting to take financial positions not representative of their physical assets will be excluded at the outset.[14] This ensures market stability during the early stages. However, the AESO is open to exploring virtual participation once the market matures.

7.1.2 Day-Ahead Commitment Product

The DAC product is designed to meet the grid's energy and ramping needs by procuring enough dispatchable capacity on a day-ahead basis. This product ensures adequate committed capacity is available over the operating day to meet forecast net demand, including built-in allowances to manage net demand forecast error.[15] Cleared resources carry an obligation to be available in real-time.[16]

Unlike specific unit commitment mechanisms used in some U.S. jurisdictions, the DAC product provides a single, transparent price for availability, compensating resources for commitment while promoting competition.[17] The single price for availability allows a variety of technologies, including load, to provide the product which helps meet the objectives of reliability and affordability. Additionally, DAC does not guarantee recovery for cycling costs through out of market payments. Instead, it relies on competition to determine the price for commitment, factoring in the possibility of recovering cycling costs through other markets like energy and reserves. The DAC will foster competition between different types of asset types so that fast-responding resources (such as thermal peakers, demand response and batteries) compete with long-lead resources to provide DAC. Compared to out of market programs, competition in the DAC market is expected to attract market response, including operational changes, incremental investment and new entry, to appropriately signal the value of this day-ahead reliability attribute.

7.2 Design Details

7.2.1 DAM Timing and Schedule

The window for DAM offers, bids, and other inputs will close at noon the day prior to the operating day; the DAM clearing process will begin immediately thereafter. The resulting DAM schedule is posted once the DAM clearing process is completed at 3 p.m. This timeline provides market participants time to plan operations for the following day. In particular, long-lead resources that clear for DAC (or other products) will need sufficient time to initiate startup to meet their commitments.

[14] The AESO could consider firm day-ahead e-Tags as akin to physical assets interconnected with the AESO.
[15] REM Design Sprint 2 Presentation, posted on AESO Engage September 20, 2024, slides 13-14.
[16] The performance penalties for failing to provide the scheduled volume of DAC are outlined in the Market Settlement section.
[17] REM Design Sprint 5 Presentation, posted on AESO Engage November 7, 2024, slides 17-19. This material includes a rationale for why DAC is preferrable to the unit commitment used in other U.S. electricity markets, like Reliability Unit Commitment (RUC).

7.2.2 Inputs to the DAM

Supply Participation

The DAM design will uphold the "must offer, must comply" obligations for source assets. The requirement to offer into the day-ahead energy market and to offer in qualified volumes into the operating reserves and DAC markets would apply to all controllable and non-controllable resources with a maximum capability greater than or equal to 1 MW.[18]

- **Conventional power plants:** must offer obligations for their maximum capability; physical availability is reflected by available AC for energy and introduce similar requirements for qualified operating reserve and DAC volumes.
- **Non-controllable or intermittent renewable assets:** offer energy up to the day-ahead forecast production volume. During the Sprints stakeholders discussed whether participants could provide their own forecast for the purpose of offer volumes. Current process will be maintained, where the AESO forecast is determined from input data submitted by participants.[19] Participants nominating their own offer volume forecast introduces a new obligation on participants, creates compliance risk and auditing difficulty. The AESO determined forecast using participant data combined with the increased day-ahead offer cap is expected to address stakeholder concerns.
- Energy storage resources:
  - Discharging (supply-side) will submit energy offers reflecting their maximum discharge capability and their qualified operating reserves and DAC volumes. Physical availability is reflected by AC (like conventional assets).
  - Charging (demand-side) a 'may bid' obligation applies to the DAM energy market up to the maximum charging capability.
  - Storage offers for DAC will be based on average energy deliverable over four hours, assuming full charge. For example, a 1 MW battery with 2 MWh of storage capability can offer 0.5 MW in any given hour in the DAC market. The DAC clearing will consider the physical capability of an asset, including those that apply to energy storage (i.e., a storage asset can output energy for four continuous hours as represented by the DAC qualification but not for 24 continuous hours).
  - Energy storage will have fewer restrictions in the financial day-ahead energy market compared to DAC. The financial day-ahead energy market requires offers for maximum discharge capability in every hour, managed through the ability to offer up to the price cap.
- Cogeneration and other generation types that self supply onsite load require further consideration on how gross and net participation will be accommodated in DAC, day-ahead energy, and day-ahead operating reserves.

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[18] The previous five MW limit was based on system tool capabilities. Through the implementation of REM and associated system tools this value can be changed, the AESO is proposing one MW.

[19] It is assumed that the day-ahead forecast production volume would be based on the AESO's day-ahead forecast. The AESO will use the existing process found in the ISO Rule Section 304.9, *Wind and Solar Aggregated Facility Forecasting*.

- Since DAC is procured based on expected net demand, the treatment of gross versus net participation will influence the DAC procurement volume. The AESO will continue to explore the participation model for generators that self-supply load in the DAC market.
- For day-ahead energy, the must offer obligation for generators with self-supply load would mirror the approach in real-time.[20]
- For operating reserves, the qualification process and the ability to submit a restatement when unable to provide reserves is intended to provide assets that have a self-supply load with enough flexibility to effectively participate in both day-ahead and real-time operating reserves markets.[21]

All supply participants must submit physical asset constraints (i.e., ramp time, minimum stable generation, minimum run time, etc.).[22] These physical constraints will apply to the market clearing process to ensure physically feasible volumes.

For assets with a start-up time longer than one hour, the market participant must indicate a start time within 36 hours,[23] consistent with current requirements for long lead time assets. When the submitted start time of an offline asset is greater than the start time of an asset using its physical constraints, the DAC clearing engine process will ignore the submitted start time. Realizing that a participant may be mid-start or starting prior to the clearing of DAC, there may be situations when a submitted start time is earlier than the start time when using the asset's physical constraints. When the submitted start time is earlier than the start time for an asset when using the asset's physical constraints, the DAC clearing engine will use the submitted start time as the first hour that an asset is available to provide DAC.[24] This ensures that assets that are in the process of starting up can be included in the DAC market clearing. Start times would not be used to clear the day-ahead financial energy market. Participation in the DAM energy market would be limited to an asset's AC without consideration of start-up status.[25]

[20] Self-supply sites can nominate to participate in the market with their gross generation and gross load positions, typically termed "gross dispatch". Alternatively, they can participate as a combined "net dispatch". Importantly, these terms relate to dispatch and not to settlement; currently, a self-supply site can be gross dispatched and still net settled.
[21] See REM Design Sprint 4 Presentation, posted on AESO Engage October 31, slide 65 for flow chart of eligibility, qualification and AOR process in the real-time market.
[22] See section 7.1.2 of *REM Day-Ahead Market Options Paper* for full list of physical constraints, updated on AESO Engage August 26, 2024.
[23] The concepts of self-commitment and start time submissions were discussed in REM Design Sprint 5 Presentation, posted on AESO Engage November 7, 2024, slides 41-46.
[24] For example, if an asset has a start-up time of 16 hours, and the anticipated posting of the DAC schedule is at 3 p.m., then the earliest the DAC clearing engine could schedule the asset for DAC is at 7 a.m. the next day (16 hours after the DAC schedule is posted). However, if that same asset began starting at 10 a.m. and, therefore, submitted a start time of 2 a.m. (16 hours after 10 a.m.), then the earliest hour that the DAC clearing engine could schedule the asset for DAC is at 2 a.m. not 7 a.m. The reverse is not true. If that same asset submits its start time as midnight the next day (a full 36 hours after the lockdown period for the DAM), then the DAC clearing engine will use the physical constraint of 16-hour start time (meaning the earliest that the asset could be scheduled in DAC would be 7 a.m.)
[25] Examples of start time submission and self-commitment alongside DAC clearing were shown in the REM Design Sprint 5 Presentation, posted on AESO Engage November 7, 2024, slides 41 46.

Virtual Participation

Initially, virtual participation is excluded in the energy market. Virtual participation refers to participation from parties that do not have a physical asset associated with their offer/bid. The REM is a significant market design change. Having participation tied to physical assets will allow for a better assessment of the market in delivering the overall objectives. The AESO will evaluate the potential for allowing virtual participation post-implementation.[26]

Load Participation

Load participation in the day-ahead energy market is voluntary. Loads may also participate voluntarily in the day-ahead reserve markets if they meet eligibility requirements (operating reserves and the DAC product).

- DAM energy market participants can bid if they are registered as pool participants, qualifying as either a controllable or non-controllable load (or a combination of both). The volume of controllable and non-controllable load would be qualified in advance.
- For operating reserves and DAC, only loads that can respond to dispatches and/or directives would qualify. Loads offer up to their qualified volumes if they choose to participate and would not have the same "must offer" obligation as source assets. Loads would have compliance obligations for responding to dispatches/directives as other assets. Market clearing will evaluate physical constraints like transmission constraints to ensure that the cleared load volumes are physically feasible day-ahead.[27]

Intertie Participation

The AESO will be re-assessing intertie participation considering the recent policy direction to restore the intertie and increase intertie capability between Alberta and connecting jurisdictions. The starting point option in consultation with stakeholders has been to progress with priced interties, in combination with a market-based mechanism to address congestion. The value to Alberta customers of progressing this option may be reduced if Available Transfer Capability (ATC) is rarely limited.

Intertie participation in the day-ahead market (both energy and reserves) would depend on the applicable qualification process. Two options for day-ahead intertie participation are a "Status Quo (Price Takers)" model or an "Intertie Pricing" participation model:

1. Status Quo (Price Taker)
   - Imports submit offers at the price floor (-$100/MWh)
   - Exports submit a bid at the offer cap of $3,000/MWh
2. Intertie Pricing
   - Imports submit offers between the price floor (-$100/MWh) and the price cap ($3,000/MWh)
   - Exports bid like voluntary load between the price floor ($100/MWh) and the price cap ($3,000/MWh)

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[26] This position on virtual participation is consistent with the *REM Day-Ahead Market Options Paper*, section 5.3 and Appendix 10.4, updated on AESO Engage August 26, 2024.
[27] See section 6.2.2 for a discussion on how loads would participate in the reserve markets.

For the DAC and the operating reserves markets, intertie participation depends on the eligibility and qualification process for each product. If an intertie participant is qualified to provide reserves, their offer obligations should align with those of domestic market participants. As noted in the Registration section, the AESO will continue discussions on eligibility criteria and qualification requirements for new reserve products in REM.

Offers/Bids

Day-Ahead Energy Market Offers:

Offers to supply energy (including imports into Alberta) consist of a price to sell energy for each operating block. The AESO has yet to finalize the number of blocks used to offer energy. The maximum offer cap for energy in the day-ahead energy market is $3,000/MWh, which is the same value as the price cap.. This day-ahead offer cap differs from the real-time energy offer cap of $800/MWh. Offers to supply energy are price quantity pairs, meaning each operating block has one price.

Operating Reserves Offers:

The offer cap for operating reserves is set at $100/MWh in both the day-ahead and real-time markets. Suppliers of day-ahead reserves will submit price/quantity pairs. The AESO has yet to determine the number of blocks for reserves.[28]

DAC Market Offers:

Qualified assets would submit single part offers capped at $100/MWh. Single part ($/MWh) offers are expressed through price-quantity pairs, or operating blocks and communicate a marginal willingness to provide availability at different prices. The AESO has yet to finalize the number of blocks for DAC. The AESO is evaluating two options for DAC offers:

1. Allowing units to submit one block for the full asset.
2. Requiring multiple blocks that reflect the flexibility of the asset in the offer.

The market clearing process in both day-ahead and real-time markets will ensure that clearing results are consistent and physically feasible across all products. Resource schedules for operating reserves, DAC, R10 and/or R60 will also consider physical feasibility for each product.

Energy Bids:

Bids to consume energy in the day-ahead energy market must be equal to or less than the energy market price cap ($3,000/MWh), with the number of blocks to be determined. Bids submitted to export energy from Alberta to other jurisdictions in the day-ahead energy market are subject to the same $3,000/MWh bid cap as domestic loads.

[28] See Excel spreadsheet posted on engage on calculation of DAC, contingency reserve, regulating reserve offer caps. See ‘Reserve Offer Cap Calculations [posted Nov 20, 2024] (28 KB) (xlsx)’ under AESO materials - [REM Technical Design | AESO Engage](#).

Reserves Offers for Loads:

Loads offering to supply operating reserves in the day-ahead market are subject to the same reserve offer caps as other participants ($100/MWh for contingency reserves and regulating reserves). They do not have the same "must offer" obligation on qualified volumes and therefore their participation is voluntary. The AESO has yet to determine the number of blocks. Qualified loads voluntarily offering to supply DAC would be subject to the $100/MWh offer cap. The number of blocks for the DAC market for loads is also to be determined.

7.2.3 DAM Market Clearing Process

Price Caps and Floors

- Day-ahead energy market: price cap of $3,000/MWh and price floor of -$100/MWh (same as the real-time energy market)
- Operating reserves market: price cap of $3,000/MWh and price floor of $0/MWh
- DAC Market: Price cap of $1,000/MWh and price floor of $0/MWh

Prices exceeding the offer cap in the operating reserves market are determined by the scarcity pricing curves and/or implied opportunity cost calculations through co-optimization. Similarly, DAC market prices above the offer cap of $100/MWh are determined by the DAC scarcity pricing curve. The difference in the price floor between energy and the reserves market is informed by the expected price outcomes in each of these markets. In the energy market, negative prices are expected to occur when the marginal energy asset is willing to pay to avoid being curtailed (a negative cost to produce energy). The same is not expected in the reserves market. The AESO is not aware of a situation where the marginal reserve asset would be willing to pay to continue to provide reserves.

Procurement Volumes

The DAM clearing process will clear volumes of day-ahead energy, DAC and Operating Reserves:

- Day-ahead energy market clears supply offers to meet the volume of bid-in demand, at or below the loads' bid price (i.e., at the intersection of supply and demand). The cleared day-ahead energy volume may differ significantly from the AESO's net demand forecast for the next day.
- DAC volumes clear based on the DAC scarcity pricing curve. The DAC scarcity pricing curve determines volumes based on expected net demand plus a volume needed to reliably manage net load forecast uncertainty.[29] Net demand is calculated using the formula:
- Net Demand = Alberta Internal Load (AIL) − Self-Supply Load − Unoffered Generation − Variable Energy Resource (VER) Output

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[29] See slide 74 of REM Design Sprint 4 Presentation, posted on AESO Engage November 1, 2024, for estimated volumes for DAC expected to be procured, posted on November 1, 2024. In that slide, the Total range of DAC volume for net was reported as 3,000 MW (3,000 + 0) to 9,200 MW (8,000 + 1,200). This inaccurately added the upper range of the forecast error to the upper range of the expected net demand, instead the upper range of the forecast error should be added to the lower range of the expected net demand. This is because forecast error is negatively correlated with expected net demand.

- The AESO has removed the "net imports" term from the previous version of the net demand equation. Qualified imports participating in DAC show up on the supply-side; removing net imports from the net demand equation therefore avoids double counting the capacity and simplifies the process. This issue may be revisited based on intertie participation in DAC and potential future need to account for intertie flows in DAC procurement volumes.
- Day-ahead operating reserve volumes are determined using a similar process to the one used today. Expected volumes are procured in the day-ahead market and unexpected increases or decreases in volumes are addressed in the real-time reserves market. The REM design eliminates the need for standby reserve products and the reserve conscription process30 with the introduction of the real-time reserve market. The real-time reserve market allows for changes to reserve schedules to better match current system conditions. The other key difference between procuring operating reserves in today's market compared to in the REM is that if the AESO is unable to procure sufficient operating reserves to meet its requirement in day-ahead or real-time, scarcity pricing for these products would be applied.

Optimization

The market clearing engine in the day-ahead market will clear energy, operating reserves, and DAC to maximize social welfare, or total surplus, over the 24-hour period of the next day. Clearing will rely on a SCED algorithm, designed to create physically feasible schedules for all products based on the co-optimization of energy and AS products. This process will be implemented through new software tools, such as the Market Management System (MMS). For details on optimization methods and co optimization refer to the *Co-optimization Information Document*.[31]

Prices for day-ahead energy, operating reserves and DAC will be determined simultaneously. The AESO will separately clear the energy market and the DAC market, but the combined clearing solutions, including reserves, must remain feasible and within the physical capabilities of each asset.[32] Specifically:

- Clearing in the DAC market will not directly impact how a participant clears in the energy market, because DAC and day-ahead energy can be cleared from the same capacity.
- The clearing of DAC and day-ahead operating reserves (OR) is mutually exclusive.
- The clearing of day-ahead energy and day-ahead OR is mutually exclusive.

Mutual exclusivity is used here to mean the same MW cannot clear in both the markets for the same hour. Additionally, the sum of cleared volumes, between the mutually exclusive markets, cannot exceed the physical capabilities of the asset.

[30] See section 7.1 of the *Operating Reserves Information Document (2013-005R)* for more information on current conscription process.
[31] *REM Co-optimization Information Document*, posted on AESO Engage August 16, 2024.
[32] This is reflected in the Asset Capacity Constraints for the day-ahead markets, below.

Constraints

The clearing process for the day-ahead markets, which includes the clearing of energy, reserves and DAC, would respect the following constraints:

- Scheduled supply must equal scheduled demand, except under day-ahead scarcity conditions
- Reserve requirement constraint: reserve supply must meet the requirement specified by the scarcity pricing curve for each product (some product requirements may be related)
- Transmission constraints: transactions must be feasible based on day-ahead expectations. For more details refer to the Congestion Management section
  - When transmission constraints are forecast to bind, expected outflow transmission constraints are managed through the congestion management process,[33] expected inflow constraints are managed through the local market power mitigation framework[34]
- Asset capability constraints: assets can only be scheduled for what they are physically capable of providing.
- Ramping constraints: Assets can only ramp up or down within their limits
  - Ramping constraints in the DAC market will also ensure anticipated ramping needs for R10 and R60 products are met; the AESO does not anticipate that this constraint will bind based on the relative volumes of DAC and ramping products

Clearing of Intertie Transactions

Intertie transactions (imports and exports) will be cleared alongside domestic offers and bids in a combined merit order. The clearing process will first attempt to clear all in-merit energy offers and bids. When the net volume of in merit offers/bids exceeds the ATC, alternative clearing methods could be implemented to avoid disorderly bidding and improve efficiency. Two options considered in the Sprints are:

- **Separate Pricing Node:** the highest priced marginal intertie offer that can clear subject to the ATC constraint will set the energy price for the intertie pricing node. This clearing option internalizes the costs of arming additional import capacity-enabling services (like fast frequency response). The process clears the efficient intertie volume accounting for the offers/bids and enabling costs. There would be two intertie pricing nodes: a combined BC—MATL node and an SK node.
- **ATC Auction:** this applies the congestion avoidance market (CAM) mechanism (see Congestion Management section for further detail) to allocate ATC capacity to the import offers with the highest willingness to pay for access. Intertie transactions would receive the uniform energy price but would pay the ATC auction clearing price.

[33] See Congestion Management section.

[34] See Market Power Mitigation section.

Refer to Sprint 3 for further explanation of intertie clearing mechanisms and examples.[35] Both mechanisms create congestion rents through price differentials between the uniform energy price and the intertie pricing node(s) or by collecting revenues through the ATC auction. Allocation of congestion rents may involve a seams agreement between Balancing Authorities. The AESO will evaluate the impact of recent policy decisions on the benefits of the two proposed intertie clearing mechanisms.

7.2.4 Outputs from the DAM

Day-Ahead Energy Schedules, Volume and Prices

Upon clearing the market, the AESO will post a single energy clearing price per hour. If the separate intertie pricing node is chosen, a clearing price will be posted for each relevant node.[36] Participants will receive notification of their cleared volumes and hourly market prices. These will form each asset's day-ahead energy schedule and will be financially-binding, without a physical delivery requirement.

DAC Volume and Prices

The AESO will post a single hourly clearing price for DAC in the day-ahead market. Participants will receive a DAC schedule for their cleared volumes and required hourly availability.

Day-Ahead Operating Reserves Volume and Prices

Hourly prices for each operating reserve product will also be posted. Participants in the spinning contingency reserve, supplemental contingency reserve and regulating reserve markets will receive a schedule for their hourly cleared volumes.

7.3 Stakeholder Feedback Summary

Stakeholders provided feedback on the day-ahead markets along the following themes:

- Support for a financial DAM, as a physical DAM carries significant unmitigable risks for generators.
- Importance of REM education to encourage load participation
- Concerns that applying day-ahead "must offer" requirements on intertie participants would be much more difficult than for domestic generators
  - Conversely, allowing intertie participation to have only a "may offer" requirement raised fairness concerns
- Specific concerns that the proposed intertie clearing mechanisms, specifically the separate intertie pricing node, erode the firm transmission rights sold outside of Alberta

[35] See REM Design Sprint 3 Presentation, posted on AESO Engage October 4, 2024, slides 67-73.
[36] The preferred option would be two separate pricing nodes: one for AB-SK and a combined one for AB-BC/MATL, as proposed in REM Design Sprint 3 Presentation, posted on AESO Engage October 4, 2024, slide 71.

- Advocating for designs that have price convergence between the day-ahead and real-time markets
- Some stakeholders suggested that offer obligations on intermittent or non-controllable assets should be based on their own forecasts rather than the AESO forecast
- Concerns that the level of the reserve offer caps and co-optimization would interfere with strategic bidding
- Clarification on the determination of offer and price caps
  - Some stated that negative energy prices do not promote reliability

7.4 Outstanding Items

- Restrictions on energy-limited technologies (energy storage, for example) in the DAC market may be necessary to ensure that assets cleared for DAC can provide the required dispatchability in real-time
  - These restrictions would be in addition to the proposed 4-hour duration capability requirement for energy-limited resources
- Cogeneration obligations: gross vs. net participation in day-ahead energy, day-ahead OR, and DAC and the definition of “qualified volume” for these assets
- Definition and standardization of offer/bid blocks across all day-ahead products
  - The determination may depend on the capabilities of the MMS
- Definitions for mutual exclusion and co-optimization of day-ahead energy and operating reserve volumes
- Accounting for net imports in the DAC procurement volumes
  - Revisit after further determination of DAC qualification for intertie participants.
- Further exploration of intertie clearing mechanisms aligned with the recent policy direction for intertie restoration
- Coordination between extra-jurisdictional transmission capacity holders and AESO import/export customers through a seams agreement
- Reporting requirements to provide information required by market participants that is in alignment with *Fair, Efficient and Open Competition Regulation* (FEOC) principles
- Confirming that the input assumptions in the calculation of reserve offer caps are reasonable

8. Intraday Unit Commitment Process

8.1 Purpose

Self-commitment and the day-ahead and real-time reserve products are the primary commitment mechanisms. The intraday unit commitment process aims to accommodate changing system conditions outside the day-ahead and real-time markets.

This process includes the potential decommitment of assets committed in the day-ahead reserve markets (including DAC). In limited situations with exceptional reliability needs, the intraday unit commitment process can also commit additional supply that was not committed through the day-ahead market nor expected to be available in the real-time market. Self-commitment decisions that occur outside DAC procurement or are indicated prior to real-time are also covered by this process.

The primary objective of this process is to address reliability needs that may emerge between day-ahead and real-time.

8.2 Design Details

8.2.1 ISO Process

The intraday unit commitment process will run regularly (for example, every 10 minutes) projecting ahead (for example, for the next 48 hours). The results are advisory and inform directives that can be issued by the AESO. If the results advise that additional assets need to be committed, or can be decommitted to meet forecasted demand, AESO operations will take appropriate action.

Commitment Process

A resource would be committed through the intraday process when a significant change in the forecast indicates that committing an additional unit is required to maintain reliability, and neither self-commitment nor the real-time reserve products are expected to provide sufficient capability. The AESO has yet to define the threshold for this action. Unit commitment decisions would occur as close to real-time as possible, respecting asset constraints like ramp up time to minimum stable generation (MSG).[37]

Settlement for intraday unit commitment may follow principles in the current ISO Rule 206.2, *Interim Supply Cushion Directives*. Under this rule costs are submitted ex post for reimbursement (if not covered through real-time prices).[38]

[37] This would be informed by the physical constraints submitted for each asset and the indicated start time.

[38] ISO Rule Section 206.2, *Interim Supply Cushion Directives*. Cost guarantee and recovery are specified in subsections 6 and 7. This ISO Rule was approved as an expedited rule proceeding by the AUC (Proceeding #29093 - Expedited Approval of Interim Market power Mitigation Rules); the AESO would look to leverage stakeholder feedback and the AUC Decision from this proceeding to inform cost recovery for intraday commitments.

Decommitment Process

A resource would be decommitted through the intraday process when a significant change in the forecast indicates that decommitting assets may be more efficient. The threshold for decommitment may differ from that used for the commitment process.

Decommitment decisions will be made as close to real-time as possible, considering asset constraints. For example, a decommitment process is ineffective if an asset has already started or ramped up to meet its DAC obligations. The decommitment process is voluntary and the AESO will notify market participants of the option to decommit.

If the market participant accepts decommitment, they will no longer be obligated to fulfill DAC requirements and would not receive DAC payment for the decommitment period. If the market participant declines, then the asset must fulfill their DAC obligation and face settlement and performance risks if that obligation is not met.

8.2.2 Outputs

The AESO may issue commitment and decommitment directives outside of the day-ahead and real-time markets.

8.2.3 Cost Recovery

For intraday commitment directives, cost recovery may align with the principles in ISO Rule 206.2, *Interim Supply Cushion Directives*. Assets that receive an intraday commitment directive but do not recover prudently incurred incremental costs during the unit commitment directive from the other markets will be eligible for cost recovery.

Conversely, an asset that accepts the option to decommit will not receive DAC payments for the duration of the accepted decommitment directive, as it is relieved of its DAC obligations.

8.3 Stakeholder Feedback Summary

The intraday commitment process was not explicitly addressed during the design sprints. However, indirectly some stakeholders asked for clarification on how the REM adopts to changing circumstances from the day-ahead and real-time markets.

8.4 Outstanding Items

- Appropriate alternatives to the intraday commitment process to address the reliability needs that may emerge between day-ahead and real-time market clearing
- Identifying what thresholds should apply to commit additional assets or allow a previously committed asset to decommit:
  - Timing threshold: respecting individual asset constraints, such that minimum stable generation levels could be reached for the intended hour
  - Change in forecast threshold, reflecting significant changes from day-ahead forecasts

- Developing inputs used in the commitment process, for example how cost information is treated if there are multiple assets that could be committed
- Refining the cost recovery mechanism based on ISO Rule 206.2, *Interim Supply Cushion Directives*, to appropriately compensate for intraday commitments
- Developing additional considerations for the decommitment process to identify which assets or combination of assets may receive the ability to decommit

9. Real-Time Market

9.1 Purpose

The real-time market is operated by the ISO for the exchange of real-time energy and ancillary services. This includes dispatches and price formation. Real-time prices reflect real-time market conditions to align incentives with delivery. The real-time market will clear products to maximize the total surplus while respecting system constraints. The real-time market will co-optimize operating reserves, ramping products (R10 and R60) and energy (because DAC is not a real-time product it is not included in the real-time clearing).

9.2 Design Details

9.2.1 Inputs to the Real-Time Market

Offers and Bids

As a design starting point, energy, operating reserve offers and bids from the DAM will roll into the real-time market and can be restated or adjusted outside the lockdown period. Modifications within the real-time lockdown period require an AOR.

Market participants must structure their real-time offers to meet their day-ahead obligations. For example, an asset with a DAC obligation must position the asset to generate or consume at specific levels to fulfill its obligation.

Real-Time Energy Offers and Bids

Energy offers are submitted as single-part ($/MWh) offers through price-quantity pairs, or operating blocks. Real-time energy offers have an offer cap of $800/MWh, energy bids have a cap of $3,000/MWh. Both energy offers and bids have an offer floor of -$100/MWh. Energy offers must be monotonically increasing for source assets and monotonically decreasing for sink assets. The AESO has yet to determine the applicable number of bid and offer blocks. Based on applicability, offers are subject to the secondary offer cap when market power mitigation is binding.[39]

[39] See the Market Power Mitigation section for more detail.

Real-Time Reserves Offers

Operating reserves offer caps are $100/MWh (the same as in day-ahead). R10 and R60 offers must be submitted for qualified volumes along with real-time energy and OR offers for qualified volumes. R10 has an offer cap of $100/MWh and R60 has an offer cap of $80/MWh.[40] All reserves have an offer floor of $0/MWh.

Load Participation

Similar to day-ahead, qualified controllable load resources may submit energy bids, and must comply with corresponding dispatches. Load resources that receive a DAC schedule must submit a corresponding amount of fully controllable energy in the real-time market as a bid. The real-time energy bid allows the provider to be available for dispatch and meet its DAC obligation.

Intertie Participation

Import and export offers will depend on whether intertie participation follows the status quo or includes intertie pricing.

Status Quo:

- Imports submit offers at the price floor (-$100/MWh)
- Exports submit a bid at the offer cap of $800/MWh

Intertie pricing:

- Imports can submit offers between the price floor (-$100/MWh) and offer cap ($800/MWh)
- Exports can submit a bid between the price floor (-$100/MWh) and the bid cap ($3,000/MWh), similar to voluntary load.

9.2.2 Real-Time Market Clearing Process

Price Cap and Floor

- Real-time energy market: price cap of $3,000/MWh and price floor of -$100/MWh.
- Operating reserves, R10 and R60: price cap of $3,000/MWh and price floor of $0/MWh.

Prices exceeding the offer cap in the operating reserves market are determined by the scarcity pricing curves and/or the implied opportunity cost calculation from co-optimization.

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[40] The rationale for the reserve offer caps and calculations were presented in REM Design Sprint 4 Presentation, posted on AESO Engage November 1, 2024, slides 84-85.

Real-Time Intertie Allocation

The intertie will be scheduled prior to the real-time market clearing. The exact timing of intertie transaction allocation has not yet been determined (i.e., it could occur one hour prior to delivery [T-1]). Intertie offers (imports into Alberta) and bids (exports from Alberta) will be integrated with domestic offers in a combined merit order based on price.

- The importance of ATC allocation may depend on how often intertie offers exceed the available capability. If the volume of in-merit offers are rarely greater than the indicated ATC, pro-rata allocation comparable to today could apply. Alternatively, when the volume of in-merit offers are greater than the indicated ATC an alternative clearing will be necessary to allocate ATC to intertie transactions. Two options include:
- **Separate pricing node:** the highest marginal intertie offer that clears under the ATC constraint will set the energy price for an intertie pricing node. There would be two intertie pricing nodes: a combined BC-MATL node and a SK node.
  - Alternative for real-time: when ATC is allocated the differential between the intertie pricing node and the AESO pool price is set and will be reflected in the real-time price received by the intertie volume that is scheduled.[41]
- **ATC Auction:** this applies the CAM mechanism (see Congestion Management section for further detail) to allocate ATC capacity to the import offers with the highest willingness to pay for access. Intertie transactions will be scheduled according to a combination of volumes and ATC access bids.

Once intertie transactions are allocated ATC, all intertie offers and bids are treated as price takers in the real-time market clearing process. Intertie participants will be required to secure an e-Tag between intertie allocation and a lockdown period prior to real-time delivery. For example, if intertie allocation occurs at T-1, then intertie participants may have until T-20 minutes to secure and submit an e-Tag. Approved e-Tags form the intertie schedule and are treated as price takers in the dispatch interval.

The AESO is interested in improving coordination of intertie transactions with the neighbouring Balancing Authorities through a seams agreement. This would allow increased efficiency by reducing barriers to trade like expectation of transmission capability, potential allocation of intertie capability and e-Tag approval.

Intertie transactions are eligible to receive scarcity pricing adders when scarcity conditions arise in the real-time market. For example, during an Energy Emergency Alert (EEA), when the real-time price is $3,000/MWh, the intertie pricing nodes would also be $3,000/MWh.

[41] By way of example, if at the time of the intertie allocation the intertie price is $50/MWh and the uniform energy price is $100/MWh, then the intertie pricing node would lock in a real time price differential of $50/MWh. When the real-time uniform energy price increases, let's say from an expected $100/MWh to $110/MWh, the index between the intertie and AESO price would be maintained ($50/MWh) and the effective intertie pricing node would be $60/MWh.

Real-Time Market Clearing Engine

The real-time market clearing process uses optimization to enhance efficiency, maintain reliability and maximize societal benefits in the presence of a complex set of constraints.

Dispatches and prices are determined in 5-minute intervals. Each market clearing interval is part of a rolling look ahead window, which spans from real-time to roughly two hours in the future. The engine simultaneously clears all 5-minute intervals within the look ahead window, accounting for both current and forecasted system conditions.

The offer lockdown period can be set independently from the look ahead window. However, aligning these enhances the certainty of market clearing solutions over the look ahead window. For example, if the look ahead window was two hours and the lockdown period was T-1, then any offer restatements outside the offer lockdown period but within the look ahead window would require the recalculation of market clearing solutions.

The market clearing engine operates based on SCED. Market clearing solutions will meet the energy and ancillary service needs of the system to maximize the net benefit to society (total surplus) of the two-hour look ahead window, while respecting constraints.

- “Security Constrained” refers to the reliability and operational limits that constrain the dispatch solution
- “Economic Dispatch” refers to the goal to maximize total surplus

A key part of SCED is the co-optimized procurement of energy and reserves. Co-optimization means scheduling or dispatching energy and reserves simultaneously (not via sequential clearing), selecting the lowest cost assets to meet energy and reserve needs. The system will co-optimize the procurement of energy, operating reserves (including regulating reserves and contingency reserves), and ramping reserves (R10 and R60). For more information on the mechanics of SCED and co optimization refer to the *Co-optimization Information Document*.[42]

Constraints

Real-time market clearing respects the following constraints:

- **Power balance constraint:** Supply must equal demand
- **Reserve requirement constraint:** reserve supply must meet the requirement specified by the scarcity pricing curve for each product
- **Transmission constraints:** real-time power flows must be feasible and respect the reliable operation of the system. See the Congestion Management section for further detail.
  - When transmission constraints are expected to bind, outflow constraints are managed through the CAM and inflow constraints are managed through the local market power mitigation framework
- **Asset capability constraints:** assets can only be dispatched within their physical capabilities
- **Ramping constraints:** Assets can only ramp up or down within their design limits

[42] *REM Co-optimization Information Document*, posted on AESO Engage August 16, 2024.

9.2.3 Outputs in the Real-Time Market

Uniform Energy Price

The uniform energy price is determined based on the Reference Bus price. The offer price of the last cleared block to serve demand at a reference location sets the uniform price. A Reference Bus does not need to be a single existing bus; it may represent a distributed bus. The Reference Bus is discussed in more detail in the *Market Clearing Options Paper*. The AESO will continue to develop the methodology for the Reference Bus.[43]

Real-Time Volume and Prices

Real-time energy, operating reserves, R10, and R60 will be dispatched and priced in 5-minute intervals. This shorter interval impacts the existing allowable dispatch variance rules.[44] DAC is not procured in real-time, but the capacity is released into the real-time markets and can be dispatched for energy, ramping reserves or operating reserves.

9.2.4 Special Conditions in the Real-Time Market

Supply Surplus

Lowering the negative price floor to -$100/MWh is expected to mitigate supply surplus conditions. However, an administrative rule will remain in place for instances where more supply is offered at the price floor than is needed to meet demand.

During supply surplus:

- Import transactions under opportunity service rates will be curtailed
- Export bid restrictions will be relaxed to allow increased export opportunities

If surplus conditions persist:

- Equally priced flexible generation offer blocks will be curtailed pro-rata

Supply Shortfall

The AESO will follow applicable procedures to manage reliability during supply shortfall. The market prices during supply shortfall will be set at the price cap. Consistent with today's practice, exports under opportunity service rates would be curtailed and some of the administrative restrictions on imports would be relaxed to allow increased scheduling of imports. Under the intertie pricing nodes option, the intertie prices would be set at the scarcity value of energy and not based on the marginal offer.

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[43] *Market Clearing Options Paper*, posted on AESO Engage August 16, 2024. This material was also in the REM Design Sprint 1 Presentation, posted on AESO Engage September 11, 2024, slides 51-52.
[44] See section 10.2.8 of this paper for further discussion on allowable dispatch variance under the REM.

9.3 Stakeholder Feedback Summary

Stakeholders provided feedback on the real-time market along the following themes:

- Some generators raised the concern that co-optimization of energy and reserves could limit their ability to strategically offer
- Stakeholders expressed concerns that the separate intertie pricing node would be difficult or impractical to implement in real-time and could result in unused transfer capability
  - If chosen, the separate intertie pricing node should only apply in the day-ahead market and may only be accessible to those with likely transmission capacity
- Stakeholders requested additional clarity on potential changes to the lockdown period, including allowing for a shorter lockdown period

9.4 Outstanding Items

- Determination of the Reference Bus location, or a weighted average Distributed Bus, requires further analysis
- Determining the applicable offer lockdown period (the period within which a market participant cannot restate an offer or bid without an AOR)
- Considering policy direction, further refining intertie participation
  - For example, defining the timing of intertie scheduling, e-Tag submission and intertie lockdown. This coordination could be improved through a seams agreement between neighbouring Balancing Authorities and the AESO.
- Further determination of market outcomes during supply surplus and supply shortfall conditions
  - For example, level of service for import/export opportunity services and how they will be treated in the REM design
- Defining the format of real-time market dispatches and schedules
- Reporting requirements to provide information required by market participants and in alignment with FEOC principles

10. Congestion Management

10.1 Purpose

This section sets out the requirements to maintain reliable operations in the presence of outflow transmission constraints. Inflow transmission constraints are dealt with separately in the Market Power Mitigation section. Congestion is managed in real-time by limiting generation or increasing consumption. Real-time congestion management achieves the lowest cost of producing energy by dispatching assets following economic merit to minimize offered-in cost, subject to transmission capability.

In its recent policy direction, the government outlined that “The AESO will develop a market-based congestion management mechanism that recognizes incumbency, provides impacted generators with a means of managing the dispatch risk arising from congestion constraints, and considers the participation of controllable load and energy storage."

A market-based congestion management mechanism also provides market participants with the means to manage certain risks created from differences between day-ahead expected congestion and real-time outcomes. For this reason, a congestion management framework can apply in day-ahead, in addition to real-time.

The market-based congestion management option was introduced in the *Market Clearing Options Paper* and presented in Sprint 1, with additional design details and examples presented in Sprint 4.[45] This market-based option, now referred to as the CAM, can be implemented in day-ahead and real-time, or only in real-time. Both alternatives will be discussed further with stakeholders.

10.2 Design Details

10.2.1 Congestion Avoidance Market

The CAM allows scarce transmission transfer out capability to be allocated to generation assets that value it the most. CAM achieves efficient dispatch through competitive price signals for energy and congestion. The congestion price provides incentives for controllable load and storage resources upstream of congestion to consume electricity and receive a payment to relieve congestion.

10.2.2 Day-Ahead Congestion Management

Congestion is physically realized and managed in the operating timeframe. However, congestion could be financially managed in the day-ahead energy market with the implementation of a day-ahead CAM. Absent any day-ahead congestion management, a supplier could clear a large volume of energy in the DAM, only to face congestion in real-time and buy back the volumes it could not deliver. The introduction of a day-ahead CAM could manage this risk and ensure that energy schedules are consistent with a physically feasible clearing solution. This would minimize the day-ahead to real-time volume risk.

If a day-ahead CAM is implemented, the day-ahead energy market and DAC will be independently cleared with respect to forecasted congestion to clear feasible schedules, which best reflect real-time conditions. Including transmission constraints in the day-ahead clearing (as opposed to an unconstrained DAM) allows the AESO to clear feasible schedules, that best reflect real-time conditions. A day-ahead CAM enables participants to partially hedge against changes in expected volume and price risk from day-ahead to real-time. The settlement approaches for a day-ahead and real-time CAM, and just the real-time CAM, are shown in the Market Settlement section.

[45] *Market Clearing Options Paper*, published on AESO Engage August 16, 2024, pages 17-18; referred to as the "Constrained-Down Market". The "Constrained-Down Market" was presented in the REM Design Sprint 1 Presentation, posted on AESO Engage September 11, 2024, slides 53-54. The CAM was also in the REM Design Sprint 4 Presentation, posted on AESO Engage November 1, 2024, slides 91-111.

Offers and Bids

Assets submit their willingness to pay for system access as a $/MWh Congestion Avoidance Bid for each operating block. The offers are either price-quantity pairs or bids that are indexed to the energy price. Bids can range from zero to the price cap.[46] If the CAM is implemented day-ahead and in real-time, then day-ahead bids are submitted along with other day-ahead offers as part of the DAM.

Like other offers, day-ahead CAM offers carry into real-time CAM offers. Like all offer restatements, CAM offers can be altered in the operating timeframe until the offer lockdown period. Load participants and energy storage that are willing to consume during congestion reflect their willingness to consume through their energy bid and may be dispatched to consume, receiving a CAM payment. Each asset's offers and bids will be used in all applicable CAMs.

CAM Clearing

The market clearing process identifies expected or existing transmission constraints in the applicable timeframe. Constraints are identified as either inflow or outflow constraints. The CAM is initiated to manage outflow constraints and applies to assets upstream of the constraint.[47]

The day-ahead CAM would identify constraints based on forecasts of energy supply and demand and transmission capability. The forecasts of generation and load could be different from the volumes that clear in the day-ahead energy market.

The market clearing process uses the network model to identify which operating blocks have a Constraint Effective Factor above a predetermined threshold for the identified constraint.[48] The identified operating blocks are cleared based on their willingness to pay rather than their energy offer. The marginal Congestion Avoidance Bid (lowest clearing bid) sets the market clearing CAM price for that specific constraint. Multiple CAMs can occur at the same time to manage multiple transmission constraints.

Outputs

The results of the CAM clearing process are applied automatically to the energy market dispatches and schedules issued by the AESO when transmission constraints are binding in the market clearing process.

The CAM settlement applies to the relevant volumes. Injections of energy upstream of the constraint pay the CAM clearing price and withdrawals of energy upstream of the constraint receive the CAM clearing price. All metered volumes are paid or charged the uniform energy price. CAM charges and payments are calculated in addition to energy settlement. Further detail is contained in the Market Settlement section.

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[46] Theoretically, the maximum willing-to-pay bid would be $3,100/MWh. This is higher than the price cap of because assets can now offer costs at -$100/MWh; If an assets costs are -$100/MWh and the anticipated price is at the price cap of $3,000/MWh, then, theoretically, the owner of that asset could be willing to pay up to $3,100/MWh to access the system.
[47] Inflow constraints are managed through local market power. See Market Power Mitigation section.
[48] During REM Design Sprint 4 Presentation, posted on AESO Engage November 1, 2024, the AESO indicated a potential Constraint Effectiveness Factor of more than 10 per cent, see slide 95.

Priority Access in the CAM

Priority access could be provided in the CAM for incumbent assets. This could be implemented by capping the CAM bids of non-priority assets. Under this example, the bid cap limits the maximum willingness to pay a non-priority asset can express in the CAM. This gives priority assets a bidding advantage in the CAM compared to non-priority assets. The AESO requires further consultation with stakeholders to develop the priority access mechanism.

10.3 Stakeholder Comment Feedback

Stakeholders provided feedback on congestion management, primarily with regard to CAM, along the following themes:

- Concerns that the CAM is too complex
- Concerns that congestion management poses a significant risk on incumbent assets
- Requests to better understand opportunities for load participation in the CAM
- The CAM may adversely impact signals for investment
- Concerns that the CAM does not align with a uniform energy price
- Consideration of Transmission Rights and Constrained Down Payments - these concepts do not align with the policy decisions and are not being progressed
- Support for the CAM depends on the allocation of CAM revenues
- Request for more details regarding the congestion management framework in the day-ahead timeframe, and the interaction between day-ahead and real-time

10.4 Outstanding Items

- Whether there are alternative market-based mechanisms to manage congestion that are aligned with the policy direction
- Testing the alignment between any congestion management framework and applicable policy direction
- If the CAM is appropriate congestion management mechanism:
  - Whether the CAM applies to the day-ahead and real-time, or only real-time
    - If the CAM applies in the day-ahead timeframe, applicable forecasts for energy
  - Further detailing the structure of CAM bids and offers
  - The treatment of MSG blocks and blocks providing reserve products in the CAM clearing

11. Market Power Mitigation

11.1 Purpose

Achieving both reliability, affordability objectives while ensuring there are strong investment signals in an energy-only market with strategic bidding requires a balance between the risk of high prices set by excessive exercise of market power and the risk of over-mitigation leading to too low of prices, less investment and less reliability. The market will primarily achieve these objectives by fostering and maximizing competition: enabling all resource types, maximizing participation of sellers and buyers, and enabling entry of new technologies.

The market power mitigation framework:

- Provides guardrails to limit the potential for excessive exercise of market power, while allowing the price of energy to be determined by the strategic offers of market participants to attract and recover investment
- Will adapt to changes over time
- Upholds principles of FEOC as established in the existing legislative framework
  - Including prohibiting physical withholding and anti-competitive behaviour
- Promote and enable competitive entry to discipline the excessive exercise of market power
- Provides limits and guardrails to protect consumers only in specific situations when the competitive response is ineffective or insufficient

11.2 Design Details

11.2.1 Day-Ahead and Real-Time Energy Market Offer Caps

The offer caps differ between day-ahead and real-time because the ability to exercise market power in the day-ahead energy market is lower than in the real-time energy market.

Day-ahead energy market offer cap is $3,000/MWh.

- In the day-ahead market all loads voluntarily participate. Elastic participation from loads reduces the ability for generators to exercise market power[49]
- A higher offer cap in the day-ahead energy market minimizes the unhedgeable risk of not supplying energy sold day-ahead in real-time, especially when the day-ahead energy market price settles lower than the real-time energy market price

Real-time energy market offer cap is $800/MWh.

- The demand for energy is generally inelastic in real-time, and therefore, a lower offer cap is required to limit the potential excessive exercise of market power
- A lower offer cap of $800/MWh limits the potential excess exercise of market power and allows scarcity pricing to increase the price to reflect real-time conditions

[49] REM Design Sprint 4 Presentation, posted on AESO Engage November 1, 2024, slide 38.

11.2.2 Broad Market Power Mitigation for the Real-Time Energy Markets Applicability

Broad market power mitigation applies exclusively to the real-time energy market. Load participation in the day-ahead market naturally limits the excessive exercise of market power in that context.

The AESO considered two applicability measures for market power mitigation the Market Share Offer Control (MSOC) metric and the Residual Supplier Index (RSI). While RSI is a more targeted approach, it is also more complex and stakeholders did not favour it. The mitigation framework will therefore apply the MSOC to determine which firms are subject to mitigation.[50]

- Mitigation applies to firms with an MSOC threshold of five per cent or higher
- Firms with an MSOC below five per cent are exempt from broad market power mitigation

The MSOC for all firms will be calculated and updated at least yearly based on values provided by the Market Surveillance Administrator (MSA) per *Section 5* of the FEOC.

Net Revenue Calculation

The net revenue calculation, which determines when the secondary offer cap is triggered, is based on the costs and operational assumptions of the reference unit. The net revenue threshold, reference unit and evaluation period were examined in Sprint 6.[51]

The reference unit is a combined-cycle generator.[52] To calculate the reference unit revenue, the reference unit is assumed to operate as a merchant generator in all markets. The reference unit is subject to assumed physical constraints. The net revenue calculation assumes that the combined-cycle reference unit operates at its maximum capability multiplied by its capacity factor if the pool price is greater than its variable cost. If the pool price is lower than or equal to its variable cost, the reference unit generates at its minimum stable generation.

The reference unit's unavoidable costs will be calculated using the methodology outlined in Section 3 of the *Market Power Mitigation Regulation*. The AESO proposes the following cost parameters for the combined-cycle reference unit:

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[50] As found in the REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slide 18.
[51] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slides 11-28.
[52] As shown in REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slides 15-27, the AESO's analysis evaluated the secondary offer cap using several generation types. The combined cycle reference unit is the most representative unit in the Alberta market and the analysis found that it provides more appropriate guardrails to protect consumers from the excessive exercise of market power (compared to a peaker unit). The analysis also considered a combined-cycle unit with carbon capture utilization and storage (CCUS), but the assumptions required to apply mitigation based on a reference unit that that is not currently operating in Alberta makes it a less appropriate benchmark. The reference unit can be reviewed as the generation fleet changes.

	Combined-Cycle Reference Unit Parameters
Maximum Capacity (MW)	418
Capital cost ($/kW – yr)	1615.35
Fixed Operations and Maintenance Cost ($/kw – yr)	21.01
Variable Operations and Maintenance Cost ($/MWh)	3.8
Heat Rate (GJ/MWh)	6.79
Life (years)	30
Capacity Factor (%)	0.86
Emission Intensity (t/GJ)	0.0561
Minimum Stable Generation (% of Capacity)	0.4

For an accurate representation of total revenue, the net revenue calculation incorporates revenues from both the energy and DAC markets. The revenue earned through the DAC is a fundamental component of the reference unit's total revenue and should not be excluded. All other ancillary services revenues are assumed to be accounted for through the energy price it receives; given the assumption that the reference unit is a price taker it receives any scarcity adders in reserves that flow into the energy price.

Secondary Offer Cap

The mitigated offer cap is triggered when the reference unit recovers twice its unavoidable costs (2x) over a fixed 12-month evaluation period, as determined by the net revenue calculation. Once triggered, the mitigated energy offer cap applies to firms with MSOC greater than or equal to five per cent for the remainder of the 12-month evaluation period.

The mitigated energy offer cap is set at $400/MWh or verified costs (if higher than the secondary offer cap). The AESO initially proposed a secondary offer cap of $250/MWh in Sprint 6. Based on stakeholder feedback from Sprint 6, the AESO evaluated a secondary offer cap of $400/MWh. The AESO conducted a historical and forward-looking analysis on a $400/MWh secondary offer cap. The analysis showed that a secondary offer cap of $400/MWh provides effective guardrails for consumers to limit potential excessive exercise of market power and provides more flexibility for participants to recover their costs when compared to the $250/MWh secondary offer cap.[53] Based on these findings, the AESO proposes setting the secondary offer cap at $400/MWh.

Treatment of Reserves (Including Operating Reserves, R10, R60 and DAC

Product specific offer caps apply to each ancillary service.[54] Qualified volumes are subject to must offer requirements. The secondary offer cap does not apply to ancillary service offers.

11.2.3 Technology-Specific Broad Market Power Mitigation Rules

The following requirements apply to specific types of assets.

- **Hydro:** Firms with five per cent or higher Market Share Offer Control must enter into a negotiated compliance plan for this asset type
- **Energy Storage (including Batteries)/Hybrid Assets:** Firms with five per cent or higher Market Share Offer Control must enter into a negotiated compliance plan for this asset type
- **Wind and Solar:** Secondary offer cap does not apply
- **Intertie Transactions:** Secondary offer cap does not apply
  - Allows for firms with market power to contract across the intertie without risk to delivery on that contract due to binding of the secondary offer cap
    - Considers that competition is inherent to the non-exclusive nature of the intertie
- **Demand Response:** Not subject to secondary offer caps

11.2.4 Local Market Power Mitigation

The market clearing process will identify inflow constraints. An RSI of less than one calculated for firms with generation in an inflow constrained area will indicate that there is local market power in that area. If there is market power in an inflow constrained area, the assets that are constrained-on to relieve the inflow constraint will receive payments based on cost-based uplifts or Transmission Must-Run (TMR) payments (described further below).

The uniform energy price is based on a Reference Bus. As a result, local constraints will not impact the uniform price. The offers from resources with local market power will be used to determine dispatch in the market clearing process. Local market power is therefore addressed through the settlement process. Local market power mitigation takes precedence over the broad market power mitigation and technology-specific mitigation limits described above.

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[53] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slide 25 showed that a $250/MWh secondary offer cap leads to a 134 per cent average realized revenue as a percentage of the cost of new entry (CONE) for a combined cycle natural gas reference unit. Additional internal analysis beyond that presented in Sprint 6 slide 25 indicates that a $400/MWh secondary offer cap leads to a 139 per cent average realized revenue as a percentage of CONE for a combined-cycle natural gas reference unit. When the secondary offer cap under both scenarios remain the same.

[54] See section 7.2.2 – 'Offers/bids' for offer caps for ancillary services day-ahead and section 9.2.1 – 'Real-time reserve offers' for offer caps for ancillary serves in real-time.

Cost-Based Uplifts

If a supply resource is constrained-on to relieve an inflow constraint, the generator is paid the greater of the competitive pool price or its cost-based uplift. The cost-based uplift is based on reference unit costs, unless the market participant can demonstrate and verify a different cost. Reference unit costs may need to be established based on several technologies to account for the range of assets that may be behind an inflow constraint.

Transmission Must-Run

This option uses the existing framework for managing local inflow constraints. Foreseeable TMR would be contracted in advance following the ISO tariff.[55] Payment terms for TMR are specified in the contract. For unforeseen TMR, the ISO Tariff outlines the payment structure for conscripted TMR. The AESO is responsible for contracting for all foreseeable TMR needs.

An approach combining elements of both options could be further explored to address local market power mitigation. For example:

- TMR contracts could be employed for foreseeable inflow constraints
- Cost-based uplifts could be reserved for unforeseen TMR requirements or real-time inflow constraints that were below the defined expectation threshold prior to real-time operations

11.2.5 Periodic Review

Market power mitigation parameters are subject to a periodic review process every five years. Parameters reviewed will include primary and secondary offer caps, reference unit, secondary offer cap triggering thresholds and applicability. The review process will consider whether the mitigation framework continues to provide the ability to attract and retain supply to support reliability balanced against protecting customers from potential for excessive exercise of market power.

11.3 Stakeholder Feedback Summary

Stakeholders provided market power mitigation feedback along the following themes:

- Concerns regarding over-mitigation potentially preventing generators from recovering their costs during tight market conditions, exacerbating the missing money problem
- Stakeholders raised that the MSA should have a more active role in determining the market power mitigation framework
- Requests for clarification on the definition of excessive exercise of market power

[55] See ISO Tariff Section 8, *Ancillary Services*. Specifically, subsections 8.4 through 8.8, which deal with Transmission Must-Run.

- In relation to broad market power mitigation:
  - Suggestions that net revenue calculation for a hypothetical plant is inadequate and that evaluating the excess exercise of market power should consider the impact of behavior on the market rather than revenues accrued from the market
  - Stakeholders suggested that a peaker would be a better reference unit as opposed to a combined-cycle plant
  - Concerns that RSI is too complicated, with preference for a simpler applicability metric
- In relation to ancillary services offer caps:
  - Concerns that the offer caps in the ancillary services markets are too low
  - Suggestion that the offer caps for operating reserves should be determined based on the opportunity costs of an energy storage asset

11.4 Outstanding Items

- Determine a procedure to verify costs for assets where costs are higher than the secondary offer cap or the reference unit costs for the purposes of local market power mitigation
- Determine the month where the 12-month evaluation period starts (i.e., January, April, or October) informed by additional analysis of price trends and how mitigation would change depending on the evaluation period chosen
- Explore the appropriate costs and operational assumptions for the reference units for both broad and local market power mitigation
- Is the five-year review cycle for market power mitigation parameters appropriate
- Determine the process for negotiated compliance plans for owners of hydro and energy storage assets that have structural market power
  - Includes how negotiations will take place once structural market power or a new hydro/energy storage asset has been identified
- Finalize local market power mitigation proposal
  - The process to identify the relevant constraints will be finalized in the market clearing process that is implemented in the MMS
- Reporting requirements to provide information required by market participants and in alignment with FEOC principles

12. Scarcity Pricing Curve

12.1 Purpose

Scarcity pricing curves are important to meet the reliability and affordability objectives of the REM.

The scarcity pricing curve represents a customer's willingness to pay for improved reliability through the purchase of additional reserves. In the short term, it enables efficient decisions to tradeoff between the cost of clearing additional volume and the implied reduction in risk. The scarcity pricing curves are used in the market clearing process to calculate the reliability benefits from incurring additional costs to meet reliability needs.[56] The scarcity pricing curves allow comparisons between products, valuing the changes to benefits and risks between products as part of the clearing process.

The pricing curve methodology supports investment by signaling acceptable levels of supply adequacy (reliability) through prices of various products. The proposed approach involves calculating separate value-based scarcity curve for R10, R60, and DAC. Each curve is calculated to reflect the reliability value associated with each product, influencing the longer-term market price signals to attract investment in resources that can provide the relevant attributes.

12.2 Design Details

12.2.1 Parameters and Calculation

The willingness to pay (price) is linked to the probability-weighted value of avoiding supply shortfall events by procuring additional reserves.[57] The value-based scarcity pricing curve is developed in three steps:

1. Estimate net load forecast error within relevant timeframes (i.e., the uncertainty which reserves are protecting against)
2. Determine the $/MWh value of avoiding EEA and load shed events and the trigger conditions for these events
3. Calculate the probability-weighted reliability value of holding more reserves

These three steps are used to determine the $/MW value of each level of reserves for the R10, R60 and DAC products which form the resulting scarcity pricing curve for each product. A point on the scarcity curve reflects the value derived from an additional one MW of reserve, based on reducing the likelihood of a net load increase causing a supply shortfall event. This value is calculated by multiplying the avoided supply shortfall events (MWh/MW) by the cost of these events ($/MWh), resulting in a price for incremental reserves ($/MW). Accurately determining the cost of supply shortfall events requires an estimate of the value of lost load (VOLL). VOLL represents the costs to consumers of shedding load. A more detailed explanation of the process to determine the width, height and shape of the scarcity curve is covered in the presentation from Sprint 6.[58]

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[56] The term reliability in the context of scarcity curves refers to meeting the grids flexibility and supply adequacy needs.
[57] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slides 36-45.
[58] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, 2024, slides 36-45.

The AESO uses the net load forecast error to calculate the probability-weighted value of avoiding supply shortfall events because the net load variability is a critical source of uncertainty in the market. The second key source of uncertainty is the risk of contingencies on the grid. While the risk of contingencies is not reflected in the net load forecast calculation, the AESO accounts for the risk of contingencies by procuring contingency reserves. The volumes procured to address net demand variability are the DAC in the day-ahead timeframe, the R60 in the 1-hour timeframe and the R10 in the 10-minute timeframe.

To maintain the scarcity pricing curve's accuracy and relevance, the net load forecast error estimates require regular updates (quarterly updates would reflect changes in the fleet).[59] The process used to calculate the scarcity curves and the inputs (VOLL and system cost of EEA events) would be updated less frequently. This ensures the stability of the curves to inform longer-term investment decisions. The process to calculate the scarcity curves would be reviewed every five years.

12.2.2 Resulting Scarcity Pricing Curve

The AESO proposes to use a value-based scarcity pricing curve, calculated separately for R10, R60 and DAC following the method described above. Refer to Sprint 6 for an example of a scarcity pricing curve derived for R60.[60] The AESO posted sample scarcity curves for all products on AESO Engage.

The scarcity pricing curve is an input in the market clearing process. When a scarcity pricing curve is triggered, the applicable amounts (“scarcity adder”) will be included in the calculation of the clearing price for the relevant product.

12.2.3 Procured Volumes and Scarcity Curve Application

Reserve volumes are calculated as the sum of 50/50 forecast and uncertainty volumes. The AESO discussed the volume calculations for all reserve products in Sprint 6.[61]

The x-axis of the scarcity pricing curve reflects the uncertainty portion of the reserves needed.[62] This uncertainty portion is added to the expected volume for each reserve product to meet the 50/50 net load forecast. Sprint 6 clarified this approach with examples for DAC, R10 and R60 volumes under tight and long supply conditions.[63]

The ramp product volumes are ‘nested’. Nesting means that the volume of R10 counts towards the R60 volume.[64] Only R10 and R60 are nested. DAC is not nested with other reserves and operating reserves are not nested with any of the other real-time or day-ahead reserves products. A given level of capability can only clear for and be paid for one reserve market. In the day-ahead market, this means that a given block of capability can clear in DAC or operating reserve, but not both, and

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[59] Historic net demand forecast error data would be updated each quarter and the historic net demand forecast error data would use the data from all months of the year.
[60] REM Design Sprint 6 Presentation, posted on November 25, 2024, slides 37-42.
[61] REM Design Sprint 6 Presentation, posted on November 25, 2024, slides 36-45.
[62] See Smooth Scarcity Pricing Curve: [Posted: Nov. 14, 2024] on AESO Engage: www.aesoengage.aeso.ca/42905/widgets/179261/documents/143142.
[63] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, slides 42-45.
[64] REM Design Sprint 6 Presentation, posted on AESO Engage November 25, Slide 44.

in the real-time market, a given block of capability can clear in only one of R10, R60, operating reserves or energy.

12.3 Stakeholder Feedback Summary

Stakeholders provided feedback on the scarcity pricing curve along the following themes:

- Emphasized the need for information and data to better understand scarcity curves
- Concerns around over procurement of reserves resulting in excessive reliability and too-low energy prices
- Concerns around reliance on administrative pricing
  - Lack of trust around administrative pricing and potential for future government intervention in the pricing rules
  - Preference that the offers of market participants set the price
- DAC specific feedback:
  - Some support for DAC scarcity pricing as a means to avoid reliance on out of market mechanism, such as strategic reserves
  - Some concerns that scarcity pricing is not appropriate or necessary for DAC
  - Concern that the interaction between DAC procurement volume and impact on the energy price will reduce the scarcity that is needed to attract long-term investment

12.4 Outstanding Items

- Formalize the calculation process for scarcity pricing curves for DAC, R10, R60 and operating reserves
- Further details on the process to update the scarcity pricing curve calculation process and parameters (VOLL and system cost of EEA events)
- Finalization of the VOLL estimate to be used as an input to the scarcity curves

13. Market Settlement

13.1 Purpose

This section describes how market participants are paid or charged for energy and ancillary services provided through the day-ahead and real-time markets. It includes the settlement intervals in the day-ahead and real-time markets and penalties for unacceptable deviations from scheduled dispatches.

All day-ahead market prices are hourly. The real-time market settles on a 5-minute interval to align energy market transactions with dispatch requirements, so that prices reflect the real-time flexibility requirements of the system. Aligning the settlement interval with the dispatch interval provides higher-quality energy market signals as one price applies over the whole dispatch interval.

13.2 Design Details

Settlements for market products involve three key components: day-ahead settlement, real-time imbalance settlement, and penalties associated with not providing the products.[65]

- **Day-ahead settlement:** calculated by multiplying the quantity cleared by the price cleared in the DAM for each relevant product
- **Real-time imbalance settlement:** calculated by multiplying the quantity difference between real-time and day-ahead by the price cleared in the real-time market for each product. The real-time quantity is the lesser of the quantity scheduled or provided in real-time.
- **Penalties:** calculated by multiplying the non-provided quantity in real-time by the real-time price. Non-provided quantities are determined as the difference between real-time dispatch and real time provided quantities. The penalty price is the real-time price of the associated product.

Some products, such as R10 and R60, would not have day-ahead settlement as they are not sold day-ahead.

13.2.1 Energy Market Settlement

$$\left(Q_{SE}^{DA} \times P_{E}^{DA}\right) + [\left(Q_{PE}^{RT} - Q_{SE}^{DA}\right) \times P_{E}^{RT}]$$

Where:

Q_{SE}^{DA} is day-ahead quantity of scheduled energy.

P_{E}^{DA} is the day-ahead price of energy.

Q_{PE}^{RT} is the real-time quantity of provided energy determined using metered volumes of energy.

P_{E}^{RT} is the real-time price of energy.

Performance Penalties for Energy Market

The AESO assesses non-compliance by determining whether an asset's real-time provided energy deviates from their real-time scheduled/dispatched energy by more than the allowable dispatch variance (ADV). The AESO will refer these non-compliance events to the MSA.

$$Q_{PE}^{RT} - Q_{SE}^{RT}| > ADV$$

Where:

Q_{PE}^{RT} is the real-time quantity of provided energy determined using metered volumes of energy or SCADA data for energy.

Q_{SE}^{RT} is the real-time quantity of scheduled energy based on energy dispatch in real-time.

[65] REM Design Sprint 4 Presentation, posted on AESO Engage November 1, 2024, slides 22-24.

13.2.2 DAC Market Settlement

$$(Q_{SDAC}^{DA} \times P_{DAC}^{DA}) + [(Q_{DAC}^{RT} - Q_{SDAC}^{DA}) \times P_{DAC}^{DA}]$$

The DAC settlement equation could be simplified as shown below as payment for DAC is based solely on the volume of DAC provided in real-time.

$$(Q_{DAC}^{RT} \times P_{DAC}^{DA})$$

Where:

Q_{SDAC}^{DA} is the day-ahead quantity of scheduled DAC.

P_{DAC}^{DA} is the day-ahead price of DAC.

Q_{DAC}^{RT} is the lesser of real-time quantity of provided DAC, or day-ahead quantity of scheduled DAC, as described below.

Performance Penalties for DAC Market

The AESO assesses non-compliance by determining whether an asset's real-time provided DAC quantity is less than their day-ahead scheduled DAC quantity. The penalty charged is the R60 real-time price multiplied by the DAC quantity that was not provided.

$$If\ (Q_{PDAC}^{RT} - Q_{SDAC}^{DA}) < 0,\ Then\ the\ penalty\ is\ (Q_{PDAC}^{RT} - Q_{SDAC}^{DA}) \times P_{R60}^{RT}$$

Where:

Q_{PDAC}^{RT} is the real-time quantity of provided DAC.

Q_{SDAC}^{DA} is the day-ahead quantity of scheduled DAC.

P_{R60}^{RT} is the real-time price of R60.

The AESO uses the R60 real-time price, as there is no DAC real-time price, and the R60 price is most comparable to the price of acquiring DAC in real-time. The R60 product measures the system's ability to meet expected ramping and uncertainty over a 60-minute interval in real-time, and its price is updated every five minutes. This provides an accurate price signal for AC in real-time, which the DAC is intended to cover. Using the R60 price for DAC penalties provides a signal for when reserves are more valuable when system conditions are tight. Failure to provide DAC during these times incurs a penalty in proportion to the greater risk to the system from non-performance.

The quantity of DAC provided in real-time quantity is measured as follows:

- For source assets that take longer than one hour to synchronize: Energy ≥ MSG for DAC, ensuring that the asset is controllable for the DAC schedule given, and AC ≥ DAC quantity
- For source assets that take less than one hour to synchronize: AC ≥ DAC quantity
- For sink assets that are dispatch "Down By": DAC provided is the difference between the consumption level (measured volume) and the reduced consumption level. Consumption reduction due to an energy dispatch will be counted towards the provided DAC quantity.

- For sink assets that are dispatch “Down To”: Consumption level (measured volume) must be larger than DAC volume sold. Consumption reduction due to an energy dispatch will be counted towards the provided DAC quantity.
- Zero MW of DAC is provided for hours the asset did not clear DAC

If a market participant accepts a DAC decommitment from the AESO, they will no longer be obligated to fulfill DAC requirements and no settlement payments or charges shall be applied for the relevant decommitment period.

13.2.3 Operating Reserves (SR, SUP, RR) Market Settlement

$$\left(Q_{SOR}^{DA} \times P_{OR}^{DA}\right) + \left[\left(Q_{OR}^{RT} - Q_{SOR}^{DA}\right) \times P_{OR}^{RT}\right]$$

Where:

Q_{SOR}^{DA} is the day-ahead quantity of scheduled OR.

P_{OR}^{DA} is the day-ahead price of OR.

Q_{OR}^{RT} is the lesser of real-time quantity of provided OR or real-time quantity of scheduled OR

P_{OR}^{RT} is the real-time price of OR.

Real-time quantity of provided OR refers to what volume of reserves the asset provided in real-time, whereas real-time quantity of scheduled OR refers to how much reserve volume the asset was dispatched for in real-time.

Performance Penalties for Operating Reserves

The AESO assesses non-compliance by determining if an asset’s real-time provided OR quantity is less than their real-time scheduled OR quantity. The penalty charged is the real-time OR price multiplied by the real-time non-provided OR quantity.

$$If\ \left(Q_{POR}^{RT} - Q_{SOR}^{RT}\right) < 0, \qquad Then\ the\ penalty\ is\ \left(Q_{POR}^{RT} - Q_{SOR}^{RT}\right) \times P_{OR}^{RT}$$

Where:

Q_{POR}^{RT} is the real-time quantity of provided OR.

Q_{SOR}^{RT} is the real-time scheduled OR.

P_{OR}^{RT} is the real-time price of OR.

When contingency reserve (CR) is directed to provide energy, the reserve provider will receive the energy price plus the reserve price in the current 5-minute interval. This asset will be dispatched for energy for the subsequent interval. After being directed for energy a CR asset could be dispatched back into the CR market based on prevailing offers at that time. Assets providing regulating reserve receive the reserve price plus the energy price for energy produced; the energy price received for the energy produced has a price floor of $0/MWh to protect assets from providing regulating reserve at negative energy prices. The assessment of provided operating reserves quantity will maintain the process used in the current market.

13.2.4 Ramping Reserves (R10, R60) Market Settlement

$$Q_{RX}^{RT} \times P_{RX}^{RT}$$

Where:

Q_{RX}^{RT} is the lesser of real-time quantity of provided ramping reserve or real-time quantity of scheduled ramping reserve. RX is ramping reserve R10 or R60.

P_{RX}^{RT} is the real-time price of ramping reserves in. RX is ramping reserve R10 or R60.

Performance Penalties for Ramping Reserves (R10/R60)

The AESO assesses non-compliance by determining if an asset's real-time provided RX quantity is less than their real-time scheduled RX quantity. The penalty charged is the real-time RX price multiplied by the non-provided RX quantity.

$$If\ (Q_{PRX}^{RT} - Q_{SRX}^{RT}) < 0, \qquad Then\ the\ penalty\ is\ (Q_{PRX}^{RT} - Q_{SRX}^{RT}) \times P_{RX}^{RT}$$

Where:

Q_{PRX}^{RT} is the real-time quantity of provided ramping reserves. RX is ramping reserve R10 or R60.

Q_{SRX}^{RT} is the real-time quantity of scheduled ramping reserves. RX is ramping reserve R10 or R60.

P_{RX}^{RT} is the real-time price of ramping reserves. RX is ramping reserve R10 or R60.

Real-time quantity of provided ramping reserves (R10, R60) is determined by the available headroom:

- For source assets: (AC – energy measured[66]) ≥ R10/R60 scheduled quantity
- For sink assets that are dispatch "Down by": R10/R60 provided is the difference between the consumption level (measured volume) and "Down to" level
- For sink assets that are dispatch "Down to": Consumption level (measured volume) must be larger than R10/R60 volume sold

13.2.5 Congestion Avoidance Market Settlement

Settlement of the congestion avoidance market depends on whether CAM is implemented in day-ahead and real-time, or only in real-time. Both alternatives will be discussed further with stakeholders.

[66] Energy measurement from SCADA or metered volumes.

Alternative 1: Settlement for CAM in Both Day-Ahead and Real-Time

If the CAM is implemented day-ahead and in real-time, then a two-settlement system for CAM imbalance will occur, similar to energy. The real-time CAM settlement is an imbalance market between the day-ahead scheduled flows over expected constraints and real-time flows with real-time constraints.

Settlement for an operating block *i*, which flowed energy across N constraints *c* ∈ { n, … , N }. Where *N* CAMs, and *N* CAM clearing congestion prices. The total congestion charge settlement would be:

$$\sum_{c=n}^{N}\left(\left(Q_{Sci}^{DA} \times P_{c}^{DA}\right) + \left[\left(Q_{Pci}^{RT} - Q_{Sci}^{DA}\right) \times P_{c}^{RT}\right]\right)$$

Where:

Q_{Sci}^{DA} is day-ahead quantity of scheduled energy that was expected to flow over constraint *c*, from block *i*.

P_{c}^{DA} is the day-ahead CAM clearing congestion price for constraint *c*.

Q_{Pci}^{RT} is the real-time quantity of provided energy that flowed over constraint *c*, from block *i*.

P_{c}^{RT} is the congestion price to flow energy across constraint *c* in real-time.

Alternative 2: Settlement for CAM in Real-Time Only

If the CAM is implemented only in real-time, the total congestion charge settlement would simplify to:

$$\sum_{c=n}^{N}\left(Q_{Pci}^{RT} \times P_{c}^{RT}\right)$$

Where:

Q_{Pci}^{RT} is the real-time quantity of provided energy that flowed over constraint *c*, from block *i*.

P_{c}^{RT} is the congestion price to flow energy across constraint *c* in real-time.

13.2.6 Force Majeure – Performance Penalty Exemption

A force majeure exempts market participants from performance penalties. The definition of force majeure for providers of existing AS products can be adopted in the settlement rules for new types of reserves:

> Force majeure is defined as (a) any occurrence which is beyond the reasonable control of the Seller which could not have been avoided through the use of Good Electric Industry Practice and which renders the Seller unable to provide the Ancillary Service in accordance with the provision of the ISO rule including, but not limited to: act of God, war, invasion, armed conflict, blockade, act of public enemy, riot,

revolution, insurrection, act of terrorism, sabotage, act of vandalism, fire, lightning, explosion, earthquake, flood, or a requirement to comply with any Applicable Law or any order, direction or ruling of any government or governmental agency, court or tribunal having jurisdiction; provided that notwithstanding the foregoing, "Event of Force Majeure" shall not include a lack of finances or any occurrence which can be overcome by incurring reasonable additional expenses, or an occurrence which arises pursuant to an Ancillary Service Contract entered into by the Seller at a time when it knew, or reasonably ought to have known, that all or part of its Facility was subject to an outage.[67]

13.2.7 Settlement Interval Transition

The day-ahead market settles hourly. REM will introduce a 5-minute settlement interval in the real-time market for transmission-connected generators and loads, as well as the interties by 2032. All market participants will need to be able to settle to a 5-minute settlement interval by 2040.

A shorter settlement interval better aligns energy market transactions with the dispatch interval in the real-time market of 5-minutes so that prices reflect the real-time flexibility requirements of the system to incent more flexible response to market conditions from generators and loads.

The proposed timeline for the transition is based on stakeholder feedback on the appropriate amount of time required to implement a change to 5-minute settlement intervals (i.e., changes to settlement systems, meters, incorporate data storage requirements, etc.) and in consideration of the costs associated with the transition.

Further implementation details relating to introducing 5-minute settlement will be developed in consultation with other agencies and with industry.

13.2.8 Allowable Dispatch Variance and Wind and Solar Power Ramp Up Management

The allowable dispatch variance, relating to the delivery of energy, is expected to change. Current energy delivery requirements contemplate 10-minute clock periods for the assessment of Generating Asset Steady State compliance. To align with the proposed 5-minute dispatch intervals in the REM, adjustments to the duration of clock periods and other requirements may be necessary.

The existing ISO rules define a formula for determining Ramping Compliance. This formula's parameters may require updates to align with the shorter dispatch intervals and other operational aspects of the market clearing engine.

The current power ramp management[68] framework will be replaced. The AESO will dispatch renewable assets based on the physical capabilities of the grid (such as the ramping capability of controllable assets and the transmission constraints on the grid) in each 5-minute interval.

[67] This definition of Force Majeure is taken from the language of the WattEX contract.

[68] ISO Rule Section 304.3, *Wind and Solar Power Ramp Up Management*.

13.3 Stakeholder Feedback Summary

Stakeholders provided feedback regarding market settlement and penalties focused on the following themes:

- Penalties for some types of assets are excessive given the buyback requirement between the day-ahead and real-time markets
- Suggestions for different types of penalties include:
  - Penalties for dispatched generators that fail to deliver
  - Penalties for dispatched generators in the day-ahead that do not operate in real-time
- Consideration for scenarios where generators may receive rewards for non-performance
- Consideration for penalties to minimize the risk of over procurement
- Stakeholders noted that 5-minute settlement by 2030 for all market participants is infeasible
- Questions were raised about the calculation of true-ups when settlement intervals for supply and demand are mismatched

13.4 Outstanding Items

- Defining the transition plan to a 5-minute settlement interval for transmission-connected generators and loads and interties by 2032 and for all market participants by 2040
  - Includes specifications for the true-up mechanism to account for the mismatch of payments from load and to generators when the settlement interval is not aligned
- Further assessment of real-time provided reserves for sink assets
  - Including discussion around qualification and definitions of “down by” and down to” sink assets within the DAC and R10/R60 products context
- Further development of the appropriate requirements and considerations for system conditions (i.e., excursions due to frequency events, curtailments, etc.) for dispatch compliance
- Detail other settlement calculations, such as uplift payments for local market power, as applicable
- Consider what changes are required to allowable dispatch variance with the changes to the market from SCED and shortened dispatch intervals
  - There may also be changes required to other parts of the dispatch compliance framework

Alberta Electric System Operator

3000, 240 4 Avenue SW
Calgary, AB • T2P 4H4
aeso.ca

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