
Market Power Screens and Mitigation Options for AESO Energy and Ancillary Services Markets

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I. Executive Summary

Under the existing “energy-only” market design of Alberta Energy System Operator (AESO), no explicit market rules in the energy and ancillary services markets address the potential exercise of market power by suppliers beyond the offer cap of \$999.99/MWh.¹ The AESO limited market rules to address market power to this offer-cap to allow market forces, to the extent possible, to respond to any scarcity of resources in the market and to incentivize new capacity additions.²

The combination of Alberta’s lower-carbon, sustainable electricity system policy, and low natural gas prices has led to a concern whether the AESO system can continue to maintain a healthy reserve and attract new investment to ensure its reliability in the future.³ The Government of Alberta approved the AESO’s recommendation to establish a formal capacity market as a means to provide greater investment incentives for generation needed to supply load in the AESO market.⁴ To transition from the energy-only market to an energy *plus* capacity market design requires changes in market rules that allow AESO markets to achieve a competitive outcome. In particular, it requires the modifications of the definition of fair and efficient competition in the energy and ancillary services markets and associated market rules that prevent suppliers’ potential exercise of market power.

A. PURPOSE

As the AESO plans for the implementation of the capacity market by 2021, it is considering modifications of market rules that include the introduction of market monitoring and mitigation processes for the real-time energy and ancillary services markets. The goal of a well-designed electricity market is to apply clear rules to ensure that high power prices are not the result of suppliers’ exercise of market power. The AESO would like its complete set of markets (energy, ancillary services, and capacity markets) to yield competitive price signals in both the short and long run and to produce generator revenues sufficient to encourage necessary investments. However, the AESO is not inclined to have those price signals distorted by continuing to permit suppliers to exercise their market power to derive adequate revenues in the energy and ancillary services markets. Instead, by instituting a centralized capacity market, the AESO is interested in ensuring that the competitive energy and ancillary services markets provide the platform for

¹ As part of Alberta’s deregulation effort, the three large Alberta utilities virtually divested their generation and entered into purchased power agreements (PPAs) in 2000.

² Exercise of market power is mitigated in part by Balancing Pool’s long-term power purchase power agreements. These contracts will expire by 2020.

³ *Alberta’s Wholesale Electricity Market Transition Recommendation*, AESO, October 3, 2016. <https://www.aeso.ca/assets/Uploads/Albertas-Wholesale-Electricity-Market-Transition.pdf>

⁴ <https://www.alberta.ca/electricity-capacity-market.aspx>.

suppliers to operate their facilities efficiently and use the capacity market to provide the necessary investment signals.

The Brattle Group (Brattle) has been asked by the AESO to assist in developing the market power screening and mitigation processes for the AESO's energy and ancillary services markets. This report contains our assessment of the various options that the AESO can consider in establishing rules that help identify and mitigate potential exercises of market power in the wholesale energy and ancillary services markets. We consider the implementation of market power screening and mitigation to be complementary with other potential changes being considered in the energy and ancillary services markets, including the potential of instituting administrative shortage pricing in the future, offer-caps, and the introduction of the AESO's capacity market. The overall wholesale market design package is intended to provide efficient short-term pricing combined with adequate long-term opportunities for investors to earn revenues that reflect the cost of new generating plants when new plants are needed.

B. OVERALL SUMMARY

The objective of market power screening and mitigation rules in an organized power market is to ensure that the market is workably competitive. These mitigation rules should minimize the risk of over-mitigation that could interfere with effective market and price-setting mechanisms. Meeting this objective implies that suppliers may offer their resources at prices that exceed their short-term marginal operating costs (consisting of fuel, emissions, and variable operating and maintenance costs) without resulting in market prices that exceed workably competitive levels. The intention of using market power screens and mitigation approaches is to focus only on suppliers who attempt to exercise market power and whose actions would cause adverse market impacts, not to affect those suppliers that are bidding competitively or have little incentive or ability to exercise market power. Market power mitigation should not discourage market participants from making efficient investments in existing and new resources while mitigating prices to competitive levels in the presence of an exercise of market power.

Market power mitigation in organized wholesale power markets typically involves three steps:

- Define market power abuses that regulators and policymakers find to be unacceptable;
- Develop screens that can identify potential market power abuses; and
- Determine a mitigation measure that can be applied when the screens detect an abuse of market power.

We use this framework to develop options for the AESO. Further, we analyze the potential impacts of alternative market power screens, safe-harbor or "no-look" thresholds, and appropriate forms of mitigation given the AESO's updated market design. To perform this

analysis, we rely on our experience with electricity markets across a variety of jurisdictions, sources of documentary evidence,⁵ and AESO’s historical offer data from 2012 to 2016.

Based on the AESO’s request, this report evaluates three specific options for the screening and mitigation of potential exercise of market power in the AESO’s energy and ancillary services markets:

- A market structure-based screen, known as the Residual Supply Index (RSI);
- A combined conduct and performance-based test, called the Conduct-Impact test; and
- A combination of the RSI screen and the Conduct-Impact test.

We provide a brief summary of each screen and our analysis below, leaving the details to the rest of the report.

1. RSI Screen

The RSI screen is based on the concept of a “pivotal” supplier. In a market with fixed supply and inelastic demand (*i.e.*, demand that is not very sensitive to changes in price), some suppliers may become “pivotal” in meeting that demand. A supplier is “pivotal” when demand cannot be satisfied without that supplier offering at least some of its resource into the market.

A pivotal supplier has the ability, and possibly the incentive, to exercise substantial market power. Such an outcome of market power exercised by a pivotal supplier is more likely to arise under relatively high load conditions.

The Residual Supply Index (RSI) for *Supplier i* in period *t* is defined as follows:

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

where $\sum_{j=1}^n Supply_{jt}$ represents total capacity in the market at time *t*, *Supply_{it}* represents the available capacity of *Supplier i* at time *t*. Consequently, $\sum_{j=1}^n Supply_{jt} - Supply_{it}$ represents the total supply available from suppliers other than *Supplier i* at time *t*, which is then compared with *Total Market Demand* at time *t*.

If the total supply available from suppliers other than *Supplier i* is less than (or equal to) *Total Market Demand*, then $RSI < (or =) 1$, then the supplier is considered “pivotal.” Thus, an $RSI < 1$ indicates conditions under which *Supplier i* would be able (and may have the incentive) to exercise market power and raise prices above competitive levels.⁶ When the $RSI > 1$, the

⁵ These include tariffs and operating manuals of specific mitigation measures, articles, and testimonies discussing market power mitigation in electricity markets.

⁶ Because a supplier is pivotal does not necessarily result in an incentive to exercise market power. For example, if the supplier would need to withhold 90 percent of its capacity to implement a significant

supplier is not considered pivotal and will be less likely to have the ability or incentive to exercise market power.

The main disadvantage of using the RSI screen is the difficulty to devise the screen and thresholds so that they can reliably screen out uncompetitive behaviors and mitigate suppliers' bids during real-time operations. (We use "bids" or "supplier bids" to refer to suppliers' offers to sell their supply resources, unless otherwise noted.) Using the RSI screen as shown in the above formula may result in over-mitigation as it focuses on a supplier's physical ability to affect market prices, rather than its incentive to exercise market power (*i.e.*, its ability to increase market prices *profitably*). At the same time, because suppliers may be able to exercise market power even before they become "pivotal," setting the RSI tolerance level at 1.0 or below risks missing some suppliers' incentive and ability to exercise their market power. Consistent with the experience in other markets, historical bidding data in the AESO market shows that suppliers' bids increase quickly at RSI levels below 1.1.

If an RSI screen were used alone, bid mitigation would automatically occur after identifying any suppliers that fail the RSI. The mitigation typically would involve setting the pivotal suppliers' bids to competitive reference levels. In the U.S. ISOs, for example, competitive reference levels are determined based on either: (1) the marginal cost of each mitigated resource, (2) the supplier's competitive offers in the past 90 days, or (3) the average market-clearing price during the 25th percentile of the lowest-priced hours during the past 90 days. Under the cost-based mitigation option, many U.S. ISOs explicitly allow opportunity costs to be included in such reference levels, with specific guidelines about what costs constitute as opportunity costs.

When mitigation is applied, the scope of RSI-type mitigation imposed on pivotal suppliers generally covers the supplier's bids for its entire portfolio of resources. In the case of Alberta, which relies on one-part bids that do not separate commitment-related cost of resources from their marginal costs, if the RSI screen were chosen for market mitigation, such mitigation could be based on prices equal to multiples of marginal costs so suppliers would be able to include in their bids (and recover in the resulting prices) the commitment-related costs of their resources.

Figure 1 summarizes the estimated impacts of RSI-based mitigation had such mitigation been applied historically during 2012–2016. Based on this analysis of AESO historical bid data, we estimate that applying an RSI screen with an RSI = 1.0 threshold and bid mitigation levels equal to 2 to 3 times a resource's estimated marginal costs, the net energy revenues for a typical natural gas combined-cycle (CC) and/or a natural gas combustion turbine (CT) would have been about 64 percent lower than in the unmitigated market. The analysis is based on applying the RSI screen with the no-look threshold of 1.0 to the five largest suppliers in the AESO market. When

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price increase (particularly when prices are already capped), it would be difficult for increase profits on the remaining 10 percent to make up for the losses on the withheld 90 percent.

a supplier failed this RSI=1.0 screen, their bids were mitigated down to either 200 percent or 300 percent of the marginal costs of pivotal suppliers' bid prices for the offered resources.

Compared to the cost of new entry (CONE) of CAD\$207/kW-year for a CC and CAD\$159/kW-year for a CT, the analysis shows that reference resources would have recovered approximately 40 percent of their CONE had historical prices been mitigated. The remainder of their annualized costs would have to be recovered through the proposed capacity market.

Figure 1
Comparison of 2012–2016 Average Net Revenues with CONE of Reference Resources
 (Unmitigated vs. RSI=1.0 Mitigation at 200% and 300% of Marginal Costs)

Scenario	Mitigation	Reference Resource CC			Reference Resource CT		
		5-Yr Net Energy Revenue (\$/kW-yr)	CONE (\$/kW-yr)	Net Energy Revenue as % of CONE (%)	5-Yr Net Energy Revenue (\$/kW-yr)	CONE (\$/kW-yr)	Net Energy Revenue as % of CONE (%)
1	200%	\$69.74	\$207	34%	\$53.17	\$159	33%
2	300%	\$82.58	\$207	40%	\$59.67	\$159	38%
Unmitigated	NA	\$230.56	\$207	111%	\$204.37	\$159	129%

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3. Section III of this report provides more detail and suggestions about how the RSI screen may be adjusted to account for Alberta-specific characteristics.

2. Conduct-Impact Test

The Conduct-Impact test is a two-part test that assesses a seller's specific bidding behavior and its associated effects on market prices. The first part, the Conduct test, identifies bids that are deemed to signal a seller's anti-competitive behavior. The conduct in question includes bidding significantly above cost, which can be a form of "economic withholding," as well as other types of anomalous bidding behavior or the physical withholding of output. The conduct test compares a supplier's bids to a No-Look threshold above competitive reference level.

The second part of the test, the Impact test, is triggered only if a supplier's bid exceeds the Conduct test's no-look threshold. The Impact test is used to trigger bid mitigation if the bid's impact on market prices exceeds a specified threshold. The test compares an estimated market-clearing price with the supplier's bid to a market price assuming that the supplier's bid were mitigated.

Similar to RSI-based mitigation, the Conduct-Impact test can be applied automatically after supplier bids are submitted to the AESO, but before the actual market-clearing price is

determined. When a bid's price impacts exceed the specified Conduct and Impact thresholds, the bid is mitigated before the actual market prices are determined.

The Conduct test threshold, above which a supplier's offer is subject to an Impact test, needs to consider the relevant costs faced by the supplier. Because suppliers to the AESO's energy market participate with "one-part" offers, market prices need to cover a generating resource's start-up, shutdown, and no-load costs, in addition to its marginal operating costs. For example, if a CC plant, once turned on, expects to operate only for several hours before having to shut down again, the supplier would only be willing to start up the plant if the expected market-clearing prices over the dispatch hours would be sufficiently high to cover the costs of starting up the plant and operating it at various output levels during this period.⁷

Figure 2 below shows that—based on the historic (2012–2016) cost profile and minimum operating hours—once a typical CC or a coal plant is turned on, the average per MWh costs of both CC and coal plants exceed their marginal operating costs by up to 1.5 times. The ratios of average per MWh cost to marginal cost of a typical CT plant also is shown in Column [10] of Figure 2.⁸ Since a thermal plant's commitment cost can vary according to the plant's temperature status at its start time, the longer a plant has been in a shutdown condition, the more fuel it needs to burn to bring its plant to an operating temperature requirement. To cover a broad range of start-up costs, this analysis includes two levels of start-up conditions—one with significantly higher start-up cost ("with Cold Start") and another for Coal plants with higher heat rate to start than the other ("with High Commitment Cost"). While a CT typically has low start-up costs,⁹ their dispatch period tends to be quite short. Assuming that a CT may be started up to serve only 30 minutes of peak load per cycle, a CT's average cost is about 2.7 times its marginal costs.

⁷ In jurisdictions where supplier offers are multi-parts, the supplier submits separate information about unit characteristics—such as start-up costs, no-load costs, minimum run-time, and minimum down time—and allows the system-operator's unit-commitment process to optimize and compensate these costs across competing resources.

⁸ The current calculations use generic CC and coal plant characteristics data from the AESO database and public sources. The coal plant with "High Commitment Costs" is based on the characteristics of the AESO coal unit with the highest start-up cost and no load cost with the heat rate of 15,137 kilojoules/kWh. The AESO database does not have a fixed start-up cost for a CC and coal unit. We therefore assume the cost for typical hot starts for CC and coal units to be CAD\$49/MW/Cycle and CAD\$81/MW/Cycle. The cost is based on converting the median costs of US\$39/MW and US\$65, obtained from *Power Plant Cycling Costs*, NREL (2012), to the Canadian dollars using the exchange rate of US\$1=CAD\$1.26. The NREL data are based on the lower bound of estimates. See Appendix B for more details.

⁹ We assume that a typical CT's cold start-up cost is CAD\$18/MW/Cycle. See Appendix B for the sources and calculations.

Figure 2
Comparison of Estimated Commitment Costs and Marginal Costs
of Proxy Combined Cycle and Coal-Fired Power Plants in Alberta

Plant Type	Start-up Cost (\$/cycle)	Shut Down Cost (\$/cycle)	No Load Cost (\$/cycle)	Total Commitment Cost (\$/cycle)	Marginal Cost (\$/ MWh)	Output @ Full Load (MW)	Average Incremental Output (MW)	Assumed Run Time @ Full Output (hours)	Total Cost (\$/cycle)	Average Cost (\$/ MWh)	Ratio of Avg. Cost to Marginal Cost
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
CC (with Hot Start)	\$9,160	\$2,062	\$25,981	\$37,202	\$17.28	400	240	9	\$73,152	\$21.10	1.2
CC (with Cold Start)	\$25,808	\$2,062	\$25,981	\$53,851	\$17.28	400	240	9	\$89,800	\$25.90	1.5
Coal (with Hot Start)	\$14,688	\$2,707	\$1,599,481	\$1,616,875	\$15.92	400	240	600	\$3,909,248	\$16.29	1.0
Coal (with High Commitment Cost)	\$39,708	\$2,707	\$2,562,907	\$2,605,322	\$15.92	400	186	600	\$4,381,911	\$18.26	1.1
CT	\$2,146	–	–	\$2,146	\$24.88	100	100	0.5	\$3,389	\$67.79	2.7

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

Going forward, the average operating costs per cycle may increase relative to the levels shown in Figure 2. As variable resources are added to the AESO system, the thermal units would likely be committed less and cycle more. This would increase the ratios of average costs to marginal costs.¹⁰ In addition, since we do not have the actual commitment costs for certain plants in Alberta, we recognize that that actual amount of start-up, shutdown, and no-load costs for plants may deviate from these estimates. For example, if a CC has a much higher start-up cost than shown in Figure 2, the resulting ratio of the average operating cost per cycle could be higher as well.¹¹ Given the results in Figure 2 and these additional considerations, setting the Conduct test's safe-harbor threshold at 300 percent of resources' marginal costs would appear to be reasonable. If costs change, the AESO can re-evaluate these comparisons and reassess the range of the tolerance thresholds.

¹⁰ For example, if we assume that the CC unit would run at its full output for only 6 hours instead of 9 hours, the ratio of the CC with Cold Start would increase closer to 2. Similarly, if we assume that the coal unit would be used for cycling more than providing energy, the ratio of its average cost to marginal cost could increase significantly.

¹¹ The start-up cost data we obtained from NREL (2012) are also based on the lower bound cost estimates.

We also evaluate how suppliers' net market revenues are affected by different thresholds for the Conduct and Impact tests and the mitigation levels that are the same as the Conduct test's thresholds. We used the AESO's 2012–2016 historical offer data and estimated the potential revenues that suppliers would earn under four different combinations of Conduct-Impact test thresholds, with mitigation down to the Conduct test's thresholds. The threshold parameters used for the Conduct test include 200 percent (2 times) and 300 percent (3 times) of the plants' estimated marginal costs. Based on the levels currently used in other wholesale markets, the threshold parameters evaluated for the Impact test were a \$100/MWh and \$200/MWh price impact.¹² We further assume that, when bids and associated market impacts are above the both Conduct and Impact test thresholds, they are mitigated down to the corresponding Conduct test threshold (*i.e.*, either 200 or 300 percent of marginal costs).

Figure 3 shows the estimated referenced generators' revenues under these different Conduct and Impact test threshold combinations based on historical market conditions for 2012–2016. Since we used historical bid levels, this analysis assumes that suppliers would not change their bidding behaviors in the presence of mitigation. The figure shows that over the 2012–2016 period, suppliers in Alberta earned on average between 111% and 129% of the average annual cost of a new generating plant.¹³ If the historical bids had been mitigated for cases in which the bids failed the specified Conduct-Impact test, supplier earnings would have dropped to a range of 50% to 56% of the annualized cost of a new combined cycle plant and to 49% to 57% of the annualized cost of a new combustion turbine plant. If actual bidding had been more competitive during this period, the relative impact of mitigation would be less. The lower net revenues earned in the energy market would lead to higher capacity prices and a higher share of generator revenues obtained from the proposed capacity market.

¹² Our analysis of the historical offer data suggests that when bids fail the Conduct test, their price impacts are usually below 100 percent. Thus, any impact threshold that is 100 percent or higher is unlikely to detect any combined Conduct-Impact test failures. We have not independently determined an appropriate percentage parameter at the time of this analysis. In ISO-NE, MISO, and NYISO, the Impact test threshold for a broad geographic market area is the lower of 200 percent or \$100/MWh increase of energy prices. Southwest Power Pool's Impact test threshold is a \$25/MWh increase in energy prices. We created the scenarios based on the dollar threshold.

¹³ Much of these high average returns occurred during the first years of this period when Alberta market prices were very high.

Figure 3
Comparison of Five-Year (2012–2016) Average Net Revenues of Reference Resources
and Gross CONE by Scenario

Scenario	Conduct	Impact	Mitigation	Reference Resource CC			Reference Resource CT		
				5-Yr Average Net Revenue (\$/kW-yr)	Gross CONE (\$/kW-yr)	Net Energy Revenue as % of Gross CONE	5-Yr Average Net Revenue (\$/kW-yr)	Gross CONE (\$/kW-yr)	Net Energy Revenue as % of Gross CONE
	(Percent of Marginal Cost)	(Dollars Above Estimated Competitive Clearing Prices)	(Percent of Marginal Cost)						
1	200%	\$100	200%	\$ 103.23	\$ 207	50%	\$ 77.62	\$ 159	49%
2	200%	\$200	200%	\$ 114.45	\$ 207	55%	\$ 88.63	\$ 159	56%
3	300%	\$100	300%	\$ 106.39	\$ 207	51%	\$ 80.32	\$ 159	51%
4	300%	\$200	300%	\$ 116.66	\$ 207	56%	\$ 90.52	\$ 159	57%
Unmitigated	NA	NA	NA	\$ 230.56	\$ 207	111%	\$ 204.37	\$ 159	129%

Source: The gross CONE for both CC and CT plants are the mid-points of their ranges, which are reported in *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3. Appendix C describes how the market prices under mitigated scenarios are derived.

3. Comparison of RSI Screen and Conduct-Impact Test

Figure 4 summarizes the advantages and disadvantages of the RSI Screen and the Conduct-Impact test.

Figure 4
Advantages and Disadvantages of Structural and Conduct-Impact Screens

Type of Tests	Advantages	Disadvantages
RSI Screen	<ul style="list-style-type: none"> Can be used to identify conditions under which market power concerns are the greatest. Avoids having to set bid-level and price-impact thresholds that trigger mitigation, which could lead to mitigation errors. 	<ul style="list-style-type: none"> Does not directly detect whether market power has been exercised. Suppliers may not be able to control the conditions under which mitigation would be implemented. As a bright line standard, it may fail to mitigate exercises of market power that may arise even when a supplier is not pivotal.
Conduct-Impact Test	<ul style="list-style-type: none"> Explicitly identifies bid and price-impact thresholds that exceed the stated tolerance levels of policy makers. Suppliers can directly control their bids based on transparent thresholds. Can be implemented in a way to test the price impact of multiples suppliers' bids' jointly 	<ul style="list-style-type: none"> The market monitor must determine the "correct" tolerance threshold for both bid levels and the price impact of the bidding behavior. Relies on either an assumed or actually observed cost for each resource. Concerns exist that suppliers can "game the system" by keeping their exercises of market power just below the mitigation threshold.

The remainder of this report is organized as follows. Section II of the report explains the framework and considerations in developing a market power mitigation process, while Sections III through V describe the market power screening options, along with their advantages and disadvantages. Section VI utilizes the AESO historical energy offer data to evaluate each screen's effectiveness and reliability. Finally, we discuss mitigation measures in Section VII.

II. Framework and Considerations of Market Power Mitigation Process

Considerable experience already exists in the monitoring and mitigation of wholesale power market.¹⁴ This experience shows that an effective market monitoring and mitigation process involves three essential steps. First, policymakers need to define what constitutes an exercise of market power, or the potential for exercising market power sufficient to induce mitigation.

Second, screens/tests and associated thresholds have to be developed to identify those situations that are conducive to the abuse of market power. The use of a market power screen needs to consider the potential costs to end users associated with a supplier's exercise of market power, as well as the costs of falsely identifying and mitigating efficient behavior. The screens provide a method (or metric) for identifying market conditions under which a particular supplier or group of suppliers would have the ability and/or the incentive to raise prices above competitive levels.

Third, appropriate mitigation procedures have to be developed. The mitigation is typically triggered when an abuse of market power has been identified via the screen or test.

The economic concept of sellers' market power¹⁵ is defined as "*the ability profitably to maintain prices above competitive levels for a significant period of time.*"¹⁶ Market power is a matter of degree. A decision on how much market power is too much will necessarily involve policy decisions. The key conceptual questions that need to be answered include:

- How should market power abuses be defined?
- Should potential market power be pre-emptively mitigated?
- If so, what are the acceptable levels of energy (and ancillary services) prices, taking into consideration that a "one-part bidding" approach is currently being used in the Alberta energy market?

Each of these questions has critical implications in choosing and implementing the market power screen and mitigation. For instance, if the industry and policymakers define market power

¹⁴ For example, for a survey and discussion of market monitoring and mitigation approaches in U.S. regional wholesale power markets, see Federal Energy Regulatory Commission (2014) and Reitzes et al (2007).

¹⁵ Certain market power actions can be nested within the definition of market manipulation, which involves impermissible actions in a primary market that affect profits in another linked market (such as derivatives). See G. Taylor, S. Ledgerwood, R. Broehm, P. Fox-Penner, "Chapter 2, Market Power and Market Manipulation: Definitions and Comparison," *Market Power and Market Manipulation in Energy Markets From the California Crisis to the Present*, Public Utilities Reports Inc. (2015).

¹⁶ U.S. Department of Justice and Federal Trade Commission *Horizontal Merger Guidelines*, April 2, 1992 (revised April 8, 1997) Section 0.1; also see W.M. Landes and R.A. Posner, "Market Power in Antitrust Case," *Harvard Law Review* 94 (March 1981): 937–966.

abuses as setting prices at an unacceptably high level, such as 300 percent of a seller’s marginal cost, the AESO would consider diagnostic tests that could analyze sellers’ bids to determine if any of them exceed their marginal costs by such a pre-determined level, and if so, whether these bids increase market prices to an unacceptable level. Below, we describe each of the steps in defining and implementing market power mitigation.

A. DEFINE THE PARAMETERS FOR UNACCEPTABLE EXERCISE OF MARKET POWER

In the context of energy and ancillary services market mitigation, the degree by which the exercise of market power can be evaluated is based on: (1) conditions of market structure that are conducive to sellers’ exercise of market power, and/or (2) sellers’ specific conduct, namely physical and economic withholding. Some ISOs have defined certain market conditions as those that would be susceptible to dominant sellers’ exercise of market power.¹⁷

As an example, the Public Utility Commission of Texas (PUCT), which regulates Electric Reliability Council of Texas (ERCOT), has accepted some degree of market power and is more specifically concerned with abuses of market power.¹⁸ Having market power is central to the notion of market power abuse, and the PUCT defines market power as “the ability to control prices or exclude competition in a relevant market.”^{19,20} The PUCT emphasizes that simply having market power does not mean that market power has been exercised.

The PUCT explicitly defines an abuse of market power as unreasonable practices that include withholding, predatory pricing, precluding entry, and collusion:

Market power abuse—Practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. Market power abuses include predatory pricing, withholding of production, precluding entry, and collusion.²¹

The ERCOT market does not include a centralized capacity market. Without capacity revenues, investment in new generation will require that the expected revenues in the energy market are sufficient to recover the capital costs associated with building a new plant. For this reason, the

¹⁷ See Section 6.5, CAISO Business Practice Manual, V. 52, Revised May 31, 2017; and “Attachment M PJM Market Monitoring Plan,” PJM Open Access Transmission Tariff, p. 7.

¹⁸ See Order Adopting Amendment to §25.502, New §25.504 and New §25.505 As Approved at the August 10, 2006 Open Meeting, Public Utilities Commission of Texas, August 2006, p. 15.

¹⁹ *U.S. v. E.I. duPont de Nemours & Co.*, 351 U.S. 377, 76 S.Ct. 994, 100 L.Ed.2d 1264 (1956).

²⁰ See Order Adopting Amendment to §25.502, New §25.504 and New §25.505 As Approved at the August 10, 2006 Open Meeting, Public Utilities Commission of Texas, August 2006, pp. 13 and 136.

²¹ *Id.*

enforcement attitude toward mitigating exercises of market power may be different in an energy-only market as compared with an energy-and-capacity market.

The Midcontinent Independent System Operator (MISO) of the U.S. defines market power as:

Market power is the ability to raise Locational Marginal Prices, Market Clearing Prices (MCPs), or Auction Clearing Prices for Planning Resources significantly above competitive levels and/or unjustifiably increase the value of Revenue Sufficiency Guarantee Make-Whole Payments (RSG MWP). Market power can be exercised by [a market participant] by withholding Capacity, output, or facilities from the market (physical withholding); by excessively raising the price or changing the value of a component of an Energy or Operating Reserve (OR) or Planning Resource Offer (economic withholding); by failing to arrange in advance for most of its supply of Energy for a Load Serving Entity (LSE) (sustained pattern of under-bidding Load that contributes to an unwarranted divergence of the LMPs between Day-Ahead and Real-Time Markets); or by uneconomic virtual bidding.²²

For New England, the ISO-New England (ISO-NE) identifies specific categories of conduct for which its market power mitigation process will detect and mitigate. These conducts include economic withholding, physical withholding, uneconomic production in absence of the ISO-NE's instruction, and anti-competitive bidding behaviors of both sellers and buyers.²³ Similarly, the New York Independent System Operator (NYISO) monitors and mitigates only “specific conduct that exceed [*sic*] well-defined thresholds.”²⁴ The categories of conduct are the same as those that warrant mitigation in the ISO-NE.

B. MARKET POWER SCREENS

Economists have developed various techniques to assess the degree of market power based on three categories of metrics. These include structural, conduct-, and performance-based tests.²⁵

Market Structure Test: This first category of tests predicts sellers' behaviors based on their ownership and controlled resources structure. This approach tests a seller's (or sellers') market

²² Section 2.1, *Market Monitoring and Mitigation Business Manual BPM-009-r12*, MISO, Effective Date: July 25, 2017, p. 18. [footnote omitted]

²³ See Section III of Appendix A, Market Rule 1, Market Monitoring, Reporting and Market Power Mitigation, Effective Date March 13, 2017. (Market Rule 1)

²⁴ See Section 23.1.1, NYISO Tariffs—Market Administration and Control Area Services Tariff (MST AttH-) ISO Market Power Mitigation Measures, New York Independent System Operator, Inc., Effective Date March 17, 2011.

²⁵ Taylor (2015), Chapter 3.

dominance. Examples of the structural test metrics include a Residual Supply Index (RSI), Herfindahl-Hirschman Index, and market share screens.

Conduct-Based Test: The second category of tests examines a seller's specific conduct in a market and makes inferences about the seller's market power from such conduct. The examples of anti-competitive conduct include physical withholding, economic withholding, and anomalous bidding.²⁶

Performance-Based Test: The third category of tests analyzes the degree in which a seller's bid price departs from its marginal costs. The measure is based on the Lerner Index concept,²⁷ which is the percentage deviation of price from marginal cost.²⁸

In addition, when assessing whether market power has been exercised and the degree by which suppliers have done so, the relevant product and geographic markets need to be defined because they determine the ability of buyers to substitute alternatives from other suppliers for the examined seller's or sellers' products. The relevant product and geographic markets for wholesale electricity could vary by time and location. Below we describe the parameters that are relevant in defining the product and geographic markets.

Relevant Product Markets: In most bilateral wholesale electricity markets, the product duration will be relevant in defining the products. For example, a buyer can buy quarterly, monthly, weekly, day-ahead, hour-ahead, and real-time power products. Each of these products has limited substitutability, particularly longer-term and nearer-term products. For example, on a day before delivery, a buyer would have a choice not to purchase power in the day-ahead time frame if it believes that hour-ahead or real-time energy product could easily substitute for day-ahead product. Typically, since day-ahead, hour-ahead, and real-time products could substitute for each other, they are the same relevant product markets.²⁹ In this paper, we do not examine any bilateral markets and we assume that all buyers of wholesale power can rely on the AESO-operated centralized energy and ancillary services markets to fulfill their needs.

Relevant Geographic Markets: In the wholesale electricity markets, a relevant geographic market covers an area in which a buyer can purchase power from a set of generators, importers, or other suppliers, who can deliver the power during the relevant delivery period. A footprint of a balancing area (BA), such as the AESO BA, plus transmission capacity that can transfer power from nearby suppliers to buyers is the logical starting point for a relevant geographic market.

²⁶ *Id.*

²⁷ Lerner Index is a measure of one firm's market power determined by a ratio of the difference between that firm's sales prices and its marginal cost to firm's sale price.

²⁸ *Id.*

²⁹ During the Western Power Crisis, however, the day-ahead, hour-ahead, and real-time product markets were less clear due to extremely unusual price differentials between day-ahead and real-time markets.

The technical attributes of transmission grids dictate how and how much power can flow across the network paths. These flows change and at times can be limited in such a way that a geographic area becomes constrained and competitive resources from outside of that limited area cannot access that portion of the market. Consequently, at times, a relevant geographic market can be smaller than a full balancing area market.

C. *EX-ANTE* VS. *EX-POST* SCREENING AND BID MITIGATION

Screens for market power can be performed prior to or after market transactions. Since *ex-post* screening could involve lengthy investigations and the prospect of future penalties, *ex-post* screening and mitigation typically are seen as creating significant uncertainties for suppliers, investors, and customers. Thus, other jurisdictions that we have reviewed tend to rely more heavily on identifying the exercise of market power using pre-specified *ex-ante* screens. *Ex-ante* screens and associated prescriptive mitigation tend to provide transparent rules and thereby decrease the uncertainties that market participants face. When *ex-ante* screening and mitigation rules are clearly set, suppliers can self-monitor prior to their bid submissions.³⁰ *Ex-ante* screens could act as a pre-emptive tool against sellers exercising market power when the likelihood of observing significant exercises of market power is otherwise substantial, and the costs of detecting and penalizing abuses of market power *ex-post* is high.

D. FALSE ALARMS AND FALSE MISSES

To evaluate whether a particular market power mitigation approach (*i.e.*, market power screens, thresholds that trigger mitigation measures) is effective, one must consider the potential costs associated with errors in selecting the bids to mitigate. Such selection errors can be categorized into two main types that lead to either under-mitigation or over-mitigation:

- *False Alarm (False Positive or Type I Error)*: What is the likelihood of over-mitigation and the associated costs of mistakenly applying a market power mitigation that prevents suppliers from charging prices that promote economic efficiency?
- *False Miss (False Negative or Type II Error)*: What is the likelihood of under-mitigation and the associated costs of applying a market power screen that fails to detect sellers' anti-competitive behavior or market power abuse?

For instance, a market structure metric typically predicts that a seller who fails the structural test has the opportunity to use and will use his market power. The structural test therefore could be viewed as a more stringent test because while it detects the conditions under which the exercise of market power is possible, it does not detect whether or not the anti-competitive behavior has actually been exhibited. False alarms could occur if the structural tests suggest that market power *can be* exercised when none has been.

³⁰ They also can have independent market monitors who evaluate the markets after-the-fact.

Another example of a false alarm would be a performance-based threshold that is set too low and triggers mitigation, *e.g.*, a level that is very close to a seller resource's marginal costs. Such mitigation may be triggered excessively if there are other reasons that the seller's offer bid prices are high.

On the other hand, if one sets a performance-based threshold too high, mitigation may never be triggered and the cost of suppliers' exercising market power will be paid for by customers.

Both over-mitigation and under-mitigation may create significant costs to a market. Thus, regulators and policymakers must weigh the potential impact of errors in employing the screens of choice, along with the potential impact of implementing the monitoring and mitigation processes in general. Regulators may view costs associated with missing market power abuses to be higher than those of false alarms and, thereby, prefer to impose a relatively more stringent approach. However, if over-mitigated, consumers may end up bearing higher long-term costs when investors raise their prices due to the earnings risk of over-mitigation. One example of how over-mitigation can adversely affect investment incentives is that customers' demand responses could be muted when prices are repeatedly mitigated downward, which would reduce the long-term efficiency of the market.

E. AESO'S MARKET POWER SCREEN OPTIONS

The AESO is considering three options for *ex-ante* screening and mitigating potential market power abuses in the AESO's energy and ancillary services markets:

- A market structure-based screen known as the Residual Supply Index (RSI);
- A combined conduct- and performance-based test called Conduct-Impact (C-I) test; and
- An integrated use of the RSI screen and C-I test.

The first two options are performed near real-time operations, with the C-I test performed on every supplier's bids after the bid submission period is closed, but before market clearing. The third option, an integrated use of RSI and C-I screens use the RSI well in advance of the real-time market with hourly C-I tests used close to real time. Such a hybrid approach could use the RSI screen for either informational "early warning" purposes to alert the AESO or its market monitor when market conditions may be more conducive to an exercise of market power or to point the market monitor to review the conduct of certain market participants in an ex-post analysis of market outcomes.

Below we use the design framework to discuss the use of the three screen options. The framework involves: (1) defining the behaviors that would be considered the exercise of market power and (2) analyzing the effectiveness of the screen. In the following sections (Sections III through VI), we describe each of the screens and discuss how the screens can be used prior to implementing the mitigation measures.

III. RSI Screen

An RSI screen is a structural test that screens for a market condition under which a pivotal supplier exists and can exercise market power. If performed appropriately, a single pivotal supplier test identifies whether one supplier has the unilateral ability to raise substantially the market prices under the identified market conditions. The concept is that a pivotal supplier can exercise market power by withholding when that supplier's resources are needed to serve the market's demand. Empirically, pivotal supplier and residual supply indices are reliable indicators of the potential for suppliers to exercise market power.³¹ However, depending on the amount of withholding that would be necessary to induce a substantial price increase, pivotal supplier(s) at times may not have the incentive to exercise market power.³²

The RSI screen formula can be mathematically written as:

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

where the sum of $Supply_{jt}$ represents all of the suppliers' total capacity at the relevant time frame. $Total\ Market\ Demand$ is the total demand in the market at time t . $Supply_{it}$ represents $Supplier\ i$'s total resources made available to the market at time t . $Supply_{it}$ is the entity being examined using the RSI analysis.

Equation [1] shows that RSI compares (1) the numerator that is the amount of capacity held by other suppliers in the market that are not owned and controlled by $Supplier\ i$ (supply margin) to (2) the denominator that is the total demand of the market. If the supply margin is greater than total market demand, RSI is greater than 1. When RSI is greater than 1, buyers have supply alternatives and do not have to rely on at least a portion of $Supplier\ i$'s resources. When $Supplier\ i$'s RSI in period t is less than or equal to 1, $Supplier\ i$ is deemed to be pivotal and its resources in whole or in part are required to satisfy demand in the market. Thus, when RSI of a supplier is less than 1.0, that supplier can exercise its market power by raising market prices without losing profits.

³¹ See for example, Genc and Reynolds (2005), Blumsack and Lave (2005), Sheffrin (2002), Borenstein, Bushnell, and Knittel (1999).

³² A pivotal supplier does not necessarily have an incentive to exercise market power. For example, if the supplier would need to withhold 90 percent of its capacity to profitably exercise its market power, it may be very difficult for increased profits on the remaining 10 percent to make up for the losses on the withheld 90 percent.

The formula for the RSI as reflected in Equation [1] focuses on a single seller's market dominance or unilateral market power.³³ However, a similar equation can be applied to joint market power by replacing the single seller by the resources owned by multiple largest sellers.

The RSI screen can be and is typically used to identify the market conditions under which a seller or multiple dominant sellers can raise prices by exercising their market power. If the bid mitigation process relies solely on using the RSI screen, when a supplier fails an *ex-ante* RSI test, its bids will be automatically mitigated down to a pre-determined level.

To capture the likelihood of market conditions that are conducive to sellers' market power at moments as close to the actual conditions as possible, the RSI screen can be applied *ex-ante*, immediately before the actual real-time energy market run. The CAISO and PJM, for example, run their version of the RSI screens for its real-time markets.³⁴ The AESO could run the screen for each supplier in each hour by using that supplier's entire portfolio offer MW data, including its owned and controlled generation and contracts, the aggregated effective supply offers (including effective imports), and an expected real-time demand. The screen therefore is not applied on a unit basis, but rather on a seller basis in order to capture a supplier's dominance.

A. ADVANTAGES AND DISADVANTAGES OF USING THE RSI SCREEN

The advantages of using the RSI screen include:

- The RSI screen can predict the potential for a supplier to exercise market power by using the size of a supplier's ownership and control of supply resources relative to the available supply for use to serve the overall market's demand. The RSI is negatively correlated with the Lerner Index or price-cost markup and load.³⁵ An empirical analysis of the relationship between RSIs and price-cost markup and load could indicate an appropriate RSI safe harbor threshold. We present these relationships in Section II.C.
- The RSI can be constructed to capture a wide range of actual market conditions, potential coordinated behavior, or multilateral market power via two- or three-joint RSIs.³⁶

³³ In many U.S. ISOs with locational marginal pricings, a three-pivotal suppliers test is used to identify sellers with local market power.

³⁴ The CAISO originally deployed its *ex-ante* three-pivotal RSI screen on an annual basis when it began its Market Redesign and Technology Upgrade (MRTU) market in 2009.

³⁵ See Anjali Sheffrin, *Predicting Market Power Using the Residual Supply Index*, Department of Market Analysis California Independent System Operator, Presented to FERC Market Monitoring Workshop, December 2002.

³⁶ The AESO is currently examining a single RSI given the concentration of players that effectively would certainly lead to many parties failing in a three pivotal supplier test.

- The use of RSI alone avoids having to set a separate safe-harbor or “No Look” threshold below which mitigation would not be triggered. This is because by definition, as shown in Equation [1], an RSI of greater than 1 is the level at which a supplier is not a pivotal supplier. Nevertheless, we discuss the disadvantages associated with the arithmetic threshold later.
- Relying on RSI alone provides more protection against exercise of market power as it errs on the side of caution. In other words, it emphasizes avoiding false misses in identifying those that could exercise market power (even if they do not).

The disadvantages of using the RSI screen include:

- The RSI test could be overly restrictive. According to MSA’s 2012 State of Market Report, in 2012, the AESO’S large suppliers failsan RSI test in almost 90 percent of the hours. With the use of an RSI solely, suppliers’ bidding behaviors may not be considered, and thereby result in a much higher level of market intervention compared to using a Conduct-Impact test that would evaluate the potential impact of certain bidding behavior prior to mitigation. (We explain the Conduct-Impact test later in Section D).
- The RSI screen does not reflect a supplier’s actual contractual position or bidding behavior used to exercise market power. For example, a supplier that has to serve certain customers and has a net purchase position in the wholesale market will not be likely to have a strong incentive to exercise market power. However, the traditional RSI focuses only on the amount of resources the supplier owns, not its net contractual obligations or positions (which depend on how much load it must serve by purchasing power from the market).
- Although an RSI greater than 1 is arithmetically identical to a seller not being pivotal, and vice versa, empirical evidence shows that the threshold of 1 is not always an accurate bright line test. For example, based on its experience, the California ISO Market Surveillance Unit suggested that a seller with an RSI greater than 1 could still have significant market power.³⁷

B. POSSIBLE REFINEMENTS TO THE RSI SCREEN

The formula in Equation [1] can be refined better to reflect a supplier’s ability and incentive to exercise market power. Below lists some proposed refinements of Equation [1], which could be used to adjust the index to reflect suppliers’ prior commitments that reduce the supplier’s incentive to exercise market power.

³⁷ In the past, the CAISO has found that a supplier with an RSI of 1.1 or below in its market would indicate that the seller has high market power. See Figure 6-5, *Annual Report on Market Issues and Performance*, CAISO Market Surveillance Unit, Section 7.2 Pivotal Supplier Analysis, June 1999, p. 7-4.

- Adjustment for load and sales obligations:
 - *Supplier i*'s total supply available at time t would be adjusted downward to reflect *Supplier i*'s load and long-term contract obligations, if any exists. As shown in Equation [2], the second term of the numerator reflects *Supplier i*'s net buyer/seller position in the market. This adjustment is particularly important when suppliers must purchase power to meet their obligations through the market with no ability to pass through the entire cost to their buyers/customers.
- Adjustment for imported resources/supplies:
 - In a given period, the total supply available in the market would include the amount of imports up to the interties' available transfer capacities.
 - If *Supplier i* has import offer bids, the total import bids should be included in *Supplier i*'s total supply.
- Adjustment for exports:
 - If the market allows participants to purchase from the market for exports, the total demand (in the denominator) should include the amount of exports.
- Adjustment for certain suppliers' must-run resources
 - Certain suppliers may be exempt from the test if their entire portfolios consist solely of must-run resources such as wind, solar, or run-of-river hydro. Such an exemption would not be applied to suppliers that own or control dispatchable resources. Although a supplier typically cannot withhold the output of the must-run resources, the supplier with dispatchable resources has the ability and potentially an incentive to withhold the controllable resources in the portfolio to raise prices if the must-run resources' revenues depend on the market prices.

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

$$RSI_{it} = \frac{\sum_{j=1}^n Supply_{jt} + Imp_t - (Supply_{it} + Imp_{it} - Obligation_{it})}{Total\ Market\ Demand_t + Export_t + Reserves_t} \quad [2]$$

C. RELATIONSHIP BETWEEN RSIs AND MARKUPS IN THE AESO ENERGY MARKET

To provide insight on how the RSI metric might inform the AESO and market participants about sellers' bidding behavior, particularly when their RSI values are below 1.0, we conducted a preliminary RSI analysis using AESO's historical supplier bid information from 2012 to 2016 for some of the large AESO market participants.^{38,39} We plotted three large sellers' RSIs against their estimated bid-offer markups. The bid markups are estimated using the AESO data for unit characteristics.⁴⁰ The offer markups are defined as the suppliers' offer prices *minus* an estimated short-run marginal cost of the supplier's resource. The short-run marginal costs include the estimated fuel and variable operation and maintenance costs.⁴¹ Figure 5 below shows the indicative relations between three individual suppliers' RSIs and their ratios of bid markups to their short-run marginal costs. We used the hours in which these three suppliers' resources' bid prices had set market clearing prices during the examined period.

As expected, Figure 5 shows the inverse relationship of the level of bid markups and the RSI values. However, there is not a bright line between the bid price markups at RSI = 1.0 versus those that have RSI slightly below or above 1.0. If anything, a bright line seems to be closer to an RSI = 1.1, below which the observed bid markups increased significantly.

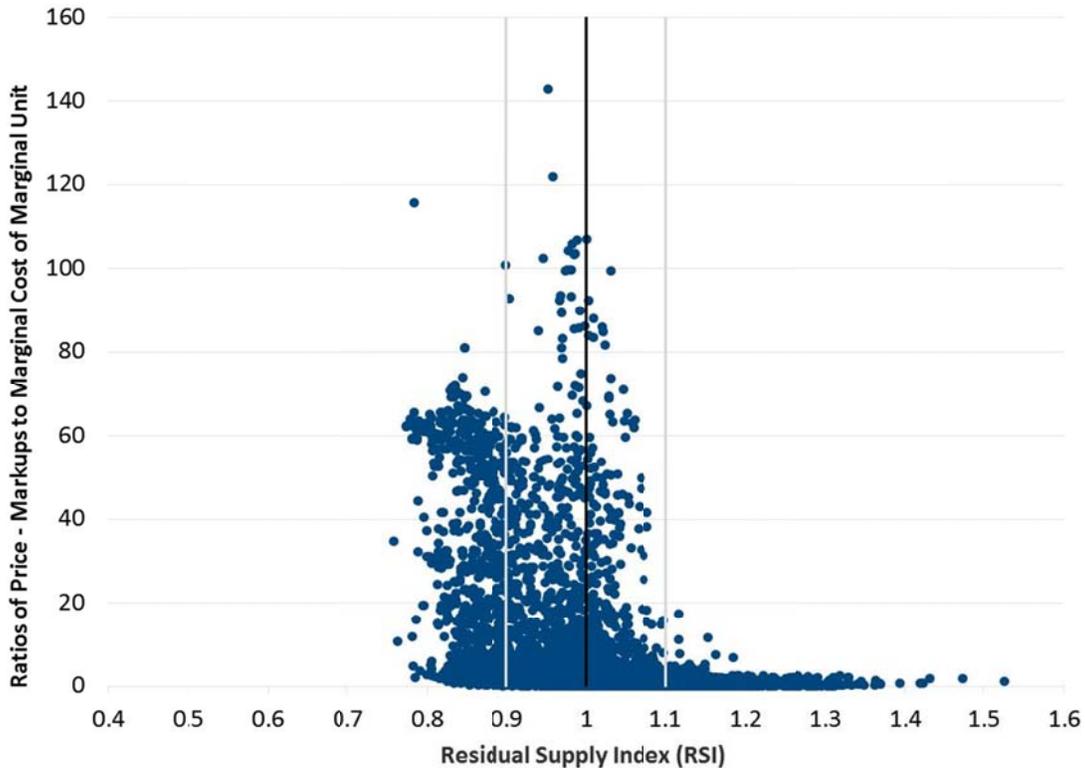
³⁸ See Appendix A for the description of how we calculated the RSIs.

³⁹ We focus on "marginal sellers" who frequently set a real-time market-clearing price in a given hour.

⁴⁰ The AESO provided the unit characteristic data (*e.g.*, heat rate curves, variable operating and maintenance costs) and the coal prices while we obtained the natural gas prices from SNL.

⁴¹ Even though a generator's marginal cost would include emissions costs, we have assumed that those costs are relatively minor relative to the other costs and the level of the bid markups. If included, the estimated bid markup levels would be smaller than depicted here. At a RSI value of 1.0, bid prices often exceeded estimated marginal costs by a factor of 60 or more.

Figure 5
RSI vs. Price-to-Marginal-Cost Ratios of Bids from Marginal Generating Units
in AESO Energy Market During 2012–2016



Source and Notes: Each dot represents a supplier’s resource bid. The y-axis is calculated as the bid price divided by the resource’s estimated marginal cost. See Appendix A for a description of the RSI Calculation. The estimated marginal operating costs include fuel costs plus variable O&M.

As shown in Figure 5, if an $RSI < 1.0$ were used as a “No Look” threshold above which suppliers’ bidding behaviors would not be examined, there could be a significant risk of under-mitigation (false misses or false negatives). Some sellers imposed markups of more than 20 times their marginal cost even when their RSI values are as high as 1.1. This may reflect the fact that some suppliers are able to exercise market power even before they become pivotal.

Figure 5 suggests that reducing the RSI’s “No Look” threshold to anything less than 1.0 would ignore market conditions under which some large sellers have been able to increase prices significantly above their marginal costs. Even if some of these historical bidding behaviors have been transitory, they would be candidates for mitigation looking forward because they could cause significant energy and ancillary services prices to increase. We further discuss the effectiveness and reliability of the RSI in Section VI of this report.

D. NET REVENUE OF REFERENCE RESOURCES UNDER RSI MITIGATION

To understand better the potential impacts of the RSI mitigation on new entry, in this section we conduct a mitigation impact analysis for the “Reference Resources” considered in the Capacity Market Design: combined cycle (CC) and combustion turbine (CT) natural gas plants. The

mitigation impact analysis estimates the net revenues reductions that these resources would have seen historically had mitigation been imposed on pivotal suppliers. These net revenues and net revenue impacts are compared against the resources' annualized fixed and investment cost, which is quantified as the Cost of New Entry (CONE).

In general, investors and generation developers' decisions to enter a market depend on an expected revenue stream of their resources. We define Reference Resources as a new CC with a heat rate of 6,700 kilojoules/kWh and a new CT with a heat rate of 9,600 kilojoules/kWh. The detail of these Reference Resources' characteristics and estimated net revenues are in the Appendix C.

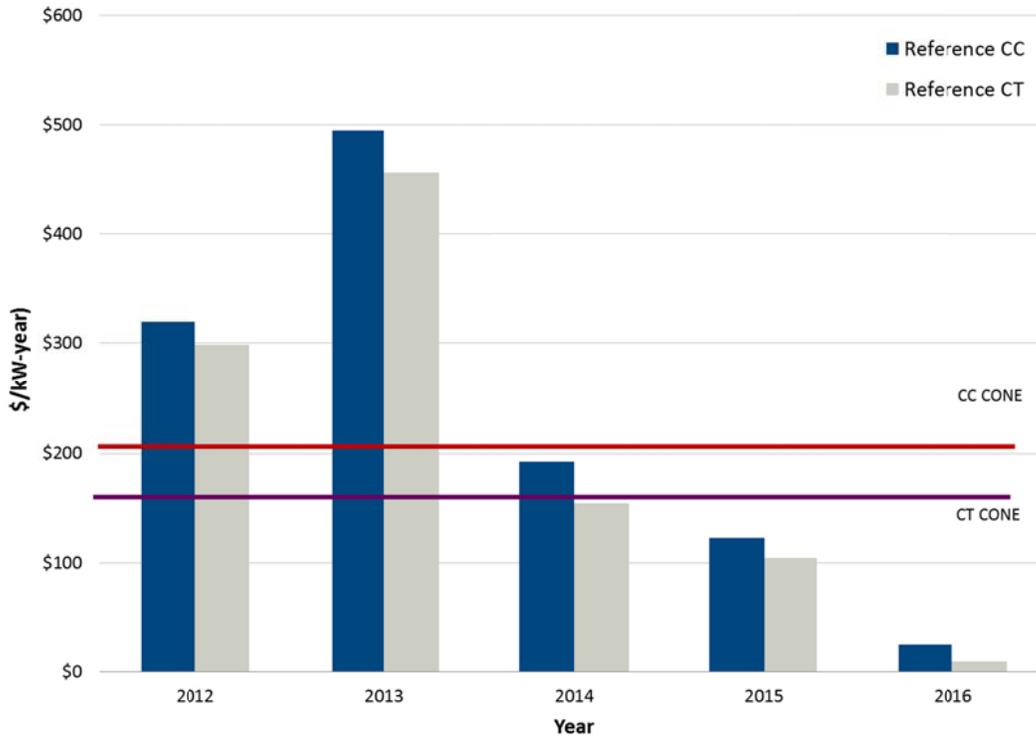
Revenues from the energy and ancillary services market are referred to as the "Gross energy (ancillary services) revenues." The gross revenues are estimated as the product of the energy (ancillary services) market price and the generation output. The net revenues are defined as the difference between gross revenues and suppliers' variable operating costs. The net revenues are the amount of revenues after paying for the variable operating costs and therefore contribute toward paying for the suppliers' fixed costs.

Using 2012–2016 data provided by the AESO, we estimate the net revenues that the Reference Resources would have earned in the AESO energy market. (We have not included estimates of the revenues from the ancillary services market.) These net revenues have fluctuated significantly from 2012 to 2016, primarily due to changes in the AESO wholesale energy prices. We estimate the energy revenues as the annual average revenues that would have been received by Reference Resources for 2012 through 2016. This estimate is derived by conducting a simple dispatch analysis, assuming that each Reference Resource would have operated whenever the hourly historical market price of the AESO was greater than the estimated variable cost of the reference resource unit.

Figure 6 below compares to the CONE values with the net energy revenues of Reference Resources as if they were to operate in the AESO energy market in 2012–2016. The AESO currently estimates gross CONE values for a new CC at \$184–\$230/kW-year and at \$144–\$174/kW-year for a new CT.⁴² We use the mid-point of these values, \$207/kW-year for CCs and \$159/kW-year for CTs. As Figure 6 shows, we estimate that new CCs and CTs would have earned \$230/kW-year and \$200/kW-year of net revenues during the 2012–2016 period. Most of these revenues were earned in 2012 and 2013, after which market prices declined significantly.

⁴² See "Table 1: Capital and Operating Cost of Natural Gas Generating Units," *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Figure 6
Net Energy Revenue of Reference Resources vs. Gross CONE
Historical Unmitigated Market Clearing Prices (2012–2016)

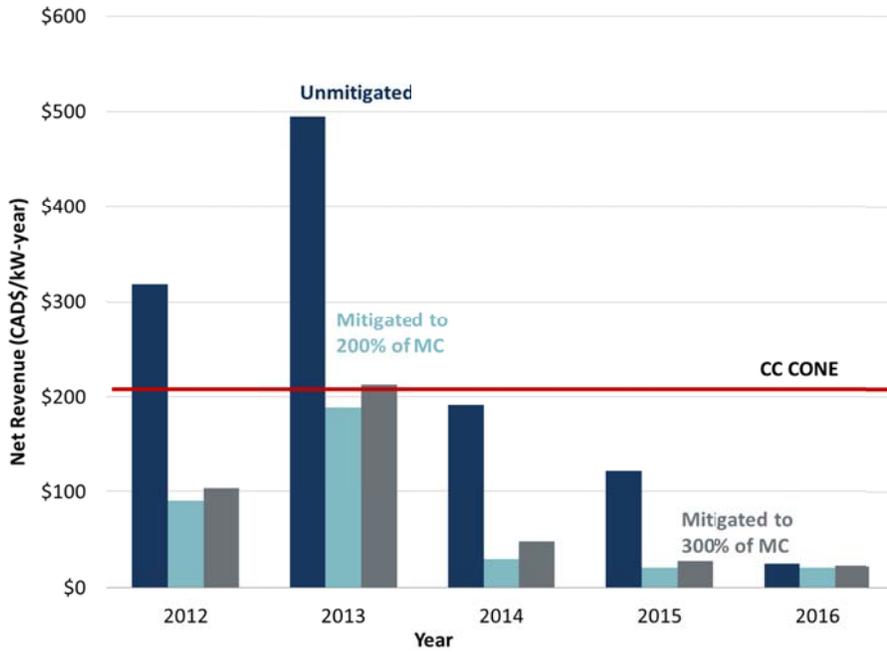


Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated 2012–2016 market prices. Marginal costs of CC and CT are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and CAD\$8/MWh and CAD\$4/MWh for variable O&M. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

To examine the potential impact that an hourly RSI screen might have had on the AESO energy market over 2012–2016, we create two mitigation scenarios for pivotal suppliers. We first identify each hour whether there is a pivotal supplier in the market based on an 1.0 RSI threshold. One of the mitigation scenarios, all bids of a pivotal supplier are mitigated to the lower of the 200 percent of its resources’ marginal costs and the pivotal supplier’s actual bid. The second mitigation scenario uses 300 percent of supplier resources’ marginal costs. We then assess how much net revenue each Reference Resource would earn in the market as a price taker under the unmitigated historical market prices and for each mitigation scenario from 2012 to 2016.

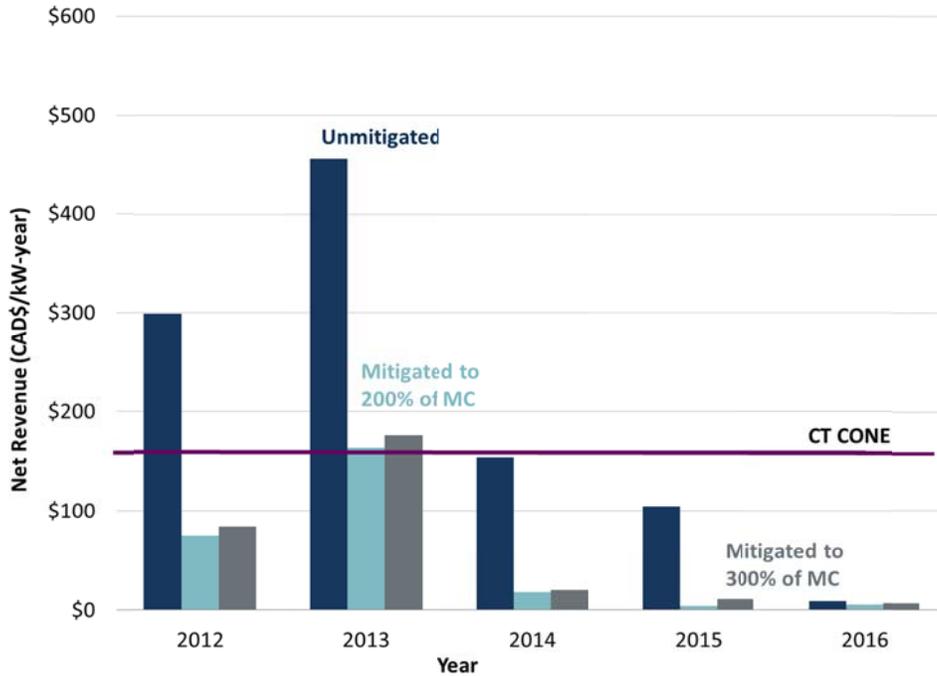
Figure 7 and Figure 8 compare the 2012–2016 annual net revenue results of Reference Resources CC and CT under the historical market condition (unmitigated) with the mitigated market conditions, respectively.

Figure 7
Net Energy Revenues of a Reference CC Resource
by RSI Mitigation Scenario



Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated versus mitigated 2012–2016 market prices. Marginal costs of CC and CT are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and CAD\$8/MWh and CAD\$4/MWh for variable O&M. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Figure 8
Net Energy Revenues of a Reference CT Resource
by RSI Mitigation Scenario



Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated versus mitigated 2012–2016 market prices. Marginal costs of CC and CT are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and CAD\$8/MWh and CAD\$4/MWh for variable O&M. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

As expected, under both mitigation scenarios the annual net revenues of these two resource types drop significantly from their net revenues without mitigation. This suggests that the RSI screen based on a 1.0 threshold detects pivotal suppliers during a significant number of hours of each year. During many of these hours, pivotal suppliers also submitted highly-priced bids that substantially exceeded their marginal costs as shown in Figure 5 above, which means resetting supplier bids the lower of their actual offers and the 200 percent or 300 percent of their offered resources' marginal costs reduces market clearing prices significantly. As a result, the mitigated net revenues of Reference Resources are far below unmitigated net revenues. On average, the estimated five-year net revenues of Reference Resources decline from 111% to 129% of CONE to only 33% to 40% of CONE.

Figure 9
2012–2016 Average Net Revenues of Reference Resources vs. and CONE
(Unmitigated vs. RSI=1.0 Mitigation at 200% and 300% of Marginal Costs)

Scenario	Mitigation	Reference Resource CC			Reference Resource CT		
		5-Yr Net Energy Revenue (\$/kW-yr)	Gross CONE (\$/kW-yr)	Net Energy Revenue as % of Gross CONE (%)	5-Yr Net Energy Revenue (\$/kW-yr)	Gross CONE (\$/kW-yr)	Net Energy Revenue as % of Gross CONE (%)
1	200%	\$69.74	\$207	34%	\$53.17	\$159	33%
2	300%	\$82.58	\$207	40%	\$59.67	\$159	38%
Unmitigated	NA	\$230.56	\$207	111%	\$204.37	\$159	129%

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated versus mitigated 2012–2016 market prices. Marginal costs of CC and CT are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and CAD\$8/MWh and CAD\$4/MWh for variable O&M. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

IV. Conduct-Impact Test

A Conduct-Impact test is a two-part behavioral test that identifies whether a supplier’s actions warrant mitigation. The first part of the test, a Conduct test, determines whether a supplier’s behavior is considered anti-competitive. The second part of the test, the Impact test, assesses whether the anti-competitive behavior, as determined through the Conduct test, has significant adverse impact on market prices to justify mitigation. Any bids that fail both Conduct and Impact tests will be subject to mitigation to acceptable cost thresholds, which we discuss below in Section IV.D.1.

A. THE CONDUCT TEST

The Conduct test defines what constitutes unacceptable behavior. It therefore can screen for physical withholding, economic withholding, and other uneconomic behaviors although each requires different criteria and timing for its evaluation. To screen for economic withholding, a supplier’s bids would be compared to a “competitive reference level” expressed in dollars per MWh. If bids are above the competitive reference level by more than a defined “No Look” threshold (in the form of dollars or percentage, such as 200 or 300 percent of the competitive reference level), those bids would be evaluated subsequently via the Impact test. The Impact test would be used to estimate the likely impact of mitigating those bids on the market-clearing price. Only when an action fails the Impact test would the conduct be deemed unjustified and mitigation imposed.

With the Conduct test, a predefined No-Look threshold based on a multiple of a resource’s short-run marginal cost (synonymous to a unit’s variable cost) or “competitive reference level” would be used to trigger evaluation of whether a supplier would need to be subjected to the subsequent Impact test and possibly bid mitigation. As discussed further in Section D.3 below, reference levels can be based on (1) bids during competitive periods, (2) market prices during competitive

periods, or (3) the resources marginal costs. If a cost-based competitive reference level were chosen, the AESO would undertake the following steps to determine that level:

- Calculate each unit's competitive reference level (estimated as the unit's marginal cost) based on heat rate \times fuel cost plus variable operating and maintenance (O&M) costs and emissions costs per MWh of power produced.⁴³
- Add to the marginal-cost-based competitive reference level, a unit's opportunity cost (if any) caused by run-time restrictions (such as environmental permit), operational risks, and fuel availability.
- If the supplier believes that the AESO's marginal cost estimate is not sufficiently accurate, the supplier could submit its actual marginal cost for AESO's consideration (in the form of a confidential submission). The suppliers' submissions could include their opportunity costs and specific guidelines would need to be developed regarding what and how the cost data would be accepted by the AESO.
- Evaluate if the supplier' bid is above a certain multiple of the unit's competitive reference level.⁴⁴

The utilization of competitive reference level in combination with a “No-Look” threshold need to consider the fact that Alberta market participants' bids are currently one-part bids and that the bid prices' reference level may be estimated solely based on suppliers' marginal costs, which include only its variable fuel costs, variable O&M costs, and emissions costs, including carbon prices. To participate in the Alberta market, some resources will require a longer lead time to start and maintain a minimum output level (no load). A seller's offer is expected to cover both their marginal operating costs and commitment costs over the period of the plant's generating hours. For example, if a natural gas CC plant, once turned on, expects to operate for at least nine hours before having to shut down again, that supplier would consider the costs associated with starting up the plant, operating it at no-load levels (*i.e.*, its minimum generation level), and other costs that the facility might incur by being dispatched for nine hours—in addition to its marginal operating costs per MWh of power generation—and include those costs in its bid prices.⁴⁵

In other regional markets where suppliers can submit three-part bids, the Conduct tests individually examine a supplier's costs of start-up, its no-load offers, and the marginal fuel and variable O&M costs of producing energy. In those markets, the “No Look” threshold of the

⁴³ For example, if natural gas prices are used for the estimation of a gas plant's short-run marginal cost, the gas price that the AESO uses will be the monthly Canadian natural gas price in \$ per gigajoule (\$/GJ) at AECO C and Nova Inventory Transfer, the Alberta Bidweek Spot Price, as published on www.ngx.com, and also in the “Canadian Gas Price Reporter.” [AESO Rule section 201.6 Pricing.]

⁴⁴ See Section VI for discussion.

⁴⁵ In jurisdictions where supplier bids are multi-parts, the supplier can explicitly submit information about its start-up costs, no-load costs, minimum run time, and minimum down time and allow the unit-commitment process to optimize these costs across competing resources.

commitment costs would be set, for instance, a level higher than the “No Look” threshold for the marginal energy component.

The AESO could also use a “No Look” threshold to detect potential physical withholding.⁴⁶ A supplier may falsely claim forced outage events or operating output below the AESO’s dispatch in order to benefit the supplier’s other transactions. The “No Look” withholding threshold would be expressed in quantity levels or in the form of a certain percentage of (1) a supplier’s generating unit’s total generating capability, (2) a supplier’s total portfolio capacity, or (3) its ISO’s dispatch instruction. For example, the ISO-NE identifies physical withholding when a supplier: (1) withholds the lower of 10 percent or 100 MW of the unit’s total owned and controlled capacity; (2) withholds in aggregate the lower of 5 percent or 200 MW of its total capacity, or (3) operates the unit in real-time less than 90 percent of the ISO-NE’s dispatch rate.⁴⁷ Even if a resource has a must-offer requirement, this additional threshold would still be helpful by allowing the AESO’s internal market monitor to detect potential instances of physical withholding and pursue further investigation, if necessary. Even if implemented as an *ex-post* test as opposed to an *ex-ante* test, this test would provide transparency about the level of tolerance for claimed outages and allow the AESO to investigate potential falsely claimed forced outages.

B. THE IMPACT TEST

The Impact test evaluates whether supplier actions that fail the Conduct test would significantly influence the market-clearing prices (including any uplift payments). The process involves comparing the market-clearing price with the supplier’s initial (failed) bid to that of a simulated “competitive” market outcome, in which the supplier’s bid is adjusted to the mitigated level. The supplier’s bids that pass the Conduct test are unchanged in the simulated competitive scenario. This test would be run for all seller bids that fail the Conduct test in a pre-market run or before the actual dispatch period.

Like the Conduct test, the Impact test would include a “No Look” threshold. Such a threshold is predefined as the magnitude of the price impact that would be tolerated. The markets that use the Conduct-Impact test typically set an impact threshold to be the minimum of a certain percentage (*e.g.*, 100 or 200 percent) and a certain price (*e.g.*, \$100/MWh) above the simulated competitive energy market prices. This means that if an unmitigated bid would affect prices only modestly, those bids would be tolerated. However, if bids that failed the Conduct test are found to cause a material price increase (above the No-Look threshold that accompanies the Impact test), the bid would be subject to mitigation.

⁴⁶ Given that the AESO has a must offer requirement, the Conduct test for physical withholding could be performed on an *ex-post* basis.

⁴⁷ Section III.A.4.2.1, Market Rule 1.

C. ADVANTAGES AND DISADVANTAGES OF USING CONDUCT-IMPACT TEST

The advantages of using the Conduct-Impact test include:

- The Conduct-Impact test has well defined No-Look thresholds that reflect the bid behaviors that would be subject to further evaluation. The test reduces the risk of over-mitigation.
- Through sufficiently high No-Look thresholds, the test ensures that shortage pricing is a result of specific shortage events and not the suppliers' exercise of market power.
- The Conduct-Impact test allows bid prices to rise during periods of scarcity so that the market can send efficient economic signals to buyers, sellers, and investors. For instance, the No-Look threshold of the Conduct test can be allowed to be considerably higher than variable production costs. For example, when a shortage condition occurs (*e.g.*, under very high demand and/or shortage supply conditions), the administrative shortage pricing could increase the prices significantly. Thus, even suppliers that fail the Conduct test may have no significant impact on the resulting high market prices set by the administrative shortage pricing. Under such a situation, the supplier will not be mitigated. Alternatively, the supplier's bid would be mitigated, but the resulting price would be driven by the administrative shortage pricing.
- The Conduct-Impact test can also be designed to capture multilateral market power through coordinated behavior or tacit collusion by suppliers. To address such concerns, the Impact portion of the test can be *applied simultaneously* to all suppliers' bids that fail the Conduct test. This would simplify the Impact portion of the test (by simulating only a single simultaneous impact scenario, while capturing the combined effect of multiple suppliers' conduct threshold violations. For example, two failed Conduct test bids that individually pass the Impact test may have a much more significant combined price impact.

The disadvantages of using the Conduct-Impact test include:

- The Conduct-Impact test requires competitive reference levels to be established for every resource in the AESO. Data on costs are needed to establish the safe-harbor or "No Look" thresholds. The initial gathering of suppliers' cost data could be time-consuming.
- The Impact test could be administratively burdensome to apply and may require significant real-time modeling capability to facilitate simulating the market prices with and without the mitigation of certain bids.

D. APPROPRIATE "NO LOOK" THRESHOLDS FOR THE CONDUCT-IMPACT TEST

The decision regarding appropriate mitigation thresholds of the Conduct and Impact tests needs to balance between short-term and long-term considerations. Electricity markets are susceptible

to the exercise of market power because the demand for and supply of electricity needs to be balanced instantaneously to maintain system reliability and prevent blackouts. When the system is tight or a supply shortage occurs, the value of available resources can significantly exceed short-run marginal costs of supply resources. Thus, an administrative shortage pricing approach may be used to accompany the marginal price setting approach in those situations to reflect the value of having adequate supply in the market during shortage conditions.

In many U.S. ISOs, the thresholds of their Conduct tests are set to be *above* a unit's competitive reference level. For instance, the ISO-NE, MISO, and the NYISO set their thresholds at the lower of 300 percent or \$100/MWh above each generating unit's competitive reference level. Their price-impact test thresholds are set such that an increase in price cannot exceed the lower of 200 percent or \$100/MWh.⁴⁸ The combination of the Conduct test's tolerance price level and the Impact test's price thresholds effectively allow the market-clearing prices to increase when the market faces scarcity of resources. In combination with administrative shortage pricing in the energy and ancillary services markets and a centralized capacity market, the wholesale electricity design aims to strike the balance of providing opportunity for investors to earn sufficient return to encourage investments when they are needed.

Next, we assess the Conduct-Impact test tolerance bands by: (1) comparing the average total costs of a natural gas CC generating station, a coal-fired power generating unit (Coal), and a CT plant with their marginal operating costs; and (2) benchmarking potential net energy revenue of "Reference Resources" under mitigation threshold options against CONE.

1. Average Operating Cost Over Operating Periods vs. Marginal Cost

To develop an appropriate threshold level for the Conduct test, we compare the average operating costs over the hours of operations with the marginal variable costs of a typical CC, a typical Coal, and a typical CT plant. We estimate each type of plant's operating costs based on its marginal operating cost (fuel, variable O&M, and emissions costs) and commitment costs (start-up, shutdown, and no-load costs). Because currently, suppliers submit their energy (and ancillary services) bids with a single cost number (termed as "one-part offers"), a seller's offer could cover both their marginal operating costs and commitment costs. Below in Figure 10, we estimate the commitment costs of a typical CC and a typical Coal plant in the AESO market based on hot and cold starts. Columns [1] to [4] of Figure 10 show our assumed commitment costs using the data from the AESO and public sources.⁴⁹ The CT plant does not need to maintain

⁴⁸ Their thresholds for both Conduct and Impact tests are much stricter when their relevant geographic markets are smaller. For instance, in the ISO-NE when the market becomes a narrowly constrained area the threshold of the price-impact test is a minimum of 50 percent or \$25/MWh.

⁴⁹ The AESO database does not list a fixed start-up cost for CC and coal units. Using the *Power Plant Cycling Costs*, NREL (2012), we assume the costs for a typical hot and cold starts for CC to be CAD\$44/MW/Cycle and CAD\$127/MW/Cycle, respectively. The Coal plants are assumed to have a hot start of CAD\$74/MW/Cycle and CAD\$156/MW/Cycle for a cold start. The costs are based on

a minimum load level; therefore, its value in Columns [2] and [3] are zero. Column [5] presents our assumed marginal operating costs that are derived based on the heat rates of 5,996 kilojoules/kWh and 10,659 kilojoules/kWh, the variable O&M expenses of CAD\$4.92/MWh and CAD\$6.30/MWh, and the fuel prices of CAD\$2.18/Gigajoule and CAD\$0.90/Gigajoule for the CC and coal units, respectively. Column [6] presents the maximum output assumed for each of these generating plants while Column [7] is the incremental output from the minimum load level. Then in Column [8] we show our assumptions of operating times of 9 and 600 hours for a typical CC and Coal plant, respectively.⁵⁰ For a CT plant, we assume that it will be used to serve peak load, which may only last 0.5 hour. Column [9] shows each plant's total costs for each dispatch cycle. This includes the operating costs during each plant's operating hours and each plant's commitment costs assuming each plant's capacity is 400 MW with a minimum load of 160 MW, with the exception of Coal with High Commitment Cost, which has a minimum load of 214 MW. We then calculate the average total costs in Column [9] and the ratios of average total costs to marginal operating costs in Column [10].

Continued from previous page

converting the costs of US\$39/MW/Cycle, U.S.\$112/MW/Cycle, U.S.\$65/MW/Cycle, and U.S.\$134/MW/Cycle to the Canadian dollars using the exchange rate of US\$1=CAD\$1.26.

⁵⁰ These assumptions are based on the 2016 historical data obtained from Ventyx.

Figure 10
Comparison of Estimated Commitment Costs and Marginal Costs
of Proxy Combined Cycle and Coal-Fired Power Plants in Alberta

Plant Type	Start-up Cost (\$/cycle)	Shut Down Cost (\$/cycle)	No Load Cost (\$/cycle)	Total Commitment Cost (\$/cycle)	Marginal Cost (\$/ MWh)	Output @ Full Load (MW)	Average Incremental Output (MW)	Assumed Run Time @ Full Output (Hours)	Total Cost (\$/cycle)	Average Cost (\$/MWh)	Ratio of Avg. Cost to Marginal Cost
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
CC (with Hot Start)	\$9,160	\$2,062	\$25,981	\$37,202	\$17.28	400	240	9	\$73,152	\$21.10	1.2
CC (with Cold Start)	\$25,808	\$2,062	\$25,981	\$53,851	\$17.28	400	240	9	\$89,800	\$25.90	1.5
Coal (with Hot Start)	\$14,688	\$2,707	\$1,599,481	\$1,616,875	\$15.92	400	240	600	\$3,909,248	\$16.29	1.0
Coal (with High Commitment Cost)	\$39,708	\$2,707	\$2,562,907	\$2,605,322	\$15.92	400	186	600	\$4,381,911	\$18.26	1.1
CT	\$2,146	–	–	2,146	\$24.88	100	100	0.5	3,389	\$67.79	2.7

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

As shown in Column [11] of the above figure, based on the assumed costs and minimum operating hours once a CC or a Coal plant is turned on, the average costs per dispatch cycle are up to approximately 1.5 times the plant’s marginal hourly operating cost.⁵¹ For a CT plant, this ratio is 2.7.

These ratios may not reflect some of the actual costs of generating units in the AESO system. The start-up costs obtained from the NREL (2012) study, for example, represent lower bound

⁵¹ For example, for a 400MW CC (with Hot Start) unit, we estimate that the cost of generating output for 9 hours is approximately CAD\$76,168. This cost includes its commitment cost of CAD\$37,202 (Column [4]) and variable operating cost of CAD\$37,332 (CAD\$17.28 × 9 hours × 240 MW), yielding an average cost of approximately CAD\$21.10/MWh.

For a 400MW Coal with Hot Start unit, the commitment cost is approximately CAD\$1,616,875 with a run time of 600 hours. If the marginal cost of the plant is approximately CAD\$15.92/MWh, operating this coal-fired plant for 600 hours would yield a total cost of CAD\$3,909,248. With these assumptions, the average cost of operating the coal plant for 600 hours would be approximately CAD\$16.29/MWh, which is approximately 1 times its marginal cost. This ratio does not materially change even when we base our calculation on a coal unit with a higher, start-up cost, and no-load cost, as shown on Row “Coal with High Cold Start and High Commitment Cost” of Figure 10.

estimates. Additionally, the AESO expects an increase in the system's net demand variability due to increasing investment in renewable resources. Thermal resources are expected to be dispatched less and cycle more. This could increase average cost to marginal cost ratios. In combination with the estimates in Figure 10, these trends suggest that a No-Look conduct threshold of three times marginal costs (300 percent) is appropriate.

Separately, in the Impact test, a No-Look threshold of CAD\$100/MWh for bids' market price impact would allow a marginal unit with an assumed heat rate of 9,600 kilojoules/kWh and a variable O&M of CAD\$5/MWh to offer almost 4 times above its marginal cost of CAD\$26/MWh if the natural gas prices are at approximately CAD\$2.2/Gigajoule. We recognize, however, that individual suppliers may have a wide range of costs. The above analysis only provides an indicative range.

2. Net Revenue of "Reference Resources"

We now examine an appropriate level of the Conduct-Impact test thresholds by estimating the potential revenues that resources would earn in the energy market under various mitigation threshold options.

Using the same assumptions for Reference Resources' characteristics, we examine how a mitigation threshold of 200 and 300 percent would affect suppliers' overall net revenues of Reference Resources. We estimate the Reference Resources' revenue streams as if historical market prices in the AESO energy market had been mitigated under various mitigation threshold options. We use the AESO's 2012–2016 historical offer data and estimate the potential revenues that suppliers would have earned with four combinations of Conduct-Impact test parameters. The four combinations of test parameters vary by the threshold levels. The No-Look threshold parameters used for the Conduct test are 200 percent and 300 percent of marginal costs. For the Impact test we included No-Look thresholds of \$100/MWh and \$200/MWh.⁵² The analysis assumes that, when bid prices and impacts are above these thresholds, the bid prices would be mitigated down to the No Look thresholds of the Conduct test—either 200 or 300 percent of marginal costs. For example, if the thresholds of Conduct and Impact tests are 200 percent and \$100, respectively, any bids failing both tests will be mitigated down to 2 times their marginal costs. The options explored are listed in Figure 11.

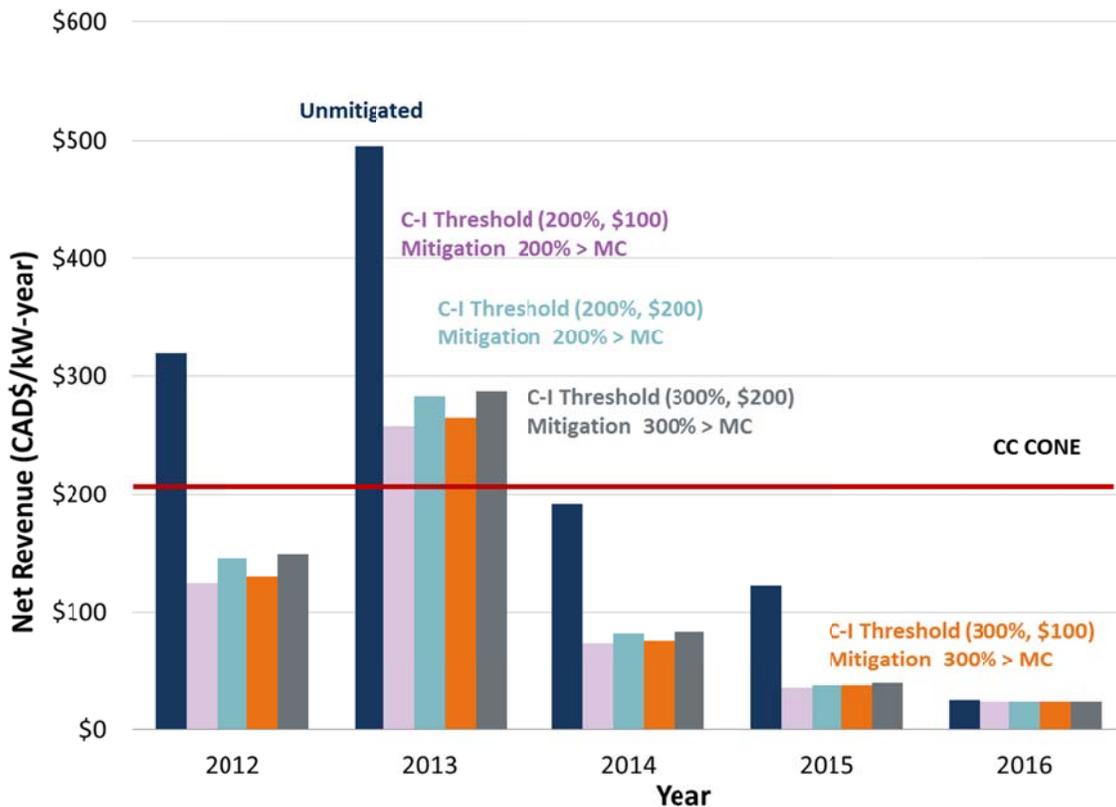
⁵² Our analysis of the historical offer data suggests that when sellers' offer bid prices fail the Conduct test, their Price impacts are usually below 100 percent of the energy prices with mitigation. We therefore created the scenarios based on the dollar threshold.

Figure 11
Conduct-Impact Test Threshold and Mitigation Scenarios

Option	Conduct Test (Percent of Marginal Cost)	Impact Test (Dollars Above Estimated Competitive Clearing Prices)	Mitigation Level (to Percent of Marginal Cost)
1	200%	\$100/MWh	200%
2	200%	\$200/MWh	200%
3	300%	\$100/MWh	300%
4	300%	\$200/MWh	300%

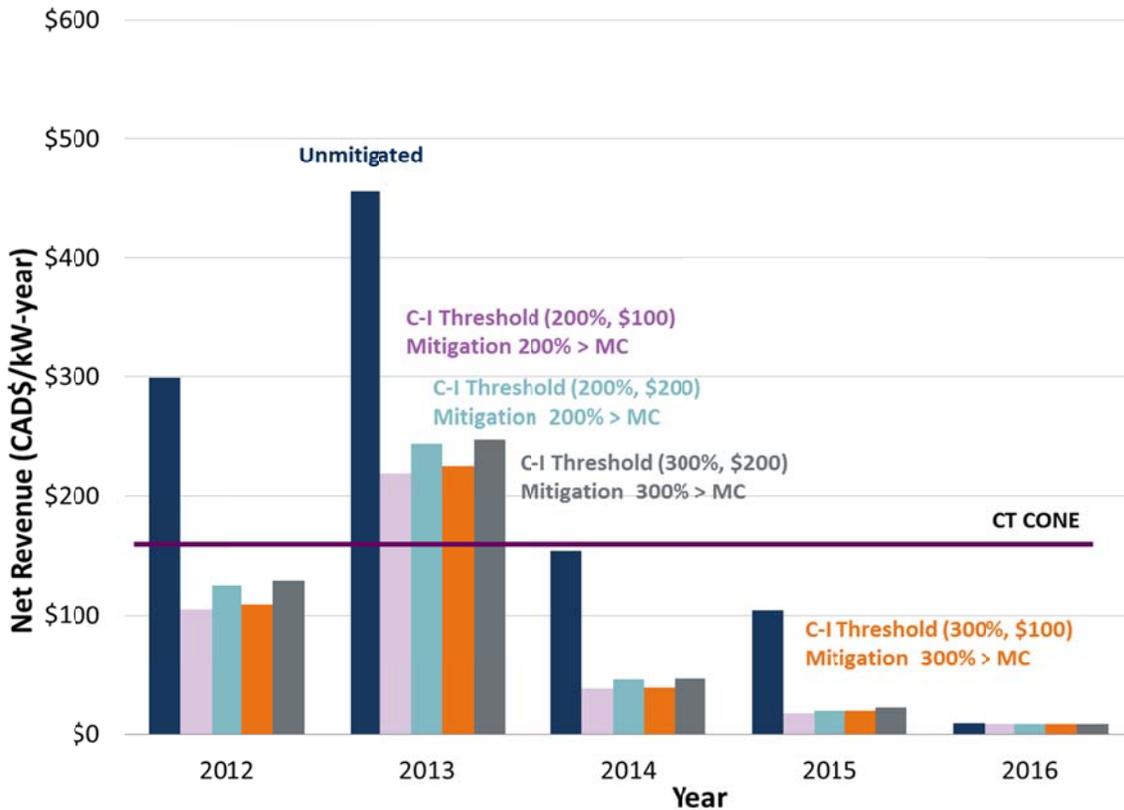
Figure 12 and Figure 13 below compare the estimated net revenue under each option to those of the unmitigated case and the CONEs of new CC and CT units, respectively. We explain our findings below.

Figure 12
Net Energy Revenues of a Reference CC Resource
Under Different Conduct- Impact Test Threshold and Mitigation Scenarios



Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated versus mitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Figure 13
Net Energy Revenues of a Reference Resource CT
Under Different Conduct-Impact Test Threshold and Mitigation Scenarios



Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated versus mitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Based on our analysis, we find that increasing the No-Look Threshold of the Conduct test and mitigated offer from 200% to 300% of marginal cost increases the net revenue of Reference Resources. However, the increases are only approximately 3 percent or less, with the exception of the increase in 2015. For the Reference Resource CC, the 2015 net revenue increases by 6 percent if thresholds and mitigation caps are increased from 200 percent to 300 percent. For the Reference Resource CT, the net revenue increases 12 percent in 2015. This is because the market-clearing prices do not significantly change whether offers that fail the Conduct-Impact test are mitigated down to 200 or 300 percent of the units' marginal costs.

Second, the net revenues of both resources decrease by no more than 17 percent when the price impact threshold is reduced from \$200 to \$100. Figure 14 below shows the Reference Resources' estimated 5-year average revenues at the various combinations of the Conduct-Impact tests thresholds and associated mitigation levels that were implemented using historical data. As we

impose a stricter threshold (\$100/MWh as opposed to \$200/MWh) on the Impact test, the net energy revenue declines.

We find that Reference Resource CC would earn \$114.45/kW-year under the Conduct test threshold of 200 percent and the Impact test threshold of \$200/MWh (Scenario 2), but its net revenue would be \$103.23/kW-year when we reduce the Impact test threshold to \$100/MWh (approximately 11 percent reduction in net revenues). Since we used historical bid levels for marginal resources that set the pool prices, this analysis does not consider any potential impact of bidding behavior changes or changes in the merit order when bidding behaviors change.

Figure 14
Comparison of Five-Year (2012–2016) Average Net Revenues of Reference Resources and Gross CONE by Conduct-Impact Test Threshold and Mitigation Scenario

Scenario	Conduct	Impact	Mitigation	Reference Resource CC			Reference Resource CT		
				(Percent of Marginal Cost)	(Dollars Above Estimated Competitive Clearing Prices)	(Percent of Marginal Cost)	5-Yr Average Net Revenue (\$/kW-yr)	Gross CONE (\$/kW-yr)	Net Energy Revenue as % of Gross CONE
1	200%	\$100	200%	\$ 103.23	\$ 207	50%	\$ 77.62	\$ 159	49%
2	200%	\$200	200%	\$ 114.45	\$ 207	55%	\$ 88.63	\$ 159	56%
3	300%	\$100	300%	\$ 106.39	\$ 207	51%	\$ 80.32	\$ 159	51%
4	300%	\$200	300%	\$ 116.66	\$ 207	56%	\$ 90.52	\$ 159	57%
Unmitigated	NA	NA	NA	\$ 230.56	\$ 207	111%	\$ 204.37	\$ 159	129%

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated versus mitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

As shown in Figure 14, the estimated five-year average net revenues range from 49 percent to 57 percent of the gross CONE. These net revenues are below the levels CCs and CTs would have earned without mitigation by approximately 55 percent and 62 percent, on average. Any remaining fixed cost would need to be recovered through a capacity market.

3. Considerations in Determining Competitive Reference Levels for Supplier Bids

The implementation of a Conduct-and-Impact test requires determining a competitive reference level potentially for each generating unit or supplier, against which a bid is compared for the purpose of identifying abusive conduct. This reference level also may serve as the reference point for the amount by which a bid is reduced when an abuse of market power is identified that fails both parts of the Conduct and Impact test.

The reference level is meant to approximate competitive offers from suppliers that operate in a workably competitive market. The types of commonly used reference levels can be grouped into three broad categories:

- *Bid-Based Reference Levels:* based on average bids from the unit that were accepted in periods when the market is operating competitively;
- *Price-Based Reference Levels:* based on the market-clearing price during periods when the market is operating competitively; and,
- *Cost-Based Reference Levels:* based on the estimated incremental operating costs of the unit (as discussed in the prior section of this report).

In addition, “opportunity costs” may need to be considered when setting cost-based reference levels. For example, with respect to hydroelectric resources or other generation resources that can shift their operations across time to maximize their revenues, the foregone revenue from selling at a different time may need to be considered when setting a cost-based reference level.

When determining a supplier’s opportunity costs, the ISO should consider the physical characteristics of the generating resource, particularly run-time restrictions, operational risk, fuel (or hydro) availability, and other inter-temporal operational tradeoffs. For example, PJM, MISO, and ISO-NE have explicitly included such considerations in determining relevant incremental costs. Accordingly, in PJM, an opportunity cost can be considered in determining a generating unit’s marginal operating cost under three specified situations:

- *Energy Market Opportunity Costs Associated with Environmental Restrictions:* A generating unit with regulatory runtime or heat-input limitations based on environmental restrictions can have its reference costs adjusted for opportunity cost considerations.
- *Physical Equipment Limitations:* PJM may consider “opportunity costs” when there are operating limitations related to physical equipment limitations, and these constraints are appropriately documented (*e.g.*, via an “Original Equipment Manufacturing” recommendation and insurance carrier restrictions).
- *Fuel Limitations:* A unit where a *force majeure* event caused a fuel supply limitation.⁵³

If a resource does not meet any of these conditions, the supplier can still make a special request to PJM for a recovery of its opportunity costs. The PJM Cost Development Guidelines provide the methodology on what a limited resource needs to consider when setting its bid prices. For instance, a pump hydro unit would use its pumping costs, which take into account the operating costs for pumping water, pumping efficiency, and performance factors, in its cost calculation. It also can include an opportunity cost adder. For instance, a pumped hydro storage resource may choose to estimate its opportunity cost adder based either a short (30 days or less) or long-term (greater than 30 days) power price forecast. The choice depends on the resource’s ability to store

⁵³ See Section 12: Energy Market Opportunity Costs & Non-Regulatory Opportunity Cost Guidelines, *Manual 15 Cost Development Guidelines*, pp. 63–64.

energy or shift its output from one period to another. PJM provides the steps for calculating both of these opportunity cost adder methods in its Cost Development Guidelines.

MISO and ISO-NE also have similar rules about submitting opportunity costs as PJM. They allow resources that have economic costs associated with emissions limits, water storage limits, and other operating permits that limit production of energy to add these costs to their marginal operating costs.⁵⁴ In both ISOs, opportunity costs are applicable only to the cost-based reference level.

V. Joint Use of RSI and Conduct-Impact Tests

The RSI screen and the Conduct-Impact test do not have to be used alone. The two approaches can be complementary to each other. For example, a market monitor could benefit from applying an RSI test before applying a Conduct-Impact test because the RSI screen may identify time periods during which specific suppliers have a relatively greater ability and incentive to exercise market power.

Thus, the AESO could combine the two approaches by using the RSI screen to identify those suppliers with the potential for exercising substantial market power, and then evaluate the actual bidding behavior(s) of these supplier(s) (*i.e.*, suppliers who fail the RSI test) via the Conduct-Impact test for purposes of applying mitigation.

Like in ISO-NE, the AESO could apply the Conduct-Impact test to only those who have failed the RSI screen, leading to a more focused application of the Conduct-Impact test. However, this approach would ignore the fact that non-pivotal suppliers may have the ability and incentive to exercise substantial market power under appropriate conditions, thereby running the risk of under-mitigating abuses of market power. Moreover, if the Conduct-Impact test can readily be applied to all bids, then there is no need to use an RSI ahead of a Conduct-Impact test.

Applying an integrated approach of using both the RSI screen and Conduct-Impact test would allow the AESO to assess the effectiveness of its market monitoring and mitigation process over time. The tools will be evaluated periodically to identify adjustments and modifications that could improve the reliability and effectiveness of the applied screens and mitigation.

If an RSI screen and Conduct-Impact test are used together, the choice of when to apply the RSI screen relative the Conduct-Impact test should be based on the purpose of the RSI screen and market characteristics. When the RSI screen is performed far in advance of the specific period of interest, such as a month or more before the actual delivery of power, the screen can be used to identify market conditions that are susceptible to particular suppliers' exercise of market power.

⁵⁴ See Section III.A.7.5.1 of Market Rule 1, ISO-NE; Section 6.9.1, BPM-009, MISO. MISO also explicitly prohibits the inclusion of opportunity cost between products in a supplier's offers. *Id.* Section 6.9.3.

Figure 15
When to Apply an RSI Screen as Part of an Integrated Approach with a Conduct-Impact Test

	Purposes	Advantages	Disadvantages
Day-Ahead/ Real-Time Assessment	<ul style="list-style-type: none"> • To identify pivotal suppliers who are then subject to the Conduct—Impact test. • If passes the RSI, no further test and no mitigation. 	<ul style="list-style-type: none"> • The data used for the screen will be based on actual suppliers’ bids and relevant market conditions. • The screen is performed close to the market-clearing run. This minimizes any mismatch between the timing of the screen that may trigger mitigation and the actual anti-competitive behavior itself. 	<ul style="list-style-type: none"> • It could be costly and administratively burdensome to run, requiring potentially significant software development to implement. • The Conduct and Impact test is not used for suppliers that pass the RSI screen. However, some suppliers may still exercise market power, particularly when the clearing prices absent mitigation are sufficiently high and near the price cap.
Monthly Assessment	<ul style="list-style-type: none"> • To define market conditions that are susceptible to particular suppliers’ exercise of market power 	<ul style="list-style-type: none"> • It informs an ISO in advance where potential market concerns are the greatest. If the capacity data do not change significantly, allowing for a certain level of confidence in the screen results. • It allows pivotal suppliers to bid competitively since they are aware that their bids will be subject to Conduct-Impact test. • It can be implemented outside the actual market run process 	<ul style="list-style-type: none"> • It needs to define carefully the relevant product and geographic markets to correspond with market realities. • The data used to perform the analysis will be based on forecasts, making the screen be vulnerable for mismatching of the screen triggers and mitigation • It needs daily or even hourly reassessment in order to avoid potential inconsistencies in the screen triggered mitigation and actual anti-competitive behavior

VI. Evaluation of Screen Effectiveness and Reliability

This section compares the AESO’s three options that are described in Sections III through V. Their advantages and disadvantages are summarized in Figure 16.

Figure 16
Advantages and Disadvantages of AESO’s Three Options
RSI vs. Conduct-Impact vs. Integrated Use of Both Screens

Type of Tests	Advantages	Disadvantages
RSI Screen	<ul style="list-style-type: none"> • Can be used to identify conditions under which market power concerns are the greatest • Avoids having to set a bid-level or price-impact thresholds to trigger mitigation, which could lead to regulatory errors. 	<ul style="list-style-type: none"> • Does not directly detect whether market power has actually been exercised, which could lead to market inefficiencies if the associated mitigation is overly stringent. • Suppliers may not be able to control the conditions under which mitigation would be implemented. • As a bright line standard, it may fail to mitigate significant exercises of market power that may arise even when a supplier is not pivotal.
Conduct-Impact Test	<ul style="list-style-type: none"> • Explicitly identifies bid and price-impact thresholds that exceed the tolerance levels. • Suppliers can directly control their bid prices based on transparent thresholds. 	<ul style="list-style-type: none"> • The market monitor must determine the “correct” thresholds for both bid levels and the price impact of the bidding behavior, where exceeding these thresholds triggers bid mitigation. • Relies on either an assumed or actually observed cost for each supplier (or unit). • When the thresholds for conduct and impact are overly transparent, concerns exist that suppliers can “game the system” by keeping their exercises of market power just below the mitigation threshold.
Integrated Use of RSI Screen and Conduct-Impact Test—<i>With RSI Screen DA and Real Time Assessment</i>	<ul style="list-style-type: none"> • Minimize potential mitigation errors from the RSI screen alone as the data used for the screen are from actual offer data and almost actual system conditions. • Improve the Conduct-Impact test by taking advantage of structural market information. It informs an ISO where potential market concerns are the greatest, and thereby could lessen the prospect of false negatives. 	<ul style="list-style-type: none"> • It could be costly and administratively burdensome to run, requiring software and IT system modifications as the screen needs to be built into a unit dispatch software. • It could fail to identify a pivotal supplier’s exercise of market power when other suppliers’ also jointly exercise market power (bids offers near or close to the offer cap)
Integrate Use of RSI Screen and Conduct-Impact Test—<i>With RSI Monthly Assessment</i>	<ul style="list-style-type: none"> • It informs an ISO far in advance where potential market concerns are the greatest, and thereby could lessen the prospect of false negatives. • It allows pivotal suppliers to bid competitively since they are aware that their bids will be subject to Conduct-Impact Test • It can be implemented outside the actual market run process 	<ul style="list-style-type: none"> • It needs to carefully define relevant product and geographic markets that represent market conditions with greater concerns • The data used to perform the analysis will be based on forecasts, making the screen be vulnerable for mismatching of the screen triggers and mitigation • It needs daily or even hourly reassessment in order to avoid potential inconsistencies in the screen triggered mitigation and actual anti-competitive behavior

One can choose among these market power screen options. The decision needs to consider the potential inconsistencies of the screen results and the seller's actual behaviors (mitigation error), the expected costs associated with monitoring and mitigating market power, and the costs of evaluating and modifying the monitoring and mitigation processes once experience is gained and market conditions change over time.

We described two types of mitigation screen errors, false alarms and false misses, in Section II.D. Once the likelihood of false alarms and false misses are estimated from various candidate-screening processes, policymakers can choose an appropriate test framework. Some policymakers may view false misses as being much more costly than false alarms and therefore prefer more stringent screens. Over-mitigation would be viewed to be less costly than under-mitigation. For instance, to comply with its legal responsibility under Section 205 of the Federal Power Act to ensure that prices charged in wholesale electricity markets are just and reasonable, the Federal Energy Regulatory Commission (FERC) uses market structure tests to evaluate whether a seller should be granted market-based authority for wholesale sales of electric power. The CAISO also chooses to “err on the side of caution” with its three pivotal supplier test because from its experience false positives have proven to be costly.

On the other hand, some policymakers may choose “an innocent until proven guilty” approach, presuming that competitive conditions exist until a seller shows behavior that is clearly inconsistent with workable competition. NYISO, ISO-NE, and MISO primarily rely on the Conduct-Impact test, while CAISO, PJM and ERCOT primarily rely on structural screens.⁵⁵ Regardless, relatively little research to date has been devoted to comparing the impact on market efficiency of structural and behavioral (*e.g.*, Conduct-Impact) approaches to the detection and mitigation of market power.

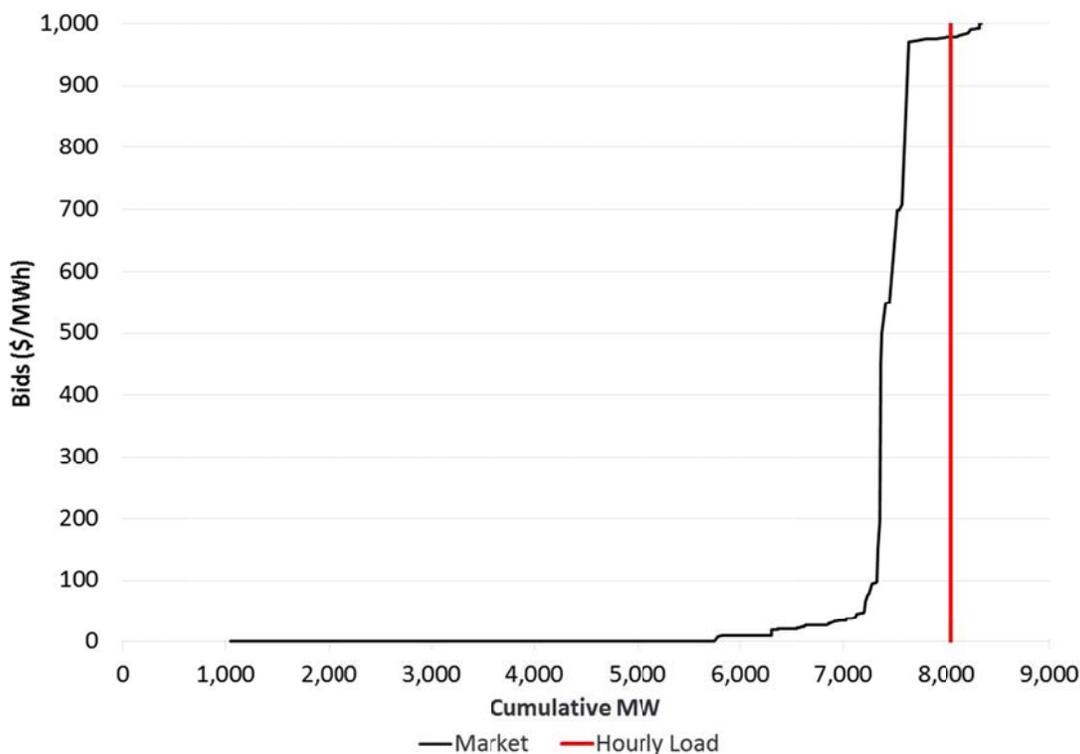
Below in Figure 17, we illustrate an example of AESO's supply offer curve during a high demand hours. The shape of the upper-end of the bid curve, between 7,500 MW and 8,000 MW, is quite flat. This suggests that, even when demand is relatively high, the certain high-priced bids may not affect the market-clearing prices and therefore would not be mitigated down to the reference levels. However, in this same hour, the RSI screen would have detected several suppliers to have unilateral market power and that the market condition was such that several suppliers had bid their resources at very high prices. If automatic mitigation were implemented, the RSI threshold at 1.0 (or higher) would have provided a stronger mitigation than the Conduct-Impact test.

For the Conduct-Impact test to protect against the situation shown in Figure 17, the Impact test may be performed simultaneously for all failed bids from all suppliers. For example, if two suppliers fail the Conduct test, both suppliers' failed bids may individually pass the price impact test as the price effect of each supplier, say CAD\$90/MWh, is below the Impact No-Look threshold of \$100/MWh. However, if the Impact test is used to evaluate the price impact of both

⁵⁵ For a survey and discussion of market monitoring and mitigation approaches in U.S. regional wholesale power markets see Federal Energy Regulatory Commission (2017) and Reitzes et al. (2007).

suppliers' bids simultaneously, their combined price effect could be larger than an individual's price effect and fail the Impact portion of the test. Thus, this simultaneous impact testing approach can detect potential exercise of multi-lateral market power from suppliers' coordination.

Figure 17
Example of AESO Market Offer Curve



VII. Mitigation Measures

When an *ex-ante* screen detects a supplier's potential exercise of market power, market monitors or automated mitigation processes will tend to impose its mitigation measure to insure workable competition in that dispatch period. The scope of mitigation, however, could apply to all bids of the failed supplier or to a specific failed bid. This depends upon a market power screen design. Either method modifies bids to mitigated price levels.

A. SCOPE OF MITIGATION UNDER DIFFERENT MARKET POWER SCREEN DESIGNS—RSI SCREEN VERSUS CONDUCT-IMPACT TEST

The difference in market power screen designs may lead to a different scope of mitigation. Specific bids of a supplier may be mitigated rather than the supplier's entire portfolio of bids. This is because some screens detect specific market behaviors while others may detect market conditions that lead to the sellers' exercise of market power.

For an RSI screen, all bids of a pivotal supplier in a defined relevant market will be mitigated. An RSI screen examines a market condition that is conducive to a pivotal supplier's exercise of market power. As a result, all of pivotal supplier's bids are deemed to be non-competitive bids. This may be different from the Conduct-Impact test in that it finds a supplier's specific bids are deemed to be anti-competitive conduct. To demonstrate the difference of the two mitigation applications, we provide the following example. Suppose in a defined relevant market a supplier owns and controls one resource. The supplier submits eight bid blocks from two resources (four blocks for each resource). When an RSI screen finds the supplier to be pivotal, all eight bid blocks will be subject to mitigation for the duration that the supplier fails the screen.

In the case of the Conduct-Impact test, two of four bid blocks of one resource fail the test, mitigation could be imposed to either: (1) those two failed bids, (2) the entire resource of the failed bids (*i.e.*, all four bid blocks), or (3) the entire portfolio of the supplier who fails the test. MISO and ISO-NE, for instance, mitigate all resources owned by the same supplier when one of the supplier resources fail the Conduct-Impact test in a day-ahead market.⁵⁶ In the real-time market, MISO mitigates only bids that fail the test.⁵⁷

However, mitigation under a certain RSI design may be imposed only on a specific or a subset of a pivotal supplier's offers instead of its entire portfolio of offers. This nuance is because of the relevant geographic market definition on which an RSI test is applied. In CAISO, for example, it defines a relevant market as a local market area where a binding transmission constraint exists. The CAISO uses a three-pivotal supplier test on binding constraints or local market areas. The three-pivotal supplier test triggers when it finds incremental offers of a supplier that are needed to serve load or relieve a binding transmission constraint in a defined local market area. Thus, only these incremental offers of a pivotal supplier that can relieve congestion would be mitigated, not the pivotal supplier's whole portfolio offers that may or may not be used to serve the relevant market. PJM applies a three-pivotal supplier test where load pockets exist in its wholesale markets. The slight difference between the PJM and the CAISO mitigation scopes is that while the CAISO applies its mitigation to a pivotal supplier's incremental bids that relieve a binding transmission constraint, PJM imposes mitigation on the entire generating unit of a pivotal supplier's incremental offer.

B. DEFAULT BIDS

A default bid is designed as if a mitigated supplier were to offer its supply under workable competition. They are used to cap bids that are deemed to be non-competitive. There are three main forms of default bids. They are described below.

⁵⁶ See Section 8.1.1 2), Market Monitoring and Mitigation Business Practices Manual, BPM-009-r12, Effective Date: July 15, 2017, p. 69, Section III, Market Rule 1, ISO-NE.

⁵⁷ See Section 8.1.2, Market Monitoring and Mitigation Business Practices Manual, BPM-009-r12, Effective Date: July 15, 2017, p. 70.

1. Accepted Offer-Based Reference Level

The accepted offer-based reference level is calculated based on the average or the median of a supplier's offers that were accepted during competitive periods of economic merit-order dispatches over the past 90 days. The reference level will be adjusted for changes in fuel prices.

2. Market Price-Based Reference Level

The market-clearing price-based reference level is calculated based on the average of the market-clearing price during the lowest-priced 25 percent of the hours that the mitigated generating unit was dispatched over the past 90-days. The reference level will be adjusted for changes in fuel prices.

3. Cost-Based Reference Level

The cost-based reference level is based on a mitigated unit's incremental costs plus bid adders. The incremental costs consist of a mitigated unit's fuel cost, variable O&M expense, emissions cost, and grid management expense. For some U.S. ISOs, suppliers facing output restrictions due to their resources' technical limitation or regulatory restrictions can recover their opportunity costs. Some U.S. ISOs also use the cost-based reference level for generating units that are frequently mitigated.

In most of the U.S. ISOs, suppliers faced with mitigation have rank-ordered options of their mitigation choice. For instance, in the CAISO, suppliers could choose their preferred ranking of a cost-based, negotiated rate option, or market-clearing price-based default bids. If the suppliers do not specify the order, the default rank order is (1) variable cost-based; (2) negotiated rate;⁵⁸ and (3) market-clearing price.⁵⁹ In contrast, ISO-NE, NYISO, and MISO, choose the accepted-offer based reference level method as their first choice. For example, the ISO-NE market monitor has the hierarchy method to calculate mitigation bids: (1) a supplier's accepted offer-based; (2) market price-based; and (3) cost-based reference levels. However, ISO-NE will allow cost-based reference levels to be default bids when a mitigated supplier requests the use of the cost-based reference level or if the cost-based reference level is higher than the first two options.⁶⁰

C. MITIGATION OF RESOURCES WITH OPPORTUNITY COSTS

Like any other resources, an ISO should monitor bids of energy-limited resources by comparing their bids to their reference levels. Under the cost-based reference level, the resource's marginal

⁵⁸ A supplier may propose a default rate along with supporting documents. The CAISO may or may not accept the proposed rate. If both the CAISO and the supplier disagree, they will request the FERC to decide the default rate.

⁵⁹ See Section 39.7.1 Calculation of Default Energy Bids, CAISO Tariff, May 2017.

⁶⁰ See other conditions in Section III.A.7.2.2 of Market Rule 1.

cost is the sum of its incremental energy cost plus opportunity costs, which include the economic costs associated with regulatory compliance and technical limitation.

An opportunity cost is a foregone value (revenue) of its best next alternative when it sold its output into a market in a given hour. For an energy-limited resource, they can operate only a fixed number of hours. When selling energy in one hour, it forecloses the opportunity to sell in another hour. A storage hydro generation, for instance, has the ability to shift its electricity generation from off-peak to peak hours, and/or from one month to another month, depending upon the size of its water reservoir. Sellers bidding energy-limited resources will try to structure their bids to sell their energy in the highest priced hours, if they have flexibility to do so. If a seller decides to sell its output today, its opportunity cost, for example, would be the potential revenue that it has to forego on its sales during peak hours tomorrow, if it has, say, only 8 hours of water storage time and needs more than 24 hours to refill its reservoir. For a hydro plant with larger reservoirs, its opportunity cost would be the forgone revenue of next month sales because the plant has more flexibility and less operational constraints.

PJM's Cost Development Guideline provides an explanation on how it would quantify opportunity cost adders for resources with economic, regulatory, and non-regulatory restrictions. Broadly speaking, its methods rely on forward gas and electricity prices, which could be based on daily or longer-term forward prices.⁶¹ The CAISO however requires suppliers to submit their opportunity cost data as part of their requests to have negotiated rates as their default mitigation bids.⁶²

Consequently, operating characteristics or restrictions of energy-limited resources are important for an ISO and its market monitor to understand in order to determine the opportunity costs of these resources, which, in turn, justify their competitive reference levels. Thus, to properly dispatch and monitor energy-limited resources, an ISO requests from each resource the information related to regulatory, environmental, technical, or other restrictions or other operating characteristics that limit the resource availability or run-time. For example, market sellers in PJM offering energy from hydropower can submit data to the Office of Interconnection to determine the available operating hours of such facilities.⁶³ The CAISO, for instance, to approve a resource as "a use-limited resource" it will review the resource's historical data and the explanation of why the resource has operating limitations.⁶⁴ When the energy-limited resources bid into the CAISO market, they must provide the daily energy limit so that the CAISO would know when and how to schedule and dispatch them.

⁶¹ See *supra* at Section IV.D.3.

⁶² See Section D.6.2, *CAISO Business Practice Manual for, Market Instrument*, October 30, 2017.

⁶³ See PJM Manual 15: Cost Development Guidelines, pg.4.

⁶⁴ See Section 40.6.4.1 Registration of Use-Limited Resources, California Independent System Operator Fifth Replacement Electronic Tariff, March 10, 2017.

Appendix A: Ex-Ante RSI Methodology

An RSI screen evaluates whether an examined market is competitive. If there is sufficient supply to meet demand after excluding a particular supplier's supply portfolio under examination, the market is considered workably competitive, and that supplier passes the RSI screen; if not, the supplier is subject to mitigation.

We explain a few RSI calculation options that the AESO could use for its ongoing market monitoring and mitigation process. We present in Section III.B a list of considerations to improve the use of the RSI approach and formula provided in Equation [1]. In addition, in Section V we describe an option for using the RSI screen along with the Conduct-Impact test.

In this appendix, we describe the steps to implement an RSI screen, focusing on: (A) an *ex-ante* monthly RSI assessment; (B) an *ex-ante* hourly RSI assessment; and (C) an *ex-post* hourly RSI assessment.

A. EX-ANTE MONTHLY RSI ASSESSMENT

The purpose of using an *ex-ante* monthly RSI assessment is to identify far in advance the market conditions under which a supplier can exercise market power. Because the assessment is forward-looking, forecast data and assumptions will be used.

The steps for calculating monthly RSI assessment are as follows:

Step 1: Define a relevant product

Relevant products are those electricity products that may be grouped together when they are good substitutes for each other from the buyers' perspective. The relevant products should reflect the substitutability of the product market being analyzed. In electricity markets, the demand for, and the supply of, electricity varies by month, day, and even time-of-day. Thus, for the purposes of the market power analysis, the relevant products should represent market conditions that could be of concern at various times of year and day (such as peak, and off-peak).

The AESO plans to implement a market power screen that monitors its spot energy and ancillary services markets. These markets are operated on an hourly basis or even in a shorter time frame. The demand for, and the supply of, electricity vary in each of these time intervals, and thus yield different market-clearing prices or potential distinct product markets. A market power screen can be applied for each time interval. For the monthly assessment, one could choose to group similar time intervals together based on similar load hours or similar price hours. In some analyses, a product's delivery hours can be used as a way to group a similar product. Using this definition, one could define a relevant product.

We offer the following guidelines for defining a relevant product market:

- Ancillary services capacity can provide energy, but not all resources offered in an energy market can provide ancillary services. Thus, a relevant product market for regulation capacity services will not be the same as that for energy.
- The relevant products can be grouped by similar time periods for an examined month.
- There could be more than one relevant product within each examined month. This would depend on the AESO's system conditions that would give rise to seller anti-competitive behavior.
- The concerned market conditions could be captured based on similar periods of (1) load levels and/or (2) prices. For example, we can use a statistic, such as an average of the highest top 10 percent hours of load/price within each month.⁶⁵
- Given that the analysis would be forward-looking, the load and price data will be based on forecasts. The price forecasts could be derived from monthly forward electricity prices. If those are not available, derived electricity prices from monthly forward prices of fuel that is expected to be on a margin could be used.

Step 2: Define a relevant geographic market

In an area where there is no transmission constraint, a geographic market can be defined as a Balancing Authority area plus the simultaneous transfer capability that would be available for imports.^{66,67} But a transmission network could be constrained during certain hours due to its operating system conditions. All suppliers within a balancing authority may not be able to reach load. Under such circumstance, only certain resources that can offer power to serve load in the constrained area are meaningful competitors. Thus, a default geographic market would become smaller as the constrained transmission limits power to flow into the other side of a binding constrained area.

For the purpose of their *ex-ante* day-ahead and real-time market monitoring and mitigation procedures, the U.S. ISOs have defined their relevant geographic markets to be smaller than the default definition. PJM, as an example, defines the relevant market as all offers with cost-based

⁶⁵ In its market power analysis for granting market-based authority to sellers, the U.S. Federal Energy Regulatory Commission requires a relevant product for its pivotal supplier test to be an average daily peak load of an annual peak month. See Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy, 107 FERC ¶ 61,018 (2004). The FERC uses this one single snapshot to determine a pivotal supply. It requires the analysis to be performed using an historical study period.

⁶⁶ See an example in Affidavit of Dr. Romkaew Broehm on behalf of Pacific Gas & Electric Triennial Market-Based Rate Update Filing, Docket No. ER10-1107, (2015).

⁶⁷ This definition is often used as a default geographic market definition in the market power analysis of the FERC. 107 FERC ¶ 61,018 (2004).

bids less than or equal to 1.50 times the competitive clearing price for the local market.⁶⁸ The ISO-NE defines a relevant geographic market as a constrained area in the real-time energy market when resources are imported into a transmission constrained area. The ISO-NE defines an area as constrained when the market clearing price of the constrained area exceeds the non-constrained area by more than \$25/MWh.⁶⁹

We therefore recommend examining the potential for narrower geographic sub-markets developing in the future when consistent transmission constraints exist.

Step 3: Define potential suppliers in a relevant geographic and product markets

The screen should take into account all suppliers offering into the AESO short-term energy market.⁷⁰ All potential suppliers to a specific market should be included in assessing the RSI.

Step 4: RSI Formula

The equation below is consistent to Equation [2] cited in the above report:

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

Supply_{jt} = Total Market Capacity at Time *t*

Imp_{it} – Total Import Capacity at Time *t*

Supply_{it} = Total Supplier *i*'s Capacity at Time *t*

Imp_{it} – Total Supplier *i*'s Import Capacity at Time *t*

Obligation_{it} – Total Supplier *i*'s load and long-term sales obligations at Time *t*

Total Demand_t – Total Market Demand at Time *t*

Exp_t = Total Exports at Time *t*

Reserves_t = Total Reserves at Time *t*

⁶⁸ PJM's relevant geographic market definition is based on the FERC's delivered price test, which is the main market power test for analyzing an impact of a proposed mergers and acquisition transaction on competition and for sellers who fail its initial market-based rate test, known as indicative screens.

⁶⁹ See Section III.A.5.2.2, *Market Rule 1*, the ISO-NE, (2017).

⁷⁰ The AESO energy market has a Must Offer requirement.

Step 5: Determine data used for the RSI monthly assessment

To conduct an *ex-ante* analysis, the *Supply* of each supplier at a given time t is its total capacity derived from the capacity of each of its generating units adjusted by known outages, and the operational and regulatory restrictions of each unit.

Capacity: This is the total capacity that each supplier owns and controls, including all operating and standby units. A generating unit that is jointly owned by more than one supplier should have its MW allocated appropriately across the owners and across the owners' rights to submit offers in the market. The MW measure used in the RSI calculation should be consistent across all units (for example, nameplate, or seasonal MW).

Known Outages: Because a supplier may derate or have a certain generating unit offline for maintenance, the actual output capability of a generating unit could be less than its rated capability. When calculating the RSI, if specific planned or unplanned outages are known and expected, the capacity used to calculate each supplier's *Supply* should be adjusted accordingly. (The information should be available as an ISO requires its market participants to report planned outages in advance and unplanned outages when they occur.) Experience has shown that suppliers may use an unplanned outage as a reason for physical withholding.

Total Market Demand: This is a demand for the product in the defined market. When an forward-looking RSI is being used, the demand information will be based on a forecast.

Obligation: This is the estimated amount of load that each supplier is committed to serve and the long-term sales obligations that the supplier must purchase from the market to meet. Each supplier's load data should be forecasted in a consistent manner as that of *Total Market Demand*. The long-term sales information could be obtained from historical data, if any is available.

Imports: The amount of import should be estimated based on the amount of available transfer capacity (based on simultaneous import limit) that can be used to deliver into the geographic market. The simultaneous import limit could vary across time. The amount of imports to tie into the RSI calculation is equal to the minimum of the available imports, and the simultaneous import limit.

Treatment of renewable and hydro resources: In the case of hydroelectric, renewables (such as wind and solar), geothermal, and cogeneration, since the generation capability depends on the weather, resource availability, environmental regulations, and other external factors. In these cases, their generating capabilities should be adjusted appropriately when considered in the RSI calculation. If the forecast data are not available, one could use historical net generation data to estimate the capacity factors for the various types of renewable and hydro resources.

B. EX-ANTE HOURLY RSI ASSESSMENT

The *ex-ante* hourly RSI assessment follows the same steps as the monthly RSI assessment, with the exceptions that:

- The assessment can be performed using hourly energy offers and close to actual system operating data; and
- The hourly relevant geographic market can be determined directly based on the existence of transmission constraints or local markets. For instance, the CAISO and PJM apply their pivotal supplier tests on transmission constraints.

Some Considerations for Applying Ex-Ante Hourly RSI in the AESO Energy Market

The AESO energy market is a real-time energy market without a day-ahead energy market although it operates a day-ahead ancillary services market. Market participants submit their bids two hours prior to a delivery hour. The hourly RSI screen can be implemented after suppliers submit their offers.

Identified Issue:

Some suppliers that own and control generating units with a long start-up times may offer their resources at very high bids in order to not being dispatched. In some cases, this could be a form of economic withholding.

In a circumstance under which the RSI screen detects this supplier as a pivotal supplier, all offers of this pivotal supplier would be subjected to mitigation, including the high offer from a long-startup-time resource. The mitigation will not be effective as the pivotal supplier will not be able to dispatch the resource to meet the market's needs.

Possible Solutions:

1. Consider pre-approving the resource's operating constraint and costs and running the screen before the time period when the supplier has to start up their resources to operate in the target hour. If they fail the screen, notify them about their screen failures and that their resources will have to be bid in at the mitigated levels (which could be a negotiated rate).
2. Conduct the RSI screen for the day-ahead ancillary services markets. If a supplier with long-lead time resources fails the RSI screen in the ancillary services markets, the supplier is subjected to mitigation for both energy and ancillary services.
3. Apply the screen but flag the incidents for further ex-post investigation only. Then assess and potentially fine their conduct ex-post.

C. HOURLY RSI ASSESSMENT

In this section, we describe the hourly RSI screen and mitigation analysis. Similar analyses could be employed by market monitors on an after-the-fact basis.

1. Methodology and Assumptions

Generally, we screen suppliers with historical bids between 2012 and 2016 based on an RSI less than or equal to 1.0 threshold. For all suppliers that fail this RSI test, we mitigate their bids down to a multiple of their marginal cost. We effectively follow the same steps as those described in the monthly assessment with some assumptions and adjustments. They include:

- We defined the relevant product market as the hourly energy product and the relevant geographic market as the AESO footprint plus available imports.
- We used actual hourly bids to estimate each supplier's capacity.
- We estimated the Total Market Demand in each hour by summing up all MW offers that cleared in the energy market.
- We observe that the suppliers who submitted import bids historically are price takers (submitted all imports at \$0). Thus, we have included all imports as available supply.
- We observe that the suppliers who purchased power from the AESO energy markets for exports also submitted their resource offers as price takers. We therefore include neither the suppliers' export MW offers as part of the AESO available supply nor the amounts that were cleared for export as part of the AESO market demand.
- Separate from the bid data, AESO provided ownership information from 2012 to 2017 for a majority of the units. The ownership data identifies the owner(s) of those units for each year, along with the proportion of the unit's capacity that is controlled by each owner. The ownership information was not provided for all years. When the ownership data is lacking, we used the ownership information from the most recent year's data.
- We do not have ownership data for some small units. We therefore do not perform the RSI calculations for those small suppliers. However, we include their bids in the total market supply.

Our *ex-post* hourly calculation has some limitations due to the data availability. Most importantly, we do not have any data on the supplier's load or long-term sales obligation. We also do not have the amount of reserve in each hour. Thus, our RSI calculated in this report is:

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

2. Data

The data used in this analysis was provided by the AESO. The primary dataset includes the hourly bids in the AESO market (including imports and exports), for the period March 28, 2012 to July 31, 2017. The data includes bids for each specific generating unit, including the number of MW offered and the number of MW that were ultimately dispatched, as well as the price of the bids and a flag if the unit is an importer or exporter.

Unit-specific data on heat rate, technology, and cost were provided by AESO for a majority of the units. Included in the data provided are annual coal prices for a variety of types of coal, as well as monthly gas prices over the same period across 2012 through 2017. All prices and costs are in Canadian dollars.

3. Reference Resources' Estimated Dispatch and Net Revenues

Below in the tables are the estimated capacity factors and net energy revenues for a reference CC and CT, after simulating an RSI screen and associated mitigation. The mitigation levels considered in this analysis are 200% and 300% of the estimated marginal costs.

Scenario 1: Mitigation to 300 Percent of Marginal Cost								
	Reference Resource CC				Reference Resource CT			
	Capacity Factor		Net Revenue (\$/kW-year)		Capacity Factor		Net Revenue (\$/kW-year)	
	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated
2012	52.86%	38.97%	\$319.22	\$103.29	32.63%	22.56%	\$298.83	\$84.28
2013	63.58%	61.27%	\$495.08	\$212.60	40.68%	35.56%	\$455.52	\$176.03
2014	47.77%	42.38%	\$191.38	\$47.52	20.71%	10.04%	\$153.75	\$19.99
2015	48.14%	46.09%	\$122.44	\$27.41	17.32%	15.29%	\$104.44	\$10.93
2016	53.43%	52.96%	\$24.68	\$22.08	22.13%	21.35%	\$9.30	\$7.10
Average	53.16%	48.34%	\$230.56	\$82.58	26.69%	20.96%	\$204.37	\$59.67

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Scenario 2 : Mitigation to 200 Percent of Marginal Cost								
	Reference Resource CC				Reference Resource CT			
	Capacity Factor		Net Revenue (\$/kW-year)		Capacity Factor		Net Revenue (\$/kW-year)	
	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated
2012	52.86%	37.67%	\$319.22	\$90.44	32.63%	15.49%	\$298.83	\$75.35
2013	63.58%	57.73%	\$495.08	\$189.18	40.68%	19.90%	\$455.52	\$163.26
2014	47.77%	26.16%	\$191.38	\$29.06	20.71%	3.25%	\$153.75	\$17.90
2015	48.14%	45.96%	\$122.44	\$19.99	17.32%	12.79%	\$104.44	\$3.82
2016	53.43%	52.89%	\$24.68	\$20.04	22.13%	19.62%	\$9.30	\$5.55
Average	53.16%	44.08%	\$230.56	\$69.74	26.69%	14.21%	\$204.37	\$53.17

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Appendix B: Calculation of Commitment Cost and Marginal Cost

The commitment cost considered in this analysis represents the sum of the (1) start-up, (2) shutdown, and (3) no-load cost (taking into account an assumed run time). We explain how we derived each component for a typical CC, coal, and CT units below.

A. METHODOLOGY

1. Start-Up Cost

A thermal generating unit needs to bring its equipment (such as boiler and turbine) from shut down conditions to the point where it can begin generating MW output. The cost of starting up the equipment include the cost of start fuel and non-fuel related costs, such as start maintenance and electrical costs for services at the station (auxiliary power, water, chemicals, *etc.*).

$$\text{Start-Up Cost} = \text{Start Fuel Need} * \text{fuel price} * \text{MinMW Start} + \text{Non-Fuel Related Cost} \quad [\text{B.1}]$$

Thermal units often are constrained to slow starts due to the need to ensure only gradual changes in equipment temperature. The ability to start a thermal unit slowly or quickly depends upon the unit's temperature at a start time relative to its required operating temperature. If the unit has been turned off more than 72 hours, for example, its equipment would have cooled off and the "cold" startup process would be more timely and costly than a "hot start" after only a 1–2 hours shut down period or a "warm start" after 7–8 hours. The amount of fuel used to start a unit therefore will differ according to these start-up types.

2. No Load Cost

Generating plants, whether as coal or CC plant, have a minimum level of output below which it cannot operate to serve load. The plant is generally less efficient at this minimum generation or "no-load" threshold.

$$\begin{aligned} \text{No Load Cost (CAD\$ per hour)} \\ &= \text{Minimum MW} * [\text{No Load Fuel (gigajoules per hour)} \\ & * \text{fuel price (CAD\$ per gigajoule)}] + \text{Non – Fuel Related Cost} \end{aligned}$$

Operating the plant at that no-load level thus is costly on a \$/MWh basis than operating the plant at its full output. This also means that the incremental cost of increasing output above the no-load level will be lower on a \$/MWh basis than either the no-load cost or the full-load cost of the plant.

3. Shutdown Cost

A unit may require to be ramped down slowly during the shutdown process. The shutdown process thus also incurs fuel costs even though the generating unit is not serving any load.

Shutdown cost (CAD\$) = [shutdown gigajoule × CAD\$/gigajoule fuel price].

B. DATA AND ASSUMPTIONS

In our analysis, we calculate each component of the commitment costs for typical CC and coal units based on hot and cold starts using the methodology explained above. We explain the data and assumptions used in calculating each component in Table B-1.

Table B-1
Assumptions and Data Sources of Commitment Costs

Components	Assumptions	Data	Sources
Start-Up Cost (\$/Start/Cycle)			
CC Start fuel (GJ/MW/start)	Average fuel used of a typical CC in Alberta For cold start, we assume the value for CC Steam based on NREL (2012), using the conversion of 1 MMBtu = 1.0556 GJ	Hot Start: 3.9 GJ/MW/start Cold Start: 9,418GJ/MW/start	AESO for CC Hot Start NREL (2012) Table 1-3 for Cold Start
Coal Start Fuel (GJ/MW/start)	Average fuel used of a typical Coal in Alberta For Coal with High Commitment Cost, we used the maximum start-up fuel burned of a coal unit in Alberta..	Typical Coal Start: 11.38 GJ/MW/start Coal High Start: 18.04 GJ/MW/start	AESO
CT Start Fuel	Median fuel used of a new simple cycle in Alberta	Start: 1.90 GJ/MW	AESO
Gas price (CAD\$/GJ)	Spot gas price delivered at AECO Storage Hub	CAD\$2.06/GJ	SNL
Coal price (CAD\$/GJ)	Coal price delivered at AESO	CAD\$0.90/GJ	AESO
CC Non-Fuel Start-Up Related Cost (CAD\$/MW/Start)	It is the sum of O&M and other start-up costs such as auxiliary power, water and chemicals. Median Hot Start O&M 75 Percentile Cold Start O&M Exchange Rate U.S.\$1=CAD\$1.2618	Hot O&M: CAD\$44.16 Cold O&M: CAD\$127.44 Hot Other Cost: CAD\$5.03 Cold Other Cost: CAD\$14.43	NREL (2012): Table 1-1 Typical low bound costs of cycling and other data for various generation types, and Table 1-3 Start-up fuel and other start-up costs
Coal Non-Fuel Start-Up Related Cost (CAD\$/MW/Start)	Median Hot Start 75 Percentile Cold Start Exchange Rate U.S.\$1=CAD\$1.2618	Hot: CAD\$74.44 Cold: CAD\$156.46 Hot Other Cost: CAD\$7.08 Cold Other Cost: CAD\$12.81	Table 1-1 Typical low bound costs of cycling and other data for various generation types, NREL (2012)
CT Non-Fuel Start-Up Related Cost (CAD\$/MW/Start)	It is the sum of O&M and other start-up costs such as auxiliary power, water and chemicals. Median Cold Start O&M Exchange Rate U.S.\$1=CAD\$1.2618	Cold O&M: CAD\$15.14 Other Cost: CAD\$2.40	NREL (2012): Table 1-1 Typical low bound costs of cycling and other data for various generation types, and Table 1-3 Start-up fuel and other start-up costs
No Load Cost (\$/Start/Cycle)			
Maximum Capacity (MW)	Large CC and Coal	400 MW	AESO

Components	Assumptions	Data	Sources
Minimum Generation (MW)	40 percent of Maximum Capacity	CC: 160 MW Coal: 160 MW Coal High: 214 MW	
Heat Rate at Minimum Generation (GJ/kWh)	Average and Maximum heat rates of AESO units at the first heat rate block for Coal and Coal High, respectively.	CC: 6,700 Coal: 11,482 Coal High: 15,137	AESO
Variable O&M (CAD\$/MWh)	Average values of variable O&M costs of AESO units	CC: CAD\$4.92 Coal: CAD\$6.30	AESO
Commitment Time	Average Values of AESO units	CC: 8.67 hours Coal: 600 hours	Based on ABB, Inc..
Shutdown Cost (\$/Cycle)			
Shutdown Fuel (GJ/MW/Cycle)	Brattle's assumption	CC: 1 GJ/MW Coal: 3 GJ/MW	Brattle's assumption
Marginal Operating Cost (CAD\$/MWh)			
Variable O&M (CAD\$/MWh)	Average variable O&M cost for a new CC and coal units in Alberta	CC: CAD\$4.92 Coal: CAD\$6.30 CT: CAD\$6.00	AESO
Heat Rate (GJ/kWh)	Incremental heat rate after minimum load based on median values	CC: 5,996 Coal: 10,659 CT: 9,155	AESO
Average Run Time @ Full Output (Hours)	Once a CC operates at its minimum level (40% of its output), it would be dispatched at full output level for the entire period of its minimum up time requirement.	CC: 8.67 hours Coal: 120 hours	Based on Abb, Inc.

C. RESULTS AND SENSITIVITIES

Tables B-2 to B-5 summarize each of these cost components for different plants and startup conditions.

**Table B-2
Start-Up Costs**

Gen Type	Capacity	Min Gen	Start Fuel	Fuel Price	Start Fuel Cost	Non Fuel Start Cost		Total Start-Up Cost
	MW	MW	(GJ/MW)	(CAD\$/GJ)	(CAD\$/Start)	(CAD\$/MW)	(CAD\$/Start)	(CAD\$/Start)
	[1]	[2]	[3]	[4]	[5]=[2]x[3]x[4]	[6]	[7]=[6]x[2]	[8]=[5]+[7]
CC-Hot	400	160	3.90	2.06	\$ 1,288	\$ 49.20	\$ 7,872	\$ 9,160
CC-Cold	400	160	9.42	2.06	\$ 3,107	\$ 141.88	\$ 22,700	\$ 25,808
Coal-Hot	400	160	11.38	0.90	\$ 1,644	\$ 81.52	\$ 13,044	\$ 14,688
Coal-High Commitment Cost	400	214	18.04	0.90	\$ 3,484	\$ 169.27	\$ 36,224	\$ 39,708
CT	100	0	1.90	2.06	\$ 392	\$ 17.54	\$ 1,754	\$ 2,146

**Table B-3
Shutdown Cost**

Gen Type	Capacity	Min Gen	Shutdown Fuel	Fuel Price	Shutdown Cost
	MW	MW	(GJ/kWh)	(CAD\$/GJ)	(CAD\$/Cycle)
	[1]	[2]	[3]	[4]	[5]=[3]x[4]
CC	400	160	1,000	2.06	\$ 2,062
Coal	400	160	3,000	0.90	\$ 2,707

**Table B-4
No Load Cost**

Gen Type	Capacity	Min Gen	Heat Rate	Fuel Price	No Load Fuel Cost	Variable O&M	Total No Load Cost
	MW	MW	(GJ/kWh)	(CAD\$/GJ)	(CAD\$/MWh)	(CAD\$/MWh)	(CAD\$/Start)
	[1]	[2]	[3]	[4]	[5]=([3]x[4])÷1,000	[6]	[8]=([5]+[6])x[7]x[2]
CC	400	160	6,700	2.06	\$ 13.82	\$ 4.92	\$ 25,981
Coal	400	160	11,482	0.90	\$ 10.36	\$ 6.30	\$ 1,599,481
Coal-High Commitment Cost	400	214	15,137	0.90	\$ 13.66	\$ 6.30	\$ 2,562,907

**Table B-5
Marginal Operating Cost**

Gen Type	Fuel Price	Heat Rate	Fuel Cost	VOM	Marginal Cost
	(CAD\$/GJ)	(GJ/MWh)	CAD\$/MWh	CAD\$/MWh	(CAD\$/MWh)
	[1]	[2]	[3]=[1]x[2]	[4]	[5]
CC-Hot	2.06	6.0	\$ 12.36	\$ 4.92	\$ 17.28
CC-Cold	2.06	6.0	\$ 12.36	\$ 4.92	\$ 17.28
Coal-Hot	0.90	10.7	\$ 9.62	\$ 6.30	\$ 15.92
Coal-High Commitment Cost	0.90	10.7	\$ 9.62	\$ 6.30	\$ 15.92
CT	2.06	9.2	\$ 18.88	\$ 6.00	\$ 24.88

Table B-6 summarizes our estimated ratios of average costs to marginal operating costs for these CC, coal, and CT units and the assumed typical dispatch periods. It shows that, in the case of a CT dispatched for 30 minutes, the average cost over the course of a dispatch cycle is up to 2.7 times the CT's marginal cost.

Table B-6
Ratios of Average Costs to Marginal Costs

Gen Type	Total Start-Up Cost	Shutdown Cost	Total No Load Cost	Total Commitment Cost	Marginal Cost	Output @ Full Load	Average Incremental Output	Assumed Run Time @ Full Output	Total Cost	Average Cost	Ratio of Average Cost to MC
	(CAD\$/Start)	(CAD\$/Cycle)	(CAD\$/Start)	(CAD\$/Start/Cycle)	(CAD\$/MWh)	MW	MW	Hours	(CAD\$)	(CAD\$/MWh)	
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]=[4]+([5]x[7]x[8])	[10]=[9]/[6]	[11]=[10]/[5]
CC-Hot	\$ 9,160	\$ 2,062	\$ 25,981	\$ 37,202	\$ 17.28	400	240	9	73,152	\$ 21.10	1.2
CC-Cold	\$ 25,808	\$ 2,062	\$ 25,981	\$ 53,851	\$ 17.28	400	240	9	89,800	\$ 25.90	1.5
Coal-Hot	\$ 14,688	\$ 2,707	\$ 1,599,481	\$ 1,616,875	\$ 15.92	400	240	600	3,909,248	\$ 16.29	1.0
Coal-High Commitment Cost	\$ 39,708	\$ 2,707	\$ 2,562,907	\$ 2,605,322	\$ 15.92	400	186	600	4,381,911	\$ 18.26	1.1
CT	\$ 2,146	\$ -	\$ -	\$ 2,146	\$ 24.88	100	100	0.5	3,389	\$ 67.79	2.7

Note: [1]: Column [8] of Table B-2, [2]: Column [5] of Table B-3,
 [3]: Column [8] of Table B-4, [4] = [1]+[2]+[3]
 [5]: Column [5] of Table B-5. [6] to [8]: See Table B-1, [7] = [6]-([2] of Table B-2).

The output of renewable resources in the AESO system will significantly increase. As a result, it will impact unit commitment plans and short-term dispatch decisions. A coal unit may be committed on a weekly basis instead of a monthly basis. In addition, coal plants may be committed for cycling purposes, instead of providing baseload energy. In this circumstance, the length of time for which a coal unit will be dispatched at its full capacity may be reduced, and when they operate, they may generate at the plant’s minimum generation level for some time during a commitment period. For illustration purposes, we create a sensitivity analysis that assumes (1) a coal unit is self-committed on a weekly basis (5 days); and (2) the plant is cycled such that these units are dispatched at full output during only 40 percent of that commitment period.

The result of this sensitivity shows that the ratios of average costs to marginal costs of coal units increase from the range of 1.0 to 1.1 to the range of 1.7 to 2.2, as shown in Table B-7.

Table B-7
Sensitivity Scenario: Coal
Weekly Commitment (240 Hours)
40 Percent Full Output Dispatch During Weekly Commitment (96 of 240 Hours)

Gen Type	Total Start-Up Cost	Shutdown Cost	Total No Load Cost	Total Commitment Cost	Marginal Cost	Output @ Full Load	Average Incremental Output	Assumed Run Time @ Full Output	Total Cost	Average Cost	Ratio of Average Cost to MC
	(CAD\$/Start)	(CAD\$/Cycle)	(CAD\$/Start)	(CAD\$/Start/Cycle)	(CAD\$/MWh)	MW	MW	Hours	(CAD\$)	(CAD\$/MWh)	
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]=[4]+([5]x[7]x[8])	[10]=[9]/[6]	[11]=[10]/[5]
Coal-Hot	\$ 14,688	\$ 2,707	\$ 639,792	\$ 657,187	\$ 15.92	400	240	96	1,023,967	\$ 26.67	1.7
Coal-High Commitment Cost	\$ 39,708	\$ 2,707	\$ 1,025,163	\$ 1,067,578	\$ 15.92	400	186	96	1,351,832	\$ 35.20	2.2

Note: [1]: Column [8] of Table B-2, [2]: Column [5] of Table B-3,
 [3]: Column [8] of Table B-4, [4]= [1]+[2]+[3]
 [5]: Column [5] of Table B-5. [6] to [7]: See Table B-1.
 [8]: Assumed a reduction of 20 percent of assumed run time @ full output in Table B-6 for Coal, respectively.

Appendix C: Analysis of Conduct-Impact Test and Net Revenue of Reference Resources Calculation

This appendix describes how we (1) examined bids in the AESO energy market during 2012–2016 using the Conduct-Impact test; and (2) calculated net revenues for Reference Resources discussed in Section IV.

A. CONDUCT TEST

The first part of the Conduct-Impact Test is the Conduct test. The conduct screen compares each bid against its competitive reference level. If the bid exceeds the reference level, the offer is deemed to fail the Conduct test. We perform the Conduct test for every bid.

1. Reference Levels

We calculate a reference level for each offer block of each supplier’s offer curve. Each offer block’s reference level is calculated based on the offer block unit’s marginal operating cost times a Conduct-test threshold parameter, which we assume in our analyses to be either 200 percent or 300 percent. Throughout our explanation in this appendix, we will use two times (200 percent) marginal variable cost for the comparison, although three times (300 percent) marginal variable cost was also considered.

2. Marginal Operating Cost

Marginal Variable Cost

Marginal variable cost is calculated as the sum of two components: marginal fuel cost and variable O&M costs. Below is an in-depth description of how each is calculated, and the assumptions made to calculate each.

Marginal Fuel Cost

Marginal fuel cost is calculated by multiplying the amount of fuel used, by the price of its fuel. To calculate the amount of fuel used to generate a certain number of MW, we use the unit-specific heat rate curve from AESO’s Aurora model. The heat rate curve parameters in the dataset are $C0$, $C1$, $C2$, and $C3$. These parameters are combined in the following formula to give the marginal fuel used for a given bid:

$$\frac{[C0 + C1 * (Cumulative kW) + C2^2 * (Cumulative kW) + C3^3 * (Cumulative kW)] - [C0 + C1 * (Prior kW) + C2^2 * (Prior kW) + C3^3 * (Prior kW)]}{10^6}$$

In this formula, *Cumulative kW* is the kW of all cheaper offers from that unit in the given hour plus the kW in that offer. *Prior kW* is simply the kW offered by that unit at prices below the current offer, for the given hour.

The heat rate parameters $C0$, $C1$, $C2$, and $C3$ are also adjusted from the raw heat rate data in several ways, depending on the type of unit:

- Cogen units have 3000 taken off of their $C1$ value, so $C1 = C1 - 3000$ for cogen units only. This was done because we observed abnormally high offer markups (offer price minus marginal cost) for cogen units, and the adjustment helps to account for this.
- Hydro units are given $C1 = 14,000$, while $C0$, $C2$, and $C3$ are set to 0. This assumption is based on the at-cost bids from hydro units in 2016, which can be modeled approximately as a gas unit with $C1$ equal to 14,000.

Now that the incremental fuel has been calculated using the above formula and assumptions, we can multiply that fuel by the price of the fuel. We use yearly type-specific coal prices from the AESO's Aurora model, and daily gas prices for gas and hydro units.

Variable O&M

The Variable O&M (VOM) cost is mostly based on generic assumptions used in AESO's Aurora model. All coal units have a VOM cost of \$6.30/MWh, which is based upon values we see for coal units in the unit information data. Gas units are split into two categories—single cycle and combustion turbine units have a VOM cost of \$4/MWh, while CC units have a VOM cost of \$8/MWh. Finally, the assumption for cogen units' VOM cost are \$0/MWh because we have assumed that the VOM of a cogen is effectively paid for by the steam host, and therefore is not included as an incremental cost of producing the power sold onto the grid.

Other Adjustments

There are a few other adjustments made to the marginal variable cost calculation:

- Non-hydro, non-wind renewables have their marginal variable cost set to \$30/MWh. This adjustment is based on their at-cost bids in 2016.
- Wind units are assumed to have zero marginal cost, since they are must-run units without any per-MWh costs.
- Biomass units have their marginal variable cost set to \$50/MWh, based on their at-cost bids in 2016. This assumption is particularly conservative to reflect uncertainty around the costs of biomass units.
- The transmission must run unit is assumed to incur a marginal variable cost that is equal to its offer price.

B. IMPACT TEST

We conducted the Impact test on every hour in which we observe any failures in the Conduct test. This analysis quantifies a change in a market-clearing price if a supplier would have submitted all of its failed (Conduct test) bids at corresponding competitive reference levels.

We perform the Impact test supplier by supplier, for each of the five largest suppliers, hour by hour, from 2012 to 2016, with the exception of Balancing Pool. In a given hour, only suppliers

who fail the Conduct test will subsequently be assessed how their fail bids would adversely affect the market clearing prices.

1. Methodology

To perform the price impact analysis for each supplier who has failed the Conduct test, we first simulated a market clearing price using the actual historic bids. The simulation we built simply replicated the actual market clearing prices in the AESO markets during 2012–2016.

We then constructed the failed offers reference levels scenario, in which we adjust offers that failed the conduct test of a given supplier to be submitted at their reference levels, which is a multiple of their marginal cost. We then sorted the new supply offer curve and determined how the new supply curve intersects with the actual demand curve. This process generates the new market clearing price in that hour. To determine the price-impact test, we compare the change in prices of the actual and reference level offers cases. If the change is greater than the Impact threshold level, that supplier fails the Impact test in that hour.

2. Impact Test Threshold

We establish the Impact test threshold and capture the bids that fail the Impact test by increasing the market prices by more than the threshold.

C. NET REVENUE CALCULATION

The final step of the Conduct-Impact test analysis is to estimate how various parameters of the Conduct-Impact test and mitigation affect the net revenue of a new resource entering the AESO energy market. We focused on two generic new natural gas-combined cycle (CC) plant and natural gas-combustion turbine (CT). We called them Reference Resources CC and CT.

1. Assumptions

Table C.1 presents our assumptions of the Reference Resources CC and CT unit characteristics.

Table C.1
Reference Resources Unit Characteristics: CC vs. CT

Characteristics	CC	CT
Heat Rate (Kilojoules/kWh)	6,700	9,600
Variable O&M (CND\$/MWh)	8	4

Based on the unit characteristics shown on Table C.1, we estimate the CC and CT’s marginal operating costs by summing the fuel cost and variable O&M. We estimate the fuel costs by multiplying their heat rates and gas prices.

2. Methodology

We estimate each Reference Resource’s net revenue stream from 2012–2016 based on the actual unmitigated prices and the simulated mitigated prices. Because we analyzed each supplier one at a time, there are more than one mitigated price series for each of the Conduct-Impact test and mitigation scenarios. In each hour, we selected the mitigated price due to mitigating the supplier who had the greatest price impact with that supplier’s bids mitigated.

We assume that these Reference Resources are self-dispatched against market prices. Thus, we compare their marginal cost estimates with market prices hour-by-hour. In a given hour, if a Reference Resource’s marginal cost is above the market price, the resource will not sell any output.

We then calculate each Reference Resource’s hourly net revenue by taking the difference between the hourly price and its marginal cost. The hourly revenues are aggregated into yearly totals.

3. Results

The tables summarize the estimated capacity factors and net energy revenues for a reference CC and CT, after simulating market prices based on various combinations of the Conduct-Impact test thresholds and associated mitigation. The Conduct test thresholds and the mitigation levels considered in this analysis are 200% and 300% of the estimated marginal costs. The Impact test thresholds are CAD\$100/MWh and CAD\$200/MWh.

Scenario 1: Mitigation to 200% of Marginal Cost, Impact Test Threshold of \$100								
	Reference Resource CC				Reference Resource CT			
	Capacity Factor		Net Revenue (\$/kW-year)		Capacity Factor		Net Revenue (\$/kW-year)	
	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated
2012	52.86%	40.34%	\$319.22	\$124.86	32.63%	23.78%	\$298.83	\$104.76
2013	63.58%	63.58%	\$495.08	\$258.04	40.68%	38.41%	\$455.52	\$219.33
2014	47.77%	47.16%	\$191.38	\$74.01	20.71%	18.77%	\$153.75	\$38.13
2015	48.14%	48.14%	\$122.44	\$35.57	17.32%	17.04%	\$104.44	\$17.59
2016	53.43%	53.43%	\$24.68	\$23.67	22.13%	22.13%	\$9.30	\$8.29
2017	42.05%	24.42%	\$18.31	\$18.31	17.52%	10.17%	\$9.55	\$9.55

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Scenario 2: Mitigation to 200% of Marginal Cost, Impact Test Threshold of \$200								
	Reference Resource CC				Reference Resource CT			
	Capacity Factor		Net Revenue (\$/kW-year)		Capacity Factor		Net Revenue (\$/kW-year)	
	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated
2012	52.86%	40.35%	\$319.22	\$145.61	32.63%	24.37%	\$298.83	\$125.35
2013	63.58%	63.58%	\$495.08	\$283.08	40.68%	39.21%	\$455.52	\$244.09
2014	47.77%	47.44%	\$191.38	\$82.28	20.71%	19.30%	\$153.75	\$45.81
2015	48.14%	48.14%	\$122.44	\$37.49	17.32%	17.06%	\$104.44	\$19.50
2016	53.43%	53.43%	\$24.68	\$23.79	22.13%	22.13%	\$9.30	\$8.41
2017	42.05%	24.42%	\$18.31	\$18.31	17.52%	10.17%	\$9.55	\$9.55

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Scenario 3: Mitigation to 300% of Marginal Cost, Impact Test Threshold of \$100								
	Reference Resource CC				Reference Resource CT			
	Capacity Factor		Net Revenue (\$/kW-year)		Capacity Factor		Net Revenue (\$/kW-year)	
	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated
2012	52.86%	40.35%	\$319.22	\$129.87	32.63%	24.86%	\$298.83	\$109.48
2013	63.58%	63.58%	\$495.08	\$264.96	40.68%	40.58%	\$455.52	\$225.41
2014	47.77%	47.67%	\$191.38	\$75.74	20.71%	19.67%	\$153.75	\$38.69
2015	48.14%	48.14%	\$122.44	\$37.68	17.32%	17.32%	\$104.44	\$19.68
2016	53.43%	53.43%	\$24.68	\$23.70	22.13%	22.13%	\$9.30	\$8.33
2017	42.05%	24.42%	\$18.31	\$18.31	17.52%	10.17%	\$9.55	\$9.55

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

Scenario 4: Mitigation to 300% of Marginal Cost, Impact Test Threshold of \$200								
	Reference Resource CC				Reference Resource CT			
	Capacity Factor		Net Revenue (\$/kW-year)		Capacity Factor		Net Revenue (\$/kW-year)	
	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated	Unmitigated	Mitigated
2012	52.86%	40.35%	\$319.22	\$148.85	32.63%	24.90%	\$298.83	\$128.45
2013	63.58%	63.58%	\$495.08	\$287.02	40.68%	40.65%	\$455.52	\$247.46
2014	47.77%	47.74%	\$191.38	\$83.70	20.71%	20.13%	\$153.75	\$46.34
2015	48.14%	48.14%	\$122.44	\$39.91	17.32%	17.32%	\$104.44	\$21.91
2016	53.43%	53.43%	\$24.68	\$23.80	22.13%	22.13%	\$9.30	\$8.43
2017	42.05%	24.42%	\$18.31	\$18.31	17.52%	10.17%	\$9.55	\$9.55

Sources/Notes: We assume that the Reference Resources are price-takers, making their economic self-dispatch decisions based on their marginal costs and unmitigated market prices. Marginal costs of new CC and CT reference resources are based on heat rates of 6,700 kilojoules/kWh and 9,400 kilojoules/kWh and variable O&M of CAD\$8/MWh and CAD\$4/MWh. The CONE data were obtained from midpoints of Table 1 of *Proposed Gross Cost of New Entry & Net Cost of New Entry Calculation Approach Draft Discussion*, AESO, November 2017, p. 3.

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