Alberta Capacity Market

Comprehensive Market Design (CMD 1)
Design Rationale Document

Section 10: Roadmap for Confirming Changes to the Energy and Ancillary Services Markets

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10. Roadmap for Confirming Changes in the Energy and Ancillary Services Market

Changes to the energy and ancillary services markets are required to facilitate the implementation of the capacity market, respond to changing Alberta generation fleet (i.e. increased variable generation, coal retirements, etc.) and to improve market efficiency. The timelines for implementation of these changes are still being evaluated, but may be variable, as some of the changes have more defined implementation timelines driven by studied system needs .

Section 10.1 outlines the energy market offer obligations; section 10.2 identifies the changes related to energy market monitoring and mitigation, and section 10.3 reviews pricing methodologies for price cap, and shortage pricing.

Section 10.4 is a summary of changes to the Energy and Ancillary Services (EAS) markets that have been evaluated as part of the EAS scope and that have been taken out of scope of the current design project. While some of these design elements may be linked to a future market or system operation trigger or a new business case, these items have been identified as nonessential for implementation of a capacity market and changes to the Alberta generation fleet at this time based on the evaluation completed.

10.1 EAS Offer Obligations

Offer Obligations Summary:

- All generation resources – including capacity resources and non-capacity resources – continue to have a must-offer obligation into the energy market.
- Imports that are capacity resources have a must-offer obligation and will be able to submit offers either with priced asset\blocks or through a price taker asset at $0.
- Capacity committed loads have a must-offer obligations and must be able to be dispatched. Capacity committed loads can offer at the offer cap to be dispatched last in the event of an energy emergency alert (EEA).
- Changes to mothball rules to align with delist capacity requirements and terms between auctions.

Rationale:

- Pool assets with capacity commitments, by receiving payments for capacity, have taken on obligations to offer their resources into the energy or ancillary service (AS) markets.This approach is consistent with current energy market obligations that all available capacity must be offered into the market.

Generating units, aggregated generating facilities and energy storage facilities

The existing ISO rules contain must-offer requirements for the maximum capability (MC) of source assets (defined as generating units, aggregated generating facilities and imports). The AESO proposes to maintain those requirements for capacity resources that are generating units, aggregated generating facilities and energy storage facilities. In contrast, other market jurisdictions typically use the concept of must-offering the ICAP equivalent of the UCAP a capacity resource supplies. However, the AESO has determined that it would be more efficient from an implementation perspective that Alberta continues the must-offer requirement for the maximum capability of a source asset outlined in the current ISO Rules.

Currently, the existing ISO rules require a generating unit or aggregated generating facility with a MC of 5 MW or greater to offer to the energy market. The AESO considers it reasonable that this 5 MW threshold continues to be applied. Those assets with a MC of 1 MW or greater and less than 5 MW will continue to have the option to offer into the energy market.

For generating units, aggregated generating facilities and energy storage facilities that are not capacity resources, the AESO considers that, in order to ensure system reliability, the system controller must have visibility of the physical capability of these assets to assess supply adequacy in and near real time . Two options for this approach were considered. First, it was contemplated that the assets could just not enter a start time when they are not available for dispatch. However, this method would not allow a reduced level of the asset's total availability, (an "all or nothing" approach). The second option considered was to continue to apply the must-offer requirement to the assets but allow them to restate their available capability (AC) without an acceptable operational reason (AOR). However, the restated AC must still reflect the maximum MW that the asset is physically capable of providing in order for the system controller to assess supply adequacy. This option would provide the flexibility of the non-capacity asset to make a portion of its total capability available to the market. However, without an AOR, the AESO was concerned about availability for dispatch.

Accordingly, it was determined that the current ISO rules would continue whether there is a capacity obligation or not. All assets must-offer to prevent physical withholding and allow for proper assessment for outages and directives.

Loads

Based on the overarching principle that capacity resources have obligations to offer into the energy or AS market, it is reasonable that capacity committed load assets must also offer into the energy or AS market. This will enable the system controller to take these load assets into consideration when assessing supply adequacy. Other market jurisdictions take a similar approach[1].

Additionally, it is reasonable that the same 5 MW threshold applied to capacity committed generators also apply to capacity committed loads. A load or aggregated load facility with capacity commitment of 5 MW or greater must-offer into the energy or ancillary services markets.Those with capacity commitments 1 MW or greater and less than 5 MW will have the option to offer.

Loads that have no capacity commitment will not have the must-offer requirement, but will continue to have the option to offer into the energy or AS market if they are equal to or greater than 1 MW in accordance to the current ISO rules.

While some capacity committed loads (i.e., price responsive loads) may offer at prices lower than the offer cap ($999.99), other capacity committed loads (i.e., demand response loads) may want to offer at much higher prices so they will not have to come off until required as part of the EEA events. Supply shortfall procedures will be developed to facilitate bids at the price cap being dispatched in a priority fashion is this option cannot be facilitated through system changes. .

For capacity committed loads that are measured based on a targeted level (i.e., referred to as "down to" as they will reduce loads to a set point), the AESO deems it appropriate that they must offer at the offer cap and be included in the shortfall steps since their energy offer MW volumes can change frequently. . Further analysis, including an assessment on market and dispatch systems, is required.

Imports and Exports

[1] https://www.aeso.ca/assets/Uploads/EAS4-Action-Item-2-load-participation-in-energy-market.pdf

Only imports will be eligible for capacity commitments. Similar to other capacity resources, an import asset that has a capacity commitment must offer the commitment volume into the energy or AS market.

The current ISO rules require imports to offer at $0 which would mean that all import offers are in-merit and will be dispatched and scheduled. As a result, it would mean that the commitment volume will always be dispatched and scheduled even when they are uneconomical. Allowing imports to request and use priced assets addresses this issue and is aligned will all other energy market assets.

An alternative approach is for imports to be provided priced assets which are allowed to offer at prices anywhere in the merit order similar to other pool assets meaning that priced import blocks would only be dispatched and scheduled when they are in-merit. In order to implement this option, intra-hour scheduling of intertie will be required. The AESO wouldaccommodate the submission of an e-tag by an import pool participant following their receipt of a dispatch from the energy market and will approve e-tag submitted intra-hour corresponding to the dispatch. However, the import pool participant would be accountable for ensuring that balancing authorities and transmission providers along the transmission path into Alberta will approve the e-tag at any time during the hour. In addition, the AESO will continue to make available the option for import as price taker at $0 and be scheduled at an hourly interval. The AESO recommends this option since it provides flexibility to import pool participants to either offer using priced assets or to continue to be price taker at $0.

The option to offer using priced assets will be made available to all imports and exports whether they are capacity committed resources or now . However, the must-offer requirement will only apply to import assets that have a capacity commitment.

Unit Commitment Summary:

- No change from status quo – the self commitment model will continue. Assets must-offer in order to manage the physical operations and financial obligations of their plants including responding to pending cycling and ramping.

Rationale:

The current self-commitment model continues to work in Alberta, given that directives issued to assets for reliability reasons occurs rarely. This means that assets have been able to respond to market signals to self-position their assets in the self-commitment model. Additionally, as shown below, the centralized commitment model yields similar results as the self-commitment model in terms of efficiency. Given that the centralized commitment model, in comparison to the self-commitment model, costs more to consumers for the same energy delivery by shifting the risk from generators to loads (through uplift payments), it was determined that the self-commitment model should continue in Alberta. An asset owner is in the best position to manage its commitment decisions. Accordingly, there is no need or value to shift away from the self-commitment model.

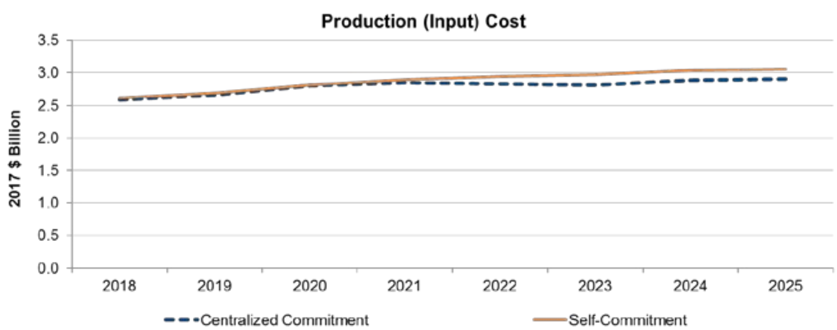
Self-commitment is supported by the following incentives and rules:

- All resources have the proper market incentives to position their assets to deliver energy and manage their own operational cost.
- Capacity resources have additional financial incentive to be available during system stressed periods in order to avoid performance payment adjustments and earn market-based revenues.
- The AESO publishes the short-term adequacy (STA) assessment report to provide a signals to market on supply tightness.
- Directives have not been required for reliability reasons; however, if required, the AESO may direct long lead time assets (i.e. Long Lead Time Energy or LLTE) resources to start up to provide energy. If

required, the AESO may direct resources to start up, and to provide energy for reliability reasons through reliability unit commitment rules. The metrics for system controller intervention will be reviewed to ensure they do not interfere with the incentives required to self commit.

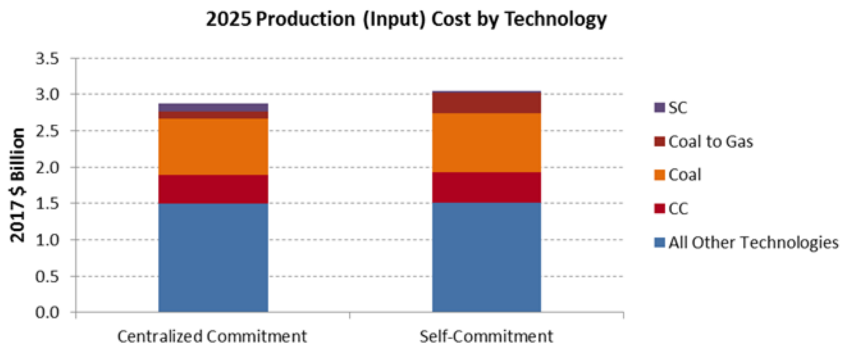
- The AESO net-demand variability (NDV) study indicated increased cycling of large commitment units (300 MW, and larger) from current level of about 5 on/off starts per unit in 2017 to about 50 on/off starts per unit in 2020/2022, and to about 90 on/off starts per unit in 2030 under the current market model. However, all scenarios tested show sufficient flexibility provided by assets assumed to be part of the overall system fleet in order to manage this flexibility within current market rules. Additional rule changes are under consideration to provide incentives and value for flexibility – which in concert with current rules will enforce the ability of the self-commitment model to continue even with future variability changes on the grid.
- The AESO commitment modelling study indicated potential but limited efficiency gains from switching to a centralized commitment model. This study showed that assets with a forward view of the market will self-position their assets to respond to expected changes. The modelling showed a reduction in unit starts in the centralized commitment model compared to the self-commitment model.
- Analysis results showed that production cost in the self-commitment model was higher than the centralized commitment model by approximately 6% higher in later years (mid 2020s). See **Figure 1** below.

Figure 1



- Further analysis of the 2025 period indicated that the estimated increase in production costs in the self-commitment model was related to lower efficient units, such as converted coal to gas units, staying online because of higher start costs and unit operational characteristics. These units displaced more efficient units, resulting in higher fuel, emission, and start-up costs. As such, the self-commitment model has higher costs related to lower efficiency commitment units producing more energy. However, these costs remained with the generator owner based on their decisions and were not assigned to loads through uplift in a centralized model. Figure 2 below shows the input cost per units modelled to be on line in 2025 and their contribution to overall production costs.

Figure 2



- The results of the modelling is that the self-commitment model can continue to support reliability objectives as participants will manage their assets to stay on line even during variability.Additionally, the AESO will continue to have the ability to direct units for reliability unit commitment, and LLTE as required. Further analysis may be required on the compensation model rules that trigger directives and costs if directed and to ensure incentives are appropriate to limit directives that limit directives where asset self-commitment could be used. The AESO will continue to monitor the impact of NDV on the fleet and continue to assess whether the rules are sufficient in the longer term.
- Moving to a centralize commitment model will require a more complicated bid offer structure (i.e.,a three part bid model that requires prices for start up, minimum run and no load in addition to energy price and ramp rates). This is a fundamental change to the energy market systems. Further, the centralized commitment model shifts some of the risk from generators to loads because the commitment model is designed to cover costs as submitted (i.e., keep whole payments if revenues are insufficient from the energy market).

Outage Scheduling Summary:

- No change from status quo – participants including new capacity committed load resources are required to submit outage information. While the AESO can cancel an outage, the AESO will not approve outages.

Rationale:

The AESO anticipates that the current outage model aligned with a capacity model will continue to work appropriately. Given that the CMD proposal does not contemplate exemptions for performance measurement due to outage approval, an examination into changes to the outage model is not required.

The AESO already has existing market rules that pertain to outage scheduling of load and generation. The AESO reviewed the options for outage scheduling for generation resources and proposes to maintain the current outage scheduling requirements for both capacity committed generation and non-capacity committed generation. The AESO also proposes that loads contracted for capacity will have to follow similar outage scheduling rules.

The current ISO rules require outage reporting where a generating unit or aggregated generating facility with a MC of 5 MW or greater changes its AC by 5 MW of more, and load decrease to its AC of 40 MW or more. Loads that have capacity commitments greater than 5 MW will be required to follow outage reporting requirements similar to the generator outage reporting requirements..

The AESO considers it reasonable that these requirements continue to apply to support the ongoing assessment of system adequacy. The AESO uses this outage information in order to assess and report Alberta's supply adequacy for both the short-term and the longer-term (next two years). The AESO needs to assess supply adequacy to manage the reliability of the system.

Supporting reasons for maintain the current outage submission process include:

- All resources have a financial incentive to plan outages to avoid stressed and higher priced times.
- Capacity resources have financial incentive to be available during system stressed periods so to avoid performance based payment adjustments.
- The risks of taking a planned outage during system stressed period should reside with the market participant.
- The CMD does not contemplate that performance exemption for a capacity resource taking an outage during performance period.
- Stakeholders expressed concerns in comments on SAM 2.0 that the requirement for AESO approving outages would pose challenges to the operation of assets and other processes.
- The AESO will continues to have the ability to issue a directive to direct cancellation of a planned outage including a mothball outage, and to direct the starting up of a long lead time asset through reliability unit commitment rules.

Dispatch and Scheduling Summary:

- Status quo dispatch of the merit orders with the inclusion of priced import assets within the merit order and a priority rule for capacity committed loads at the price cap with the exception of:
  - Further evaluation of the security constrained economic dispatch (SCED)model in terms of flexibility value to be assessed prior to CMD 2.0.
  - Consideration of rule changes at supply shortfall to address directives for capacity committed load resources and incentives for long lead time assets.
  - Consideration of rule changes at supply surplus to consider dispatch of flexible units.
  - Rules for ramp rate submissions by block and requirements for compliance of dispatch at directed levels to address system management especially during increased variability.
  - 15 minute settlement will be examined for pool assets except hourly settlement for retail loads.
- Energy and AS markets will continue to be cleared separately and dispatched sequentially subject to further coordination with a possible SCED dispatch. To be assessed prior to CMD 2.0.

Rationale:

The current dispatch rules continue to be appropriate; however, further options may be considered to address incentives and value for provision of asset flexibility needed to manage pending increased variability.

SCED is being evaluated as it is intended to provide a price for energy separate from ramp which then provides additional incentives and value for ramp capability from assets across the system. The signals for flexibility rely on a combination of rules that ensure the assets follow dispatch. Further analysis is ongoing to assess rule options individually or as a group that provide value for flexibility including submitting ramp rate by block offers, tighter dispatch tolerance in addition to pricing signals that optimize and pay for ramping response across the system. SCED will be evaluated against these other options.

SCED is an optimization process that determines what dispatch schedules will meet electricity demand at the lowest cost, given a specific set of constraints. In today's market, the constraints would be offers and supply sufficient to meet forecasteddemand. Energy price and dispatch schedules would be an output. Ramp could be included as a constraint to the algorithm where the output of the algorithm would be energy price, dispatch schedules, and the shadow price of the ramp requirement (if the ramp constraint is binding). The dispatch schedules output from SCED would provide the least cost solution to meet the ramp requirements in the future interval. In this way, ramp would be valued separately from energy to ensure price fidelity. The SCED would run in advance to support the system controllers in dispatching for these constraints.

Current settlement interval is hourly. Shortening the settlement interval to 15 minutes will improve price fidelity as the settlement price will be closer to the value of the energy at the time when it is produced, and may provide financial incentives for market participants to respond more quickly to dispatches

Cooptimization of EAS on its own generates some production savings (based on further study results). However, the results are likely not sufficient to warrant the required system changes but will be reviewed as part of SCED. The summary of the results are as follows:

- The AESO uses sequential selection where ancillary services offers are selected first to meet the reserve requirement and then remaining MW are selected from the energy market to meet demand. A single clearing price in the energy market results, with offers priced from $0 to 999.99 and AS offers priced from $-999.99/MWh to the bid are used to calculate an AS clearing price. Due to the nature of the clearing price mechanism, the gains from co-optimization are limited compared to how other jurisdictions price, based on the analysis refinement to comparison between sequential selection and co-optimization between energy and ancillary service markets.
- Other jurisdictions that have implemented co-optimization have done so on a premise of positively priced offers.
- The analysis concludes that in years that exhibit relatively lower system marginal prices, benefits from co-optimization ranged from 1% to 2% of total EAS revenue, under the assumptions stated in the paper. The benefits from co-optimization can increase with changes to ancillary services offer structure to cost based offers.
- Priced imports and capacity committed loads are no different than generation assets currently in the merit order.

Other considerations

- While the decrease in revenues is an implication, choosing whether to co-optimize or run a realtime AS market can result in other benefits.

- Currently, the AESO procures contingency reserves one day ahead based on forecasted contingency reserve volumes, and if procurement of active reserves falls short during real time, the AESO will use standby reserves. This introduces forecast error and could potentially lead to situations where there insufficient active contingency reserve to facilitate imports.

  With co-optimization, the full ancillary services offer curve can be optimized closer to real time to meet contingency reserve requirements and therefore the likelihood of falling short of active reserves decreases.

Input from Working Group Members and Industry Stakeholders Through SAM 3.0:

- The majority of the EAS working group members agreed that all committed supply capacity must-offer physical availability (including loads that are committed on the supply side of the capacity market) and all non-capacity resources do not have a must-offer requirement but must provide visibility.
  - Although there were no objections to this approach, there were continuing reservations, including:
    - An unclear understanding what information is required for ‘visibility’ for non-capacity resources; and
    - An unclear understanding of whether any differences will exist on bid mitigation for non-capacity resources.
  - Reservations to this provisional recommendation were based on:
    - Not clearly understanding what information is required for visibility for non-capacity resources.
    - Requiring a better understanding of whether any differences will exist on bid mitigation for non-capacity resources.

- Note: No working group members objected to this provisional recommendation.
- Industry feedback on SAM 3.0 provided similar commentary to that of the EAS working group:
  - Industry is supportive of cleared capacity resources having a must-offer obligation, and providing visibility of non-committed resources to the AESO.
  - In providing visibility information for non-committed resources, the AESO should consider options that focus on providing only availability and operation related information (e.g. start-up time, ramp rate, etc.).
- Additional commentary provided on imports as it relates capacity committed resources:
  - A must-offer requirement must permit capacity committed imports to price into the Energy market. However, in doing so, the AESO must ensure that this does not exacerbate jurisdictional seams issues. If this issue cannot be resolved prior to the implementation of the capacity market, then the must-offer requirement be suspended for imports on a temporary basis.

Rationale for Deviation from SAM 3.0 Position:

- Current must offer obligations are best able to address requirements for visibility and ensure consistency across assets.
- SAM 3.0 position on imports was incomplete; the priced import alternative will be discussed at the working group.
- Some working group members asked for evaluation of a ramp product; however, after preliminary assessment, this options should be evaluated against a fulsome SCED model Accordingly, the SCED option will be explored with the working group.

10.2 Energy Market Monitoring and Mitigation

Market Power Mitigation Summary:

- The energy market will adopt an *ex ante* market power mitigation based on an hourly residual supplier index (RSI) structural screen will be set at RSI of 0.9,
- Companies that fail the *ex ante* mitigation screen will be have their offers automatically mitigated to a multiple of a reference bid price that is based on fuel and variable O&M costs by technology type
- The bid threshold will be calculated at 3 x marginal cost defined as heat rate x fuel price + variable O&M + carbon cost.
  - For non-thermal resources, market participants will have the ability to submit opportunity cost for approval. In those cases, if approved, the opportunity cost would replace the reference bid price, upon which the bid threshold will be set.
- *Ex poste* monitoring and mitigation will continue

Rationale:

In Alberta's current energy-only market framework, all revenues, including those attributed to return on and of capital, are enabled through a price-formation mechanism that includes economic withholding (in-market offers resulting in scarcity pricing, especially during tight supply conditions). With the introduction of a capacity market, the need for acceptable economic withholding to recover cost of capacity was removed. While it is expected that the capacity market will capture a significant portion of the revenues attributed to return on capital, the majority of aggregate revenues will be captured in the Energy and Ancillary Services market, and these two markets will continue to have a role in incenting the appropriate investment in flexible resources, and optimal operational behaviour. This will be done through the energy market, and Ancillary Service market price signal. In a capacity market framework, some portion of the return on capital will be captured through revenues from the capacity market. As such, the need for these revenues to be captured in the Energy and Ancillary Services market through economic withholding, and in-market scarcity pricing is lessened, and the justification for economic withholding is weakened.

It is expected that competition in the energy market should tend to short run marginal costs (SRMC) in normal conditions (that is, except in scarcity or shortage events where the price will reflect market conditions.)

In other jurisdictions, capacity committed resources are required to offer at costs; however in Alberta's market where it is proposed that we continue with a one part bid/offer model with self-commitment, an acceptable range on costs will be determined to proxy "at cost". This range on costs will also address future cycling of assets that is more than reflected in historic data. Further, because of the expected competition in the energy market, assets that pass an *ex ante* screen will be able to submit their offers at any price below the offer cap.

Ex post mitigation will continue. However, with current uncertainty in Alberta's market, a move to an *ex ante* model was accepted and will be proposed. An *ex ante* mitigation approach provides control of risk of market power while still providing for scarcity pricing. The *ex ante* market power mitigation approach provides participants a forward looking assessment of whether they are a pivotal supplier in certain hours and a range of acceptable offers. This model does not prevent *ex post* mitigation of dispatch volumes, real time behavior and issues related to gaming by the Market Surveillance Administrator (MSA). However, this model provides greater certainty of how offers will be assessed.

Several options were considered for the *ex ante* mitigation model including different variations of the structural screen/pivotal supplier test and conduct and impact test. The AESO is considering the practicality of implementing the screen and setting the threshold for bid mitigation. There will be a tradeoff in determining the precision of the screen, and cost band, and the administrative and systems impact of any choice the AESO proposes. The AESO has determined that the use of an hourly pivotal supplier test will be the most practical to implement. The AESO is also proposing to use levels of RSI<0.9 to reduce the issues related to false positives. However, the AESO recognizes that having an RSI<0.9 will leave some suppliers (those above 0.9) opportunities to exercise their market power and will need to continue to evaluate the competitive nature of the market.

A conduct and impact test was considered. However, the AESO considered the test to be overly onerous from a implementation perspective. The AESO proposes to strike a balance between complications associated with conducting a cost-based hourly conduct and impact test but may still consider it for the future if the concentration level is sufficient to warrant further assessment.

Based on the historical bid analysis conducted by Brattle and AESO, the AESO has evaluated the potential revenues supplier can earn when bids were mitigated down to 3x costs. Brattle has found that mitigating down to 3x costs would be sufficient to cover most resources' start up and no-load costs based on historic costs and some expectation of future cycling and would not allow suppliers to earn more than the market's cost of new entry. Thus, the AESO is proposing 3x costs as a reasonable band on costs for setting the mitigation levels.

The AESO has based its proposal related to mitigation on its own assessment and work conducted by Brattle. The full paper will be circulated to the working group. Excerpts from the Brattle report are included below.

RSI Screen

The RSI screen is based on the concept of a "pivotal supplier." In a market with a fixed supply and inelastic demand, when nearly all-available supplier capacity is needed to meet demand, some suppliers may become "pivotal" in meeting the demand. The RSI test is typically used to detect market conditions when a supplier would have the capability to raise prices profitably by exercising market power through withholding a portion of their supply. The RSI's prescribed arithmetic formula, when applied to the specific market conditions, means a supplier is pivotal when that supplier's RSI is less than or equal to 1.0.[2]

Equation [1]

The RSI for $Supplier_i$ in period t is:

$$RSI_{it} = \frac{\sum_{j=1}^{n} Supply_{jt} - Supply_{it}}{Total\ Market\ Demand_t}$$

Where the sum of $Supply_{jt}$ represents the total capacity in the market at the relevant time t. *Total Market Demand* is the total demand in the market at time t. $Supply_{it}$ represents $Supplier_i$'s total resources made available to the market at time t.

The equation shows that RSI compares (1) the amount of capacity held by other suppliers in the market that are not owned and controlled by $Supplier_i$ (supply margin) to (2) the total demand of the market. If the supply margin is greater the total market demand, the RSI is greater than 1.0 and demand can be met without any of $Supplier_i$'s resources. When $Supplier_{i'}$'s RSI in period t is less than or equal to 1, *Supplier i* is deemed to be pivotal and its resources in whole or in part are required to satisfy demand in the market. Thus, an RSI < 1.0 indicates conditions under which *Supplier i* would be able (and may have the incentive) to exercise its market power and raise prices.

If the AESO chooses to use the RSI for market power mitigation in the energy and ancillary services markets, adjustments to account for Alberta-specific characteristics in the calculation of the RSI for each supplier (including all of the resources in each supplier's portfolio) would be highly recommended.

The formula in Equation [1] can and should be refined to better reflect a supplier's ability and incentive to exercise market power. The proposed refinements of Equation [1], include:

An adjustment for load and sales obligations: *Supplier i*"s total supply available at time *t* would be adjusted downward to reflect *Supplier i*"s load and long-term contract obligations, if any exists. As shown in Equation [2], the second term of the numerator reflects *Supplier i*"s net buyer/seller position in the market. This adjustment is particularly important when suppliers must purchase power to meet their obligations through the market with no ability to pass through the entire cost to their buyers/customers.

- Adjustment for imported resources/supplies:
  - In a given period, the total supply available in the market would include the amount of imports up to the interties' available transfer capacities.
  - If *Supplier i* has import offer bids, the total import bids should be included in *Supplier i*'s total supply.
- Adjustment for exports:
  - If the market allows participants to purchase from the market for exports, the total demand (in the denominator) should include the amount of exports.
- Adjustment for certain suppliers' must-run resources.

[2] Because a supplier is pivotal does not necessarily result in an incentive to exercise market power. For example, if the supplier would need to withhold 90 % of its capacity, it would be difficult for increased profits on the remaining 10% to make up for the losses on the withheld 90 percent.

- Certain suppliers may be exempt from the test if their entire portfolios consist solely of must-run resources such as wind, solar, or run-of-river hydro. Such an exemption would not be applied to suppliers that own or control dispatchable resources. Although a supplier typically cannot withhold the output of the must-run resources, the supplier with dispatchable resources has the ability and potentially an incentive to withhold the controllable resources in the portfolio to raise prices if the must-run resources' revenues depend on the market prices.

Equation [2]

Equation [2] presents these proposed adjustments to Equation [1] and may serve as an approach for Alberta to consider:

$$RSI_{it} = \frac{\sum_{j=1}^{n} Supply_{jt} + Imp_t - (Supply_{it} + Imp_{it} - Obligation_{it})}{Total\ Market\ Demand_t + Export_t + \ Reserves_t}$$

Conduct-Impact Test

A Conduct-Impact Test assesses a seller's specific conduct and its associated impact on market prices. The conduct in question includes bidding above cost (economic withholding) or engaging in physical withholding of output, and other anomalous bidding behavior. A Conduct-Impact test can be used to trigger bid mitigation if bids and their market price impacts exceed certain thresholds. The test is applied after bids (offer prices) are submitted to the AESO, but before the actual market-clearing price is determined. When applied, bids will be mitigated to reference cost levels before market prices are determined whenever both bid offers and associated market price impacts exceed the set thresholds.

The Conduct-Impact Test is a two-part test. The first part, the Conduct test, identifies bids that are deemed to signal a seller's anti-competitive behavior. A supplier's bids would be compared to a competitive Reference Cost level. The Impact analysis would be triggered only if suppliers' offers are above the Reference level by more than a defined threshold, which can be in the form of dollars or percentage of cost-based reference level. If the offers are below this level (the "No Look Threshold"), there would be no subsequent investigation via the Impact test. But if suppliers' bid offers are above the Reference Cost level, their bids' impacts on market prices will be evaluated in the second part of the test, the Impact Test.

The Impact test quantifies the likely impact of the identified bids on the market-clearing price. Only when the identified bids increase market prices by more than the impact threshold (relative to bids that would have been submitted at the reference level), would the action fail the Impact test and trigger mitigation. The process compares the market-clearing price with the supplier's initial (failed) bid, to the price of a simulated "competitive" scenario in which the supplier's failed bids are adjusted to the Reference level. The scenario with the mitigated bid is simulated by assuming that the supplier would have submitted its bids at the competitive reference level.

Like the Conduct test, there would be a "no look" threshold for the Impact test. Such a threshold is predefined as the magnitude of the adverse price impact, in dollars or percentage of a market-clearing price, which would be tolerated.

Mitigation levels under the Conduct-Impact tests need to consider short- and long-term impacts. Because suppliers to the Alberta's energy market participate with a "one-part bid," a seller's offer is expected to cover both their marginal operating costs and commitment costs over the period of the plant's generating hours. For example, if a natural gas combined-cycle (CC) plant, once turned on, expects to operate for at least eight hours before having to shut down again, the supplier would consider the costs associated with starting up the plant, operating it at no-load levels, its minimum generating level, and the other costs the facility might incur by being dispatched for eight hours—in addition to its marginal operating costs per MWh of power generation—and include those costs in its bid offer prices.[3]

Brattle conducted a historic analysis of costs per asset based on operations over the period of 2012-2016. This analysis concludes that, historically approximately 2x base marginal costs by fuel type appear a reasonable threshold to recover historic costs based on the assumptions in the calculations. In anticipation of increased ramping and cycling of assets in the future (as summarized in the NDV studies), the proposed threshold of 3x allow a mitigated market participant to address historic costs while accounting for increased cycling costs should the asset be dispatched off. Relevant excerpts from the Brattle analysis are included below, and will be discussed with the working group.

Excerpts from Brattle paper:

The Conduct test threshold needs to consider the relevant costs faced by the supplier. Because suppliers to the AESO's energy market participate with "one-part" offers, market prices need to cover a generating resource's start-up, shutdown, and no-load costs, in addition to its marginal operating costs. For example, if a natural gas combined-cycle (CC) plant, once turned on, expects to operate only for several hours before having to shut down again, the supplier would only be willing to start up the plant if the expected market-clearing prices over the dispatch hours would be sufficiently high to cover the costs of starting up the plant and operating it at various output levels during this period.[4]

Table 1 below shows that—based on the historic (2012-2016) cost profile and minimum operating hours—once a typical CC or a coal plant is turned on, the average per MWh costs of both CC and coal plants exceed their marginal operating costs by up to 1.5 times. The ratios of average per MWh costs to marginal costs of typical Coal and CT plants also are shown in Column [10] of Table 1.[5] Since a thermal plant's commitment cost can vary according to the plant's temperature status at its start time, the longer a plant has been in a shutdown condition, the more fuel it needs to burn to bring its plant to an operating temperature requirement. To cover a broad range of start-up costs, this analysis includes two levels of start-up conditions—one with significantly higher start-up cost (with Cold Start) and another for Coal plants with higher heat rate to start than the other (with High Commitment Cost). While a CT typically has low start-up costs,[6] their dispatch period tends to be quite short. Assuming that a CT may be started up to serve only 30 minutes of peak load per cycle, a CT's average cost is about 2.7 times its marginal costs.

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[3] In jurisdictions where supplier bids are multi-parts, the supplier can explicitly submit information about its start-up costs, no-load costs, minimum run time, and minimum down time and allow the unit-commitment process to optimize these costs across competing resources.

[4] In jurisdictions where supplier offers are multi-parts, the supplier submits separate information about unit characteristics—such as start-up costs, no-load costs, minimum run-time, and minimum down time—and allows the system-operator's unit-commitment process to optimize and compensate these costs across competing resources.

[5] The current calculations use generic CC and coal plant characteristics data from the AESO database and public sources. The coal plant with "High Commitment Costs" is based on the characteristics of the AESO coal unit with the highest start-up cost and no load cost with the heat rate of 15,137 kilojoules/kWh. The AESO database does not have a fixed start-up cost for a CC and coal unit. We therefore assume the cost for typical hot starts for CC and coal units to be CAD$49/MW/Cycle and CAD$81/MW/Cycle. The cost is based on converting the median costs of US$39/MW and US$65, obtained from *Power Plant Cycling Costs*, NREL (2012), to the Canadian dollars using the exchange rate of US$1=CAD$1.26. The NREL data are based on the lower bound of estimates. See Appendix B for more details.

[6] We assume that a typical CT's cold start-up cost is CAD$18/MW/Cycle. See Appendix B for the sources and calculations.

Table 1
Comparison of Estimated Commitment Costs and Marginal Costs of Proxy Combined Cycle and Coal-Fired Power Plants in Alberta

Plant Type	Start-up Cost ($/cycle)	Shut Down Cost ($/cycle)	No Load Cost $/cycle)	Total Commit-ment Cost ($/cycle)	Marginal Cost ($/MWh)	Output @ Full Load (MW)	Average Incremental Output (MW)	Assumed Run Time @ Full Output	Total Cost ($/cycle)	Average Cost ($/MWh)	Ratio of Avg. Cost to Marginal Cost
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
CC (with Hot Start)	$9,160	$2,062	$25,981	$37,202	$17.28	400	240	9	$73,152	$21.10	1.2.
CC (with Cold Start)	$25,808	$2,062	$25,981	$53,851	$17.28	400	240	9	$89,800	$25.90	1.5
Coal (with Hot Start)	$14,688	$2,707	$319,896	$1,616,875	$15.92	400	240	600	$3,909,248	$16.58	1.0
Coal (with High Commitment Cost)	$39,708	$2,707	$512,581	$2,562,907	$15.92	400	186	600	$4,381,911	$18.96	1.1
CT	$2,146	-	-	2,146	$24.88	100	100	0.5	3,389	$67.79	2.7

Sources and Notes: [1]: Calculated based on average fuel cost plus other start-up costs. The data were obtained from the AESO and NREL (2012). [2] Calculated based on Brattle assumptions. [3] Calculated based on (commitment hours) x (marginal cost) x (minimum MW) required for a unit's operation, which is assumed to be approximately 40 % of the unit's full capacity or the difference between [6] and [7]. The commitment hours for coal and CC units are 600 hours and 9 hours, respectively. [8]: Assumed run time at full output based on economic dispatch. [9]: [4]+([5]x[7]x[8]). [10]: [9]/[6]. [11]: [10]/[5]. All $ are Canadian dollars. See Appendix B for full sources.

Going forward, the average operating costs per cycle may increase relative to the levels shown in Table 1. As variable resources are added to the AESO system, the thermal units would likely be committed less and cycle more. This would increase the ratios of average costs to marginal costs.[7] In addition, since we do not have the actual commitment costs for certain plants in Alberta, we recognize that actual amount of start-up, shut-down, and no-load costs for plants may deviate from these estimates. For example, if a CC has a much higher start-up cost than shown in Table 1, the resulting ratio of the average operating cost per cycle could be higher as well.[8] Given the results in Table 1 and these additional considerations, setting the Conduct test's safe-harbor threshold at 300 per cent above resources' marginal costs would appear to be reasonable. If costs change, the AESO can re-evaluate these comparisons and reassess the range of the tolerance thresholds.

[7] For example, if we assume that the CC unit would only run at its full output for only 6 hours instead of 9 hours, the ratio of the CC with Cold Start would increase closer to 2. Similarly, if we assume that the coal unit would be used for cycling more than providing energy, the ratio of its average cost to marginal cost could increase significantly.

[8] The start-up cost data we obtained from NREL (2012) are also based on the lower bound cost estimates.

Table 2 below summarizes the advantages and disadvantages of the RSI Screen and the Conduct-Impact test.

Table 2
Advantages and Disadvantages of Structural and Conduct-Impact Screens

Type of Tests	Advantages	Disadvantages
RSI Screen	• Can be used to identify conditions under which market power concerns are the greatest. • Avoids having to set bid-level and price-impact thresholds that trigger mitigation, which could lead to mitigation errors.	• Does not directly detect whether market power has been exercised. • Suppliers may not be able to control the conditions under which mitigation would be implemented. • As a bright line standard, it may fail to mitigate exercises of market power that may arise even when a supplier is not pivotal.
Conduct-Impact Test	• Explicitly identifies bid and price-impact thresholds that exceed the stated tolerance levels of policy makers. • Suppliers can directly control their bids based on transparent thresholds. • Can be implemented in a way to test the price impact of multiples suppliers' bids' jointly	• The market monitor must determine the "correct" tolerance threshold for both bid levels and the price impact of the bidding behavior. • Relies on either an assumed or actually observed cost for each resource. • Concerns exist that suppliers can "game the system" by keeping their exercises of market power just below the mitigation threshold.

Risks and Mitigations:

With a new *ex ante* market power mitigation approach, the AESO and industry are interested in ensuring that the industry will be able to set prices that reflect that market conditions. The concerns are as follows:

- Over-mitigation.
  - Over-mitigation has the potential to dampen the Energy and Ancillary Services market price signals and result in a sub-optimal generation fleet mix and real-time operational behaviour from both supply and demand side market participants.
- Under-mitigation.
  - Under-mitigation would result in prices set by an exercise of market power and means that consumers are paying more than is necessary.

The proposal strikes a balance both in implementation practicality and in ensuring that market power is mitigated. The proposal is based on historic cost assessments and expected prices when the market is at a competitive level. The approach may be adjusted if further issues are identified in the market.

Input from Working Group Members and Industry Stakeholders Through SAM 3.0:

The EAS working group recommendation supported an *ex ante* process to evaluate market power with varying degrees of support (7 members agreed, 4 members agreed with reservations and 5 objected).

- Reservations to this recommendation were based on:
  - Not understanding the position of the MSA.
  - If being bid mitigated, there needs to be reasonable opportunity for scarcity (and shortfall) pricing to be realized.
- Objections were based on the following concerns:

- Concerns that the market will be over mitigated.
- Participants require a price signal and volatility, and therefore, would prefer a market based solution without mitigation.
- There is a need to incent flexible generation.

- The EAS working group voted on pre-defined screens and mitigation to a multiple of short-run marginal cost by fuel type based on the assumption that *ex ante* process would be recommended by the AESO.
  - The working group was supportive of using an RSI screen, with an hourly conduct and impact model.
    - Reservations to this recommendation were based on:
      - Any bid mitigation mechanism put in place, needs to support appropriate price signals.
      - One member disagreed with any form of screen, but was more supportive of a conduct and impact test.
      - Initial modeling results from Brattle did not include carbon tax implications, and would like to better understand the implications of carbon tax on the analysis completed.
  - The EAS working group recommendation was supportive of bid mitigation to a multiple of short-run marginal cost by fuel type with varying degrees of support (5 members agreed, 5 agreed with reservations, and 6 members objected).
    - Reservations to this recommendation were based on:
      - Dependent on what the cap value is, and the approach that is used to calculate and determine the value of short-run marginal cost.
      - Wanted to better understand the implications if Natural Gas is trading negative (i.e., what is the floor?).
    - Objections to the recommendation were based on:
      - Objecting to mitigating by fuel type, and would propose using a process that selects one reference technology (e.g. SCGT) and some multiplier of that reference technology (e.g. 2x – 3x).
      - Concerns that administering by fuel type could be burdensome on the AESO.

- Industry feedback on SAM 3.0 was consistent with the commentary provided by the working group.
  - Many participants expressed that the energy market should not be over mitigated and must allow for a high-fidelity price signal, including a scarcity and shortage pricing mechanism during periods of tight-supply.
  - The energy market should not be over mitigated reducing its efficiency, and the value should be maintained in the energy market, and not driven into the capacity market.
  - There was general support for using an *ex ante* market power mitigation process with an RSI screen, and a Conduct and Impact test.
  - Industry participants should only be mitigated if they fail the screen and the Conduct and Impact Test (i.e., those that both have, and have exercised market power are mitigated).
  - Bid mitigation should not be set strictly at short-run marginal cost, and a multiplier like 300% of the reference technology is more appropriate. Those participants that supported a narrower band (e.g. 1.2X) would want the calculation of short-run marginal cost to include variable operating and maintenance costs, startup costs, operating risks, and other opportunity costs.
  - Industry participants that were not supportive to an *ex ante* process, believe the current pricing framework, in conjunction with a must-offer requirement has proven to be successful, ensuring price fidelity and incenting appropriate new investment.
  - Differing perspectives from industry stakeholders on whether portfolio bidding should be permitted to continue.

Rationale for Deviation from SAM 3.0 Position:

- The AESO proposal is based on the ongoing assessment of the mitigation options, input from working group members and practical application.
- The use of the hourly RSI model instead of a Conduct and Impact Test is due to a practical implementation and it is expected that market participants can be self-disciplined by the competitive levels when capacity resources are committed to offer into the energy and ancillary services market in addition to non-committed capacity resources in the market. The AESO's proposal allows the market to compete while identifying and limiting the potential for larger, pivotal suppliers to exercise their market power and raise the pool prices.
- Setting the RSI at 0.9 was discussed in the working group. This level will continue to be monitored and may be adjusted as required for over or under mitigation.
- Setting the mitigation level at 300% of the resources' variable cost is supported by the Brattle analysis that 300% is sufficiently high for most resources to cover their operating costs based on historic data and expected increases to cycling costs.
- Further rule development is required to set a standard for suppliers' submission of actual operating and opportunity costs such that when necessary, suppliers have the ability to demonstrate that their costs are higher than the ones that that AESO estimates.

10.3 Pricing Model

Pricing Model Summary:

- No change to offer or price cap
- No change to price floor
- Administrative shortage pricing will remain at $1000.

Rationale:

- The suppliers offer prices in the energy market are bounded by the price cap and floor. The price cap does not appear to be limiting especially given pending changes to bid mitigation; however, a pricing signal may be of value to clear surpluses in the energy market. The cap and floor need to be wide enough to allow scarcity pricing to occur.
- The price signals in the energy and ancillary services markets will serve to provide incentives for flexible operational behavior (for dispatch, and operational reliability needs), and incent an economically efficient level of investment in flexible resources especially in combination with potential changes to the dispatch and settlement models (SCED and shorter settlement))
  - Depending on the type, and level of offer mitigation, and the degree of in-market scarcity pricing resultant from mitigation, additional administrative shortage pricing may need to be considered to enable an effective price signal. The AESO understands the value associated with shortage pricing but has determined that it is not required at this time
  - As the frequency and impact of supply surplus increases, negative pricing may assist in addressing supply surplus. This enables a market-based approach to address surplus rather than the current administrative curtailment mechanism. However, given the additional risks identified in a negative pricing model and in concert with increasing renewables on the system with competing pricing incentives, the negative pricing model will not be considered at this time.

Administrative Shortage Pricing

- Administrative shortage pricing provides a mechanism for increasing EAS market prices above offered prices during times of supply shortage—typically measured by release, or depletion, of operating reserves. The purpose of adminstrative shortage pricing is to enhance market price signals for response to these events and to provide an enhanced investment signal for quick-start and fast-ramping resources (such as peakers and demand response) both designed to avoid loss of load while capacity is tight in the energy market. Administrative shortage pricing has been adopted by many independent system operators with centralized wholesale markets. In our discussions, it should be noted that administrative shortage pricing is separate from scarcity pricing which can occur within the market when offer prices are higher than resources' actual short-term marginal costs.

Considerations in design of administrative shortage pricing:

- There may be little or no regulatory tolerance for energy and ancillary services prices above $1,000/MWh. Price tolerances like this are not uncommon in other jurisdictions.
- Shortage pricing will be activated infrequently (0–50 hours per year, depending on planning and operating reserve levels),
- The magnitude and frequency of shortage pricing (when it is triggered and what price it is triggered to) is dependent on market design objectives across all markets (Energy, Ancillary Service and Capacity). Capturing an effective price signal for flexible investment and operational behavior will be accomplished through mechanisms in all three markets.
- Shortage pricing levels and maximum price levels ($/MWh)—

  the entire price signal (from all markets, not just energy and ancillary services) in the worst shortage conditions when involuntary load-shedding occurs should theoretically reflect cost of that load-shedding: value of lost load, or VOLL.

Negative Pricing

The AESO currently employs an administrative mechanism to address supply surplus. Upon reaching $0/MWh in the energy market merit order, the AESO first curtails import assets, then $0 flexible blocks, including renewables, then $0 non-flexible blocks, and finally curtailing generation offline. Negative pricing is widely considered an improved alternative to manage congestion and over-generation that improves market efficiency and liquidity, particularly with increasing variable energy production. However, other jurisdictions may be encountering issues with negative pricing, where subsidized resource offers may be capable of offering even below inflexible generation. As noted in various forms by PJM and the US DOE in 2017, as well as the creation of resource specific offer floors by the IESO, there may be potential concerns on the impact of subsidies distorting market outcomes and eroding revenue streams.

Further Considerations and Risks for Implementing Negative Pricing:

- **Setting the Price Floor**: A negative price floor may simply move the high level of equal price offers to a new floor thus moving the supply surplus issue to a new price. The price floor must be set low enough to promote additional depth in the merit order.
- **Products Indexed to Pool Price:** Active operating reserves are indexed to pool price and currently cannot go below $0/MWh. However, the real power provided for a product (e.g. regulating reserve) during negative pricing would incur a cost to the provider. Requires consideration on whether they are isolated from the effect.
- **Importers**: If importers continue to submit $0 offers and are not eligible to set pool price, there may be an issue with negative pricing.
- **System Changes:** Scope of changes to ETS, DT and settlement processes to be assessed.
- **Impact on Transmission Constraint Management (TCM):** TCM may require adjustments to accommodate negative pricing; further assessment required.
- **Dispatch:** Would need to align with current or potential SCED dispatch algorithm.

Input from Working Group Members and Industry Stakeholders Through SAM 3.0:

- The EAS working group members recommendation was supportive of introducing a shortage pricing mechanism. Support for this was driven by the assumption that the market would have an *ex ante* bid mitigation process and the price cap was to remain unchanged.
  - Reservations to this l recommendation were based on:
    - A shortage pricing mechanism is appropriate, but not as a tradeoff for a stringent mitigation model.
    - Shortage pricing may not be politically acceptable, or supportive from a consumer point of view.
  - Note: No working group members objected to this provisional recommendation.
- The EAS working group members recommendation was that that no change is required to the price cap, assuming an administrative shortage pricing mechanism is introduced.
  - Objections to this recommendation were based on:
    - Supportive if settlement remains at one hour, but if it went to a 15-minute settlement period this should be further investigated.
    - Belief that additional analysis is required to explore the price cap value as it has not been reviewed since it was established.
- The EAS working group members recommendation was supportive of further evaluating negative pricing to address supply surplus.
  - Reservations to this l recommendation were based on:
    - Need to be further explored and understand the implications on co-gen assets.
    - Dependent on market structure for clean energy attributes.
  - Working group members that were not supportive of the recommendation raised the following concerns:
    - There are other higher priority items to explore than changing the price floor as there are other ways to deal with supply surplus.
- Industry feedback on SAM 3.0 was consistent with the commentary provided by the.
  - There was broad support for the introduction of both a scarcity and shortage pricing mechanism and leaving value in the Energy market to create real-time incentives for flexible resources.
  - Introduction of scarcity and shortage pricing mechanisms is favorable with a shorter pricing interval.
  - The impacts of a bid mitigation model need to be carefully evaluated, so that they do not negatively impact price and investment signals.

Rationale for Deviation from SAM 3.0 Position:

- While the AESO as part of the working group considered changes to the pricing methodology, at this time it was proposed that no changes are required so these items would be considered as a separate item in another consultation as required. These items are not a priority and would need to be carefully considered prior to implementation, so they are set aside for now.

10.4 Out of scope items

Summary:

The AESO has determined that the following design changes will not be included as part of the capacity market design, but may be considered as part of a separate evaluation in the future:

- Locational marginal pricing
- Offer cap above $999.99
- Negative pricing
- Administrative shortage pricing

- Security constrained unit commitment (SCUC)
- Dynamic I-intertie scheduling
- Co-optimization of EAS (will be evaluated as part of SCED)
- Day-ahead market (DAM)

Rationale:

- Locational Marginal Pricing – With the current policy related to unconstrained and recent system build out, pricing on transmission grid is not required at this time.
- Offer cap above $999.99 --

  The current offer cap is effectively non binding and will increasingly not be an issue with the introduction of the capacity market. While the majority of revenues will be expected to remain in the EAS markets, the offer cap consultation is not a priority at this time.
- Negative pricing – The supply surplus events are currently cleared administratively and few issues have resulted. The introduction of negative pricing comes with some issues as well and will be reviewed as warranted. Requires futher review to implement. However, the AESO does not consider negative pricing to be a priority at this time.
- Administrative Shortage Pricing --

  Supply shortfall events are also managed administratively and with few issues arising. Further, it is anticipated that with the introduction of a capacity market, the frequency of shortage events will be lessened. However, this concept may befurther reviewed as required to incent price responsive behaviour near shortages but is not a priority at this time.

  Security Constrained Unit commitment --

Centralized unit commitment will be evaluated in the future if reliability issues develop from increased frequency of supply surplus events or as part of an integrated solution like time ahead market . A self commitment model maintains the risk with generators and provides incentive for flexible resources.

- Dynamic Intertie scheduling — Moving to a priced intertie model with real-time scheduling addresses the issues in the market today without excessive system changes. A dynamic model is complex and not a priority at this time.
- Co-optimization of EAS --

  On its own, shows marginal benefits which are likely less than the implementation costs to do so. However, may be considered as part of pending SCED evaluation.
- Day-ahead Market (DAM) --

  The value of a DAM is heightened if concerns about market power are not mitigated or if the market values moving to a SCUC model are required to manage reliability risk. As a separate design element, the DAM effectively acts as a financial trading model, which most participants can handle independently outside of the market and accordingly this design element has been taken out of scope at present.

  In other jurisdictions, particularly those with larger markets, the BDAM has been implemented as part of a larger market including SCUC, SCED, cooptimization and in order to establish net settlement positions as part of market power mitigation . Given that the concept of BDAM has previously been been raised by industry two times before and each time rejected each time, the AESO through this working group process intended to evaluated each element of a full BDAM separately and develop conclusions based on its modelling efforts. As noted in the conclusions of this modelling analysis, which were presented to the working group, and as summarized in this rationale paper:

  1. The centralized unit commitment model (SCUC) does not show increased in production efficiency and as it would result in shifting the risk from a generator to the AESO (and charged to loads), this signal was viewed to be counter-intuiative to pricing and valuing flexibility in the market to handle additional future system variability;

2. Market power mitigation is being addressed through *ex ante* RSI screens as indicated above and a mitigation level in addition to continued *ex post* monitoring and accordingly the creation of an imbalance market (net settlement) is not required;

3. Given the current indexed model for AS, partial optimization is occurring. Modelling for cooptimization of EAS is showing small incremental value in converting to a co-optimized model, likely less than the systems change required. However this element will further be considered with SCED; and

4. SCED is under consideration as an alternative to addressing current and future variability but is best incorporated as a look ahead or five minute dispatch format. .

Input from Working Group Members and Industry Stakeholders Through SAM 3.0:

The EAS working group and industry provided feedback on some of the items that were not included as part of the capacity market rule package. Presented below is a summary of that feedback:

- Security Constrained Unit Commitment (SCUC):
  - EAS working group feedback: The majority of working group members voted that self-commitment can continue.
    - Reservations to this provisional recommendation were based on the belief that self-commitment can continue in the short-term, but going forward in the long-term other unit commitment models should be investigated.
    - Objections to this provisional recommendation were based on the belief that there is a cost that comes with self-commitment, and it is in everyone's best interest for efficient unit commitment decisions to be made. There are also secondary benefits of unit commitment for generators as there will be lower cycling with larger units. In addition, if we continue with self-commitment, the AESO should improve forward market information to make informed unit commitment decisions.
  - Industry feedback on SAM 3.0:
    - The majority of industry participants support the continued use of self-commitment in the Energy market.
    - There is a belief that moving away from self-commitment would subsidize less flexible generation, causing increased costs to consumers. The benefit of potential of SCUC should be balanced against reduced incentives for operational flexibility and ramp.
    - Maintaining self-commitment will help ensure timely, simple, and straightforward initial implementation and will minimize changes to EAS markets and the risk of regulatory delay.
    - There are industry participants while are supportive of self-commitment in the short-term, believe it would be valuable for the AESO to further explore centralized commitment models for changes in the long-term, and inclusion in the Energy and AS roadmap.
    - Those that oppose self-commitment and are supportive of the further exploration of a central commitment model believe that it may prove to be more efficient in the long-term. In addition, there is a cost with self-commitment, as sub-optimal commitment decisions may be made by participants with less than full information of future market conditions. Without centralized commitment, it may result in higher and more volatile costs to consumers.
- Co-optimization of EAS Markets:
  - EAS working group Feedback: The majority of EAS working group members voted that the current AS market (sequential model) can continue, and there is no need for co-optimization of EAS markets.
  - Two working group members objected to this recommendation and believe that the AS market is an antiquated design. Co-optimization will facilitate the effective integration of Energy and AS.
- Industry Feedback on SAM 3.0:

  - Some industry participants do not believe that further consideration of co-optimization is required given the initial study results by the AESO on net demand variability. These participants indicate that no additional time should be spent on this topic given the volume and importance of other work.
  - There are participants that believe that additional investigation should be spent on the co-optimization of EAS.
- Time Ahead Market (i.e. BDAM):
  - EAS working group Feedback: The working group was unwilling to vote on further investigation of a time ahead market. There was support from six members for further investigation and exploration of a time ahead market.
  - Industry Feedback on SAM 3.0:
    - Similar to comments on changing to a centralized commitment model, that the benefit of a time ahead market should be balanced against reduced incentives for operational flexibility and ramp.
    - Participants that are also not supportive of further investigation a time ahead market, believe that it would impose unneeded complexity, with minimal or no recognized long-term efficiency benefits. Belief that a time ahead market, particularly with cost guarantees, does not support inventive to build more flexible generation.
    - The exploration and development of a recommendation to move to a time ahead market, requires a broader consultation process and to allow industry to participate given the complexity of this topic.
    - There are participants that believe that additional investigation should be spent exploring time ahead market models.
    - Some participants that are supportive of additional investigation of a time ahead market, believe it would be valuable for the AESO to further and inclusion in the EAS roadmap.
- Ramp Product:
  - The EAS working group was equally divided on whether a ramp product was required at this time.
    - Working group members that agreed, or agreed with reservations, that a ramp product was not required at this time. This was based on the initial results from the NDV study, and it was viewed that additional rule changes could help incent flexibility.
    - Working group members that were supportive of the introduction of a ramp product believed that generators with that capability, should be compensated for the capability. This also allows generators to select and participate with resources that are best suited to meet the defined ramp requirement. In addition, there is a view that the AESO should pay for the attributes that it requires (i.e., reliance on over-dispatching the EMMO ; impacts the fidelity of the price signal).

- Industry Feedback on SAM 3.0:
  - There are some participants that believe that given that changes to the fleet and introduction of more variability, that the AESO may require additional ancillary services market products to address the need for flexibility.
  - Appropriate product differentiation in the AS market will help ensure that the function and purpose of each electricity product is maintained.
  - Early adoption of a ramping product is warranted given the level of new variable generation contemplated in Alberta's Climate Leadership Plan.
  - There are some industry participants that believe a shorter settlement period (e.g. 5 minutes) would be more valuable to investigate, than an AS ramp product.

10.5 EAS changes Assessed Ggainst the Capacity Market Design Criteria

The proposed design includes modifications to the EAS markets that are simple and straightforward for the initial implementation. As part of the roadmap discussions, the EAS team will consider limiting the initial degree of change to the current EAS market to only those modifications necessary to help ensure the capacity market opens in 2019 for start of first capacity procurement, and minimize the risk of regulatory delay and need for re-design. Some projects have already been indicated as out of scope to manage the delivery and to respond to market needs.

In an ongoing effort to ensure our Alberta's markets are fair, efficient, and openly competitive, a staged implementation of enhancements to meet growing system flexibility needs (possibilty in stages), and to enable new technologies to compete will be pursued. These efforts will be provided in a roadmap highlighting the expected timing and nature of these future changes before the first capacity procurement. Provision of a roadmap also meets the criteria of providing the expected timing and nature of future changes before opening the first procurement.