ONTARIO ENERGY BOARD

IN THE MATTER OF the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A, as amended;

AND IN THE MATTER OF an application by the Association of Major Power Consumers in Ontario requesting that the Ontario Energy Board review a set of Market Rule amendments made by the Independent Electricity System Operator (MR-00439-R00 to R05: Transitional Capacity Auction).

EB-2019-0242

COMPENDIUM OF DOCUMENTS FOR SUMMARY OF CLOSING SUBMISSIONS OF THE ASSOCIATION OF POWER PRODUCERS OF ONTARIO

December 11, 2019

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TAB 1

EB-2007-0040

IN THE MATTER OF the *Electricity Act, 1998*, S.O.1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by the Association of Major Power Consumers in Ontario under section 33 of the *Electricity Act, 1998* for an Order revoking an amendment to the market rules and referring the amendment back to the Independent Electricity System Operator for further consideration, and for an Order staying the operation of the amendment to the market rules pending completion of the Board's review.

DECISION AND ORDER
(Issued April 10, 2007 and as corrected on April 12, 2007)

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Pamela Nowina
Member and Vice Chair

Bill Rupert
Member

The Application

On February 9, 2007, the Association of Major Power Consumers in Ontario ("AMPCO") filed with the Ontario Energy Board (the "Board") an Application under section 33(4) of the *Electricity Act, 1998* (the "Act") seeking the review of an amendment to the market rules approved by the Independent Electricity System Operator (the "IESO") on January 17, 2007. The Board has assigned file number EB-2007-0040 to the Application.

The amendment that is the subject matter of the Application is identified as MR-00331-R00: “Specify the Facility Ramping Capability in the Market Schedule” and relates to the ramp rate assumption used in the market pricing algorithm within the IESO-administered markets (the “Amendment”).

The specific relief sought in the Application is the following:

- an order under section 33(7) of the Act staying the operation of the Amendment pending completion of the Board’s review of the Amendment;

- an order under section 33(9) of the Act revoking the Amendment and referring the amendment back to the IESO for further consideration; and

- an award of costs, such costs to be payable by the IESO.

On February 9, 2007, the Board issued its Notice of Application and Oral Hearing in relation to the Application.

Under section 33(6) of the Act, the Board is required to issue an order that embodies its final decision in this proceeding within 60 days after receiving AMPCO’s application.

This is the first application of its kind to proceed to a hearing before, and a decision by, the Board. An earlier application by a different applicant and in relation to a different amendment to the market rules was subsequently withdrawn.

Although the Board has considered the entirety of the record in this proceeding, the Board has summarized the record only to the extent necessary to provide context for those findings.

The Amendment

The Amendment relates to the calculation of the energy price (the market clearing price or “MCP” that is calculated in five-minute intervals) in the real-time energy market administered by the IESO and, more specifically, to a change (from 12x to 3x) in the assumption that is made about the ramping capabilities of generation facilities when determining market prices.

The algorithm that is used to compute MCP – known as the “market schedule” and sometimes referred to as the unconstrained schedule – contains a parameter (the “TradingPeriodLength”) that specifies the ramp rate multiplier to be used in determining energy market prices. Ramp rate, which is usually expressed in MW per minute, indicates how quickly the output of a generation facility can be increased or decreased.

Prior to the Amendment, the market rules authorized the IESO (then known as the Independent Electricity Market Operator or IMO)[1] to establish the “TradingPeriodLength” parameter for the pricing algorithm but did not define its value. Prior to market opening, the value of the parameter was set at 60 minutes, which is the equivalent of a 12x ramp rate. Most generation facilities, and in particular those that typically set market prices, can change their output from minimum levels to full output in roughly one hour. The result of the 12x ramp rate multiplier is that the market schedule has since market opening assumed that generation facilities are able to ramp output up or down 12 times faster than is, in fact, the case. It is widely acknowledged that use of the 12x ramp rate multiplier was implemented as a temporary solution to address extreme price excursions that were experienced during testing prior to opening of the wholesale market.

Further examination of the ramp rate multiplier issue was initiated by the IESO in December, 2005. Stakeholder consultations ensued, principally through the Market Pricing Working Group as well as through the IESO’s Stakeholder Advisory Committee.

At the end of this examination, the IESO proposed to amend the market rules by setting the value of the “TradingPeriodLength” parameter at 15 minutes, which is the equivalent of a 3x ramp rate. To that end, on December 27, 2006, the IESO published the Amendment for comment. Five submissions were received in response; one from AMPCO opposing the Amendment and four from generators supporting the Amendment as a move in the right direction albeit not as the preferred solution. The Board of Directors of the IESO approved the Amendment on January 17, 2007, and it was published on January 19, 2007. The Amendment was scheduled to go into effect on February 10, 2007, the earliest date permitted by section 33(1) of the Act.

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[1] For convenience, this Decision and Order will refer throughout to the IESO even though, at the time relevant to the point under discussion, it may have been called the IMO.

Once implemented, the Amendment would result in the market schedule assuming that generation facilities are able to ramp output up or down 3 times faster than is, in fact, the case.

It is to be noted that the 3x ramp rate multiplier relates solely to the calculation of energy prices. The physical dispatch algorithm (known as the “real-time schedule” and sometimes referred to as the constrained schedule), which is used by the IESO to dispatch facilities to meet market demand in any given interval, reflects the actual ramping capabilities of generation facilities (in other words, the value of the “TradingPeriodLength” parameter is set at 5 minutes, equivalent to a 1x ramp rate).

The role played by, and the impact of, the ramp rate multiplier in the determination of real-time energy prices is discussed further below under the heading “Pricing and Dispatch in the Real-time Energy Market”.

The Proceeding

A brief description of the issues and the orders issued by the Board is summarized below.

1. *Stay of Operation of the Amendment*

The Amendment had an effective date of February 10, 2007. AMPCO’s arguments in support of its application for an order under section 33(7) of the Act staying the operation of the Amendment pending completion of the Board’s review of the Amendment were that: (i) it is in the public interest to order the stay; (ii) there are legitimate concerns with respect to the Amendment that should be considered by the Board; and (iii) the balance of convenience favours a stay.

On February 9, 2007, the IESO filed a letter with the Board indicating that it consented to the stay of the operation of the Amendment, such consent being without prejudice to any arguments that the IESO might make in relation to the Board’s review of the Amendment. The IESO noted that it had given due consideration to the balance of convenience and the short duration of the stay given the Board’s statutory deadline for completion of its review of the Amendment.

By Order dated February 9, 2007, the Board stayed the operation of the Amendment pending completion of the Board’s review of the Amendment and issuance by the Board of its order embodying its final decision on AMPCO's application for review of the Amendment. The Board noted in particular that the balance of convenience favoured a stay of the operation of the Amendment, particularly given the long history of the ramp rate issue in the IESO-administered markets.

2. Intervenors

The following parties requested and were granted intervenor status in this proceeding: the Association of Power Producers of Ontario ("APPrO"); Coral Energy Canada Inc. ("Coral Energy"); the Electricity Market Investment Group ("EMIG"); Hydro One Networks Inc. ("Hydro One"); the IESO; Ontario Power Generation Inc. ("OPG"); TransAlta Energy Corp. and TransAlta Cogeneration L.P. (collectively "TransAlta"); TransCanada Energy Ltd. ("TransCanada"); and the Vulnerable Energy Consumers Coalition ("VECC").

In addition, the Board received on March 30, 2007 a letter of comment filed by Constellation Energy.

3. *Procedural Order No. 1*

On February 16, 2007, the Board issued its Procedural Order No. 1. In addition to establishing the process and timelines for this proceeding, Procedural Order No. 1 also:

- indicated that cost awards would be made available in this proceeding to eligible intervenors, and solicited written submissions on the issue of the party from whom cost awards should be recovered;

- directed the IESO to file materials associated with the development and adoption of the Amendment; and

- identified the following as the issues to be considered in this proceeding:

  (i) is the Amendment inconsistent with the purposes of the Act?

  (ii) does the Amendment unjustly discriminate against or in favour of a market participant or a class of market participants?

4. *Cost Awards*

Requests for eligibility for an award of costs were made by AMPCO, VECC and APPrO. TransAlta reserved its right to apply for an award of costs should special circumstances arise in the proceeding. In its letter of intervention, the IESO also indicated that it would seek an award of costs.

In response to Procedural Order No. 1, four parties made submissions in relation to the issue of the party from whom cost awards should be recovered. The submissions are summarized in the Board's Procedural Order No. 2 issued on March 9, 2007.
The Board determined that cost awards in this proceeding should be recovered from the IESO, for the reasons stated in Procedural Order No. 2. The Board also determined that VECC, APPrO and AMPCO are eligible for an award of costs in this proceeding, subject to any objections that the IESO might wish to make for consideration by the Board. By letter dated March 16, 2007, the IESO indicated that while it accepts and respects the Board's decision regarding cost eligibility, it reserved the right to ask the Board to limit the amount of costs recoverable by parties objecting to the Amendment in the event that it appears, at the end of the proceeding, that some or all of the grounds for the objection ought not to have been advanced.

5. *Production of Materials by the IESO*

As noted above, among other things Procedural Order No. 1 directed the IESO to file materials associated with the development and adoption of the Amendment. By letter dated March 2, 2007, AMPCO alleged that the IESO's filing in response to Procedural Order No. 1 was deficient in a number of respects. By letter also dated March 2, 2007, the IESO replied to the allegations contained in AMPCO's letter, stating that there is no merit to AMPCO's allegations and that the IESO had produced all of the materials required by Procedural Order No. 1.

In its Procedural Order No. 2, the Board among other things ordered the IESO to produce certain materials, including material prepared by the IESO in the context of the Day Ahead Commitment Process and/or the Day Ahead Market initiative that directly relates to ramp rate (the "DAM/DACP Materials"). In ordering the IESO to produce the DAM/DACP Materials, the Board expressly recognized that the relevance of those Materials to the criteria set out in section 33(9) of the Act, which form the basis of the issues list set out in Procedural Order No. 1, is not clear. Procedural Order No. 2 thus also invited parties to make submissions on the issue of the relevance to this proceeding of the DAM/DACP Materials, and more specifically to the criteria set out in section 33(9) of the Act and the issues list set out in Procedural Order No. 1.

On March 12, 2007, the IESO filed a letter with the Board in response to Procedural Order No. 2. In that letter, the IESO stated that the nature and extent of the task involved in satisfying the document production requirements of Procedural Order No. 2 makes completion of the task within anything remotely close to the specified timeframe completely impractical. Without waiving any of its rights or accepting the relevance to this proceeding of the materials identified in Procedural Order No. 2, the IESO put forward a proposed plan to meet the Board's information requirements within the requisite timeframes. On March 14, 2007, AMPCO filed a letter with the Board expressing its concerns regarding the IESO's proposed plan. The concerns related principally to the scope of the IESO's production in respect of the subject matter and time period to be covered.

On March 14, 2007, the Board issued its Procedural Order No. 3. The effect of Procedural Order No. 3 was to revise the nature of the production required of the IESO under Procedural Order No. 2, generally in line with the proposed plan submitted by the IESO in its letter of March 12, 2007 but with the exception that the production should cover a longer period than that proposed by the IESO.

6. *Technical Conference*

Procedural Order No. 1 made provision for a technical conference to be held in this proceeding. On March 20, 2007, and in response to inquiries received by certain parties, Board staff communicated with the parties to confirm whether they wished to proceed with the technical conference. Based on the responses received to that communication, the Board decided to cancel the technical conference and the parties were so advised by Board staff on March 21, 2007.

7. *Submissions on the "Relevance Issue"*

On March 21, 2007, AMPCO filed with the Board a letter setting out a proposal for submissions on the issue of the relevance of certain materials to this proceeding. As noted above, in its Procedural Order No. 2 the Board invited parties to make submissions on the relevance of the DAM/DACP Materials. AMPCO's proposal, made with the consent of the IESO, was to the effect that AMPCO would provide the Board and all parties with a "comprehensive submission on the relevance of materials produced by the IESO in relation to a central theme contained in AMPCO's application: "that the Amendment violates fundamental principles of procedural fairness". The proposal also suggested that, rather than filing submissions in accordance with Procedural Order No. 2, parties should await production of AMPCO's comprehensive submission and respond to that document.

On March 22, 2007, the Board issued its Procedural Order No. 4 setting out the timeframe for the filing of AMPCO's submissions on relevance. The Board encouraged intervenors to make written submissions in response to those of AMPCO but, given the imminence of the commencement of the oral hearing, indicated that it would allow all intervenors to make oral submissions on the relevance issue at the beginning of the oral hearing.

Written submissions on relevance were filed by AMPCO, the IESO, APPrO and Coral Energy. The positions of the parties are summarized below under the heading "The Board's Mandate".

8. *The Oral Hearing and Final Written Argument*

The Board held an oral hearing in this proceeding, commencing on March 29, 2007 and concluding on March 30, 2007. The first day of the hearing was devoted almost exclusively to submissions by the parties on the "relevance issue", as described in greater detail below under the heading "The Board's Mandate". On the second day of the hearing, witnesses gave evidence on behalf of AMPCO, the IESO, APPrO and TransCanada, principally in relation to the nature and impact or effect of the Amendment. The position of the parties in this regard is discussed in greater detail below under the heading "The Impact of the Amendment".

During the hearing, proposals were also made by certain of the parties in relation to the filing of final written argument, and these were accepted by the Board. AMPCO filed its final written argument on April 2, 2007. VECC filed its final written argument on April 3, 2007. The following parties filed their final written argument on April 4, 2007: the IESO; APPrO; and TransCanada. OPG filed a letter with the Board indicating its support for the final argument filed by APPrO. Coral Energy did not file final written argument, but did indicate during the oral hearing that it would address the substantive issues associated with the Amendment through APPrO. AMPCO filed its written reply argument on April 5, 2007.

The Board's Mandate

The "relevance issue", as it has been referred to in this proceeding, arose initially in relation to the DAM/DACP Materials. As stated in Procedural Order No. 4, the issue is relevance of materials – and hence of the position or argument that the materials support – relative to the criteria set out in section 33(9) of the Act. This issue, of necessity, requires consideration of the scope of the Board's mandate on applications to review amendments to the market rules under section 33 of the Act.

As the proceeding progressed, it became clearer that AMPCO's views as to the scope of the Board's mandate differs markedly from the views of other parties. A number of the concerns raised by AMPCO regarding the Amendment relate not to the impact or effect of the Amendment, but rather to the process by which the Amendment was made by the IESO. Many of the materials filed by the IESO in response to the Board's Procedural Orders are relevant to those concerns, but have little or no relevance to the issue of the impact or effect of the Amendment.

The position of the parties in relation to the scope of the Board's mandate, as expressed in the written submissions filed in response to Procedural Order No. 4 and/or in oral submissions made at the commencement of the oral hearing, may be summarized as follows.

AMPCO's position is that the Board's mandate is not limited to the grounds set out in section 33(9) of the Act. Rather, the Board has a "plenary review jurisdiction" that would allow the Board to address what AMPCO alleges as significant failures of procedural fairness by the IESO. In support of its position, AMPCO referred to and relied on sections 33(4), 33(5) and 33(6) of the Act, on section 19(4) of the *Ontario Energy Board Act, 1998*, on the Board's authority to determine all questions of law and fact in all matters within the Board's jurisdiction, and on the Board's public interest role. On that basis, in AMPCO's view the criteria expressed in section 33(9) of the Act are better understood as the two instances in which the legislature has directed the Board on how it must exercise its review discretion, leaving the Board otherwise able to exercise its review discretion as the Board sees fit.

By contrast, the position of the IESO, APPrO, Coral, OPG and TransCanada is that the Board's mandate is limited by section 33(9) of the Act to a determination of whether (a) the amendment is inconsistent with the purposes of the Act; or (b) the amendment unjustly discriminates against or in favour of a market participant or a class of market participants. On that basis, whether the IESO has, and breached, a common law duty of procedural fairness or acted in a manner giving rise to a reasonable apprehension of bias (both of which allegations were denied by the IESO), are not matters for consideration by the Board on a market rule amendment review application under section 33 of the Act. Materials produced by the IESO that are relevant only to the IESO's processes in making the Amendment should therefore be disregarded. The IESO also specifically requested that the Board strike AMPCO's March 26, 2007 submission from the record.

On March 29, 2007, the Board rendered an oral decision on this issue. Specifically, the Board determined that its mandate under section 33 of the Act is limited to an examination of the market rule amendment against the criteria set out in section 33(9) the Act. The Board also ordered that any evidence relating to the IESO's stakeholdering process, including AMPCO's March 26, 2007 submission, be struck from the record. An excerpt from the transcript of the oral hearing that contains the Board's decision and order in this regard is set out in Appendix A to this Decision and Order.

The parties agreed to, and filed with the Board, a list of the materials affected by the Board's decision (i.e., those to be struck from the record and those to remain on the record).

The Impact of the Amendment

It remains for the Board to determine whether the Amendment is inconsistent with the purposes of the Act or unjustly discriminates against or in favour of a market participant or a class of market participants.

A brief summary of the position of the parties is set out below, followed by the Board's findings.

In order to better understand the position of the parties, however, it is necessary to provide some further context around the setting of prices in the IESO-administered energy market and the role that the ramp rate multiplier plays, if only at a high and simplified level.

1. *Pricing and Dispatch in the Real-time Energy Market*

The MCP, which is calculated in five-minute intervals, is determined using a market schedule (pricing algorithm) that calculates the price based on the most economical offers submitted by generators that would satisfy the demand for energy in a particular five-minute interval. Dispatchable generators receive the MCP for their output, and dispatchable loads pay MCP for the energy they consume. All other generators and loads receive or pay, respectively, the Hourly Ontario Energy Price ("HOEP"). HOEP is a simple average of the 12 MCPs determined for the hour. Ontario currently has a uniform pricing system and MCP (and thus HOEP) are the same everywhere in the province. The introduction of locational marginal pricing for the province, which has long been the subject of discussion, is not expected to occur at least in the short term. However, the IESO does calculate what the prices would be in different locations were locational marginal pricing to be in place. These are referred to as "shadow prices".

Three aspects of the market schedule are of particular relevance to this proceeding:

- the market schedule is "myopic", in that it ignores expected demand in future intervals and sets the MCP based solely on demand conditions in each five-minute interval;

- the market schedule ignores transmission constraints, and assumes for pricing purposes that the cheapest available generation facility anywhere in Ontario is available to satisfy demand in any interval when, in fact, it may be unavailable due to transmission constraints; and

- the market schedule assumes for pricing purposes that generation facilities are able to ramp output up or down faster than they might actually be able to do so (by a factor of 12 currently or by a factor of 3 under the Amendment).

By contrast, the algorithm used by the IESO to dispatch facilities has the following characteristics:

- the dispatch algorithm has, since 2004, incorporated multi-interval optimization ("MIO"), which "looks ahead" to expected demand in future five-minute intervals;

- the dispatch algorithm takes account of all physical constraints on the system; and

- the dispatch algorithm respects the actual ramping capabilities of generation facilities.

The result is that MCP does not necessarily reflect what the prices would have been had the prices been determined on the basis of the offers submitted by generation facilities that are actually dispatched to provide energy to meet demand in a given five-minute interval. The ramp rate multiplier allows the market schedule to set prices on the basis of generation facilities that are cheaper but unavailable due to actual ramping restrictions, and as a result reduces both price volatility and the average level of prices. The same can be said for the market schedule assumption that the system is unconstrained.

A consequence of the lack of complete alignment between the pricing algorithm and the dispatch algorithm is that generation facilities that were assumed by the market schedule to be supplying energy in a five-minute interval might not in fact be dispatched due to the presence of transmission or ramping constraints. A generation facility may have to be dispatched even though it had offered to supply electricity at a price that is higher than HOEP. These generation facilities will be “constrained on”, and under the market rules are entitled to an additional payment referred to as a Congestion Management Settlement Credit (“CMSC”) payment. Similarly, when a cheaper generation facility is not dispatched due to the presence of transmission constraints or because it can ramp down more quickly than a more expensive generation facility, the cheaper facility will be “constrained off” and also entitled to a CMSC payment. In both cases, the CMSC payment reflects the difference between HOEP and the offer made by the generation facility that has been constrained on or constrained off, as the case may be. CMSC payments are not reflected in the energy price, but are recovered through uplift charges from wholesale market participants on a pro-rata basis based on their energy consumption at the time at which the CMSC payments were incurred.

2. *Position of the Parties on the Impact of the Amendment*

The following summary is based principally on the final arguments filed by the parties. For the most part, these largely reflect the tenor of each party’s participation in this proceeding.

The position of the parties to this proceeding fall into two distinct camps: AMPCO and VECC oppose the Amendment while the IESO, APPrO, Coral Energy (through APPrO), OPG and TransCanada support it. The letter of comment received from Constellation Energy also supports the Amendment. TransAlta was not an active participant in this proceeding, but is one of the generators that indicated its support for the Amendment as an interim solution in response to the IESO's request for submissions referred to above. EMIG (of which Coral Energy and Constellation Energy Group Inc. are members) was also not an active participant in this proceeding, but noted in its letter of intervention its belief that "in order to support new private investment in generation, Ontario must transition towards a competitive market where prices reflect the true cost of power". Hydro One did not take a position in this proceeding.

A number of the arguments made by AMPCO and VECC challenge the validity or reliability of the IESO's assessment of the costs and benefits associated with the Amendment, and are therefore better understood if the position of the parties supporting the Amendment is presented first.

Parties Supporting the Amendment

Active participants in this proceeding that support the Amendment assert that the Amendment is consistent with the purposes of the Act and does not unjustly discriminate against or in favour of a market participant or a class of market participants. Certain parties have added that the evidence in this proceeding is overwhelmingly to that effect.

The IESO's position is that the Amendment is consistent with, and will promote, a number of the purposes of the Act. Specifically, the IESO submits that the Amendment will: enhance overall reliability, better protecting the interests of consumers in that regard (sections 1(a) and 1(f) of the Act); encourage conservation and demand management (sections 1(b) and 1(c) of the Act); promote economic efficiency (section 1(g) of the Act); and cultivate a financially viable electricity industry (section 1(i) of the Act). According to the IESO, the Amendment will contribute to the achievement of these objectives by: more closely aligning the dispatch and pricing algorithms; resulting in more accurate price signals for consumers and producers; reducing uneconomic exports out of Ontario with resulting efficiency gains realized through the mechanism of export arbitrage; providing immediate efficiency gains for the Province; reducing fossil fuel generation; and achieving a significant improvement in efficiency for the Ontario market.

The IESO further submits that the Amendment, a superior solution to the available alternatives (including incorporation of MIO in the pricing algorithm), will be simple and inexpensive to implement and will achieve the noted benefits with minimal, if any, impact on average prices for consumers. The IESO has estimated that the impact of the Amendment on HOEP will be an average 2.6 percent increase. However, the IESO has also estimated that the impact on consumer bills will be mitigated by: the export arbitrage response that is expected to follow implementation of the Amendment; the global adjustment; the rebate that is currently paid out on revenues earned by OPG on its non-prescribed assets (the "OPG Rebate"); savings in CMSC payments; and savings in Intertie Offer Guarantee payments (these being payments made to importers to reduce price risks for imports that result from the fact that they are scheduled based on pre-dispatch prices but settled on the basis of real-time prices). After accounting for such mitigation, and based on 2006 market prices, the impact of the Amendment would, according to the IESO, vary from a net cost of $6.68 million or 0.004 cents/kWh (assuming an export arbitrage response of 50%, which the IESO considers conservative) to a net saving of approximately $13 million or 0.008 cents/kWh (assuming an export arbitrage response of 100%). As a supplementary mitigation measure, the IESO intends to disburse surplus funds from the transmission rights clearing account (the "TR Clearing Account") over 12 consecutive months to begin in conjunction with implementation of the Amendment.

With respect to the issue of unjust discrimination, the IESO argues that discrimination, in the context of a market for electricity, refers to economic discrimination. As such, more must be involved than an economic advantage accruing to one party rather than the other. The IESO further states that, by lessening subsidies and better aligning prices and dispatch costs, the Amendment plainly lessens inappropriate economic treatment of market participants.

Similar to the IESO, APPrO submits that improvements resulting from implementation of the Amendment are consistent with the purposes set out in sections 1(b), 1(c), 1(f), 1(g) and 1(i) of the Act. According to APPrO, the Amendment addresses many of the challenges and inefficiencies resulting from the use of the 12x ramp rate multiplier by creating just price signals for generators and loads, and does so with minimal, if any, customer cost impacts. APPrO also argues that the effects resulting from the 12x ramp rate multiplier are prejudicial to, and discriminate against, consumers and suppliers. APPrO states that, by more closely aligning the pricing algorithm with the dispatch algorithm, the Amendment would mitigate those prejudicial and discriminatory effects (such effects including that consumers are not paying the true cost of the electricity they consume and are paying for inefficiencies through uplift charges).

TransCanada's position is that the Amendment will improve the operation of Ontario's competitive electricity market and, since many of the purposes of the Act have as their object the promotion of a competitive market, improvements to the market support the purposes of the Act. According to TransCanada, by moving the market closer to real prices, the Amendment will also specifically encourage conservation (section 1(b) of the Act) and promote the use of cleaner energy sources (section 1(d) of the Act). TransCanada also submits that market efficiency will be promoted by: more closely aligning the pricing and dispatch algorithms; increasing the internal consistency of the market rules; improving price signals and inducing more efficient investment; and improving price transparency and reducing less transparent uplift payments (by reducing CMSC payments). While not a perfect solution, in TransCanada's view the Amendment represents an important step in the right direction.

On the issue of unjust discrimination, TransCanada agrees with the view expressed by Coral Energy in submissions made before and during the oral hearing to the effect that "unjust" discrimination equates with "inefficient" discrimination.

Parties Opposing the Amendment

AMPCO and VECC take the position that the Amendment fails when considered in light of the criteria set out in section 33(9) of the Act, and should therefore be revoked and referred back to the IESO for further consideration.

AMPCO's position is that the Amendment is inconsistent with certain of the purposes of the Act. The purposes of the Act that underlie this position are: (i) ensuring the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand (section 1(a) of the Act); and (ii) protecting the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service (section 1(f) of the Act). AMPCO also submits that the Amendment unjustly discriminates against consumers (by increasing prices) and in favour of generators (by providing "windfall profits" to generators – such as nuclear generators – that are unable to respond quickly to changing demand conditions).

In support of its position, AMPCO submits that the IESO is not at liberty to pick and choose the purposes of the Act that it will further while ignoring others in favour of perceived improvements in efficiency. The Act does not assign differing weights or priorities to the various purposes of the Act and, if anything, the protection of the interests of consumers has been given priority.

AMPCO also submits that the IESO's estimates of the costs and benefits of moving to a 3x ramp rate multiplier in terms of determining the wealth transfer implied by the Amendment are unreliable. According to AMPCO, the efficiency gains flowing from the Amendment, as articulated by the IESO and other parties, are: (i) not supported by economic theory having regard to the "Theory of the Second Best"; (ii) based on the mistaken view that uneconomic exports are principally the result of the 12x ramp rate multiplier rather than being largely attributable to Ontario's uniform pricing structure; and (iii) overstated. AMPCO states that, by contrast, the impact of the Amendment on consumers – a price impact variously estimated by the IESO at approximately $225 million, $197 million, $112 million and $100 million depending on whether the effect of arbitrage is taken into account – has been understated. AMPCO notes that a number of the price mitigation mechanisms identified by the IESO are of short (the OPG Rebate and the disbursement of funds from the TR Clearing Account) or uncertain (the global adjustment) duration or are speculative (export arbitrage), and a longer term price mitigation strategy is required. AMPCO also notes that the 3x ramp rate multiplier solution is inferior to incorporation of MIO in the pricing algorithm, which is a superior solution that could be implemented at a modest cost, and is not the preferred option identified by any market participant.

In its reply argument, AMPCO submits that the evidence in this proceeding does not, contrary to the position expressed by APPrO, answer the question of whether the Amendment will result in a HOEP that more closely approximates the price that would result were the pricing and dispatch algorithms perfectly aligned. AMPCO also submits that the evidence does not address what the "true cost" of electricity might be, nor how such notion compares based on the current HOEP versus HOEP calculated on the basis of the Amendment. Moreover, given the hybrid nature of the market, prices are not in AMPCO's view expected to have more than a marginal impact on investment decisions. AMPCO also notes that, contrary to the view articulated by TransCanada, the Act does not have as one of its objectives the promotion of a competitive market.

VECC's position is that the Amendment unjustly discriminates against consumers because it results in a pricing algorithm that moves away from, rather than towards, the prices generated by the IESO's dispatch algorithm, resulting in overall inefficiency in the setting of HOEP by unjustifiably increasing the prices consumers pay on a province-wide basis. While agreeing that the Board's role is not to "remake" the IESO's decision in relation to the Amendment, VECC submits that the Board must determine whether the decision-making process was sound and led to a reasonable result in that: the issue was clearly defined; the criteria used by the IESO were comprehensive and consistent with the purposes of the Act; and the criteria were applied on a consistent and balanced basis throughout the decision-making process. VECC argues that the IESO's characterization of the issue changed over time from a focus on the differences between the pricing algorithm and the dispatch algorithm to a focus on inefficient exports. According to VECC, there is no confidence that the Amendment is the best way to address the newly framed issue without unjustly discriminating against consumers. In VECC's view, the IESO should therefore be directed to reconsider alternative solutions to the inefficient export issue that do not unjustly discriminate against consumers by inexplicably raising domestic prices.

VECC also expressed concern regarding use of the IESO's cost/benefit analysis as the measure of economic efficiency for changes in rules dealing with the market schedule and the determination of energy prices, noting that: uneconomic exports are largely the result of the fact that Ontario has uniform pricing; the IESO has narrowly redefined the issue of economic efficiency as reducing exports to New York; certain of the benefits that the IESO has identified in relation to the Amendment are unsubstantiated; and any amendment to the market rules that increased market prices would be judged as economically efficient when based on the IESO's analytical framework.

3. *Position of the Parties on the Burden of Proof*

An issue that arose most squarely in the exchange of final written argument is the question of which party bears the burden of proof in an application under section 33 of the Act.

Certain references in the IESO's final written argument make it clear that, in the IESO's view, in an application under section 33 of the Act the burden of proof is on the applicant to demonstrate that the market rule amendment is inconsistent with the purposes of the Act or is unjustly discriminatory.

AMPCO takes a different view, and submits that the burden of proof is ultimately on the IESO to show that the market rule amendment at issue in fact satisfies the test to be applied by the Board as set out in section 33(9) of the Act. In support of that view, AMPCO notes that a market rule amendment review is fundamentally different from a more typical proceeding before the Board in that, among other things, applicants have no ability to pursue the relief of their choice by seeking an alternative or different amendment to the one adopted by the Board of Directors of the IESO. AMPCO also notes that the 60-day timeline within which the Board must issue its order on an application under section 33 of the Act supports AMPCO's position on the burden of proof issue. It would be patently unreasonable to expect that any applicant could develop a traditional applicant's filing complete with a full array of econometric and other analyses in the time allowed.

4. *Board Findings*

a. The Burden of Proof

In applications before the Board, the burden of proof is typically on the applicant to satisfy the Board that the requested relief should be granted. The Board certainly expects that the IESO will participate fully in proceedings relating to applications under section 33 of the Act in support of the amendment that is under review. However, the Board has heard no compelling reason that would cause it to take a different approach and place the burden of proof on the IESO in the circumstances of this case.

b. The Merit of Addressing the 12x Ramp Rate Multiplier Issue

Before turning to an examination of the impact or effect of the Amendment, the Board considers it useful to provide further context regarding the history and impact of the 12x ramp rate multiplier in the marketplace. Several parties noted that, as the wholesale market was designed for implementation at market opening, inputs to both the pricing algorithm and the dispatch algorithm were aligned in relation to the value to be used to reflect the ramping capabilities of generation facilities (in both algorithms, the value of the "TradingPeriodLength" was set at 5 minutes). To this day, that remains the case for the dispatch algorithm. As noted above, however, prior to market opening the market rules were amended to allow the IESO to set a different value for the "TradingPeriodLength" parameter in the pricing algorithm as a temporary measure to address extreme real-time price excursions that occurred during market testing. This is reflected in the "Explanation for Amendment" contained in market rule amendment proposal MR-00189-R00, dated April 16, 2002, which proposed the amendment to the market rules that would allow the IMO the discretion to set the value of the TradingPeriodLength parameter in the pricing algorithm:

> The proposed amendment would permit the IMO to establish a longer Trading Period Length in the market schedule (unconstrained) to overcome the [price excursion] problems identified above. With a longer Trading Period Length within the market schedule (unconstrained), generation facilities will have large ramping capability and there will be less need to select additional higher cost resources to meet the increasing demand. As a result, less extreme price excursions will occur.
>
> The real-time schedule (constrained) will continue to use the 5 minute Trading Period Length. Therefore, discrepancies will increase between the real-time schedule and the market schedule (unconstrained). As a consequence, congestion management settlement credit (CMSC) payments will increase. However, the decreases in energy prices, resulting from the change in the ramp time in the market schedule, are expected to offset increases in CMSC payments.
>
> It should be noted that using a longer Trading Period Length in the determination of the market schedule is judged to be a transitional provision. It is expected that a longer term solution will need to be considered which could include a day-ahead market with unit commitment, increased generator self-scheduling, contracted ramp capability, or multi-period optimization.

The Board has not heard any evidence in this proceeding that would point to the introduction of the 12x ramp rate multiplier as having a basis rooted in market economics. To the contrary, the evidence in this proceeding is that the 12x ramp rate multiplier distorts wholesale market prices downwards and engenders adverse consequences for the marketplace in the form of generation and demand side inefficiencies. For example, dampened wholesale prices diminish incentives for conservation, load management and demand side management. The evidence in this proceeding is also that the 12x ramp rate multiplier contributes to inefficient exports. Inefficient exports, in turn, can increase the need for coal-fired generation to meet Ontario demand and thereby contribute to increased emissions. These adverse consequences were identified and discussed at some length in the evidence filed by, and the testimony given on behalf of, the IESO and APPrO, and are also discussed in the evidence filed by TransCanada. That adverse consequences flow from the 12x ramp rate multiplier was not seriously contested by evidence to the contrary filed by

AMPCO, although AMPCO did challenge the strength of any causal connection between the 12x ramp rate multiplier and inefficient exports.

The Board also notes that the 12x ramp rate multiplier issue has been the subject of comment by the Market Surveillance Panel. Specifically, the potential adverse market impact of the 12x ramp rate multiplier has been referred to or discussed in the following Market Surveillance Panel semi-annual monitoring reports, which were referred to by a number of parties to this proceeding: December 13, 2003 (covering May 2002 to October 2003); December 13, 2004 (covering the period May to October 2004); June 9, 2005 (covering the period November 2004 to April 2005); June 14, 2006 (covering the period November 2005 to April 2006); and December 13, 2006 (covering the period May to October 2006).

For example, after concluding that a significant portion of the difference between the constrained and unconstrained real-time prices, and of the remaining difference between HOEP and the unconstrained pre-dispatch price, is due to the 12x ramp rate assumption, the Market Surveillance Panel stated as follows in its December 13, 2004 report (at page 66):

> The Panel is of the view that the continued understatement of the HOEP leads to inefficient decisions by both loads and generators in both the short-term and the long-term. This takes the form of an inefficient load profile and of under-investment in both conservation and generation.
>
> With respect to the argument that the assumption that ramp rates are 12-times their true value results in a more stable HOEP, the Panel recognizes that price stability can be beneficial to market participants. The Panel observes, however, that it is open to market participants to insulate themselves contractually from price variation. Moreover, price volatility presents a profit opportunity for more price responsive generation and loads. To the extent that it is efficient to do so, volatility can be reduced by the actions of market participants. This is much better, in the Panel's view, than suppressing price variation by artificial means, especially when this has the side effect of understating the average price. The Panel strongly recommends that actual ramp rates be used to determine the HOEP.

Eighteen months later, the Market Surveillance Panel further commented on the issue in its June 14, 2006 report (at page 79) as follows:

> For these and possibly other reasons, arbitrage between Ontario and New York is focused on the HOEP. The result is inefficient exports and the effective extension of the cross-subsidy inherent in Ontario's uniform price regime to New York loads. This problem has been exacerbated by market rules that, other things being equal, would have reduced the HOEP relative to prices in the constrained schedule. For example, the 12 times ramp rate assumption, which has the appearance of systematically lowering the HOEP (i.e., because it removes ramp effects in price), may simply lead to more exports than would otherwise occur.

In its most recent report, dated December 13, 2006, the Market Surveillance Panel stated as follows on page 106:

> There are two major causes of socially inefficient exports from Ontario to New York. First, like privately inefficient exports, the lack of accurate price signals or information can lead to "guessing wrong" and hence socially inefficient exports ex post. Improvements in price signals should result in a higher frequency of socially efficient exports. Socially inefficient exports can also occur, however, if there are defects in the market design. Ontario's uniform pricing regime is poorly designed in the sense that it admits to the possibility that the prices that exporters pay do not reflect the incremental cost of supply. Other aspects of the unconstrained pricing algorithm such as the 12 times ramp rate assumption can further misalign the HOEP and the relevant nodal prices thereby contributing to the potential for ex post socially inefficient exports… (footnote omitted)

And again at pages 147 and 148:

> Moreover, with the Global Adjustment dampening the redistributive effects of changes in HOEP and mitigating any harm that might be said to be visited upon consumers from potentially higher HOEP, the Panel contends that there may be no better time than now to address the remaining sources of inefficiency in the design of the Ontario spot market. Artificially reducing the HOEP, as is the outcome under the current market design, simply means that consumers pay more (or receive a smaller rebate) through the Global Adjustment, all the while inducing market inefficiencies from which all Ontarians lose.

> The real-time price signals generated by an efficient wholesale market are central to the economic success of the new hybrid market for several reasons:
>
> - First, the real time production and consumption decisions of many wholesale market participants will continue to be guided by real-time prices. If these price signals continue to ignore certain system realities such as transmission constraints or the actual ramping capabilities of generation facilities, they will at times induce these participants to make decisions that reduce the short-term dispatch efficiency. As we have indicated in Chapter 3, factors such as the uniform pricing system and the 12 times ramp rate assumption create a wedge between the HOEP and local shadow prices. This can result in inefficient production and consumption decisions such as the inefficient exports from Ontario to New York that we began documenting in our last report….(footnote omitted)
>
> - Second, even though long-term investment will be guided through central planning in the near term, price signals from an efficient wholesale market can and should play an important role in guiding this planning process…Furthermore, as we have argued above, attempts to subsidize consumers by suppressing real-time prices leads to over-consumption and could ultimately lead to over-investment by the planners at [the Ontario Power Authority].

These comments reinforce the evidence in this proceeding as to the inefficiencies to which the 12x ramp rate multiplier contributes.

The observations of the Market Surveillance Panel in its most recent (December 13, 2006) report also support the assertion made by the IESO and others that addressing efficiency of the market remains a relevant objective even in the context of the hybrid framework under which Ontario's electricity sector operates at this time. Even AMPCO's expert witness, Dr. Murphy, who questioned the relevance or merits of the Amendment in light of the evolution of the market to a hybrid structure, conceded on cross-examination that improvements in wholesale market efficiency and accurate price signals are important even in a hybrid market.

The Board accepts that the 12x ramp rate multiplier, introduced as a temporary measure, has price distorting effects that can and do engender inefficiencies. The Board therefore also accepts that, in principle, there is merit in addressing the 12x ramp rate multiplier issue if and to the extent that efficiency improvements can be expected to result, and that this is so even in the context of the hybrid market.

c. Evaluation of the Amendment as a Solution

The IESO has put forward credible evidence that the Amendment will result in greater efficiency in the IESO's real-time market as compared to the status quo. The benefits from this improved efficiency include, but are not limited to, reduced uneconomic exports to New York. The impact of this latter benefit is quantifiable, and has been quantified by the IESO. The other benefits are less easily quantified, but bear consideration nonetheless.

The Board does not agree with AMPCO's argument that the Amendment is inconsistent with the purposes of the Act and that the IESO has selectively chosen the purposes of the Act it will further while ignoring others. AMPCO asserts that the Amendment is contrary to section 1(a) of the Act ("responsible planning and management of electricity resources, supply and demand"). The Board concurs with the IESO's view that greater economic efficiency will further that objective. AMPCO also argues that the Amendment is inconsistent with section 1(f) of the Act ("protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service"). As discussed more fully below, the Board finds that the IESO has carefully considered the impact of the Amendment on consumers' average bills and determined that the impact is likely to be relatively modest. It may even be positive. The IESO has also noted that, while there may be a modest impact on consumers' bills, the Amendment is consistent with the purpose of protecting the interests of consumers with respect to the adequacy and reliability of supply.

There is no evidence before the Board in this proceeding that would lead the Board to take issue with the assertion made by the IESO and others that improvements in the economic efficiency of the electricity system in Ontario will promote adequacy and reliability of supply by providing more accurate price signals and triggering more appropriate price responsive behaviour. The same can be said for the assertions that the Amendment will encourage conservation, load management and demand side management and will, by reducing inefficient exports, also reduce the need for coal-fired generation to meet Ontario demand and thereby contribute to a lessening of emissions.

AMPCO and VECC both assert that the "3x myopic" Amendment is, by the IESO's own submission, inferior to a "1x MIO" solution. They support this view by reference to documents that were prepared by the IESO at various times in the Amendment development process. They submit that this is a valid basis on which the Board should revoke the Amendment.

The Board does not accept that view. Although it is obvious that the IESO reviewed several alternatives in the course of developing the Amendment, it has consistently taken the position in this proceeding that a “3x myopic” rule is superior to a “1x MIO” option. This conclusion appears in the document issued by the Board of Directors of the IESO when the Amendment was approved, and it is supported by the IESO’s and APPrO’s experts. Other than referring to earlier assessments that the IESO does not currently support, AMPCO and VECC provided no evidence that “1x MIO” is a superior solution.

d. The Anticipated Impact on Consumer Bills

The Board has also considered the possible impact of the Amendment on consumers’ electricity bills.

As noted above, the IESO has calculated that the net annual cost to consumers of adopting the 3x ramp rate assumption in the pricing algorithm is $6.68 million, or 0.004 cents/kWh. That calculation is based on the following assumptions and estimates:

- an average annual HOEP of $49 per MWh (the average price in 2006);
- an increase of 2.6% in the average HOEP as a result of the Amendment, before consideration of mitigating factors;
- mitigation of 50% of the estimate increase in HOEP due to “export arbitrage”;
- mitigation of 80% of the net price increase (that is, after the export arbitrage effect) due to the global adjustment and the OPG Rebate; and
- reductions in CMSC payments and Intertie Offer Guarantees that are paid through uplift charges.

In its calculation of the net consumer impact, the IESO also takes into account a planned distribution to consumers of approximately $54 million from the IESO’s TR Clearing Account. The Board does not believe that this particular distribution is appropriately considered as a mitigation measure in relation to the Amendment. Elimination of this particular mitigation measure does not affect the Board's overall assessment of the Amendment.

Dr. Rivard of the IESO testified that, on the basis of additional analysis on the elasticity of export response, the export arbitrage effect on HOEP would likely be higher than 50%, which would reduce further the net cost of the Amendment to consumers. He noted that were the export arbitrage effect to reach approximately 65%, and keeping the other assumptions the same, the impact of the Amendment would be a net reduction in consumers' bills.

AMPCO disputes most of the assumptions and estimates that underlie the IESO's calculations. It claims that the IESO's estimates are unreliable, although it provided little evidence about the estimates it believes should be used.

Predicting the net effect of the Amendment on consumer's bills is a complex exercise and is not something the Board believes can be done with precision. The Board does, however, view the IESO's calculation as an indicator of the order of magnitude of the net effect of the Amendment. The Board agrees with AMPCO that the base price of $49 per MWh, which is the starting point of the IESO's calculation, is low by historical standards. The Board notes, however, that the IESO provided additional information on a range of net consumer costs using higher average HOEPs. The Board also acknowledges AMPCO's comment that the OPG Rebate is scheduled to expire in two years. Even if the OPG Rebate is discontinued at that time, the IESO has estimated that the global adjustment would still provide significant price mitigation, approximately 60% compared to the current 80% from the combined global adjustment and OPG Rebate.

The Board finds that the expected impact on consumers' bills is relatively modest. The IESO's published calculation shows a very minor impact – just 0.004 cents/kWh – based on estimates that the IESO considers to be conservative. Even if a higher base price were used (an average annual HOEP of $70 per MWh based on 2005 prices), and assuming no replacement for or extension of the OPG Rebate in two years, the estimated net impact would be larger but still relatively small. The difference resulting from the use of a higher base price relative to use of the lower one would be much less than 1/10th of a cent/kWh.

e. Conclusions

The Board concludes that the efficiency benefits that are anticipated to arise as a result of the Amendment are consistent with the purpose of the Act that speaks to promoting economic efficiency in the generation, transmission, distribution and sale of electricity. The Amendment also supports the purposes that relate to encouraging electricity conservation, demand management and demand response; ensuring the adequacy, safety, sustainability and reliability of electricity supply in Ontario; and protecting the interests of consumers in relation to the adequacy and reliability of electricity service. While the Board acknowledges that the Amendment may result in an increase in average consumer bills, that increase is anticipated to be modest.

The Board is also of the view that, in the context of its mandate under section 33 of the Act, unjust discrimination means unjust economic discrimination.

Based on the record of this proceeding, the Board finds that the Amendment is consistent with the purposes of the Act. The Board also finds that the Amendment does not unjustly discriminate for or against a market participant or a class of market participants.

Other Matters

1. *Stay of the Amendment Pending Appeal*

By the terms of the Board's February 9, 2007 Order, the stay of the operation of the Amendment applies pending completion of the Board's review of the Amendment. Issuance of this Decision and Order completes the Board's review, and has by the terms of the Order the effect of lifting the stay. For greater certainty, however, the Board will include an order to that effect in this Decision and Order.

In its final written argument, AMPCO requested that, in the event that the Board does not revoke the Amendment, the Board order a stay of the Amendment pursuant to section 33(6) of the *Ontario Energy Board Act, 1998* pending appeal to the Divisional Court.

In the letter accompanying its final written argument, the IESO noted that this request for relief was not included in the Application and is out of time. While the IESO therefore did not address this request in its final written argument, the IESO did in its letter express the view that the Board does not have jurisdiction to grant such relief, and that if AMPCO wants a stay it must apply to the Divisional Court. APPrO's position is to the same effect.

In the circumstances of this case, the Board has decided not to extend its February 9, 2007 order staying the operation of the Amendment.

The Board understands that the IESO may wish to proceed with implementation of the Amendment on a timely basis, and that parties that are supportive of the Amendment would be equally supportive of prompt implementation. However, the Board does not believe that it is in the best interests of the wholesale electricity marketplace to face the prospect of the Amendment being implemented one day and suspended shortly thereafter further to the invocation of a judicial process. The Amendment is not urgently required for reasons such as reliability and the ramp rate issue is one that has been outstanding for several years. In the circumstances, the Board expects that the IESO will act responsibly by allowing AMPCO a reasonable opportunity to request judicial recourse prior to taking whatever steps may be required to implement the Amendment. The Board similarly expects that AMPCO will act responsibly by ensuring that any request for a stay of the operation of the Amendment that it may wish to make to the Divisional Court is made without undue delay.

2. *New Obligations for IESO under its Licence*

In its final written argument, AMPCO requested that the Board require the following, either under an existing condition of the IESO's licence or by way of a new licence condition:

- that the IESO prepare and submit to the Board, for every proposed market rule and market rule amendment, a report supported by appropriate analysis and available to the public, that explains how the proposed rule or amendment is consistent with the objects of the IESO and promotes the purposes of the Act; and

- that, in relation to the Amendment and such other market rules or market rule amendments as the Board considers appropriate, the IESO report publicly on an annual basis with respect to whether and the extent to which the amendments have met the IESO's objectives and provided the benefits anticipated by the IESO at the time each of the amendments were made.

In the letter accompanying its final written argument, the IESO noted that this request for relief was not included in the Application, is out of time, was not dealt with in any way in this proceeding and is entirely inappropriate.

Whatever the Board may think of AMPCO's request on the merits, the Board does not consider it appropriate to address the request at this stage in the proceeding. The issue of new reporting requirements for the IESO in relation to amendments to the market rules was not raised by AMPCO on a timely basis, and the other parties to this proceeding will not have had a fair opportunity to consider and respond to the request. AMPCO may, if it so wishes, pursue this matter further outside the context of this proceeding.

3. *Cost Awards*

Parties eligible for an award of costs, as identified in Procedural Order No. 2, shall submit their cost claims by April 24, 2007. A copy of the cost claim must be filed with the Board and one copy is to be served on the IESO. The cost claims must comply with section 10 of the Board's *Practice Direction on Cost Awards*.

The IESO will have until May 8, 2007 to object to any aspect of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

A party whose cost claim was objected to will have until May 15, 2007 to make a reply submission as to why its cost claim should be allowed. Again, a copy of the submission must be filed with the Board and one copy is to be served on the IESO.

The Board will issue its decision on cost awards at a later date once the above process has been completed.

THE BOARD ORDERS THAT:

1. The Application by the Association of Major Power Consumers in Ontario for an order under section 33(9) of the *Electricity Act, 1998* revoking the market rule amendment identified as MR-00331-R00: "Specify the Facility Ramping Capability in the Market Schedule" and referring the amendment back to the IESO for further consideration is denied.

2. The stay of the operation of the market rule amendment identified as MR-00331-R00: "Specify the Facility Ramping Capability in the Market Schedule", as ordered by the Order of the Board dated February 9, 2007, is lifted.

DATED at Toronto, April 10, 2007.

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

to

Decision and Order
April 10, 2007

Association of Major Power Consumers in Ontario
Review of Market Rule Amendment
EB-2007-0040

<u>Excerpt from Transcript of Oral Hearing Held March 29, 2007</u>

(see attached document)

our binder. I apologize, it might just be me, but the record, the decision does not bear out the quote that that included.

MR. RUPERT: Mr. Rodger, I was going to mention, I think the page 5 reference, at least as I read it here, didn't refer to the page that was doing what you thought it did. Maybe there is a cross-reference issue in your submissions.

MR. RODGER: I'll certainly check that. Sorry, Mr. Rupert.

MR. KAISER: Why don't you have a look now, and see if you can help us.

MR. RODGER: Mr. Chair, we'll endeavour to get copies during the lunch break.

MR. KAISER: All right. We'll take the lunch break now. We'll come back at 2 o'clock.

--- Recess taken at 12:34 p.m.

--- On resuming at 2:11 p.m.

DECISION:

MR. KAISER: Please be seated.

The Board has decided to issue a decision now on the matter of the relevance of the evidence with respect to the process, rather than deferring it, as Mr. Rodger suggested, in order that we can proceed with the case in a more orderly manner.

We are dealing with an application by AMPCO under section 33(4) of the *Electricity Act* for review of the three times ramp rate market rule amendment. In that context there has been a discussion and a concern about the scope of the case, and particularly whether evidence regarding the process by which the IESO reached this rule is relevant.

AMPCO submits that the three times ramp rate market rule amendment should be revoked by this Board and referred back to the IESO for stakeholder consultation, based on the following grounds: First, that the process followed by the IESO in the three times ramp rate stakeholder consultation process violated IESO's common-law duty of procedural fairness, by breaching AMPCO's legitimate expectation that the IESO would follow its published stakeholder engagement process and apply its stakeholder engagement principles, and raising a reasonable apprehension of bias that the IESO favoured the interests of generators; secondly, that the integrity of the statutorily-mandated consultation process has been undermined. They say this is inconsistent with the purposes of the *Electricity Act* and unjustly discriminates against Ontario consumers in favour of Ontario generators.

They also allege certain substantive failures, as well, which are not at issue in the proceeding this morning.

Accordingly, AMPCO argues that the materials produced by IESO relating to procedural matters are relevant both to the issue of procedural fairness and also the substantive issues.

The starting point in this discussion is section 33(9) of the *Electricity Act*. It has been referred to by virtually everyone this morning. It provides that:

> "If, on completion of its review, the Board finds that the amendment is inconsistent with the purposes of this *Act*, or unjustly discriminates against or in favour of a market participant or a class of market participants, then the Board shall make an order revoking the amendment on the date specified by the Board and referring the amendment back to the IESO for further consideration."

AMPCO argues that all of the IESO materials are relevant because they demonstrate that the IESO failed to follow procedural fairness in developing the amendment. According to AMPCO, the lack of procedural fairness demonstrates that the amendment unjustly discriminates against its members in favour of generators.

In other words, AMPCO argues that it has rights of natural justice in IESO rule-making and that those rights should be enforced by the Board in the market review amendment process.

All of the other parties appearing before us this morning state that this is an incorrect interpretation of section 33(9), because it equates the term "unjustly discriminates" with a violation of the rules of natural justice and it equates the Board's review process with a judicial review application.

They argue that the purpose of the Board's review in a market review amendment should be aimed at economic efficiency and not natural justice.

They say that the OEB should be reviewing an amendment to the IESO rules and not the IESO stakeholdering process; that the scope of the Board's review should be aimed at the rule itself, and the impact of that rule, not the process by which the amendment was made.

In other words, it's argued before us that the issue is whether the rule is unjustly discriminatory. The Board agrees with that position.

Sections 19(1) and 20 of the *OEB Act*, read together, provide that the Board has general authority to determine any question of law or fact arising in any matter before it except where that authority is limited by statutory provision to the contrary.

In the case of a market rule amendment, another statutory provision does limit the Board's jurisdiction. Section 33(9) of the *Electricity Act* specifically sets out certain grounds on which the Board may make an order.

Accordingly, we find that section 33(9) of the *Electricity Act* is a jurisdiction-limiting provision, not another jurisdiction-granting provision. That is, with respect to a market rule amendment, the Board's jurisdiction is not as broad as suggested by section 20 of the *OEB Act*, but limited by section 33(9) of the *Electricity Act*.

In this regard, the Board has also considered the submissions of various parties, and agrees, that the 60-day time limit for disposing of this review is consistent with the conclusion that the Board's scope of review is limited to the criteria set out in section 33(9).

The legislature can be taken as having known that an exhaustive review of the process would render it impossible to meet these timelines.

We then come to what can be seen as a second and distinct issue. That is whether there is a common-law principle of administrative law that the IESO has violated in the course of this market rule amendment process which yields a separate and distinct remedy.

The IESO says the common-law principles of administrative law do not assist AMPCO in extending the jurisdiction of the Board to review the details of the stakeholdering process. They say that the IESO is a statutory corporation whose affairs are managed and supervised by an independent board of directors, and the functions carried out by the IESO under the review at issue in this proceeding is a rule-making function and is essentially a legislative function.

They rely upon the Supreme Court of Canada's 1980 decision in the Inuit Tapirisat as support for the proposition that in legislative functions these rules do not apply.

AMPCO takes a different view and it relies upon the Supreme Court of Canada 1990 decision in Baker, as well as the Divisional Court decision in Bezaire.

The aspects of the decision that AMPCO relies upon can be found at pages 15 and 14, where the Court stated that one of the criteria that must be looked at in determining whether the rules of natural justice apply to a process is whether the parties had a legitimate expectation that those rules would be followed. The Court states, in part:

> "Fourth, the legitimate expectations of the person challenging the decision may also determine what procedures the duty of fairness requires in given circumstance."

They go on to say:

> "This doctrine as applied in Canada is based on the principle that the circumstances affecting procedural fairness take into account the promises or regular practices of administrative decision-makers and it would generally be unfair for them to act in contravention of representations as to procedure or to backtrack on substantive promises without according significant procedural rights."

The Court also noted that another factor to be considered in determining the nature and extent of the duty of fairness that's owed to the parties is the importance of the decision to individuals involved.

As has been pointed out, there's no question that there's a significant amount of money involved in this decision; it's an important decision. With respect to the expectations of the parties, there is a provision in section 13.2 of the *Electricity Act* requiring the IESO to establish processes by which consumers, distributors and generators may provide advice. AMPCO makes the point that a framework was established to govern the process by which these rules would be amended and implemented. They say that this procedure, despite the expectation they were entitled to, has not been followed.

That may or may not be the case, but this Panel is of the view that that is not a matter for our consideration. Mr. Vegh in his submissions questioned whether the Board should be a parallel Divisional Court. We don't think it should be.

IESO may or may not have followed the rules of natural justice. And they may or may not have been required to do so based upon the different authorities that have been cited by the different parties. But that, we believe, is a matter to be determined by the Divisional Court, not the Ontario Energy Board.

Mr. Rodger did refer us to a decision of this Board on September 20th, 2005. That appears at tab 11 of Ms. DeMarco's brief. I'm reading in part:

> ”The Board concludes that stakeholder concerns have been substantially met. The true test will, however, be the experience of stakeholders in the new process. Stakeholders and the Board will have opportunities to review how well the process works over time as they are implemented. The Board therefore approves the IESO proposals on its stakeholdering process. It should be noted,

however, that this approval relates to the processes that the IESO has proposed. It does not change the Board's obligation to review IESO programs that have implications for IESO fees, expenses and revenue requirements, even when these programs have been subjected to the IESO stakeholdering process."

Mr. Rodger's submission was that having approved the stakeholdering process it was incumbent upon the Board to follow through and police, if you will, the rule-making process.

We differ on that. The two are distinct functions. The review at question is a judicial review and best reserved for the courts.

That leads us to the Order requested. Pursuant to this decision, the Board will order that any evidence relating to the stakeholdering process be struck. That would include Mr. Rodger's submission of March 26th. If the parties are unable to agree on what evidence is to be excluded or not excluded, the Board may be spoken to.

That completes the Board's ruling in this matter.

PROCEDURAL MATTERS:

Mr. Rodger and Mr. Mark, we were going to suggest, subject to your convenience, that you may want to adjourn for the rest of the day and regroup in light of that.

MR. MARK: It probably makes sense.

MR. KAISER: Unless there be some debate and discussion as to what evidence is to be struck and what

TAB 2

ONTARIO ENERGY BOARD

FILE NO.: **EB-2019-0242** **AMPCO Motion**

VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

capacity once. If it's not there, you can't drop it again. And I think that is a key distinction from Dr. Rivard's evidence.

MR. MONDROW: Thank you, Mr. Anderson.

Madam Chair, Mr. Anderson is now available for cross-examination.

MS. SPOEL: Thank you, Mr. Mondrow. Ms. Krajewska, I think you are going first on our list.

MS. KRAJEWSKA: I believe it is Mr. Barz.

MS. SPOEL: Oh, Mr. Barz, okay, sorry.

CROSS-EXAMINATION BY MR. BARZ:

MR. BARZ: Good morning. If I may approach the Panel, I have dropped off two copies of the compendium, but I have a third for -- I'm not sure -- but if I might approach and just give you it.

MS. DJURDJEVIC: We will make that Exhibit K1.4.

EXHIBIT NO. K1.4: ASSOCIATION OF POWER PRODUCERS OF ONTARIO COMPENDIUM FOR AMPCO PANEL 1.

MR. BARZ: I may refer to some of the exhibits throughout the cross, but not all of them. Were all of the Panel members able to locate their copies?

MS. FRANK: No.

MR. BARZ: It should just say Association of Power Producers of Ontario at the bottom, on the top -- on the first page, the cover page.

MS. SPOEL: We have it.

MR. BARZ: You have got it?

MS. SPOEL: Yes.

MR. BARZ: Perfect.

Good morning, Mr. Anderson. Do you as well have a copy of the Association of Power Producers of Ontario's compendium?

MR. ANDERSON: I do, thank you.

MR. BARZ: So in your direct it was established you're the president of AMPCO. That's correct?

MR. ANDERSON: That is correct.

MR. BARZ: And you have held -- you have been closely monitoring these amendments since March of 2019. Is that your evidence?

MR. ANDERSON: I have been personally involved in both the TCA discussions and the Demand Response Working Group since March of 2019. A number of my members have been involved with that for years before then.

MR. BARZ: And you have held regular meetings with your AMPCO members throughout that time, obviously, board meetings, and then you have had informal discussions as well with AMPCO members about the amendments?

MR. ANDERSON: I have routine meetings with my members, and I have board meetings not quite once a month, probably about eight board meetings per year, and I can guarantee you this has been an agenda item on the board's agenda every month since it started.

MR. BARZ: I believe your evidence was that you've also had informal meetings with your members about the amendments as well or informal discussions.

MR. ANDERSON: Informal discussions, yes, correct.

MR. BARZ: So you specifically discussed the TCA at length then, correct?

MR. ANDERSON: We have had a number of discussions of the transitional capacity auction, yes.

MR. BARZ: And your members have raised concerns throughout that time about the TCA?

MR. ANDERSON: My members had raised the concern that, in respect of energy payments for demand response resources prior to that time, as others had as well.

The reason why it becomes so bright is when the TCA is opened up to a second class of participant and both of those classes are not treated the same, it starts to bring forward the issue of the discretionary impact of the market rule amendments.

MR. BARZ: When would you say that issue coalesced for you?

MR. ANDERSON: I was just going to say so while my members were engaged in this before, it became particularly bright for them when it was determined that the TCA would commence in December of 2019 in such a way as to make real this discretionary impact.

MR. BARZ: When was that made real for you, in terms of timing?

MR. ANDERSON: I think the first time it was announced publicly was March 7th, 2019.

MR. BARZ: So since March, you have had that -- you and your members have had that knowledge?

MR. ANDERSON: Correct.

MR. BARZ: And so to be clear, for about nine months you have known that this was planned, and that this was coming?

MR. ANDERSON: We have known that this was the IESO's plan, yes.

MR. BARZ: And the IESO, I believe at their board meeting on August 28th, 2019, they announced -- or sorry, they announced a decision to formally adopt the amendments?

MR. ANDERSON: The IESO board meeting on August 28th is where the amendments were finally approved by the IESO board, that is correct.

MR. BARZ: And they were published on September 5th, 2019, correct?

MR. ANDERSON: I think that is the date. It sounds approximately right.

MR. BARZ: I could take you to it in your affidavit, but I am sure that is not really in dispute.

In any event, my question is -- you have been involved in this process. You have known since March 2019 this was coming. And you saw the market rule amendments published in September, the decision to pass those amendments in August.

And since that time, AMPCO or its members have not put forward one study regarding the effects of the amendments on AMPCO members, or a particular member?

MR. ANDERSON: No, we have not advanced any studies.

MR. BARZ: Not one report?

MR. ANDERSON: We have not advanced what I would call a report. We have made no less than five submissions, another one in October, and a joint one with AAEMA, which was a legal brief, all of which detailed the discretionary nature of the market rule amendments, in our opinion.

MR. BARZ: Absolutely, and we will get to those. But you don't have one affidavit attesting to the quantifiable impact of the TCA on a member of AMPCO, or on the membership at large of AMPCO?

MR. ANDERSON: I think in my direct we talked about why you are having this conversation with me, instead of some of my members.

As I said in my direct evidence, I don't necessarily believe any retribution is going to take effect. But the perception of my members senior management team is otherwise, so...

MR. BARZ: I appreciate that I think that was made clear in direct. But I do also want to make clear that there isn't actually any evidence of that kind on the record. That's correct?

MR. ANDERSON: We haven't filed affidavits from the members and I haven't done a report.

MR. BARZ: But you have filed six separate submissions in this proceeding?

MR. ANDERSON: That is correct.

MR. BARZ: Between March and July of this year?

MR. ANDERSON: Between March and October of this year.

MR. BARZ: As you referenced, there was one submission from -- that attached, I believe, a lengthy legal brief from your counsel, Gowlings, that set out your legal arguments in respect to this case?

MR. ANDERSON: Yes.

MR. BARZ: It didn't -- again, it didn't have any actual quantifiable evidence regarding the impact of the TCA on AMPCO members or AMPCO -- a specific member generally?

MR. ANDERSON: I think what was heavily relied upon, counsel, was that this very issue has been debated, fought over, decided and enacted in the US pursuant to FERC order 745.

We have referenced that in, I believe, every single submission that we filed. And while I understand Ontario is not jurisdictional, with the exception of course of the OEB, FERC is probably the pre-eminent energy regulator in North America. And one of its decisions, I would expect, would hold some weight, even in non-jurisdictional areas, as supported by some of the evidence that was filed by the IESO.

MR. BARZ: I do intend to get there, but just so I am clear, I know nothing was filed in this proceeding in terms of a report or study from your members or a member. But did your members ever undertake any analysis, or a report or study at any time?

MR. ANDERSON: I wouldn't know.

MR. BARZ: So that wasn't discussed with your members during your various meetings?

MR. ANDERSON: It was not.

MR. BARZ: Do you agree that AMPCO or its members had sufficient time to prepare such an analysis, report or study during the nine months this was made clear to you?

MR. ANDERSON: I would expect it would have been sufficient in terms of timing.

MR. BARZ: So can I take you quickly to an October 31st, 2019, letter that was submitted on behalf of AMPCO by your counsel. It is tab 3 in our compendium.

This letter was submitted on October 31st, and it attempted, or at least initially sought permission of the Board to file evidence in this proceeding from Charles Rivers and Associates. Is that correct?

MR. ANDERSON: That is correct.

MR. BARZ: And I am just going to quote here. I think it is on the second page. If you go to the second line of the second page, it talks about what that evidence will look like and it says:

"This evidence was projected to relate to," and I quote, "experience with compensation for economic activation of demand response in markets in FERC-regulated jurisdiction," and this is the second piece, the big important piece, "as well as the implications of seeking to apply such compensation in a market like Ontario's."

Is that correct?

MR. ANDERSON: This was submitted in response to -- it was either Procedural Order 2 or 3. I believe it was Procedural Order 2 in which there was an indication that the Board would appreciate some additional evidence of this sort, where it had further clarification of the FERC order, order 745, and its implications for Ontario.

That is why we were framing our discussions along this line.

MR. BARZ: Thank you for clarifying that.

So this October 31st letter, it proposes filing this evidence by November 8, and that is on the third page. There is a short paragraph on the third page, but I believe it says: "Given the November 8th deadline for filing evidence in this matter, CRAI has already commenced work on this evidence."

So I believe that was the deadline that CRAI was working towards.

MR. ANDERSON: That was the deadline we were discussing with Charles River.

MR. BARZ: So this was filed on October 31st. You were projecting potentially filing that evidence on November 8th. So from my understanding, that would be approximately ten days that they could have prepared that evidence in?

MR. ANDERSON: It was under discussion between ourselves and Charles River, yes.

MR. BARZ: If such a report could be commissioned in ten, even twenty, even thirty days that would provide implications of seeking to apply such compensation in the Ontario market, so essentially explaining how that compensation mechanism would have impact on the Ontario market and potentially your members, how come you never filed that evidence before, if you knew about this for nine months and you had all of that time to prepare such evidence?

MR. ANDERSON: As I indicated before, we were looking at this within the context of the request that we had read as part of procedural order No. 2.

We approached Charles River, and as I said, we were having conversations, both with respect to schedule and with respect to cost during the time that we wrote this.

Immediately after this, there were, I believe, two letters filed with the Board that indicated those objections to AMPCO filing additional evidence, stating that they didn't think we had this opportunity and consistent with the procedural order, it didn't specifically call out the applicant. It called out, I Believe, the IESO or intervenors.

So given the fact that we had not yet confirmed the schedule with Charles River, we had not yet confirmed the cost with Charles River, I represent a not for profit association, sir. That association does not have unlimited funds and the fact that I am here today is -- I am counting as we go, let's put it that way.

This has not been a cheap endeavour. I wish it had been. And at the point at which we got the two letters of objection, I said to Mr. Mondrow, that's it. We're not filing, because I don't have a schedule from Charles River. I don't have a full-on cost from Charles River. We haven't signed anything yet and I am not going to tell my Board, who I already convinced that I was going to file some additional evidence, yes, we got the evidence done, it's very good. Unfortunately, we couldn't file it. That was a conversation I didn't want to have.

So given the lack of firm schedule, the lack of firm cost, plus the letters from the IESO -- and forgive me, I don't know who the other was -- we decided that's it. We're not going to file evidence because I am not fighting to file this, potentially losing and spending more money and not even being able to file it. So that's what played out.

MR. BARZ: Thank you, I appreciate that clarification. Just to clarify, though, you could have potentially had that evidence within, say, twenty days, ten days, that was a possibility?

MR. ANDERSON: We were discussing that with Charles River. And as you see from page 2 of the Gowling letter, that was the scope of the evidence.

The scope of the evidence was purposely made to resemble what was requested in Procedural Order 2, to try to be of assistance to the Board.

MR. BARZ: And as I believe you indicated, on November 4th, 2019, AMPCO withdrew its request to file that additional evidence?

MR. ANDERSON: That's correct.

MR. BARZ: So the Board never ruled on the objection letters that were received from the other parties or never even ruled on your initial request to file that evidence.

MR. ANDERSON: No, they didn't. They didn't need to.

MR. BARZ: So just to be clear, you have put forward no quantifiable evidence of unjust economic discrimination for AMPCO members or an AMPCO member specifically in this proceeding. Correct?

MR. ANDERSON: Yes. I don't think I want to agree with you completely on that, counsel.

MR. BARZ: I said quantifiable evidence.

MR. ANDERSON: I understand that.

MR. BARZ: Have you put forward any quantifiable evidence?

MR. ANDERSON: I would like to talk to that, if I may.

There's been a lot of discussion and a lot of innuendo in respect of quantifiable evidence and why AMPCO hasn't filed quantifiable evidence, and we don't have members sitting next to us and they haven't disclosed their entire offer strategies.

I guess what I would like to say is, I can't use absolute cost numbers because I don't have those absolute cost numbers. Those absolute cost numbers belong to my members, and they don't disclose those to an association or its president, so I don't know what their absolute cost numbers are.

And with all due respect, counsel, you don't know either, and neither does Mr. Short. The IESO response to AMPCO number 2, the second batch of interrogatories, where the IESO confirms that it's not privy to the costs or bidding strategies of DRA participants.

But I do know this: Directionally, we know that the inclusion of a utilization amount can only increase the demand response capacity offer, regardless of what probability is assigned to its activation, and also that utilization amount for a generator will be zero, because they qualify for energy payments. So there will be upward pressure applied to DR offers, but none applied to off-contract generators.

And if we look at Mr. Windsor's affidavit, he expects that capacity prices will be lower than they have been in the past.

Finally, paragraph 101 of the IESO evidence shows that they're only securing 675 megawatts, again, in this auction, which is pretty much the same amount that they secured the last time.

So to summarize, we have lower prices. We have more participants. We have upward pressure on one class of participant. And we have the same capacity requirement as last year.

So I get that it's not quantifiable evidence, but I will be amazed if somebody can look at those four points and say that it's not less likely that DR will clear these auctions.

MR. BARZ: Thank you for that lengthy explanation. So I will take it that your answer was that you haven't put forward quantifiable evidence, which is fine.

Currently, the only affidavit then from AMPCO is from yourself, correct?

MR. ANDERSON: That's correct.

MR. BARZ: And to confirm, as president of AMPCO you are not directly responsible for any demand resources, and you have already indicated that you don't have any insight into the actual bidding that your members make in the auction.

MR. ANDERSON: Also correct.

MR. BARZ: And AMPCO is a not-for-profit consumer interest advocacy organization?

MR. ANDERSON: Yes, we are.

MR. BARZ: And advocacy organization, effectively a lobbyist, correct?

MR. ANDERSON: We do do some lobbying, yes.

MR. BARZ: Thank you. And in your evidence you have made some reference to FERC order 745. And I believe there's no actual reference to that order in your affidavit, is there? You don't actually mention the words FERC order 745 in your affidavit, do you? You don't have to do a complete scan. I can assure you, it's not there. But what is there is, you do attach six submissions to your affidavit. They're Exhibit B to your affidavit. They're tab 1 in my compendium, I believe.

And all of those refer to FERC order 745 at some point and to some extent. And I believe that -- and each of the cover letters that precede those submissions are signed by yourself, correct?

MR. ANDERSON: They are.

MR. BARZ: So do you agree with me that the main proposition that you rely on FERC order 745 for is the notion that demand response resources must be compensated for the service it provides to the energy market at the market price for energy?

MR. ANDERSON: I think what I rely on order 745 for mostly is just an illustration of how comprehensively this has been debated in another jurisdiction with another energy regulator who is well respected in North America.

All the pros and all the cons, all of the economists and all of the engineers have had their day to put forward their perspective, and FERC has issued order 745, where four out of five of those commissioners have upheld the notion that there should not be discriminatory treatment associated with energy payments for loads versus energy payments for generators.

So while I don't necessarily say we should import 745 exactly, I do say that it's indicative of how much effort and energy has been put into this, and it should be respected for that.

In Ontario we can take what's there, the FERC order, and we can customize it, but certainly the general bones of it have already been argued. I think that is really what the main point of FERC order 745 and all of my submissions is.

MR. BARZ: So you will agree with me, though, that there is significant differences between IESO administrative markets and the FERC-regulated

jurisdictions, correct?
MR. ANDERSON: There is always differences.
MR. BARZ: So for example, in Ontario the large electricity customers pay real-time energy prices; is that correct?
MR. ANDERSON: Yes.
MR. BARZ: And Ontario's electricity market is also expected to evolve differently than the U.S. market, correct?
MR. ANDERSON: I'm sorry. I didn't hear that. sir.
MR. BARZ: Just that the Ontario market is expected to evolve differently than the U.S. market in terms of off -- currently on-contract generators coming off-contract? That's a difference between the markets here and the market in the U.S.? FERC-regulated jurisdictions?
MR. ANDERSON: As I said, there is always differences from market to market, but certainly there is lots of times when we look to the south as an indication of a potential idea for what we want to look at in terms of market renewal or anything else. There is always a customization that takes place, but in terms of a general direction, a starting point, if you will, we do that quite frequently.
MR. BARZ: And so another difference would be the global adjustment. That's another unique factor, and I know you have already addressed it a bit in your evidence, but it is also a unique factor of Ontario's market -- it is just a simple yes or no question -- that doesn't exist in the U.S. Correct?

MR. ANDERSON: Global adjustment in its Ontario form does not exist in the U.S.; that's correct. Its components obviously do, capacity and any other policy charges.

MR. BARZ: So despite these clear differences between FERC-regulated jurisdictions and Ontario, AMPCO has elected to rely on the FERC order to some extent rather than putting forward any specific evidence of the direct, potentially quantifiable, even theoretical analysis of the impacts on AMPCO members or an AMPCO member in Ontario?

MR. ANDERSON: We have, yes. Because as I said before, FERC order 745 is representative of a tremendous amount of effort expended by all parties involved, and it came to a conclusion.

We feel that conclusion is robust and could be taken and customized within the Ontario context. And we could customize it with respect to some of the things you have referred to and maybe some other things as well. It provides a starting point and a direction and it should be respected as such.

MR. BARZ: And AMPCO has not undertaken any analysis of the costs that would be borne by Ontario ratepayers of provide energy payments to demand response resources, correct?

MR. ANDERSON: We have not done an analysis; that's correct.

MR. BARZ: I just have one more line of questions I would like to ask you.

In your estimation, has the actual auction in Ontario, the demand response auction to date, has it been very successful? Just a simple yes or no --

MR. ANDERSON: I am looking for my evidentiary reference where the IESO has indicated that it has been tremendously successful --

MR. BARZ: I was about to go --

MR. ANDERSON: I'm happy to take you there, but you can go there.

MR. BARZ: Perfect. So if you go to tab 2 in your compendium, it is a news and updates publication. I believe this is what is quoted in your affidavit.

And in your affidavit -- we don't need to go to both. It is probably better to go to my tab 2, but I believe you quote it at page -- or paragraph 10 of your affidavit.

The quote you use:

> "The auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year over year demonstrate the ongoing maturity of the demand response market as more consumers participate and competition increases."

Is that the correct reference in your affidavit?

MR. ANDERSON: It is.

MR. BARZ: And while we're looking at that news and updates publication there, you will agree with me this publication provides information on how demand response auction has shown growth, in terms of participation in the auction, and the decrease in the cost over the years, on a general high level about what it shows?

MR. ANDERSON: Yes, it does. Yes, I would agree.

MR. BARZ: But this news and updates publication does not address the effect particularly of demand response resources when called upon to be activated by the IESO, correct?

MR. ANDERSON: I don't see it in there, if it does.

MR. BARZ: One of the statistics provided in this publication relates to the total amount of megawatts that was cleared in the auction in 2018 for 2019. I believe it is at paragraph 4. The total number of cleared megawatts, in the second line there, is 818 megawatts for the 2009 summer commit, and 854 megawatts for the 2019/2020 winter commitment period. Is that right?

MR. ANDERSON: I see that.

MR. BARZ: What is your understanding of the total megawatt shortage the IESO presently anticipates for the summer of 2023?

MR. ANDERSON: Well, you would be better off asking the IESO that question. But I think it is measured in thousands of megawatts.

MR. BARZ: I believe it is around 3,844 megawatts was the most recent projection. I think it is at paragraph 11 of the Short affidavit. I don't know if we need to go there, but we can even say 3,500 if that is okay.

MR. ANDERSON: That's fine.

MR. BARZ: This is a considerable gap, is it not?

MR. ANDERSON: Between 3,500 and 800?

MR. BARZ: Yes.

MR. ANDERSON: Yes, it would be.

MR. BARZ: Are you familiar with the performance to date of demand response resources and test activations?

MR. ANDERSON: I am familiar with the evidence that's been filed on that, yes.

MR. BARZ: I would like to take you to tab 5 of my -- sorry, tab 4 of my compendium. This is an hourly Demand Response Testing Update, presented to the Demand Response Working Group on April 25th, 2019.

Are you familiar with this PowerPoint presentation, having participated in the Demand Response Working Group?

MR. ANDERSON: As a matter of fact, I was there.

MR. BARZ: All right. So that's great, that's helpful. Can I take you to page 7 of this presentation, please?

This is just a graph that shows the hourly demand response testing performances and the activations. It is easy to digest because it is a graph.

What's the overall failure rate, at the bottom left hand corner of the page, for test activations that were four hours in duration?

MR. ANDERSON: Sorry, the overall? Or all 4 hours?

MR. BARZ: The overall failure rate, total.

MR. ANDERSON: It says at the bottom of the page 58 percent.

MR. BARZ: So based on this failure rate and the looming capacity gap that we just talked about for 2023, you can understand why the IESO has concerns about the demand response auction?

MR. ANDERSON: Well, I think we're looking at this a little bit differently, sir. Certainly the IESO has been more than complimentary about demand response and about the auction performance and the number of participants, the increased competition and the reduction in terms of the cost.

In any situation where they have non-compliances, I would expect them to use the processes that are well established for them to deal with those non-compliances. I don't think that they should look at that and say, well, the construct should be thrown out.

If you have people that are not compliant, there are processes that exist pursuant to the market rules to deal with those people. I would expect that is what should happen here, not throw out the entire construct.

MR. BARZ: Thank you. I am just going to look through my notes to see if I have any more questions for you.

That's it for me. Thank you very much, Mr. Anderson.

MR. ANDERSON: Thank you.

MS. SPOEL: Thank you, Mr. Barz. Ms. Krajewska, I think you are up now, right?

MS. KRAJEWSKA: Yes, Madam Chair, I am, thank you.

CROSS-EXAMINATION BY MS. KRAJEWSKA:

MS. KRAJEWSKA: So just for the Panel and for the witness, we have prepared a cross-examination compendium for Mr. Anderson. It looks like this. I am just holding

TAB 3

EB-2019-0242

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Application for Review of an Amendment to the Independent Electricity System Operator Market Rules

AFFIDAVIT OF COLIN ANDERSON

I, COLIN ANDERSON, of the City of Oakville, in the Province of Ontario, MAKE OATH AND SAY:

1. I am employed as the President of the Association of Major Power Consumers in Ontario (AMPCO). AMPCO is a not-for-profit consumer interest advocacy organization that is active in the electricity sector. AMPCO's members represent Ontario's major industries: forestry, chemical, mining and minerals, steel, petroleum products, cement, automotive and manufacturing, and industrial consumers in general.

2. Since March of 2019, in my role as AMPCO President, I have been closely following and actively participating in the stakeholder process leading up to the market rule amendments at issue on this application. As such, I have knowledge of the matters attested to in this affidavit. I have also had discussions with AMPCO members who directly participate in the Ontario Independent Electricity System Operator (IESO) Administered Market (IAM) as Demand Response resources (DR Resources). Where statements made in my affidavit are based on information from AMPCO members I have so stated.

3. AMPCO has brought this Application on behalf of its members who will be negatively impacted by the amendments at issue. I am providing this evidence, in my role as President of AMPCO, and because of reticence that I perceived among my members to do so themselves. In my view this is an important role for an industry advocacy association, and its President.

4. Accordingly, I provide this affidavit in support of the Application brought by AMPCO for review and revocation of the IESO Ontario Electricity Market Rules (Market Rules) amendments MR-00439-R00-R05 as published by the IESO on September 5, 2019[1] (Amendments). This affidavit also supports the motion brought by AMPCO to stay the operation of the Amendments pending resolution of the Application for review. This affidavit is made for no other or improper purpose.

The Amendments.

5. On September 5, 2019 the IESO published the Amendments on its website.[2]

6. The Amendments facilitate the expansion of the current IESO Demand Response Auction (DRA) to a broader, Transitional Capacity Auction (TCA).

7. The first TCA is scheduled for early December, 2019. Attached at Exhibit A is the IESO's *2020 Transitional Capacity Auction (TCA) Phase 1 Timelines for TCA held in December, 2019*.

8. Although the issue of appropriate compensation for DR Resources for the services they provide to the IAM (i.e., the issue of energy payments to DR Resources) has long been outstanding and has been discussed for some time as part of the IESO's Demand Response Working Group (DRWG), in which I have participated in 2019, the IESO has not yet resolved the issue. It is unlikely that this issue will be resolved before the first TCA happens in December, 2019.

9. AMPCO participated in the stakeholder process leading up to the Amendments, and the six written submissions which AMPCO provided to the IESO between March and July 2019 as part of that process are attached at Exhibit B.

[1] Filed herein as part of AMPCO's Notice of Appeal, Attached as Footnote 1, pages 3 through 60.
[2] The notice of publication is filed herein as part of AMPCO's Notice of Appeal, Attached as Footnote 1, pages 1-3.

AMPCO Members' Participation in the IAM, including the DRA.

10. The IESO's existing Demand Response Auction (DRA) process permits the participation of only DR Resources. The IESO reports that the DRA is a *"valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases..."*. Attached at Exhibit C is a copy of the IESO's published report on the most recent DRA held in December of 2018.

11. The TCA, proposed to be conducted in early December 2019 under the Amendments, will allow generators to participate in the process, alongside DR Resources.

12. In the existing DRA, the only revenue stream available to participants is a capacity payment. There are currently no payments made for energy activations in the DRA. If the TCA proceeds in December 2019, in a situation where energy is activated, DR Resources will still only qualify for capacity payments, whereas generators will qualify for both capacity payments and energy payments.

13. If the TCA proceeds in accordance with the Amendments, the TCA will allow for two distinct classes of participant – one whose members receive an energy payment (generators) and one whose members do not (DR Resources).

Implications of the proposed TCA.

14. If the TCA is implemented in December 2019, pursuant to the Amendments:

    (a) generators will be able to offer into the auction taking into account their anticipated energy payments, which would allow them to set their "offer price" factoring in the anticipated value of the energy payment stream that they will receive when dispatched;

    (b) DR resources will not have the benefit of such anticipated energy payments, and so will not have an anticipated energy payment stream to factor in when setting their "offer price"; and

    (c) DR resources will thus be at a competitive disadvantage to generators in the auction because they will not have additional anticipated IAM payment streams to factor in when setting their "offer price".

15. I am informed by AMPCO members and verily believe that in the existing DRA process, an IESO proposed “work-around” has sometimes been used. In that “work-around” DR Resources have increased their capacity offers by an amount sometimes referred to as a “utilization payment”. This “utilization payment” is thought of as a partial proxy for energy payments upon activation. Inclusion of this proxy allows the DR Resources to offer a price that would provide them with some compensation if they are activated for energy. If this proxy methodology were to be used by DR Resources in the TCA it would increase their offers and make them uncompetitive relative to the generators.

16. Any DR Resource that includes a “utilization payment” amount in its capacity offer (as a proxy for the nonexistent energy payments to DR Resources) will move itself up the offer stack (i.e., make itself more expensive) and no longer be competitive with those entities that do not include such cost elements in their capacity offers.

17. Those participants who include “utilization payments” in their capacity offers (DR Resources) are unlikely to clear the capacity market since they will be including cost elements that other participants (generators) will not be including, because those other participants will cover those costs in their energy payments that they will receive when activated.

18. I am informed by some AMPCO members and verily believe, it can be problematic for DR Resources to simply omit “utilization payment” amounts from their capacity offers, since they have no other reasonable means of recovering those amounts in the event that they are activated in the energy market.

19. In other words, if they include utilization amounts, they cannot compete in the capacity market and if they do not include them they may clear the capacity market, but cannot recover legitimate costs if they are activated to provide energy.

20. If the TCA proceeds before appropriate resolution by the IESO of the issue of energy payments for DR Resources, it is unlikely that DR Resources will clear the new capacity market. DR Resources’ inability to be cost competitive will effectively exclude them from participation in a process that was originally exclusive to them (the DRA), and the TCA would thereby replace one set of capacity auction participants (DR Resources) with another (generators).

Harm to DR Resources can be Avoided.

21. By staying the Amendments pending the outcome of AMPCO's broader Application, the effective exclusion of DR Resources from the capacity auction can be avoided. A stay would delay the implementation of the first TCA. That delay would allow the IESO time necessary to appropriately resolve the issue of energy payments to DR Resources – an issue that the IESO has already acknowledged as a barrier to DR Resources' participation in the IAM and that the IESO has long been discussing through the DRWG (see Exhibit D, which is a copy of the IESO *"Active Engagements"* web page discussion of the ongoing IESO work on energy payments for activation of DR Resources). With that issue appropriately resolved, a capacity auction process could be conducted in a manner that is fair for all participants.

22. On the other hand, staying the Amendments pending the outcome of AMPCO's broader Application should have no negative impact to the IAM. Attached as Exhibit E is a copy of a communication from the IESO's CEO, Peter Gregg, stating that, "*it is clear that over the next decade, we have enough energy to meet provincial demand and a limited need for new capacity if existing Ontario resources are reacquired when their contracts expire. We believe these limited capacity needs can be met through existing and available resources such as Demand Response (DR), imports, generators that are coming off long-term contract, uprates and energy efficiency.*" The IESO has also indicated that there is no need for additional capacity until the year 2023 when the phase-out of the Pickering nuclear plant begins, as stated in Stakeholder Advisory Committee Meeting Notes dated August 14, 2019, which indicate that the attached Exhibit F.

SWORN BEFORE ME at the City of Toronto, in the Province of Ontario on October 11, 2019

Commissioner for Taking Affidavits
LSUC 55408S

COLIN ANDERSON

TAB 4

COLIN J. ANDERSON, P.Eng, MBA

2302 Ridge Landing
Oakville, Ontario, L6M 3M8
C (905) 483-0285
colinanderson6@gmail.com

WORK EXPERIENCE

2016 - Present **ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)**

President

AMPCO is a not-for-profit consumer interest advocacy organization. AMPCO's members represent Ontario's major industries: forestry, chemical, mining and minerals, steel, petroleum products, cement, automotive, industrial air, manufacturing and business consumers in general. AMPCO members are major investors, major employers and a major part of communities across Ontario.

- **Policy** – Responsible for all advocacy work in the area of policy development.
- **Regulatory** – Responsible for all regulatory interventions and consultations that could impact members.
- **Operations** – Responsible for all day to day operations of the Association.

2001 – 2016 **ONTARIO POWER GENERATION INC. (OPG)**

(2012 – 2016) Director, Major Applications
(2007 – 2012) Director, Ontario Regulatory Affairs
(2005 –2007) Regulatory Affairs Manager – Operations
(2001 – 2005) Senior Advisor – Regulatory Affairs

Responsible for all aspects of OPG's major applications filed with the Ontario Energy Board (OEB) associated with all of OPG's regulated assets, both Hydroelectric and Nuclear. Some key points:

- **Case Management of OPG Rate Applications -** This includes resolution of senior executive level strategic and tactical issues, coordination of all internal and external stakeholder activities, creation and review of all evidence, witness preparation, and full case management responsibilities. Applications typically deal with annual revenue requirements in the $5 billion range.
- **Supervisory -** Direct activities of all staff and consultants on OPG's rate applications. I was also a member of OPG's Corporate Grievance Review Board, whose mandate was to dispose of grievances jointly with union representatives. I have supervised both represented and management staff.
- **Market Activities -** Supported OPG senior management in decisions associated with OPG's activities within Ontario and other markets, including both state/provincial jurisdictions and the U.S. Federal Energy Regulatory Commission (FERC).
- **Reliability -** Directed OPG's involvement in North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC) reliability standards development and compliance activities. Served as Chairman of NPCC's Reliability Coordinating Committee in 2008.
- **Compliance Initiatives -** Designed and implemented compliance programs, including Competition Compliance in coordination with operating Business Units. Resulted in increased awareness of, and attention to, compliance issues associated with the open electricity market.

2000 - 2001 **DELOITTE CONSULTING**

Manager – Energy Practice

Provided management consulting services to energy sector clients. Some key points:

- **Strategic Initiatives -** Developed an Energy Market Study for Deloitte Global Office to uncover market-driven insights and opportunities. Results informed investment planning within the Energy Practice for the firm.
- **Energy Market Readiness Initiatives -** Implemented market readiness programs for generating companies that were preparing for deregulation as part of a multi-disciplinary team. Focused on the integration of operations and energy markets activities from strategic, people and systems perspectives, with a focus on business processes.
- **Supervisory -** Directed activities of consultants and senior consultants on an engagement-by-engagement basis. Able to influence decisions in client organizations in which I had no direct management authority.

1994 - 1998 **WESTINGHOUSE CANADA INC.**

Senior Engineer - Steam Turbine Design

Employed in the Product Engineering Group whose mandate included responsibility for new product design and service engineering issues. Some key points:

- **Project Management / Internal Consulting -** Consultant to Joint Venture Partners in both South Korea and China. Scope of Korean engagement included design reviews, process implementation and reengineering, cost reduction analysis, component outsourcing, training and quality assurance audits.
- **Technical -** Lead Engineer for the "first-of-its-kind" co-manufacturing project with a new Strategic Alliance Partner in Korea. Achieved success in design, manufacturing support, and technical consultation resulting in the first ever Westinghouse technology steam turbine shipment from the JV Partner's new facility.
- **Supervisory -** Key senior player in multi-disciplinary, team-based structure. Managed activities of junior engineering staff and draftspeople on a project-by-project basis.

1988 - 1994 **ONTARIO HYDRO (LENNOX AND NANTICOKE GENERATING STATIONS)**

Assistant Thermal Station Engineer

Assigned to the Maintenance Department where responsibilities included support in all areas of power plant management. Some key points:

- **Production Work** – supported all day to day operations and maintenance of the facilities.
- **Asset Management** – responsible for both capital projects and operations, maintenance and administrative (OM&A) budgets, as well as life cycle plans for station assets.
- **Supervisory -** including all staffing, training, health & safety and labour relations issues in a heavily unionized environment.

EDUCATION

2000 **University of Toronto (Rotman School of Management) -** Masters of Business Administration

1988 **Queen's University -** B.Sc. (Honours) Mechanical Engineering

TAB 5

EB-2019-0242

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

APPLICATION TO REVIEW AMENDMENTS TO THE MARKET RULES MADE BY THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR

AFFIDAVIT OF DAVID SHORT
(Sworn October 25, 2019)

I, David Short, of the Region of Halton, in the Province of Ontario, **MAKE OATH AND SAY**:

1. I am the Director of Capacity Market Design for the Independent Electricity System Operator ("**IESO**"). I hold a BSc (Honours) in Applied Science (Electrical Engineering from Queen's University and have more than 25 years of experience in the power sector. I have been employed by the IESO since 2005 in various positions of increasing responsibility and scope. I have held the position of Director of Capacity Market Design since March 2019. Prior to that, I was the Director of Power System Assessments between March 2017 and March 2019.

2. As the Director of Capacity Market Design, I am responsible for overseeing the design and implementation of changes to the IESO's existing demand response capacity auction, including evolving it to acquire power system supply capacity in a manner that increases participation, competition, power system reliability and economic efficiency. As such, I have knowledge of the matters to which I hereinafter depose. Where I have obtained information from others, I verily believe such information to be true.

3. I swear this affidavit in response to a motion filed by the Association of Major Power Consumers in Ontario ("**AMPCO**") seeking to stay the operation of market rule amendment MR-00439-R00 to R05 (the "**Amendment**") pending the Board's review of the Amendment.

The Transitional Capacity Auction

4. The purpose of the Amendment is to implement a Transitional Capacity Auction ("**TCA**") in Ontario.

5. In the context of the IESO-administered markets, "capacity" represents the need to have sufficient resources available to ensure that the demand for electricity in Ontario can be met at all times. At a high level, capacity can be provided by supply resources through energy injections or from loads in the form of demand response. The purpose of a TCA is to create a market-based mechanism that secures incremental capacity to help ensure that Ontario's reliability needs are met in a cost-effective manner.

6. The IESO's previous capacity auction – the demand response auction ("**DRA**") – was introduced in 2015. The DRA consisted of an auction in December of each year for a one-year commitment period starting in May of the following year. If called upon by the IESO, DRA participants fulfilled their capacity obligation by refraining from consuming energy from the IESO-administered market. DRA participants could participate as either a dispatchable load (which responds to a five-minute schedule) or as an hourly demand response participant. DRA participants received availability payments and were subject to non-performance charges.

7. The TCA is the first step in evolving the DRA into a more competitive capacity auction that includes additional resource types. The Amendment enables non-contracted and non-regulated Ontario generators to participate in a capacity auction alongside dispatchable loads and hourly demand response resources.

8. The TCA will run on December 4, 2019 for a commitment period of May 1, 2020 to April 30, 2021. The successful participants in the TCA will be required to become authorized as Capacity Market Participants, which will enable them to register resources with the IESO to deliver on their capacity obligations. TCA participants will receive availability payments for providing auction capacity, subject to non-performance charges.

9. The IESO is planning subsequent phases of its capacity auction design that will enable additional resource types to participate (such as imports and storage) and will introduce new auction features. Each phase is expected to require further changes to the market rules.

10. The IESO plans to increase the forward period for future capacity auctions. The IESO's intention is to run future capacity auctions in June 2020 (for a May 1, 2021 to April 30, 2022 commitment period), December 2020 (for a May 1, 2022 to April 30, 2023 commitment period) and in 2021 (for a May 1, 2023 to April 30, 2024 commitment period).

The Need for a Transitional Capacity Auction

11. The TCA is part of the IESO's strategy to address a significant capacity gap that is forecast to start in 2023. On September 13, 2018 the IESO released the Electricity Planning Outlook that forecasted a capacity deficit in summer 2023 of 3844 MW. A copy of the September 2018 Planning Outlook is attached as **Exhibit "A"** (see page 51).

12. As part of its Market Renewal initiative, the IESO was planning to implement an Incremental Capacity Auction ("**ICA**") which would address the future capacity gap. However, in September 2018 the IESO came to the realization that it was not feasible for the ICA to be launched in time to address the projected 2023 capacity gap and that alternative measures were required.

13. To address this capacity gap, the IESO, in January 2019, announced its intention to enhance the DRA – calling the enhanced auction the TCA – by allowing more resource types to compete. Between February and August 2019, the IESO conducted a formal stakeholder engagement initiative to gather and incorporate feedback from stakeholders on the design of the TCA. Written submissions were received from generators, demand response aggregators, the Market Surveillance Panel, consumers and associations representing local distribution companies, generators and consumers.

14. While work on the ICA was discontinued by the IESO in July 2019, there continues to be a forecasted capacity gap that must be addressed by the IESO to ensure the reliability of Ontario's electricity system. Attached as **Exhibit "B"** is a presentation to the IESO's Stakeholder Advisory Committee dated August 14, 2019 that contains an updated forecast of a capacity gap of approximately 4000 MW in summer 2023 (see page 4).

The Adoption of the Amendment by the IESO Board

15. The Amendment was adopted by the IESO Board at its meeting of August 28, 2019. Attached as **Exhibits "C"** and **"D"** respectively are the Resolution of the IESO Board adopting the Amendment and the Reasons of the IESO Board in respect of the Amendment (the "**Reasons**").

16. The Reasons state that the IESO Board reviewed the market rule amendment materials, including the positions of stakeholders and issues raised during the market rule amendment process, and decided to adopt the Amendment with an effective date of October 15, 2019.

17. The IESO Board identified the following reasons for adopting the Amendment:

a) The Amendment is the first phase in evolving the DRA into a more competitive capacity acquisition mechanism that includes new resource types. This allows for increased competition in the acquisition of capacity for the benefit of Ontario customers.

b) The Amendment enables the IESO to begin implementing the TCA in a phased approach in order to be ready to address forecasted capacity needs in Ontario. The implementation of the first phase of the TCA will enable important experience and learnings with respect to integrating and administering new resource types in the Ontario capacity market sufficiently in advance of more significant capacity needs, currently projected to arise in the 2023 timeframe. A phased approach will reduce risk, while ensuring continued evolution of the market through the phased inclusion of new resources. This is a more prudent approach than attempting to implement a new capacity auction mechanism just prior to the time when there is a more significant capacity need.

c) The Amendment enables non-committed dispatchable generators to participate in the TCA alongside dispatchable loads and hourly demand response resources. The Amendment provides an important opportunity for existing non-committed generators coming off contract to compete to provide reliability services, in this case capacity. In the absence of this opportunity to compete, these generators may choose to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario customers.

18. In its Reasons, the IESO Board specifically addressed the position of AMPCO that the Amendment unjustly discriminates against demand response resources. The Board noted that AMPCO's position "relies heavily" on Order 745 from the Federal Energy Regulatory Commission ("**FERC**") which requires energy payments to demand response resources when they are dispatched subject to the condition that they meet a "net benefit requirement." The IESO Board observed that FERC Order 745 is not determinative because:

a) while FERC Order 745 is a relevant consideration, it is not binding in Ontario;

b) it is unclear whether the net benefit requirement applies in Ontario, given the differences in Ontario's market design;

c) the IESO has committed to completing an independent study to determine whether there would be a net benefit to Ontario consumers if demand response resources receive energy payments for economic activations; and

d) the energy payment issue is not material because economic activations in the DRA have historically occurred in very limited circumstances and are not expected to be a material consideration for the December 2019 auction.

19. The IESO Board concluded that implementing the Amendment is a prudent decision and that delaying the Amendment until the study is complete would be detrimental to the market overall, as it would "delay the introduction of increased competition, create an unnecessary delay in the phased approach to developing the auction in advance of substantial future capacity needs, and risk failing to retain access to existing generation assets coming off contract." [1]

20. The IESO Board also noted that the Technical Panel recommended the Amendment in a vote of 11-1 and "exercised its discretion on an informed and reasonable basis." A copy of the Technical Panel's Rationale for recommending the Amendment is attached to this affidavit as **Exhibit "E"**.

Stakeholder Engagement on Energy Payments for Demand Response Resources

21. In conjunction with the adoption of the Amendment, the IESO has commenced a separate stakeholder engagement initiative to consider changes to the market rules to provide for energy payments to demand resources as part of future phases of the capacity auction.

22. The provision of energy payments would represent a substantive change to the IESO-administered energy markets. Loads do not receive energy payments under the market structure that has been in place since market opening in 2002. Prices bid by dispatchable loads in the energy market represent a point at which a load no longer wishes to consume electricity.

[1] Exhibit "D", *Reasons of the IESO Board in respect of an Amendment to the Market Rules* (August 28, 2019), p. 4.

23. The IESO previously studied the merit of utilization payments[2] for demand response resources through its Demand Response Working Group ("**DRWG**"). In July 2017, the IESO retained Navigant Consulting ("**Navigant**") to provide research on utilization payments and inform a dialogue on their possible merits to drive additional, economically efficient demand response to meet a variety of electricity system needs. Navigant examined practices adopted in other markets and considered arguments for and against providing utilization payments.

24. In December 2017, the IESO released a Discussion Paper prepared by Navigant, which concluded that in considering the case for utilization payments in Ontario:

> The arguments for and against utilization payments are nuanced and prudent. Responsible stakeholders can arrive at different conclusions based on preferences for evaluation criteria.
>
> A unique consideration for Ontario is that today, almost all generation resources are compensated under long-term contract or through regulation that guarantees a certain level of revenue. The economic efficiency arguments under this current market structure are different than they would be if considering the future state of the wholesale power market where generation resources are largely compensated through energy and capacity market revenues. Under the current conditions, more DR activation (as a result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced costs to consumers since generators have their compensation guaranteed.

Attached as **Exhibits "F"**, **"G"**, **"H"**, **"I"** and **"J"** respectively are a copy of IESO presentations dated May 11, 2017 and May 30, 2017; a Navigant presentation on utilization payments dated November 16, 2017; the Navigant Discussion Paper, dated December 18, 2017; and an IESO presentation, dated March 1, 2018.

25. The issue of utilization payments for demand response resources resurfaced in 2019 as part of the IESO's stakeholder consultation on the implementation of the TCA. Due to the complexity of the issue, the IESO ultimately determined that a broader stakeholder engagement

[2] Navigant defined a utilization payment as a payment made to demand response resources when they are called upon to modify their load. A utilization payment could be an energy payment or some other form of compensation.

was needed to consider the issue. The IESO decided to commission a study to examine whether there is a net benefit to Ontario electricity ratepayers if demand response resources are compensated with energy payments for economic activations.

26. On August 22, 2019, the IESO launched a stakeholder engagement initiative entitled *Energy Payments for Economic Activation of Demand Response Resources* (the "**Energy Payments Stakeholder Engagement**"). The IESO commissioned a third-party consultant, Brattle Group, to support the research and analysis and is currently seeking stakeholder feedback on the "[i]nputs and outputs of third-party research and analysis to inform [the] IESO's decision on the energy payment issue". A copy of a presentation made by the IESO at the October 10, 2019 stakeholder meeting is attached as **Exhibit "K"**.

27. The IESO expects to present its draft decision and rationale on the issue for stakeholder review in May 2020 and render a final decision and rationale in June 2020. The IESO would then commence the market rule amendment process for any changes that are needed to implement the decision.

The IESO's Decision to Proceed with the TCA

28. Preparations are currently underway for the TCA on December 4, 2019. In addition to demand response resources, four market participants representing generators have already registered with the IESO as capacity auction participants.

29. As stated by the IESO Board in its Reasons, the IESO has decided to proceed with the TCA in parallel with the Energy Payments Stakeholder Engagement in order to ensure that the IESO will be prepared to address the significant capacity gap that is projected to arise in 2023.

30. Due to the complexities of creating an enduring capacity auction, it would be impractical and imprudent to attempt to introduce the full suite of changes required on the eve of the significant capacity need the auction would be required to address. Progressing in a phased approach, as the IESO has planned, allows the IESO to:

a) introduce new resource types into the auction gradually;

b) assess and respond to how new resource types behave in the capacity auction;

c) provide participants with an opportunity to develop and test business processes and business models to support their participation in capacity auctions;

d) provide participants an opportunity for price discoverability;

e) ensure that committed capacity resources are capable of satisfying their capacity obligations;

f) provide sufficient time to assess and evolve auction design features, informed by stakeholder input;

g) allocate the necessary resources to implement new auction design features in manageable steps; and

h) monitor and identify unforeseen consequences arising from new auction design features.

31. It is critical that the IESO evolve its capacity auction in a manner that promotes confidence in the auction process amongst existing and potential auction participants. A phased implementation of changes will help promote that confidence and is consistent with the IESO's general practice for prudently evolving market design incrementally.

32. Given the short timeframe in which the IESO must be prepared to meet the 2023 capacity gap, it is critical that the phased implementation of the enduring capacity auction begin with the TCA in December 2019. As stated at paragraph 10 above, there are only three planned auctions (December 2019, June 2020 and December 2020) before the IESO undertakes the auction for the critical summer 2023 period. This provides for limited opportunities for the IESO to execute, learn from and evolve the TCA prior to 2023.

33. As stated above, the introduction of energy payments for demand resources would be a substantive change to the fundamental design of the IESO-administered energy market. While the IESO has committed to studying the issue as part of the Energy Payments Stakeholder Engagement, the IESO is not prepared to forego the planned auctions to await the outcome of the Energy Payments Stakeholder Engagement. Any delays in the implementation of the planned auctions will reduce the margin for error and may force the IESO to rely upon less competitive mechanisms to address the capacity gap in 2023.

34. The IESO cannot rely upon the existing DRA to produce sufficient capacity to satisfy the coming capacity gap. The last DRA in December 2018 attracted a qualified capacity of over 1000 MW. This is insufficient to meet the forecast capacity gap of approximately 4000 MW in summer 2023. Hourly demand response resources also have a history of poor performance during test activations. Between February 2018 and January 2019, hourly demand response resources had a 58% failure rate for test activations which were four hours in duration. Attached as **Exhibit "L"** is a copy of the Hourly Demand Response (HDR) Testing Update presented to the DRWG on April 25, 2019 (see page 6). These results suggest that the actual capacity available to the IESO under the DRA may be substantially less than the results of prior DRA auctions suggest.

35. As noted by the IESO Board in its Reasons, the IESO believes that allowing supply resources to compete in the TCA will reduce the likelihood that the operation of generation facilities coming off contracts will be shut down. These generation assets could play a role in addressing the future capacity gap and increasing competition in future capacity auctions. The IESO is concerned that some of these generation resources may cease operations if the TCA is delayed as they will have no opportunity to compete in the IESO's capacity auction.

36. The IESO Board concluded that access to energy payments for demand response resources is not expected to have a material impact on the TCA. Demand response resources have been activated in very limited circumstances under the DRA. Hourly demand response resources have only been economically activated on one occasion since the introduction of the DRA; and dispatchable loads have been dispatched less than 1% of the time over that same period. The IESO does not expect the likelihood of economic dispatch to appreciatively increase in the commitment period under the December 2019 auction (May 1, 2020 to April 30, 2021).

SWORN BEFORE ME at the City of Mississauga, in the Province of Ontario, on October 25, 2019.	
Commissioner for Taking Affidavits LSUC · 59826S	DAVID SHORT

TAB 6

EB-2019-0242

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by the Association of Major Power Consumers in Ontario, pursuant to section 33 of the *Electricity Act, 1998, S*.O. 1998, c. 15, Sched. A and Rule 17 of the Ontario Energy Board *Rules of Practice and Procedure* for review of amendments to the Independent Electricity System Operator market rules related to the implementation of a Transitional Capacity Auction (MR- 00439-R00-R05).

AND IN THE MATTER OF a notice of motion by the Association of Major Power Consumers in Ontario, pursuant to section 33 of the *Electricity Act, 1998*, *S*.O. 1998, c. 15, Sched. A and Rule 17 of the Ontario Energy Board *Rules of Practice and Procedure* to stay the operation of amendments to the Independent Electricity System Operator market rules pending determination of the Application.

AFFIDAVIT OF
Brian Rivard, Adjunct Professor at the Ivey Business School and
Research Director of the Energy Policy and Management Centre, Western University

November 8, 2019
Revised: November 21, 2019

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N.	Exhibit “N”	Paper by David Brown and David Sappinton published in the Journal of Regulatory Economics in 2016

TAB 1

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I, Brian Rivard, of the Town of Paris, in the Province of Ontario, MAKE OATH AND SAY AS FOLLOWS:

A. INTRODUCTION

A.1 Q: Please state your name and occupation.

1. My name is Brian Rivard. I am Adjunct Professor at the Ivey Business School at Western University and the Research Director of the school's Energy Policy and Management Centre.

A.2 Q: For whom are you testifying in this proceeding?

2. I am testifying on behalf of Kingston CoGen Limited Partnership ("KCLP"). Attached hereto as **Exhibit "A"** is a signed copy of Form A pursuant to the Ontario Energy Board's (the "Board") Rules of Practice and Procedure.

A.3 Q: What is your educational background?

3. I hold a Ph.D. and M.A. in Economics from Western University. My field of specialization is industrial organization with an emphasis on the study of competitive markets, economic efficiency, and regulatory economics. I also have a B.A. in Economics from the University of Windsor.

A.4 Q: What is your professional background?

4. A copy of my curriculum vitae is attached hereto as **Exhibit "B"**. I began my career working as an Economist and then as a Senior Economist at the Canadian Competition Bureau. The Competition Bureau is the agency responsible for enforcing the Canadian *Competition Act* and protecting the Canadian economy against anti-competitive business conduct such as collusion or price fixing, abuse of dominant position, and anti-competitive mergers. My primary function as an Economist at the Competition Bureau was to conduct economic analysis in support of the Bureau's various enforcement actions.

5. After briefly working as a Senior Economic Consultant for the economic consulting firm, LECG, I joined the Independent Electricity System Operator ("IESO") (then called the Independent Electricity Market Operator) in 2000 as a Senior Economic Advisor in the Market Assessment and Compliance Division, reporting to the Market Surveillance Panel. Within this role, I was responsible for monitoring the Ontario electricity market for anomalous conduct, including abuses of market power or gaming, and for structural or market design deficiencies.

6. In 2006, I was promoted to Manager of Economics with the responsibility of conducting analysis of the effects of changes in wholesale electricity market design or government policy on the efficient operation of the IESO's wholesale market.

7. In 2010, I assumed the role of Manager of Regulatory Affairs and Sector Policy Analysis. In this role, I represented the IESO on the ISO-RTO Council ("IRC") as a member and Chair of the IRC's Market Committee. The IRC is a member group of North America's competitive wholesale market operators.[1] I was the Chair of the Market Committee at the time the United States Federal Energy Regulatory Commission (the "Commission") issued its Final Rule in Docket No. RM10-17-000, Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets* ("FERC Order No. 745").[2]

8. In 2013, I was appointed the position of Director of Markets. As Director of Markets, I was responsible for evolving the design of the Ontario electricity market to ensure it operated fairly and efficiently. As Director, I oversaw the transition of the responsibility for administering demand response programs from the Ontario Power Authority

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[1] In addition to the IESO, the IRC includes the Alberta Electric System Operator ("AESO"), the California Independent System Operator Corporation ("CAISO"), the Electric Reliability Council of Texas, Inc., ("ERCOT"), ISO New England, Inc., ("ISO-NE"), the Midcontinent Independent System Operator, Inc. ("MISO"), the New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C., ("PJM") and the Southwest Power Pool ("SPP").

[2] Being Tab 8 to the IESO's Book of Authorities in Response to AMPCO's Request for a Stay, dated November 5, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/657752/File/document [FERC Order No. 745].

("OPA") to the IESO. I initiated the design and implementation of the IESO Demand Response Auction ("DRA").

9. In 2015, I left the IESO to join Charles River Associates International as a Principal in their Energy Practice. I advised clients on a variety of issues, most notably competitive wholesale market design, market power and market manipulation issues.

A.5 Q: What is your current position?

10. I am Adjunct Professor and Research Director of the Energy Policy and Management Centre for the Ivey Business School at Western University. My primary role at Ivey is to further the mission of the Energy Centre which is to:

   a. Contribute to energy policy-making through the production and dissemination of evidence-based research and analysis on major policy issues affecting the electricity, gas, oil and pipeline sectors in Canada;

   b. Provide a transparent and reliable forum for industry, government, academia, and interested stakeholders to discuss and exchange ideas on energy sector development and policy; and

   c. Educate students, executives, and government officials on national and global energy sector issues.

A.6 Q: What other professional experiences do you have?

11. I serve as a peer reviewer for the Energy Journal. I am a Member of the International Association of Energy Economists. I am an occasional lecturer at Ryerson University and Osgoode Hall Law School.

A.7 Q: Have you previously submitted testimony before Board or other regulatory agencies?

12. I provided oral testimony before the Board on behalf of the IESO in EB-2007-0040 (regarding the 3x Ramp Rate). I provided written and oral testimony before the

Commission on behalf of Shell Energy North America (US), L.P. in Docket No. EL02-71-057.

A.8 Q: What is the purpose of your testimony in this proceeding?

13. I was retained by counsel for KCLP to review the Association of Major Power Consumers of Ontario's ("AMPCO") Notice of Appeal (the "Appeal") to Market Rule Amendments MR-00439-R00-R05 (the "Amendments") and supporting evidence, and to offer my independent views on the economic merit of AMPCO's position in this proceeding.

14. The Amendments enable the evolution of the IESO's DRA into a Transitional Capacity Auction ("TCA") that will allow non-contracted and non-regulated generators ("non-committed dispatchable generators") to participate in future capacity auctions alongside Demand Response ("DR") resources.

15. The focus of the Appeal is the appropriate level of compensation for DR resources. The IESO provides non-committed dispatchable generators an energy payment if / when the generators respond to an IESO instruction to produce energy based upon their offered price. Under the Amendment, DR resources will not receive an energy payment (or "utilization payment") when DR resources respond to an IESO instruction to reduce their energy consumption (an "economic activation").[3] AMPCO claims that this

[3] Application for Review of an Amendment to the Independent Electricity System Operator Market Rules, Notice of Appeal, EB-2019-0242, filed September 26, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/653723/File/document, at para. 12. The terms "energy payment" and "utilization payment" are used interchangeably in the proceeding material. For clarity, a ***utilization payment*** is a payment made to a demand response market participant that responds to an instruction from the system operator (IESO) to reduce the amount of electricity (energy) that they are consuming. The instruction from the IESO to a demand response resource to reduce energy consumption is referred to as an ***energy activation***. For this reason, utilization payments are sometimes referred to as ***activation payments***. Utilization payments at the wholesale market-clearing price are called ***energy payments***. A DR resource could receive an energy activation instruction from the IESO as part of the IESO's economic dispatch process, called an ***economic activation***, as a test of the DR resources capability, or for reliability or emergency reasons. The issue in the Appeal is compensation for economic activation. The IESO plans to compensate DR resources if the IESO instructs the resource to reduce consumption to test the resources capability or for reliability and emergency reasons.

represents inequitable and unfair treatment of DR resources, places DR resources at a competitive disadvantage to non-committed dispatchable generators in the TCA, and results in a TCA that is unfair and inefficient, and effectively anticompetitive and discriminatory. AMPCO also contends that the Commission, in FERC Order No. 745, has definitively recognized "that failure to compensate DR resources for such services is unjust and unreasonable."[4]

16. Counsel further asked that I address the issue the Board raised in Procedural Order No. 2. The Board stated that "it is particularly interested in receiving evidence that describes the experience with compensation for DR in markets in other relevant jurisdictions, and the extent to which that experience is informative in the context of the Amendments having regard to any pertinent differences such as differences in market design or structure."

17. Specifically, my evidence will:

a. analyze the economic merit of AMPCO's assertions of inequitable and unfair treatment, competitive disadvantage, and the negative impacts on competition and efficiency; and

b. identify pertinent similarities or differences between the United States wholesale markets and the Ontario market, such as differences in market design or structure, to inform the Board of the applicability of FERC Order No. 745 to Ontario and in the context of the Amendments.

A.9 Q: How is your testimony organized?

18. The remainder of my testimony consists of three parts. In Part B, I offer my analysis of the economic merit of AMPCO's assertions. In Part C, I summarize the conclusions of FERC Order No. 745 and identify unique aspects of the Ontario market that should

[4] *Ibid* at para. 36.

inform a conclusion on the applicability of the Order to Ontario. In Part D, I provide my summary conclusions.

A.10 Q: What are your conclusions?

19. In my opinion, the Amendments provide an equitable treatment of TCA participants. I give evidence that demonstrates the Amendments afford fair and equitable treatment to TCA participants, do not place DR resources at a competitive disadvantage to non-committed dispatchable generators, and promote fair and efficient competition to the benefit of Ontario consumers. I further conclude that the application of FERC Order No. 745 in Ontario will not achieve the effects the Commission intended when it issued its decision. This is due to several unique aspects of the Ontario electricity market, each of which I will speak to herein.

B. AMPCO'S ASSERTIONS ARE VOID OF FACTUAL SUPPORT AND LACK ECOMOMIC MERIT

B.1 Q: What is your understanding of the basis of AMPCO's appeal?

20. The basis of AMPCO's appeal is that generators receive a payment for energy services provided (economic activations) but DR resources do not. AMPCO asserts that this represents "an inequity in treatment between generation resources and DR resources."[5] AMPCO further asserts that this unequitable treatment puts "DR resources at a competitive disadvantage to generators"[6] in the TCA and would allow generators to "effectively and unfairly displace"[7] DR resources in the TCA. AMPCO concludes that this would "undermine competition"[8] and is "inimical to the IESO's own objective of

[5] *Ibid* at para. 4.
[6] *Ibid* at para. 22.
[7] *Ibid* at para. 4.
[8] *Ibid* at para. 14.

enhancing competition for the benefit of consumers."[9] The failure to compensate DR resources for economic activations "would result in a capacity market that is unfair and inefficient, and effectively anticompetitive and discriminatory."[10]

B.2 Q: What evidence has AMPCO provided to establish competitive disadvantage?

21. AMPCO's assertion of competitive disadvantage is articulated in the Affidavit of Mr. Colin Anderson at paragraphs 12 through 19. Mr. Anderson reasons as follows:

a. In the existing DRA, the only revenue stream available to participants is a capacity payment (called an availability payment). There are currently no payments made for energy activations. If the TCA proceeds in December 2019, non-committed dispatchable generators will qualify for an availability payment and an energy payment when economically activated. DR resources will still only qualify for an availability payment.[11]

b. Non-committed dispatchable generators will be able to submit a capacity offer into the TCA taking into account their anticipated energy payments. They will be able to set a capacity offer price that is lower by the amount of their anticipated energy payments. DR resources will not have the same opportunity.[12]

c. DR resources incur "legitimate costs" when they are economically activated to curtail demand. If they do not receive an energy payment, they will not be able to recover these costs.[13]

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[9] *Ibid* at para. 25.

[10] *Ibid* at para. 45.

[11] Affidavit of Colin Anderson, sworn October 11, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/655144/File/document, at para. 12.

[12] *Ibid* at para. 14

[13] *Ibid* at para. 19.

d. DR resources will have two options on how to deal with this. First, they can include the anticipated cost of activation in their capacity offer price. This would put DR resources at a competitive disadvantage to non-committed dispatchable generators that do not have to include these costs in their capacity offer price. Second, they could omit including the anticipated cost of activation in their capacity offer price, but then risk not recovering these costs when economically activated.[14]

B.3 Q: If a market participant cannot recover legitimate cost in the market does that not place it at a competitive disadvantage to others that can recover their cost?

22. From an economic perspective, if a DR resource incurs a cost when economically activated to curtail demand that it would ***avoid*** if it continued to consume, then it could be competitively disadvantaged by the Amendments. However, AMPCO has provided no factual evidence or even conceptual evidence that explains the nature, magnitude or legitimacy of these ***avoidable*** costs.

23. By contrast, a natural gas fired generator could provide both conceptual and factual evidence that it incurs a fuel cost when economically activated in order to produce energy that it can avoid (save) by not producing. This evidence is readily and publicly available, and is the basis for the energy payments made to these generators.

B.4 Q: Why does it make economic sense to pay a generator an energy payment for economic activation?

24. In order to induce a generator to produce energy, it must receive a payment that allows it to recover its avoidable cost of activation. If it did not receive a payment, it would be in its economic interest not to produce to avoid incurring the fuel cost. To induce efficient energy production, the IESO pays generators the energy market-clearing price to cover these costs.[15] The market-clearing price is designed to reflect the cost to

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[14] *Ibid.*

[15] The IESO currently operates a "two-schedule" pricing and dispatch energy market, which is described in the IESO's "The Single Schedule Market Backgrounder." In the two-schedule system, the physical limitations of the

produce one more MW of electricity (marginal cost), or the value to reduce one more MW of consumption (marginal willingness to pay) on the system. Paying generators this price incentivizes only those generators whose avoidable cost of economic activation is less than the market price. This is how the IESO manages the efficient use of the province's generation assets.

B.5 Q: Based on your experience in the electricity industry, what types of costs might a DR resource incur with an economic activation?

25. To my knowledge, the only cost that a DR resource may incur with an economic activation is the value of lost consumption, or what is sometimes called the value of lost load.[16] The value of lost load is the amount a consumer would be willing to pay to avoid disruption of service (i.e., to maintain its level of consumption). If a DR resource receives an energy activation when its value of lost load is greater than the price it would pay to consume, it would incur a legitimate cost from activation that it could have avoided if it had continued to consume. In this instance, the cost from activation would equal the difference between the value of lost load and the price the DR resource would have paid had it consumed.

B.6 Q: Does AMPCO provide evidence that DR resources are at risk of incurring this cost with an economic activation?

26. No. In fact, the IESO market rules provide DR resources the means to manage this risk. Two types of DR resources can participate in the TCA and the IESO's energy market: dispatchable loads and Hourly Demand Response ("HDR") resources.

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system are ignored in the "pricing" schedule that sets an Ontario-wide market price and establishes the most economic set of resources to meet demand. This requires a second "dispatch" schedule that includes the physical limitations of the system. The result is there are times when resources who cleared the market based on economics are told they cannot proceed, and others that were initially unsuccessful are told they are required to run in order to reliably meet demand. The differences between the two-schedules requires a complex system of out-of-market compensation to some participants.

[16] Navigant's Demand Response Discussion Paper, being Exhibit "I" to the Affidavit of David Short, sworn October 25, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/656576/File/document ["Navigant Report"]. The Navigant Report considers the costs associated with curtailment of a DR resource. This is the only type of cost they identified.

27. Dispatchable loads submit hourly energy bids to the IESO that define the quantities of energy they are willing to consume at different price levels. They receive dispatch instructions from the IESO every 5-minutes based on these energy bids. When they consume, they pay the market-clearing price (the 5-minute price) for the amount they consume. When the market-clearing price is above the price in their energy bid, they receive an economic activation to reduce their demand as per the amount stated in their energy bid. Dispatchable loads that are successful in the TCA are eligible to receive an availability payment by submitting and maintaining energy bids in the day-ahead through to real-time markets during a defined availability window that changes between the summer and winter months but generally covers the expected peak demand hours on business days. The energy bid prices must be greater than $100/MWh but less than $2,000/MWh, which is the maximum market-clearing price. As long as the price in the dispatchable load's energy bid reflects their value of lost load, they are not at risk of incurring a cost from an economic activation; they will only be economically activated when the market price exceeds their value of lost load.

28. HDR resources also submit hourly energy bids. When they consume, HDR resources pay the Hourly Ontario Energy Price ("HOEP"). In order to receive an availability payment, HDR resources must submit energy offers within the hours of availability. HDR resources receive a "standby report" in advance of a potential economic activation between 15:00 EST of the day ahead until 07:00 EST on the dispatch day, if the IESO's pre-dispatch schedules signal they could be curtailed for the hours of availability. In this instance, HDR resources must continue to submit energy bids for the dispatch day consistent with their capacity obligation. HDR resources are economically activated when the pre-dispatch 3-hour ahead price is greater than their energy bid price. The HDR resource is notified that they will be economically activated by receiving an Activation Notice approximately 2.5 hours before the start of the first dispatch hour to which it relates. HDR resources may be activated once per day for up to four consecutive hours. Attached hereto as **Exhibit "C"** is a copy of IESO Market Manual 4, which sets out the rules for activating HDR resources at section 7.2. Like dispatchable loads, HDR resources can manage the risk of incurring a cost associated with lost load from an

economic dispatch through their energy price bid. As the IESO evidence indicates, HDR resources have been economically activated on only one occasion since the implementation of the DRA.

B.7 Q: In response to Board Staff Interrogatory question 1, AMPCO provided a list of costs related to curtailment. What are your views on the nature of these costs?

29. AMPCO identified two types of costs related to economic activation under the heading “Cost per Curtailment.” AMPCO called the first set of costs “lost opportunity”. These costs all influence the price the DR resource is willing to pay to consume, i.e. the value of lost load. AMPCO indicates that there are several things to consider in establishing the value of lost load for a DR resource, and these things vary over time, even day to day and hour to hour. However, these costs all should be captured in the DR resource’s energy bid price. As discussed above, the DR resource can avoid incurring a lost opportunity cost by properly estimating its value of lost load and using this estimated value for its energy bid price. This is not to say that it is easy to estimate the value of lost load, and that there is not a risk that the estimate is wrong and that there is ex post regret that they bid too low or too high. This is possible in the same way it is possible that when a generator submits an energy offer with an expectation of its fuel costs and operating conditions: they guess wrong and fail to recover some costs.

30. AMCPO calls the second set of costs “semi-variable costs,” which included labour cost and other overhead costs for the production facility. These costs are costs that the DR resource must incur to ensure that they are available as a capacity resource to respond to an economic dispatch. These costs are not avoided if the DR resource is not economically activated. These are costs that can be avoided only if the DR resource chooses not to be available. I would call these costs fixed avoidable costs. For example, if they wanted to operate as a non-dispatchable load, they may require fewer staff on shift to monitor for dispatch instructions from the IESO. These costs should be recovered through the availability payment and not through an energy payment. This is no different than the types of costs that a non-committed generator may incur to make

sure a generator is available to respond to an IESO dispatch. Non-committed dispatchable generators would also need to recover these types of fixed avoidable costs if they choose to sell capacity and be available for dispatch by the IESO. They would include these costs in their capacity offer price, not in their energy offer price.

B.8 Q: If a generator receives an energy payment for balancing supply and demand, but a DR resource does not, is this not inequitable treatment, and does it not place the DR resource at a competitive disadvantage?

31. Contrary to AMPCO's assertion, I contend that *providing* DR resources an energy payment for economic activations would represent *inequitable treatment* and afford DR resources a *competitive advantage* over non-committed dispatchable generators in the TCA. I come to this conclusion by applying the concept of horizontal equity and by way of example.

B.9 Q: What is horizontal equity?

32. *Horizontal equity* requires that people who are alike in all relevant respect be treated the same. It corresponds to common notions of fair play and non-discrimination. For example, if two people have the same pre-tax income, they would have equal after-tax incomes. *Vertical equity* holds that people who differ in relevant respects should often be treated differently. This notion of equity is more contentious. Vertical equity is typically concerned with the "preferred" distribution of wealth in society. What represents the "preferred" distribution of wealth is a normative question that requires a value judgement. For example, it can be argued that those who earn higher pre-tax income *should* pay higher taxes.

B.10 Q: How does this concept of equity draw you to conclude that providing DR resources an energy payment would be inequitable?

33. I come to this conclusion through an example. The example is an adaptation of the example the IESO presented to stakeholders in the Demand Response Working Group

on March 11, 2018 to elicit views on the issue of the equal treatment of "negawatts and megawatts."[17]

34. Consider two companies, DR Corp. and GEN Corp. DR Corp. consumes 6 MW of electricity. Its value of lost load is $10,000/MWh. DR Corp. also owns a behind-the-meter generator. The generator has a capacity of 4 MW. It incurs a cost of $100/MWh to generate electricity. DR Corp. also incurs a fixed cost of $1,000 to staff and maintain the generator so that it is available to produce electricity when needed. If DR Corp. chose not to maintain the generator to be available to produce electricity, it would avoid incurring this cost. This makes the $1,000 a fixed avoidable cost. GEN Corp. is exactly the same as DR Corp. with one arbitrary exception: GEN Corp. is electrically connected to the IESO market metered separately as a load and a generator, while DR Corp. is connected by meter to the IESO market as a load with its generator operating behind the meter. Figure 1 depicts the situation for both companies.

35. To simplify the discussion, assume there is just one hour in the year and based on the prevailing supply and demand conditions, the two companies expect the energy market price to be $100/MWh. Both companies plan to compete in the IESO TCA. DR Corp., because it is metered with the IESO as a load, competes as a DR resource and can offer 4 MW of capacity (the amount of net-metered load it is capable of decreasing through use of its behind-the meter generator). If successful in the TCA, DR Corp. will be obligated to submit an energy bid in the IESO's energy market for 4 MW. The energy bid price that DR Corp. will submit is equal to $100/MWh as it will be less costly to use its generator to self-supply its demand than to buy energy from the IESO energy market at a price higher than $100/MWh. GEN Corp. competes as a non-committed generator and can offer 4 MW of capacity in the TCA. If successful in the TCA, GEN Corp. will

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[17] IESO Presentation to Demand Response Working Group on Utilization Payments Discussion, dated March 1, 2018, being Exhibit "J" to the Affidavit of David Short, sworn October 25, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/656576/File/document at 10-14 ["IESO March 1 Presentation"]. A "negawatt" is a unit of energy saved, such as through the curtailment of demand. This issue of whether a "negawatt" and a "megawatt" are functionally and economically equivalent is a contentious issue. The issue was addressed in FERC Order No. 745 where Commissioner Moeller disagreed with the Commission majority that the two were equivalent.

be obligated to submit an energy offer in the IESO's energy market for 4 MW. The energy offer price it will submit is $100/MWh, which is its marginal cost of generation.

36. Assume in the first instance, as per the Amendments, DR resources do not receive an energy payment for an economic activation. What will be the capacity offer price of each company? I answer this with reference to Figure 1.A.

Figure 1: DR Corp. and GENCorp. are identical in all relevant aspects

Figure 1.A: No Energy Payments for DR Resources

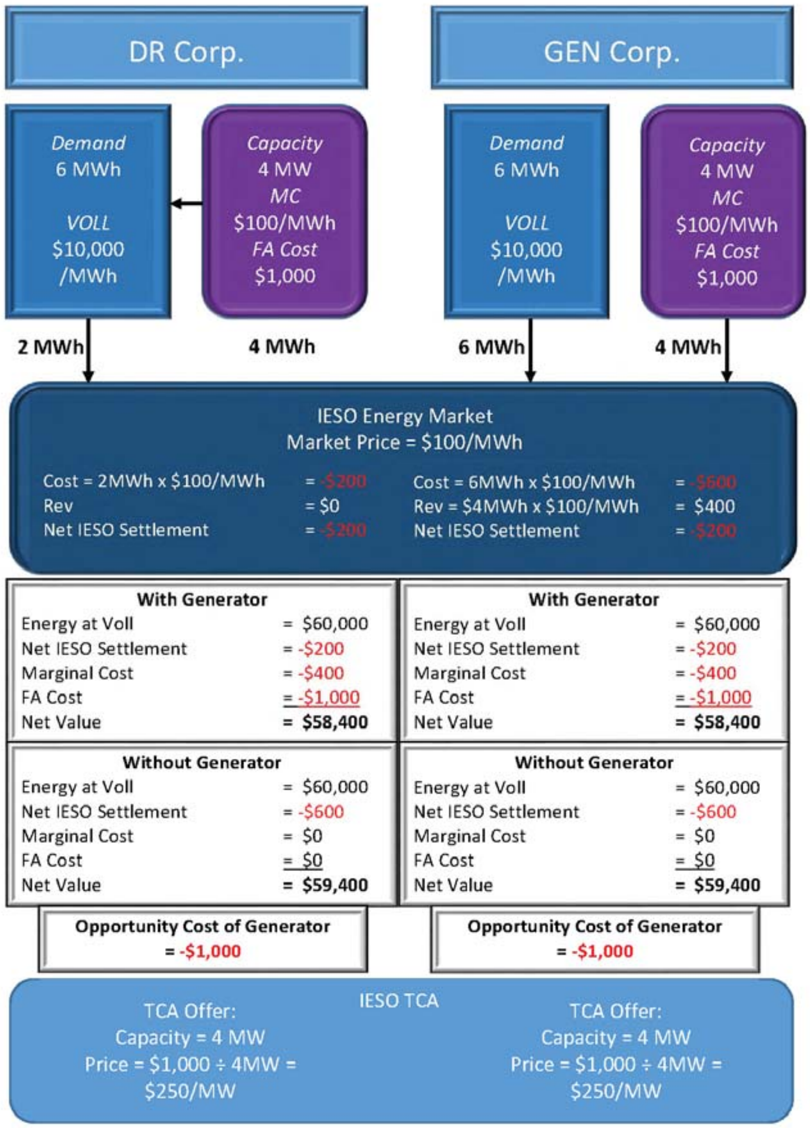
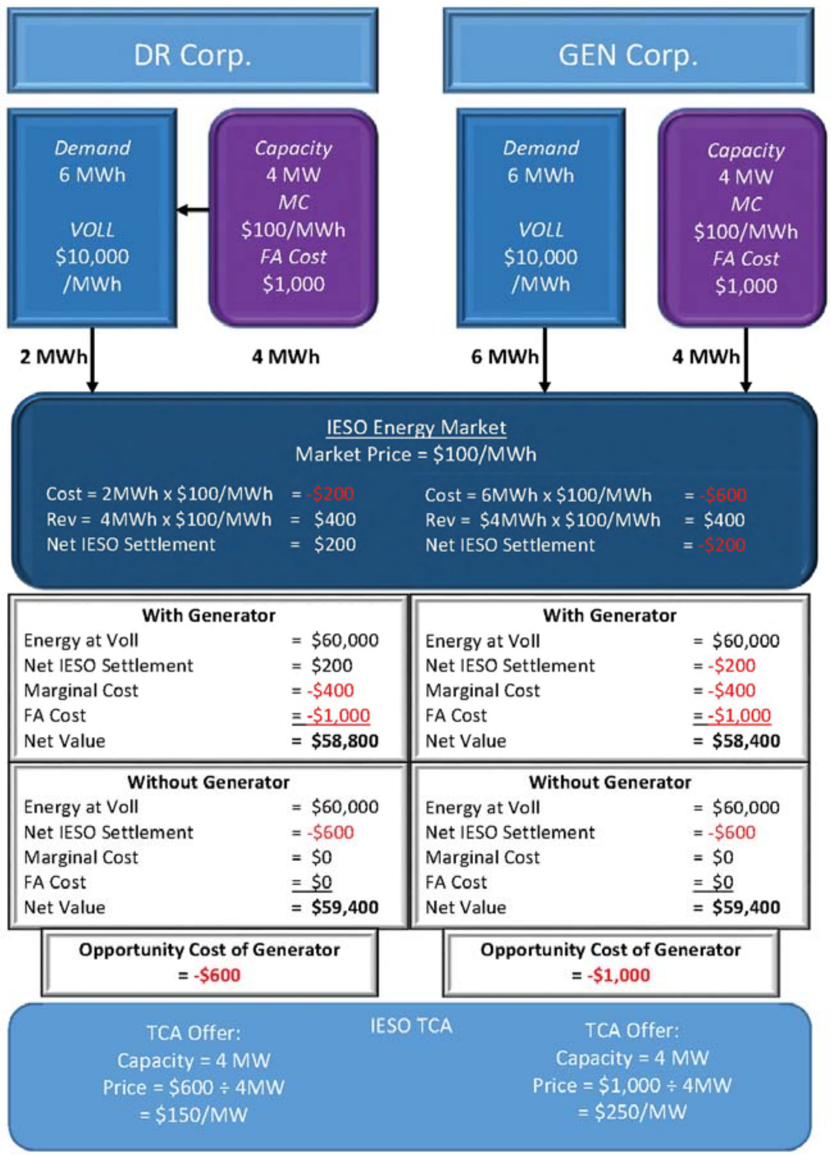


Figure 1.B: Energy Payments for DR Resources



37. With an expected market price of $100/MWh, DR Corp. anticipates that it will receive an economic activation to reduce its net-metered load by 4 MWh. It will not receive an energy payment for this activation, so as AMPCO argues, it will not be able to incorporate this revenue in the calculation of its capacity offer price. DR Corp. will make an energy payment to the IESO of $100/MWh x 2 MWh = $200 for its net-metered demand. It will incur a cost of $100/MWh x 4 MWh = $400 to generate electricity to

supply the balance of its 6 MWh of consumption. It will incur the fixed avoidable cost of $1,000 to ensure the generator is available. Overall, DR Corp. will realize a net value of $58,400 for its activities. These calculations are listed in the box for DR Corp. titled "With Generator" in Figure 1.A (numbers in red are negative values).

38. For it to be profitable for DR Corp. to participate in the TCA, the net value it realizes if successful must be greater than the net value it would realize by shutting down its generator and buying all of its electricity from the IESO. This net value is calculated in the box for DR Corp. titled "Without Generator" in Figure 1.A and is equal to $59,400. The net opportunity cost of DR Corp of participating in the TCA is the difference between these two values and is equal to -$1,000. That is, DR Corp. can increase its net value by $1,000 by shutting down its generator and saving the fixed avoided cost of $1,000 to maintain the availability of the generator. Therefore, to keep the generator available, it must recover this amount in the TCA through the availability payment. DR Corp. will submit a capacity offer price of $250/MW for 4 MW of capacity with the hope of recovering the fixed avoided cost of making the generator available. If it is not successful in the TCA, it will shut down the generator.

39. With an expected market price of $100/MWh, GEN Corp. anticipates that it will receive an economic activation to generate 4 MWh of energy. The IESO will pay GEN Corp. the market price per MWh of energy produced for a total energy payment equal to $400. As AMPCO conjectures, GEN Corp. can anticipate earning this energy revenue when calculating its capacity offer price. **<u>However, it costs GEN Corp. $400 to generate the electricity.</u>** What GEN Corp. factors in to its capacity offer price is not the revenue it earns, but the net revenue it earns which is the difference between the energy payment and variable energy cost. This is the "benefit" that GEN Corp. receives by participating in the energy market. As I will discuss more below, it is important to draw the distinction between the energy payment and the net revenue when considering the AMPCO's assertion of competitive advantage. In this case, the market price and GEN Corp.'s marginal cost are equal; GEN Corp. earns zero net revenue. Like DR Corp., GEN Corp. computes its capacity offer price based on the difference between the net value it realizes

from making its generator available and the net value it realizes if it shuts down the generator, which is -$1,000. GEN Corp. submits a capacity offer price in the TCA equal to $250/MW, the same as DR Corp. This is what we might expect given that DR Corp. and GEN Corp. are identical but for the arbitrary physical positioning of their meters.

40. Assume now that contrary to the Amendments, DR resources are paid the market price for an economic activation. How does this affect each company's participation in the TCA and in the energy market? This is presented in Figure 1.B above.

41. First, note that by receiving the market price for an activation, DR Corp. has an incentive to lower its energy bid price. It will be optimal to use its generator to self-supply its demand whenever the market price is greater than half its marginal generation cost (i.e., market price > $50/MWh). To see this, assume the market price is $51/MWh, and DR Corp. does not use its generator to self-supply. DR Corp. pays $51/MWh x 6 MWh = $306 to the IESO. If instead, DR Corp. does use its generator to self-supply, it pays only $51/MWh x 2 MWh = $102 to the IESO to consume, receives an energy payment for economic activation equal to $51/MWh x 4 MWh = $204, and incurs a generation cost of $400 for a net cost of $298. It is better off to self-supply when the energy market price is $51/MWh. By this reasoning, DR Corp.'s net cost of participation in the IESO market if it self-supplies is lower whenever the market price exceeds $50/MWh. As a result, DR Corp. will lower its energy bid price to $50/MWh from $100/MWh.

42. Now assuming that DR Corp.'s lower energy bid price does not result in a lower energy price (which it could), it will now factor this additional energy payment into its capacity offer price calculation. As Figure 1.B demonstrates, the net value to DR Corp. increases when it is eligible for an energy payment for an economic activation. DR Corp. requires a smaller capacity offer price of $150/MW in order to cover its fixed avoided cost of making its generator available. This capacity offer price is lower than the capacity offer price of GEN Corp.

B.11 Q: Can you summarize what this example demonstrates of AMPCO's assertions of inequality and competitive disadvantage?

43. Yes. The example shows that AMPCO's assertions are incorrect. In my example, DR Corp. and GEN Corp. are identical but for the physical placement of a meter; an arbitrary and irrelevant difference. Horizontal equity requires like treatment for people (or corporations) that are alike. When DR resources do not receive an energy payment for an economic activation, DR Corp. and GEN Corp., whom are identical, are treated alike for their participation in the IESO markets and realize the same net value for their activities. When DR resources receive an energy payment for an economic activation, DR Corp. avoids the cost of consuming by reducing its net-metered load (a benefit). At the same time, it receives a payment from the IESO to avoid this cost (a second benefit). This amounts to a double benefit for the energy service provided (as evidenced by DR Corp.'s willingness to submit an energy bid price that is half its marginal generation cost). As a result, DR Corp. realizes a higher net value than GEN Corp. for participation in the IESO markets, even though the two companies are identical. The preferential treatment gives DR Corp. a competitive advantage over GEN Corp. in the TCA. What amounts to a double benefit for the energy service allows DR Corp. to cover more of its fixed avoided cost through the energy market. DR Corp requires less in the way of an availability payment to cover these costs and hence they can submit a lower capacity offer price than GEN Corp. in the TCA.

B.12 Q: What other conclusion do you draw through this example?

44. Through this example, I can demonstrate that contrary to AMPCO's assertions, paying DR resources an energy payment for economic activations would harm fair and efficient competition. With only slight modifications to the example I described above, I can show that providing DR resources an energy payment for economic activations can lead to more expensive resources being selected before less expensive resources in the TCA and more expensive resources being dispatched ahead of less expensive resources in the energy market.

45. In Figure 2, I assume DR Corp. incurs a fixed avoided cost of $1,100 to staff and maintain its generator to ensure it is available to produce electricity, which is $100 higher than the previous example. DR Corp. is now a higher cost capacity resource than GEN Corp. DR Corp. will have to recover $100 more in the TCA than GEN. If as per the Amendments, DR resources do not receive an energy payment for economic activations, DR Corp. will submit a capacity offer price of $275/MWh in the TCA. It has less chance of success in the TCA than GEN Corp. From the perspective of promoting fair and efficient competition, this is the desired outcome; the least cost capacity resource is selected ahead of the higher cost resource. If in the alternative, DR resources are provided an energy payment for economic activations, DR Corp. can anticipate a benefit of reducing its energy payment to the IESO and receiving an energy payment from the IESO for doing so, (i.e., a double benefit). This reduces the amount of fixed avoided cost that it must recover through the TCA by $400. DR Corp. is now able to reduce its capacity offer price to $175/MW, which is lower than GEN Corp.'s capacity offer price of $250/MW. DR Corp. now has an advantage over GEN Corp. in the TCA, even though it is the higher cost capacity resource. As a result, it is possible that DR Corp. is successful in the TCA and GEN Corp. is not. GEN Corp. would be forced to shut down its generator. This would be a wasteful and inefficient use of the province's resources. Providing DR resources an energy payment for economic activations would be harmful to fair and efficient competition.

Figure 2: DR Corp. has a higher fixed avoided cost

Figure 2.A: No Energy Payments for DR Resources

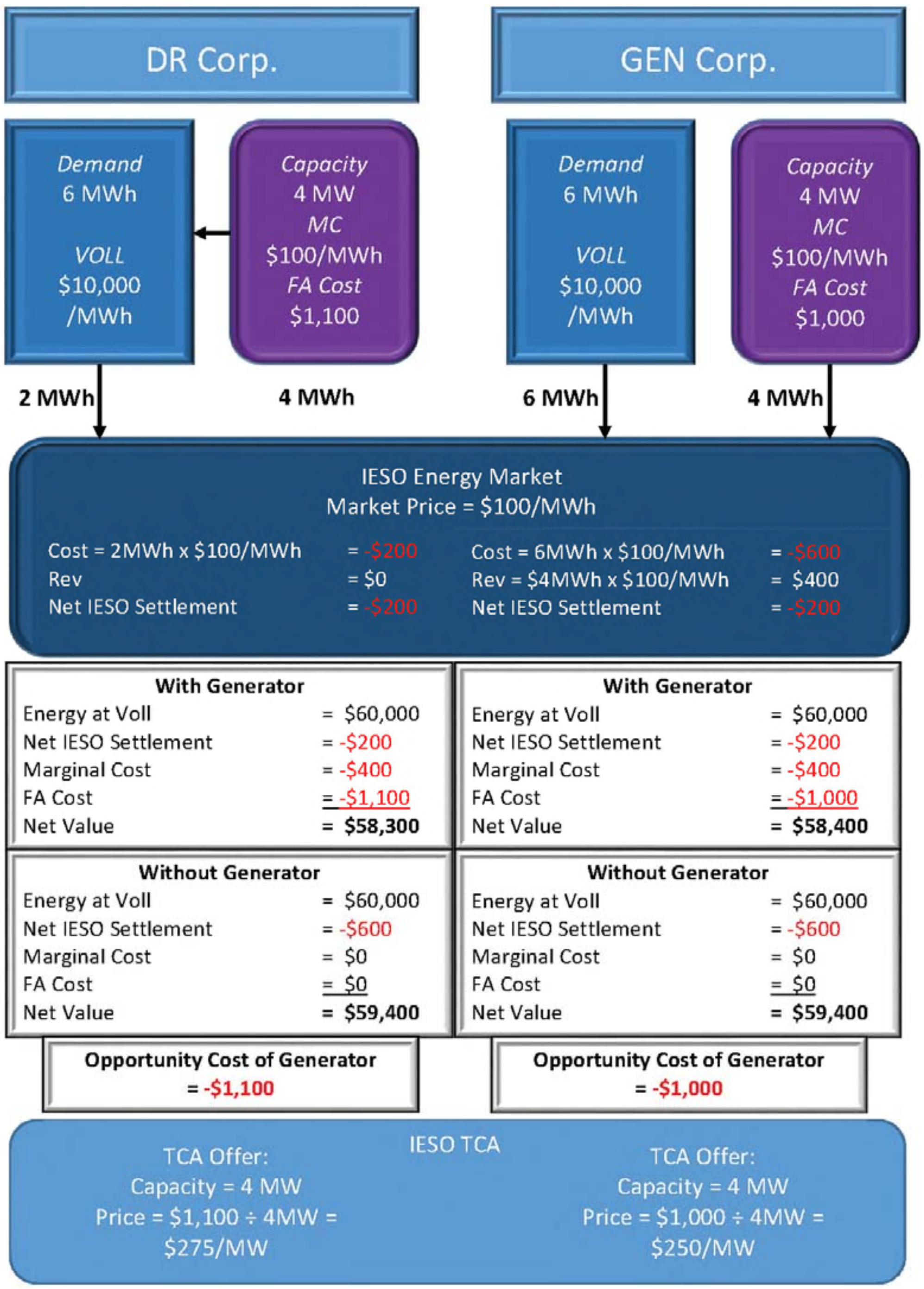


Figure 2.B: Energy Payments for DR Resources

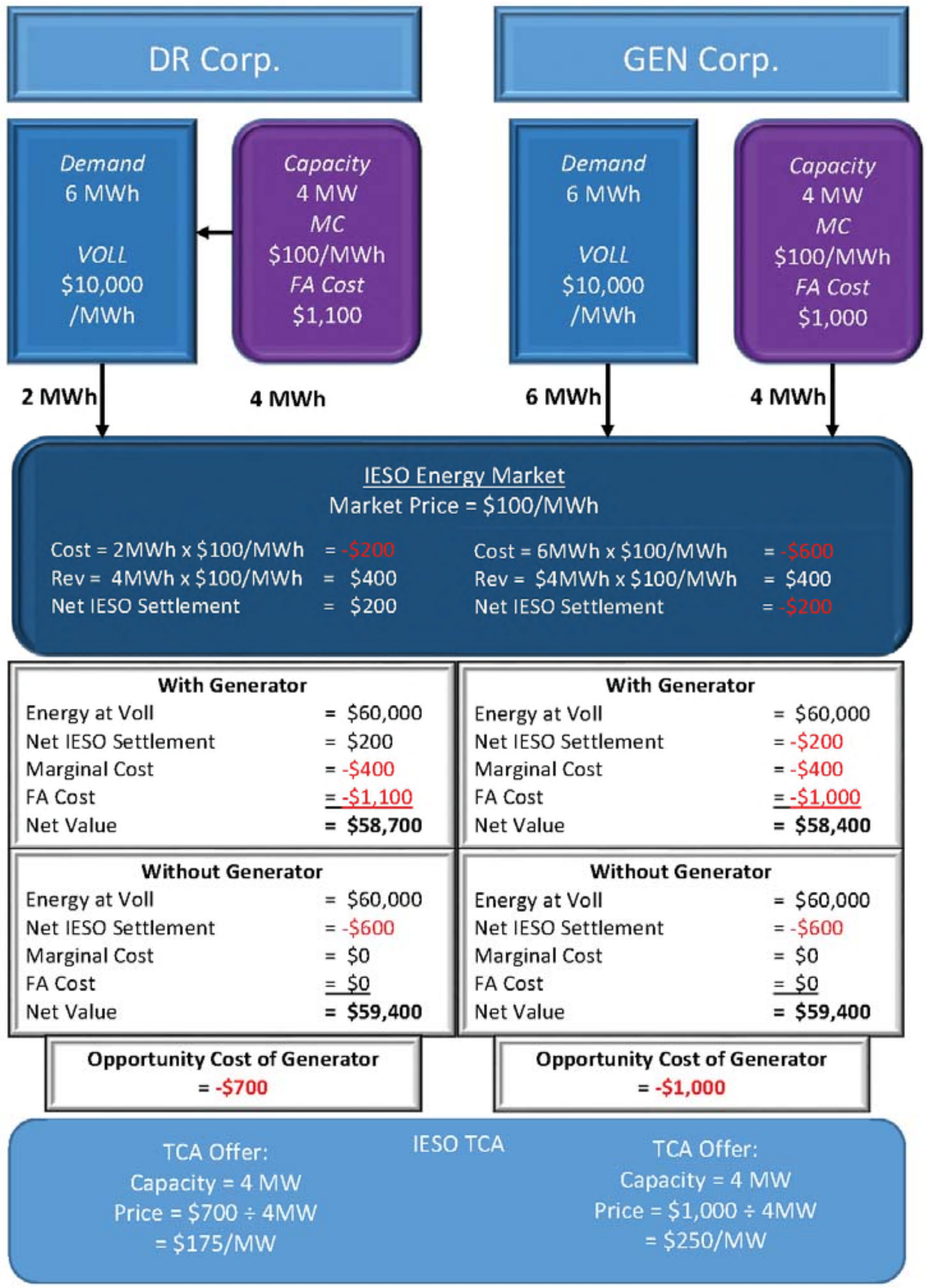


Figure 3: GEN Corp. has a lower marginal generation cost

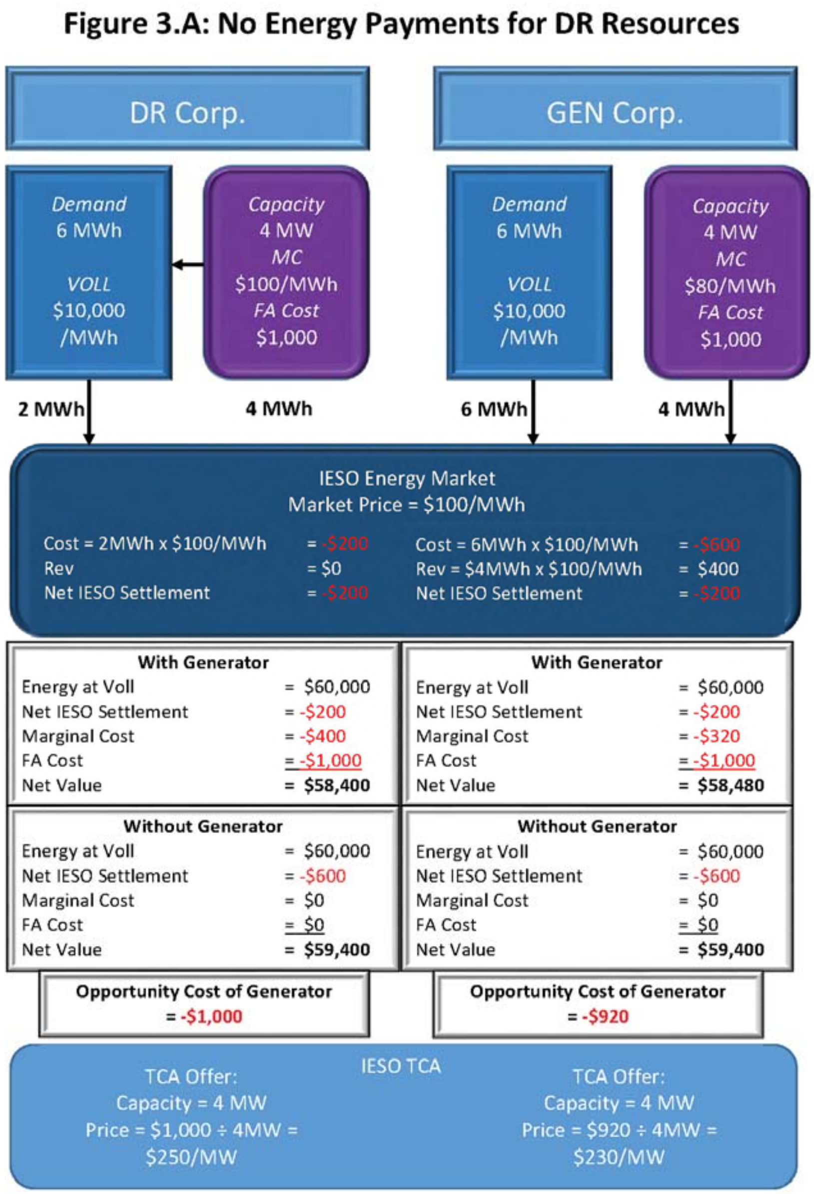
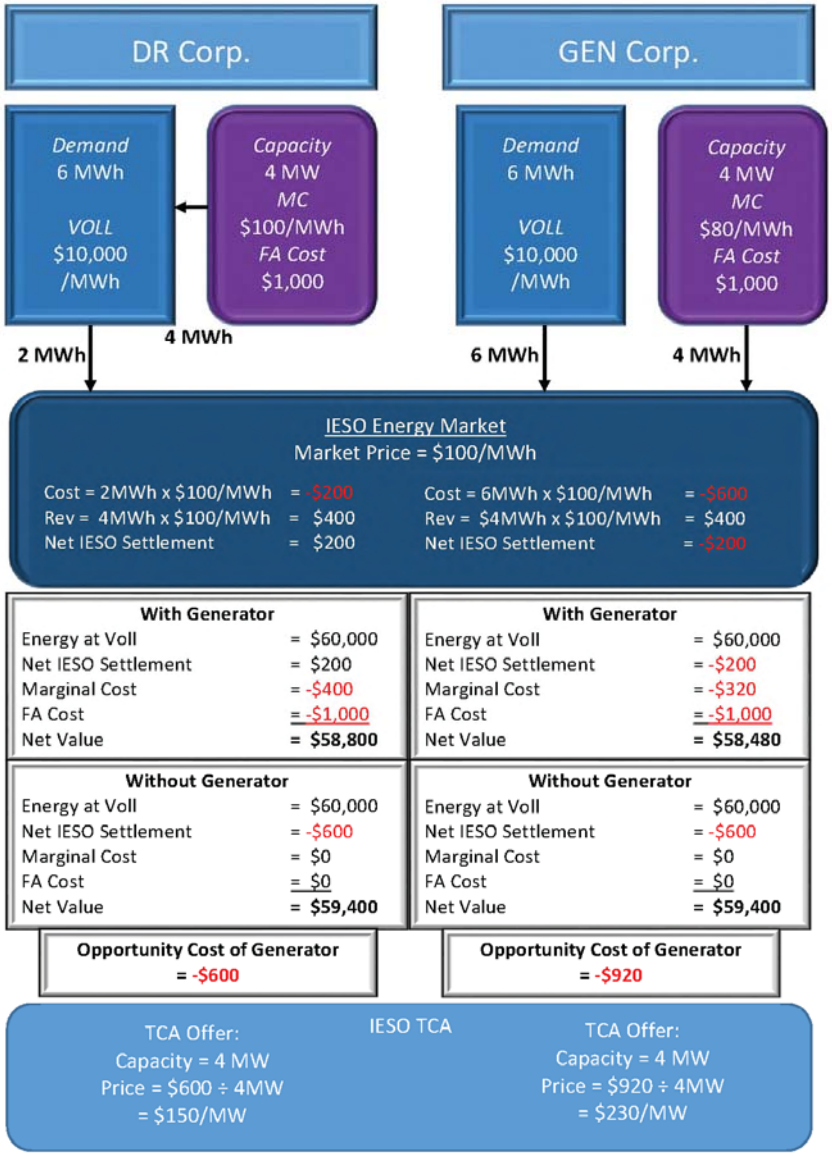


Figure 3.B: Energy Payments for DR Resources



46. In Figure 3, I modify the original example by assuming GEN Corp. has a marginal generation cost of $80/MWh, which is lower than the $100/MWh marginal generation cost of DR Corp. In this case, GEN Corp earns a net revenue equal to the difference between the energy market price of $100/MWh and its marginal generation cost of $80/MWh; a benefit of $20/MWh that it can contribute to the recovery of its fixed avoided cost of making the generator available. It can factor this amount into its capacity offer price. Again, I draw a distinction between the net revenue and the full energy

payment; GEN Corp. will factor only the net revenue into its capacity price calculation as this is the only true benefit it receives from the energy market.

47. If DR resources are provided an energy payment for economic activations, Figure 3 illustrates that DR Corp. will submit a lower capacity offer price than GEN Corp. That is, because of the double benefit DR. Corp. receives from activation (a benefit for the energy payment it avoids and a benefit for the energy payment it receives) it has a competitive advantage over GEN Corp. It is also the case that because DR Corp. lowers its energy bid to $50/MWh, (half of its marginal generation cost) it will be dispatched ahead of GEN Corp. for energy. This is not only harmful to fair and efficient competition in the TCA, it leads to the inefficient dispatch of the province's generation resources, which is in conflict with the IESO's least cost dispatch objective.

B.13 Q: In your examples, you did not consider the effects of the Global Adjustment. How does the Global Adjustment affect your conclusions?

48. The manner in which consumers are charged the Global Adjustment will also provide certain DR resources a competitive advantage in the TCA over non-committed dispatchable generators, even if DR resources are not provided energy payments for an economic activation as per the Amendments.

49. The Global Adjustment is an accounting mechanism through which the fixed costs to build and maintain generation assets in the province and to deliver Ontario's conservation programs are recovered from Ontario electricity consumers. It is, at a high level, calculated as the differences between payments made to generators at the wholesale market price and payments made through regulation or contract that differ from the market price. The Global Adjustment was established in 2005 as a means to attract private investment in new generation capacity and to offer Ontario consumers price stability. The Global Adjustment has become the largest component of an average consumer's electricity cost, representing between 45 to 60 percent of a typical electricity bill. Attached hereto as **Exhibit "D"** is a copy of a policy brief I authored on this subject.

50. The Industrial Conservation Initiative ("ICI") is a government policy that defines how the costs in the Global Adjustment are allocated to different classes of consumers. Large consumers, known as Class A consumers, are charged global adjustment on the basis of their share of the total system demand during the highest five peak hours of the year. Class A consumers include consumers with an average monthly peak demand greater than 1 MW and consumers in certain manufacturing and industrial sectors, including greenhouses with an average monthly demand greater than 500 kilowatts (kW). Smaller consumers, known as Class B consumers, pay Global Adjustment as a monthly fee based on the kilowatt-hours of electricity they consume in the month, or as part of their regulated time of use prices. I understand that most AMPCO members qualify as a Class A consumer.

51. The Board's Market Surveillance Panel has shown that the ICI provides Class A consumers with an extreme price incentive to reduce their demand in the expected system peak demand hours to avoid paying the Global Adjustment. This will provide DR resources that are Class A consumers a competitive advantage over non-committed dispatchable generators in the new TCA. I demonstrate this in Figure 4. Attached hereto as **Exhibit "E"** is the Market Surveillance Panel's Report.

52. Figure 4 assumes the same characters for DR Corp. and GEN Corp. as Figure 1, except it also considers the effects of the incentives provided by the ICI. Both DR Corp. and GEN Corp. qualify as a Class A consumer. Assume that both companies anticipate the Global Adjustment charge to be $5,000/MWh. The Global Adjustment is charged based on the metered quantity consumed at the level of the IESO (i.e., based on metered quantities at the transmission level). As a result, DR Corp. can avoid Global Adjustment charges by self-suppling its demand and reducing its net-metered quantity with the IESO to 2MWh. GEN Corp. cannot avoid Global Adjustment by generating. As Figure 4.A demonstrates, even if DR resources are not provided an energy payment for economic activations, DR Corp. has an extreme incentive to generate electricity to avoid $5,000 x 4MWh = $20,000 in Global Adjustment charges. This decreases the opportunity cost of not incurring the fixed avoided cost to maintain the availability of its generator by

$20,000. DR Corp. is clearly better off by maintaining the availability of its generator; it will do so even if it does not earn an availability payment through the TCA. DR Corp. can offer a capacity price of $0/MWh in the TCA. In effect, the ICI rewards DR resources that are also Class A consumers by compensating them twice for making their generator available; once through the avoidance of the Global Adjustment (which recovers the capacity cost of the committed generator) and once through the availability payment. As Figure 1.B demonstrates, paying DR resources an energy payment for an economic activation would only further DR Corp.'s competitive advantage over the non-committed generator of GEN. Corp.

Figure 4: Effects of the Global Adjustment

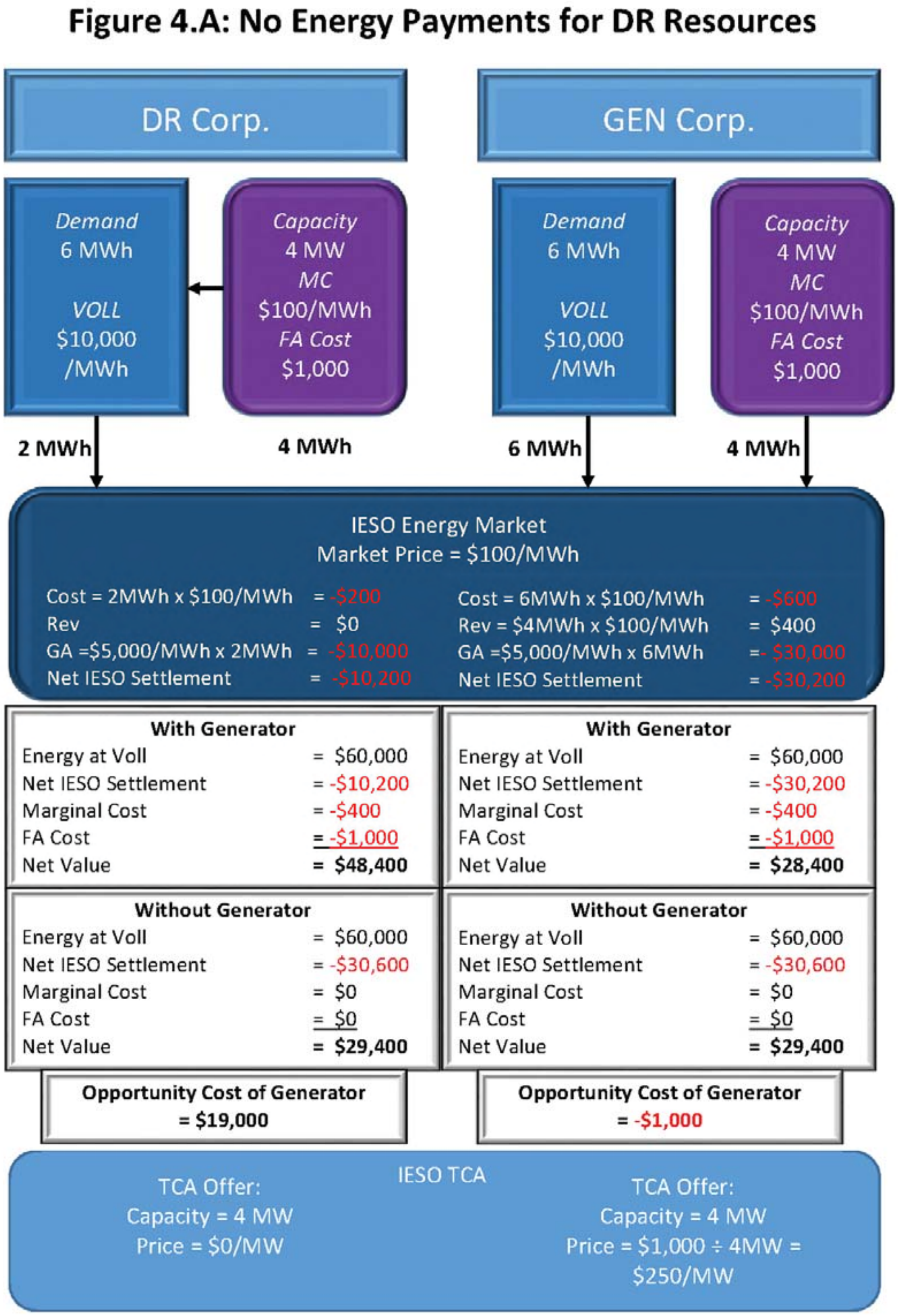
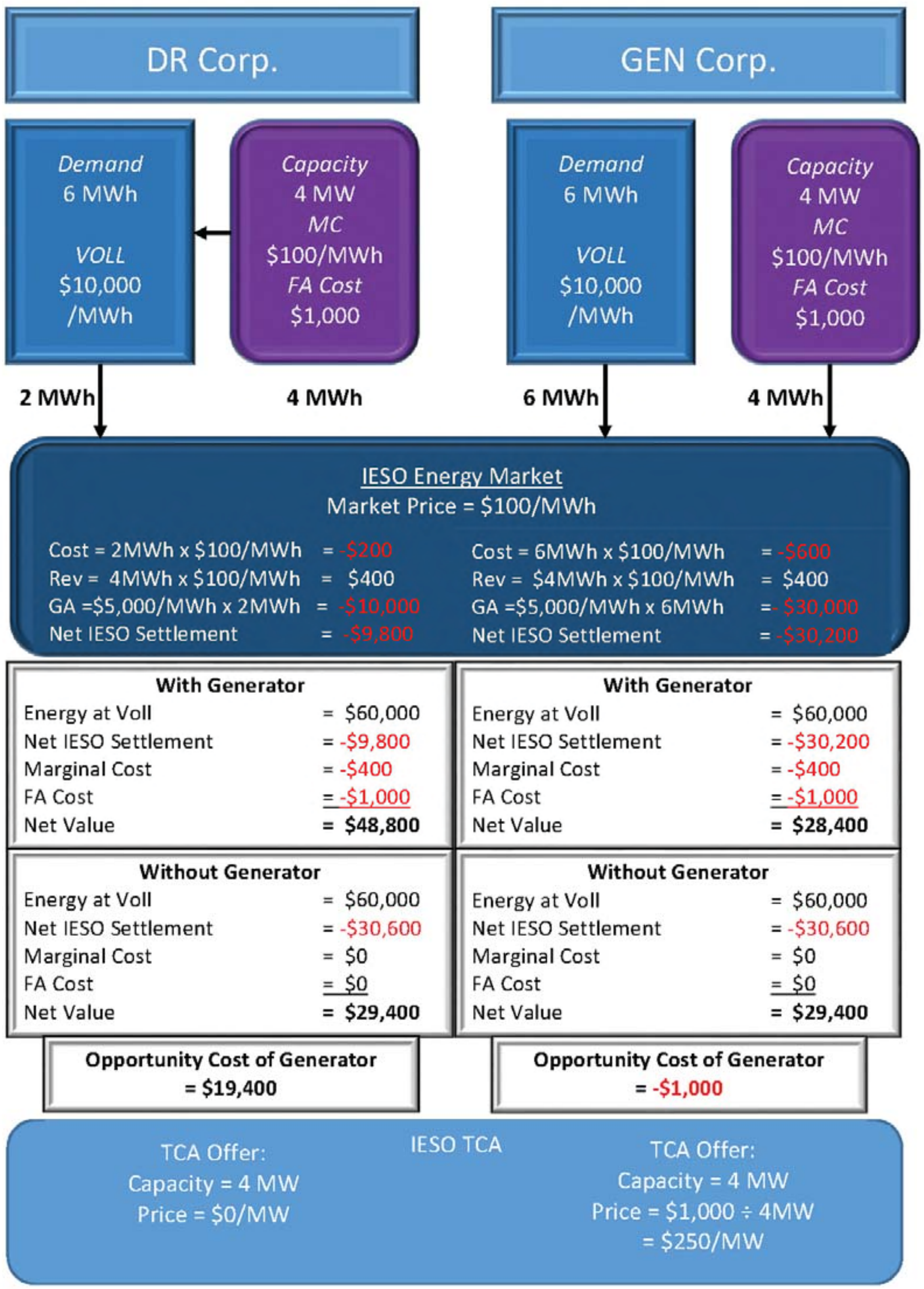


Figure 4.B: Energy Payments for DR Resources



C. APPLICATION OF FERC ORDER NO. 745 IN ONTARIO WILL NOT ACHIEVE THE COMMISSION'S INTENDED EFFECTS

C.1 Q: Can you briefly describe the conclusions of FERC Order No. 745

53. Yes. FERC Order No. 745 addressed the issue of compensation of DR resources in Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") organized wholesale energy markets in the United States.[18] The Commission concluded that when a DR resource satisfies two conditions, it "must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP)."[19] ***First,*** the DR resource must have the capability to provide the service, which is described as displacing a generation resource in a manner that serves to balance supply and demand. ***Second***, the payment of the market price to the DR resource for the provision of the service must be "cost-effective" as determined by a "net-benefits test."

C.2 Q: What was the basis for the Commissions' conclusion?

54. The key objective of FERC Order No. 745 was to "remove barriers to participation of demand response resources in organized wholesale electricity markets."[20] FERC Order

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[18] FERC Order No. 745 at para. 9 focused on "customers or aggregators of retail customers providing, through bids or self-schedules, demand response that acts as a resource in organized wholesale energy markets".

[19] *Ibid* at para. 2.

[20] *Ibid* at para. 5. The Commission states this objective is "consistent with national policy requiring facilitation of demand response." It references Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005):

> "f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.—It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying

No. 745 was promulgated on the premise that "active participation by customers in the form of demand response in organized wholesale energy markets helps to increase competition in those markets."[21] Ensuring the competitiveness of organized wholesale energy markets is "integral to the Commission fulfilling its statutory mandate" and to ensuring "just, reasonable, and not unduly discriminatory or preferential rates."[22] The Commission observed that prior to the Order, "the level of compensation for demand response" varied from market to market, and that "some existing, inadequate compensation structures hindered the development and use of demand response." The Commission acknowledged that customers "must have confidence that appropriate price signals will be sustained by stable competitive pricing structures, before they will make an investment in demand response." Attached hereto as **Exhibit "F"** is a copy of the Commission's Notice of Proposed Rule Making in which these observations were made.

C.3 Q: Did the Commission elaborate on the types of barriers to DR resources that it was concerned with, and how FERC Order No. 745 would eliminate those barriers?

55. The Commission reasoned that "[d]ue to a variety of factors, demand responsiveness to price changes is relatively inelastic in the electric industry and does not play as significant a role in setting the wholesale energy market price as in other industries."[23] The Commission cited as barriers:

> "the lack of a direct connection between wholesale and retail prices, lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow

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such technology and devices, but who are part of the same regional electricity entity, shall be recognized."

[21] *Ibid* at para. 9.

[22] *Ibid* at para. 8.

[23] *Ibid* at para. 57.

> electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change."

The Commission concluded, "paying LMP can address the identified barriers to potential demand response providers."[24]

C.4 Q: You indicated that for DR resources to be eligible for compensation it must be cost-effective as determined by the FERC net benefits test. Can you explain this test?

56. Yes. The Commission recognized that paying DR resources the market price to curtail demand would have two effects. First, paying DR resources the market price would encourage more participation of these resources in the energy market. Their participation would involve an energy bid in the wholesale market. Additional energy bids in the market would lead to a lower wholesale energy price whenever a DR resource's bid was selected in the energy market ahead of a generator offer. All other consumers (non-DR consumers) would realize a benefit from the lower price. Second, these non-DR consumers would have to make an additional payment to the DR resource equal to the market price times the amount of demand curtailed. The net benefits test is satisfied when the savings the non-DR consumers realize from the lower wholesale price are greater than the additional payment they must make to DR resource. FERC Order No. 745 refers to this as the "the billing unit effect of dispatching demand response."[25] In this sense, paying DR resources is deemed cost effective if it leads to lower bills for all non-DR consumers.

C.5 Q: Is this how an economist would define "cost-effective"?

57. No. As many commentators noted in the FERC proceeding, in economics, an outcome would be defined as cost-effective if it leads to society making the best use of its

[24] *Ibid* at para. 58.

[25] *Ibid* at para. 3.

available resources. Economist call this an allocatively efficient outcome. An allocatively efficient outcome maximizes the benefits to all participants. This is sometimes called "total surplus" which is equal to the sum of consumers' surplus (the difference between what they are willing to pay and the price they pay) and producers' surplus (the difference between the price they receive and avoided variable cost). The IESO's dispatch model seeks to maximize allocative efficiency or total surplus. The net benefits test seeks to maximize the benefit to non-DR participants, or non-DR consumers' surplus and comes at the expense of producers' surplus. Promoting efficiency is also a purpose of the *Electricity Act, 1998*.

C.6 Q: Do you see any implications for the IESO or Ontario consumers if the IESO were required to apply a net benefits test in order to pay DR resources the market-clearing price?

58. Yes. If the intent of the FERC net benefit test is to compensate DR resources only when it results in a reduction in the bills of non-DR consumers (non-DR consumers' surplus), then the IESO would have to take into account the effect of the Global Adjustment in this calculation. This has two implications for the IESO and Ontario consumers. First, it means that (all else held constant) the net benefits test will be satisfied less frequently (if ever) than in the United States markets.[26] Second, it adds additional complications for the IESO in implementing the test that the United States RTO/ISOs did not have to encounter. Furthermore, as several commenters noted in the FERC proceeding, "cost-effective" as defined by the net benefits test, and "allocative efficiency" are different things. An additional implication of Ontario implementing the net benefit test is that it could, if ever satisfied, contribute to a less efficient dispatch of resources and less efficient use of the province's generation resources. This is a point I already established above.

[26] This same point was recognized in Section 3.2 of the "Navigant Report".

C.7 Q: Can you explain why the Global Adjustment means the net benefits test is not likely to be satisfied on Ontario?

59. Yes. This can be explained with reference to Figure 5. In Figure 5, an hourly offer curve and an hourly demand curve (labeled D^1) are drawn. The demand curve D^1 is drawn under the assumption that DR resources are not provided an energy payment for an economic activation. The market-clearing price is determined as the intersection of the hourly offer curve and the hourly demand curve, which is P^1 in Figure 5. This illustration is based on a figure contained in the Californian ISO's final proposal for implementation of FERC Order No. 745, which is attached hereto as **Exhibit "G".**

60. Paying a DR resource the market-clearing price for an economic activation changes the DR resource's incentives for participation in the market. This was the desired effect of the Commission in FERC Order No. 745. As I outlined above, in the Ontario context, if a DR resource is paid the market price for an economic activation, it will be incentivized to submit a lower energy bid price.[27] This causes the demand curve to become more "elastic" and shift downward. This is represented by the new hourly demand curve D^2 in Figure 5. The lower DR resources' energy bids mean that the market clears at the lower price of P^2.

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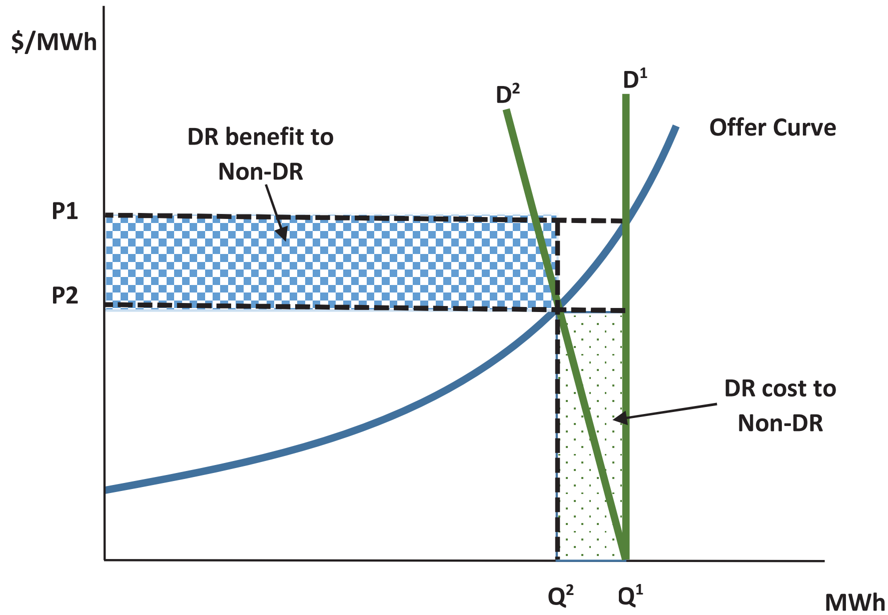
[27] This point was discussed in the "IESO March 1 Presentation" at 5.

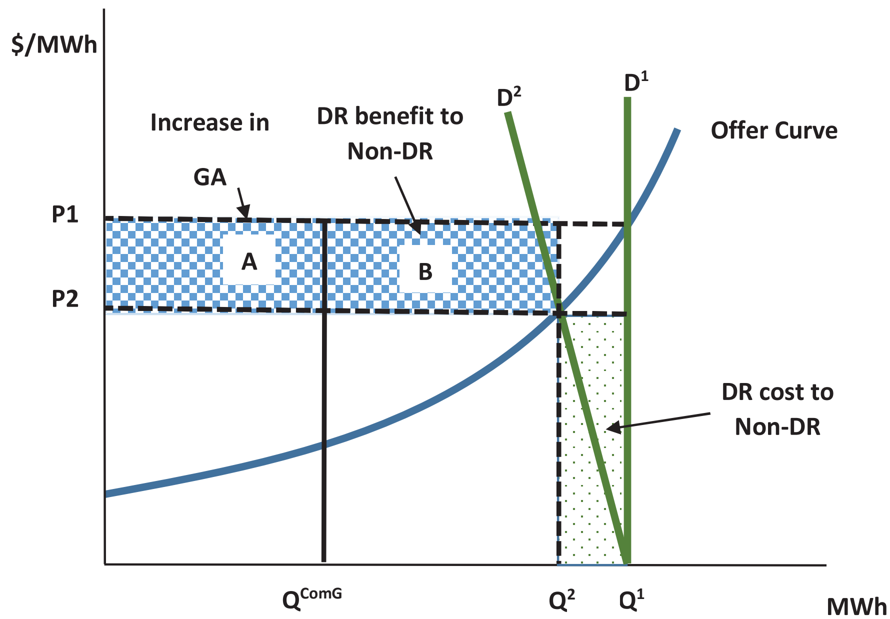
Figure 5: The Net Benefits Test under FERC Order No. 745



61. The FERC net benefits test is satisfied if the savings the non-DR consumers realize from the lower wholesale price are greater than the additional payment they must make to DR resources. Under the FERC model, this occurs when the shaded blue area is greater than the shaded green area in Figure 5.

62. If the net benefits test were applied to Ontario, the IESO would have to incorporate the effects of payments made to contracted and regulated ("committed") generators by non-DR consumers through the Global Adjustment. As discussed above, the Global Adjustment includes differences between payments made to generators at the wholesale market price and payments made through regulation or contract that differ from the market price. If providing DR resources an energy payment for economic activations lowers the market-clearing price as the Commission expected in FERC Order No. 745, in Ontario, a portion of the benefit non-DR resources get from the lower energy price will be offset by an increase in the payments the same consumers have to make to committed generators through the Global Adjustment. This means that all else held constant, the net benefits test condition for compensating DR resources will be satisfied less often in Ontario than in the United States. This is illustrated in Figure 6.

Figure 6: The Net Benefits Test illustrated for Ontario



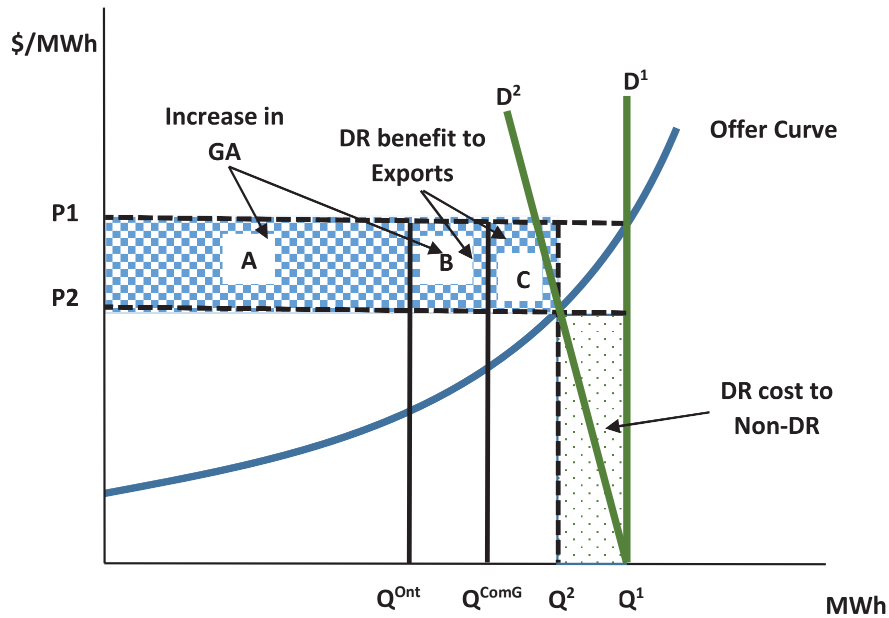
63. In Figure 6, the amount of supply provided by committed generators is Q^{COMG}. When lower energy bid prices of DR resources cause the energy market price to fall from P^1 to P^2, the amount of net revenues earned by the committed generators falls in proportion to the price decrease (the area marked as A in Figure 6). The decline in net revenue is fully offset by higher payments to the committed generators as per their contract terms or regulated rates. Non-DR consumers cover these higher payments through higher Global Adjustment charges. As a result, the benefit that non-DR consumers receive from the lower energy price is reduced by the amount A; they realize the smaller benefit represented by area B. Since the net benefit is smaller in Ontario, it is less likely that the net benefits test condition will be satisfied in Ontario.

C.8 Q: Are there conditions in Ontario in which the net benefits test is certain to fail?

64. Yes. Ontario is a large net exporter. Exporters do not pay the Global Adjustment. In many hours, committed generators are required to produce to meet both the Ontario demand and the export demand. When the amount of energy provided by committed

generators exceeds the Ontario demand, energy price decreases caused by lower DR resource energy bids would lead to an increase in Ontario non-DR consumers' Global Adjustment charges that exceeds benefits they realize from lower energy market prices. That is, exports would realize the benefit of the lower market prices, but because Ontario consumers must cover the higher Global Adjustment charges, they would be worse off, even before paying DR resources not to consume. This is illustrated in Figure 7.

Figure 7: Sufficient condition for Net Benefits Test failure in Ontario,



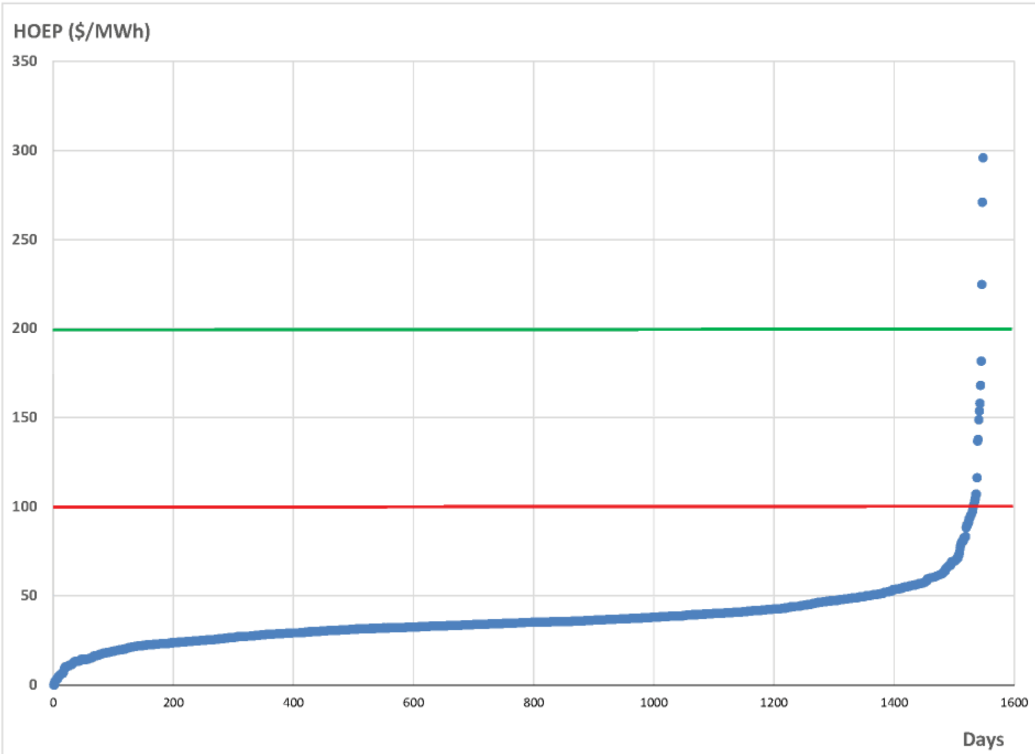
65. In Figure 7, the Ontario non-DR consumers' demand is Q^{ONT}. The difference between Q^2 and Q^{ONT} is export demand. The amount of energy produced by committed generators is Q^{COMG}, which is greater than the Ontario non-DR consumers' demand. The benefit that non-DR consumers realize from the energy price reduction is represented by the area A. However, the amount of Global Adjustment that these consumers will have to pay increases by the area A + B. Ontario non-DR consumers are made strictly worse off by compensating DR resource for economic activations. They are made worse off even before accounting for the amount they have to pay to DR resources for economic activations (the green shaded area).

C.9 Q: Have you done any analysis that could provide the OEB some guidance on the likelihood that the net benefits test would be satisfied in Ontario?

66. Yes. The IESO provided me with hourly data for the period January 1, 2018 to October 28, 2019 which is attached hereto as **Exhibit "H"**. The data included hourly HOEP and hourly quantities of Ontario non-dispatchable demand, Ontario dispatchable load demand, committed generation output, non-committed generation output, exports and imports for a total of 15,984 hours. I calculated the number of hours when output from committed generators exceeded Ontario non-dispatchable demand plus dispatchable load demand (the sufficient condition for the net benefits test to fail in Ontario). There were 14,436 hours out of 15,984 hours (90.3% of hours) in which the output of committed generators exceeded the Ontario demand between January 1, 2018 and October 28, 2019. The net benefits test would have failed in these hours.

67. In the remaining 1,548 hours (9.7% or hours) when Ontario demand was greater than the output of committed generators, I considered the likelihood that compensating DR resources for economic activations would lead to sufficient reductions in DR resources' energy bid prices to cause a decrease in the energy market price. If DR resource energy bid prices remain relatively high, then it is not likely a price decrease could occur and hence a net benefit to non-DR consumers is not possible. Figure 8 provides some insights in the number of hours that this might be possible. Figure 8 ranks the 1,548 hours between January 1, 2018 to October 28, 2019, in which Ontario demand exceeded committed generation output, from lowest HOEP to highest HOEP.

Figure 8: HOEP in hours with Ontario demand greater than committed generation Output, January 1, 2018 to October 28, 2019



68. First, DR resources must submit energy bid prices that are greater than $100/MWh. Compensating DR resources for economic activations could not have a net benefit in hours when the HOEP was less than $100/MWh because DR resource energy bid reductions could not fall below this price level. HOEP exceeded $100/MWh in only 17 of the 1,548 hours (0.106% of all hours in the data set).

69. IESO analysis found in a presentation to the Demand Response Working Group indicated the following:

> The historical contracting programs required DR energy bids to be priced at $200/MWh. Once the $200 price requirement was removed for HDR resources, the IESO observed that the majority of DR bids were priced by participants much higher than $200/MWh. This implies DR

participant's value of energy consumption is much higher than this level.[28]

70. If we consider prices above $200/MWh as the benchmark for a possible price effect, there were only 3 of the 1,548 hours (0.019% of the total hours in the data set) in which the HOEP exceed this benchmark.

71. Overall, recent historical data suggest that the net benefits test would rarely, if ever, be satisfied in Ontario (0.019% of the time).

C.10 Q: You also said that there would be additional complications for the IESO to implement the FERC net benefits test. What are the additional complications?

72. FERC Order No. 745 required the RTO/ISO's "to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective."[29] Essentially, the ISO and RTOs are required to use historic offer data, adjusted to reflect resource availability and fuel costs, to create a representative aggregated supply curve for a trade month.[30] This representative curve is used to determine "the monthly threshold price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources."[31] The ISO and RTOs must post this threshold price on their website and update it on a monthly basis.

73. As discussed above, the IESO will require additional information to implement the net benefits test in Ontario. They will require a forecast of Ontario non-DR load, the production of committed generation and the amount of net exports. Realistically, these values will change often during the month, which makes the use of a representative

[28] "IESO March 1 Presentation" at 7.

[29] FERC Order No. 745 at para. 4.

[30] This is described in Exhibit "G".

[31] FERC Order No. 745 at para. 4.

supply stack and a monthly price test less practical. Furthermore, applying a blunt monthly test is more likely to lead to false positives and harm to Ontario consumers given the unique conditions and relative infrequency in which the net benefits test is likely to be satisfied. The IESO would likely have to identify improvements to the way the nets benefits test is implemented in Ontario compared to the United States to limit false positives.

C.11 Q: Do you think there are any other aspects of the Ontario market that should inform a decision of whether or not to apply FERC Order No. 745 in Ontario?

74. Yes. As I outlined above, the key objective of FERC Order No. 745 was to "remove barriers to participation of demand response resources in organized wholesale electricity markets."[32] The Commission stated in its Notice of Proposed Rule Making that:

> "Despite the benefits of demand response and various efforts by the Commission, ISOs and RTOs to address barriers to and compensation for demand response participation, demand response providers collectively play a small role in wholesale markets. After several years of observing demand response participation in ISO and RTO markets with different, and often evolving, demand response compensation structures, the Commission is concerned that some existing, inadequate compensation structures have hindered the development and use of demand response."[33]

75. FERC Order No. 745 further describes the types of barriers to demand response participation that concerned the Commission. These barriers primarily related to the disconnect that existed at the time between wholesale and retail prices and the lack of incentives this created for the investment in the capability to be price responsive.[34]

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[32] *Ibid* at 113.

[33] Exhibit "F" at para. 9.

[34] FERC Order No. 745. This was a point made by Commissioner Moeller on his dissenting opinion: "the lack of dynamic prices at the retail level is the primary barrier to demand response participation."

FERC Order No. 745 sought to remedy these barriers by providing DR resources additional compensation.[35]

76. However, the types of barriers to demand response the Commission was concerned with at the time of FERC Order No. 745 do not seem relevant to present day Ontario. First, as Navigant noted in a report prepared for the IESO:

> "It is important to note that Ontario is different from many U.S. jurisdiction in that many of the DR resources are wholesale market participants or large customers that are exposed to real-time electricity prices as opposed to retail prices. This means that Ontario DR customers avoid the entire real-time electricity price when curtailing and are exposed to high price spikes. When DR providers are only exposed to retail rates as they are in many U.S. jurisdictions, they are unlikely to have the same avoided cost benefit when curtailing during spikes in prices."[36]

77. Second, Ontario has already done a great deal to help DR resources recover the costs of investments needed to enable their participation in wholesale markets. As early as 2007, the IESO (formerly the OPA) recognized the capacity value of DR resources and implemented the DR3 program. The DR3 program procured DR resources through multi-year standard offer contracts that paid DR resources both an availability payment and a utilization payment. The proceeds of the availability payment could contribute in the investment in meters and control systems that would enable price responsiveness. It

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[35] *Ibid.* Commissioner Moeller in his dissenting opinion challenged the majority on this point. Commissioner Moeller stated in his dissent:

> "The Rule [FERC Order No. 745] finds that "greater uniformity in compensating demand response resources" is required and as justification for its action, references the existence of various barriers that limit the participation of demand response in the energy markets. The majority ultimately concludes that these barriers can be removed by better equipping demand response providers with the financial resources to invest in enabling technologies. This is to say that the majority believes that paying demand resources more money will help overcome these barriers and encourage more participation. The Rule, however, never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP to demand resources."

[36] "Navigant Report".

also helped fund investments made by load aggregators to sign-up and compensate consumers that could reduce demand upon an activation from the IESO. In 2015, the former OPA DR3 program was integrated into the IESO-administered market through a program called capacity backed demand response and through the DRA. This provided further learning for the IESO and DR resources on how demand response could respond to economic activations. DR resources were provided availability payments for providing the capacity service, which again could be used to fund investments in the technologies needed to enable demand response. These availability payments were made during a time when Ontario had more than enough capacity to meet its obligations. This means Ontario consumers paid to help remove the barriers to demand response when it did not need the capacity. Arguably, as evidenced by the number of DR resources that now participate in the DRA, Ontario has been successful in removing the types of barriers to demand response participation in the wholesale market that were the focus of FERC Order 745.

78. Third, the ICI has been very effective at stimulating demand response during peak demand periods. The Market Surveillance Panel estimates that "ICI participants reduced their consumption by 42% during peak demand conditions in 2016."[37] They do so to reduce the amount of Global Adjustment that they pay. The Panel "estimates that by reducing consumption by one megawatt during each of the five peak demand hours in 2016, a Class A consumer would have saved approximately $520,000 in Global Adjustment charges."[38] The benefit from reducing peak hour consumption are so significant, it "creates an incentive for Class A consumers to invest in new generating or storage capacity located at their facilities."[39]

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[37] Exhibit "E" at 2.

[38] *Ibid* at 8.

[39] *Ibid* at 16.

C.12 Q: Are you aware of any research that demonstrates the effect that FERC Order No. 745 has had on the United States wholesale markets?

79. Yes, in the short time that I had to prepare this testimony, I conducted a non-exhaustive scan of the academic literature and reports prepared by the RTOs, ISOs and their market monitors for empirical evidence on the effects and implications of the implementation of FERC Order No. 745. I was surprised to find only a few reports or academic papers on the topic.

80. Monitoring Analytics LLC, the market monitor for PJM, prepare quarterly and annual reports on the PJM market. They dedicate a section in the reports specifically to demand response. Attached hereto as **Exhibit "I"** and **Exhibit "J"**, are the 2015 and 2019 Quarterly State of the Market Reports. The 2015 report states that FERC Order No. 745 "increased incentives to participate" in the PJM economic demand response program.[40] Figure 6-2 shows a sudden increase in both credits paid to economic demand response and economic MWh reductions starting in April 2012, when PJM implemented the Order No. 745. The 2019 report includes the same Figure 6-2, which shows the elevated levels of credits, and MWh reductions largely continued through 2019 and then subsided, although they are still above the April 2012 levels.[41]

81. The reports also provide the monthly net benefits test threshold prices. Threshold prices have never exceeded $34.07/MWh since April 2012 when PJM implemented Order No. 745.[42]

82. Steve Dahlke and Matt Prorok published a paper in the Energy Journal in 2019 that estimated the consumer savings, CO_2 emission reductions, and price effects that *could* be achieved in the MISO electricity market through the removal of regulatory and market rule barriers to market-based deployment of DR. This paper is attached hereto as **Exhibit "K"**. They argue that even after implementation of FERC Order No. 745,

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[40] Exhibit "I" at 213.

[41] Exhibit "J" at 297.

[42] *Ibid* at 300.

there continue to be barriers to DR participation in MISO and that considerable consumer savings and CO_2 emissions could be realized through the removal of the barriers. Through their analysis, they uncover a shortcoming of the FERC net benefits test. They note that DR resources that reduce their consumption in a peak hour because of an economic activation often shift their consumption to future off-peak hours. The shift in consumption increases the price in the future hours and reduces some of the benefits to non-DR resources. That is, "deploying demand response resources that pass the net benefits test in the hour they were deployed actually increased overall costs after taking into account the off-peak increase of energy."[43]

83. Kai Van Horn et al, published a paper in the Electricity Journal in October 2013 that also identified shortcomings in the net benefits test and proposed improvements to the test. This paper is attached hereto as **Exhibit "L"**. Van Horn et al, argue the failure of the net benefits tests "to integrated the impacts of transmission is a significant limitation that has unintended consequences for the total benefits which DR resources may bring to the system and for the distribution of those benefits among the buyers in the system."[44]

84. Xu Chen and Andrew N. Kleit published a paper in the Energy Journal in 2016 (attached hereto as **Exhibit "M"**) that provided empirical result to show how incentive-based DR programs can be "manipulated" to inflate customer baseline load measurement. They suggest, "policy makers in FERC, RTOs and states regulatory agencies consider the threat of manipulation when modifying DR market rules following the Supreme Court's recent upholding of the FERC Order 745."[45]

85. Finally, David Brown and David Sappington published a paper in the Journal of Regulatory Economics in 2016 that derives an optimal DR policy and uses the optimal

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[43] Exhibit "K" at 258.

[44] Exhibit "L" at 152.

[45] Exhibit "M" at 201.

policy to estimate the welfare losses that can arise under FERC Order No. 745. This paper is attached hereto as **Exhibit "N"**. They show that the implementation of Order No. 745 overcompensates DR resources and "reduces welfare well below the level secured by the optimal DR policy."[46] They argue that the policy offered by the critiques to FERC Order No. 745, to compensate DR resources the difference between LMP and the retail rate provided higher welfare than compensation at full LMP as per the FERC Order No. 745.

D. SUMMARY CONCLUSIONS

D.1 Q: Can you summarize for the Board the key findings of evidence?

86. Yes. The evidence in my testimony demonstrates the following.

87. First, the Amendments provide an equitable treatment of TCA participants. Horizontal equity requires that like people be treated alike. I show by way of example, that two identical companies, which differ only by the arbitrary placement of their meters, are treated exactly alike under the Amendment; *horizontal equity*. I then show that compensating DR resources for an economic activation provides preferential treatment to the company that operates a behind-the meter generator; *horizontal inequity*. The company that operates the behind-the-meter generator, DR Corp. is provided preferential treatment because it benefits twice when it reduces its net-demand with the IESO: first, it reduces the energy payment it makes to the IESO, and second, it receives a payment from the IESO for doing so.

88. In my opinion, applying the horizontal equity test is a more accurate way of assessing equitable treatment, than a test of functional equivalence in service provided, which is the test I understand AMPCO has asked the Board to rely on in this matter. As my example demonstrates, both DR Corp. and Gen Corp. are functionally equivalent in terms of their capability of balancing supply and demand on the IESO controlled grid;

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[46] Exhibit "N" at 265.

one by reducing demand and one for producing electricity. Doing so fails to recognize that DR Corp. is effectively compensated twice for reducing demand while GEN Corp. receives no net benefit for producing electricity (i.e., it earns zero net revenue). I argue that when designing fair and efficient electricity markets, it is important to understand the underling incentives of participants.

89. Second, the Amendments do not place DR resources at a competitive disadvantage to non-committed dispatchable generators in the TCA as per AMPCO's assertion. To the contrary, pay DR resources the market price for economic activations would place non-committed-generators at a competitive disadvantage. Through examples, I show that paying DR resources the market price for an economic activation compensates them twice for their demand reduction. This double benefit would allow them to bid lower in the energy market, and offer lower capacity prices in the TCA to the disadvantage of non-committed generators. Furthermore, I demonstrate that DR resources that are Class A consumers already have a competitive advantage over non-committed generators in the TCA since they can avoid paying Global Adjustment as a capacity resource. This later point creates incentives for large-consumers to invest in behind-the-meter generation at a cost greater than the cost to operate and maintain a non-committed generator facility.

90. Third, the Amendment is consistent with the promotion of fair and equitable competition as it provides the proper incentives for DR resources to operate efficiently within the TCA and the IESO's energy market.

91. Fourth, the presence of the Global Adjustment means that the FERC net benefits test will rarely if ever be satisfied in Ontario. Furthermore, there would be significant complications for the IESO to implement the net benefits test in Ontario due to the Global Adjustment. In my opinion, the evidence shows that there is no net benefit to even further studying the merits of the application of the net benefits test in Ontario.

92. Fifth, Ontario has made significant progress towards reducing the types of barriers to DR resources that concerned the Commission at the time of FERC Order No. 745. In

my opinion, providing DR resources energy payments for economic activations is not required to overcome any legitimate barriers to DR resources, to the extent there are any remaining barriers.

93. With this I conclude my testimony.

SWORN before me at the Town of Paris, in the Province of Ontario, this 21st day of November, 2019	)))))))	
A Commissioner for Taking Affidavits	)	**Brian Rivard**

Lauren Theresa Daniel, a Commissioner, etc., Province of Ontario, while a Student-at-Law. Expires April 8, 2022.

TAB 7

EB-2019-0242

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by the Association of Major Power Consumers in Ontario, pursuant to section 33 of the *Electricity Act, 1998, S.*O. 1998, c. 15, Sched. A and Rule 17 of the Ontario Energy Board *Rules of Practice and Procedure* for review of amendments to the Independent Electricity System Operator market rules related to the implementation of a Transitional Capacity Auction (MR- 00439-R00-R05).

AND IN THE MATTER OF a notice of motion by the Association of Major Power Consumers in Ontario, pursuant to section 33 of the *Electricity Act, 1998, S.*O. 1998, c. 15, Sched. A and Rule 17 of the Ontario Energy Board *Rules of Practice and Procedure* to stay the operation of amendments to the Independent Electricity System Operator market rules pending determination of the Application.

AFFIDAVIT OF
John Windsor, Vice President of Energy Services and Asset Management

October 25, 2019

TABLE OF CONTENTS

I, John Windsor, of the City of Burlington, in the Province of Ontario, MAKE OATH AND SAY AS FOLLOWS:

A. INTRODUCTION

A.1 Q: Please describe Kingston CoGen Limited Partnership ("KCLP").

1. KCLP is an Ontario partnership that is indirectly wholly-owned by Northland Power Inc. ("Northland"). KCLP owns and operates a 110 MW combined-cycle, natural-gas fired facility located in Kingston, Ontario. Originally a cogeneration facility, the steam host (Invista) has since been shut down and decommissioned. The power purchase agreement ("PPA") that KCLP had with the Ontario Electricity Financial Corporation ("OEFC") expired January 31st, 2017.

A.2 Q: What is your position and what are your responsibilities as an employee of KCLP?

2. I am Vice President of Energy Services and Asset Management at Northland. In this role I also serve as CEO of Northland's energy marketing business (power and gas trading). I have been working in the power industry for 28 years, 18 of which are directly in the Ontario market, although I have also worked in the US power markets of the New York Independent System Operator ("NYISO") and ISO-New England ("ISO-NE") for 6 years. At Northland, I am responsible for the commercial aspects of Northland's operating businesses, which include market participation and post PPA revenue strategy, such as capacity market participation for KCLP. I serve as chair for four (4) Northland-owned partnerships, which operate power projects within the Ontario power market. I am a 1st Class Power Engineer, and a designated member of The Canadian Institute of Management (CIM, P.Mgr, C.Mgr). I hold a Graduate Diploma in Management (GDM) and a Master of Business Administration degree (MBA) from Athabasca University.

A.3 Q: On whose behalf are you submitting evidence?

3. I have prepared this evidence for and on behalf of KCLP in response to the Association of Major Power Consumers in Ontario's application to the Ontario Energy Board ("OEB" or the "Board") for review of the Independent Electricity System Operator ("IESO") market

rule amendments for the implementation of a Transitional Capacity Auction ("TCA") (the "Amendments")[1] (the "Application")[2], and a motion to stay the operation of the Amendments pending the Board's determination of the Application (the "Stay Motion")[3], which were filed with the Board on September 26, 2019.

A.4 Q: Have you previously submitted evidence before the Ontario Energy Board?

4. I have not provided any previous evidence to the OEB personally.

A.5 Q: What is the purpose of your evidence?

5. The purpose of my evidence is to:

   a. provide factual information about KCLP's business operations; and

   b. describes the harm to KCLP's business operations should the OEB grant the Stay Motion or approve the Application.

B. KCLP'S BUSINESS OPERATIONS

B.1 Q: Does KCLP have a PPA with the IESO or the OEFC?

6. No, the PPA that KCLP had with the OEFC expired on January 31st, 2017 and KCLP has since been without a PPA.

7. KCLP participates in the Ontario (IESO) energy market daily by submitting energy offers to the market. However, this practice does not produce any material energy market revenue due to KCLP's offers reflecting higher costs than the typical energy market clearing price in Ontario. My understanding is that this is a result of the IESO energy market price reflecting generator variable costs, which represents approximately 20% of the cost of electricity in Ontario. For most other generators, fixed costs are covered by PPAs and

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[1] MR-00439-R00-R05, available online at: http://www.ieso.ca/en/Sector-Participants/Change-Management/Proposed-Market-Rule-Amendments

[2] Application for Review of an Amendment to the Independent Electricity System Operator Market Rules, Notice of Appeal, EB-2019-0242, filed September 26, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/653723/File/document.

[3] Application for Review of an Amendment to the Independent Electricity System Operator Market Rules, Notice of Motion, EB-2019-0242, filed September 26, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/653721/File/document.

consumers pay the contract or PPA portion of the energy costs in the global adjustment portion of their energy bill, which makes up most of the remaining 80% of energy costs to consumers.

B.2 Q: Would KCLP qualify to compete in the TCA in December 2019?

8. KCLP has met all the pre-qualification requirements to participate in a TCA auction in December 2019. KCLP continues to work to ensure all requirements are met for participation in the auction.

B.3 Q: Do you expect that the TCA will result in lower capacity prices due to increased competition amongst capacity resources?

9. I believe that could happen. Auction supply / demand economics will determine the auction clearing price in the upcoming TCA. Although we will not know the clearing price until after the auction takes place, I can offer the following insights that inform my belief:

   a. KCLP has reviewed historical DR auction clearing prices and believes its offers could be competitive with those prices.

   b. Allowing more competition from generators and future imports (e.g. NYISO) may put some downward pressure on price.

   c. In addition, if the IESO changes the procurement volume, it could impact clearing prices.

B.4 Q: Are there any guarantees that KCLP will be successful in the upcoming December 2019 TCA?

10. There are no guarantees that KCLP will be successful in the December 2019 TCA. Like all other resources, KCLP will need to compete for the opportunity to provide capacity to the market. Each participant will also need to determine a minimum clearing price and volume award that they are willing to accept, including whether they will accept a partial award depending on their offer strategy.

B.5 Q: Prior to the adoption of the TCA, could KCLP sell capacity into the Ontario IESO administered markets (IAM)?

11. Prior to the adoption of the TCA, there are no mechanisms available to KCLP to sell its capacity into the IAM.

12. While the IESO has agreed that KCLP may participate in the NYISO Installed Capacity Market (ICAP) as an external supply of capacity since the summer of 2017, the capacity revenues earned from that market are relatively small compared to KCLP's fixed costs. As such, those revenues have only offset a small portion of KCLP's fixed costs.

B.6 Q: Does the lack of an IAM for generation capacity in Ontario differ in any way from the NYISO, PJM Interconnection LLC ("PJM"), and ISO-NE markets that were the subject of FERC Order No. 745?

13. Yes, NYISO, PJM and ISO-NE each had defined market-based capacity markets as part of the RTO/ISO's scope of services. Generators could already compete in those market-based capacity markets, and FERC Order No. 745 was focused on changing certain mechanisms within those existing capacity markets. By contrast, as noted above, the Ontario IAM does not, in the absence of the TCA, have a capacity market in which generators can participate.

B.7 Q: But KCLP can sell energy and other services into the IAM. Describe those services. Are the revenues earned from those services (in the absence of capacity revenues) sufficient to maintain KCLP as a going concern? If no, why not?

14. KCLP has been a market participant in the IAM energy market since the market opened.

15. When KCLP's OEFC contract expired in January 2017, it continued to be a market participant in Ontario, and continued to offer its energy into the IAM. However, the energy market in Ontario at this time does not provide KCLP sufficient opportunities to generate revenues above its marginal operating costs.

16. Put another way, KCLP has both fixed and variable operating costs that it cannot recover from the energy market (including ancillary services) alone.

17. As a result, KCLP does not have access to a mechanism to recover its fixed operating costs by participating in the IAM energy market.

B.8 Q: Prior to the adoption of the TCA, are you aware of any other off-contract Ontario generators being forced to make the difficult decision to suspend operations, lay-off employees, and otherwise dispose of equipment?

18. Yes. Northland recently had to suspend operations at, and ultimately sell, its Cochrane generation facility. After the expiry of Cochrane's OEFC contract, there were no mechanisms (such as a capacity auction) to pay for fixed operating costs for the facility. Prior to this, Cochrane provided 40 MW of capacity to the IAM and employed 30 people. As a result, this capacity is no longer available for use by the IESO in planning for the IAM.

19. If a capacity market had existed for capacity resources coming off contract at the time Cochrane came off contract, then that facility may have been retained by Northland.

B.9 Q: Is there a risk that this could happen at KCLP if the TCA does not proceed as planned?

20. Yes. KCLP has been operating for almost three years where it is not recovering its fixed operating costs via market-based mechanisms available to it. The parent company of KCLP has indicated that it is not willing to continue losing money without some indication that a mechanism will become available to recover sufficient revenues to keep the facility operating. If KCLP is prevented from competing in the upcoming TCA, I believe that it is likely that the parent company will decide to discontinue facility operations.

B.10 Q: How would a decision of the OEB granting the Stay Motion affect KCLP's business operations in the near-term?

21. It is my understanding that the TCA auction scheduled for December 2019 will cover a commitment period of May 1, 2020 to April 30, 2021. The commitment period will consist of two seasonal obligation periods – a summer and a winter period. KCLP intends to participate in the auction for both seasonal periods.

22. If the stay is granted, and the auction is delayed from its planned December 2019 auction date, then KCLP would lose out on the opportunity to compete for capacity for both the summer and winter periods. This would result in a lost opportunity cost for KCLP, which could cost KCLP millions of dollars and potentially force KCLP to shut down.

B.11 Q: How would a decision of the OEB approving the Application affect KCLP's business operations going forward?

23. The impact would be similar to if the OEB grants the stay, as discussed above. Ultimately, if KCLP is unable to compete in a TCA, and otherwise secure an adequate revenue stream, this will place more pressure to shut down the facility permanently, as it continues to lose millions of dollars annually in the absence of a contract.

24. Once shut down, the facility will not be available to meet future capacity needs in the IAM.

B.12 Q: Does this complete your evidence?

25. Yes.

SWORN before me at the City of Toronto, in the Province of Ontario, this 25 day of October, 2019	
A Commissioner for Taking Affidavits	**John Windsor**

Lauren Theresa Daniel, a Commissioner, etc., Province of Ontario, while a Student-at-Law. Expires April 8, 2022.

TAB 8

ONTARIO ENERGY BOARD

FILE NO.: **EB-2019-0242** **AMPCO Motion**

VOLUME:	**3**	
DATE:	**November 29, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

resources competing together to supply capacity. It's all in theory the same capacity product, and so we want them all running in an open, competitive process, not boxed off in mini-auctions.

And another alternative may have to be some semblance of a contract, if we can't run the auction, because we do have to get ready NERC requirements -- sorry, the North American Electrical Reliability Corporation, as the standards authority for Ontario, wants to know what our plans are.

So we have to establish those plans and start moving forward with them. Whether it's contract opportunity or an alternative auction, we need to start moving forward now.

MR. ZACHER: Can I ask you -- and Chair Spoel alluded to this in a question, I think at the end of the day yesterday, is whether one of the purposes of the TCA, or capacity auctions more generally, is specifically to save or prevent certain off-contract generators from going out of business, so that they will be available in a few years.

Is that a fair characterization of the purpose?

MR. SHORT: I would say -- no, I wouldn't characterize it that way. The IESO wants to run a competitive and open process where all resources have an opportunity to compete in the supply capacity. It's not -- we're not picking a winner or loser in this case. We are trying to again provide that open competition, technology neutral, down the road.

So it's -- sorry, technology neutral and we will add resources down the road as we continue to expand the auction.

So, you know, with respect to an off-contract generator, we recognize that -- and I've talked about it before, this pending need is not just a DR; DR can't do it alone. And so when we look at the possible opportunities to obtain capacity, it comes from generators, certainly. We've got 27 generators, 640 some megawatts that are off contract today.

I don't know if they are all willing and able to compete in an auction, but I would like to give them that opportunity to compete.

We know that other jurisdictions have capacity that could be available to Ontario from, say, Quebec or New York. I'd like to give them the opportunity to compete and supply capacity to Ontario.

So over time, you know, we've had this essentially a sandbox, where DR's been --I'll say somewhat protected from the rest of the playground. They have been -- we have been working with them to improve the product, add features, improve the test results of capacity. But we think that it's time to let other resources compete.

And, you know, if I look at generators, I am not picking generators to say we are not guaranteeing -- I'll pick on Kingston Cogen. I am not guaranteeing them they will get a capacity obligation if they're -- you know, if we open the auction up. It's simply giving them the opportunity to compete.

If they remain economic, then they will be successful and they may beat out a DR provider that is less economic, if they are a higher price in the end.

But it's a matter -- I also look at the risk going forward to 2023. We need to be kind of all hands on deck, as far as all the available opportunities to meet that 4,000 megawatt need. Could we do it with resources other than generators that are off contract? Probably, hopefully.

But if you've got a resource that's already built and it's in the ground and assuming it's -- I don't know the state of Kingston Cogen, not to pick on them again, but if the facility is still up and running and viable, then why not afford them that opportunity to stay around. It's likely they are a less -- sorry, a more -- sorry, a less costly resource to ratepayers ultimately than say building a brand new gas generator from scratch to supply the need in 2023.

So we are not picking winners and losers. We are really just trying to provide that competitive process.

MR. ZACHER: Thank you. Let me just switch gears for a moment. As you know, AMPCO says the demand response resources will but put at it a competitive disadvantage vis-a-vis generators in the capacity auction, because they may need to include the cost of potential energy market activations in their TCA bids and. And you heard Dr. Rivard explain yesterday why he does not believe that is the case.

TAB 9

ONTARIO ENERGY BOARD

FILE NO.: **EB-2019-0242** **AMPCO Motion**

VOLUME:	**2**	
DATE:	**November 28, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

your time --

MS. DJURDJEVIC: I have, I have, indeed. Yeah, I am -- I am done. Thank you very much. Sorry for taking that time.

MS. SPOEL: That's fine.

Let's take a short afternoon break. I think we only have -- oh, we've got more people to make it through. Let's resume at 3:20 so we can try to get this done in a reasonable amount of time. Thank you.

--- Recess taken at 3:06 p.m.

--- On resuming at 3:24 p.m.

MS. SPOEL: Please be seated. Okay, Mr. Barz, I think you are on next.

MR. BARZ: Thank you, Madam Chair. Just as a preliminary matter, I am going to be referring to KCLP's compendium. APPrO did not file its own compendium for today. So that is panel 4, Brian Rivard, examination in-chief revised, and it is K2.5.

MS. SPOEL: Thank you.

CROSS-EXAMINATION BY MR. BARZ:

MR. BARZ: Thank you. Do you have a copy of that as well, Dr. Rivard?

DR. RIVARD: I do somewhere. Yes, I do.

MR. BARZ: Thank you. Just so you know, I am Evan Barz. I am here on behalf of the Association of Power Producers of Ontario.

DR. RIVARD: Nice to meet you.

MR. BARZ: Nice to meet you. I would just like to begin by taking you to paragraph 8 of your affidavit, which is tab 1 of KCLP's compendium.

DR. RIVARD: Okay.

MR. BARZ: In 2013, you were the director of markets at the IESO. Correct?

DR. RIVARD: Yes.

MR. BARZ: And in that capacity, you oversaw the design and implementation of the IESO demand response auction, correct?

DR. RIVARD: Up until -- yes, although it was actually implemented after I left.

MR. BARZ: Okay. But you were involved with the design process?

DR. RIVARD: Yes.

MR. BARZ: Okay. And in 2013 when you held that position with the IESO, was it understood that the demand response auction was a first-step, or that it was a step in evolution of the auction, and that other resources would be added at a future date?

DR. RIVARD: Yes. It was seen to be something that we would want to do in stages.

The idea first was to take what was previously the DR 3 program and to convert that to a more competitive-based program.

So previously it was a contract program. Everybody was paid the same based on some determined contract price. We thought that if we -- and I should say the amount of megawatts that were being procured for demand response was actually an amount that was directed by the government to procure. Whether we needed it or not, in a sense we were obligated to procure that level of demand response.

So the idea was let's transition it from a contract base approach to a competitive-based approach. That will set the stage for as other contracts expire, i.e., generator contracts, we can transition this to a more complete form of attracting capacity and procuring capacity.

MR. BARZ: Okay. So it was anticipated at that time that off-contract generators or non-utility generators might be added to the auction at a future date?

DR. RIVARD: Eventually, we would have an auction that they would all compete in, yes.

MR. BARZ: It was never intended the auction would be exclusive to demand response resources in perpetuity, so to speak?

DR. RIVARD: No.

MR. BARZ: Okay. Do you want to give a little bit of rationale for why that evolution was planned out, or what the thinking was behind wanting it to evolve in that manner?

DR. RIVARD: Yes. Based on any analysis that we did, we believe that procuring capacity using competitive means would lead to lower costs overall than the approach that had been used to that point, which was largely contract approaches.

So we eventually wanted to use more competitive means to ensure we could meet our capacity obligation.

MR. BARZ: Could I take you just to paragraph 21 of your affidavit, which is at page 10 of the KCLP's compendium?

DR. RIVARD: Okay.

MR. BARZ: This section is just premised by the question what evidence has AMPCO provided to establish competitive disadvantage.

As part of your retainer in this proceeding, did you review AMPCO's notice of appeal and supporting evidence?

DR. RIVARD: Yes.

MR. BARZ: You were also asked to give your independent views on the economic merit of AMPCO's position in this proceeding, correct?

DR. RIVARD: Yes.

MR. BARZ: And at paragraph 21 of your affidavit, you kind of give a concise summary or describe the evidence that AMPCO has put forward in this proceeding, correct?

DR. RIVARD: That was my attempt, yes.

MR. BARZ: Thank you. And you note there that that would be the affidavit of Mr. Colin Anderson, correct?

DR. RIVARD: That's correct, yes.

MR. BARZ: If I could take you over to the next page, paragraph 22, this was a reference that my friend, Mr. Mondrow, has referred to multiple times today. So I won't dwell on the first sentence, but I will read it out. It says:

"From an economic perspective, if a demand

response incurs a cost when economically
activated to curtail demand that it would avoid
if it continued to consume, then it could be
competitively disadvantaged by the amendments."

The second part of this paragraph, of that same paragraph 22, goes on to state:

"AMPCO has provided no factual evidence or even
conceptual evidence that explains the nature,
magnitude or legitimacy of these avoidable
costs."

Correct?

DR. RIVARD: That's what it says, yes.

MR. BARZ: So I am looking from your perspective as an economist. What would you have expected to have seen as evidence in this proceeding, in terms of evidence from an entity seeking to establish competitive disadvantage or unjust discrimination?

DR. RIVARD: I think what I will do is I will answer that based on my experience and my training as an anti-trust economist in my time at the Competition Bureau.

And what I -- how I might put it is that what I saw in the evidence was probably akin to what we would see as a complaint made by a competitor. It is a hypothesis of competitive harm, an allegation. So that would come to the Bureau.

That would just be the start of the situation. Based on the allegations or the, you know, the complaint, we would then decide how to proceed and it would generally be to actually look for evidence of what that competitive disadvantage would be.

So we would interview more of the complainant -- others in the industry to understand the nature of competition, the nature of the cost involved, differences in the products that they provided, all with an idea to see, well, is there merit to that allegation.

MR. BARZ: So this complaint or hypothesis that you are referring to would have just been a high-level beginning, then you would want to see the underlying economic evidence which establishes -- or that may establish that competitive disadvantage or that discrimination?

DR. RIVARD: Yes, certainly, yes.

MR. BARZ: Okay.

MS. SPOEL: Dr. Rivard, at the Competition Bureau, do you do it ex post facto, or do you do it forward-looking when you are looking at competitive -- if someone files a complaint about anti-competitive behavior, are those two entities already in the marketplace? Or is it a situation where there is proposed to be activity in the marketplace?

DR. RIVARD: It could be both, really, yes. It could be some kind of restraint on trade that a larger company is imposing on an existing company that's not allowing that company to grow, so it's kind of existing competitors.

It could be someone that wants to enter the industry, but are making a case as to why there is a restraint from their entry. It could be both.

And it could be retrospective, the actions actually occurred and the harm is in the past, or it could be prospective.

MS. SPOEL: Okay, thank you, that is helpful.

MR. BARZ: Just continuing with that thread, I believe you mentioned that once you got that initial complaint, you would want to go out and speak with the complainants to get some understanding of the facts underlying their complaint. You would perhaps want to see the underlying economics, maybe their books, to see what is underlying their complaint. Correct?

DR. RIVARD: Yeah. We would start with the complaint and then we would build the facts to see whether or not there is legitimacy to the complaint.

MR. BARZ: And then would you agree with me that in this proceeding, we don't have those underlying facts before us because we don't have evidence from those parties that have been allegedly impacted, or that will be allegedly impacted through these market rule amendments?

DR. RIVARD: I would agree that the level of facts that are in this case are not the level of facts that we would have expected to uncover in a Competition Bureau review, that's for sure.

MR. BARZ: That's fair, thank you. So I am just going to jump ahead a little bit. I am going to take you to paragraphs 74 and 75 of your affidavit, which is at page 44 of the compendium.

DR. RIVARD: Okay.

MR. BARZ: And this section is preceded by question C.11, which says, do you think there are any other aspects of the Ontario market that should inform a decision of whether or not to apply FERC order number 745 in Ontario?

Just as a starting point, in your affidavit you noted that you were chair of the IRC's market committee at the time that FERC issued order 745, correct?

DR. RIVARD: Yes.

MR. BARZ: So you are familiar with the order and you have reviewed it?

DR. RIVARD: Yes.

MR. BARZ: So in AMPCO's various submissions both to the demand response working group and as referenced by my friend, Mr. Mondrow, today, AMPCO has relied on FERC order 745 for its statement that failure to compensate demand response resources for the services they provide to the market is unjust and unreasonable.

Is it fair to say that that's come up before and it has been relied on by AMPCO?

DR. RIVARD: It is fair to say that that was the conclusion of the FERC order, and it has come up in this proceeding, yes.

MR. BARZ: Okay. And at paragraph 74 of your affidavit, you note that the key objective of FERC order number 745 was to "remove barriers to participation of demand response resources in organized wholesale electricity markets", correct?

DR. RIVARD: Yes.

MR. BARZ: And barriers to participation would effectively be barriers that are preventing consumers that may be able to participate as demand response resources from choosing to participate as a demand response participant. Correct?

DR. RIVARD: Yes, yes.

MR. BARZ: And you further noted that these barriers -- and this is in paragraph 75 -- you noted these barriers to demand response participation, I quote, "primarily related to the disconnect that existed at the time between wholesale and retail prices and the lack of incentives that's created for the investment in the capability to be price-responsive".

And you also note that FERC order number 745 sought to remedy these barriers by providing additional compensation to demand response resources. Is that correct?

DR. RIVARD: That's what I note, yes.

MR. BARZ: And you further indicate that the types of barriers that FERC was concerned with at the time of order 745 do not seem relevant to present-day Ontario. Correct?

DR. RIVARD: That's correct, yes.

MR. BARZ: So I just want to take you to paragraph 77, which is one of several reasons you give for that. You note among other reasons at that paragraph 77 that:

> "Ontario has already done a great deal to help demand response resources recover the costs of investments needed to enable their participation in wholesale markets."

Correct?

DR. RIVARD: Yes.

MR. BARZ: And one of those programs that you refer to is the DR3 program, and that is something we have talked about today. I was just hoping you could give me a little bit of an elaboration on how that DR3 program worked.

DR. RIVARD: Hmm-hmm. So as I was saying earlier, this is a program that was created by the Ontario Power Authority. Initially the idea -- my understanding was that they wanted to get demand more involved in the market, perhaps kind of in a similar vein as what FERC were looking at.

And they recognized that there might be some cost that someone would need to incur just to become available, you know, controls, et cetera, and that they can create a contract that would compensate them -- an availability payment to recover those costs, and that they would then pay also a utilization payment per megawatt released, and that would help, again, companies that might be willing to invest in technologies or whatever it took to be responsive.

And then for that payment they would then be asked to reduce demand in some hours. And the trigger for that reduction by my memory was related to what was called the supply cushion. It was a measure of when the difference between how much was available to generate electricity and how much demand there was going to be, whenever that got really small by some measure, then they would activate the demand response.

MR. BARZ: So the contract, just at a basic level, the contract and the activation payment was a way to maybe incentivize these demand response resources to participate, to build up their capacity, and to be available to be a demand response resource?

DR. RIVARD: It had that effect.

MR. BARZ: Okay. And that DR3 program was then integrated into the administrative market through the capacity-backed demand response and then ultimately through the demand response auction which you were involved with?

DR. RIVARD: That's correct. That's how it transitioned, yes.

MR. BARZ: And the availability payments that were made through the DR3 program, the capacity-backed demand response and demand response auction, they were made at a time when Ontario had more than enough capacity to meet its obligations. Correct?

DR. RIVARD: Correct to the last point, but not correct to the first point.

Let me correct that. There was a utilization payment made under the DR3 program. That was carried over into the capacity-backed demand response program because -- to continue with the contract. But once those DR resource transitioned into the demand response auction, there was no availability payment.

But your last point, the amount that was procured was largely based on the amount that was directed to the OPA at the time by the government of how much demand response they wanted to buy, which was roughly 500 megawatts.

MR. BARZ: So it wasn't based on the lack of capacity. It was based on this mandated amount?

DR. RIVARD: I can't say why they chose that mandate amount, but I can answer, yes, it was based on a mandate amount.

MR. BARZ: So essentially at that time Ontario consumers through those programs basically paid to help remove the barriers to demand response participation when Ontario did not really need the capacity. Is that correct? Is that a fair statement?

DR. RIVARD: Demand response resources were getting a payment that would be helpful to offset costs that they may have incurred to become available.

It did happen at the time that the province had more capacity needed. But I think, to be fair, there are generators that weren't needed either at that time, that also had a contract and were being paid.

MR. BARZ: Over those years the number of demand response resources that participated increased?

DR. RIVARD: I can't say factually, but my memory -- which by the way, my capacity for that is declining the older I get and the longer I sit here, but...

[Laughter]

MR. MONDROW: I have some more questions.

[Laughter]

DR. RIVARD: My memory is that, yeah, we started to see much more, and I will say innovative ways of providing demand response. We saw aggregators and dispatchable loads, yes.

MR. BARZ: Okay. So then arguably then, based on the number of resources that are involved and the types that became involved, aggregators that became involved in the demand response auction, these programs were successful in removing some of the barriers to demand response auction participants.

DR. RIVARD: I think from the perspective of, let's call it reveal preference, we saw what actually happened. It brought about demand response. That's right. So they were successful in that regard.

MR. BARZ: So arguably helping demand response resources at this early stage as Ontario did already addressed the key objective of FERC order 745, which was to get -- to remove barriers to demand response participants.

DR. RIVARD: To the extent that that's what FERC order 745 was hoping to do, bring about more demand response, those programs helped that, yes.

MR. BARZ: Beyond that specific issue of removing barriers, in your view how applicable is FERC order 745 to Ontario's market?

DR. RIVARD: How applicable? So I want to make sure I define what applicable is. Applicable in the sense that if the objective was to lower the cost for all other consumers, as FERC said, by inducing more response than would otherwise be there and lowering the price, I think my evidence shows that it's -- because of the global adjustment specifically, it really is not likely to have that effect.

MR. BARZ: So you mentioned the global adjustment, which is one of the distinctions between the FERC-regulated jurisdiction and Ontario. Can you elaborate on some of the differences between Ontario and those FERC-regulated jurisdictions which might distinguish and might make an impact in terms of the applicability of that order?

DR. RIVARD: Yes, again, I think what I wanted to point out in the evidence is that if your objective is to lower the cost for all other consumers and that you wanted to apply the FERC order as defined, paying demand response when capable, but also when lowering the price that has a net benefit to all other consumers, I think you have to factor the global adjustment in that. And the evidence, at least the historic evidence is that that is not likely to happen.

MR. BARZ: Okay. I just have a couple of more lines of questioning. You were present during Monday's hearing day, correct?

DR. RIVARD: I was.

MR. BARZ: And you would have heard some of the discussion with London Economics regarding designing market rule amendments that are technology neutral?

DR. RIVARD: Yes.

MR. BARZ: Can you describe what technology neutral means to you?

DR. RIVARD: I think when I hear technology neutral -- and I have used this term as well -- I think it is an attempt to kind of point out that we really want to let competition determine the outcome, and it's a sense of saying, and so we want to be not recognize technology per se. And it's got an aesthetic appeal to it.

I think it is often the raise when people are talking about, hey, you don't want to pick winners, and you don't want to give a subsidy to something just because you favour a technology. I think that is the context that I think about it.

What I would also say though is, I think -- I don't think you want to stop at that kind of principle. It seems like an admirable principle. But again, when you are designing markets, I think it is important to recognize that there are differences, economic differences in participants and when you design a market, sometimes you might have to recognize those technological differences and treat them in a way that brings about the best of them in the market. And I think that, you know, that is something that we see in the market today in Ontario even.

We have, just thinking when the generation fleet, there are certain situations where baseload nuclear facilities, when they may go off line, are treated in a way that other generators may not be, and that is to reflect kind of the economic situation of those plants.

We have hydro limited resources, we only have so many hours' worth of water to produce electricity. We allow them to put that information into the market about what their limitations are, to hopefully optimize when we use it.

We have quick-start fossil generators and non-quick start fossil generators, and the rules apply differently to those. But the idea, I think, is to try and recognize what it is that those technologies bring, and to make sure that we can bring about the best in those technologies to the benefit of whatever that objective is.

And I think the objective of the market rules and of the market itself is promoting competition, not so much to watch it happen, but because it leads to the most efficient outcome.

MR. BARZ: So in relation then -- with that in mind in relation to these market rule amendments that are before us, how do you believe that the concept of technology neutral should be considered, or how is it applied, or how should it be applied?

DR. RIVARD: Within the specific issue of should demand response be paid to an energy price to reduce its consumption?

MR. BARZ: Yes. In the context of these market rules, amendments and with that specific issue in mind.

DR. RIVARD: Right.

MS. SPOEL: Sorry, Mr. Barz, we're not actually here, as I understand it, on this application to determine how things should be compensated.

We're here to determine whether or not the amendments that have been put forward by the IESO, whether they will or will not lead to unjust discrimination or not be consistent with the objectives, the purposes of the Electricity Act.

So I don't think we need to spend time on how it should be fixed, because we actually don't have jurisdiction to say you should or shouldn't make certain kinds of payments.

What we're here to do is actually look at the amendments themselves and if the amendments -- if it goes forward as proposed, or as enacted by the IESO, then will the result be that there will be unjust discrimination. And of course the rules around who gets paid what for how much and when is a component of -- well, it's a component.

But we are not here to figure out how we would do it better, because we don't actually have the jurisdiction to do that.

MR. BARZ: Thank, you Madam Chair, I appreciate that. I think my line of questioning was going at -- and I think that might have been where Dr. Rivard was going.

But I guess then I could ask you just point blankly, then, do you think that these energy payments would result in -- sorry, the lack of an energy payment, would it result in unjust discrimination for a demand response resource?

DR. RIVARD: I would say no. Not paying the demand response, the market price for reducing demand will not have a discriminatory effect.

MR. BARZ: Okay. Then I guess my final question, which is somewhat related, a more general question related to the TCA is do you believe the TCA or market rule amendments will limit competition in Ontario?

DR. RIVARD: I don't see how they would, no.

MR. BARZ: Okay, thank you. Those are all of my questions.

MS. SPOEL: Thank you. Mr. Rubenstein?

CROSS-EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Thank you very much. Is this on? I will be referring to K2.5 as well, which is potentially one interrogatory response which Staff, as I understand, will pull up if need be.

Dr. Rivard, I want to follow up on something you talked about during your in-chief when you were providing the examples. One thing you talked about was the potential for what you called -- and what I believe was discussed in FERC 745 -- is the problem of potentially double compensation. A demand response resource is avoiding the HOEP, the market clearing price at a given time, and then is also being compensated for that market clearing price.

Do you recall that -- your comments from that respect?

DR. RIVARD: Yes.

MR. RUBENSTEIN: As I understand in FERC 745 -- which as I understand you are familiar with based on your affidavit -- that was a discussion which the dissent talked a lot about.

DR. RIVARD: Yes.

MR. RUBENSTEIN: And my understanding is that the