ALBERTA UTILITIES COMMISSION

Application by the Alberta Electric System Operator for Approval of the
First Set of ISO Rules to Establish and Operate the Capacity Market,
Proceeding 23757, Application 23757-A001

MARKET DESIGN ISSUES IN THE ALBERTA CAPACITY AND ENERGY MARKETS

Panel

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February 28, 2019

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ACKNOWLEDGEMENT

This evidence was produced by the undersigned panel members. The panel members attest that they will provide independent, unbiased, professional opinions that are fair, objective, and non-partisan. This report was prepared with the assistance of Dr. Adonis Yatchew.[1]

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I. Introduction

A. Report Objective and Structure

We have been asked by the Market Surveillance Administrator ("MSA") to provide expert advice on the transition to a capacity market, including "interactions between capacity markets, energy markets, and ancillary services markets" and "experience and expertise from capacity markets in other jurisdictions."[2] This report constitutes our assessment of potential areas for improvement of the energy and capacity market rules proposed by the AESO and filed on January 31. In particular, we have been asked to consider the following areas of the AESO's proposed rules:

- ISO rule 206.7 (Capacity Market Mitigation)
- ISO rule 203.5 (Energy Market Mitigation)
- ISO rules 207.1 (Resource Adequacy), 207.2 (Gross Minimum Procurement Volume), 207.3 (Calculation of Net-CONE), and 207.4 (Shape of Demand Curve)

The MSA posed the following specific questions:

- To what extent do market design elements and parameters differ between the AESO's proposal and existing US RTO markets?
- Are there any adverse impacts on energy or capacity prices that might result from the proposed ISO rules compared to practices in U.S. capacity markets?
- Are there alternatives to the rules proposed by the AESO that you would recommend?
- If so, why are the alternatives superior to those proposed by the AESO?

In response to these questions, we have identified elements of the proposed capacity market rules that raise particular concerns. This report is structured around these market design elements, with one section for each element. Each section is structured as follows:

1. Description of the AESO's proposal, in relevant part.
2. Summary of the AESO's rationale for its proposal, including any material provided in the Application or in documents accompanying the Application.
3. Comparison to design elements and parameters in existing U.S. RTO markets with a centralized capacity market (i.e., PJM, ISO-NE, and NYISO).
4. Discussion of the AESO's proposed rules in the context of our analysis and the U.S. RTO experience.
5. Proposed alternative rules.
6. Discussion of impact of proposed alternatives, including required conforming changes.

2 Letter from Government of Alberta to the MSA, March 27, 2017.

B. Overall Assessment, Conclusions, and Summary of Recommendations

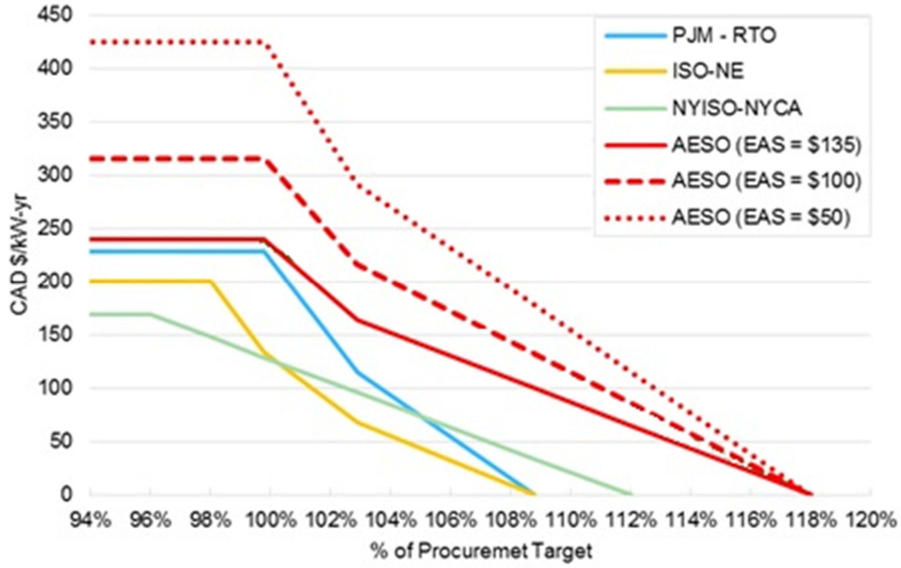
Designing a new capacity market is a massive undertaking. The AESO's proposed capacity market rules, and proposed revisions to its existing energy market, contain all of the high level elements necessary to implement a capacity market. Our assessment, however, is that the AESO's proposal will:

- fail to effectively mitigate the exercise of market power in both the energy and capacity markets;
- lead to volatility and uncertainty in both the energy and capacity markets;
- fail to facilitate efficient investment, retirement, and repowering decisions by its market participants;
- likely cause Alberta to maintain a capacity margin that is substantially higher than needed to satisfy its reliability needs; and
- ultimately lead to inefficiently high price outcomes in both the energy and capacity markets.

Customers will ultimately bear costs that are greater than necessary to competitively achieve the target level of resource adequacy.

The AESO has proposed a set of capacity market rules we expect will systematically lead to prices that are higher than necessary to achieve the target level of reliability. This outcome stems from a series of design choices, each of which, intentionally or not, will have the effect of raising prices. The capacity market power mitigation rules do not effectively constrain the ability of large suppliers to economically withhold capacity and raise prices above competitive levels. This will not only lead to high costs to consumers but will also dampen price signals that facilitate efficient retirement. The provisions related to adjusting net-CONE, as well as the choice of reference technology, appear to consistently bias capacity price outcomes upwards. The proposed E&AS offset is likely a poor predictor of actual energy market outcomes and threatens to significantly increase volatility in the capacity market, thus reducing the quality of the long-term price signal. The aggregate result of some of these design decisions can be observed in Figure 1, which shows the Alberta demand curve compared to other demand curves in US RTO markets.

Figure 1: Demand Curve Comparison, Market-wide Curves Only



It is clear from this figure that the parameters proposed by AESO will likely result in the prices and revenues that are higher at every level of capacity than the market-wide capacity demand curves in New York, New England, or PJM. This is attributable to the proposed choice of the reference technology, the proposed slope of the demand curve, and the position of the demand curve The position of the curve is defined by the amount of excess capacity above the procurement target on the x-axis) that corresponds to the net CONE price on the y axis. This report discusses the shortcomings of the AESO proposal in each of these areas.

Concurrent to implementation of the capacity market, the AESO has rightfully proposed changes to its energy market. These rules reflect the new role of the energy market as a tool for static efficiency. The energy market is no longer the sole mechanism for achieving dynamic efficiency.[3] Consistent with this purpose of the energy market under this alternative electricity market paradigm, the AESO has devised a set of market power mitigation rules for the energy market. While the intention is correct, the specific proposed mitigation rules are not well supported by theory or evidence, nor are they sufficient to effectively mitigate the exercise of market power to the degree necessary to achieve competitive, efficient prices. The proposed mitigation rules are inconsistent with practices in US RTOs. Furthermore, they highlight the challenges inherent in achieving efficient outcomes while declining to implement best practices in energy markets (see section II.B).

In this report, we lay out in detail how certain elements of the AESO's proposal will result in prices that are inefficient and non-competitive, ultimately leading to

3 By design, energy market prices in the new paradigm should be expected to be lower than historically observed in Alberta, and inadequate to support the all in costs of generation investment. This creates the need for the capacity market. If the energy market produces sufficient revenue to cover all-in annualized costs, there is no need for a price greater than $0 / kw-year in the capacity market.

unreasonably high costs for consumers. We then recommend a series of alternatives that the AUC may require of the AESO to remedy shortcomings in the proposed rules. Individually, each of our proposed recommendations will improve the efficiency and competitiveness of the Alberta electricity market. Our recommendations need not all be adopted in order to have the intended positive effect, nor are they all completely interdependent, but they are mutually reinforcing. Adopting the full set is the course of action that we recommend. A summary of our recommendations can be found in Table 1, all of which are consistent with practices in US markets.

Table 1: Summary of Findings and Recommendations

Market Design Element	Consistent w/ US Markets?	Adverse Impacts	Recommended Alternative
Market Power Mitigation in Capacity Market	No	Fails to constrain economic withholding. Likely to lead to inefficiently high prices, high costs to consumers, over-procurement of capacity. Dampens price signals for retirement.	Mitigate capacity offer prices of mitigated resources to the price of the expected marginal offer to sell capacity. Allow asset-specific showings for demonstrated net avoidable going forward cost in excess of revised, recommended default cap.
Treatment of Delisting in Capacity Market	No	Fails to constrain physical withholding by early uneconomic retirement of capacity supply. Likely to lead to inefficiently high prices, high costs to consumers.	Create requirement that resources must submit economic delist offers in capacity market. Screen and mitigate delist offers consistent with requirements for non-delisting market participants.
Market Power Mitigation in Energy Market	No	Fails to constrain economic withholding. Likely to lead to productive and allocative inefficiency, high costs to consumers. Increases volatility and uncertainty.	Mitigate energy market offer prices of mitigated resources to SRMC plus a fixed adder ($25/MWh) regardless of supply cushion. Implement an operating reserves demand curve. Create start-up cost recovery guarantee for resources expected to operate for short periods. Allocate costs via uplift.
Calculation of Energy and Ancillary Services Offset	No	Inaccurate owing to forward markets that are illiquid and historically poor predictors. Dependent on arbitrary sample date. Increases volatility and uncertainty.	Employ forward-looking, simulation-based E&AS offset calculation, at least for first several capacity market auctions. Revisit appropriateness of forward- vs. backward-looking methodology once historical data is available in new market paradigm.
Selection of Reference Technology	No	Not based on least cost resource to provide incremental capacity needs. Will likely drive unjustifiably high capacity cost to consumers.	Revisit selection of reference technology once E&AS methodology and energy market power mitigation rules finalized, but before first auction. Selection should be based on least-cost resource for fulfilling incremental capacity need, accounting for regulatory constraints.
Calculation of Adjusted net-CONE	Adjustment – Yes Update - No	Not updated to reflect market conditions. Will likely drive unjustifiably high capacity cost to consumers.	Update performance factor, used to calculate adjusted net-CONE, on an annual basis. Use rolling average of three historical performance factors to calculate adjusted net-CONE ahead of each capacity auction.
Shape of Demand Curve	Shape – Yes Parameters – No	Likely to sustain capacity levels well above minimum capacity requirements. Will likely drive unjustifiably high capacity cost to consumers.	Modify demand curve to result in values that are in line with demand curves that have been tested in other markets, probably by adjusting the slop of the down-ward sloping segment to better align with incremental reliability benefit of supply.

II. Initial Observations and Commentary

Before moving to the body of our report, there are several overarching themes that will carry through our analyses, findings, and discussion. We describe these below, ahead of our discussion of specific elements of the proposed rule.

A. Expectations for Market Outcomes and Market Efficiency

The proposed market reforms – the addition of a capacity market and the shift to an energy market with mitigation of market power – constitute a paradigm shift for Alberta's power sector. The sources of revenues to market participants will shift, overall expected levels of revenues may change, and market participants will face a different set of incentives in energy markets and new incentives in the capacity market. It should be expected that market economics in the new paradigm will drive outcomes that are different than in the prior paradigm, both in terms of static (short-run) and dynamic (long-run) outcomes. As a corollary, we note that design decisions should not be justified based on the objective of achieving results similar to the pre-reform Alberta market, particularly in terms of overall revenue, market prices, and supply mix.

Relatedly, it is our view that the transition to an electricity market that incorporates a capacity market fundamentally changes how dynamic efficiency is achieved and the role of the energy market, particularly when making the transition from a competitive, energy-only construct. In short, the capacity market becomes a primary tool for achieving dynamic efficiency. A central role of the energy market will be to ensure that there are appropriate short term price signals for static efficiency. No longer are additional rents in the energy market as essential – for example, through the exercise of market power - for providing sufficient overall revenue to support new and existing investments in supply infrastructure. Discussion of proposed rules should reflect this new reality.

B. Ongoing Importance of Energy Market Improvements

Though the role of energy markets changes in an electricity market that includes a capacity market, energy markets should not be neglected. We acknowledge the important role that capacity markets can play in addressing shortcomings in electricity markets that lead to the 'missing money' problem. However, we caution against a policy of over-reliance on capacity markets to achieve long-term (or short-term) economic objectives. Capacity markets serve to complement the energy markets in providing the long-term revenues that should guide investment and retirement decisions. Hence, good energy price formation that increases energy revenues will reduce Alberta's reliance of the capacity market revenue

Capacity markets are fundamentally administrative constructs. They can be subject to political scrutiny and, some have suggested, regulatory capture. Additionally, capacity markets have proven both controversial and difficult to administer. If payments available in capacity markets are smaller, less time and energy will be spent debating the effects of arcane market rules, and less effort will be expended in rent seeking efforts and regulatory responses thereto.

Thus, it should be a constant goal of market operators, market oversight entities, and market regulators to improve the efficiency of price signals from the energy and ancillary service markets and develop effective shortage pricing, and to thereby balance the relative roles of capacity and energy markets and limit reliance on capacity market payments to the extent reasonable within the overall market design. This is beneficial because efficient shortage pricing provides superior incentives for generators to be available, flexible and reliable.

Many promising energy market reforms have been raised as possibilities for improving the Alberta energy market. Unfortunately, many of these have been tabled. Such market reforms include the following:

- Establishment of a day-ahead market;
- Locational pricing;
- Submission of multi-part bids, cost recovery guarantees, and uplift payments;
- Security constrained unit commitment and dispatch;
- Co-optimization of the energy and ancillary services markets; and
- Dynamic intertie scheduling

Through improvements such as these, improved energy market rules and processes, including shortage pricing, can increase market efficiency and the quality of price signals in AESO markets by better optimizing unit commitment and dispatch; they can improve price signals during shortage; and, they can incentivize investment in capabilities like fast ramping. If implemented effectively, they could also increase revenues and margins available in the energy market, thus potentially reducing dependence on the capacity market. Though we understand that such reforms are not squarely before the AUC in this proceeding, we encourage the AUC, AESO, and all Alberta electricity market stakeholders to continue to drive towards improvements in the energy market even while the capacity market is being implemented.

There is also an important distinction to be made between blindly driving towards higher energy market prices (and margins) and making principled improvements that enhance the quality of price signals in the energy market. By our reading, this view of the energy market's role and energy market revenues is consistent with that of the AESO. In its AESO's Responses to the Additional Application Requirements ("AESO Response", Appendix J), it states that its goal is not "maximizing the extent to which revenues received by committed capacity come from the energy market." Instead, the AESO comments that, "the objective of the capacity market is to ensure efficient price signals, rather than to target revenue from a certain market segment. Revenue in the energy market should not be maximized at the expense of efficiency in the energy market."[4]

4 AESO Response (Appendix J), p. 3.

C. Currency

All dollar values in this report are presented in Canadian Dollars. Where conversions were necessary for the purposes of our analysis, the assumed currency conversion ratio is 1.30 CAD to 1.00 USD.

III. Capacity Market Mitigation: Offer Price Cap Mitigation Level

A. AESO Proposal

Market participants that are identified as having market power prior to a given base capacity auction[5] must offer all resources they control at or below a default offer price cap set to 80% of adjusted net-CONE.[6] Should the price cap in the base auction be set at a multiple of gross-CONE rather than net-CONE, the price cap will be equal to gross-CONE multiplied by 80% of the ratio between the multiple of gross-CONE and the multiple of adjusted net-CONE. We will focus on the former case for the sake of simplicity of discussion.

An asset-specific offer price cap is available to any market participant that failed the market power screen but can demonstrate that a given qualified capacity asset's costs are higher than the default offer price cap. The AESO will consider and decide on any requested exemptions.

B. AESO Rationale

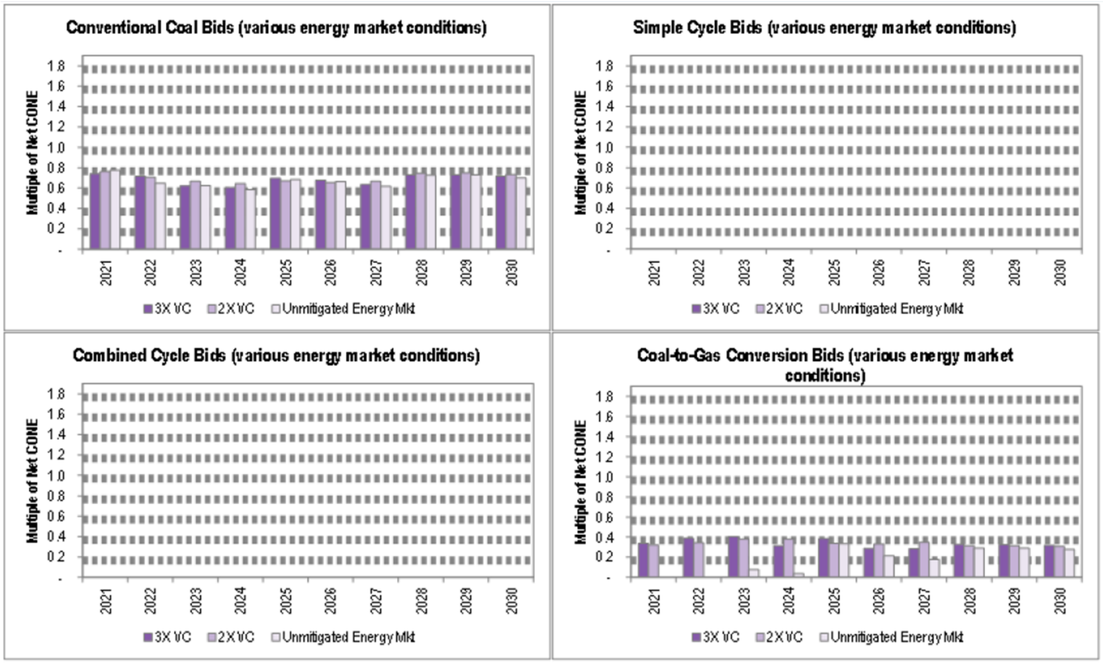
The AESO states that it elected not to set price caps for assets on an individual basis because that would require an assessment of the net fixed costs of each asset ahead of each base auction. The AESO contends that the market-wide offer cap approach reduces the administrative burden on market participants and the AESO while maintaining a safeguard against "uncompetitive economic withholding behaviour." It also states that the use of a default offer cap will reduce subjectivity and focus mitigation efforts on companies with the greatest ability to exercise market power.

The AESO based the 80% multiplier on an analysis of the net avoidable costs of various asset classes under certain energy market dispatch assumptions. The AESO initially determined that most capacity supply resources would be able to recover net avoidable costs should the offer price cap be set to 50% of net-CONE. More specifically, the net avoidable costs of existing CC and simple cycle gas-fired units would be 0% of net-CONE. This indicates that expected E&AS revenues would be higher than avoidable costs. In the case of coal-to-gas conversion units, AESO analysis suggests they must recover 20-40% of net-CONE to recover avoidable costs. The lower end of the range applies post-conversion. Finally, the net avoidable costs for conventional coal units range from 60-80% depending on assumptions. These results are shown in Figure 2.

5 A participant is identified as having market power in a capacity auction if it has the ability to profitably increase the Alberta capacity market price by 10% (from a particular reference price) by withholding capacity. We understand that this will likely result in the four largest participants being subject to offer price mitigation, at least under current market conditions.

6 The adjusted net-CONE is defined as the calculated net-CONE divided by a factor (set to 0.8 in the AESO proposal) to account for the unavailability of the average unit of the reference technology type. Though it is not clear if this was purposeful, the result of this proposed default offer cap level, combined with the proposed performance factor (used to adjust net-CONE), results in a default offer price cap at exactly net-CONE (on an ICAP basis).

Figure 2: Estimate of Net Avoidable Costs by Technology Type[7]



Some stakeholders raised concerns in the CMD process that 50% of net-CONE as an offer price cap was too low, arguing that "would cause over-mitigation in the capacity market, discourage investment in new capacity, and would negatively impact supply adequacy." The AESO therefore considered multiple options for raising the offer price cap, and settled on a market-wide cap of 80% of net-CONE, which it contends is consistent with its stated goals.

Generally, the AESO acknowledges the need to protect consumers from paying more for capacity than would be expected under a competitive market outcome, and that economic withholding in the capacity market can result in artificially high prices to consumers. The balance to be struck, in this case by the proposed offer price cap for mitigated capacity market offers, is between reasonable cost and reliable supply. The AESO states that its approach "avoids over-mitigation which has a negative impact on a reliable supply of electricity while ensuring that capacity prices are reflective of competitive outcomes." [8] The AESO goes on to state that there is also a balance to be struck between letting competitive forces work and "taking active steps to restrict offer prices when required to ensure effective consumer protection and reasonable prices in the capacity market."[9]

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7 AESO CMD Final Rationale (Appendix A), section 7.1.6. We note that the results of this analysis are relatively insensitive to the assumed mitigation regime.

8 AESO Capacity Market Application, P 443. The AESO later reasons that "An over-mitigated market discourages investment and negatively impacts supply adequacy." (P 444)

9 AESO Capacity Market Application, P 444.

The AESO, in its Application, also addressed the MSA's letter dated August 23, 2018, related to the capacity market default offer cap.[10] The AESO specifically addresses three points that the MSA made in its letter. The AESO contends:

- The use of the default offer cap allows competitive behaviour and does not require the use of "an administratively onerous process where there may be little benefit in having one." This is particularly true for companies that do not have the ability or incentive to raise market price through economic withholding.
- The default offer cap set at 80% of net-CONE limits consumer exposure to higher prices that might result from economic withholding while also allowing the risks of economic withholding (i.e., not clearing) to discipline offer behaviour.
- The proposed approach allows space for flexibility in market offers by capacity supply resources "rather than defaulting to an administrative approach with characteristics of a regulated, cost-based model."[11]

In the AESO Response, the AESO elaborates on its concerns regarding over-mitigation. Over-mitigation can take place if a resource is forced to offer below its true costs, or if resources are mitigated that do not have an ability or incentive to raise the market clearing price through economic withholding. Furthermore, the more conservative the market power screen, the more resources are likely to face mitigation, which threatens to increase the administrative requirements on both the AESO and market participants.[12]

C. Comparison to US RTOs with Capacity Markets

Table 2 compares the AESO's proposed capacity offer mitigation level with those of other North American capacity markets. The AESO's fixed mitigation level proposal stands opposed to the more dynamic approaches taken in the US markets. In ISO-NE and NYISO, offer allowances for mitigated units are generally based on expected market outcomes and offers are mitigated if they are above expected levels. Unit-specific showings are allowed in both cases. In PJM, in relevant part, resources subject to mitigation are mitigated to a level tied to the demonstrated net avoidable cost rate, or a technology average avoidable cost rate.

10 https://albertamsa.ca/uploads/pdf/Archive/000000-2018/2018-08-23%20MSA%20response%20to%20AESO%20CMD.pdf

11 AESO Capacity Market Application, P 448.

12 AESO Response (Appendix J), AUC-AR-17, p. 34.

Table 2: Comparison of Capacity Offer Price Caps in AESO Proposal and US Jurisdictions

	Offer Price Cap for Mitigated Units in Capacity Market
AESO Proposed	0.8 x adjusted net-CONE
ISO-NE	Cap at "dynamic delist bid threshold," which is the estimated cost of the next marginal capacity resource[13] (Note: only new and delisting resources submit price offers)
NYISO	Higher of projected auction price (intersection of demand curve and available supply) or unit-specific net going forward costs
PJM	Pool-wide capacity performance opportunity cost[14] or Resource-specific net avoidable cost, as reviewed by market monitor (or technology-specific avoidable cost rate)

D. Assessment and Analysis

We will start by laying out our areas of agreement with the AESO's proposal. Consistent with widely accepted practice in capacity markets, we concur that it is important to screen capacity market participants for market power to safeguard against uncompetitive economic withholding behavior and to focus attention on market participants with the incentive and ability to exercise market power. The importance of such screening is illustrated in Figure 3, which, among other things, shows the effect of moving along the demand curve as a function of price as a percent of adjusted net-CONE. For the sake of illustration, this shows the effect should the capacity clearing price be set at or close to the default offer cap level for mitigated resources, as compared to levels below the 80% proposed cap.[15] As shown in Table 3, the change in capacity market outcomes is considerable both in terms of capacity price and capacity cost to consumers.

Table 3: Total Capacity Costs Relative to Clearing Location

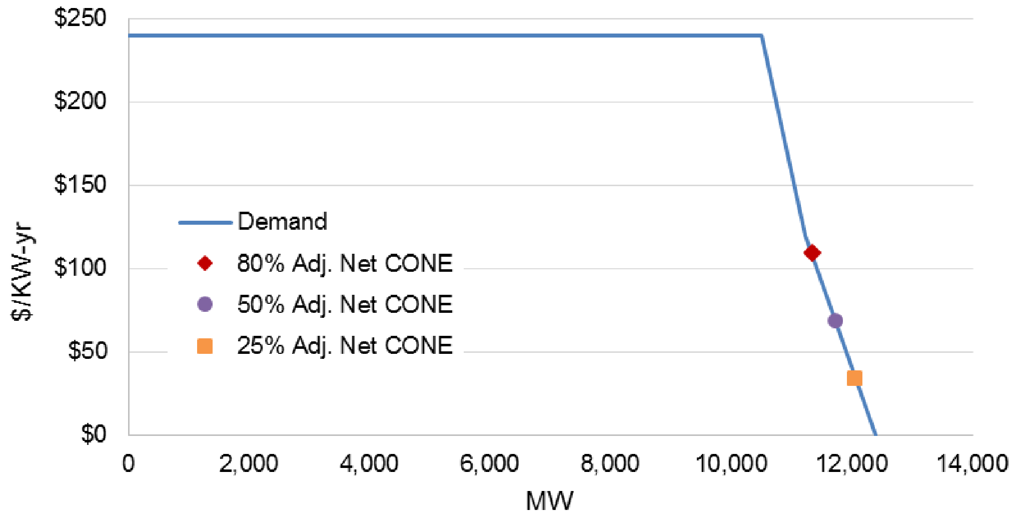
Clearing Price →	80% Adj. Net-CONE	50% Adj. Net-CONE	25% Adj. Net-CONE
Approx. Clearing Quantity (MW)	11,300	11,725	12,050
Approx. Clearing Price ($/kw-yr)	$ 111	$ 68	$ 34
Total Capacity Market Cost	$1,250	$802	$412

13 https://iso-ne.com/static-assets/documents/2017/08/a6_presentation_dynamic_delist_bid_threshold.pdf

14 This market rule is specific to the PJM market with the Capacity Performance rules in place. Owing to the differences in the design of the proposed capacity incentives program in Alberta, the underlying logic behind this mitigation level is not relevant to Alberta.

15 We do not necessarily believe that mitigated market participants will offer at the available price cap, though it is a real possibility and some will have a strong incentive to do so.

Figure 3: Illustrative Alberta Demand Curve Locations as Function of Net-CONE[16]



Having addressed the importance of screening for market power from a cost perspective, we support the AESO's view that an *ex ante* mitigation scheme is an effective and appropriate approach to addressing uncompetitive behavior. For screened resources, we agree that avoiding over-mitigation is a concern, both from an efficiency and fairness standpoint. We also acknowledge that implementation of a well-designed default offer cap (or caps) may be an administratively straightforward approach for treating mitigated resources, and that such a default cap is appropriately accompanied by an allowance for unit-specific showings to support an offer above the default cap.[17] However, we do not believe that the AESO's proposed default cap is well designed in its current form.

With the proposed capacity market power mitigation, we expect that relatively large suppliers will likely have the incentive under the AESO proposal to raise prices to 80% of net-CONE when it would otherwise fall. To see why this may occur, consider the following example:

- Assume a supplier with a 14% market share and that the market has a surplus of 12%.
- Under the capacity demand curve proposed by AESO:
    - The price will be 80% of Net-CONE at a surplus level of 7%.
    - The price will be 40% of Net-CONE at a surplus level of 12%.
- In this case, the supplier can double the price (from 40% to 80% of net-CONE) if it reduces the capacity market procurements from 12% to 7%.

16 Assumes procurement target of 10,500 MW, E&AS offset of $135/kw-year, and gross-CONE of $244/kw-year.

17 Unit specific showings should allow for estimation of expected penalty or bonus payments associated with the performance incentive regime in the calculation of net avoidable going forward costs.

- Hence, the supplier may choose the following:
  - Do not withhold: sell its 14% market share at 40% of net-CONE; or
  - Withhold 5 percentage points of its capacity: sell 9% of the market capacity at 80% of Net-CONE.

Comparing these two alternatives, the supplier will receive **30%** more revenue if it withholds than if it does not withhold.[18] This incentive to withhold will exist for the largest suppliers over all levels of surplus capacity that would produce competitive prices less than 80% of net-CONE. This is why the US markets employ much lower thresholds for reviewing and mitigating economic withholding.

As a further matter, we have concerns about the AESO's view of what constitutes "higher" or "lower" capacity market prices, and making decisions on that basis. It appears that the AESO's impression is that offer mitigation, such that a capacity auction price result is 80% of adjusted net-CONE, constitutes "limiting consumer exposure to higher prices resulting from economic withholding." Based on the US experience with capacity markets, an auction outcome of 80% of net-CONE would be considerably above average outcomes. As shown in Table 4, the US capacity markets have successfully procured sufficient capacity to maintain resource adequacy (and beyond) at price levels averaging between 30% and 50% of net-CONE. In more constrained locales, such as New York City and Eastern PJM, prices have averaged between 50% and 60% of net-CONE. Thus, competitive forces have allowed procurement of sufficient levels of supply for considerably less, on average, than 80% of net-CONE. Based on this set of facts, our view is that limiting capacity markets to outcomes at 80% of adjusted net-CONE is not protective from high prices; those *are* high prices.

Table 4: Historical Capacity Market Outcomes as Compared to Net-CONE[19]

$/kW-yr	UK	PJM EMAAC	PJM ComEd	PJM RTO	NYISO NYC	NYISO NYCA	ISONE ROP
Net-CONE	92	147	164	150	227	122	125
Average Prices	35	77	58	48	129	34	55
% of Net-CONE	38%	53%	35%	32%	57%	28%	45%

We now turn to the AESO's rationale for the proposed mitigation approach, with a default offer cap at 80% of net-CONE for all mitigated resources. As we understand

18 The firm loses 35% of its quantity by withholding 5 percentage points but it doubles the price it earns. Therefore revenue non-withholding = Revenue(Non) = 0.4 x net-CONE x Q. Revenue withholding = Revenue(WH) = 0.8 net-CONE x 0.65Q. Revenue (WH) – Revenue(Non) = Net-CONE x Q(.52-.4) = net-CONE x Q x 0.12, which is 30% of Revenue(Non)

19 Data sourced from each market operator's website. Historical data begin for 2014 for NYISO, 2015/2016 for PJM, 2018/2019 for ISO-NE, and 2018/2019 for the UK. For ISO-NE, prior year market rules do not lend themselves to this type of comparative analysis. For NYISO, prices are based on 6-month strip located to each June-May delivery year used by PJM and ISO NE.

the AESO's argument, this approach rests on the balance struck between reliable supply (achieved through letting competitive forces work) and reasonable cost (ensuring competitive outcomes while limiting administrative burden). The AESO seems to argue that half of this balance, allowing competition and fostering reliable levels of supply procurement, could potentially be undermined if AESO engaged in "over-mitigation." It properly defines over-mitigation as compelling resources to offer below their true costs. An unstated assumption by AESO in raising this concern is that it will not have the capability to set Asset-Specific Default Offers that accurately reflect resources' true costs. Properly administered default offers would eliminate all concerns regarding over-mitigation. Nonetheless, we agree that fostering reliable levels of supply could be undermined by mitigating suppliers below their true costs

Achieving reasonable costs in capacity markets requires balancing the administrative burden of mitigation and resource-specific showings with the potential cost impact of allowing bids that are uncompetitive. These uncompetitive bids can lead to higher than efficient capacity price outcomes and, therefore, unreasonably high costs to consumers. This trade-off can be quantified, if imperfectly. By the AESO's analysis,[20] the only types of resources studied that have net going forward costs meaningfully larger than zero are coal units and coal-to-gas conversions. There are currently 15 generating units in the Alberta market operating as coal units and that are controlled (in full or in part) by a market participant that is likely to fail the capacity market power screen, and one of those (Battle River 3) will retire before the first capacity delivery period. Also, a number of these units are expected to undergo coal-to-gas fuel conversions in addition to repowerings at Genesee that have already been announced. These resources are listed in Table 5.[21]

Table 5: Coal Units Likely to Face Capacity Market Mitigation

Plant	Owner	Generating Capability	# Units
Battle River (4, 5)	ATCO	540 MW	2
Genesee (1, 2)	Capital Power	800 MW	2
Genesee 3	Capital Power and TransAlta	466 MW	1
Keephills (1, 2)	TransAlta	790 MW	2
Keephills 3	Capital Power and TransAlta	463 MW	1
Sundance (3, 4, 5, 6)	TransAlta	1,581 MW	4
Sheerness (1, 2)	ATCO and TransAlta	790 MW	2
Total			*14*

20 There is insufficient information available in the AESO rationale documentation for us to assess the quality of the analysis associated with net going forward costs for existing plants. However, we will accept it for our purposes here for lack of an alternative.

21 MW values are from the MSA's 2018 Market Share Offer Control Report.

Presumably, the maximum administrative cost scenario – were the default mitigation threshold set below their going forward costs – would be if every one of these resources elected to submit an asset specific showing every year ahead of the capacity auction. If we liberally assume that the administrative cost is $100,000 per showing[22] – both for preparation and review – the total administrative burden would be 1.5 million dollars per year. See Table 6. In our view, this administrative burden is justifiable when compared to the potential impact on capacity market outcomes and cost to consumers should capacity offers be allowed in excess of true cost, which could be as much as hundreds of millions of dollars, as shown in Table 3.

Table 6: Possible Cost of Capacity Market Offer Reviews

Category	Value
Cost per Review	$ 100,000 / year
Number of Offer Reviews per Year	15
Total Cost of Offer Reviews	$ 1,500,000

E. Suggested Alternatives

We recommend adopting market rules that:

- Apply a substantially lower default offer cap default offer cap to all resources that fail the capacity market power screen. We recommend this offer cap be based on the competitive price expected in the auction, similar to the approached used in NYISO and ISO-NE.
- Allow for asset-specific showings for resources that wish to offer into the capacity market above the default offer cap.
- The MSA be tasked with administering the asset-specific default offers, rather than the AESO.

Should the AUC not require an approach that entails calculating an expected market outcome to determine the default offer cap, other options are available. For one, the AESO could rely on a market-wide offer cap that is a multiple of net-CONE, though the multiple would need to be much lower than the proposed 80% figure. For example, MISO uses an offer cap of 10% of net-CONE for mitigated resources.

As a second-best alternative, the capacity market rules could do away with a default offer cap for all resources. Instead, they could apply a technology-specific offer cap. This would be more consistent with the approach historically employed by PJM. The rationale that supports PJM's market rules would, in this respect, also be reasonably applicable in Alberta. In our view, this would also be an effective approach and would limit administrative burden. It would, however, require additional analysis and administrative judgement on the part of the AESO – as well as the MSA, potentially –

22 This number is entirely made up, but is on the order of magnitude of certain fees in US RTOs for reviewing project proposal of various types. We are open to revising this figure, but our conclusions are insensitive to even large variations in the actual number. We note that there may be economies of scale with preparing and reviewing unit-specific showings because of the preparation and review of showings by multiple units at the same plant.

and require generalizing determinations about costs across an entire resource class. If this is the direction the AUC wishes to proceed, we recommend that the AESO be required to provide a more comprehensive and transparent analysis of technology-specific going forward costs. What has been provided in the AESO's application is insufficient to support such an important market parameter.

F. Discussion of Alternatives

Consistent with a number of the AESO's design choices, the proposed mitigation levels are likely to bias capacity prices and costs to consumers upwards. Implementing a more constraining approach to mitigation of market power in the capacity market would be consistent with accepted practices in other North American capacity markets and also consistent with all of the AESO's stated objectives for handling market power in the capacity market:

- The proposed approach protects consumers from paying significantly more for capacity than would be expected under a competitive market outcome.
- The proposed approach addresses over-mitigation:
  - The proposed screen ensures that resources are not mitigated that do not have the ability or incentive to exercise market power through economic withholding.
  - The availability of a resource-specific showing and offer price cap ensures that no resource will ever be forced to offer below its true costs.
- The proposed approach does not require "an administratively onerous process where there may be little benefit in having one." Rather, it creates some additional requirements where there are clear and quantifiable benefits that are likely to significantly outweigh the costs.

This alternative has been highly successful in the US Capacity markets. Potomac Economics actively participates in the process of establishing reference prices or default offers in three of the US capacity markets. Having participated in this process for years, Potomac Economics believes unequivocally that administrating asset-specific can be done accurately so as to avoid the potential for over-mitigation, and is not unduly burdensome.

As compared to a market in which a default offer cap of 80% of net-CONE is employed, this rule change would either have no effect on market prices or drive them down, on average. We expect the latter is more likely. The resulting prices would also be more reflective of competitive outcomes.

These proposed rule adjustments would require limited conforming changes elsewhere in the market design. The necessary screens, offer thresholds, and procedures for units-specific showings are already in place. Were the AUC to direct a technology-specific offer cap, technology-specific reference levels would need to be added. The process for identifying these levels might be extensive, but the required market rule changes would not be.

In closing, we emphasize the importance of a reasoned and thorough *ex ante* market power mitigation scheme in the capacity market, and our recommendations, if implemented, would better achieve this objective. In an energy market, outcomes are transient and the effects of uncompetitive behaviour may expire after one or several hours. The total cost stakes in the energy market are relatively small in any given hour. Furthermore, bad behaviour can often be observed and addressed on a more expedient basis before the overall effects accumulate to large costs to consumers. In a capacity market, on the other hand, outcomes persist for long periods; commitment periods are a full year. As we have shown, it is straightforward to describe how certain types of offer behaviour can drive uneconomic costs to consumers in excess of tens or hundreds of millions of dollars. Thus, in our view, more conservative approaches are warranted in the capacity market to ensure prices are competitive.

IV. Delisting: No Market Power Screening for Permanent Delist

A. AESO Proposal

The AESO has not proposed to apply any market power screen, nor any mitigation measures, to resources that plan to permanently delist from the capacity market. Permanent delisting is the equivalent of retiring an asset from all Alberta markets.[23] Permanent delist notifications cannot be submitted after the first balancing auction.

A permanent delist is described as a "notification" to the AESO and not an "offer" with economic terms that would drive a capacity resource to retire.

B. AESO Rationale

In its January 31 filing, the AESO does not discuss in the body of its Application the issue of whether to apply any market power screening or mitigation to permanent delist action from the capacity market.

Some additional discussion is provided in the CMD documentation. The AESO notes that "a permanent delisting decision is a long-term one and is likely not dependent on the price outcome of a single obligation period."[24] More to the point, the AESO states that it agrees with multiple stakeholders "that a legal owner of a capacity asset is entitled to make their own judgement about the economic viability of their assets and whether to retire them permanently."[25]

C. Comparison to US RTOs with Capacity Markets

Table 7 compares the AESO's proposed treatment of retirement decisions – and associated capacity market actions – with those of other North American capacity markets. In US markets, it has generally been accepted that decisions to retire plants and to delist from the capacity market raise concerns over physical withholding. In each US market, therefore, the decision to retire is viewed as an economic decision. Resources place delist offers, and delist offers are subject to review and mitigation. Generally, resources that wish to submit such an offer have their offer price reviewed through the lens of the net avoidable going forward costs for that unit or the relevant technology type. The AESO has not proposed such a review.

23 Some exceptions are provides for a generation source that has permanently delisted for more than five years.

24 CMD Final Rationale (Appendix A), section 2.3.15.

25 CMD Final Rationale (Appendix A), section 2.3.18.

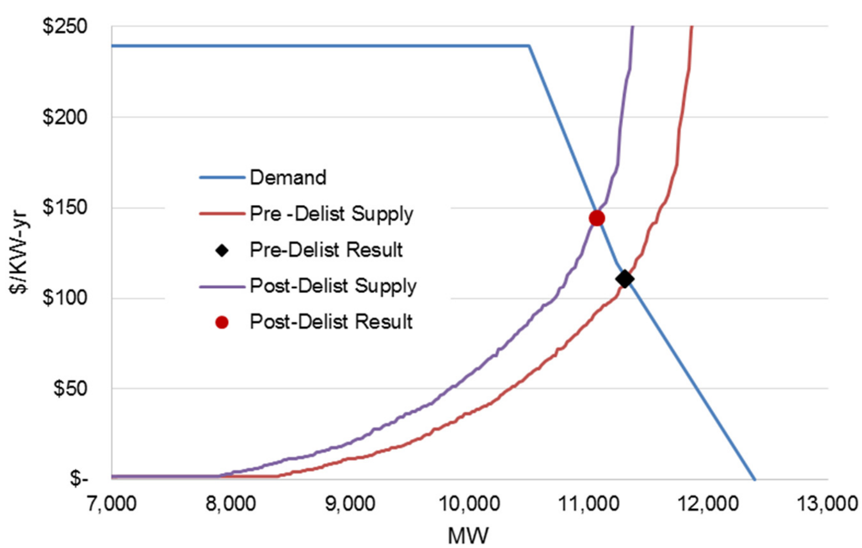
Table 7: Comparison of Delist Bid Rules in AESO Proposal and US Jurisdictions

	Screening for Permanent Delists	Mitigation Level for Permanent Delists
AESO Proposed	No	N/A
ISO-NE	Reviewed if >20 MW	Review by IMM to verify offer price consistent with resource's going forward costs
NYISO	All offers subject to review	Subject to review and audit, and compared to resource-specific calculated net going forward costs
PJM	All offers subject to maximum offer thresholds	Offers limited to maximum net avoidable cost rates

D. Assessment and Analysis

We have concerns over allowing permanent delist decisions to be made without review. Permanent delisting of capacity can have the same results, particularly in the near-term, as physical withholding. Firms with market power may have the ability and incentive to retire plants early in order to drive up capacity market prices and revenue. While the plant that retires will not receive capacity market revenues, the remainder of its owner's portfolio stands to benefit. Furthermore, the early reduction in available capacity in the market could persist for several years and thus the exercise of market power could have lasting benefits to the market participant (and lasting costs to consumers). Particularly in a smaller market, the retirement of one large asset can have a considerable effect on prices and costs, particularly in a smaller market. This is shown in Figure 4 and Table 8, which illustrate possible market impact of a 500 MW retirement.

Figure 4: Illustrative Effect of 500 MW Delist[26]



26 The capacity auction analysis presented here – and throughout this report – is described in Appendix A.

Table 8: Illustrative Effect of 500 MW Delist on Market Outcomes

Clearing Price →	Pre-Delist	Post-Delist
Approx. Clearing Quantity (MW)	11,300	11,060
Approx. Clearing Price ($/kw-yr)	$ 111	$ 145
Total Capacity Market Cost	$ 1,250 M	$ 1,604 M

The owners of capacity assets, if the owner fails the market power screen, should be required to make a showing of their net going-forward costs for a unit seeking to retire. As with other resources, bidding above this level should be disallowed. This will prevent inefficient early exit and reduce concerns over the exercise of market power.

We also question the AESO's reasoning underlying permanent delisting without an economic review. A permanent delist decision is based on a long-term calculus and likely not dependent on any single auction result. However, that is not to say that any one auction result cannot tip the scales for a resource that is only marginally profitable and towards the end of its useful life. Retirement decisions are also not made in a vacuum, particularly for portfolio owners, who may make delist decisions based on the how they expect it to affect their fleet economics, not just the individual plant.

The AESO has evidently agreed with stakeholders that asset owners are entitled to make their own judgement about the economic viability of their assets when it comes to retirement. However, the timing of retirement, to the extent that it can impact market outcomes, bears similarity to other actions in the capacity market (i.e., offer prices), all of which are subject to screening for market power and may be subject to mitigation. The AESO acknowledges that permanent retirement is a fundamentally economic choice, but declines to exercise oversight over that choice in a manner consistent with other choices.

E. Suggested Alternatives

We recommend adopting capacity market rules that:

- Replace the retirement notification process with a retirement delist offer process;
- Apply capacity market mitigation for delist offers to the same set of market participants that are otherwise screened for capacity market power;
- Require an asset-specific showing of net avoidable going forward costs for all retirement offers consistent with the asset-specific offer price cap proposed by the AESO for other types of resource offers; and
- Allow for exceptions to economic delist offer requirements for resources facing regulatory requirements to retire.

In the alternative, mitigation could be applied in the same manner as for other mitigated units, including a default offer price cap with the option to make an asset-specific showing and receive an asset-specific offer price cap in excess of the default. However, we would not recommend this approach unless the AUC mandates a lower default offer price cap (less than 80% of adjusted net-CONE) consistent with our recommendations.

F. Discussion of Alternatives

The requirement to place permanent delist offers along with subsequent review and screening would potentially mitigate a variant of the exercise of market power in the capacity market (by physical withholding) while also limiting uneconomic early exit of capacity resources. This approach would be consistent with rules in the US RTOs that operate capacity markets. As compared to a market in which retirement offers are not screened, this rule change would either have no effect on market prices or drive them down, on average.

The proposed rule adjustments would require limited conforming changes elsewhere in the market design. The changes would be made to the delist procedures, with limited changes likely necessary to the capacity market power monitoring and mitigation rules. The necessary screens, offer thresholds, and procedures for unit-specific showings are already in place.

V. Energy Market Mitigation: Offer Price Cap Levels and Tiered Mitigation Thresholds

A. AESO Proposal

Market participants that are identified as having market power in a settlement interval[27] must offer all resources they control at or below an asset-specific reference price ("ASRP") that depends on the prevailing supply-demand conditions. The ASRP is a function of the calculated short run marginal cost ("SRMC")[28] of a generator times a multiplier that depends on the prevailing supply cushion. If the supply cushion is greater than 1000 MW, the market is considered well supplied and the multiplier is 3x; therefore, mitigated resources are constrained to offering three times their marginal cost. If the supply cushion is between 250 MW and 1000 MW, the market is considered moderately tight and the multiplier is 6x; therefore, mitigated resources are constrained to offering six times their marginal cost. With the market has a supply cushion of less than 250 MW, it is considered "very tight" and there are no constraints on offer behaviour for any market participants.

The floor of the ASRP will not be less than $25/MWh and not greater than $999.99/MWh.

Participants that are not identified as having market power in a settlement interval are permitted to offer supply resource they control into the energy market in that settlement interval at any price between the $0/MWh (the energy offer price floor) and $999.99/MWh (the energy offer price cap).

Table 9: Supply cushion and ASRP multiplier for mitigated units in energy market

Supply Cushion	ASRP Price Multiplier
>= 1000	3x SRMC
250-999	6x SRMC
<250	No-look

B. AESO Rationale

1. Graduated Mitigation MW Thresholds

Consistent with the graduated scarcity approach, the AESO has proposed two supply cushion thresholds that trigger the alternative mitigation rules. Those are 1000 MW,

27 The AESO has proposed to screen market participants for market power in each settlement interval. The proposed market power screen calls for the calculation of a residual supplier index ("RSI") for each market participant based on offer control shares and adjusted for forward sales. The RSI measures how important supply from a participant is to meeting overall market demand. Participants that are large enough such that demand cannot be met without them – that is, they have an RSI of less than 1.0 – are determined to be pivotal and are identified as having market power in the energy market in that settlement interval.

28 SRMC is calculated as the heat rate times the fuel price plus variable operation and maintenance costs plus the cost of carbon associated with compliance with Alberta's greenhouse gas regulations.

where the supply cushion is "relatively low but not very near zero," and 250 MW, when market conditions are considered scarce and the market is approaching a supply shortfall. [29] Above 1000 MW, the supply cushion is considered "relatively high."

a) 1000 MW Threshold

In its Application, the AESO provides no additional data to support the establishment of a graduated mitigation threshold at 1000 MW. The CMD documentation also provides little quantitative support for the 1000 MW threshold.

b) 250 MW Threshold

The AESO likewise provides little quantitative support for the 250 MW threshold for "scarce hours" in its Application. However, here, the CMD Final Rationale document provides some support. First, the AESO states that at 250 MW the market will be approaching a shortfall. At 500 MW of supply cushion, the Alberta market has sufficient cushion to cover its most severe single contingency. Furthermore, at 250 MW of supply cushion, the market would be "near emergency conditions," according to the AESO. Its assessment of historical pool price data leads the AESO to conclude that scarcity-type pricing occurs below 250 MW of supply cushion. The AESO examines the relationship between pool prices and supply cushion using market data from February 1, 2008 to June 30, 2010, relying on an analysis performed by the MSA and prior to the establishment of offer behaviour enforcement guidelines.[30] The AESO focuses on the observation that for the data bins with supply cushion of 0-250 MW and 250-500 MW, the mean price plus three standard deviations is greater than $1000 / MWh, the market price cap. Thus, by the AESO's reckoning, "there are no pool price outliers when the supply cushion is in this range." The AESO concludes that the "historical analysis supports the conclusion that when the supply cushion is sufficiently low, supply is sufficiently scarce such that it is appropriate to expect the pool price to rise above marginal cost as a market-based signal of scarcity."[31]

2. Offer Price Cap Mitigation Levels

The AESO states that the graduated scarcity approach was designed to be consistent with the use of a structural market power screen rather than a conduct and impact test. It then states that "[t]he pool price must reflect market conditions if the energy market is going to efficiently allocate resources."[32] Thus, the AESO reasons that, when supply is limited relative to demand, prices should rise to reflect this

29 The AESO acknowledges, "As noted in CMD 2, the original scarcity screen of 500 was based on the measure of a contingency. The AESO recognizes that this threshold is somewhat arbitrary and is binary as it may limit competitive outcomes and, at the extreme when the supply cushion is zero, all firms would be identified in the screen." CMD Final Rationale (Appendix A), section 10.7.10.

30 Market Surveillance Administrator (2012). "Supply cushion methodology and detection of events of interest." https://albertamsa.ca/uploads/Supply_Cushion_Data/Supply_Cushion_and_Outliers_120604.pdf

31 CMD Final Rationale (Appendix A), sections 10.7.10-10.7.11.

32 AESO Capacity Market Application, P 588.

scarcity. This objective, and the choice of a structural test based on a screening threshold of 1.0 RSI, create a situation where the AESO is concerned about over-mitigation of all resources when the supply cushion approaches zero, as nearly all suppliers will become pivotal in such times. The AESO also contends that the graduated scarcity approach allows higher prices, which improves signals for investment in flexibility and ramping capabilities, as well as reactions from price responsive load and imports, all of which support system reliability.

As described above, there are three price cap mitigation levels associated with the AESO's proposed approach, 3x SRMC, 6x SRMC, and no-look.

a) 6x SRMC Threshold

The AESO explains that the 6x SRMC threshold, proposed when the supply cushion is between 250 and 1000 MW, is intended to be a proxy for price responsive load. In its Application, the AESO states that "this is the price level where price responsive load has historically been observed to reduce consumption."[33] The AESO concludes that allowing this level of price offers will enhance competition, convey the static price signal for price responsive loads, and maintain the dynamic price signal for flexibility, all while keeping offers at risk. The AESO's Application does not provide the necessary analytic support for the 6x value. The CMD Final Rationale notes that the loosening of the mitigation screen between the 3x period and the no-look period allows for some graduation in the pricing rules.[34]

The AESO contends that, at this level, offers from market participants with portfolio volumes less than 250 MW, from imports, and from hydro resources, will effectively price the shortfall condition without significant risk for efficiency loss. The AESO states on several occasions that high prices during such periods reflect market conditions and do not constitute an exercise of market power.

b) 3x SRMC Threshold

The 3x SRMC threshold was based on an analysis of average and marginal costs for each type of generating unit. The concern being addressed by the AESO is generator cost recovery on an operational basis considering the fact that Alberta's energy market only allows single-part bids and operates on a self-commitment model. There is no provision for uplift costs nor guarantee of the recovery of start-up costs. This arrangement creates risk that generators may not be able to recover their full costs across an operational period, particularly if they only offer into the energy market at their SRMC, which does not incorporate start-up costs. Generally, in a case where a generator submits an SRMC-based single-part offer, start-up costs might be recovered through infra-marginal rents during a given operating period. However, this type of cost-recovery is less likely if a generator is only operating for a short period of time, and especially so if it is the marginal supplier during that period.

33 AESO Capacity Market Application, P 591.

34 In section 10.7.17(b) of the CMD Final Rationale (Appendix A), the AESO also makes the comment: "Scarcity pricing is a critical element for investment, retirement, and decisions related to consumption and production in the energy market."

The AESO's proposed solution to this problem is to set a mitigation threshold that allows for assets that might face such a scenario to place an offer sufficient to recover all operating costs, including the asset's SRMC, cycling costs, and start-up costs. The threshold should be set such that this is possible for most conceivable operating periods. More specifically, the AESO suggests that the threshold should be set equal to the ratio of average costs to marginal costs for the asset type at most risk of cost under-recovery. The AESO considers that the ability to submit full operating costs – and thereby recovering them – is important to ensuring reliability.

Brattle performed the supporting analysis.[35] This analysis showed that simple cycle generators have the highest ratio of average to marginal cost, driven largely by the fact that they are the generators that are frequently expected to operate for very short periods, in turn providing them less MWh of sales across which to spread start-up costs during a given operating period. For a hypothetical simple cycle gas turbine during a moderate gas price period, a 30-minute operating cycle result in an average-to-marginal cost ratio of 2.73. From this, the AESO determined the appropriate mitigation threshold would be 3x SRMC. As proposed, this threshold would also apply to all other resource types.

Of note, the assumed 30-minute run time was based on an assessment of historical operating data for simple cycle units during full output events in the 2013-2014 time frame. The AESO also expects the need for certain plants to operate for short periods to increase in the future given increased cycling needs caused by greater penetrations of variable generation. Furthermore, using a market-wide threshold allows the AESO to address other future uncertainties in cycling and start-up costs.

In the CMD Final Rationale, the AESO presents an additional argument in support of the 3x multiplier and mitigation of offer prices more generally: offer price mitigation stabilizes net energy revenue across a variety of market conditions. In doing so, such mitigation also stabilizes net-CONE values and the location of the supply curve. This result is shown by simulating market outcomes and net energy revenues for CC and CT units under varying mitigation schemes and varying market conditions, exemplified by using historical data from the 2013-2016 period. The result for the simple cycle CT case is shown in Table 10.

Table 10: Effect of various market-wide energy offer mitigation multipliers on net energy revenues and net-CONE for a simple cycle unit[36]

Generic New Simple Cycle (heat rate = 9,600)

	[a] Gross CONE	Net Energy Revenues ($/kW-year)								Net CONE ($/kW-yr) = [a]-[b]							
		At cost	1.2x Band	2x Band	3x Band	$400 Cap	$600 Cap	$800 Cap	Unmitigated	At cost	1.2x Band	2x Band	3x Band	$400 Cap	$600 Cap	$800 Cap	Unmitigated
2013	$140.0	$3.5	$7.2	$31.8	$60.0	$290.0	$369.5	$426.8	$455.5	$136.5	$132.8	$108.2	$80.0	-$150.0	-$229.5	-$286.8	-$315.5
2014	$140.0	$1.5	$4.0	$14.0	$23.6	$92.6	$122.0	$145.2	$153.7	$138.5	$136.0	$126.0	$116.4	$47.4	$18.0	-$5.2	-$13.7
2015	$140.0	$1.4	$3.4	$12.3	$19.2	$62.4	$81.4	$97.7	$104.4	$138.6	$136.6	$127.7	$120.8	$77.6	$58.6	$42.3	$35.6
2016	$140.0	$1.8	$3.1	$6.0	$7.0	$8.2	$8.6	$9.0	$9.3	$138.2	$136.9	$134.0	$133.0	$131.8	$131.4	$131.0	$130.7

35 Brattle (2018), "Market power screens and mitigation options for AESO energy and ancillary services markets." https://www.aeso.ca/assets/Uploads/4.2-Brattle-Paper-Mitigation.pdf.

36 Brattle, "Assessment of bid mitigation options." November 21, 2017. Available online at: https://www.aeso.ca/assets/Uploads/Vote-screens-mitigation-shortage-11-22-2017.pdf

The AESO concludes its support for energy market mitigation, and the 3x SRMC threshold, with the following statement:

> *The AESO is of the view that to the extent that the market power mitigation framework can support predictability (stability) in energy market outcomes, expectations about energy market outcomes will be formed with greater confidence. This approach hopefully results in better informed offer prices in the capacity market while reducing the likelihood of the capacity market clearing on the basis of expectations of minimal exercise of market power in the energy market, only to have substantial market power be exercised in the energy market, with consumers having to pay twice for capacity (once in the capacity market and then again in the energy market). As discussed at the beginning of this section, this would not be consistent with the evolving purpose of the energy and ancillary services markets.37*

c) No-look Threshold

Any offer mitigation is lifted below a supply cushion of 250 MW, effectively creating a "no-look" period with respect to offer review when the AESO contends that the market is facing scarcity conditions. The AESO supports the no-look approach during such periods stating, "High prices during tight supply cushion hours maintain the real-time price as a signal of real-time scarcity and provide important incentives for flexibility and ramping. This is not to be conflated with the exercise of market power, as it is a reflection of system conditions."[38] Rather, during such conditions, lifting any market power mitigation rules will allow prices to reflect market conditions. The result would be "similar to what would occur in other markets that have an operating reserve demand curve." [39] Furthermore, the AESO reasons, lifting mitigation rules will address the weaknesses in a structural market power test and serve as a practical solution that avoids mitigating even smaller firms when supply is tight. Finally, the AESO concludes that, "Without testing for impact, continued mitigation during these tight times may mitigate companies who made offers that had little impact on the resulting prices."[40]

3. AESO Efficiency Assessment

As part of its capacity market filing, the AESO submitted an Efficiency Assessment related to its energy market mitigation proposal. The Assessment is responsive to concerns raised by the MSA during prior phases of the capacity market design process. The Efficiency Assessment presents a counterfactual analysis, based on historical data, of the effect of alternative mitigation schemes on economic efficiency in the energy market. The two types of efficiency studied are:

- **Productive Efficiency**: Are the least cost set of resources selected to serve load during any given period? Any deviation causes productive inefficiency.

37 CMD Final Rationale (Appendix A), section 10.7.17(a).

38 AESO Capacity Market Application, P 592.

39 AESO Capacity Market Application, P 593.

40 AESO Capacity Market Application, P 593.

- **Allocative Efficiency**: Is less energy consumed as a result of high prices as compared to a case where all resources offer at SRMC? Any deviation causes allocative inefficiency.

These measures of efficiency, including expected average pool prices, were quantified under three scenarios:

- No mitigation, consistent with historical market conditions
- The AESO's proposed graduated energy market mitigation methodology
- An alternative graduated energy market mitigation methodology with a 3x SRMC offer threshold for all mitigated resources regardless of supply cushion

The results of comparing historical actual market outcomes to estimated outcomes under the proposed mitigation scheme are shown in Table 11. The AESO comments that the proposed mitigation framework increases allocative and production efficiency. Also, the proposed mitigation proposal has the greatest effect in years that experienced higher average pool prices.

Table 11: AESO comparison of historic efficiencies to estimated efficiencies under proposed energy market mitigation scheme[41]

Summary Table 1

Year	Number of hours that were mitigated	Average actual pool price ($/MWh)	Estimated Average pool price after proposed mitigation ($/MWh)	Estimated Historic productive inefficiency ($ millions)	Estimated Productive efficiency gain after proposed mitigation ($ millions)	Estimated Productive efficiency gain after mitigation (%)	Estimated Productive efficiency gain after proposed mitigation ($/MWh)	Estimated Historic allocative inefficiency ($ millions)	Estimated Allocative efficiency gain after proposed mitigation ($ millions)	Estimated Allocative efficiency gain after proposed mitigation (%)	Estimated Allocative efficiency gain after proposed mitigation ($/MWh)
2013	1,274	80	51	16.32	2.08	13%	0.10	21.35	13.19	62%	0.77
2014	1,078	50	34	23.43	5.73	24%	0.37	6.7	4.99	75%	0.71
2015	362	33	23	10.27	0.56	5%	0.04	5.36	4.67	87%	0.72
2016	46	19	19	5.01	0.08	2%	0.00	0.32	0.03	10%	0.00
2017	79	22	22	10.76	0.09	1%	0.00	0.58	0.05	8%	0.01
2018	209	50	42	26.86	0.28	1%	0.01	7.61	2.99	39%	0.29

The results of adding to the comparison a 3x SRMC flat mitigation approach (across all supply cushions) are shown in Table 12. The AESO notes that the results are most different across the different scenarios for the years when supply was tightest (i.e., 2013) and prices were highest. Otherwise, "[p]ool prices on average would have been very similar, and the incremental efficiency gains from moving from non-graduated to graduated are small for both productive and allocative efficiency."[42]

41 AESO Efficiency Assessment (Appendix R), p. 6.

42 AESO Efficiency Assessment (Appendix R), p. 6.

Table 12: AESO comparison of historic efficiencies to estimated efficiencies under proposed energy market mitigation scheme and an alternative scenario with flat 3X mitigation[43]

Summary Table 2											
Year	Average actual pool price ($/MWh)	Estimated Average pool price after proposed mitigation ($/MWh)	Estimated Average pool price without graduated mitigation ($/MWh)	Estimated Historic productive inefficiency ($ millions)	Estimated Productive inefficiency after proposed mitigation ($ millions)	Estimated Productive inefficiency after non-graduated mitigation ($ millions)	Estimated Incremental productive efficiency gain from non-graduated mitigation (%)	Estimated Historic allocative inefficiency ($ millions)	Estimated Allocative inefficiency after proposed mitigation ($ millions)	Estimated Allocative inefficiency after non-graduated mitigation ($ millions)	Estimated Incremental allocative efficiency gain* (%)
2013	80	51	41	16.32	14.24	12.94	8.0%	21.35	8.16	5.50	12.5%
2014	50	34	33	23.43	17.7	16.75	4.1%	6.7	1.71	1.36	5.2%
2015	33	23	23	10.27	9.72	9.64	0.7%	5.36	0.69	0.56	2.4%
2016	19	19	19	5.01	4.93	4.93	0.0%	0.32	0.29	0.29	0.8%
2017	22	22	22	10.76	10.67	10.66	0.1%	0.58	0.53	0.51	2.5%
2018	50	42	40	26.86	26.58	26.52	0.2%	7.61	4.61	3.49	14.8%

C. Comparison to US RTOs with Capacity Markets

Table 13 compares the AESO's proposed energy offer mitigation level – including whether there is any gradation – with those of other North American capacity markets. The AESO's graduated proposal with mitigation to multiples of SRMC is distinct from the approaches taken in the US markets. In ISO-NE and NYISO, efforts are made to mitigate resources to levels that are similar to recently accepted bids or recently observed market prices in their location. Short of those options, energy offers are mitigated to levels based on cost. In PJM, except for frequently mitigated units, resource offers that are mitigated are limited to 110% of SRMC.

Table 13: Comparison of Energy Market Offer Mitigation Levels in AESO Proposal and US Jurisdictions

	Tiered Offer Mitigation Thresholds for Energy Market Mitigation	Offer Price Cap (or Reference Levels) for Mitigated Units in Energy Market
AESO Proposed	Yes, based on supply cushion	3x SRMC (Supply Cushion > 1000 MW) 6x SRMC (Supply Cushion 250 – 999 MW) None (Supply Cushion < 250 MW)
ISO-NE	No	Option between offer-based reference level (recent accepted bids), LMP-based reference level (recent LMPs at generator node), or cost-based reference level (based on submitted operating costs)
NYISO	No	Similar to ISO-NE
PJM	No	SRMC + 10% Separate treatment for frequently mitigated resources

D. Assessment and Analysis

The AESO's proposal is multifaceted and supported or informed by several analyses. We will address each in turn. Our analysis drives us to question the principles and

43 AESO Efficiency Assessment (Appendix R), p. 7.

underlying analytics of the AESO's proposal. We conclude that as a whole the graduated mitigation approach, including the associated mitigation thresholds and offer price caps, is poorly supported. Furthermore, some of the design trade-offs are not warranted. As a roadmap, our discussion will cover:

- The 1000 MW threshold is unsupported.
- The 250 MW threshold is poorly supported.
- The 6x SRMC threshold is poorly supported.
- The 3x SRMC threshold attempts to solve a real problem, but does so in a very costly manner. Better solutions are available.

We ultimately suggest a more constraining approach towards energy market mitigation that is more in keeping with the objectives of an energy market design in an electricity market framework that incorporates a capacity market. Roughly speaking, the goal is to achieve static efficiency through energy markets, while deferring design elements specific to achieving dynamic efficiency to the capacity market.

1. Graduated Mitigation Thresholds

a) 1000 MW Threshold

In our review of the AESO's Application, we were unable to identify quantitative or qualitative support for this market parameter. Nor has our analysis identified any support for the conclusion that there is a threshold in the Alberta market at 1000 MW that justifies a change in market power mitigation rules.

b) 250 MW Threshold

The AESO brings forth several arguments in support of its proposed 250 MW threshold. First, the AESO states that at 250 MW of supply cushion the market will be approaching a shortfall or "near emergency conditions." While this may be true, no quantitative support is provided, nor any theoretical argument as to why such conditions warrant a change to market mitigation rules and support a different type of pricing dynamic in the energy market.

Similarly, the AESO states that at or around 500 MW of supply cushion the Alberta market has a sufficient available supply to cover its most severe single contingency. This is also an important consideration, but not a clear indicator of when pricing rules should change or shifts in pricing dynamics should be expected. We note that procurement of reserves is intended to address contingencies. We are not clear on the economic logic that supports a change in market rules associated with a supply cushion – or supply cushion equivalent – approaching the size of the largest contingency. Rather, rules that result in higher prices in recognition of scarcity or reserves shortage usually activate after the supply cushion has been depleted and/or when the availability of sufficient reserves becomes a concern. Under such conditions, as we will discuss, we support shortage pricing rules.

The quantitative analysis provided by the AESO in support of the 250 MW threshold hinges on an assessment of historical pricing outliers during certain supply cushion "bands." First, we note that the provided analysis was performed with dated data (2008-2010) so its usefulness may be of limited value.[44] Second, the AESO does not provide a rationale as to why or how historical market outcomes should inform expectations about reasonable energy pricing results under the new market design. As we have described, the expectations for market dynamics in an energy market in a capacity market setting should be fundamentally different than in an energy-only market. The latter has limited utility in informing the former. Third, the AESO does not sufficiently explain why an analysis of pricing outliers should be especially helpful. Nor are we clear on the theoretical support for this analytic framework.

Setting aside whether the outliers-based framework is relevant to diagnosing scarcity, there are additional problems with the AESO's evidence. If the analysis is repeated for a more contemporary time frame, the observations of outliers are no longer present. As shown in Table 14, the same analysis performed for the 2013-2018 period shows no outliers[45] below 750 MW of supply cushion. This result almost becomes a definitional issue, as the standard deviations on the data set are so large that just one standard deviation away from the mean exceeds the market price cap. There are a very small number of outliers at higher supply cushion levels, again driven by the decline in standard deviation in the data, which enables some "outliers" below the price cap. While not shown, these general trends hold if the same analysis is completed for individual years.

Table 14: Supply Cushion "Bucket" Analysis for 2013-2018

Supply Cushion "Bucket"	Count in Bucket	Mean	Standard Deviation	Within Mean + 3x St. Dev.	Count of "Outliers"	% Outliers
0-250	176	641	1784	176	0	0%
250-500	522	333	1487	522	0	0%
500-750	1534	155	1066	1534	0	0%
750-1000	3159	85	787	3159	32	1%
1000-1250	4951	62	634	4951	80	2%
1250-1500	6135	43	519	6135	39	1%
1500-1750	6735	31	441	6735	10	0%
1750-2000	6381	26	393	6381	1	0%

In order to provide some additional insight, we have included two additional figures. Figure 5 shows the frequency of pricing hours within supply cushion buckets, the same type of groupings as the AESO used for its analysis of outliers. Generally, statistical analysis that focuses on means and standard deviations from those means is applied to distributions where the standard deviation is known to capture a certain

44 The AESO alludes to the fact that choosing the 2008-2010 time frame is appropriate because it was before the implementation of the Offer Behavior Enforcement Guidelines were implemented. However, it is unclear why this is relevant.

45 We will work with the AESO's definition of outlier as +/- 3 standard deviations from the mean.

portion of the probability mass (such as the normal or log-normal distributions). It is clear from these graphs that such distributions are not observed in the data.

Figure 5: Historical Frequency of Pricing Hours when Supply Cushion in 250-500 MW Range[46]

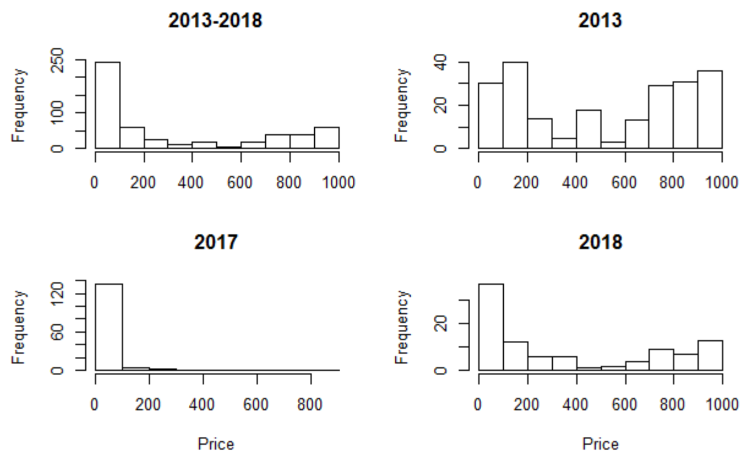
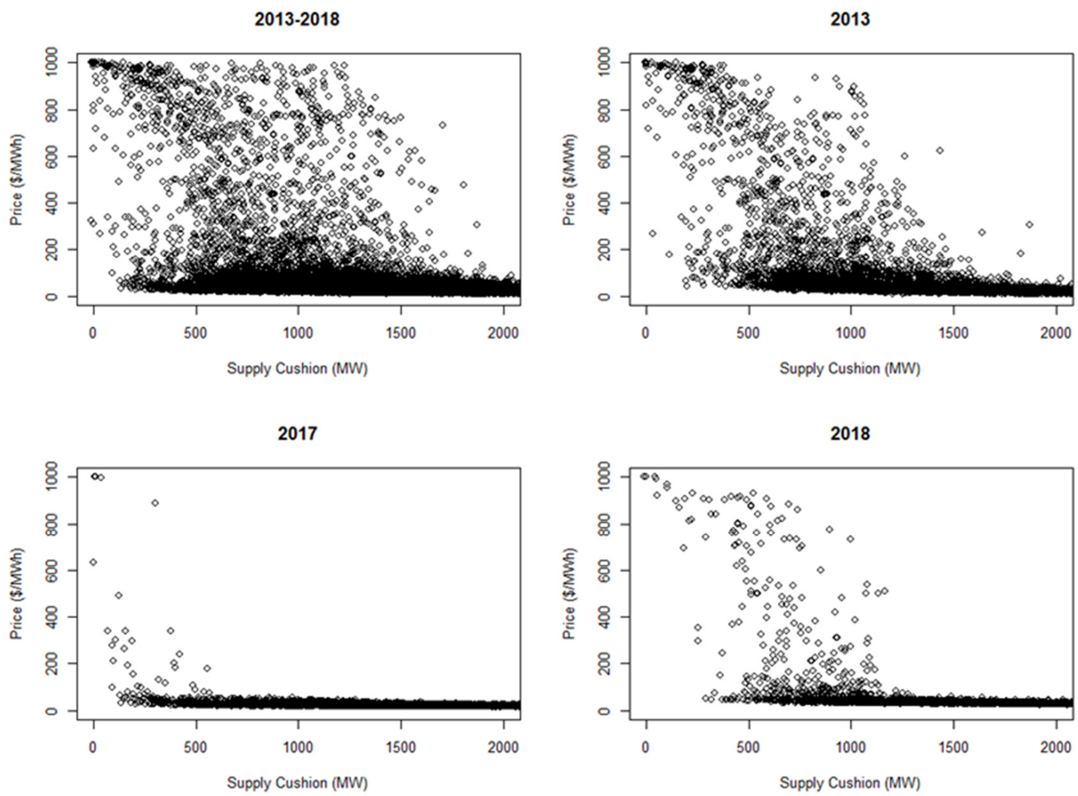


Figure 6 shows supply cushions as compared to the Alberta market price. Dynamics clearly vary from year to year. Prices at lower supply cushions do tend to be higher. Prices at higher levels of supply cushion tend to be lower, particularly above a certain level (that appears to vary from year to year). Bu,t in any case, at least based on a visual inspection, there do not appear clear thresholds in the Alberta market when pricing outcomes shift from one level to another, and there are certainly not thresholds that persist from year to year, at 250 MW, 1000 MW, or otherwise.

46 Data sets for periods marked 2013-2018 include 2014, 2015, and 2016. The selection of the years 2013, 2017, and 2018 is described in more detail in Appendix A. The reasoning for presenting data for these years holds throughout this report.

Figure 6: Historical Alberta Supply Cushion Compared to Pool Prices



2. Offer Price Cap Mitigation Levels

a) 6x SRMC

The AESO describes the 6x SRMC offer cap for mitigated resources as being based on the approximate level at which price responsive load has been observed. However, it does not provide data or analytic support for this statement. We are aware of earlier analysis of price responsive load in the Alberta market.[47] This analysis found only a limited amount of MW that are responsive. It is also not clear if this is the data to which the AESO is referring. Furthermore, the notion that price responsive load is observed at 6x SRMC is entirely ambiguous. The AESO does not specify to what SRMC it is referring; SRMC is likely to be constantly changing. For example, if the AESO is referring to the SRMC of the marginal resource, that could vary from $10 / MWh in one hour to $100 / MWh in another, with the 6x multiple varying accordingly. Thus, 6x SRMC is not one value that can be identified as when responsive load, or any other market participant behaviour, is observed.

The AESO has also noted that the 6x SRMC offer cap level provides some graduation between a proposed 3x SRMC offer cap period and the proposed no-look

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47 Alberta MSA, "Assessment of Static Efficiency in Alberta's Energy-Only Electricity Market: An assessment undertaken as part of the 2012 State of the Market Report," December 21, 2012. p. 25.

period. While true, this fact does not constitute principled support for a proposed market rule.

b) 3x SRMC

We understand that the AESO is concerned with ensuring that resources that are able to respond to system needs quickly, and that may only operate for short periods, are not put in a position in which they are unable to recover their short-term fixed costs (i.e., start-up costs) due to constraints imposed upon them by the market rules. The analyses presented by the AESO to support the 3x energy offer price cap appears to be a reasonable analytic framework for assessing the frequency and scale of potential cost under-recovery as compared to a scenario in which resources are limited to offering at their SRMC.

To confirm that the AESO's findings hold across a longer time period – Brattle's analysis was done with data from 2013-2015 – and across a range of input assumptions, we replicated the analyses with different input data and parameters. Figure 7 shows the frequency of run times at full output for a selection of simple cycle gas units in the Alberta market. Provided in Table 15, these simple cycle units average, in aggregate, approximately 230 full output operating events per year that last 30 minutes or less, which constitute about 10% of their full output events. On a percentage basis, this is somewhat lower than what was presented by the AESO (16%). This is likely due in part to analysis over a different time span, but there is also likely variation introduced by different analysis methodology.[48] Table 16 shows the sensitivity of the average-to-marginal cost calculation to variation in assumed gas price and marginal unit heat rate. The ratio shows some sensitivity to these assumptions, and 3x appears to be a conservative but not unjustified approximation of the multiple of SRMC that would need to be permitted to allow an average gas turbine to recover its cost during most operating periods.

Table 15: Run Times Event Frequency for Simple Cycle Units, 2013-2018 (Full Output Events)[49]

	% of Total Observed Output Events				Total Observed Output Events			
Period	**2013**	**2017**	**2018**	**13-18**	**2013**	**2017**	**2018**	**'13-18 Avg.**
<= 30 Minutes	8%	11%	9%	10%	187	179	218	231
<1 Hour	21%	19%	17%	22%	469	321	401	493
<2 Hours	31%	31%	23%	32%	689	512	546	727
<3 Hours	37%	39%	27%	39%	817	645	651	879
<4.5 Hours	44%	52%	34%	49%	973	857	820	1,115

48 Insufficient information was presented to allow exact replication of the AESO analysis.

49 The 2013-2018 totals and averages do include, 2014, 2015, and 2016.

Figure 7: Run Times for Simple Cycle Units, 2013-2018 (Full output events[50])

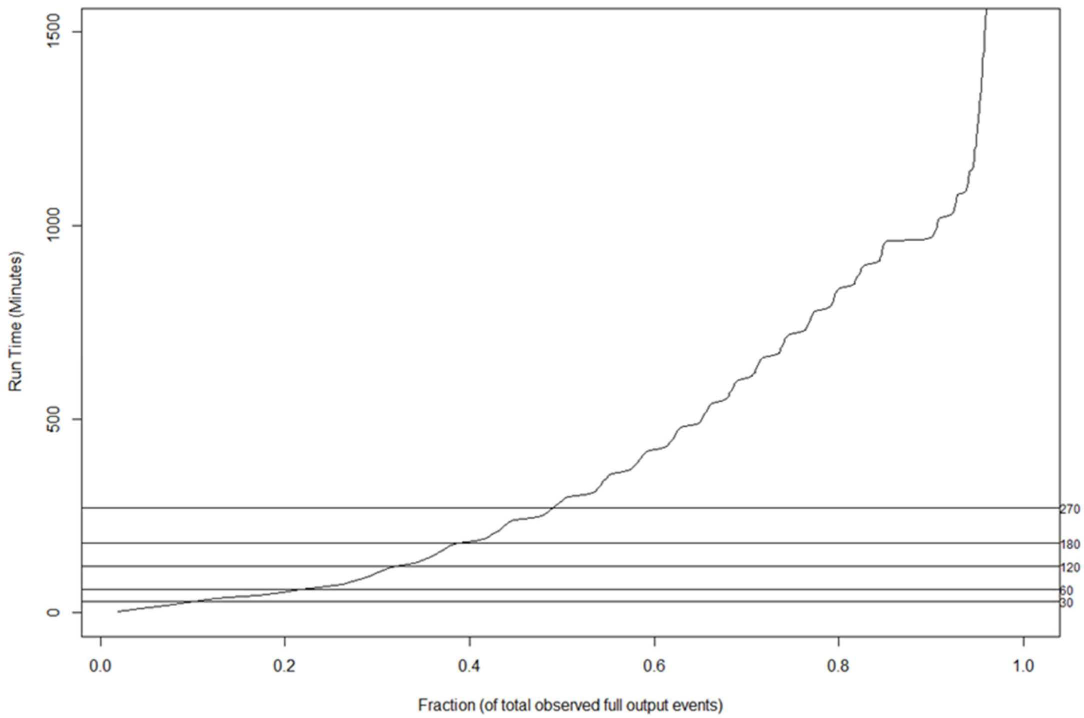

Table 16: Sensitivity of Average-to-Marginal Cost Ratio to Gas Price and Heat Rate (for 30 min run time)[51]

		Gas Price ($ / GJ)									
Basis	**GJ/MWh**	**1.20**	**1.40**	**1.60**	**1.80**	**2.00**	**2.20**	**2.40**	**2.60**	**2.80**	**3.00**
Brattle Market Power Study	9.15	3.32	3.14	2.98	2.86	2.75	2.66	2.57	2.50	2.44	2.38
Frame CT	10.06	3.18	3.00	2.85	2.73	2.63	2.54	2.46	2.39	2.33	2.28
Aero CT	9.68	3.24	3.06	2.91	2.78	2.68	2.59	2.51	2.44	2.38	2.32
Observed[52]	12.95	2.83	2.67	2.53	2.42	2.33	2.26	2.19	2.13	2.08	2.03

50 Analysis is based on full output events, using 5-minute data, defined as discrete operating periods when the average output during a cycle is greater than 75% of a units maximum capacity. This analysis is designed to be analogous to the analysis conducted by Brattle and presented in section 10.7.17(a) of the CMD Final Rationale documentation. Given timing constraints, we analyzed a subset of relevant units, including: Crossfield (1, 2, 3), Cloverbar (1, 2, 3), Judy Creek, Carson Creek, Poplar Hill, Valley View (1, 2), Edson.

51 Assumes similar plant characteristics to those assumed by Brattle in terms of start fuel cost and non-fuel start cost and variable operations and maintenance expenses. http://files.brattle.com/files/13751_market_power_screens_and_mitigation_options_for_aeso_energy_and_ancillary_service_markets.pdf (p. 54-55)

52 Based on CRA research and Energy Velocity data sets for CT generators in Alberta.

Returning to the rationale for this market design element. The 3x SRMC mitigation level is designed, primarily, to allow for all-in resource costs to be offered into the energy market consistent with the single-part bid model. We have found no fatal flaws with the analysis underlying this reasoning. However, it is our view that this design decision, while leading to simplification, reduces market efficiency, diminishes checks on the exercise of market power, and unjustifiably increases costs to load. We address these concerns in order.

First, with respect to economic efficiency in an energy market, an efficient energy price is set by the marginal operating cost of the marginal unit.[53] Any energy market rule that allows or intends for the market price to be set by a supply resource based on an offer that reflects its marginal cost *plus* an adder to recover fixed operating costs is inherently inefficient. In a marginal cost plus mark-up offer structure, there are other costs included in the energy market offer price in additional to the marginal operating cost. Relying on “marginal cost plus” offers threatens both productive and allocative efficiency. Such offers may not lead to the selection of the most efficient set of operating resources during any period. Furthermore, this type of offer creates the risk that demand may shift based on a prices signal that is inconsistent with the cost of the next unit of available supply.

Second, the proposed approach is likely to fail in thoroughly mitigating the exercise of market power in the energy market. Allowing mitigated offers at 3x SRMC raises concerns that, even with offer mitigation, there will considerable opportunities to raise prices above competitive levels. Indeed, such an approach *allows* the exercise of market power, if only up to the set multiplier of SRMC. This holds for both the 3x SRMC offer cap and the 6x SRMC offer cap. Surely, some mitigated offers will include adders for the sole purpose of ensuring recovery of fixed costs, but that does not change the fact that the proposed approach is not effective at mitigating the exercise of market power for firms that fail the RSI screen.

Third, as we argued on the topic of capacity market power mitigation, there appears to be a trade-off here that has been made by the AESO in formulating its proposal. In this case, it is between implementing a sufficiently constraining set of mitigation rules (i.e., requiring energy market offers at or near SRMC) and creating additional administrative requirements and rules, which may also result in additional cost to consumers. Here, those requirements and rules would need to create an alternative approach to making generators whole that operate economically during a period but are nonetheless unable to recover their start-up costs during that period. In other markets, this is generally achieved through multi-part offers and uplift payments.

As with the case of our capacity market mitigation critique, we can attempt to quantify the trade-off. We focus, on the one hand, on the magnitude of the cost of allowing energy market offers to cover all in operating costs. On the other hand, the cost that actually needs to be recovered by some other mechanism to allow recovery of start-up costs. If the difference between these two values is sufficiently large, we would posit that would be a good indicator that proposed rules do not strike the appropriate

53 Bowring, Joseph. Testimony of Joseph Bowring before the Ohio Energy Mandates Study Committee. April 16, 2016. p 3

balance, and the additional administrative effort would be justified to implement a more complex solution to facilitate cost-recovery.

For simplicity, we focus on the test case relied on by the AESO, in which CT resources that operate for less than 30 minutes fail to cover their all-in costs. Consistent with Brattle analysis, we assume start-up costs of $2,146, marginal cost of $24.88 / MWh and 100 MW output at full load. We assume a price-setting offer at exactly the amount necessary to fully recover costs in a 30-minute operating period, which is 2.73x SRMC, or $67.80 / MWh. We assume the average Alberta internal load for 2018, which is 9,740 MW. In Table 17, we calculate the cost that is passed to consumers in excess of what is necessary to allow the hypothetical marginal generator to recover its all-in costs. We then expand the result to the number of events representative of a historical average year. In this case, the cost of the proposed 3x SRMC approach to enabling cost recovery is nearly one hundred times more expensive than providing directly compensating the marginal generator for its un-recovered start-up costs and the costs to load amount to tens of millions of dollars per year.

Based on this analysis and the prior discussion, we conclude that an alternative approach to recovering fixed-costs is warranted to protect consumers from inefficient market outcomes and large costs that would result from the AESO's proposed energy market mitigation offer cap at 3x SRMC.

Table 17: Calculation of Additional Cost to Load of Allowing Start-up Cost Recovery through Energy Market Offers (30-minute events only)

Category		Value	Equation
Marginal cost of marginal unit	[A]	24.88 / MWh	
Expected mark-up to account for start-up cost recovery	[B]	2.73 x	
Market offer of marginal unit	[C]	$ 67.80 / MWh	[A] x [B]
Mark-up portion of offer applied to all market energy during price setting period	[D]	$ 43.04 / MWh	[C] – [A]
Hourly demand	[E]	9,740 MW	
Event duration	[F]	0.5 hours	
Cost to load of mark-up	[G]	$209,604	[D] x [E] x [F]
Cost necessary to make marginal generator whole	[H]	$2,146	
Additional hourly cost to load in excess of necessary make-whole payment	[I]	207,459	[G] – [H]
Average events per year	[J]	231	
Additional annual cost to load		**$48.923 M**	[I] x [J]
Total make-whole payments required		**0.496 M**	[H] x [J]

While the above is a severe case, the result can be generalized. The underlying logic holds: the problem is that when a resource offers its all-in operating costs, clears the market, and sets the clearing price, every generator in the market is paid not only the marginal cost of the next unit of supply, but also the mark-up for start-up costs. While this is convenient for the marginal unit and a boon for the rest of the market participants, it also means that consumers wind up paying the associated mark-up across all energy consumed during that period.

We also acknowledge that this is a very rough approximation. We likely underestimate the number of occurrences because we have not analysed historical outcomes for all plants to derive the 231 annual average event count. We also agree with the AESO that this type of event is more likely to happen in the future owning to increased deployment of variable energy resources. We have also not counted the larger number of less severe cases (i.e., smaller mark-ups) when resources would face start-up cost under-recovery during longer events (e.g., 1 hour run time).

In certain respects, our simplifications also may lead to over-estimation of the AESO proposal's costs. We do not account the fact that some cost in excess of marginal costs may be recovered if the plants in question – those operating at full output for fewer than 30 minutes – are not in fact marginal during the entire period and collect inframarginal rents. There is also the issue that not all such plants will be subject to mitigation, and may therefore offer without constraints. Despite these shortcomings, we believe that our analysis is a good indicator of the general order of magnitude, on an annual basis, of the trade-off in question.

It is possible to perform a more thorough analysis of this type. Indeed, the AESO has done so. In its Efficiency Assessment, filed with its application, the AESO provided the results of a far more nuanced analysis. While the Efficiency Assessment did not assess the benefit of going from a 3x SMRC offer cap to an offer cap closer to 1x SRMC, it did examine going from no offer mitigation to the proposed graduated mitigation to a mitigation offer cap of 3x SRMC in all hours.[54] With each successive level of mitigation, the AESO's analysis shows that:

- Productive efficiency improves; and
- Allocative efficiency improves; and
- Cost to load decreases.

The results are summarized very briefly in Table 18. The same dynamics drive the AESO's results as drive the results in our rough calculation provided here.

54 We suggest that the AESO could be asked to expand the analysis provided in the Efficiency Assessment to examine the effects of more aggressive approaches to mitigating screened energy offers.

Table 18: Load Cost and Economic Efficiency Impact of Alternative Energy Mitigation Approaches (Summary of AESO Efficiency Assessment)

Mitigation Scenario	Proposed Graduated Mitigation	No Graduation 3x SRMC for All Hours
Historical Pool Price	$ 42.3 / MWh	
Average Reduction in Pool Price	$ 10.5 / MWh	$12.7 / MWh
Estimated Reduced Cost to Load (assumes 80 TWh annual load)	$ 840 M	$ 1,013 M
Productive Efficiency Improvement	Yes ~8% average	Yes ~2% average
Allocative Efficiency Improvement	Yes ~48% average	Yes ~6% average

c) No-Look Period

The AESO presents three qualitative arguments in support of the no-look period and the absence of any market power mitigation measures when the supply cushion is below 250 MW. These include:

- Allow prices to reflect real-time scarcity;
- Create incentives for generator ramping and flexibility; and
- Avoid mitigating even smaller firms when supply is tight, thus addressing one of the perceived weaknesses of the RSI-based energy market power screen.

Shortage pricing is an important issue in electricity markets. We deal with this in more depth in the following section.

This issue of appropriate pricing levels during no-look periods leads us to our second concern, which is associated with the exercise of market power. When the 250 MW threshold is passed, there is, by definition, a small supply cushion. And when there is a small supply cushion, there is arguably a greater potential for profitable exercise of market power because a much higher number of suppliers are likely to be pivotal. This is precisely when the screen should be capturing the largest number of firms. During these periods, waiving the RSI-based market power screen leads to heightened opportunity to exercise market power when the market is most vulnerable to such behavior. The result would likely be inefficiently high prices that reflect exercise of market power and fail to reflect supply and demand fundamentals. Such a result would be inconsistent with the AESO’s objective of achieving competitive price discovery during periods when the balance between supply and demand is tight.

With respect to sending dynamic signals for investment in ramping capability, we are skeptical. It would be helpful to have quantitative evidence that there is a shortage of such capability in the Alberta market, that ramping capability is what is actually lacking during low supply cushion periods, and that the kinds of price signals during such periods would in fact be sufficient to incent this kind of investment. We are skeptical that the no-look periods would create a strong incentive to support investment in ramping capability; the price signal could be too volatile to serve this purpose.

d) Shortage Pricing

A long-run equilibrium in wholesale electricity markets is achieved when energy and ancillary services market (including shortage pricing in those markets) along with capacity market revenues allow a marginal resource to cover its entry costs. In order for "energy-only" markets to provide enough revenue to sustain adequate planning reserves, significant amounts of revenue must be earned during shortage events so that units that are almost always idle cover their fixed cost. In Alberta, a sort of shortage pricing has been in place historically that allows market power exercised so that some contribution to fixed cost can be earned.

With the introduction of a capacity market, participants now have three sources of revenue: (1) energy and ancillary services markets; (2) "shortage" pricing in the energy and ancillary services markets; and (3) and the capacity market. In theory, Alberta will have the three main sources of revenue that are found in most modern electricity markets. However, an effective shortage pricing framework should not rely on market power during shortage periods, but instead rely on efficient pricing during actual shortages. Efficient shortage pricing would likely generate higher revenues than the exercises of market power allowed under the AESO proposal. This would shift revenues out of the Alberta capacity market and into the energy market where they will provide meaningful incentives for suppliers to be flexible and available.

We are also concerned that the proposed approach to achieving shortage-type pricing conflates several objectives and economic concepts. Proper shortage pricing – distinguished here from the historical approach to scarcity pricing – allows energy prices to rise above marginal cost during periods when there are capacity constraints. In theory, prices should reflect marginal cost of supply until there is an actual capacity constraint. During such capacity constrained periods, the price would be set by the demand side (or a proxy for the demand side, like administrative shortage-level pricing) at the marginal value of consumption.[55]

Inconsistent with theory, however, the proposed rules implement "no look" procedures ahead of the period when supply technically becomes scarce (i.e., when the system starts to run short of reserves) and shortage pricing is actually indicated. We question why prices this high are warranted at such a time. These factors lead us to conclude that the proposed rules may lead to premature allowance of prices approaching shortage levels, and set prices at levels that are not necessarily competitive nor economically justified.

Taken together, there are two critical problems with the proposed approach:

- Relying on suppliers to exercise market power by raising their offer prices in order to set efficient shortage prices is extremely unreliable – it can result in prices that are much higher than efficient shortage prices or much lower.

55 See, *e.g.,* Peter Cramton, *Electricity Market Design*, Oxford Review of Economic Policy, Volume 33, Number 4, 2017, p. 599.

- The "shortage" price is capped at $999/MWh, which can be significantly lower than the true marginal value of energy during substantial shortage conditions.

Shortage pricing rules in other RTO markets can serve as guidance for the AESO. In general, other RTOs in North America trigger shortage pricing when operating reserve levels are less than required.[56] The shortage pricing in these markets is set by operating reserve demand curves, which establish the value of the operating reserves. When reserve levels are short, this value is embedded in both the energy and reserve prices. In general, the shortage price increases as the ancillary service shortage deepens. This is logical given that the system is at increasing risk of involuntary outages as the shortage increases.

A framework like this has the virtue of removing shortage price from economic withholding. Economic withholding is a function of a participant's portfolio (it maximizes profits over its portfolio, considering the lost revenue from withheld units against the higher prices induced). This is not related to the value of scarce reserves. The second virtue is that the shortage price can be linked to actual shortage costs, which likely exceed the $999/MWh offer cap.

The ERCOT market in Texas may provide a good example of shortage pricing for AESO because, like AESO, ERCOT does not jointly optimize its dispatch of resources for energy and operating reserves. In Texas, the real time clearing is increased by the 'Real-Time Reserve Price' which is determined based on the level of reserves being maintain on the system in accordance with an operating reserve demand curve ("ORDC"). The ORDC reflects the incremental value of a MW of operating reserves at any given level of available operating reserves. It is based on Loss of Load Probability (LOLP) at that reserve level multiplied by Value of Lost Load (VOLL). For some levels of shortages, the real-time shortage price adder exceeds $999/MWh.

E. Suggested Alternatives

We recommend market rules that:

- Mitigate resources that fail the market power screen to SRMC plus a price-based adder, without regard to supply cushion. We recommend an adder of $25/MWh.[57]
- Establish procedures for resources to submit start-up-costs (and other fixed costs associated with each unit operating cycle) and to monitor such submissions for accuracy.

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56 https://www.aeso.ca/assets/Uploads/4.3-Brattle-Paper-Shortage-Pricing.pdf

57 We suggest $25/MWh as an adder to SRMC for mitigated units, consistent with the market rules for conduct and impact screening thresholds in ISO-NE as well as other mitigation measures in MISO. This level has been supported as sufficient to provide for uncertainty in fuel prices during tight conditions, provides leeway for inaccuracies in estimating SRMC, and provides for accounting factors that may be difficult to quantify but are appropriately included as marginal operating costs.

- Provided compensation for unrecovered fixed costs to certain resources that fail to recover fixed costs during a given operating period.[58]
- Allocate the costs make-whole payments to customers via uplift charges.
- Implement a set of rules to specifically reflect shortage prices. This could take several forms, including an ORDC or price adders during reserves shortages.

The AUC may be interested in alternatives that fall between our recommended approach and the AESO's proposal. We view these alternatives as inferior to our recommendation, but superior to the proposed mitigation scheme.

- Implement technology-specific energy offer mitigation. Mitigated resources would be allowed to offer at SRMC plus a technology-specific adder (or multiplier) to account for start-up costs.[59] Coal and CC units would be assigned lower adders (or multipliers). No cost recovery guarantee through uplift.
- Implement 3x SRMC offer cap for mitigated resources during all other periods rather than depending on the graduated scarcity methodology. No cost recovery guarantee through uplift.

Either of the above alternatives could be implemented with a no-look period or an ORDC-type approach to representing scarcity. For the reasons we have described, the latter is highly preferable. If the no-look provisions are to be maintained, we recommend diligent monitoring of that provision's efficacy. Ex-post analysis of no-look periods should assess the extent to which prices during these periods reflect market fundamentals, and the extent to which they reflect the exercise of market power.

In any scenario in which energy market offers are not mitigated close to SRMC, considerable inefficiencies are likely to be introduced to the market and consumers will face increase costs, as illustrated in the Efficiency Assessment and Table 17.

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58 The availability of the cost guarantee would need to be limited to certain resources to avoid shifting unit commitment risk unnecessarily to consumers and to limit opportunities for manipulative behavior. The set of applicable resources should be constrained to those resources for which the cost guarantee provision was created. For example, this may be defined based on how quickly a unit is able to start and a reported minimum run time. Resources like Long Lead Time units should not qualify. Oversight will be necessary to validate stated start-up costs.

59 Technology-specific adders would likely be higher for generators that operate the least frequently and have to collect their total operating costs across shorter operating periods. On the other hand, adders would be expected to be close to zero for inframarginal resources that operate during long periods and are consistently able to recover costs through inframarginal rents. The specific price adders could be denominated in a fixed $/MWh quantity or as a multiplier of marginal cost. (Given that many VOM parameters are not dependent on fuel price or other market conditions, it likely makes more sense to establish adders that are a fixed $/MWh quantity rather than a multiple that varies the bid cap based on market conditions.) The exact levels of adders or multipliers would be based on a more thorough analysis of resources in Alberta, and the supporting analysis could be mechanically similar to the total vs. marginal operating costs study performed in support of the AESO 3x SRMC proposal. This would also need to be updated on a regular basis as experience is gained with dispatch patterns in the new marketplace and as dispatch patterns change with increased penetration of renewables in Alberta. Such an approach could also be undertaken on a resource-specific basis as opposed to a technology-specific basis. Our view is that adders are superior as they avoid spiraling up in the ASRP in periods when fuel cost may be experiencing a short-term spike.

F. Discussion of Alternatives

a) Impact of Recommendations

Our analysis suggests serious flaws with the justifications for many of the elements of the AESO's proposed energy market power mitigation rules. We found little compelling support for the 1000 MW supply cushion threshold, 250 MW supply cushion threshold, and the 6x SRMC offer cap. We do not find credible the rationale that underlies the allowance of a no-look period when the market is tight. The justification for the 3x SRMC mitigation offer cap is supported by evidence but threatens to be a very costly approach to handling the issue of start-up cost recovery in an energy market with single-part offers. As a whole, our view is that the AESO's proposal in this regard will result an inefficient market while creating costs to consumers considerably in excess of what is reasonable.

Our recommended approach to mitigating screened resources in the energy market would address the shortcomings of the AESO's proposal and bring the energy market rules in line with the goal of static efficiency. They would also bring the Alberta market more in line with practices in the US RTOs. Were our recommendation implemented, we would expect energy market prices to fall, on average, owing to capping of mitigated resource offers at lower levels. Correspondingly, we would expect capacity market prices to rise, as market participants revise their offer behaviour in the capacity market and net-CONE increases (because of a lower E&AS offset).[60] Furthermore, as we discuss in more detail below, both energy and capacity prices would become less volatile. The increased certainty will support investment and reliability, and may also facilitate a more active forward market.

Our proposal would eliminate the concept embodied in the AESO's proposed rules that allows the exercise of market power as a stand-in for a more controlled shortage pricing regime. We are not aware of any economic theory that suggests the exercise of market power would efficiently approximate shortage pricing. Simply creating rules that lead to higher prices does not mean an efficient outcome will be achieved. We recommend against relying on the exercise of market power in the energy market to send proper shortage pricing signals. Instead, we recommend a shortage pricing mechanism, even the simplest of which would be superior to AESO's proposal in this area.

The primary conforming change associated with our recommended approach would be the need to create rules for submitting start-up costs along with energy market offers, as well as the need to create a mechanism for allocating uplift costs. We suggest that the existing rules associated with "Payment to a Supplier on the Margin"[61] may provide a ready model for how to accomplish this.

Our proposal is considerably different from, and more stringent than, the AESO's proposal for energy market power mitigation. Not only do we believe this is justified, as we have described extensively, but such conservativism is also appropriate in a

60 This result is dependent on effective formulation of the E&AS offset rules, which we discuss in the following section.

61 ISO Rules 103.4.

market design process. Specifically, before the first set of market rules has been approved. It is at this time that it may be most appropriate to set tight constraints on market participant behaviour. Constraints can be eased later if there is justification to do so, but it can be challenging to tighten such rules later. Permissive market rules are much more difficult to pull back once a market is underway.[62]

We provide several additional comments on the implementation of uplift rules. First, providing a start-up cost recovery guarantee actually increases certainty for generators. Particularly in the face of expected changes in market conditions, like increased wind generation, frequent short operating periods could magnify the aggregate financial risk of under-recovery of all-in generating costs. Second, moving away from the 3x SRMC approach to the uplift approach eliminates risk that the administrative 3x threshold is incorrect (in either direction), which could cause over- or under-mitigation and drive controversy. Finally, we recognize that providing such an uplift scheme shifts some commitment cost risk to consumers. It is our view that the overall benefit of the proposed uplift approach outweighs this risk (and cost).

b) Benefits of Recommendations to Both Energy and Capacity Markets

As a whole, we would expect our recommended approach to improve efficiency in both the energy and capacity markets. Energy markets are linked to the capacity market through net-CONE (via the E&AS offset) and through resource expectations for future energy and ancillary service revenues that drive calculations of net going-forward costs. The more market power that may be exercised in the energy market (either explicitly allowed or made possible through lenient mitigation rules) the more difficult it is for all parties to calculate expected energy and ancillary service market revenues. We would expect such calculations to discount the possibility of market power-driven prices. Doing so is both simpler and less risky to market participants. If prices are indeed driven by the exercise of market power, market entities relying on fundamentals-based forecasts would underestimate expected energy and ancillary service revenues, thus driving up their estimations of both net-CONE and net going-forward costs. Higher estimates for these parameters would lead to higher capacity market prices, and potentially inefficiently high consumer cost.

The benefits of our recommended approach also include reducing the extent to which energy market prices are unpredictable because they are not based on economic fundamentals – as is likely to result from the proposed energy market power mitigation rules. The resulting risk and uncertainty may lead to inefficient outcomes and additional costs in the capacity market. This dynamic between energy market outcomes and capacity market parameters is illustrated Table 10.

62 For example, market participants may claim they have already made investment decisions, the economics of which might be undermined by a change in market rules that threatens to reduce revenue below expected levels.

c) Concerns over Physical Withholding

Both the AUC[63] and the AUC's expert, Dr. Cramton, have raised concerns over physical withholding in the energy market.[64] In particular, that constraining offers to a level close to SRMC will create incentives to physically withhold either to (i) increase total available energy margins in response to lower average energy market prices or (ii) limit unit commitment risk during periods when there is concern that a resource – particularly an LLT resource – may operate but fail to recover costs. Cramton, in his further comments, states, "[a]ttempts to prevent economic withholding by requiring cost-based bids can backfire as large suppliers can engage in physical withholding instead of economic withholding. This is especially easy with long lead time assets in the Alberta market." [65]

First, we point out that we are not proposing to impose "cost-based bidding" on all market participants. Rather, we are proposing near-cost based offer constraints on resources that represent a concern over the exercise of market power. This appears to be within the realm of what Dr. Crampton believes is acceptable. He states, "It is neither desirable nor practical to impose cost-based bidding, except as part of a narrowly tailored remedy to mitigate market power."[66] We agree.

Second, we point out that the existence of incentives to physically withhold capacity with the objective of driving up market price is a problem that exists with or without restrictive energy market mitigation rules. Declining to mitigate market power is not the solution, nor is implementing a permissive mitigation regime. This problem is appropriately addressed through creating incentives not to physically withhold – as the AESO has proposed through its performance incentive rules – and through active monitoring of market participant behavior. For example, in the markets monitored by Potomac Economics, outages are monitored to determine whether there is a price impact, in which case the market monitor may investigate the nature of the outages and justification for it. Cases of unwarranted outages can result in sanctions, including financial penalties.[67]

Finally, we address concerns that our recommended mitigation will create additional commitment risk for LLT resources, leading market participants to hold their resources out of the market. We suspect that this concern is overstated. The underlying problem would be that such resources would be unable to recover their costs if they operate but do not receive sufficient revenue from system prices. As

63 Related Application Requirements: AUC-AR-40.

64 The proposed energy market power mitigation framework lacks provision for monitoring and mitigating physical withholding. Physical withholding occurs in the energy market when a participant derates its capacity (so the system has less physical capacity available) or the participant changes its physical parameters (e.g., maximum dispatch level, minimum run time, minimum down time, ramp rate) so it is not available to the market.

65 "Further Comments on the Design of the Alberta Capacity Market", Peter Cramton, February 22, 2019, p. 4.

66 "Further Comments on the Design of the Alberta Capacity Market", Peter Cramton, February 22, 2019, p. 3.

67 Potomac Economics also monitors and mitigates physical withholding by way of reviewing physical offer parameters.

shown in Brattle's run-time analysis,[68] coal and CC resources exhibit calculated average-to-marginal cost ratios of 1.01 to 1.45 in the representative scenarios shown. This implies that such resources must receive up to 1.45x their SRMC (cold start CC operating for 9 hours) their SRMC to guarantee cost recovery during an operating period. Here, we point out that this multiplier is only relevant as an offer multiplier for cost-recovery if such a resource is the marginal-price setting supply during the entire operating period. It is unlikely that a resource operating for an extended period would be marginal; infra-marginal rents would be available and would likely enable recovery of start-up costs. We expect that this would be confirmed via further analysis.

d) Treatment of Storage Resources

The AESO has proposed a technology-specific treatment for mitigating energy storage assets. This treatment is based on the AESO's contention that, "these assets have unique energy limitations or environmental considerations that affect their operations and they are also unique with respect to how opportunity costs are determined."[69] If a storage resource is controlled by a firm that is determined to be pivotal, its asset-specific offer cap (a.k.a., the ASRP) will be set at three times the rolling average pool price. However, such a screened resource will also have the option to offer its full capability into the ancillary services market on an unmitigated basis. If the storage resource does offer into the ancillary services market, the AESO reasons that the ancillary service clearing prices will effectively set the opportunity cost for water.

If the resource fails to clear in the ancillary services market, it may then offer the same generating capability into the energy market and an offer price up to the offer cap. The AESO states that, "This approach ensures that first, a mitigated hydro asset cannot withhold or avoid their capacity obligation simply because they are mitigated and second, that the mitigated hydro asset can only use the energy market to manage their water once they have tested the need for the certain ancillary services products."[70] The AESO continues that, "While operators of these assets may be motivated to participate in the ancillary services market regardless, this approach ensures that energy storage offers do not distort energy market prices if the asset is held by a company that holds market power."[71]

The result of the proposed rule is inconsistent with the intent of market power mitigation objectives. As we understand it, all a storage resource must do to avoid market power mitigation measures is to offer into the ancillary services market. There is no requirement to clear in that market, and no constraints on that price at which such a resource may offer. This effectively allows a hydro resource – operated by a market participant found to be pivotal in the energy market during a given period – to fully skirt energy market power mitigation simply by placing a very high offer into the

68 CMD Final Rationale (Appendix A), section 10.7.17 (a).

69 AESO Application, P 579.

70 AESO Application, P 581.

71 AESO Application, P 583.

ancillary services market. Confident that an offer has been placed at such a high price it will not clear, the market participant may then proceed with any offer strategy it so pleases in the energy market, which may include the exercise of market power. We are not clear as to why this is an effective approach to addressing potential exercise of market power by storage resources based on the logic provided.

We recommend that the AESO be required to provide more clarity on its proposal. In the alternative, we recommend that the AESO develop an approach to calculating the SRMC for such resources. This approach should be designed to be a reasonable proxy for the opportunity cost of stored energy, and may account for the specific characteristics (e.g., water cycling period) of a unit. Potomac Economics has be able to effectively establish such protocols, including the calculation of reference prices, in the markets it monitors. Once a storage-specific SRMC methodology has been created, such resources should be mitigated similarly to all other resources in the energy market.

e) Multi-lateral Exercise of Market Power and Conduct and Impact Mitigation as an Alternative

The energy offer cap is imposed on participants that are identified as having market power in each settlement interval. For each participant in each settlement interval a variable called the Residual Supply Index ("RSI") is calculated. The RSI measures how important supply from a participant is to meeting demand. Participants which are sufficiently large so that demand cannot be met without them producing a positive amount of output are called "pivotal" and are identified as having market power in the energy market in that settlement interval. The AESO will use an automated process initiated two hours before the dispatch interval to evaluate the RSI and to mitigate accordingly.[72]

Relying only on an RSI to determine if a firm has market power can be inadequate in many important circumstances. For example, it fails to address market power that may be exercised through coordinated interaction. Given the frequent interaction of participants in the energy market and the fungibility of the product, tacit collusion is a considerable concern. Failing to impose market power restraints that pass the screen could miss instances of multi-lateral market power. While an individual may not be pivotal, two or more acting in concert may be. The RSI does not account for this.

An alternative approach to the RSI screen, one that is employed in several US RTOs, is a conduct-impact structure. Alberta could employ such a system. It would overcome the deficiencies of the RSI as a market power screen and would avoid over-mitigation by employing mitigation only when a participant significantly affects price.

The conduct-impact test mitigation is a two-step process that uses "reference levels" to test both a participant's conduct as it relates to a competitive norm and its impact

72 Participants that are not identified as having market power in a settlement interval are permitted to offer their supply to the energy market in that settlement interval at any price between the $0/MWh (the energy offer price floor) and $999.99/MWh (the energy offer price cap).

on the market. A reference level is an estimate of participant's competitive offer. Notwithstanding our critique above, the ASRP is a reference level to the extent it tries to identify cost-based offers. The first part of the conduct-impact test considers whether a participant's offer exceeds the resource's reference level by some pre-established threshold. If the threshold is exceeded, then a second part of the test determines whether the conduct (i.e., the offer) has caused an impact on the market clearing price for energy.[73]

The impact test simulates a re-clearing of the market with offers of resources that fail the conduct test replaced by the resources' reference level values. If the simulated re-clearing results in a significantly higher price (i.e., a price greater that the initial clearing by some threshold), then the mitigated offers remain in the market for that settlement interval. If no participant fails the conduct test, then the impact test is not performed. In RTO markets that employ the conduct and impact framework, the threshold normally ranges from:

- **Conduct threshold of roughly $5 per MWh above the unit's reference level.** Applied in chronically-constrained, highly-concentrated areas like the load pockets in New York City. Applying such a threshold elsewhere would be unreasonable because it would likely result in unjustified mitigation because it does not account for measurement errors and factors that are difficult to quantify in the reference levels.
- **Conduct threshold of the lower of $100 per MWh above the unit's reference level or 300% of the reference level.** Applied in areas where market power is not a frequent concern, such as areas that are not chronically constrained in MISO. This threshold would likely be unreasonably high for Alberta because of the highly concentrated market structure.

A conduct threshold of $25 per MWh is commonly used in areas with limited competition, such as constrained areas in ISO-NE and in areas where units are committed for reliability purposes in MISO.

The conduct-impact test restrains excessive intervention because participants are only affected if they have a market impact, rather than permanent offer caps or market wide price caps. Such an approach could be automated as is the case in a number of the U.S. markets. Especially because the market power indicator (RSI) is calculated two hours in advance of the market, it would seem that the necessary information systems and technology are in place to arrange a rather straightforward price comparison such as the one described. It takes less than a minute to conduct reruns of a market case in the markets that Potomac Economics monitors. It could also be implemented in a simpler, more manual process that would constrain resources to cost-based offers for a period of time once they fail both the conduct test and an offline impact test.

The mitigation measures that the AESO has proposed for the energy market are intended to address only extreme cases of unilateral market power and only when the system is not operating under tight conditions. This is a significant departure

73 The impact test can also be applied to uplift payments.

from practices in other North American markets. We would recommend the AUC consider adopting a conduct-impact framework with a separate shortage pricing scheme, as discussed previously, as a superior alternative for the future. In this way, participants are first tested for non-competitive conduct and then market impact before being mitigated. And the process remains consistent regardless of system conditions.

VI. Capacity Market Demand Curve: Calculation of the E&AS Offset

A. AESO Proposal

The AESO has proposed to calculate the energy and ancillary services offset ("E&AS offset") via a forward looking methodology based on market forwards. [74] To determine the E&AS margins expected for the reference unit, the AESO will calculate both hypothetical revenues and costs across an expected amount of energy generation:

- Revenues are approximated based on forward prices averaged from NGX settlement prices.
- Operational expense is based on the forward gas price, associated fuel charges, the unit heat rate, variable operations and maintenance costs, greenhouse gas emissions rate, carbon price, transmission losses, and an energy market trading charge.
- The total energy across which this calculation is performed is set equal to the number of hours associated with the given forward product.

Consistent with the selection of the reference technology, for the purposes of these calculations the average capacity of a unit is assumed to be 2.5%, the average capacity is 87 MW, the maximum capability is 93 MW, the heat rate is 9.677 GJ / MWh, VOM is $4.60/MWh, and the emissions level is 0.5 tonnes of CO2 equivalent / MWh.

The AESO retains flexibility to select the timeframe used to sample settlement prices. The selection of the sampling period is not disclosed in advance. The AESO will calculate the E&ASA offset for a range of forward products[75] (e.g., peak, or round-the-clock flat) and the highest of those calculated E&AS offset values will be used in the calculation of net-CONE.

The AESO has proposed to not assume any ancillary service revenue in the calculation of the E&AS offset.

74 The E&AS offset is used to calculate net-CONE, which is determined by subtracting the E&AS offset from gross-CONE. This allows for the quantification of the expected "missing money" for a unit of the reference technology – that is, what remains of overall annualized assets costs after accounting for margins available from the energy and ancillary services markets. We recognize that the AESO proposed approach is applied only to offsets from the energy market and therefore is referred to as the "energy offset" in the AESO proposal. However, here we refer to the "E&AS offset" as it is a common and more broadly applicable term of art.

75 These include NGX Fin FUT FF, FP for AESO Flat, Ext Off Peak. Ext Peak, Off Peak, On Peak, Super Peak, and Hourly.

B. AESO Rationale

The AESO states that its rationale for the proposed E&AS offset considers both the challenges of forecasting future market outcomes[76] and the desire for transparency, replicability, and simplicity. The AESO reasons that such traits will improve market signals and promote competitive behaviour, and the stated methodological objectives will “ensure that participants can conduct their own projections and make internal assessments about the future Alberta capacity market without further uncertainty from an energy offset methodology that lacks transparency and is disconnected from market fundamentals.”[77]

The AESO rejected a historically based approach and a forward-looking approach based on market simulation. The primary issue with a historical approach is that historical prices, at least for the first several years of the capacity market, would necessarily be based on market outcomes from a distinct market paradigm. The market simulation approach has the drawback that it requires numerous assumptions and complex modelling that is difficult to replicate for stakeholders. On the other hand, the forwards-based forward-looking approach is challenged by the small size and general illiquidity of the Alberta forward market, which raises concerns that market participants could and might game the forwards market in an effort to affect capacity market parameters.

The AESO settled on the proposed forwards-based approach. The AESO contends that concerns over gaming can be addressed by not informing the market in advance as to when forward prices will be collected for the purposes of the E&AS calculation. Moreover, the AESO expects that NGX forward settlement prices will reflect market participants’ expectations of market outcomes and developments. The AESO states that concerns over accuracy of market forwards as a predictor remain an issue, but that issue would also be present with a simulation-based approach. As a whole, the AESO determines that the forward-based methodology is the best indicator of future market expectations that also is transparent, repeatable, and simple.

With respect to which calculated E&AS offset to use – these offsets are calculated for each forward product – the AESO notes that the section of the highest value aligns with competitive behaviour and the assumption that the proxy unit offers “all of its potential energy at variable cost while ensuring that the asset is available to provide capacity with the exception of forced outage periods.”[78]

The AESO reasons that ancillary service margins will not be included because they are a smaller revenue stream, particularly for natural gas units in Alberta. Furthermore, given the multiple products, it can be difficult to forecast. Considering

76 For example, challenges include forecasting fuel prices, emissions costs, generator additions and retirements, demand growth, and changes to market power mitigation rules.

77 AESO Capacity Market Application, P 202.

78 AESO Capacity Market Application, P 214.

both the forecasting complexity and the small volume of ancillary service margins for units of the reference technology type, the focus is to be only on energy margins.

In the AESO Response, the AESO notes that forward prices may improve in their accuracy in the future, supported in part by reductions in pool price volatility. The AESO references the MSA's quarterly report, which states that recent reductions in power price volatility have had this observed effect.[79] In turn, this improvement in forward price accuracy may increase interest in trading forward products. This is further supported by expected energy market mitigation rules associated with the implementation of the capacity market, which are expected to reduce variability in offer behaviour, and therefore prices, in the energy market. The existence of a capacity market may also increase certainty about expected supply levels and the resulting energy market dynamics. The AESO reiterates that such changes reduce price volatility, increases price discovery in the forward market, and support convergence between forwards and spot energy prices as well as increased trade volumes.[80]

C. Comparison to US RTOs with Capacity Markets

Table 19 compares the approach to calculating E&AS offsets between the AESO's proposal and the US jurisdictions with capacity markets. All three US jurisdictions employ and approach based on the average of three previous years of net revenue that would have been received by the reference unit. They vary primarily in whether the assessment of the offset value is based on calendar years (ISO-NE and PJM) or capacity delivery years (NYISO).

79 MSA, "2018 Q1 Report", p. 8, (https://albertamsa.ca/uploads/pdf/Archive/000000-2018/2018-04-27%202018%20Q1%20Quarterly%20Report.pdf)

80 AESO Response (Appendix J), AUC-AR-14, p. 28.

Table 19: Comparison of E&AS Offset Methodologies in AESO Proposal and US Jurisdictions

	E&AS Offset Methodology	Most Recent E&AS Values
AESO Proposed	Forward looking based on forward trade data and calculated margins for the reference technology selling at forward prices during the periods covered by forward traded product	N/A (see calculations)
ISO-NE	Annual average of the revenues that would have been received by the Reference Resource from the ISO-NE energy markets during a period of three consecutive calendar years preceding the time of the determination	$48.87 / kW-year
NYISO	Annual average of the revenues that would have been received by the Reference Resource from the NYISO energy markets during a period of three consecutive years (September - August) preceding the time of the determination	$40.92 / kW-year
PJM	Annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination	$32.31 / kW-year

D. Assessment and Analysis

In other capacity markets, E&AS offset calculations are straightforward and uncontroversial. E&AS offset quantities vary only a limited amount from year to year, owing in part to the employment of rolling averages and in part to relatively stable market conditions. The AESO's proposal, however, is likely to be unstable and to elicit controversy. There are a number of smaller issues that add up to a larger overall problem with the proposed methodology: (i) it is both a poor predictor of actual E&AS outcomes and (ii) it threatens to introduce significant volatility into the capacity market as a whole. The smaller concerns are as follows:

- There is an element of subjectivity introduced because the date at which the AESO will pull forwards data is not pre-defined. While this element of the proposal is well-intentioned, we believe it threatens to introduce bias (or claims of bias) and the prospect of controversy or dispute.
- The AESO proposes to base the E&AS calculation on the simultaneous calculation of the E&AS offset for seven different forward products. The AESO will then select the highest resulting offset from the seven results. We believe this logic to be sound and in keeping with capacity market design principles. However, though this could change in the future, we are concerned that only two of these products – flat and extended peak – are traded in volumes that could remotely be considered "liquid." The rest are not, including the more narrowly defined peak and super-peak, which could result in unexpected outcomes in either direction. In turn, the resulting calculation may or may not represent reasoned expectations of market outcomes.

- Not only are power price forwards thinly traded, they have been poor predictors of realized Alberta pool prices. Both of these facts are observable in Table 20. While the AESO may be correct that there may be increased convergence between forwards and actual prices in the future, that observation remains speculative. It also does not address the fact that several years of capacity market auctions will need to be conducted before it can be determined that such improvements in the forwards market are actually taking place.
- Even more than power forwards, gas forwards have also been bad predictors of realized spot prices for gas in Alberta. This relationship can be seen in Table 21.
- Setting aside issues with the accuracy of forwards, the simplified forwards-based methodology does a poor job of approximating actual market margins available to a unit of the reference technology. Table 22 presents the results of an analysis that we performed to study this dynamic. For each historical year between 2013 and 2018, we calculated the E&AS offset using actual average power (all hours) and gas prices. For each year, we also performed a highly simplified dispatch of a generating unit with the characteristics of the Aero CT reference technology to calculate annual margins.[81] We then compared the "dispatch" margins with the forward-style calculated margins. In some years the two approaches produced similar results, but in some years they diverge significantly. The directionality of the divergence is not predictable. In short, even using *actual* values rather than predictive forwards, the proposed formula for calculating E&AS margins is inaccurate.

81 This simplified dispatch included calculating an operating cost for the generating unit in each hour based on the fuel cost (based on prevailing daily fuel prices and plant heat rate), variable operations and maintenance cost, carbon compliance costs (when relevant), transmission losses, and trading charge. For any hour in which the Alberta pool price exceeded the plant operating cost, that planned was assumed to be "dispatched" and could accrue margins if the pool price exceeded the operating cost. We understand that this is a simplification and not perfectly representative of reality, but it is a sufficient tool for this purpose.

Table 20: Calendar Year Flat Forwards, Prices ($/MWh) and Cumulative Volumes (MW) [82]

Calendar Contract	4 Years Out		3 Years Out		2 Years Out		1 Year Out		Final Trade Price	Total Cum. Volume	Realized Pool Price
	Price	*Cum. Vol*	Price	*Cum. Vol*	Price	*Cum. Vol*	Price	*Cum. Vol*			
2013	-	*0*	$ 57.00	*120*	$ 53.02	*150*	$ 72.25	*300*	$ 59.50	535	$ 80.19
2014	-	*0*	-	*0*	$ 63.00	*15*	$ 51.00	*410*	$ 53.50	752	$ 49.42
2015	-	*0*	$ 66.00	*50*	$ 47.50	*265*	$ 48.50	*590*	$ 49.00	1359	$ 33.34
2016	-	*0*	$ 52.00	*70*	$ 52.25	*215*	$ 48.50	*463*	$ 34.50	1414	$ 18.28
2017	$ 53.50	*30*	$ 52.50	*100*	$ 52.00	*173*	$ 40.00	*1031*	$ 31.40	1836	$ 22.19
2018	$ 57.50	*23*	$ 52.00	*78*	$ 51.00	*513*	$ 39.00	*1133*	$ 52.50	2263	$ 50.35
2019	$ 58.75	*15*	$ 56.00	*195*	$ 41.00	465	$ 53.25	*1,525*	$54.75	2,351	-
2020	$ 58.00	*60*	$45.00	*190*	$ 46.50	785	$ 47.50	*1,660*	-	-	-
2021	$ 58.00	*85*	$ 43.50	*110*	$ 46.50	*305*	-	-	-	-	-
2021	$ 58.00	*85*	$ 43.50	*110*	$ 45.00	*340*	-	-	-	-	-
2022	$ 50.00	*10*	**$ 43.50**	*55*	-	-	-	-	-	-	-
2023	$ 45.00	*20*	-	-	-	-	-	-	-	-	-

Table 21: Gas Forwards and Realized Prices

	SNL Forwards (AECO, by trade date)								NGX Forwards	Delivered Prices	
	2012 Dec	2013 Dec	2014 Dec	2015 Dec	2016 Dec	2017 Dec	2018 Dec	2019 Jan	AB-NIT[83]	AECO Hub[84]	Phys, FP, AB-NIT[85]
2016	5.12	4.06	3.72	1.62	-	-	-	-	-	2.07	2.08
2017	5.38	4.01	3.90	1.65	3.00	-	-	-	-	2.08	2.25
2018	5.85	4.11	4.10	1.69	2.73	1.48	-	-	-	1.47	1.49
2019	6.23	4.40	4.35	1.83	2.56	1.73	1.31	1.46	1.86	-	-
2020	-	4.73	4.64	1.97	2.55	1.88	1.33	1.57	1.59	-	-
2021	-	-	4.93	2.13	2.54	2.13	1.45	1.63	1.63	-	-
2022	-	-	-	2.38	2.56	2.29	**1.62**	1.75	1.72	-	-

82 Table supplied by MSA. Some products are still trading. Totals and prices shown here are as of December 31, 2018. Bold value used in "base case." The table only includes trades that cleared on NGX, it does not include all trades in the market. It is our understanding that this is likely to be similar to what is observable by the AESO; the AESO will likely only see trades that clear on NGX. Also, as a matter of clarification, the numbers in the table show the cumulative amount of trading before a particular time. For example, the 340 MW traded 2 years out for the delivery in 2021 includes the 110 MW traded 3 years out.

83 Data from NGX, average of trades from February 15-18, 2019. Bold value used in "base case."

84 SNL. Storage Hub.

85 NGX.

Table 22: Proposed E&AS Calculation Compared to Margins Based on Actual Market Outcomes

$/kw-year	2013	2014	2015	2016	2017	2018
Proposed E&AS Calculation						
Energy Market Revenue	475	427	392	276	251	419
Variable Expenses	282	377	247	205	229	198
E&AS Offset	194	50	145	71	22	222
Simplified Dispatch Result						
Energy Market Revenue	578	233	143	28	55	418
Variable Expenses	132	87	41	22	35	191
E&AS Offset	446	146	102	6	21	228

The overarching concern with the forwards-based methodology, however, is that it is highly volatile relative to its two primary inputs, the forward gas and power prices, as shown in Table 23. Relatively small shifts, on the magnitude of those regularly observed on a month to month basis,[86] can cause significant swings in the calculated E&AS offset. All of the other drawbacks associated with the proposed E&AS offset methodology serve to magnify this shortcoming. In particular, the volatility, lack of liquidity, and poor predictive power of power and gas forwards are likely to manifest in significant sensitivity to the sampling date (which will drive annual controversy over this choice) as well as large year-over-year variation in the net-CONE parameter. Such unfounded variability and dependence on the sample date is likely a further indicator that the approach is inaccurate. Moreover, the resulting volatility is likely to swamp uncertainty driven by any other price-based parameter and lead to considerable uncertainty in the capacity market as a whole. In this, we believe that we are in agreement with the AESO that significant volatility in the capacity market is undesirable, both for consumers and capacity suppliers.

86 For example, short terms swings in gas expectations are common: http://www.gasalberta.com/gas-market/market-prices?p=pricing-market.htm

Table 23: Sensitivity of Proposed E&AS Methodology to Power and Gas Price Forwards (table in $/kw-year)[87]

Power Across ($/MWh) Gas Down ($/GJ)	$ 20	$ 25	$ 30	$ 35	$ 40	$ 45	$ 50	$ 55	$ 60
$1.00	-4	36	76	116	156	196	236	276	316
$1.10	-12	28	68	108	148	188	228	268	308
$1.20	-20	20	60	100	140	180	220	260	300
$1.30	-28	12	52	92	132	172	212	252	292
$1.40	-35	5	45	84	124	164	204	244	284
$1.50	-43	-3	37	77	117	157	196	236	276
$1.60	-51	-11	29	69	109	149	189	229	268
$1.70	-59	-19	21	61	101	141	181	221	261
$1.80	-67	-27	13	53	93	133	173	213	253
$1.90	-75	-35	5	45	85	125	165	205	245
$2.00	-83	-43	-3	37	77	117	157	197	237
$2.10	-90	-50	-11	29	69	109	149	189	229
$2.20	-98	-58	-18	22	61	101	141	181	221
$2.30	-106	-66	-26	14	54	94	134	173	213
$2.40	-114	-74	-34	6	46	86	126	166	206
$2.50	-122	-82	-42	-2	38	78	118	158	198

E. Suggested Alternatives

We recommend adopting market rules that:

- Establish a process by which the AESO will forecast (i.e., simulate) expected energy market margins for a capacity delivery period ahead of the auction for that delivery period. This may require a stakeholder process to review modelling assumptions. The AESO should use its existing Aurora modelling capability, which is a widely recognized and well-understood tool for forecasting energy market dynamics.
- Use the simulation results – plus a reasonable expectation of shortage revenues that are not estimated by the simulation – to establish the E&AS offset for each capacity auction.

The forward-looking, simulation-based approach may be a permanent solution or a temporary solution to calculating the E&AS offset. Once there is sufficient historical data on the operation of the Alberta energy market in the new capacity market paradigm, the AESO should reassess whether an E&AS calculation based on historical outcomes is more suitable to the market. This assessment should also include the accuracy of the forward-looking approach based on forecasted and actual market outcomes.

87 Assumes Aero CT reference technology.

a) Other Alternatives: Historically-based E&AS Offset

An alternative approach to calculating the E&AS offset would be:

- Establish a process for deriving a backwards looking estimation of E&AS margins based on the reference technology characteristics, actual energy market prices, and actual fuel prices; and
- Calculate the E&AS offset to be used in the capacity market as the 3-year historical rolling class average of the calculated E&AS margins.

This is a second-best approach for the Alberta capacity market. As the AESO rightly points out, "a methodology based on historical prices as it inherently includes market elements that are not expected to be aligned with the future of the Alberta market and therefore are not representative of future market operations and profitability."[88] The underlying rationale for adopting this alternative would be to balance the need to reduce volatility with a sacrifice in principled design. We benefit from the practical knowledge (i.e., calculations based on current forwards) that the result of this approach would likely be an E&AS offset for the initial Alberta capacity auctions (probably in the $80-$100 / kw-yr range) that is between the high level identified by the current forwards (using the AESO approach), and lower levels (in the $30-$40 / kw-yr range) that have been observed in the US capacity markets. Over time, the nature of the 3-year rolling average would reduce volatility in the E&AS parameter, and therefore volatility in net-CONE and the capacity auction as a whole.

If the AUC were to direct a historically based approach, we recommend the consideration of a simulation-based approach in the 18-month process. Notably, the shortcomings in the historically-based approach – that is, the reliance on market outcomes from a different market model – will be overcome by the first auction following the first full capacity year. Once there is sufficient data on market outcomes under the new structure, the AESO will be able to develop a representative historical sample. At this point, the shift could be them be made from a simulation-based to a historically-based approach. In the long run, though not our recommendation now, adopting the historically based E&AS offset calculation would considerably reduce volatility in auction parameters and would be consistent with rules in the US RTOs that operate capacity markets.

b) Other Alternatives: Ex Post E&AS Offset

We recognize yet another alternative approach would be to calculate the E&AS offset on an *ex post* basis similar to the manner proposed by the AUC in Question 15 of the Additional Application Requirements. The approach presented holds promise, and has the potential to alleviate some of the issues that we have identified both with the E&AS offset and other elements of the AESO's proposed market rules. However, we also agree with the AESO that "Pursuing this design option would be a fundamental change from what is currently proposed for the capacity market technical design."[89] It is likely that shifting to an *ex post* E&AS offset methodology would require revisiting a

88 AESO Proposal, P 204.

89 AESO Response (Appendix J), AUC-AR-15.

number of design decisions across various aspects of the market rules. For these reasons, we have not performed an in depth analysis here. However, we are available to the MSA and AUC to provide additional evidence should the AUC wish to study this approach further.

F. Discussion of Recommended Alternative

As compared to the proposed forwards-based approach, we expect our recommended change to increase capacity prices in the near term.[90] In the longer term, the volatility of the proposed E&AS offset methodology makes it difficult to predict the relative effect of our proposal. The strength of our recommended approach is that it achieves consistency between the method used to establish the E&AS offset and the operating paradigm when capacity will be delivered. This would be facilitated should the AUC direct adoption of a more-stringent energy market power mitigation scheme, similar to what we have proposed, which allows a more accurate approximation of expected energy market offer behaviour. Importantly, the capacity market parameters and the resulting prices will be more stable than the resulting outcomes from the AESO's proposal.

These recommended rule adjustments would require no conforming changes elsewhere in the market design. The effects of the modified calculation of the E&AS offset calculation would automatically flow through the market parameters following its use in the calculation of net-CONE and net going forward costs. Some additional stakeholder processes may be appropriate to review modelling assumptions. Alternatively, the forecasting effort could be delegated to an independent third party. We note that energy market simulations sometimes do a poor job representing shortage conditions and transient price spikes, both of which can be major drivers of energy market margins, particularly for peaking units. This can be addressed by establishing an adder to simulated energy market margins based on assumptions about the expected number and severity of shortages.

Finally, we emphasize again the importance of *not* adopting the AESO's proposal for calculating the E&AS offset. Here, it is not our view that the priority is to accept our specific proposed alternative, though it is our view that it would be practically effective. Rather, it is vital that the AUC direct some alternative approach – adhering as much as possible to principles – that mitigates the considerable amount of volatility that may be caused by the proposed forwards-based approach.

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90 This assumes that gas and power market forwards share a similar relationship today as they do when the AESO would identify the relevant forwards for the first capacity auction. If the forwards are closer together, the effect of our recommended approach could be similar to AESO's proposed approach.

VII. Capacity Market Demand Curve: Selection of Reference Technology

A. AESO Proposal

The AESO has proposed an aeroderivative combustion turbine (“Aero CT”) as the capacity market reference technology.

B. AESO Rationale

The AESO’s decision to propose an Aero CT as the reference technology was based on the results of a report prepared by Brattle and Sergeant & Lundy, the “Gross-CONE Report.” This report screened a range of technologies and determined that three were candidates for a reference technology: an Aero CT, a frame-type CT (“Frame CT”), and a combined cycle (“CC”) plant, owing to their expected role in the long term Alberta supply mix and the absence of constraints to their future development. The report then calculated bottom-up costs for each technology to estimate the annualized average net revenues a resource owner would need to earn over the economic life of a plant to support merchant investment. This analysis resulted in the figures seen in Table 24.

Table 24: Gross-CONE Estimates from Gross-CONE Report

Reference Technology	Winter Capacity	Overnight Capital Costs	Overnight Capital Costs	Overall (After-Tax) Cost of Capital	Annual Carrying Charge	Plant Capital Costs	Fixed O&M Costs	Gross CONE
	MW	*$million*	*$/kW*	*%*	*%*	*$/kW-yr*	*$/kW-yr*	*$/kW-yr*
Aeroderivative CT	93	$138	$1,479	8.5%	12.6%	$186.9	$57.3	$244.2
Frame CT	243	$163	$671	8.5%	12.7%	$85.0	$29.2	$114.1
Combined Cycle	479	$657	$1,371	8.5%	13.3%	$182.2	$53.9	$236.1

The AESO states that it used several criteria to assess the candidate technologies in light of the analysis results. They are:

- frequency of historical development of each technology type and current Alberta connection queue;
- time to energization, in particular whether commissioning can be completed in less than 36 months;
- capital costs, financing risks, and magnitude of investment;
- cost to load, including competitiveness and the resulting market efficiencies.

The AESO selected an Aero CT for the reference technology because:

- more have been built over the past 10 years, both in number and generating capability; this indicates familiarity with the technology type;
- concerns that Frame CTs, though observed in the interconnection queue, may be restricted due to changes in environmental regulations (except in co-gen applications);
- the speed of deployment for Aero CTs (and Frame CTs) is faster than for CCs;

- the smaller capacity size of Aero CTs reduces investment relative to other technologies, especially CCs; lower investment requirements may be more attractive to investors and ease financing, thus enabling market entry; [91]
- gross-CONE for the Aero CT and CC are similar, but Aero CTs have higher operating costs and will therefore likely result in higher net-CONE values; frame CTs, on the other hand, have a lower gross-CONE but may realize limited energy market margins owing to high operational costs (high heat rates); thus, a Frame CT may be more dependent on capacity market revenue and less suitable as a representative technology selling into both the energy and capacity markets.

The AESO concludes the description of its decision by stating that the selection of the reference technology is not intended as a guarantee that one technology type will clear the market nor as an endorsement, nor that the technology is needed or preferred. The AESO states, instead, that “the reference technology represents a developable cost effective technology that provides significant capacity value and sets the benchmark against which prices along the demand curve are indexed.”[92]

C. Comparison to US RTOs with Capacity Markets

Table 25 summarizes the capacity market reference technologies in other North American jurisdictions with centralized capacity markets. In all three markets – NYISO, ISO-NE, and PJM – the reference technology is an industrial frame simple cycle gas turbine. Each market also has a slightly different approach to selecting the reference technology:

- **ISO-NE**: in supporting the selection of the reference technology the ISO-NE states, “From a market design perspective, the final CONE and Net-CONE values generally should be based on the technology that is expected to be the most economically efficient and that is commercially available to new capacity suppliers.”[93] Applying this design principle ensures cost-effective procurement of sufficient supply. Accordingly, ISO-NE proposes to use the Frame CT technology because it has the lowest expected net-CONE.
- **NYISO**: the NYISO Services Tariff defines the peaking unit as the “technology that results in the lowest fixed costs and highest variable costs among all other units’ technology that are economically viable.” [94] Consistent with this rubric,

91 The AESO contends that “The overnight capital cost and capacity of an Aero CT are more aligned with the potential magnitude of investment required to meet the needs of the Alberta market, especially if load growth increases at a marginal pace, relative to the other two reference technology candidates which are larger in capacity and in capital cost.” AESO Capacity Market Application, P 193.

92 AESO Capacity Market Application, P 194.

93 ISO-NE Filing of CONE and ORTP Updates. (Submitted to FERC January 13, 2017) Note that in prior such filings, ISO-NE had proposed to employ a CC as the reference technology. In its filing to shift to a CT reference, ISO-NE discusses the rationale for this shift at length.

94 NYISO Proposed ICAP Demand Curves for the 2017/2018 Capability Year and Parameters for Annual Updates for Capability Years 2018/2019, 2019/2020 and 2020/2021. (Submitted to FERC November 18, 2016)

FERC has approved NYISO's use of an industrial frame turbine as the reference technology.

- **PJM**: PJM has maintained a Frame CT reference unit since the RPM market began. PJM states that this has supported stable auction design and the consistency has reduced the perception that there is regular switching between technologies based on opportunistic economics. The Frame CT technology remains an economic option for new entry as demonstrated by recent new development. They are not the largest entry category – that would be NGCC facilities – but they remain economically viable as a peaking unit as demonstrated by their clearing in RPM auctions. PJM's position, supported by Brattle's analysis, is that CT plants represent the cheapest option and fastest option should market signals dictate. Finally, there is less risk of mis-estimating CT net-CONE, given the reduced dependence on E&AS revenues, relative to a CC technology.[95]

Table 25: Comparison of Reference Technology and Gross-CONE in AESO Proposal and US Jurisdictions

	Reference Technology	Current Gross-CONE $CAD
AESO Proposed	Simple Cycle Aeroderivative Gas Turbine GE LM6000-PF SPRINT	$244.2 / kw-year
ISO-NE[96]	Simple Cycle Industrial Frame Gas Turbine GE 7HA.02	$176.1 / kW-year
NYISO[97]	Simple Cycle Industrial Frame Gas Turbine Siemens SGT6-5000F5	NYC: $231.84 / kW-year NYCA (upstate): $126.83 / kW-year
PJM[98]	Simple Cycle Industrial Frame Gas Turbine GE 7F.05	$175.9 / kW-year

Furthermore, FERC has generally established that economic viability determinations are a matter of judgment that is informed by the consideration of multiple factors including: (i) the availability of the technology to most market participants; (ii) existence of sufficient operating experience to demonstrate that the technology is proven and reliable; (iii) whether the technology is dispatchable and capable of being cycled to provide peaking service; and (iv) the ability to achieve compliance with applicable environmental requirements and regulations.

95 PJM Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters. (Submitted to FERC October 12, 2018, FERC Docket No. ER19-105)

96 Parameters for FCA13 for delivery period 2022/2023.

97 ICAP Reference Values reported for 2019/2020.

98 RPM Parameters for 2021/2022 Base Residual Auction.

D. Assessment and Analysis

The choice of reference technology presents an interesting problem with a unique fact pattern in Alberta. As described by the AESO, there are a range of criteria. Here, we will point out where we agree with the AESO's assessment and where we think particular additional attention may be paid.

- Our present view is that the CC technology is not a good fit for Alberta. The lead time for development is too long and the generator size is large relative to the small overall size of the Alberta market. Owing to these characteristics, the CC technology does not lend itself to being an incremental generation source in Alberta.
- There may indeed be regulatory issues associated with new Frame CT development given the potential for new national regulations governing greenhouse gas emissions in Canada.[99] While we understand there is uncertainty here and rules may change before or after implementation, it is potentially troublesome that Frame CTs may be caught up in a different category of generation resource compliance (>150 MW) that would limit their allowed capacity factor.
- The overnight dollar investment requirements for an Aero CT are smaller than a Frame CT. The AESO suggests this may make such plants more attractive to investors and ease financing. However, we are not confident in this assertion. In the Gross-CONE study, a 93 MW Aero CT has an overnight cost of $138 M as compared to a 243 MW Frame CT for $163 M. While on an absolute basis the Aero CT is less expensive, the marginal additional investment in a Frame CTs buys considerably more generating capacity; that is, the per MW cost of the Frame CT is much lower.
- We also do not find compelling the AESO's logic based on familiarity with technology type. There is clearly sufficient experience with both types of CT, both in Alberta and in North American markets more generally, to support either type of generation development for Alberta's needs. Second, though it is possible that the statistics presented in support of the "familiarity" argument bear scrutiny, it is not clear from the evidence presented. Without being privy to the full dataset – the summary of which is presented in Table 26 – it is not clear that the majority of experience in Alberta is with Aero CTs, at least on a MW basis. It is possible that a number of the "planned" units are those grid-connected gas CTs in the AESO's connection queue, shown in Table 27. If the Brattle assessment is counting these units, that is potentially misleading. As shown in Table 28, four of these six units have been in the queue for years and may not represent serious intent to build. If this were the case with some or all of these units, it would shift the balance of what one might conclude about which technology is the most familiar in the Alberta market. At the very least, it is worth taking a second look at this conclusion and the supporting data.

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99 http://gazette.gc.ca/rp-pr/p1/2018/2018-02-17/html/reg4-eng.html

Table 26: Turbine Models of CT Plants Built Since 2008 or Planned in Alberta[100]

Turbine Model	Turbine Type	Capacity Installed and Permitted since 2008 *MW*	Number Installed and Permitted since 2008 *Count*
GE LM6000	Aeroderivative CT	719	15
Siemens SGT6-5000F	Frame CT	600	3
GE LMS100	Aeroderivative CT	200	2
Rolls-Royce Trent 60	Aeroderivative CT	198	3
GE 7EA	Frame CT	177	2
Wartsila 18V50SG	Reciprocating	94	5
Caterpillar-G16CM34	Reciprocating	65	10
Solar Turbines Inc-Titan 130	Aeroderivative CT	30	2
Cummins C2000 N6C	Reciprocating	20	10
Jenbacher JGS 620	Reciprocating	18	6
Wartsila 20V34SG	Reciprocating	9	1
Total		**2,130**	**59**

Table 27: Planned CTs in Alberta (non-BTM)[101]

Plant	Planned ISD	Generating Capability	# Units	Turbine
Maxim Power Deerland Peaking Station	1-Dec-20	185.8	4	Aero CT GE LM6000
Whitetail Peaking Station	25-Oct-19	200	4	Aero CT GE LM6000-PF
Kineticor Peace River Power Generator	30-Sep-21	93	1	Aero CT GE LM6000-PH
Calgary Energy Centre Peaking Plant	1-Dec-21	150	1	Aero CT Rolls-Royce Trent 60
Quill Rocky Mountain Gas	1-Sep-20	295	Early Stages	Early Stages
ATCO Rainbow Lake Gas	1-Apr-20	55	Early Stages	Early Stages
Total		*629 MW Aero GT* *350 MW Unknown*	*10 Aero GT* *2 Unknown*	

100 Brattle CONE Analysis (Appendix K), p. 12. (September 4, 2018)

101 Based on AESO Connection Process, February 2019.

Table 28: In Service Date Progression for Select CTs[102]

AESO Reporting Date	Deerland Peaking Station	Whitetail Peaking Station	Peace River Power Generator	Calgary Energy Centre Peaking Plant
Older	14-Dec	14-Nov		
February 2014	15-Nov	15-Aug		
November 2015	17-Dec	17-Jan		18-Apr
May 2016	17-Dec	17-Jul	17-Nov	18-Apr
May 2017	17-Dec	18-Oct	18-Apr	19-Jul
February, 2018	20-Dec	18-Oct	19-Sep	21-Dec
February, 2019	20-Dec	19-Jul	21-Sep	21-Dec

Taking a step deeper into the analysis underlying the AESO's proposed reference technology, we question the choice of the GE LM6000 as the candidate Aero CT model over the GE LMS100. This decision is not discussed, but it does not bear scrutiny. It is our view that this decision may meaningfully bias the resulting gross-CONE upwards. The GE LMS100 model line combines the LM6000 and GE's Frame CT technologies, and is more efficient and less expensive than the LM6000 model line. For example, ISO-NE's 2016 CONE study compared LMS100 PA and LM6000 PF+, and reported a capital cost for LMS100 (1,477/kw $/kW, in a 1x0 configuration) that was 20 percent lower than that of LM6000 ($1,837/kw, in a 2x0 configuration). The assumed heat rate for the LMS100 was 9,021 Btu/kWh, while the LM6000 was 9,774 Btu/kWh.[103] These advantages are evident in recent installation trends. Over the last five years in North America, as shown in Table 29, twice as many LMS100 units were installed as LM6000 units, constituting nearly four times as much generating capability.

Table 29: Model-Specific Aero CT Installation Trends in North America (2013-2018)[104]

Model	Total MW	# of Units
GE LM6000 Model Line	641	12
GE LMS100 Model Line	2,519	24

Failure to consider the GE LMS100 as the candidate Aero CT model is concerning. This choice is poorly explained, if at all, and we expect that it inappropriately biases

102 AESO Connection Process Reports and Long Term Adequacy Metric Reports.

103 ISO New England Inc. Filing of CONE and ORTP Updates, Attachment 1, Concentric Energy Advisors ("CEA"), ISO-NE CONE and ORTP Analysis: An evaluation of the entry cost parameters to be used in the Forward Capacity Auction to be held in February 2018 ("FCA-12") and forward, Jan. 13, 2017, pp. 32, 34. (https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf)

104 Ventyx Energy Velocity. Summary refers to all installations in a model line. For example, the GE LM600 model line units include units referenced as GE LM6000, GE LM6000 PF SPRINT, and GE LM6000 PA-SAC.

the results of the analysis upwards. The upward bias in the gross-CONE determination results in a higher net-CONE parameter and therefore auction clearing price expectations. At the end of this section, we suggest that the AUC require the AESO to revisit the selection of the reference technology. When the AESO does this, we recommend they also revisit the selection of the Aero CT model used as to represent this technology class in addition to whether or not the Aero CT is the appropriate technology.

Setting aside what we view largely as screening criteria, the criterion that remains is described by the AESO as "cost to load of each candidate technology, including the competitiveness of the reference technology and the resulting efficiencies." It is appropriate that this is the factor that remains, because as we see it, this is the one that requires the most judgement; we see the other criteria as largely acting as screens. Save for the regulatory concerns over Frame CTs, both of the CT technologies pass.

How exactly to operationalize this last criterion is challenging. In general, it is our view that the reference technology should represent the least cost alternative that is capable of serving capacity needs on a near-term basis. This is similar to the approaches taken in the US RTOs, and may best be approximated by NYISO's "lowest fixed costs, highest variable costs" test. By this measure, the Frame CT would probably be considered the winner, as the fixed costs are lowest on a per unit basis and the variable costs are comparable or higher than the more-efficient Aero CT (though very low gas prices may shift the variable cost calculus). In a vacuum, this would be our recommendation.

There are several complicating factors, however, in the Alberta case. The first is the national greenhouse gas regulation, which we have already discussed. It is possible that this hampers implementation of this technology, or that the regulatory uncertainty poses unacceptable risks to investors. The second is size relative to the Alberta market; Frame CTs are larger than Aero CTs and may represent an unnecessarily large increment of supply, particularly in a period of low load growth.

Third, at least with the E&AS offset calculation formulated as proposed, there is the practical issue that the choice of a Frame CT as the reference technology is likely to result in a negative value for net-CONE, while net-CONE would be positive for an Aero CT. This result is seen in Table 30, which shows the result if the proposed E&AS offset calculation is applied with the various technologies and prevailing gas and power price forwards at the time of the issuance of this report. In practice, it would be odd to introduce a new capacity market with no price on capacity.

Table 30: Calculated net-CONE for Alternative Technologies Using Forwards Data for 2021

$/kw-year	Aero CT	Frame CT	Combined Cycle
Gross-CONE	244.2	114.1	236.1
E&AS Offset	134.7	164.1	229.8
Net-CONE	109.5	(50.0)	6.3

The above suggests to us that it is first advisable to seek a more thorough resolution to the root problem, which is shortcomings in the proposed E&AS offset methodology. As it stands, that methodology would suggest that – because there is no missing money (net-CONE less than $0) for a strong reference technology candidate – there is no need for a capacity market at all, or at least no need for a capacity price in excess of zero. While it is possible that this is the case, it is perhaps more likely that this is a result of a weak E&AS offset methodology that relies on forwards, which are poor predictors of actual market outcomes, as described in more depth in the prior section. An improved methodology would allow for a better representation of the actual expected market outcomes under the AESO's new operational paradigm – which will also depend on the energy market mitigation scheme that is implemented – and would allow for a more reasoned choice between the Frame and Aero CT technologies.

E. Suggested Alternatives

We recommend that the AUC require the following:

- update the E&AS offset methodology and recalculate the E&AS offset for the 2021/2022 delivery period based on the updated methodology;
- recalculate net-CONE for the alternative technologies for the 2021/2022 delivery period;
- revisit the selection of the reference technology based on the updated net-CONE; and
- implement a mandatory triennial review of reference technology selection.

When the AESO revisits the selection of reference technology, we recommend that the AESO also consider whether the GE LM6000 is the appropriate Aero CT model to consider. The GE LMS100 appears more appropriate based on our analysis.

F. Discussion of Alternatives

We recommend revisiting the selection of the reference technology after having remedied shortcomings in the E&AS offset methodology. This will allow a consistent, reasoned selection of the reference technology based on a superior representation of the conditions in the Alberta energy market. Our recommendation will constitute a fix to the analytic underpinnings of the reference technology selection process, rather than an approach that requires ex post reasoning to explain away the questionable outcomes of the supporting analysis (i.e., that the least-cost incremental supply option is not an appropriate reference technology).

When the AESO has completed its calculation and is ready to revisit the choice of reference technology, we recommend that assessment include an updated review of expectations related to regulatory constraints. If the runtime of a Frame CT is expected to be limited by national greenhouse gas regulations, the AESO should be expected to show that Frame CTs would be expected to operate in excess of those limitations in order to use regulatory issues as a determining factor in excluding Frame CTs as an option.

Consistent with a number of the AESO's design choices, we expect the selection of an Aero CT as a reference technology to bias capacity prices and costs to consumers upwards. As we have recommended, this choice should be revisited once shortcomings with the cost determinants of this decision have been remedied. While it is possible that the selection of an Aero CT will not change, we think it is likely that the revised net-CONE calculations will indicate a Frame CT is the least cost increment of new capacity supply for the Alberta system. This finding would be consistent with the US RTO markets and this approach will result in a more competitive outcome that will reduce costs to consumers.

Regular review of the reference technology is well advised in any case owing to technological change and market dynamics, particularly when shifting market conditions may have such a sizeable impact on the selection criteria. Adding a triennial review mandate would require just that, and no conforming changes would be required. Should a triennial review result in the selection of a different reference technology, conforming changes would be required to other parts of the market rules (e.g., E&AS calculation parameters) that are dependent on the characteristics of the reference technology.

VIII. Capacity Market Demand Curve: Calculation of Adjusted net-CONE

A. AESO Proposal

The AESO has proposed to calculate an adjusted net-CONE value in order to express net-CONE in UCAP terms for the purposes of the capacity auction. This calculation is performed by dividing the calculated net-CONE by a factor that accounts for the availability of the reference unit, (the "performance factor"). The performance factor is set to 80% and will remain constant on a going forward basis.

B. AESO Rationale

The AESO states that the auction price cap will be adjusted such that net-CONE, which is calculated in ICAP terms, is presented in terms of UCAP for the purposes of the capacity market demand curve. The AESO contends that this approach "ensures price levels are aligned with the treatment of all assets participating in the capacity market, where the value of their supply is measured by the UCAP calculated by the AESO."

The proposed 80% fixed performance factor is based on the class average of Aero CT assets currently operating in Alberta. This approach is consistent with the proposed calculation of UCAP values for new assets. The AESO decided to keep the performance factor constant – rather than re-calculating it on a periodic basis – in order "to avoid adding another layer of uncertainty to the net-CONE calculation that is not required for the purpose of setting price levels along the demand curve."[105]

This adjusted net-CONE value is also used in the determination of the offer price cap for mitigated resources.

The concept of an adjusted net-CONE input for the capacity demand curve appears to not have been raised in the CMD documentation nor was it suggested or analysed in the Brattle demand curve study. Based on documentation provided with the application, the adjusted net-CONE concept appears to have been first presented in September 2018.[106]

C. Comparison to US RTOs with Capacity Markets

The US capacity markets, particularly PJM[107] and NYISO[108], do apply an adjustment to the price component of the demand curve input (net-CONE or equivalent) that is comparable to the AESO's proposed adjustment. In practice, these adjustments are much smaller than the one proposed in Alberta. We note the ISO-NE Forward

105 AESO Capacity Market Application, P 238.

106 See Consultation Record for the Development of the First Set of ISO Rules (Appendix I Sec I), PDF p. 377.

107 https://www.pjm.com/-/media/documents/manuals/m18.ashx, pp 39-40.

108 https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338 (pp. 165-166)

Capacity Market is transacted in ICAP, and therefore such an adjustment would not be applicable.

Table 31: Comparison of net-CONE adjustments in AESO Proposal and US Jurisdictions

	Product Denomination	Adjustment to net-CONE	Adjustment Factor
AESO Proposed	UCAP	Yes	0.8 (fixed, based on assumed 80% average availability rate)
ISO-NE	ICAP	No	N/A (ref. unit EFORd = ~5.5%)
NYISO	UCAP	Yes	N/A (ref. unit outage rate = 1-3%)
PJM	UCAP	Yes	N/A (market-wide outage rate = ~6.5%)

D. Assessment and Analysis

As an initial matter, there is a question as to whether it is logical to adjust the net-CONE from ICAP to UCAP. By way of background, we observe that the AESO's proposed approach to establishing a resource's UCAP differs considerably from the approaches taken in other capacity markets. As defined, UCAP in Alberta is based on availability factors, which evidently discount UCAP more significantly than a demand equivalent forced outage rate ("EFORd") approach.[109] This appears to be because EFORd calculations primarily discount resource availability during outages, which are infrequent.[110] However, in Alberta, the availability approach accounts for any availability less than maximum capability during all hours. In a majority of hours, most plants' availability is limited to a percentage of nameplate generating capability.[111] This results in adjustment to ICAPs that are much larger in Alberta than in other markets, as shown in Table 32. Given this difference, we recognize that it seems reasonable to incorporate the performance adjustment into the demand curve formulation, and may be particularly important in Alberta to do so.

109 Our observation is based on data that we have reviewed.

110 Though the underlying justification is not forthcoming, the low EFORd figures would lead to minimal shift in the demand curve were an equivalent adjustment employed in PJM and NYISO. Thus the adjustment has not been included.

111 Data suggests that unit availability in most hours is reported to be some fraction (e.g., 80-90%) of the maximum generating capacity.

Table 32: Historical Availability of Representative CT Units[112]

Year	Average Price	Availability All Hours	Availability: Top 250 Supply Cushion Hours
2013	80.19	86%	83%
2014	49.42	87%	83%
2015	33.34	87%	82%
2016	18.28	86%	84%
2017	22.19	84%	78%
2018	50.35	82%	80%
	Average	***85%***	***82%***

With respect to the selected performance factor of 0.80, the AESO has apparently not provided a supporting analysis. Our analysis suggests a more accurate value, based on the units studied, might be 0.82, which is similar to the AESO's proposed level. Furthermore, as seen Table 32 (across the third and fourth columns, as well as across years), we observe that there is some variability in the availability factor for the representative CT units we analysed. Resources tend to be available more frequently when observed across all hours than when observed during the 250 tightest supply cushion hours.[113] Furthermore, we expect to see improved availability statistics as a result of the performance incentives for capacity resources – which are also tied to the top 250 supply cushion hours – that are included in the AESO's Application.

Finally, Figure 8 and Table 33 demonstrate that variation in the designated class average performance factor can have a meaningful effect on demand curve parameters and capacity market outcomes. For example, should the class average improve to 90% from 80%, the resulting change in capacity market costs could exceed $50 M. If the class average were to improve but the resulting demand curve parameter was not updated, the market would over-procure capacity and result in unwarranted costs to customers. There is a serious risk that failure to update the performance factor could result in unnecessarily high capacity prices.

112 Crossfield (1, 2, 3), Cloverbar (1, 2, 3), Judy Creek, Carson Creek, Poplar Hill, Valley View (1, 2).

113 To a certain degree, tight supply cushions may be driven by resource unavailability, so the two statistics may not be fully independent.

Figure 8: Illustrative Effect of Alternative Performance Factors

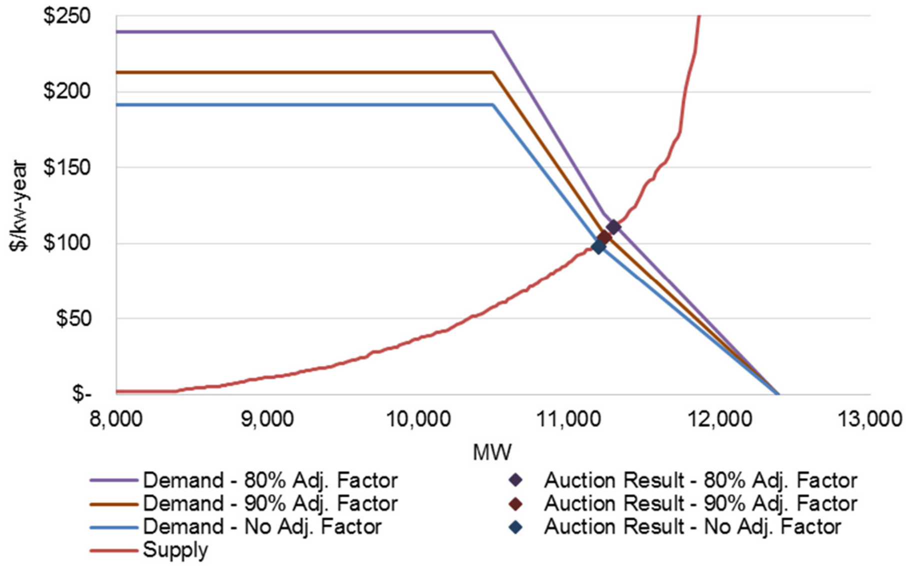


Table 33: Impact Analysis of Performance Factor

	80% Adj. Factor	90% Adj. Factor	No Adj. Factor
Approx. Clearing Quantity (MW)	11,300	11,240	11,200
Approx. Clearing Price ($/kw-yr)	$ 111	$ 104	$ 98
Total Capacity Market Cost	$ 1,250 M	$ 1,168 M	$ 1,095 M

E. Suggested Alternatives

We recommend adopting market rules that:

- include the performance factor adjustment to net-CONE;
- require updates to the performance factor in advance of each capacity auction; and
- use a 3-year rolling average performance factor for development of demand curve parameters.

F. Discussion of Alternatives

It is our view that the arguments for updating the performance factor outweigh those to fix the parameters in the market rules. As we understand, the AESO has made two core arguments:

- **Avoid adding another layer of uncertainty**: In our view, updates to the performance factor will add a modest amount of uncertainty, particularly given the overall range of uncertainties in the market. On balance, any added uncertainty is outweighed by the benefit of improving the objectives of the market design. Additionally, using a 3-year rolling average will mitigate volatility in the performance factor term, and one year of unusual performance behaviour will not have an outsize effect on demand curve parameters. Reducing volatility thorugh a rolling average will increase the ability of market participants to develop expectations about market outcomes.

- **The parameter is not required for the purpose of setting price levels along the demand curve**: It is not clear exactly what the AESO means by this. The performance factor has a meaningful impact on the demand curve for any given capacity auction as well as on the auction results.

In conclusion, because class average performance factors are knowable and may change over time, it would be prudent to adjust them on a regular basis. The associated uncertainty will be relatively small. Capacity market outcomes would be more consistent with the principles used in developing the demand curve. We expect our proposed alternative would result in slightly lower capacity prices over time, all else held equal. This is based on our expectation that the AESO's proposed performance incentives will lead to increased unit availability, which in turn will drive high availability factors and smaller adjustments to net-CONE.

The proposed alternative to the AESO's proposal would not require conforming changes elsewhere in the market rules. Employing a 3-year rolling average would be consistent with our preferred methodology for calculating the E&AS offset, though the two do not depend on one another.

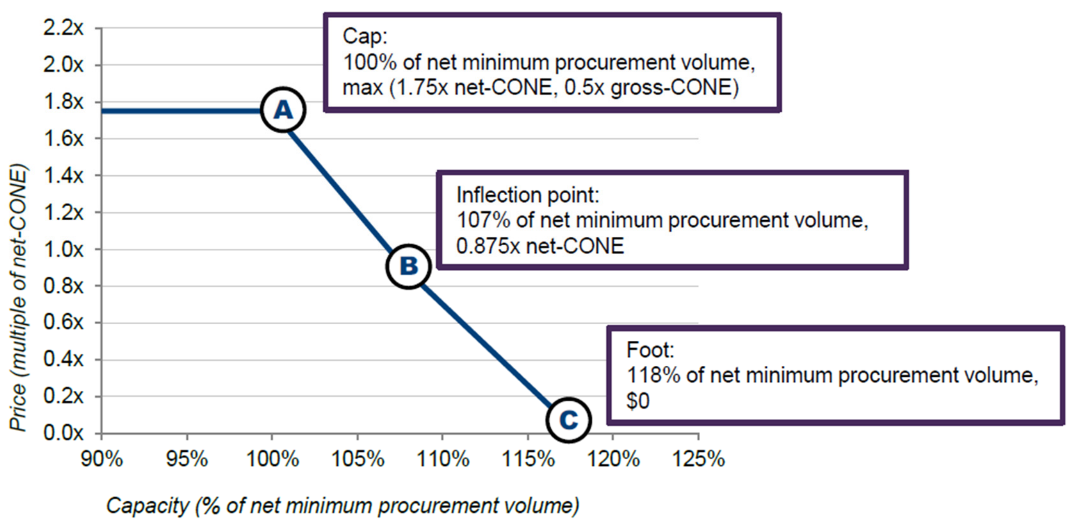
IX. Capacity Market Demand Curve: Overall Shape

A. AESO Proposal

The AESO has proposed a kinked, downward sloping demand curve. As shown in Figure 9, the curve includes:

- A horizontal segment from zero quantity to minimum quantity (where the downward sloping section begins). The minimum quantity is proposed to be set at a value of capacity commensurate with 0.0011% Expected Unserved Energy ("EUE") in one year based on the output of the Resource Adequacy Model ("RAM"). The price along this horizontal segment is the price cap based on the larger of 1.75 times net-CONE and 0.5 times gross-CONE.[114]
- A downward-sloping segment from the minimum quantity at "A" to the inflection point at "B". The quantity at the inflection point is 7% above the target quantity and the price is set at 0.875 x net-CONE. The target quantity is set at 400 MWh of EUE.
- A second downward-sloping segment from the inflection point at "B" to the foot at "C" (set at a quantity 18% above the target quantity), at zero price.

Figure 9: Proposed AESO Demand Curve



B. AESO Rationale

The AESO considered a range of possible demand curves, supported by Brattle, in designing the capacity market. The underlying considerations included, in brief:

- procurement of sufficient capacity to meet resource adequacy objectives while avoiding over- or under-procurement;

114 That is, max (1.75 x net-CONE, .5 x gross –CONE).

- efficient price signals in the capacity market, limits on volatility, reduced opportunities to exercise market power;
- parameters set to balance reasonable cost and resource adequacy across time;
- price expectations that will attract new investment and maintain existing capacity necessary to achieve resource adequacy objectives;
- robustness and compatibility with reasonably foreseeable changes in supply, demand, energy prices, and other factors in energy market;
- incorporation of experience and lessons learned in other jurisdictions, particularly the inclusion of a price cap and a procurement target informed by the resource adequacy standard; and
- consideration of unique aspects of Alberta's electricity system.

Using analyses performed by Brattle, the AESO considered alternative shapes for a convex downward-sloping curve. It then selected the demand curve "that would best: achieve sufficient capacity to meet the resource adequacy standard at reasonable cost to consumers; provide price levels high enough to attract new entry when required and low enough to incent exit when the market is oversupplied; and best mitigate the over procurement of capacity while providing stable capacity price signals to enable investor confidence."[115]

We note that the AESO has compared its proposed demand curve to demand curves in other North American markets with capacity markets and downward-sloping demand curves. The curve proposed by the AESO has a price cap (1.75x net-CONE) that is comparable to or slightly higher than the price cap in other jurisdictions. This AESO justifies such a price cap by stating that it helps support reliability when the market is short while also constraining price volatility and consumer cost. Likewise, the sloped portion of the demand curve has a horizontal width comparable or slightly wider than those in other jurisdictions. The AESO states that this is necessary to manage entry and exit of lumpy supply in Alberta's relatively small market.

C. Comparison to US RTOs with Capacity Markets

The AESO's proposed capacity market demand curve is depicted in relation to other North American capacity market curves in Figure 10 and the curve parameters are compared in Table 34.

115 AESO Capacity Market Application, P 131.

Figure 10: Graphical Comparison of Demand Curves in AESO Proposal and US Jurisdictions[116]

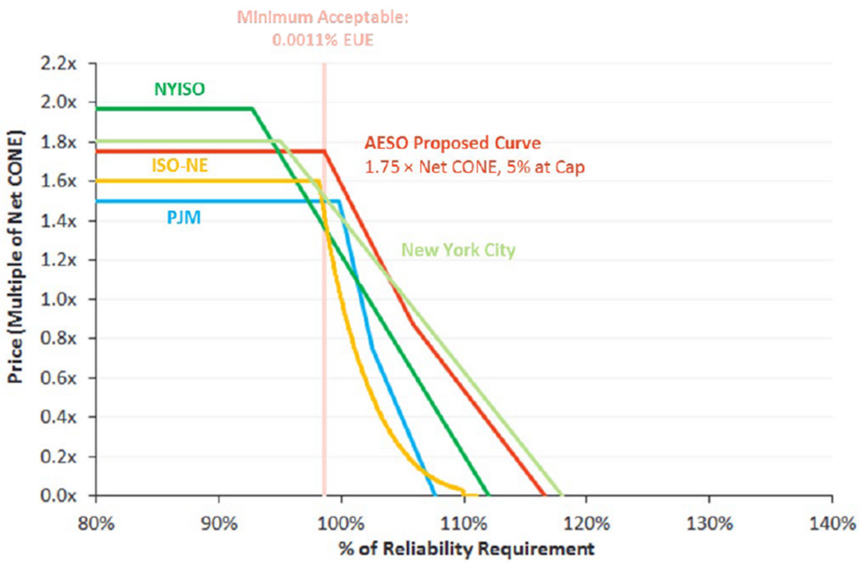


Table 34: Comparison of Demand Curve Parameters in AESO Proposal and US Jurisdictions

	Start of Sloped Section (% of Target)	Shape of Sloped Section	Foot of Sloped Section (% of Target)	Width of Sloped Section (% of Target)
AESO Proposed	100% (1.75 x adjusted net-CONE)	Convex Inflection @ 107 % of Target (0.875 x adjusted net-CONE)	118%	18%
ISO-NE	98% (1.6 x net-CONE)	Marginal Reliability Impact ("MRI") Shape		
NYISO	92% (1.5 x gross-CONE)	Straight Line passing through 100% Target and Zero Crossing Point	112%	19%
NYISO (NYC)	95% (1.5 x gross-CONE)	Straight Line passing through 100% Target and Zero Crossing Point	118%	23%
PJM[117]	99.8% (150% net-CONE)	Convex Inflection @ 101.9% of Target (75% net-CONE)	108.8%	8%

116 AESO Capacity Market Application, section 6.2.5.1.

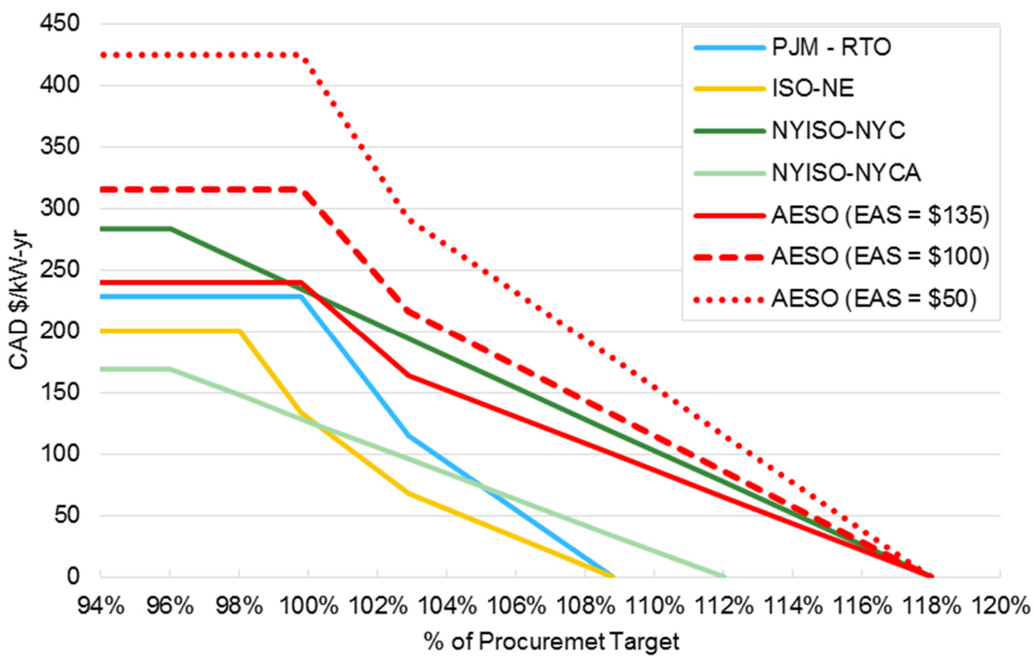
117 Does not include minor modifications as proposed in most recent VRR refresh proceeding, FERC Docket No. ER19-105.

D. Assessment and Analysis

a) Overall Result of Proposed Input Parameters

With respect to the overall shape of the demand curve, we highlight the end result of the AESO's proposed capacity market design. Figure 11 shows what the AESO's demand curve looks like compared to other North American capacity markets, but this time plotting actual values on the price axis. The "base" assumption assumes an Aero CT reference unit and applies prevailing power and gas forwards contemporaneous with the drafting of this report, as described in the E&AS offset section, which leads to a calculated offset of $ 157 / kw-year. The graphic also shows how the Alberta capacity demand curve would change with an E&AS offset of $100 / kw-year and $50 / kw-year. (We expect future E&AS offsets to fall, and have also proposed alternative methodologies we expect will lead to that result.)

Figure 11: Demand Curve Comparison Accounting for Recent CONE Parameters[118]



As a whole, the demand curve defined in the AESO Application appears aggressive in terms of the volume that it seeks to procure and the price that the market is willing to pay. The demand curve shape is more extreme when one acknowledges the relatively high E&AS offset in the "base" case. The "richness" of the proposed demand curve is amplified in the likely case that the E&AS offset is smaller in the future.

Of the demand curves originating in other jurisdictions, the one closest to the expected AESO demand curve (red) is the NYISO-NYC (green). The wide downward-sloping portion of the proposed demand curve serves to reduce volatility.

118 Represents most recent parameters for completed auctions. Some detail related to the curve of the downward-sloping portion of the ISO-NE MRI curve is omitted.

However, New York City probably has one of the most complex and constrained electricity grids in North America. It is expensive and difficult to build new electric generating capacity in New York City. In our view it strains credulity that the overall demand curve formulation for Alberta should so closely resemble capacity demand in New York City and that it may, under foreseeable future circumstances, significantly exceed the New York City curve in terms of price. This is concerning and is consistent with what we have observed as a consistent trend in this proposed market design of electing rules that will bias upwards the resulting prices, not only in the capacity market but also the energy market. We suggest that the AUC consider the richness of the proposed demand curve when making determinations about other aspects of the market design, particularly the nature of the energy and capacity market mitigation measures.

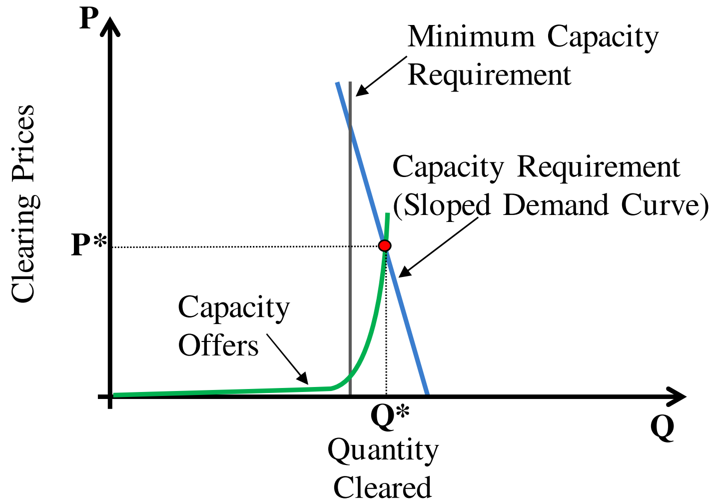
b) Specific Concerns with Proposed Demand Curve

The capacity demand curve is central to the AESO capacity market. It will determine the prices and quantities of capacity that are cleared in the auction. Capacity demand curves are used in all of the major centrally-organized markets in North America. Capacity demand curves have three essential features - a price cap that limits the clearing price in the auction and creates a horizontal section of the demand curve from the vertical axis to a “kink” where the curve begins to slope downward. The downward sloping portion intercepts the horizontal axis at what is called the demand curve “foot” or “zero-crossing point”. Sometimes there is a second kink in the downward sloping portion of the downward curve, or the sloping portion may be curved (convexly), resulting in reduced sensitivity to the clearing price as excess capacity on the system increases. The AESO’s proposed demand curve adopts these conventional aspects for its demand curve, including a kink.

While these main elements are conventional, how they are parameterized is critical. We find that the proposed demand curve parameters are likely to result in sustained excess capacity that is not required to meet the reliability requirements, which will impose excess costs on consumers. Moreover, because of the loose market power mitigation measure where suppliers may offer up to 80% of net-CONE, it is likely that the system have sustained and chronic excess capacity and substantially higher costs.

To understand this finding, consider the following figures that illustrate how prices are determined under a sloped capacity demand curve. Figure 12 shows that prices are determined where supply intersects the demand curve. The auction clearing price is paid to all resources that offer below that price.

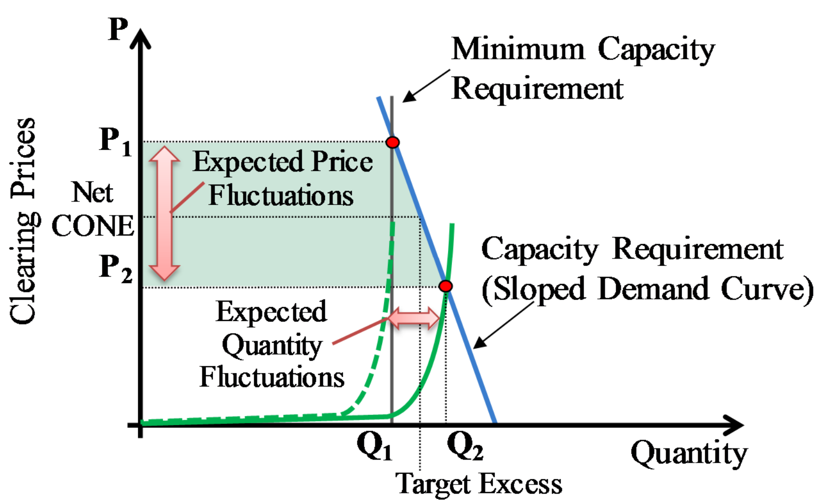
Figure 12: Capacity Pricing Under a Sloped Capacity Demand Curve



In establishing the slope and position of the demand curve, it is important to recognize that supply levels will fluctuate over time and the market must provide an efficient level of expected revenues to developers. Over the life of an investment, a developer must expect to recover that resource's gross-CONE amount from the energy, ancillary services, and capacity market revenues. Hence, the revenues expected from the capacity market must equal the resource-specific gross-CONE less the expected revenues from the energy and ancillary services markets, referred to as net-CONE. Again, these values may vary by capacity resource.

In order for developers to expect to recover resource-specific net-CONE over the long-run, prices must fluctuate above and below net-CONE as the quantity of supply fluctuates. This is depicted in Figure 13.

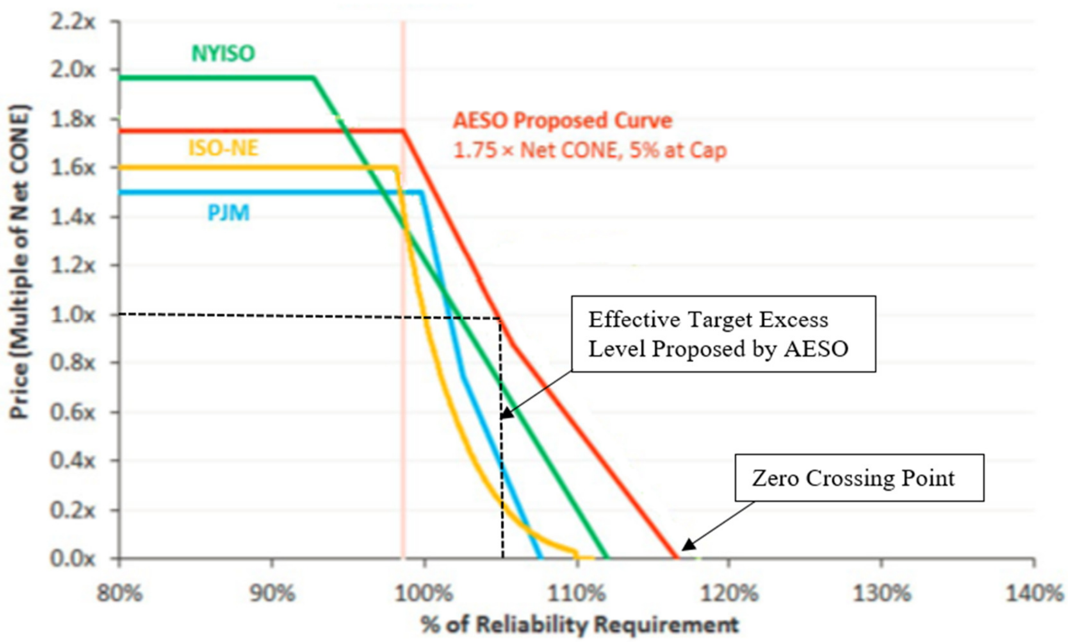
Figure 13: Establishing a Target Excess Capacity Level



In this figure, the quantity of supply is illustrated as fluctuating between Q_1 and Q_2, while prices fluctuate between P_1 and P_2. In order that prices average are approximately equal to net-CONE in this example, while ensuring that the overall supply in the market will not fluctuate below the minimum requirement, a target excess capacity level must be established above the minimum requirement. The target excess in NYISO and PJM ranges from 1% to 3% of the minimum requirement. In contrast, AESO has proposed a capacity demand curve with a target excess capacity level corresponding to net-CONE that exceeds 5%, as shown below.

Figure 14 is taken from the AESO filing and shows a comparison of the AESO proposed demand curve to that of other major markets. We removed the New York City curve from the figure because it is a load pocket and its relevance is of limited value when evaluating the proposed market-wide demand curve proposed for Alberta. We have also added an indicator of the level of excess that corresponds to Price = net-CONE (the Target Excess Level), as well as the "zero crossing point," beyond which additional capacity is assumed to have no additional value.

Figure 14: AESO Proposed Demand Curve with Comparisons[119]



The AESO's proposed demand curve has a horizontal segment that intercepts the vertical axis at 175% of adjusted net-CONE, capped at 50% of gross-CONE. Setting aside the adjustment to net-CONE and the values that feed into net-CONE, this is a fairly standard intercept that is comparable to ISO-NE and PJM. The horizontal segment of the demand curve extends from the vertical intercepts at the price cap to the first kink at slightly less than 100% of the minimum capacity requirement. Although the cap on the demand curve (the horizontal segment) is comparable to demand curves in other major capacity markets, the slope and location of the curve

119 AESO Application, Figure 5 with the New York City curve removed.

results in prices that will be much higher at every level of surplus capacity than any of the established capacity markets in the U.S. For example, the Target Excess Level is roughly double the typical values in other markets, while the proposed zero-crossing point at 118% of the minimum requirement is substantially higher than the 108 to 112% in the other markets shown in the figure. Because AESO is proposing a capacity demand curve that is higher priced at every level of capacity than the existing markets in the US markets, it will likely sustain a capacity base that exceeds its reliability requirements and generate excess costs as a result.

To see why this is true, consider the point on the vertical axis corresponding to 1.0x net-CONE. This is the clearing price that would theoretically incent the entry of new capacity. This point corresponds to the level of capacity that we have referred to as the Target Excess Level of capacity as shown in Figure 14 above. This should reflect the average level of capacity sustained over time because net-CONE is the average quantity of revenue required to induce investment. Therefore, we would expect the capacity levels to fluctuate above and below this level, which is roughly 106% of the minimum capacity requirements for Alberta. We find this value to be excessive and a substantial departure from the lower Target Excess Levels of capacity in the existing capacity markets in the US, which range from 0 to 3%, and have been sufficient to maintain capacity levels that exceed their respective minimum capacity requirements. Implementation a capacity demand curve that will perpetually sustain a capacity level that is 2% to 3% higher than necessary will be costly to Alberta's consumers.

The sustained excess capacity levels and costs is likely to be exacerbated by the market power mitigation measures we discuss earlier in this report. As we explained in the previous section, participants with market power are allowed to offer up to 80% of adjusted Net-CONE (the default offer). For most pivotal suppliers, if the market would otherwise clear significantly below 80%, they will have a strong incentive to withhold to raise prices to 80% of Net-CONE. To understand this, consider again the example of economic withholding of capacity that was provided in section III.D, in which a large supplier of capacity was able to increase its capacity market revenue by 30% withholding the equivalent of 5% of the markets total available supply.

Given the clear incentive to withhold by large suppliers, one can expect additional revenues at high surplus levels. This will further increase the propensity to sustain capacity levels well above the minimum capacity requirements because it will increase the expected revenues for new suppliers. Although AESO has expressed a preference for structuring the market to favor higher reliability levels (above the minimum requirement level), it is our view that the proposed capacity demand curve is excessively skewed toward maintaining excessive capacity levels.

E. Suggested Alternatives

We recommend that the slope and/or position of the curve proposed by AESO be modified to result in values that are in line with capacity demand curves that have been tested in other settings. The slope is likely the most reasonable parameter to modify. Ideally, the slope should be determined by how the incremental reliability benefit (as measured by the reduction in Loss of Load Expectation or LOLE) falls as additional capacity enters. This generally will produce a slope that is steeper than the slope proposed by the AESO. For example, ISO-NE's methodology explicitly determines the slope and shape of its curve in this manner, which produces a much steeper curve than proposed by AESO.

F. Discussion of Alternatives

The recommended modifications to the AESO's proposed capacity demand curve will result in capacity procurement levels that are less likely to result in over-procurement of capacity in Alberta relative to the procurement target and target excess level. In doing so, we would expect that a modified capacity demand curve will drive prices downward as compared to the prices that would be observed under the AESO's proposal. Furthermore, this approach would be consistent with rules in the US RTOs that operate capacity markets.

The proposed rule adjustments would not require conforming changes elsewhere in the market design.

X. Additional Commentary on Market Design Elements

A. Capacity Market Mitigation: Mitigation Screen

The market power screen proposed by the AESO is a structural test that is designed to identify those firms that have a portfolio of UCAP sufficiently large to profitably exercise market power. An *ex ante* market power screen will be applied by the AESO prior to each base auction in an attempt to identify which firms may have the ability to profit from a specified increase in the capacity market clearing price – 10% from the reference level of 0.875x adjusted net-CONE – by economically withholding capacity volumes. The failing firm(s) will be subject to market power mitigation measures, as described in the following sections. Based on the AESO's initial analysis, firms with 1,070 MW of UCAP would be able to profitably raise the clearing price consistent with this criterion. Currently, this will screen the four largest firms in the market.

While it appears the AESO's approach will be effective at screening for market power in the capacity market, at least in the near-term, we would recommend eventually that a more principled approach be taken. We point out that, despite the fact that the AESO has performed a sensitivity analysis on the results, a 10% price shift threshold is arbitrary. Additionally, the base price from which to calculate the 10% price shift is also arbitrary. The proposed approach uses the inflection point as the baseline. However, in a year in which the clearing price would otherwise have been much lower than reference level, an "acceptable" increase could actually be much greater than 10% than the counterfactual.

Good alternatives to the proposed test exist, including pivotal supplier tests – joint or unilateral – or conduct and impact-type tests. These alternatives would be more transparent, less arbitrary, and more grounded in principle. For this reason, they would also be more robust to future changes in market concentration that may not be well accounted for by the proposed test. Alternatively, the capacity market rules could draw from thresholds established elsewhere in Alberta law. For example, the MSA has as a legislated threshold for certain oversight tasks at 5% market share.[120] A statute-based alternative would reflect market share thresholds determined to be relevant by Alberta policymakers.

B. Capacity Market Mitigation: Rebalancing Auction Mitigation

Rebalancing auctions will allow participants to modify their short or long positions from the primary base auction. AESO expects the bulk of the capacity to be cleared and contracted in the base auction and that omitting mitigation in the rebalancing auction will save on administrative costs. Therefore, it has not proposed market power mitigation in the rebalancing auctions.

The market power mitigation measures proposed in the base auction are not complex and do not likely require expensive administration to execute. Because the rebalancing auction is likely to be thinly traded does not mean there will conditions in which suppliers have substantial market power. We know of no other market where

[120] http://www.qp.alberta.ca/documents/Regs/2009_159.pdf

market power mitigation in the forward market is not carried to the market clearing closer to operating horizon. As a result, we propose the market power mitigation be carried into the rebalancing market.

C. Capacity Performance Incentives

The AESO's proposed performance incentives are similar to ones proposed by ISO-NE and PJM. In these proposals, payments are made to or collected from resources based on their energy output during periods when the system is in shortage (typically an operating reserve shortage). A payment is made to suppliers providing energy in excess of their capacity obligation at these times. Conversely, a payment is collected from suppliers producing less energy than their capacity obligation during these periods. Essentially, the performance incentives are a form of real-time shortage pricing intended to strengthen the incentive for suppliers to be available in real time when the system most needs their energy. However, this is not a sound approach because the proposal would create a shortage pricing regime for energy and reserves outside of the energy and reserves markets. This raises the following concerns.

As we have indicated above, the energy and ancillary services spot markets are the most effective way to provide incentives for resources to be available and flexible during the operating horizon to efficiently meet demand at peak times. Real-time prices provide effective incentives for resources being available, providing needed flexibility, and following dispatch instructions. If the system relies on mandated performance of capacity resources, the effective price paid to capacity resources that are supplying energy during peak times will be greater than the price paid to other, non-capacity resources that are responding to the system needs. Relying on real-time prices would reward all resources that respond to the system needs.

If well-designed energy and ancillary services markets are in place, units will have a strong incentive to provide flexibility and availability at the time of system peak. This will naturally make its way into planning studies and, consequently, lead to reduced capacity requirements. There will be savings in the overall costs of maintaining and operating the system over time. As a result, the focus on effective energy and ancillary services market design is critical.

Nonetheless, if the reform process retains performance penalties, they should be linked to real-time prices in order to allow the energy and ancillary services markets to provide efficient incentives. For example, Alberta could require that suppliers that have sold capacity be charged the shortage pricing premium (e.g., the portion of any system-wide energy price greater than $500). This would essentially embed a forward energy contract for the shortage revenues within the capacity product. It is analogous to the capacity performance structures implemented in the U.S., except that it is linked directly to the shortage pricing in the energy market rather than to a shortage settlement that occurs outside of the energy market.

D. Prompt Markets for Capacity

Capacity markets have been designed and implemented under two primary procurement timeframes:

- **Forward procurement:** The auction is conducted years ahead of the planning year (usually 3 years) to allow potential new resources to be offered. Typically, the auctions procure capacity for one planning year on behalf of all of the load. This is not a typical forward commodity market where procurement is voluntary and the prices clear best on expectations of the spot price for the commodity.
- **Prompt procurement**: The auction is conducted only a few weeks or months in advance of the planning year. The price will clear based on the expected supply and demand for the planning year and offers by new resource participants once they have entered the market.

We have monitored and evaluated the performance of forward capacity markets and prompt capacity markets in the U.S. Based on our evaluation of these markets, we believe there can be clear advantages to prompt capacity procurement over forward capacity procurement. Forward capacity markets can adversely affect decisions to invest in new resources and to retire existing resources.

a) Adverse Effects on New Investments.

Under a forward procurement, a competitive offer by a new resource would be close to the resource-specific net-CONE. If they do offer competitively, then the market will clear at an efficient price when new resources are needed to satisfy the ISO's planning needs. However, new resources are not likely to make competitive offers near net-CONE for at least two reasons:

New resources clear for only one year – less than 3% of the life of most resources. This may cause some investors to inflate their offers since no revenue after the first year is guaranteed and future revenue uncertainty may be high.

New resources face substantial risk of completing its entry within three years so many developers commit to entering prior to the capacity auction. This may cause some investors to incur a substantial fraction of its costs prior to the auction, creating the incentive to offer well below their net-CONE.

The first of these two scenarios prompted some U.S. RTOs to establish revenue "lock-in" provisions to ensure that new suppliers submit offers close to net-CONE. Lock-in provisions enable a new resource that clears to elect to be guaranteed the clearing price for a certain number of years. For example, ISO-NE allows a new resource to lock-in the clearing price for up to seven years. Unfortunately, these provisions are only partially efficient and generally raise costs by discriminating against existing resources. This discrimination causes new resources to inefficiently displace existing resources.

The second scenario is likely more common, in part because of the risk the new supplier faces of not completing its project by the start of the planning year. To address this risk, it is rational for the investor to begin incurring costs and securing permits well before the auction. Additionally, because the new unit's return on investment will almost entirely depend on the subsequent revenues after year one, these expectations should dominate the investor's decision (which is, therefore, likely to be made prior to the auction). Incidentally, this second scenario describes how investors make new investment decisions in prompt capacity auctions -- they form a long-term expectation (and/or sign long-term contracts) and make the decision to invest based on the expectation. To the extent investment decisions in both forward and prompt auctions are based on future expectations, the forward market does not offer any benefits over the prompt auction from the perspective of facilitating new investment.

Therefore, we find that procuring capacity years in advance provides does not provide a clear advantage over procuring capacity through a prompt capacity market, and likely has many disadvantages. In fact, given the much greater supply and demand uncertainty that exists in the forward procurement timeframe, we believe that forward capacity markets are less likely to facilitate efficient investment and capacity prices.

b) Adverse Effects on Retirements

The other long-term decision that is facilitated by the capacity market is the retirement decision – a resource will retire if it does not expect to earn enough revenue in the capacity and energy/ancillary services markets to pay for the fixed going-forward cost of staying in service. While we do not believe mandatory forward procurement improves the new investment process, we believe it may harm efficient retirement decisions. In a mandatory forward procurement, suppliers must determine whether old resources will continue to operate for an additional four years (three years plus the planning year). This is not optimal for units facing physical or regulatory uncertainty. Not surprisingly, almost all units on the brink of retirement are very old and face substantial uncertainty.

In contrast, a well-functioning prompt auction allows existing suppliers to make rational economic decisions regarding when to suspend or retire a unit. In prompt procurement markets, old units can operate until they suffer equipment failure and can make efficient decisions to mothball or retire based on the auction.

c) Other Benefits of Prompt Auctions vs. Forward Auctions

Given that forward capacity procurement provides few if any benefits over a prompt auction, it is useful to recognize that there are a number of benefits of prompt auctions:

- There is very little uncertainty regarding the true capacity needed since AESO would not be required to forecast the demand three years in advance.
- Prices will more closely be a reflection of the current supply and demand conditions in the market. For example, if a resource suffers a catastrophic failure and is out of service for an extended period, the supply will be reduced in the prompt auction.
- There is very little exposure to the risks that the entry of new resources will be delayed because new resources begin selling into the auction after they become operational. Such delays have been a substantial problem in the forward markets in the U.S.

Hence, having monitored and analyzed both prompt and forward capacity markets in the U.S., we conclude that prompt capacity markets are the superior alternative.

E. Seasonal Capacity Procurement

Alberta is planning to implement a capacity market that would clear on an annual basis. However, both the demands of the system and the available system supply change substantially from one season to the next. Hence, procuring capacity on a seasonal basis can be valuable and we believe that this is a best practice in the context of capacity markets. This would produce the following benefits:

- The revenues would be better aligned with the value of the capacity;
- Relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder seasons;
- Resources retiring mid-year would have more flexibility to retire mid-year without having to procure significant replacement capacity to satisfy post-retirement capacity obligations; and
- The qualification of resources with extended outages can better match their availability.

Appendix A: Selected Analysis Background

1. Modeling Capacity Market Outcomes

In certain instances in our assessment and analysis of the AESO's proposed rules, and our suggested alternatives, we determined that it would be helpful to be able to examine the effect of a proposal, or a proposed alternative, on market outcomes. To accomplish this, we developed a simple representation of the AESO's proposed capacity market. We populated it with generic assumptions for the 2021/2022 capacity delivery period, as shown in Table 35.

Table 35: Capacity Auction Base Case Parameters

Parameter	Value
Procurement Target	10,500 MW
Reference Technology	Aero CT
Gross-CONE	$ 244 / kw-year
A&ES Offset[121]	$ 135 / kw-year
Net-CONE	$ 109 / kw-year
Performance Factor	0.8
Adjusted Net-CONE	$ 137 / kw-year

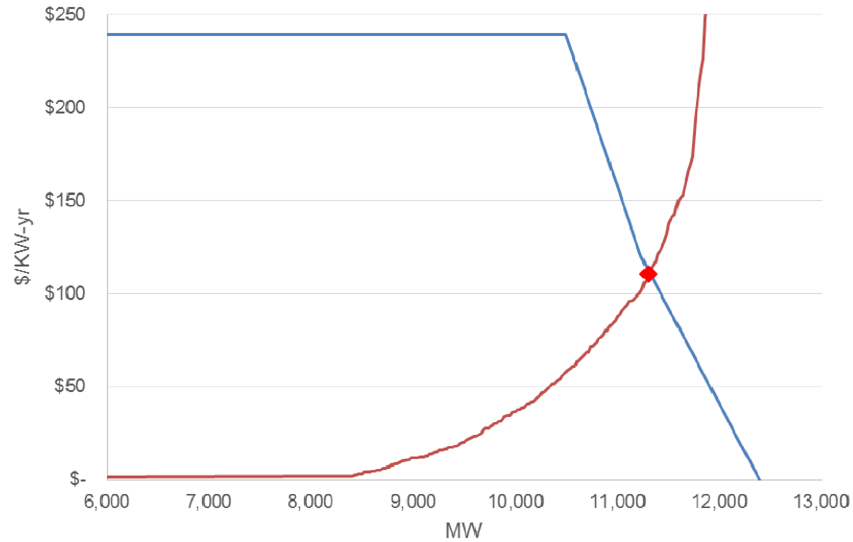
As in all cases with capacity market modeling, one of the most difficult elements of the analysis is the appropriate representation of the supply curve.[122] Capacity markets in other jurisdictions, generally, do not make supply curve data public. The situation is even more difficult in Alberta, where there has yet to be a capacity auction and there is no basis upon which to estimate a supply curve. We dealt with this issue in a similar fashion as the AESO: by using a rough representation of the shape of the PJM demand curve.[123] We calibrated the supply curve to intersect the demand curve in our "base case" at net-CONE (equivalent to 80% of adjusted net-CONE) and to have some elasticity across the range of prices between zero and the price cap. This calibration facilitates the range of comparisons we present.

121 Calculation performed as per the AESO's proposed methodology and using available information on NGX forwards. Natural gas forward prices for 2022 were $1.62 / GJ (based on trades from the end of December 2018). Power forwards prices (flat) for the same period were $43.50 / MWh (also based on data dated to December 2018).

122 Here, we are referring to the act of modeling a capacity market in a market that has already been established and therefore also has a defined demand curve.

123 Specifically, we based the supply curve on the stylized depiction in Figure 4 of Brattle's Demand Curve Analysis (Appendix L to the AESO's Application, p. 12). That analysis appears to use confidential, non-public supply curve data from Brattle's prior and ongoing work with PJM. This limits transparency and makes it difficult or impossible for other market participants to deliver evidence on a comparable basis. It is also difficult to determine whether PJM's historical supply curves are actually a good representation for what capacity supply offers may be like in Alberta.

Figure 15: Illustrative Capacity Market Outcome



We emphasize that our hypothetical modeling is not intended to forecast actual Alberta capacity market outcomes. Rather, as it is employed, the purpose is to illustrate how the proposed market rules, and potential changes to those market rules, might result in corresponding changes to market outcomes, both in terms of magnitude and direction. We further acknowledge that a "smooth" representation for a supply curve may be considerably different from the lumpiness that is likely to be present in the elastic portion of Alberta's capacity supply curve, with consequent impacts on market dynamics.

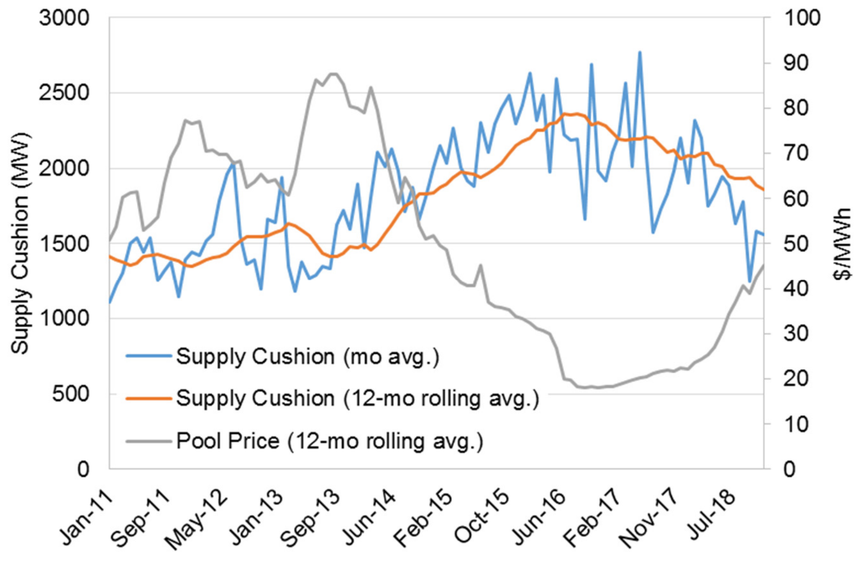
2. Year Selection

In certain instances, it was necessary to select a set of historical years against which to perform a given analysis. To moderate the volume of information presented, we performed certain analysis items for three years: 2013, 2017, and 2018. The intent was to roughly present three "states" of the Alberta market. The 2013 period represents a year in which supply was relatively tight and prices were high. The 2013 period was also before the Offer Behavior Enforcement Guidelines ("OBEG") were revoked.[124] The 2017 period represents a year when there was considerable supply cushion and prices were low. We also understand that, during this period, conservative offer behavior on the part of Balancing Pool resources, which set the price in a significant number of hours, moderated pricing outcomes and contributed to market clearing prices below historical averages. The 2018 period falls between these two "extremes." There was observed recovery in demand, decreasing supply cushions, and pool prices more in line with historical averages. The dynamics are observable in Figure 16.

124 Available at https://albertamsa.ca/index.php?page=offer-behaviour-enforcement-guidelines.

We recognize that these may not be perfect generalizations, though we do believe they have utility in allowing us to make meaningful observations about historical market outcomes in Alberta.

Figure 16: Historical Alberta Supply Cushion



Appendix B: Curriculum Vitae of Testifying Experts

Christopher J. Russo

Vice President & Energy Practice Leader

MS, Technology & Policy (Energy)
Massachusetts Institute of Technology

BS, Mechanical Engineering
Tufts University

Christopher Russo is a Vice President and the head of CRA's Energy Practice. He advises domestic and international clients in the electricity and gas industries in the areas of investment strategy and economic analysis, asset valuation, energy technology, and generation and transmission development. His expertise covers electricity and gas markets in North America, Europe, the Middle East, and worldwide.

He has testified in litigation and regulatory matters on issues regarding the economics, planning and operation of energy markets and has testified numerous times at trial. Mr. Russo also served on the Board of Directors of Neuco, a Boston-based company which provides software to enable neural network control of coal and gas-fired power plants.

Prior to joining CRA, Mr. Russo was a senior consultant with Cambridge Energy Research Associates in Paris, and prior to that, owned his own energy consulting firm as well as working for ABB Corporate Research in the US and Switzerland. He started his career at MIT as the Plant Engineer for the campus cogeneration power plant, and later held an academic appointment as a Visiting Scientist at the MIT Energy Laboratory where he investigated electricity technology and energy policy.

Areas of Expertise

Mr. Russo is an energy economist and consultant with expertise in the following areas:

- The dynamics of electricity and gas markets in North America, Europe and worldwide, including market operations, regulatory economics, system planning, physical and economic grid characteristics, generation/dispatch system operations, power systems, and power plant operations. His experience covers nuclear, coal-fired, gas, hydroelectric and renewable (including solar, wind and hydro) generation resources and transmission projects.
- Expert witness testimony and reports related to energy disputes in multiple venues
- Strategic planning and advice for companies engaged in energy markets
- Financial valuations and assessments of generation and transmission assets
- Master planning for energy systems, including assessments of upstream supply sources, energy conversion, transmission, and demand sectors

Professional History

2007–Present *Vice President & Practice Leader*, Charles River Associates, Boston

(*Previously held positions as Associate Principal, Principal and Vice President)*

2006	*Senior Consultant*, Cambridge Energy Research Associates (CERA), Paris
1999–2006	*Principal*, Russo & Associates LLC, Boston

- Worked with numerous market participants and regulators in markets in the US and abroad on the operations and software for restructured energy markets.
- Provided economic analysis for market participants and regulators on generation and transmission assets.

1998–2002 *Consultant*, Department of Energy & Global Change, ABB Corporate Research Center, Baden-Dättwil, Switzerland

- Investigated CO_2 reduction strategies, new generation, and end-use technologies and helped to initiate the China Energy Technology Program. Acted as liaison between ABB and MIT. Worked closely with researchers from ETHZ and PSI. Held a Visiting Scientist appointment at the MIT Energy Laboratory.

1995–1998 *Plant Engineer*, MIT Cogeneration Project, Massachusetts Institute of Technology, Cambridge, MA

- Managed gas turbine and cogeneration plant operations, negotiated environmental permits, managed gas market purchases and contracts, and performed regular performance analyses for a cogeneration and district energy plant. Was a guest lecturer in the Department of Aeronautics teaching students about gas turbine technology.

Selected Commercial Consulting Experience

- Mr. Russo has directed the analysis of over one hundred transmission and generation assets for utilities, equity and debt investors, infrastructure funds, regulators and market operators. He has analyzed assets in all major power markets, including ISO-NE, PJM, ERCOT, SPP, SERC, NYISO, CAISO, IESO, AESO, MISO and the Pacific Northwest. These include thermal, renewable, and hydro assets.
- Mr. Russo directed and lead due diligence efforts related to nuclear technology and power markets for a major private equity investor acquiring a nuclear fuel and services vendor in bankruptcy.
- Mr. Russo led the analysis for a major foreign investor entering the North American gas pipeline, processing and midstream market, consisting of strategic guidance and the analysis and due diligence of numerous North American and Mexican midstream assets.
- Mr. Russo supervised the analysis for the Alberta Electric System Operator on the development of new capacity market mechanisms in the provincial electricity market.
- Mr. Russo led the financial and transactional analysis for a group of investors on a combined heat and power gas-fired cogeneration plant.

- For a major renewable energy and transmission developer, Mr. Russo led the analysis of market impacts of proposed projects and assisted in developing commercial and regulatory strategy in New England and New York.
- Mr. Russo led the analysis for a major transmission project in PJM, including analysis of costs and benefits, production cost modeling, regulatory implications of FERC Order 1000 and other rules, and strategic advice on project development.
- For a transmission developer, Mr. Russo designed and directed the economic and technical analysis of a 2,000 MW HVDC project in the northeast US with detailed analysis of ISO-NE and NYISO markets.
- For a worldwide operator of data centers, Mr. Russo directed a risk exposure analysis of multiple markets, commodities and assets to assess the company's exposure to global trends.
- Mr. Russo directed the analysis of new regulatory approaches and energy technologies for a large African electric utility.
- Mr. Russo assessed the economic and technical suitability of large-scale photovoltaic technologies for a large Middle Eastern utility.
- Mr. Russo directed the analysis of renewable energy (solar and wind) procurement options for one of the largest renewable energy purchasers in the world. This evaluated technical, financial, and economic factors affecting the renewable technologies.
- Mr. Russo directed the analysis of capacity need and market conditions related to the siting of new capacity on Long Island for a client.
- Mr. Russo led a major review of new nuclear development strategy, including technical reviews, risk analyses, economic forecasts and prudence reviews for a US-based electric utility.
- Working for the mayor and city council of a major US city, Mr. Russo managed a due diligence effort to determine the feasibility of supporting new nuclear licensing applications for a municipally owned utility. This included a review of nuclear technology, market conditions, Nuclear Regulatory Commission (NRC) resource constraints, and federal regulatory policy related to nuclear loan guarantee programs.
- Mr. Russo led the analysis for a large industrial client of how electricity market rules related to reliability affected prices in installed capacity markets, including analyses of resource-adequacy and short-term grid contingency events.
- For a major municipal utility, Mr. Russo provided an independent review of the utility's investment analysis to retrofit emissions control equipment to a coal-fired power plant to comply with pending environmental regulations.
- For a transmission developer, Mr. Russo advised on the open-season transmission requirements and FERC process for a new merchant transmission line.
- Mr. Russo directed the analysis of the socioeconomic benefits of advanced coal technology in European, Chinese and South Asian markets, focusing on market effects, induced and indirect benefits and social impacts.

- Mr. Russo led the effort to develop an electrical market model for Europe for a Paris-based client. Working with the production-cost modeling software and his team, he assembled databases of resources, demand, fuel prices, and transmission network characteristics to build a comprehensive model of the EU grid.
- Mr. Russo directed and led a project to synthesize and summarize the nuclear technology risk and seismic hazard data for a two-unit nuclear reactor in North America.
- Mr. Russo directed an engagement for a client to assist in the purchase and contracting of large amounts of electricity to support aluminum smelting operations. This consisted of financial analysis of North American power markets including the MISO and PJM and financial evaluation of proposed contract structures.
- Mr. Russo managed a major effort for the City of New York to develop a Master Electrical Transmission Plan to address economic and reliability needs in the context of a multi-stakeholder process, incorporating the Mayor’s Office, Economic Development Corporation, NYISO, ConEd, and the NYS Public Service Commission. The program addressed the economic and technical factors associated with AC and HVDC transmission, as well as the policy and financial impacts of public-private partnerships and equity investment strategies.
- For a major power development company, Mr. Russo led several projects to determine the optimal strategy for entering the gas-fired development market under pending environmental constraints and regulations. In a related project, he led efforts to investigate the feasibility of new and waste coal development in the PJM energy market.
- For the City of New York, Mr. Russo led a major effort to investigate the reliability and economic and environmental impact of the closure of the Indian Point Nuclear Energy Center on consumers and the economy. This comprised a report as well as testimony before various commissions.
- For a private equity firm, Mr. Russo directed the due diligence assessment of an energy storage technology manufacturer, focusing on the analysis of market opportunities for energy storage.
- For a major global semiconductor manufacturer, Mr. Russo led an effort to develop a global energy procurement strategy, analyze potential power contracts, and benchmark procurement activities against other similar firms
- Mr. Russo directed the review of the internal technical and financial modeling processes for an investor in the liberalized UK energy market.
- For a gas pipeline developer, Mr. Russo directed the analysis of a new pipeline project’s impact on gas basis differentials.
- For a major European utility, Mr. Russo designed and managed a process to develop internally consistent analysis scenarios to enhance corporate planning. The effort involved soliciting input from different groups throughout the enterprise, designing scenarios, analyzing the results, and presenting the results to internal and external stakeholders.
- For a major Internet search provider, Mr. Russo directed the evaluation of potential sites for data centers in Europe and the US.

- For a major Asian utility, Mr. Russo managed an engagement to develop a growth strategy for a subsidiary of the parent firm, including a review of current operations, market positioning, potential risks, and strategic alliances, culminating in a concrete division growth plan.
- Working for the Executive Office of Sheikh Mohammed of Dubai, Mr. Russo was a principal in a major study examining the effectiveness of Dubai's current electric utility, petrochemical resources, and water resources. Working closely with local personnel, he spent significant time interviewing Dubai Electricity and Water Authority (DEWA) and Dubai Supply Authority (DUSUP) personnel, Emirati leaders, and stakeholders; evaluating petrochemical and water resources; and developing a comprehensive multi-attribute, multi-scenario energy system model of the emirate for evaluation of future energy strategies.
- Mr. Russo was a principal in a project to restructure a major utility in the United Arab Emirates, including long-term planning functions, regulatory efforts, customer service systems, IT architecture, and financial systems.
- Mr. Russo led a project for a major Hong Kong-based utility to help them adapt their management processes, planning infrastructure, and IT systems to pending emissions and energy trading regulations through performing needs assessments, sourcing strategies, and drafting RFPs.
- While with ABB, Mr. Russo helped design and organize the China Energy Technology Program, a joint ABB/AGS program to investigate sustainable energy systems in China, which included Electric Generation Expansion Analysis (EGEAS) modeling of the eastern China power network to identify long-term, cost-effective strategies for environmental improvement. The project was conducted in conjunction with the Swiss Federal Institute of Technology (ETHZ) and the Paul Scherrer Insitut (PSI).
- Working with the MIT Cogeneration Plant, Mr. Russo provided continuing guidance and expertise on cogeneration plant and gas turbine operations, as well as conducting several economic cost-benefit analyses to plan future plant expansion.
- For a major software firm and federal clients, Mr. Russo helped prepare and develop a wide-area synchronized phasor measurement system to measure phase angle and frequency perturbations across the Eastern Interconnection to enhance grid stability.
- For PJM, Mr. Russo developed software and systems to visualize market participant bidding behavior to assist market monitors and dispatchers.
- For New York ISO, Mr. Russo designed and implemented a PI data historian system for tracking all operational data. He also trained system operators on its use, played an integral part in the standard market design to implementation and EMS development and developed various software applications to analyze system operations.
- For the California ISO, Mr. Russo worked as a consultant during the startup, developing systems to track generator dispatch operations and identify anomalous generator behavior to assist market surveillance personnel. During the power crises and rolling blackouts, he managed and maintained a critical system in use by all ISO personnel and developed a system to analyze results of Stage 2 and 3 events.

- Mr. Russo began his career in power as an intern for the Trigen Energy Corporation analyzing the operations and economics of Trigen's fleet of cogeneration plants.

Testimonial History, Litigation Consulting & Major Public Reports (Prior Ten Years)

- *Offer Behaviour Guidelines Prior to the Implementation of a Capacity Market.* Report prepared on behalf of the Alberta Market Surveillance Administrator, December 2018. Filed jointly with Dr. Adonis Yatchew, Dr. David Hunger, and Mr. Jordan Kwok. Presentation and oral appearance at Stakeholder Meeting January 2019.
- *Petition of Eversource & National Grid et al., for approval of long-term contracts for renewable energy, pursuant to Section 83D of An Act Relative to Green Communities, dockets DPU 18-64, 18-65 and 18-66*. Testimony related to the proposed Quebec- Maine New England Clean Energy Connect transmission line on behalf of NextEra Energy. Testimony filed jointly with Robert Stoddard and Stephen Whitley, December 2018.
- *In the matter of Trina Solar Limited, Cause No. FSD 92 of 2017 (NSJ), Grand Court of the Cayman Islands.* Expert testimony submitted on behalf of Maso Capital Investments Limited and Blackwell Partners LLC related to the solar energy industry and the valuation of Trina Solar. Expert report submitted October 2018.
- *Affidavit on behalf of Vistra Energy Corp. & Dynegy Marketing & Trade, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000, Federal Energy Regulatory Commission*. Testimony related to proposed PJM capacity market reforms. Affidavit filed October 2018, answering affidavit filed November 2018
- *Hydro One Networks Inc. Lake Superior Link Project Leave to Construct Application, Ontario Energy Board,* Docket EB-2017-0364 and EB-2017-0182, Expert testimony submitted on behalf of NextBridge Infrastructure. Expert report filed April 2018. Testimony at hearing May 2018.
- *Request for Approval of CPCN for the New England Clean Energy Connect Consisting of a 1,200 MW HVDC Transmission Line from Québec-Maine Border to Lewiston (NECEC) and Related Network Upgrades, State of Maine Public Utilities Commission,* Docket 2017-00232. Direct testimony on behalf of NextEra Energy Resources filed April 2018. Testimony and cross-examination at technical conference and hearings, June 2018, August 2018, and January 2018.
- *Massachusetts Superior Court,* Expert report submitted on behalf of a plant owner calculating damages from operational limitations on a district energy plant in the ISO-New England Market. Expert report submitted March 2018. Case is currently in mediation.
- *State of New Hampshire, e*xpert report submitted on behalf of a plant owner and operator in a tax certiorari proceeding in February 2018. Case was settled before hearing.

- *In re: Request for Advanced Ratemaking Principles by Interstate Power & Light Company*, Docket RPU-2017-0002, Iowa Utilities Board. Direct Testimony on behalf NextEra Energy Resources commenting on IPL's resource plan and the Duane Arnold Energy Center nuclear power plant. Direct, rebuttal and sur-rebuttal written testimony, and cross-examination at hearing, November 2017.
- *ABB AB v. Alstom Grid AB, Alstom Grid SAS and Alstom Grid UK Ltd., Stockholms Tingsrätt (Stockholm District Court), Cases 7403-15 and 11527-15*. Expert testimony submitted on behalf of Alstom related to economic damages resulting from the alleged IP infringement of HVDC technology. Expert report filed August 2017. Direct and cross-examination (in English with translation) at trial, October 2017.
- *State of California v. Coral Power LLC et al., Docket EL02-71-057, Federal Energy Regulatory Commission*. Testimony on behalf of Shell Energy North America (f/k/a Coral Power) related to the causes of the 2000-2001 California Power Crisis and alleged energy market manipulation. Written testimony filed February 2017, deposition March 2017, direct and cross-examination at trial April 2017.
- *AAA Arbitration,* Lead economic expert in a dispute related to the economics of environmental regulations, coal-fired power plants, and railroad coal supply contracts in the US. Expert report filed September 2016, deposition November 2017, direct and cross-examination at trial December 2016.
- *In re: Direct Application Of MidAmerican Energy Company For The Determination Of Ratemaking Principles*, Docket RPU-2016-001, Iowa Utilities Board. Direct Testimony on behalf of Google Inc., Facebook Inc., and Microsoft Corporation related to the economics of MidAmerican's Wind XI proposal, filed June 2016. Case was settled before hearing.
- *MAG Energy Solutions Inc. v. TEC Energy Inc. et al., Province de Québec, Cour Supérieure, Case No. 500-17-087823-152*. Expert report submitted on behalf of TEC Energy on issues related to energy trading in Canada and the United States, filed May 2016.
- *Northern States Power Company, Southern Minnesota Municipal Power Agency, Aegis Insurance Services et al., v. General Electric Company, State of Minnesota, Tenth Judicial District, Case 71-CV-13-1472*, Expert report submitted on behalf of GE calculating damages related to the outage of the Sherburne county power plant, filed March 2016. Deposition June 2016.
- *Entergy Nuclear FitzPatrick, LLC v. Town of Scriba, et al.*, *Supreme Court of the State of New York,* Expert report of behalf of Entergy in a tax certiorari case projecting electricity revenue and nuclear fuel cycle costs for the James A. FitzPatrick Nuclear power plant, expert report filed January 2016. Case was settled before trial.
- *State of Maryland v. NRG, Case 09-RP-CH-261-265; 09-RP-CH-280-284; and 09-RP-CH-294-298.* Expert report on behalf of NRG projecting energy and capacity revenues for the coal-fired Mirant Mid-Atlantic Dickerson facility, 2014. Deposition March 2017, direct and cross-examination at trial, May 2014

- *In the Matter of Entergy Nuclear Indian Point 2, LLC & Entergy Nuclear Indian Point 3, LLC, DEC: 3-5522-00011/00004, SPDES: NY-0004472, DEC: 3-5522-00011/00030, DEC: 3-5522-00011/00031,* Direct and rebuttal pre-filed testimony on behalf of the City of New York related to the operations and economic impact of the Indian Point nuclear power plant, filed March 2014. Direct and cross-examination at hearing April 2014
- *State of Maryland v. NRG, Case 09-RP-CH-261-265; 09-RP-CH-280-284; and 09-RP-CH-294-298*. Expert report on behalf of NRG, jointly filed with Robert B. Stoddard, projecting energy and capacity revenues for the coal-fired Mirant Mid-Atlantic Morgantown facility, January 2014
- *ThyssenKrupp Companhia Siderúrgica do Atlântico v. CITIC Group, ICC Case*, expert report for international arbitration submitted on behalf of CITIC group related to damages from improper operation of a power plant in Brazil, filed July 2012. Case was settled before hearing.
- *Indian Point Energy Center Retirement Analysis*, Prepared for the City of New York, August 2011
- *Summary of economic effects for proposed Spectra NJ-NY gas pipeline*, Memo prepared for Spectra Energy, and submitted to the New Jersey Bureau of Public Utilities, March 2011
- *Confidential Arbitration,* Expert report provided on behalf of a power plant investor regarding the appraised value of a coal-fired power plant in the PJM market, August 2011. Case was settled before hearing.
- *Proceedings before the New York State Assembly on the economic and reliability impact of the potential closure of the Indian Point Nuclear Energy Center.* Direct testimony at hearing January 2012
- *Confidential Arbitration*, Expert report related to the valuation of a hydroelectric plant in California, which was settled before hearing, June 2013.
- *Coordination between Natural Gas and Electricity Markets, Docket AD12-12-000, Federal Energy Regulatory Commission*, Comments filed jointly with Dr. Richard Tabors and Scott Englander, 2012
- *In the Matter of Hudson Transmission Partners, LLC Case 08-T-0034*, direct and rebuttal pre-filed testimony on behalf of the City of New York before the New York State Public Service Commission in the Article VII proceeding for the proposed Hudson Transmission Partners HVDC cable. Direct and cross-examination at hearing April 2010
- *A Master Electrical Transmission Plan for New York City*, Prepared for the City of New York, May 2009
- *Public Utility Commission of Texas proceedings Cost-Benefit Analysis of the Texas Nodal Market.* Expert report on behalf of the Public Utilities Commission of Texas filed jointly with Alex Rudkevich and Ellen Wolfe December 2008. Direct testimony at hearing January 2009
- Mr. Russo prepared an expert report calculating damages from the delayed construction of a gas-fired combined cycle power plant in the United States for a civil litigation matter. The case settled before his report was submitted and he was disclosed and thus remains confidential.

- Mr. Russo prepared testimony and analysis on behalf of a client accused of electricity market manipulation before the FERC. The case relates to alleged cross-product manipulation involving renewable and thermal assets and financial instruments. The case was settled before hearing.
- Mr. Russo acted as an expert in a case concerning coal mines and fuel contracts with coal-fired power plants. The case was settled before his report was submitted and he was disclosed and thus remains confidential.
- Mr. Russo assisted in the damages analysis for a case litigated in federal court related to damages associated with renewable power plant revenue as a result of market rule changes in the MISO market.
- Mr. Russo assisted in analyzing how transmission upgrade costs were allocated in Quebec for new development in support of testimony before the Régie d l'Ēnergie.
- Mr. Russo performed analysis on behalf of a party in FERC litigation resulting from the California energy crisis, including simulation of the CAISO market clearing process and trading strategies employed by different parties.

Additional Professional Training

- New York ISO Market Operations Course
- New York ISO DSS Market Participants Course
- California ISO Market Participants Course

Selected Books

"*Economic Evidence of Market Manipulation,*" chapter in the *Guide to Energy Market Manipulation* with Robin Cohen, David Hunger and Brian Rivard. Published by Global Competition Review, March 2018

"*Data Collection*," chapter in *Integrated Assessment of Sustainable Energy Systems in China: The China Energy Technology Program*. Baldur Eliasson. Kluwer Academic Publishers, 2003.

Citizenship and Languages

Mr. Russo is a dual citizen of the United States and Italy.

- English (native)
- Italian (proficient)
- German and French (basic)

POTOMAC ECONOMICS

PROFESSIONAL BACKGROUND OF
DAVID B. PATTON, PH.D.
(2019)

EDUCATION

Ph.D., Economics, George Mason University
Areas of specialization: Industrial Organization, International Finance

M.A., Economics, George Mason University

B.A., Economics, New Mexico State University
Minor in Mathematics

EMPLOYMENT

President, Potomac Economics, 2001 – present

Serve as Market Advisor for the New York ISO and ISO New England, responsible for assisting in monitoring the markets to identify and remedy market design flaws and market power concerns.

Lead and direct Potomac Economics' activities in its role as Independent Market Monitor for the Midcontinent ISO; Responsible for developing and performing the market monitoring function in the Midcontinent ISO region.

Lead and direct Potomac Economics' activities in its role as Independent Market Monitor for the ISO-NE; Responsible for developing and performing the market monitoring function in the ISO-NE region.

Lead Potomac Economics' activities in its role as Market Monitoring Unit for the NYISO; Responsible for developing and performing the market monitoring function in the NYISO region.

Lead Potomac Economics' activities in its role as Market Monitoring Unit for the ERCOT (Texas); Responsible for developing and performing the market monitoring function in ERCOT region.

Provide expert testimony, analysis, and advice for clients on competitive issues in the electricity and natural gas industries, including mergers, market power and antitrust issues, competitive market design, and transmission pricing.

Director of Energy Practice, Capital Economics, 1997 – 2001

Provided expert advice and testimony to clients in cases involving transmission pricing, wholesale electric market design, mergers, market power, and antitrust matters.

Assisted electric utilities in developing regional transmission organizations by providing expert advice regarding transmission pricing, congestion management, market development, and market monitoring.

Retained by the New York ISO to service as the Independent Market Advisor regarding the development and monitoring of the wholesale electricity market.

Senior Economist, Office of Economic Policy, Federal Energy Regulatory Commission, 1995 – 1997

Developed transmission open access policies, including power pool, ISO, and comparability requirements in FERC's Open Access Rule (Order 888).

Developed the analytical framework in FERC's Merger Policy Statement for assessing the competitive effects of electric and natural gas utility mergers.

Responsible for analysis of transmission and ancillary service pricing issues associated with restructuring of the electric utility industry.

Director of Buildings Policy, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, 1992 – 1995

Responsible for development of U.S. policy related to the energy efficiency of housing and commercial buildings. Managed data and analysis programs to estimate the effects of energy efficiency policies and programs.

Staff Economist, Office of Policy, Planning and Analysis, U.S. Department of Energy, 1989 – 1992

Responsible for development and assessment of energy policies in President Bush's National Energy Strategy and federal legislation, including the Energy Policy Act of 1992.

REPORTS AND ANALYSES

Midwest ISO. Prepared Annual State of the Market Reports that review the performance of the New York electricity markets, including recommending improvements to the operation and design of the markets.

ISO New England. Prepared Annual Reports that analyze the performance of the nodal electricity markets implemented in New England in March 2003.

New York ISO. Prepared Annual Reports that review the performance of the New York electricity markets, including recommending improvements to the operation and design of the markets.

New York ISO. Prepared expert testimony and affidavits in 2007 to 2011 regarding market power in the New York City capacity market, including the design and execution of both supply-side and buyer-side mitigation measures to address the market power.

Midwest ISO. Prepared filed comments and answer in 2012 regarding capacity trading between MISO and PJM.

New York ISO. Filed multiple affidavits and supplemental affidavits regarding proposed installed capacity demand curves in 2007 to 2011.

Midwest ISO. Prepared and filed multiple comments in 2011 with FERC regarding the need for a sloped capacity demand curve and market power mitigation in the MISO capacity market.

New York ISO. Prepared affidavit in 2010 regarding market power and proposed mitigation associated with local reliability requirements.

Midwest ISO. Prepared a report and multiple affidavits addressing cost-causation and the allocation of Revenue Sufficiency Guarantee Payments, 2008-2011.

Midwest ISO. Prepared Market Power Study in 2007 evaluating market power issues in the proposed Ancillary Services Markets in the Midwest and proposing mitigation to address the market power concerns.

Public Utility Commission of Texas. Provided expert testimony and rebuttal testimony in 2005 regarding the proposed design of the nodal energy markets to be implemented in 2009.

Public Utility Commission of Texas. Prepared an assessment of the operation of the current ERCOT market in 2004, which provides detailed recommendations to address a number of issues identified in the report.

Midwest ISO. Prepared quarterly reports regarding the effectiveness of market power mitigation from 2004 to 2011. Also prepared expert testimony supporting filings to renew the mitigation measures.

Public Utility Commission of Texas. Prepared Annual Reports for 2003 to 2006 that evaluate the ERCOT electricity markets. The reports provide recommendations for improvements to the existing zonal markets.

ISO New England. Prepared a report evaluating the market operations during the first six months of the new multi-settlement wholesale electricity markets in New England.

Midwest ISO. Prepared annual reports for 2002 through 2004 evaluating the sale and utilization of electricity transmission capacity in the Midwest, the results of the wholesale market, and the potential for market power problems in the future.

ISO New England. Prepared annual reports for 2001 and 2002 analyzing withholding and market power in the New England electricity markets.

Midwest ISO. Assessed the economic efficiency and potential risks associated with the configuration of the RTO's in the Midwest.

ISO New England. Prepared a report analyzing the pricing in New England's energy and ancillary services markets, and recommending changes in the market rules.

New England Power Pool. Developed and negotiated a market power monitoring and mitigation plan with the NEPOOL, the State Commissions, and the New England Independent System Operator.

TransConnect LLC. Provided expert advice and analysis to transmission owners seeking to form an independent transmission company regarding an incentive pricing proposal to promote efficient operation of and investment in the transmission network.

Northern States Power. Advised client on alternative transmission pricing and service proposals associated with the development of an independent transmission Co.

FirstEnergy Merger (Ohio Edison Company / Centerior). Advised client on competitive issues related to the merger and on market power mitigation alternatives.

Exxon and British Petroleum. Prepared economic analyses of wholesale gasoline prices in the California market.

Northern States Power/Wisconsin Electric Power merger (Primergy). Advised FERC regarding competitive issues associated with the merger.

Electricity and Transmission Pricing in Electric Utility Industry. Analyzed alternative auction and bilateral contracting regimes for FERC.

Ameren Merger (Union Electric/ Central Illinois Public Service). Advised FERC regarding competitive issues associated with the merger.

American Electric Power / Central & Southwest Merger. Negotiated market power mitigation commitments with FERC staff on behalf of client.

PJM Power Pool. Analyzed the generation and transmission pricing aspects of restructuring proposal for FERC.

Fannie Mae/U.S. Department of Energy. Developed partnership to use loan and mortgage products to improve the energy efficiency of U.S. housing.

Freddie Mac. Analyzed the issues related to liquidity and risk in the mortgage finance and asset-backed securities markets.

Gas Pipeline Analysis. Submitted a competitive analysis of a potential natural gas pipeline acquisition to the Federal Trade Commission.

Midwest Natural Gas Market. Submitted a competitive analysis of Midwest pipeline and storage capacity to the U.S. Department of Justice regarding a civil antitrust investigation of a natural gas marketing joint venture.

SELECTED PUBLICATIONS AND PRESENTATIONS

"RTO Energy Markets: Theory, Design and Challenges", presented at the Energy Bar Association 2012 Annual Meeting, April 2012.

"How Markets Improve Reliability in Wholesale Electricity Markets", workshop presented to the Western Electricity Coordinating Council, December 2011.

"Independent Market Monitoring: In RTO and Non-RTO Areas", presented to the Entergy Regional State Committee and its stakeholders, August 2011.

"Independent Market Monitoring: Current Issues", presented to the Harvard Electricity Policy Group, June 2011.

" Emerging Issues in Forward Capacity Markets", presented at an EUCI industry conference, October 2010.

"The Role of Financial Entities in Wholesale Electricity Markets", presented at the Energy Bar Association 2009 Annual Meeting, April 2009.

"Comments of the Midwest ISO Independent Market Monitor", presented at a Technical Conference hosted by the Federal Energy Regulatory Commission regarding market monitoring policies, April 2007.

"Potential Market Power in the Midwest ISO Ancillary Services Markets", presented to Midwest ISO Markets Committee and the Federal Energy Commission in Fall 2007.

"Load Pockets and Local Market Power", presented at a Technical Conference hosted by the Federal Energy Regulatory Commission, February 2004.

"Electric Power: Generating Controversy", with R.A. Sinclair, Industry Studies, 3rd edition, Larry Duetsch, editor, New York: M.E. Sharpe (2003).

"Market Configuration and Coordination in the Midwest", presented to the Energy Bar Association, October 2003.

"Market Monitoring Roles and Responsibilities", presented at the National Association of Regulatory Utility Commissioners' 2003 Winter Meeting, Committee on Electricity, February 2003.

"Lessons Learned from Market Monitoring in North American Electricity Markets", presented at the World Bank Electricity Forum, February 2003.

"Setting Efficient Wholesale Electricity Prices During Periods of Shortage", presented to the Electric Power Supply Association, October 2002.

"Development of Competitive Wholesale Markets in the Northeast", presented to the NARUC Winter Meeting, February 2002.

"Detecting and Mitigating Market Power in Deregulated Electric Markets", presented at the Market Monitoring Conference hosted by the American Antitrust Institute, December 2001.

"Monitoring Wholesale Electric Markets", presented to the MIT Energy and Environmental Policy Workshop, December 2001.

"The Role of Market Monitoring in Competitive Electric Markets", presented to the Energy Bar Association, November 2001.

"Assessing the Competitive Performance of Electricity Markets", presented at the Market Monitoring and Mitigation Workshop by the Edison Electric Institute, June 2001.

"Transmission Pricing Issues", presented to the EEI Transmission Pricing Workshop, May 2001.

"Developing Efficient Incentives for A Transco", presented to the Electric Power 2001 Conference, March 2001.

"Managing and Pricing Congestion in Competitive Electric Markets", presented to the Energy Bar Association, February 2001.

"Defining an Appropriate Role for Market Monitoring in a Deregulated Electric Industry", Association of Power Exchanges and International Electric Industry Conference, October 2000.

"Defending Innovative Pricing Proposals for Regional Transmission Organizations", Edison Electric Institute Members' Workshop -- Developing Incentive Rates: Applications and Problems, July 2000.

"Cost Shifting and Other RTO Pricing Issues", EEI – Energy Daily Incentive Transmission Ratemaking Conference, July 2000.

"Innovative Pricing Workshop: Developing and Defending Proposals for RTOs", Infocast Transmission Pricing Conference, May 2000.

"Addressing Market Power in Deregulated Electric Markets", presented at the Spring Meeting, Antitrust Law Section of the American Bar Association, April 2000.

"Evaluating Investment Opportunities in Emerging Competitive Power Markets", presented at Lehman Brothers' Competitive Generation Conference, March 2000.

"RTO Monitoring of Competitive Electric Markets", presented at the Annual Energy & Project Finance Conference, February 2000.

"Monitoring Competitive Electric Markets", presented at 1999 Mid-Year Meeting of the Federal Energy Bar Association, November 1999.

"Merger Review and Analysis", presented at Antitrust Issues in Competitive Electric and Natural Gas Markets sponsored by Howrey and Simon, September 1999.

"The Role of Regional Transmission Organizations in Emerging Competitive Electric Markets", *CCH Power and Telecom Law,* July 1999.

"Transmission Congestion in Competitive Electric Markets", presented at the Transmission Business Forum, July 1999

"Designing Efficient Performance Based Rates", Incentive Ratemaking Workshop conducted at Independent Transmission Company conference hosted by Infocast, April 1999.

"Designing an Independent Transmission Company to Promote Competition and Efficiency", presented at Independent Transmission Company conference hosted by Infocast, April 1999.

"Mitigating Market Power in a Deregulated Electric Utility Industry", *CCH Power and Telecom Law,* May 1998.

"ISOs as a Safeguard Against Market Power Abuse", presented at Independent System Operator conference sponsored by Howrey & Simon, May 1998.

"Competitive Analysis of Electric Utility Mergers: An Evolving Standard", *CCH Power and Telecom Law*, March 1998.

"Key Transmission Issues for an Independent System Operator", presented to Desert Star Independent System Operator participants, August 1997.

"FERC Perspective on Electricity Trading and Derivatives", presented at Electricity Trading and Derivatives Strategies Conference hosted by Infocast, March 1997.

"Market Power in Electricity: Analysis and Mitigation", presented to National Association of Regulatory Utility Commissioners' Winter Meeting, February 1997.

PROFESSIONAL ACTIVITIES AND AWARDS

American Economic Association
International Association of Energy Economists
National Association of Business Economists
U.S. Department of Energy, Commendation from Secretary of Energy, 1992
Phi Kappa Phi honorary society
Omicron Delta Epsilon, economics honorary society

CRA Charles River Associates

P. Jordan Kwok
Associate Principal

MS, Technology and Policy
Massachusetts Institute of Technology

BS, Materials Science and Engineering
Northwestern University

Jordan Kwok is an Associate Principal with the energy practice of CRA. He has worked with regulated utilities and merchant operators throughout the United States with a focus on regulatory strategy, ISO/RTO market policy, and project valuation. At CRA, Mr. Kwok has managed and contributed to project work supporting clients in regulatory interventions, conducting commercial analysis generator purchases and sales, executing market power assessments, and developing strategies for energy and capacity market participation. Part of his experience was gained during his time as an Energy Industry Analyst at the Federal Energy Regulatory Commission, where he worked on filings and policy development related to power markets and infrastructure development, including transmission planning and cost allocation, utility incentive rates, market structure, and resource adequacy constructs. Prior to joining CRA, Jordan managed the State Department's Power Sector Program, a technical assistance program supporting power sector reform in developing countries by fostering solvency, competition, sustainability, and access. Mr. Kwok has an MS in Technology and Policy from MIT and a BS in Materials Science and Engineering from Northwestern University.

Professional history

2016–Present — *Associate Principal*, Charles River Associates, Washington, DC
Other Titles Held: *Senior Associate*

2014–2016 — *Program Manager, Power Sector Program*, US Department of State, Bureau of Energy Resources, Washington, DC

- Managed a technical assistance program supporting power sector reform in developing countries by fostering solvency, competition, sustainability, and access (focus regions: Africa, South Asia, and Southeast Asia)
- Administered contracts and grants throughout the technical assistance implementation process, including research and scoping, procurement, invoicing, oversight, review of deliverables, and close out

2010–2014 — *Energy Industry Analyst, Office of Energy Policy and Innovation*, Federal Energy Regulatory Commission, Washington, DC

- Performed policy analysis, balancing industry and stakeholder input with the goals of the Commission, on issues related to electric transmission development and electric power markets

- Prepared and delivered memoranda, whitepapers, docket summaries, and oral presentations to communicate the results of economic, technical, and legal analysis to senior management and Commissioners' offices

2008–2010 *Research Assistant,* MIT Energy Initiative, Cambridge, MA

Projects

- For the Alberta Market Surveillance Administrator, Mr. Kwok contributed to a report on issues associated with offer behavior guidelines during Alberta's transition period ahead of capacity market implementation. The report provided analysis and discussion of whether offer behavior guidelines were indicated. CRA witnesses, including Mr. Kwok, presented the results and answered questions in oral testimony before Alberta stakeholders and the Market Surveillance Administrator.
- For the Alberta Market Surveillance Administrator, Mr. Kwok contributed to a report on issues associated with the Alberta System Operator's proposed capacity market, which was submitted to the Alberta Utilities Commission. The report identified areas where the Alberta Utilities Commission should focus its assessment of the system operator's proposal, and provided critique of some early assessments of the market design performed by other consultants.
- For an international hedge fund, Mr. Kwok contributed to an expert report on the state of the solar photovoltaics industry, with a particular focus on historical and expected technology and cost trends.
- For the Alberta Market Surveillance Administrator, Mr. Kwok led a team in reviewing the Alberta System Operator's proposed Comprehensive Market Design with a particular focus on how draft provisions of the energy, ancillary services, and capacity market rules and their ability to effectively identify and mitigate opportunities for the exercise of market power.
- In support of a potential acquisition of behind-the-meter generation assets, Mr. Kwok advised a utility client on numerous provisions of the ISO-NE market tariff that would affect the value proposition of the assets, including revenue streams tied to capacity costs, transmission rates, and demand response rules.
- For a competitive power producer, Mr. Kwok managed an assessment of comparative market opportunities for a plant determining whether to sell into MISO or PJM, including analysis of future capacity revenues, regulatory uncertainties, and administrative burdens and risks associated with the different marketing options.
- For a renewable generation developer, Mr. Kwok contributed to several reports to provide background and insight into rules, processes, and strategies for offering renewable generation into RTO/ISO capacity markets.
- In support of the Alberta Department of Energy, Mr. Kwok managed development of a study to inform the design of capacity market governance structures in Alberta. The report provides a review of governance arrangements in multiple international jurisdictions in order to understand possible alternative approaches, including pros and cons of different structures with respect to best practices, and identification of gaps in the Alberta governance system.

- For a proposed utility merger, Mr. Kwok managed development of a market power analysis to be presented to a state regulatory commission. The analysis included assessment of competitive impacts on gas and electricity at the wholesale and retail level, including consideration of cross fuel competition.
- For an operator of cogeneration facilities, Mr. Kwok supported a mediated proceeding by performing a damages analysis associated with an underperforming facility upgrade, which included impacts on energy, ancillary services, and capacity sales.
- For an infrastructure development fund, Mr. Kwok managed and performed market analyses to support commercial valuations. Acquisition targets spanned multiple regions and market structures, and included complex contractual and operational arrangements.
- For a major vertically integrated utility, Mr. Kwok provided analytical support to a client under investigation by the Federal Energy Regulatory Commission for its energy market offer practices. Particular areas of focus included the impact of non-price offer components, the market impacts of wind penetration, and pricing dynamics between transmission congestion, generation, and load.
- Mr. Kwok managed the development of a report for the Alberta Utilities Commission detailing the economic foundations for capacity markets to prepare the AUC for possible future regulatory oversight of such a market.
- Mr. Kwok contributed to a survey for the Alberta Electric System Operator of global practices in design and implementation of capacity market mechanisms, an exercise intended to support development of a capacity compensation scheme in the provincial electricity market.
- For a major offshore renewable energy developer, Mr. Kwok managed analysis of commercial and regulatory strategy for development of offshore wind generation of the coast of New York and New Jersey.
- For several major vertically integrated utilities, Mr. Kwok provided analysis and expert guidance on development and implementation of requests for proposals for the purchase of generation capacity, including developing analytical tools for scoring proposals and calculating the net present value of alternative solutions.
- For an infrastructure investment firm acquiring a cogeneration facility, Mr. Kwok managed review of financial models and development of a market report in support of a robust assessment of facility revenues and costs across its operating horizon.
- On behalf of several major generating utilities and power traders, Mr. Kwok has supported development of expert testimony on market power issues in FERC dockets associated with market based rates, merger, and litigation proceedings. He has also supported analysis and development of testimony related to market based rates for natural gas storage facilities.
- On behalf of a trade organization, Mr. Kwok performed analysis and managed the development of expert testimony in support of a FERC complaint related to market participant charges in the New England energy and capacity markets.

- On behalf of several large technology companies, Mr. Kwok supported development of testimony in a state proceeding to ensure the interests of industrial consumers were considered as the local utility implemented plans to expand renewable generation capacity.
- For several utilities operating in PJM, Mr. Kwok contributed to analysis and strategic support related to understanding the PJM capacity market – particularly capacity performance rules – and developing bidding strategies to mitigate risk.
- On behalf of a generating utility, Mr. Kwok managed the development of expert testimony in an arbitration proceeding related to matters of tariff implementation and interpretation in the Southwest Power Pool.

Public Reports and Testimony

Mr. Kwok has experience supporting development of expert testimony before FERC, US state utility commissions, and arbitration panels related to capacity market design, market power issues, and electric ratemaking. He has also contributed to authorship of a number of reports related to the development of the Alberta capacity market, including:

- *"Offer Behaviour Guidelines Prior to the Implementation of a Capacity Market,"* consulting report prepared for the Alberta Market Surveillance Administrator, December 10, 2018, including oral testimony at hearing regarding considerations for new guidelines before Alberta stakeholders.
- *"Comments on Capacity Market Design Issues in Alberta,"* consulting report prepared for the Alberta Market Surveillance Administrator for submission in Alberta Utilities Commission Proceeding 23757, November 2, 2018.
- *"Assessment of Market Power Mitigation Measures in Alberta's CMD2 Reform,"* consulting report prepared for the Alberta Market Surveillance Administrator, June 13, 2018.
- *"Governance Institutions and Processes for Electric Capacity Markets: A Jurisdictional Review,"* consulting report prepared by CRA for the Alberta Department of Energy, October 6, 2017.
- *"The Economic Foundations of Capacity Markets,"* consulting report prepared by CRA for the Alberta Utilities Commission, June 2, 2017.
- *"A Case Study in Capacity Market Design and Considerations for Alberta,"* consulting report prepared by CRA for the Alberta Electric System Operator, March 30, 2017.