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

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ARGUMENT COMPENDIUM OF THE SCHOOL ENERGY COALITION

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***Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B**

Board objectives, electricity

1 (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

1.1 To promote the education of consumers.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

4. To facilitate the implementation of a smart grid in Ontario.

5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities. 2004, c. 23, Sched. B, s. 1; 2009, c. 12, Sched. D, s. 1; 2015, c. 29, s. 7.

***Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A**

Purposes

1 The purposes of this Act include the following:

(a) to ensure the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand;

(a.1) to establish a mechanism for energy planning;

(b) to encourage electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

(c) to facilitate load management in a manner consistent with the policies of the Government of Ontario;

(d) to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario;

(e) to provide generators, retailers, market participants and consumers with non-discriminatory access to transmission and distribution systems in Ontario;

(f) to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;

(g) to promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity;

(g.1) to facilitate the alteration of ownership structures of publicly-owned corporations that transmit, distribute or retail electricity;

(g.2) to facilitate the disposition, in whole or in part, of the Crown's interest in corporations that transmit, distribute or retail electricity, and to make the proceeds of any such disposition available to be appropriated for any Government of Ontario purpose;

(h) to ensure that Ontario Hydro's debt is repaid in a prudent manner and that the burden of debt repayment is fairly distributed;

(i) to facilitate the maintenance of a financially viable electricity industry; and

(j) to protect corridor land so that it remains available for uses that benefit the public, while recognizing the primacy of transmission uses. 2004, c. 23, Sched. A, s. 1; 2014, c. 7, Sched. 7, s. 1; 2015, c. 20, Sched. 9, s. 1; 2016, c. 10, Sched. 2, s. 1.

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Amendment of market rules

33 (1) The IESO shall, in accordance with the market rules, publish any amendment to the market rules at least 22 days before the amendment comes into force. 2004, c. 23, Sched. A, s. 42.

Notice to the Board

(2) The IESO shall give the Board a copy of the amendment and such other information as is prescribed by the regulations on or before the date the IESO publishes the amendment under subsection (1). 2004, c. 23, Sched. A, s. 42.

Board's power to revoke

(3) Despite section 4.1 of the *Statutory Powers Procedure Act* and section 35.1 of this Act, the Board may, not later than 15 days after the amendment is published under subsection (1) and without holding a hearing, revoke the amendment on a date specified by the Board and refer the amendment back to the IESO for further consideration. 2004, c. 23, Sched. A, s. 42.

Application for review

(4) Any person may apply to the Board for review of an amendment to the market rules by filing an application with the Board within 21 days after the amendment is published under subsection (1). 2004, c. 23, Sched. A, s. 42.

Application of *Ontario Energy Board Act, 1998*

(5) Subsection 19 (4) of the *Ontario Energy Board Act, 1998* applies to an application under subsection (4). 2004, c. 23, Sched. A, s. 42.

Review by Board

(6) The Board shall issue an order that embodies its final decision within 120 days after receiving an application for review of an amendment. 2004, c. 23, Sched. A, s. 42; 2017, c. 2, Sched. 10, s. 1.

Stay of amendment

(7) No application for review of an amendment under this section shall stay the operation of the amendment pending the completion of the Board's review of the amendment unless the Board orders otherwise. 2004, c. 23, Sched. A, s. 42.

Same

(8) In determining whether to stay the operation of an amendment, the Board shall consider,

(a) the public interest;

(b) the merits of the application;

(c) the possibility of irreparable harm to any person;

(d) the impact on consumers; and

(e) the balance of convenience. 2004, c. 23, Sched. A, s. 42.

Order

(9) 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 class of market participants, the Board shall make an order,

(a) revoking the amendment on a date specified by the Board; and

(b) referring the amendment back to the IESO for further consideration. 2004, c. 23, Sched. A, s. 42.

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Other reviews of market rules

35 (1) On application by a person who is directly affected by a provision of the market rules, the Board may review the provision. 2002, c. 23, s. 3 (20).

Exception

(2) Subsection (1) does not apply to a provision of the market rules that was reviewed by the Board under section 33 or 34 within the 24 months before the application. 1998, c. 15, Sched. A, s. 35 (2).

Review of market rule made by the Minister

(3) Subsection (1) does not apply to a provision of the market rules that was made by the Minister before May 1, 2002 unless the application is made before May 1, 2005. 2004, c. 23, Sched. A, s. 44 (1).

Restriction

(4) An application shall not be made under this section by a market participant unless the applicant has made use of the provisions of the market rules relating to the review of market rules. 1998, c. 15, Sched. A, s. 35 (4).

Stay of provision

(5) An application under this section does not stay the operation of the provision pending the completion of the review. 1998, c. 15, Sched. A, s. 35 (5).

Referral back to IMO

(6) If, on completion of a review under this section, the Board finds that the provision is inconsistent with the purposes of this Act or unjustly discriminates against or in favour of a market participant or class of market participants, the Board shall make an order directing the IESO to amend the market rules in a manner and within the time specified by the Board. 1998, c. 15, Sched. A, s. 35 (6); 2004, c. 23, Sched. A, s. 44 (2).

Publication

(7) The IESO shall, in accordance with the market rules, publish any amendment made pursuant to an order under subsection (6). 1998, c. 15, Sched. A, s. 35 (7); 2004, c. 23, Sched. A, s. 44 (2).

Further reviews

(8) Sections 33 and 34 do not apply to an amendment made in accordance with an order under subsection (6). 1998, c. 15, Sched. A, s. 35 (8).

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.

<u>Parties Opposing the Amendment</u>

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. <u>The Anticipated Impact on Consumer Bills</u>

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. <u>Conclusions</u>

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

Excerpt from Transcript of Oral Hearing Held March 29, 2007

(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

PART I - INTRODUCTION

1. The Independent Electricity System Operator's ("**IESO**") Board of Directors ("**IESO Board**") approved MR-00439-R00 to R05 (the "**Amendment**") enabling the IESO's Transitional Capacity Auction (**"TCA"**) on August 28, 2019, with an effective date of October 15, 2019.

2. The Amendment is a first step in broadening and increasing competition in the IESO's capacity auction and addressing a forecast summer 2023 capacity gap of approximately 4,000 MW.

3. As further explained herein, the IESO opposes the Association of Major Power Consumers in Ontario (**"AMPCO"**) Application request that the Amendment be revoked, and the TCA be suspended, until such time as the IESO amends other market rules to provide for energy payments to demand response (**"DR"**) resources in the energy market. It is the IESO's considered opinion that:

(a) It is important for reliability purposes to launch the TCA in December 2019 and to progress the TCA in a phased manner which provides the IESO and TCA participants the opportunity to learn and, as necessary adapt, in advance of the forecast 2023 capacity gap. It is the IESO's view that it would be imprudent, risking future reliability, to delay the TCA and launch it closer to the eve of the 2023 capacity gap;

(b) The TCA will provide an opportunity for existing non-committed generators coming off contract, which may in the absence of the TCA choose to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario consumers; and

(c) The TCA will increase competition and benefit consumers by allowing for participation by new capacity resource types and increasing the supply of capacity into the auction.

4. The IESO disagrees that AMPCO's members or other DR resource participants will be materially harmed, let alone unjustly discriminated against, by proceeding with the TCA prior to resolving the issue of energy payments for DR resources. No DR

participants who participated in the Demand Response Auction ("**DRA**") have provided any evidence of potential harm. Further:

(a) AMPCO is requesting a fundamental change to Ontario's energy (not capacity) market design and market rules by proposing energy payments for loads and this issue is very complex, particularly in the context of Ontario's hybrid electricity market, and warrants necessary study and analysis. The IESO has prioritized the concerns of AMPCO members by undertaking a comprehensive stakeholder engagement and third party study on energy payments for DR resources, which will be completed in Q2 2020 following which the IESO will make a final determination and, as necessary, initiate market rule changes.

(b) There will be no harm, or negligible harm, to DR resources in the interim. DR participants in the DRA have rarely been economically activated in the energy market and the IESO does not anticipate any material increase in DR activations over the period governed by the December 2019 TCA. DR participants will also be compensated for out-of-market activations, which is their only material exposure to activation.

5. The IESO is pleased to submit to the Board its written evidence, which is presented below in question and answer format.[1]

PART II - LEGAL AUTHORITY

A. Who is the IESO?

6. The IESO is a public agency, that is continued under the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A (the "***Electricity Act***") and its responsible for maintaining the reliability of the provincial transmission grid, administering Ontario's wholesale electricity market and planning the province's bulk power system.

[1] Much of the evidence contained herein overlaps with and relies on the Affidavit of David Short, sworn on October 25, 2019, which the IESO submitted to the Board in response to AMPCO's Motion to Stay the operation of the Amendment. For coherence, we have reproduced portions of the said affidavit herein.

receive more profits as compared to resources that clear near the final auction price. Typically a number of auction participants are not price competitive, do not clear the auction and do not receive an obligation to supply capacity.

32. DRA participants who have incurred a DR capacity obligation through the DRA receive a monthly payment for every month of the commitment period for being available to supply capacity if called upon (referred to as an availability payment).

D. How are DRA resources activated or called upon?

33. All DRA resources are expected to be available to reduce their consumption during the summer commitment period from 12:00 to 21:00 EST, and during the winter commitment period from 16:00 to 21:00 EST.

34. Dispatchable load resources are activated (dispatched automatically by the IESO's Dispatch Scheduling Optimization software) on a 5-minute interval if the bid in the energy market is economic, either to meet Ontario's provincial need or a local energy need.

35. HDR resources have restrictions on their ability to be reduce consumption so they require a standby notice from the IESO at any time between 15:00 EST day-ahead up to 07:00 EST on the day of. HDR resources that are on standby can then receive an activation at least two hours in advance for one to four hour hourly blocks of reduced consumption – and only if they are economic compared to other resources for the hour(s) they are activated. HDR resources can only receive one activation per day.

E. What's the frequency for the activation of DR resources under the DRA?

36. DRA participants have been activated in the energy market in very limited circumstances since the DRA was launched in 2015. This is likely due to the relatively high prices at which DRA participants have bid into the energy market.

37. During this period, the Hourly Ontario Energy Price (**"HOEP"**) has averaged approximately $25/MW. During the same period, dispatchable load bid prices have averaged approximately $1500/MWh and HDR bid prices have averaged approximately $1700/MWh.

38. HDR resources have only been economically activated on one occasion since the introduction of the DRA in 2015. The Market Surveillance Panel of the Ontario Energy Board noted, in its Monitoring Report of the IESO-Administered Markets published in May 2017, that "the likelihood of an activation is remote".[5] The Panel observed that between May and December 2016, 82% of HDR resources offered bid prices were $1999/MWh while the remaining 18% of HDR resources offered bid prices were $500/MWh. The Panel further concluded that any bid price over $220/MWh would not have been activated during the period.

39. Dispatchable loads have been economically dispatched less than 1% of the time over that same period.[6] These activations generally occur due to localized short-term price spikes resulting from contingencies such as unanticipated generation and transmission outages.

PART V - ENERGY PAYMENTS FOR DR RESOURCES

A. What are energy payments for DR resources?

40. Reference has been made in this proceeding to both "utilization payments" and "energy payments". A utilization payment is a generic category which includes energy payments.

41. Energy payments for DR resources, which is what AMPCO is seeking in this Application, would be payments to loads that bid into the energy market and reduce energy consumption based on the applicable wholesale market clearing price.

B. How are DR resources treated in the IESO energy market?

42. The design of the IESO energy market was based on the recommendations of the Ontario Market Design Committee and on standard market design in other jurisdictions in North America.

43. Ontario's energy market design, as codified in the market rules, provides that generators and loads may be either dispatchable or non dispatchable; and, that

[5] Attached at **Tab "2"** is the *Monitoring Report on the IESO-Administered Electricity Markets*, Market Surveillance Panel, dated May 2017.

[6] Attached at **Tab "3"** is the IESO Response to the Board Staff's Interrogatory No. 8.

(b) Economic efficiency - Arguments for/against providing utilization payments to DR resources in light of current and future system needs;

(c) DR Participation – The likely impacts of utilization payments to the dispatch frequency of HDR resources in Ontario;

(d) Wider market impacts - Spillover effects on the wider market.

G. What were the findings of the Navigant study?

53. On December 19, 2017 the IESO published a discussion paper by Navigant (the **"Navigant Paper"**)[10] which, among other things, presented arguments for and against utilization payments, as summarized in the table below:

Arguments against utilization payments	
Wholesale Price Efficiency	Real-time wholesale prices are an efficient price signal because they match supply and demand based on bids and offers on a minute-by-minute, and hour-by-hour basis, and introducing an additional payment could create an inefficacy in the market because dispatchable loads would receive an out-of-market payment that could alter their bid/offer strategy. In Ontario, this argument applies to loads that receive the wholesale energy price.
Disproportional Benefits	Providing a utilization payment compensates a DR resource disproportionately relative to a supply resource because the DR resource does not incur a cost associated with the production of electricity. Therefore, a DR resource should be treated as if it had first purchased the power it wishes to resell to the market. This argument is based on the premise that the value of a megawatt of electricity curtailed (a "negawatt") is not equivalent to a megawatt of electricity, and assumes that the cost of curtailment for a DR resource is immaterial.
Harm to Other Suppliers	Utilization payments will result in downward pressure on wholesale prices because DR resources are able to bid into the energy market at prices lower than traditional supply and will be dispatched more frequently. However, in Ontario, to have a material impact on capacity or energy prices, utilization payments would have to result

[10] Attached at **Tabs "8", "9"** respectively are Navigant, *Demand Response Discussion Paper* (the "***Navigant Paper***"), dated December 18, 2017; and Navigant Demand Response Discussion Paper (Presentation to DRWG), dated November 16, 2017.

	in a considerable increase in levels of participation and activation Under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence consumer costs are largely fixed.
Harm to Economy	Utilization/energy payments will incentivize loads to reduce production to provide demand reductions into the electricity market, reducing the supply of other goods in the economy and increasing prices.
Arguments for utilization payments	
Reducing Consumer Costs	Utilization payments will increase the level of DR participation and activation, which is a less expensive form of capacity and energy than traditional supply resources, and hence will result in lower consumer costs
Disconnect Between Wholesale and Retail Prices	Retail prices do not reflect the real-time fluctuations in the cost of electricity and are inefficient and utilization payments are a way of improving the economic efficiency of the retail price by providing an additional financial incentive during high-price events. However, this argument is only valid for customers on retail rates and not exposed to real-time energy prices.
Fairness	Generation resources receive a utilization payment in the form of an energy payment when they produce electricity and DR resources should be treated fairly and receive a utilization payment when they curtail electricity. The argument is based on the FERC Order 745 which requires that the energy payments result in a *net benefit* to consumers. However, this argument is based on the assumption that, in Ontario, a megawatt of electricity curtailed (negawatt) is equivalent to a megawatt of electricity.
Other Costs Associated with Curtailment	There is a cost associated with curtailing demand (or producing a negawatt of electricity), which is equal to the value of lost load, which can be higher than the avoided cost of electricity, utilization payments compensate DR resources for these costs. However, for large commercial and industrial customers, the value of lost load can be very high, which could result in limited activation of DR resources regardless of whether utilization payments are offered.

54. In its conclusion, Navigant commented on the complexity of the matter and also expressed doubt on whether the benefits associated with energy payments to demand resources in other markets would apply 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 (section 3.2).

H. What was the feedback from DRWG members to the Navigant Paper?

55. The IESO encouraged DRWG members to review, ask questions and provide feedback about the Navigant Paper.[11]

56. In early 2018, the DRWG convened to continue discussion on Navigant Paper and the issue of utilization payments in the DRA.[12] The IESO responded to feedback from the DRWG members which generally fell into three categories: (1) impact on utilization; (2) fairness; and (3) market efficiency:

(a) The IESO addressed stakeholder comments that utilization payments would incentivize residential DRA participants to bid lower energy prices, which could increase utilization (p. 5). The IESO acknowledged that in

[11] Attached at **Tabs "10", "11", "12"** respectively are IESO, *Communication to DRWG Members,* dated December 19, 2017; *Utilization Payment Discussion Paper*, Demand Response Working Group (Presentation), dated January 30, 2018; and IESO, *Communication to DRWG Members*, dated February 12, 2018.

[12] Attached at **Tabs "13", "14"** respectively are *Utilization Payments Discussion*, Demand Response Working Group, dated March 1, 2018 (**"*DRWG Presentation of March 1, 2019*")**; Demand Response Working Group, *Meeting Notes – March 1, 2018*, dated April 5, 2018.

theory this could incentivize participants to lower energy bid prices, which could lead to increased utilization of DR resources. However, the IESO observed that stakeholder feedback indicated utilization payments might not lead to increased utilization.

(b) The IESO addressed stakeholder comments that under the former Capacity Based Demand Response ("**CBDR**") regime, CBDR resources were prepared to be activated at $200/MWh provided they received this payment demonstrating that revenue is a strong incentive for activation (p. 7). The IESO responded that 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 phenomenon implied that that DR participants' value of energy consumption was much higher than this level.

(c) The IESO addressed stakeholder comments that if paying a DR resource for utilization reduces the cost of electricity, then DR payments are a positive system benefit (p. 8). The IESO acknowledged that if DR utilization payments could reduce total system costs then it would yield a positive system benefit. However, the IESO observed that on balance, it was not clear that there would be a positive system benefit. Even if providing a utilization payment might reduce the energy price of electricity for that event, other system costs such as uplift and capacity costs would increase.

(d) The IESO addressed stakeholder comments that DR utilization payments based only if "negawatts" and megawatts are functionally and economically equivalent (pp. 10- 14). The IESO provided some illustrative examples where resources could receive additional payments – creating an unequal treatment depending on the configuration of the capacity contribution.

I. Did the IESO reach any conclusions after the publication of the Navigant Paper?

57. No, the IESO did not come to any definitive conclusions on this issue. After further consultation with stakeholders, the IESO, however, did offer the following observations as part of March 1, 2018 presentation to DRWG members:

(a) It appears that the current practice for compensating DR utilization is equivalent treatment and a DR utilization payments would introduce non-equivalent treatment;

(b) There was no clear indication that utilization payments would increase activation for most load types;

(c) For resources exposed to market prices, further discussion did not appear to be merited; and

(d) For resources not exposed to market pricing, the IESO did not see merit in continuing discussion on utilization payments - however, the IESO expressed uncertainty regarding the impact of utilization payments on these type of participants and the IESO requested more input from stakeholders;

(e) Based on the quantity of stakeholder feedback received, the IESO did not see a strong interest from the DRWG on the topic of utilization payment. Only two members submitted feedback on and members declined to present their views for discussion at the DRWG.[13]

58. The issue of utilization payments for DR resources in the DRA ceased to be a priority item for the DRWG after the spring of 2018.

PART VI - THE NEED FOR THE TCA

A. Why did the IESO decide to evolve the DRA into the TCA?

59. As part of its Market Renewal initiative, the IESO had been planning an Incremental Capacity Auction (**“ICA”**) to address Ontario’s future incremental capacity

[13] *DRWG Presentation of March 1, 2018*, pp. 16-18

can be scheduled on a 5-minute or hourly interval both inside and outside of Ontario. The IESO could not assure reliability if all the 2023 and beyond capacity came from only one resource type – diversity in fuel supply and operating characteristics are needed to maintain reliability.

C. Is the IESO still forecasting a capacity gap in summer 2023?

68. Yes, there continues to be a significant 2023 capacity gap that must be addressed by the IESO to ensure the reliability of Ontario's electricity system.

69. This gap has been recognized by the Northeast Power Coordinating Council (**"NPCC"**) and the North American Reliability Corporation ("**NERC"**),[17] with which the IESO is required to report annually on the state of reliability of Ontario's electricity system, including resource adequacy. The assessments are based on NERC and NPCC planning criteria to ensure a consistent approach to reporting and evaluation of the broader regional and continent-wide power system reliability.

70. There are inherent uncertainties with any planning projection. Ontario's extensive nuclear refurbishment and retirement schedule contributes to the capacity gaps in the near-term as the fleet is readied life-extending work or shutdown. As noted in the NERC Report, "there are uncertainties in the projections that could see the shortfall grow or shrink. As a result, the Independent Electricity Service Operator (IESO) will continue to update and refine its forecasts to gain more certainty about the size of the gap" (p. 15, *Figure 1.5*)".

71. In a presentation to the IESO's Stakeholder Advisory Committee dated August 14, 2019, the IESO provide an updated forecast of a capacity gap of approximately 4000 MW in summer 2023. [18] This is the IESO's most up-to-date forecast.

D. Why is it necessary for the IESO to proceed with a phased implementation of the TCA?

72. The introduction and implementation of the TCA, and subsequent capacity auction phases, is complex and challenging. The IESO has never before undertaken a capacity auction which includes supply resources. The IESO is accordingly initiating this

[17] See *NPCC Report; NERC Report.*
[18] *SAC Presentation*, p. 4.

process gradually and incrementally by, at the outset, only including off-contract dispatchable generation facilities. Thereafter, subsequent capacity auctions will include and add new resource types and broaden resource eligibility criteria. New resource types are anticipated to include storage, system-backed imports, resource-backed imports and self-scheduling generation facilities. Resource eligibility criteria may also be broadened to include, for example, surplus or uprated capacity (i.e. merchant capacity) at existing contracted facilities.

73. These changes will present new requirements and pose additional challenges. For instance, the addition of system-backed and resource-backed imports will necessitate negotiating operating agreements procedures with other independent system operators (**"ISOs"**) and addressing other jurisdictional issues. Likewise, rules governing the participation and compensation of imports must be tailored to reflect the unique operating features of different import types. These differences introduce complexity to the potential participation of imports in the capacity auction and energy market.

74. In addition to the introduction of new resource types and new eligibility criteria, each capacity auction phase, beginning with the TCA, will introduce modified design elements, including capacity qualification criteria, testing and audit requirements, connection assessment criteria, market power mitigation parameters, auction parameters, etc. For instance, introducing new qualifications of capacity will require the IESO to assess each resource's offering into the auction prior to the auction's execution. The intent is to better align the auction results with the IESO's system planning assumption; however, the new process may change a participant's offer strategy and ultimately the auction outcome.

75. In addition to known and foreseeable challenges, there are potential unforeseen consequences. The IESO knows from experience that major new market changes and programs invariably have unforeseen implications and consequences affecting market efficiency or reliability that will need to be addressed through market rule and market manual amendments, and possible tool changes.

76. 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 in a

single step, or closer to the eve of the 2023 capacity gap which the TCA is 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.

77. 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. The IESO, as the Province’s reliability authority, is not willing to forgo the important opportunities, experience and learnings that these auctions, each with a year long commitment period, provides and which are critical to implementing a capacity auction mechanism to prudently and cost-effectively address Ontario’s future capacity needs.

(f) providing energy payments to economic activations to DR resources is a wider market issue that will require more consultation has implications for the entire design of Ontario's electricity (energy and capacity) market; and it is It is not worth holding up TCA for this;

(g) the issue of energy payments for DR resources' is not-material because economic activations have historically been infrequent, and are projected to be infrequent in the future;

(h) TCA is a first step toward enabling competition to provide capacity;

(i) TCA is a prudent approach to maximizing future participation in advance of more significant capacity gap emerging; and

(j) TCA broadens participation while retaining features and functionality required for participation by HDR and dispatchable loads.

B. What were the IESO Board's reasons for adopting the Amendment?

93. As noted above, the Amendment was adopted by the IESO Board at its meeting of August 28, 2019.[26] The IESO Board provided reasons for its decision (the "**Reasons**").[27]

94. 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.

95. 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.

[26]Attached at **Tab "27"** is the Resolution of the IESO Board, dated August 28, 2019.

[27] Attached at **Tab "28"** are the Reasons of the IESO Board in Respect of an Amendment to the Market Rules, dated August 28, 2019 (the **"*Reasons*"**).

(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.

96. 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 FERC Order 745 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.

97. The IESO Board concluded that implementing the Amendment was 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." [28]

98. The IESO Board also noted that the Technical Panel recommended the Amendment in a vote of 11-1 and that in respect of a process issue related to the AEMA/AMPCO joint brief, "exercised its discretion on an informed and reasonable basis."[29]

PART IX - RESPONSE TO AMPCO'S EVIDENCE

A. What is the IESO's response to Mr. Anderson's statements about the IESO proposing that participants in the DRA include "work around" payments in their bids?

99. The IESO does not know what Mr. Anderson is referring to in this statement. It is up to a DRA participants to determine their auction bid prices, including what costs they factor into their bid prices.

B. Why does the IESO say the impact of the Amendment on DR Resources is not material?

100. As noted above, DRA participants have historically been rarely activated in the energy market because their price bids have been far excess of the HOEP.

[28] *Reasons,* p. 4.
[29] *Ibid*, p. 5.

101. The IESO does not expect the likelihood of economic dispatch to materially increase in the commitment period under the December 2019 auction (May 1, 2020 to April 30, 2021). There has been no material change in the target capacity for the December 2019 commitment period (675 MW for summer and winter commitment periods) as compared to the December 2018 commitment period (611 MW for summer and 606 MW for winter).[30] The total target capacity is negligible in the context of total system need.

102. As a result, the IESO does not anticipate any activations of HDR resources during the December 2019 commitment period (HDR resources have constituted the significant majority of participants in the DRA). The IESO also anticipates infrequent activations of dispatchable loads during the December 2019 commitment period.

103. Given this low probability of DR resource activation, the inclusion of a work around payment should have no material impact on DR auction offers for the December 2019 commitment period.

104. In the IESO's view, there is no justifiable rationale for DR resources participating in the TCA to include any work around payments in their bids. The amount of any work around should reflect both the costs of being activated and the very low likelihood of activation. The IESO has not been presented with any economic analysis to the contrary, and, in fact, AMPCO's answers to Board staff's interrogatories confirm the IESO's views (see AMCPO's interrogatory response to Board Staff's interrogatory No. 1).

C. Would energy payments increase the likelihood of activations of DR resources under the TCA?

105. The IESO does not expect any energy payments to be material in the December 2019 commitment period. Therefore, the IESO does not expect that the availability of an energy payment would influence frequency of activations of DR resources. As Navigant states in section 3.1.5 of the Navigant Paper, "[l]arge commercial and industrial

[30] Attached as **Tab "29"** is *Demand Response Auction Pre-Auction Reports*, dated September 26, 2019.

customers with a high value of lost load are not likely to change their bids into the energy market because of utilization payments”.[31]

D. Does the IESO have a view on the applicability of FERC “net benefit test” in Ontario?

106. No. This is a complex issue, which as noted by Navigant, has to consider the unique aspects of the Ontario market. The IESO has not yet made a final decision on the appropriateness and outcome of the net benefits test in Ontario, which is why the IESO is in the process of engaging with stakeholders and studying this issue as part of the Energy Payments Stakeholder Engagement.

107. That said, the only Ontario-specific analysis available is from Navigant who concluded that “more DR activations (as a result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced cost to consumers since generators have their compensation guaranteed.”[32] In other words, any reductions in the IESO market price may simply be offset by out of market Global Adjustment payments.

E. Will the IESO consider energy payments for DR resources?

108. Yes. While DR resources will not be entitled to receive energy payments if activated under the TCA during the December 2019 commitment period, the IESO has not made a final determination on the issue and will not do so until the conclusion of the Energy Payments Stakeholder Engagement. Following the conclusion of this engagement and issuance of the Brattle study, the IESO will make a final determination, including initiating any necessary market rule amendments to provide for energy payments to DR resources.

F. Why won’t the IESO delay the TCA until it has resolved the issue of energy payments for DR resources?

109. In summary and as stated above:

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[31] *Navigant Paper*, at 3.1.5

[32] *Navigant Paper*, at 3.2.

(a) It is the IESO's judgment as the province's reliability and planning authority that it is prudent to proceed now with the TCA in an incremental and phased manner and that there are real reliability and cost risks to delaying and not proceeding in this manner. These risks include losing the opportunities for the IESO and TCA participants to learn and adapt from a series of TCA auctions, as well as risking the loss of existing off contract generation facilities that may be important and cost-effective for the purpose of addressing the 2023 capacity gap in future capacity needs.

(b) AMPCO does not object to the TCA. It objects to commencing the TCA without changing the market rules to provide for energy payments to loads. This would be a major change to Ontario's electricity market design and it is the IESO's opinion that this sort of fundamental change should not be made without broad consultation and necessary study and analysis. FERC Order 745 is a relevant consideration but it is not binding in Ontario and, as the Navigant Paper makes clear, there are differences in Ontario's hybrid market and there are real doubts as to whether energy payments to DR resources would result in net benefits as conceived by FERC. This is why the IESO is undertaking the current stakeholder engagement on energy payments and third-party study, which the IESO is prioritizing and will result in an IESO final recommendation by the end of Q2 2020.

(c) AMPCO's members' interests are not determinative. The IESO, in accordance with its statutory mandate, must consider system reliability and the broader interests of other market participants and consumers. These considerations, as noted, weigh heavily in favour of proceeding with the TCA without delay. That being said, even if the IESO were to more narrowly focus on the interests of AMPCO members and other DR resources, there is no evidence that they will be materially harmed by proceeding with the TCA. The IESO has not seen any evidence from AMPCO that its members or other DR participants will be harmed. Moreover, AMPCO's assertions that DR participants will be competitively disadvantaged in the TCA auction is contradicted by the fact that DR resources have rarely been activated in the energy market and the IESO does not anticipate any material change in this respect over the December 2019 TCA commitment period.

* *

Ontario Energy Board Commission de l'énergie de l'Ontario

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2015 – April 2016

May 2017

associated with a megawatt-hour of export demand. As a result, exporters benefit disproportionately when disbursements are based on demand; such a methodology does not result in what the Panel considers to be a fair allocation.[75]

Had disbursements been allocated in line with the Panel's view on fairness, Ontario transmission customers would have received disbursements totalling $405 million while exporters would have received $7 million. Under such an allocation, Ontario transmission customers would have received an additional $51 million in disbursements that was actually paid to exporters.

Given the IESO's revised TR Clearing Account policies aimed at balancing congestion rents and TR payments, the Panel expects all future auction revenues to be disbursed to transmission customers. Since 2010, auction revenues have increased each year, eclipsing $100 million per year in 2015 and 2016. Left unremedied, the disbursement allocation methodology will continue to be a significant issue going forward.

Recommendation 4-1:

A. ***The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.***
B. ***The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.***

3.2 *Assessment of the IESO's Demand Response Auction*

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods.[76] Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

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[75] The transmission charges applicable to Ontario transmission customers are broken down into three separate OEB approved rates: Network Service Charge, Line Connection Service Charge and Transformation Connection Service Charge. Together these rates currently total $8.97/MWh. Exporters are subject to the Export Transmission Service (ETS) charge, which is currently set at $1.85/MWh. Both the rates charged to Ontario transmission customers and exporters are set annually and have varied over time, though the rates applicable to Ontario transmission customers have always been higher than the ETS charge.

[76] The Ministry of Energy's *Conservation First: A Renewed Vision for Energy Conservation in Ontario* report states that, "Ontario's vision is to invest in conservation first, before new generation, where cost-effective." The report is available at: http://www.energy.gov.on.ca/en/files/2013/07/conservation-first-en.pdf

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none.

The DR auction occurs once annually and procures DR resources for a period of one year. As part of the auction process eligible resources submit the quantity of DR capacity they are willing to provide, and the price at which they are willing to provide it; the IESO uses those offers to build a supply curve. The DR auction clearing price is set where the supply curve intersects the administratively determined demand curve; all resources selected in the DR auction receive the clearing price.[77] To be paid, resources procured through the DR auction must be made available to reduce consumption during specified periods, and must actually reduce consumption when certain activation criteria are met. For this service, resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers through an uplift charge.[78]

Two types of resources are permitted to participate in the DR auction: dispatchable loads and hourly demand response (HDR) resources. Dispatchable loads already participate in the energy market, changing their consumption in response to five-minute price signals; participating in the DR auction should not materially change the behaviour of these resources. For that reason, the following sections focus on HDR resources, unless otherwise stated. HDR resources are not willing or able to respond to five-minute price signals, and would not participate in the energy market absent some incentive, such as the payments received through the DR auction. To date, approximately 72% of all DR procured through the DR auction has been from HDR resources.

[77] Given the differences in supply and demand in different areas of the province, the IESO limits the amount of DR procured in each zone. If the limit is reached in a given zone, the clearing price in that zone may differ from the others.
[78] While auction payments are technically recovered from Ontario consumers via uplift, the uplift is allocated in the exact same manner as the Global Adjustment. In other words, a consumer’s share of this uplift is based on whether they are Class A or Class B customers: Class A customers are charged based on their share of consumption during the five coincident peak demand hours during a year, Class B customers based on their volumetric consumption on all days. Exporters do not pay this uplift.

The IESO has stated that the DR auction is part of a suite of programs and incentives that will help meet the Ministry of Energy's conservation related policy goals.[79] However, for the reasons explained in this section, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

3.2.1 Meeting the Ministry of Energy's Policy Goal

Having said that, it is worth noting that the IESO views the DR auction as an initial step towards the evolution of capacity procurement in the province; one in which all generating and DR capacity is procured through an integrated auction.[80] The Panel supports this longer-term objective.

In 2013, the Ministry of Energy issued its most recent conservation related policy goal: use DR to meet 10% of peak demand by 2025 (approximately 2,400 MW under then forecasted conditions).[81] The IESO views the DR auction as a means of achieving the Ministry's policy goal:

> *Creating a DR auction will support the province's objective for DR to meet 10 per cent of Ontario's peak demand by 2025 and encourage new competitive DR resources to help meet that goal for Ontario's electricity system.*[82] – IESO

In order for the IESO's suite of DR programs and incentives to achieve peak demand reductions, DR not only needs to be available during periods of peak demand, but must also be activated during those periods. As such, it is important to understand the difference between the procurement of DR capacity (i.e. DR availability), and achieving peak demand reductions (i.e.

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[79] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en

[80] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en

[81] For more information on the Ministry of Energy's policy goal see pages 20-27 of the *2013 Long Term Energy Plan* report, available at: http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf

[82] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en

DR activations). A program that procures DR capacity, but does not result in DR activations during peak demand, will not help achieve the Ministry of Energy's policy goal.

As currently designed, DR procured through the IESO's DR auction is unlikely to be activated during periods of peak demand. To understand why that is, it is necessary to understand both the availability obligation placed on DR resources and the criteria under which they are activated.

Availability Obligation

DR resources procured through the DR auction are required to participate in the energy market for certain pre-determined commitment periods and availability windows. The availability window applies to business days only: 12 PM to 9 PM from May to October (Summer Commitment Period) and 4 PM to 9 PM from November to April (Winter Commitment Period).

During the availability windows DR resources must enter bids into the energy market at prices between $100/MWh and $2,000/MWh. These bids represent the price at which the resource is willing to be activated for DR. The bids must be entered into the market before the IESO's day-ahead process starts, and remain in the market until the IESO determines the resource will not be activated, or until an activation is completed.

Activation Criteria

In order for a DR resource to be activated during the applicable availability window, it must receive both a standby notice and an activation notice from the IESO.

First, a DR resource will receive a standby notice at or before 7 AM if the pre-dispatch nodal price at its location is above its bid price for four consecutive hours within the availability window. Second, if the resource receives a standby notice, it may next receive an activation notice 2.5 hours prior to activation, so long as the price remains above its bid price for four consecutive hours within the availability window. If a DR resource receives an activation notice it must reduce its consumption for a period of four hours, beginning with the first hour included in the activation notice.

Consider the following example: a DR resource is procured for the Winter Commitment Period; to fulfill its availability obligation it bids $1,999/MWh into the energy market during all hours of the availability window. For simplicity, assume that any activation will start at 4 PM and conclude at 8 PM.[83]

Under these conditions the DR resource will receive a standby notice if, during any of the hours before 7 AM, the pre-dispatch nodal prices for the 4 PM to 8 PM activation period exceed the resource's $1,999/MWh bid. To then receive an activation notice, the same conditions must persist at 1:30 PM, in which case the resource must reduce its consumption for the 4 PM to 8 PM activation period.

Prospect of Being Activated

Given the activation criteria described above, the likelihood of an activation is remote. This is borne out by events since the Current Reporting Period; since the first commitment period started in May 2016, no HDR resource has been activated.

Under the program rules DR resources can bid into the energy market at any price between $100/MWh and $2,000/MWh; the higher the bid price, the lower the likelihood of being activated. Table 4-1 contains the prices used to date by HDR resources when submitting their bids to the energy market.

***Table 4-1: HDR Resources' Bids into the Energy Market
May 2016 – December 2016***

Observed Bid Prices	HDR Capacity Bid at Observed Price
$1,999/MWh	82%
$500/MWh	18%

Since the start of the first commitment period 82% of all DR capacity has been bid into the energy market at the program's maximum allowable price. While the Panel supports DR resources being able to bid into the energy market at any price, bidding at the maximum allowable price, in conjunction with the current activation criteria, means that HDR resources will not be activated. Indeed, the Panel's analysis indicates that any bid price over $220/MWh would not have been activated during the period.

[83] During the Winter Commitment Period, a DR resource may also have an activation period from 5 PM to 9 PM. During the Summer Commitment Period an activation period may span any four consecutive hours between noon and 9 PM.

Given Ontario's current surplus supply conditions and the prices that persisted over the period, it is not surprising that there were no activations.

That said the province has not always been flush with surplus supply. In 2005 and 2006 all-time demand records were being set in Ontario, and in the winter of 2014 the "polar vortex" weather event increased demand and constrained supply. To get a sense of the likelihood of an activation given the current activation criteria, the Panel applied the same criteria to all hours dating back to the high demand conditions experienced in 2005. Table 4-2 displays the number of HDR activations that would have occurred at various bid prices since 2005.

Table 4-2: Hypothetical HDR Activations by Bid Price
2005 – 2016
(Number of Activations)

Energy Bid Price ($/MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
100 - 200	552	152	199	188	1	26	18	16	4	168	66	88
200 - 300	65	16	7	4	-	3	4	-	5	51	-	33
300 - 400	27	9	-	4	-	-	-	-	-	6	-	-
400 - 500	27	9	-	-	-	-	-	-	-	-	-	-
500 - 600	25	3	-	-	-	-	-	-	-	-	-	-
600 - 700	15	1	-	-	-	-	-	-	-	-	-	-
700 - 800	8	1	-	-	-	-	-	-	-	-	-	-
800 - 900	4	-	-	-	-	-	-	-	-	-	-	-
900 - 1,000	1	-	-	-	-	-	-	-	-	-	-	-
1,000+	-	-	-	-	-	-	-	-	-	-	-	-

Since 2005, no bid price above $1,000/MWh would have been activated, yet most HDR resources bid at twice that price. Any bid price over $400/MWh would not have been activated since 2006.[84]

Even under the most aggressive of demand projections, peak demand is not expected to return to record 2005 and 2006 levels until 2029.[85] Ontario is also in a better supply situation than it was during those years, having added thousands of megawatts of capacity to the grid.[86]

84 Going forward, new HDR resources may emerge at different locations on the grid; their likelihood of activation may differ.
85 See the IESO's most recent *Ontario Planning Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
86 See *The Need for Capacity* section below for a summary of Ontario's current supply and demand conditions.

The Panel is mindful that reducing consumption during periods of peak demand is a means to an end, and should not be a goal unto itself. A DR resource may wish to consume during periods of high demand, but may be incented to abstain in order to alleviate the need to build additional supply. In this way, DR programs incur short-term costs (i.e. curtailing otherwise efficient energy consumption) in order to avoid long-term costs (i.e. reducing the need for additional peak generation capacity). As long as the avoided long-term costs exceed the incurred short-term costs, reducing peak demand can be efficient.

Ontario is currently flush with supply, and will continue to be for the foreseeable future (see *The Need for Capacity* section below). Even with considerable demand growth, there is little need to build new capacity. Consequently, consumption during peak periods results in no additional long-term capacity costs, meaning demand reductions during these periods are unnecessary and likely inefficient. It follows that payments to procure DR, such as those provided by the DR auction, are also unnecessary and inefficient.

3.2.2 Meeting the IESO's Capacity Objective

As mentioned in the previous section, the IESO's DR auction is unlikely to provide energy through DR activations given the current activation criteria.

The notion that the DR auction is procuring capacity only is consistent with the program's availability obligations, as well as the manner in which DR resources are compensated. Specifically, DR resources are paid to be available for activation, not to be activated; there are no minimum requirements on the number of times a resource must be activated. In furtherance of this idea, the IESO plans to integrate the DR auction and its participants into the broader capacity auction currently being developed through the IESO's Market Renewal initiative.[87] In the sections that follow, the Panel assesses the appropriateness of the DR auction as a means to procure capacity.

[87] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en

Availability Obligation and Activation Criteria

Unlike meeting the Ministry of Energy's policy goal of using DR to reduce peak demand, procuring capacity does not necessarily come with the expectation that it will be utilised regularly or predictably. The IESO must procure enough capacity to ensure that Ontario's electricity needs are met, plus some additional capacity to ensure reliability. On that basis, one would expect there to be a portion of capacity that is rarely if ever used. Specifically, capacity resources with high bids in the energy market, such as those procured to date through the DR auction, are the last to be activated and are likely only needed on rare occasions. For DR capacity to be of use, the activation criteria needs to result in consumption reductions on those infrequent occasions when those resources are needed.

As noted earlier, HDR resources bidding at the maximum allowable energy market price (82% of all HDR resources to date) would not have been activated from 2005 onwards; resources bid above $400/MWh would not have been activated since 2006. There have been occasions since 2005, including during the very tight supply conditions experienced during the winter of 2014, when DR activations could have been beneficial.[88] To that end, the Panel encourages the IESO to assess whether changes to the current availability obligations and activation criteria should be made in order to facilitate activations when needed.

Technology-Specific Procurement

In terms of satisfying the need for capacity, capacity from DR is no different than capacity from other resources, such as gas-fired generators. Given the substitutability of capacity from different technologies, the procurement process should be technology neutral, not favouring one technology over another. Technological neutrality allows the procurement mechanism to select the lowest cost capacity, no matter the resource type. In order for the procurement mechanism to be technologically neutral it must permit all resources to compete against one another to supply capacity, and place identical obligations on all resources procured. The need for technology-neutral procurement was recently supported by the Minister of Energy, Glenn Thibeault:

[88] The Panel finds it instructive that, over the same period, there were numerous other DR programs with differing activation criteria that resulted in activations, including activations under the program the DR auction is effectively replacing.

Upon taking this office, I was interested to learn that our previous procurements were essentially segmented into "technology-specific" allotments. In this day and age, with the level of innovation, pace of technological change – as well as the clear benefit to ratepayers from competitively procured resources; it is essential that we begin moving towards more "technology-agnostic" procurements.

Too often we have sought to impose strict requirements on the system operator. Rather, as we seek to undertake future procurements – we should be focused on outcomes, rather than contracting with specific technologies. Moving to become technology-agnostic will provide new opportunities for innovation and modernization. We must unleash the electricity sector and our system operator to find the appropriate mix to fulfil a capacity auction would ensure that ratepayers receive the best prices possible.[89]

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Allocating the precise mix of technology types has largely been arbitrary and led to suboptimal siting, uncompetitive prices and heightened community concerns.[90]

The DR policy goal set by the Ministry of Energy in 2013 is technology specific, as was the IESO's corresponding procurement. Currently, DR is the only capacity procured through an auction process. By limiting competitive procurement to one resource type, the IESO is limiting its ability to procure capacity at least cost. Fortunately, the IESO is considering the introduction of a technology-neutral capacity market, allowing for DR resources to compete against other technologies to provide capacity at least cost in the future.

The Need for Capacity

The quantity of DR capacity procured through the DR auction is determined by the intersection of the participant-offered supply curve and the IESO determined demand curve. The demand curve sets the bounds for how much DR capacity will be procured at different prices, including the maximum quantity at the auction's lowest price, and the minimum quantity at its highest price.

[89] Speech delivered by Glenn Thibeault (Minister of Energy) to the Empire Club of Canada on November 28, 2016.
[90] Comments made by Glenn Thibeault following his speech to the Economic Club of Canada on February 24, 2017, as reported in the Globe and Mail's article: *Ontario Liberals Eye Electricity Market Overhaul to Lower Rates*, available at: http://www.theglobeandmail.com/news/ontario-liberals-eye-electricity-market-overhaul-to-lower-rates/article34128778/

The IESO sets the position of the demand curve (i.e. how much DR will be bought at different prices) by setting a target quantity and price for procuring DR capacity. Recall that prior to the auction, DR was procured through bilateral contracting; those legacy contracts expire at different times, the last of these expires in 2018.[91] For the first DR auction, the IESO set the target quantity equal to the capacity that was expiring under those legacy contracts.[92] The IESO set the target price equal to the agreed upon price in those expiring contracts. In effect, the quantity of DR procured for 2016, and the price at which it was procured, was largely determined by market conditions that prevailed when those legacy contracts were signed (upwards of five years prior in some cases).[93] The IESO plans to increase DR capacity targets in future auctions by 7% per year, with additional increases as more legacy DR contracts expire.[94] In the Panel's view, the procurement of capacity for future periods should not be based on administratively determined growth rates or the volume of contract expirations, but rather on a reasonable expectation of capacity needs during the commitment period.

Regardless of the procurement mechanism, the decision on how much capacity to procure, if any, should be directly tied to the need for capacity. The IESO recently assessed the long-term need for capacity in Ontario, noting the province's strong capacity position in its *Ontario Power Outlook* report, "Ontario will have sufficient resources to meet demand requirements generally over the next decade across all [demand] outlooks".[95] This assessment is consistent with the IESO's most recent *18-month Outlook*.[96] Indeed, even without the expected capacity contributions of resources procured through the DR auction,[97] Ontario has sufficient capacity to

[91] See slide 4 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf
[92] See page 3 of the IESO's approved Market Rule Amendment Proposal (MR-00416-R01), available at: http://ieso.ca/Documents/Amend/mr2015/MR_00416_R01_Amendment_Proposal%20v5.0.pdf
[93] See slide 10 of the Ontario Power Authority's April 2014 presentation: *Demand Response Programs in Ontario*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/drwg-20140403-DRWG-OPA-Presentation.pdf
[94] See slide 3 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf
[95] See page 11 of the IESO's *Ontario Power Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[96] See page ii of the IESO's *18-Month Outlook,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlook_2016sep.pdf
[97] The IESO's target procurement capacity for the DR auction is 648 MW in 2018, growing to 1,246 MW in 2025. For more information see the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at:

meet its needs for many years. Based on the IESO's most aggressive demand outlook (plus a reserve margin), and without any contribution from the DR auction, Ontario has sufficient capacity to meet its capacity needs until 2021. Under the most conservative demand outlook, Ontario has sufficient capacity until 2025.

Accordingly, the IESO is procuring capacity through the DR auction at a time when capacity is not needed. This procurement comes at a significant cost: resources procured through the 2016 and 2017 DR auctions will be paid upwards of $73 million in total. Under the most aggressive of assumptions, additional capacity is not needed until 2021. Fortuitously, the technology-neutral capacity auction in development is expected to have its first capacity auction in 2020 to procure capacity for future years.[98] Not only is the technology-neutral capacity auction a more cost effective way to procure capacity, but the timing of its implementation aligns far better with Ontario's capacity needs. [99]

In this regard it is noteworthy that various other capacity procurement projects have been cancelled or scaled back in recent years, including round two of the Large Renewal Procurement process,[100] and rounds five and six of the Feed-In Tariff program.[101]

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

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http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf

[98] See slide 44 of the Brattle Group's December 2016 presentation: *IESO Market Renewal Benefits Case: Preliminary Benefits Case Findings*, available at: http://ieso.ca/-/media/files/ieso/document-library/engage/me/me-20161219-preliminary-benefits.pdf?la=en

[99] As part of its reasoning for implementing the DR auction, the IESO stated the auction will, "Provide a stable transition [from bilateral DR contracts] that offers a learning opportunity for DR providers to be able to successfully compete in a full capacity auction." While that may be true, that learning opportunity comes at a cost that will well exceed $100 million, all the while providing little benefit. For more information on the IESO's justification for the DR auction, see its Market Rule Amendment Submission (MR-416-Q00), available at: http://www.ieso.ca/Documents/Amend/mr2015/MR-00416-Q00.pdf

[100] See the Minister of Energy's Letter to the IESO, dated September 27, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-lrpii-efwsop-20160927.pdf?la=en

[101] See the Minister of Energy's Letter to the IESO, dated December 16, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-nug-20161216.pdf?la=en

Assessment of Impact of Rule Amendment on Consumers re Prices, Reliability and Quality of Electricity Service

This form is used to document the *IESO's* assessment of the impact of a proposed *market rule amendment* on the interests of consumers with respect to prices and the *reliability* and quality of electricity service. Please complete all parts of this form.

Terms and acronyms used in this Form that are italicized have the meanings ascribed thereto in Chapter 11 of the *Market Rules*.

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00439-R00-R05
Title:	Transitional Capacity Auction

PART 2 – ASSESSMENT

The following is the *IESO's* assessment of the impact of the proposed *market rule amendment* on the interests of consumers with respect to prices and the *reliability* and quality of electricity service.

Impact on Prices

The Transitional Capacity Auction (TCA) represents an evolution of the demand response auction (DRA) into a more competitive capacity acquisition mechanism. Prices have decreased year-over-year in the DRA, with a 42 per cent decrease in prices since the first DRA in 2015. By enabling non-committed dispatchable generators to participate in the TCA, the increased competition is expected to put downward pressure on price.

Impact on Reliability of Electricity Service

The TCA is expected to acquire a reliable source of capacity to help meet Ontario's resource adequacy needs.

Impact on Quality of Electricity Service

No concerns have been identified that would negatively impact the quality of electricity service.

Date Assessment Prepared: March 6, 2018

Demand Response Discussion Paper

Utilization Payments

Prepared for:

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December 18, 2017

3.1.4 Harm to Economy

The argument is as follows. Providing utilization payments may incentivize companies to reduce production to provide demand reductions into the electricity market. Reducing production would in turn reduce the supply of goods in the economy that could increase the cost of these goods.

This argument comes back to the concept of allocative efficiency. It relies on the argument that the wholesale energy price signal is efficient and that introducing a utilization payment will result in inefficient outcomes.

For example, if a company which is producing widgets is incentivized through utilization payments to curtail their load and stop producing widgets fewer widgets will be available to buy. This reduced supply may increase the price of the widgets in the market. In practice, the impact of providing a utilization payment is not expected to be significant enough to cause a material impact on supply of goods (widgets) in the market.

Considerations for Ontario: This argument only valid for supply constrained and non-trade exposed sectors of the economy where prices are set based on local supply and demand. Ontario has a diversified and open economy that responds effectively to changes in supply.

For Activation Payments in Ontario

3.1.5 More DR Activation Reduces Consumer Costs

The argument is as follows. Utilization payments will increase levels of DR participation and activation in lieu of more expensive generation resources.

Utilization payments are a way to incentivize higher levels of DR participation and activation. These DR resources will provide less expensive capacity and energy that in turn will lead to lower consumer costs. This argument is based on the concept of productive efficiency.

For example, if a utilization payment incents DR resources to bid into the energy market at lower prices they will likely be activated more often. If the DR resources are bidding lower than the traditional generation resources the wholesale energy price will be lower. These reduced prices will be passed through to customers in the form of reduced consumer electricity costs.

Large commercial and industrial customers with a high value of lost load are not likely to change their bids into the energy market because of utilization payments however smaller commercial or residential customers who may have a lower value of lost load are likely to bid into the energy market below the ceiling price. While this will lower energy prices, the impact is not expected to be significant since these resources do not represent a significant amount of the supply required in Ontario.

Considerations for Ontario: To have a material impact on capacity or energy prices, utilization payments would have to result in a considerable increase in levels of participation and activation. Under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence consumer costs are largely fixed. It is also possible that reduced electricity costs could lead to reduced manufacturing costs that may be passed along to consumers as reduced cost of goods.

3.1.6 Disconnect Between Wholesale and Retail Prices

The argument is as follows. There is a disconnect between retail energy prices and wholesale energy prices. Retail prices don't reflect the real-time fluctuations in the cost of electricity and hence are inefficient. DR resources that are exposed to retail prices behave inefficiently because they are not exposed to the true cost of electricity on a short-term basis. Utilization payments are a way of improving the economic efficiency of the retail price during high-price events.

Retail rates paid by some consumers are fixed in advance and do not fluctuate during peak periods. Even when the market price (and the cost) of generating an additional megawatt of electricity during a peak period is relatively high, retail customers (who typically have unlimited access to supply at a fixed rate) do not curtail demand in response to the price signal. For that reason, many economists agree that it may be useful to provide retail consumers with an incentive to avoid using electricity, i.e., to stimulate DR during peak periods.[11] The economically efficient goal should be for resources to reduce their consumption whenever the value of their consumption is lower than the cost of supplying it. It should be noted that many of the existing DR resources in Ontario are exposed to real-time wholesale prices. Emerging DR resources such as aggregated residential or commercial loads are exposed to retail prices as opposed to wholesale prices. As a result, these resources would benefit from a price signal that would incent them to curtail in response to wholesale prices.

<u>Considerations for Ontario:</u> This argument is only valid for customers on retail rates who are not exposed to real-time energy prices. As described previously, many providers of DR in Ontario are already exposed to wholesale rates.

3.1.7 Fairness/Consistency

The argument is as follows. Generation resources receive a utilization payment in the form of an energy payment when they produce electricity. DR resources should be treated fairly/consistently and receive a utilization payment when they curtail electricity.

The argument takes the position that a DR resource and a generation resource providing a megawatt of electricity for the same period are equivalent and should be compensated equivalently. The principle behind this argument is that both demand and supply are "electricity resources". DR has demonstrated that it can serve as a reliable and economic resource for wholesale markets and integrated resource plans. It has demonstrated its ability to mitigate market power that can arise in a generation-only market.

This argument was supported by FERC in the FERC 745 ruling[12]. The Commission argued that when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers. FERC indicated that they believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.

[11] https://sites.hks.harvard.edu/fs/whogan/Economists%20amicus%20brief_061312.pdf

[12] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

The Public Service Electric & Gas Company (PSE&G) argues that a MW of demand response does not make the same contribution towards system reliability as a MW of generation, because demand response committed as a capacity resource is only required to perform for a limited number of times over the peak period.

Considerations for Ontario: This argument is the counter-point to the disproportionate benefits argument. Whether the equivalence of the product provided by DR and generating resources is accepted is a main point of contention on utilization payments.

3.1.8 Other Costs Associated with Curtailment

The argument is as follows. For dispatchable loads, electricity is as much an input as an output. The cost of producing a megawatt of electricity for a load is equal to the value of lost load, which can be higher than the price cap imposed in most organized wholesale energy markets (in Ontario the price cap is CAD $2,000 per megawatt-hour).

Another way to think about this argument is that, for a load, the cost of producing electricity in the form of curtailment is equivalent to the lost revenue and additional costs incurred (i.e. lost profit) associated with a reduction in production. DR resources have both fixed costs such the initial investment in technology such as monitoring and controls software to manage and execute DR operational activities and variable costs, such as labor cost and loss of productivity during the DR activation period. This value may vary significantly by DR resource. In jurisdictions where utilization payments are provided, activation levels for DR in the energy market are still relatively low. This suggests that even when provided with a utilization payment, the lost profit or value of lost load may still be much higher.

Considerations for Ontario: For large commercial and industrial customers, the value of lost load (VOLL) can be very high, which could result in limited activation of DR resources regardless of whether utilization payments are offered. Residential customers generally have a lower VOLL ($0/MWh - $17,976/MWh) than commercial and industrial customers (whose VOLLs range from about $3,000/MWH to $53,907/MWh)[13]. Given the sensitivity of VOLL to a variety of specific factors such as customer's consumption profile, a region's macroeconomic and climatic attributes, as well as the types of outage these ranges these ranges may be different for Ontario.

3.2 Considerations for 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

[13] http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

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. In the future when if DR resources compete against generation assets in the capacity market, traditional generators may lose revenue because of being under bid by DR. This would result in reduced (though likely not significant) costs to consumers.

IESO UNDERTAKING J3.4

UNDERTAKING

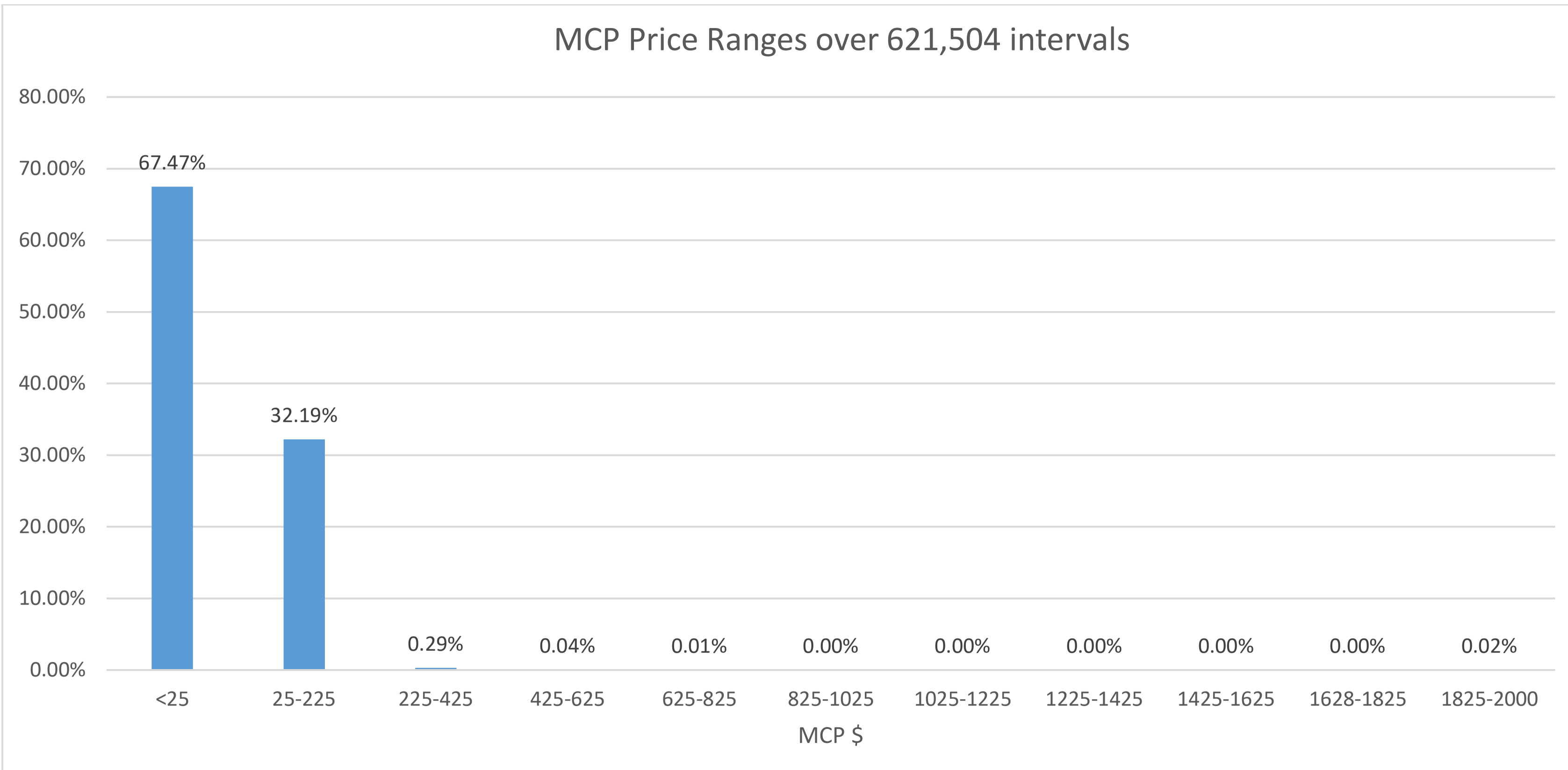
To produce a distribution graph of five-minute-interval real-time energy prices in $200 increments, between $25 and the maximum over the last five years

RESPONSE

The distribution graph for the over 621,000 5-minute intervals over the last five years is attached.

UNDERTAKING NO. J3.4:

TO PRODUCE A DISTRIBUTION GRAPH OF FIVE-MINUTE-INTERVAL REAL-TIME ENERGY PRICES IN $200 INCREMENTS, BETWEEN $25 AND THE MAXIMUM OVER THE LAST FIVE YEARS.



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

[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

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[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".

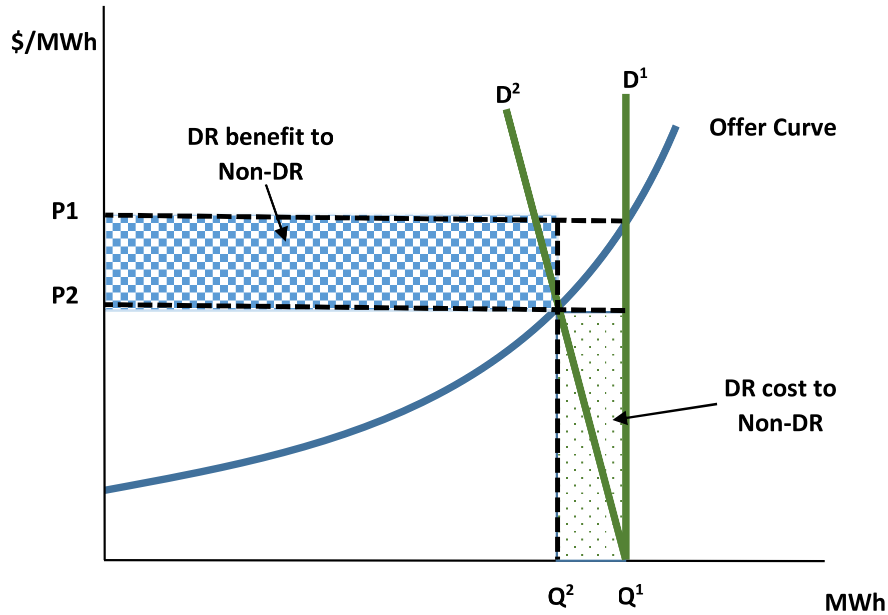
C.7 Q: Can you explain why the Global Adjustment means the net benefits test is not likely to be satisfied on Ontario?

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.

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

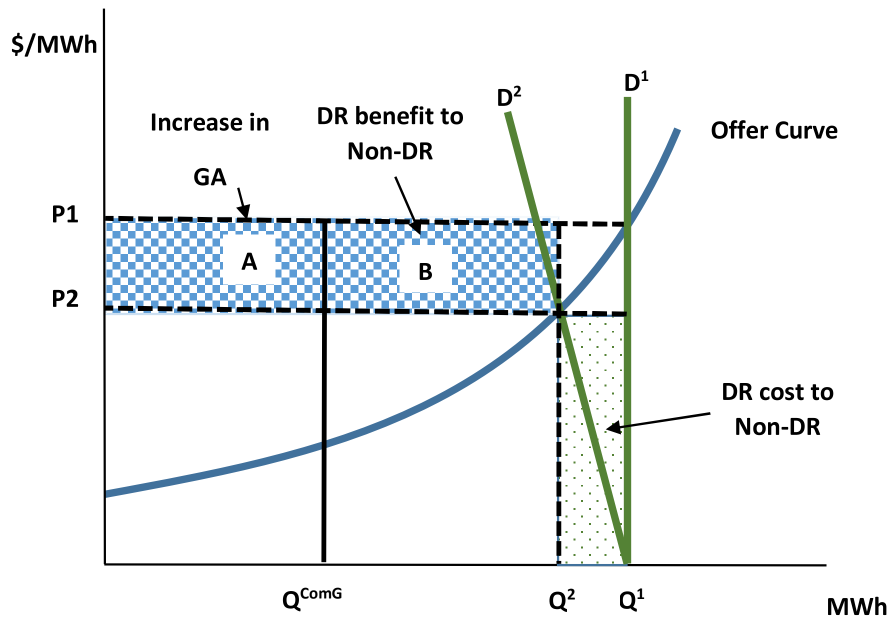
Figure 5: The Net Benefits Test under FERC Order No. 745



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



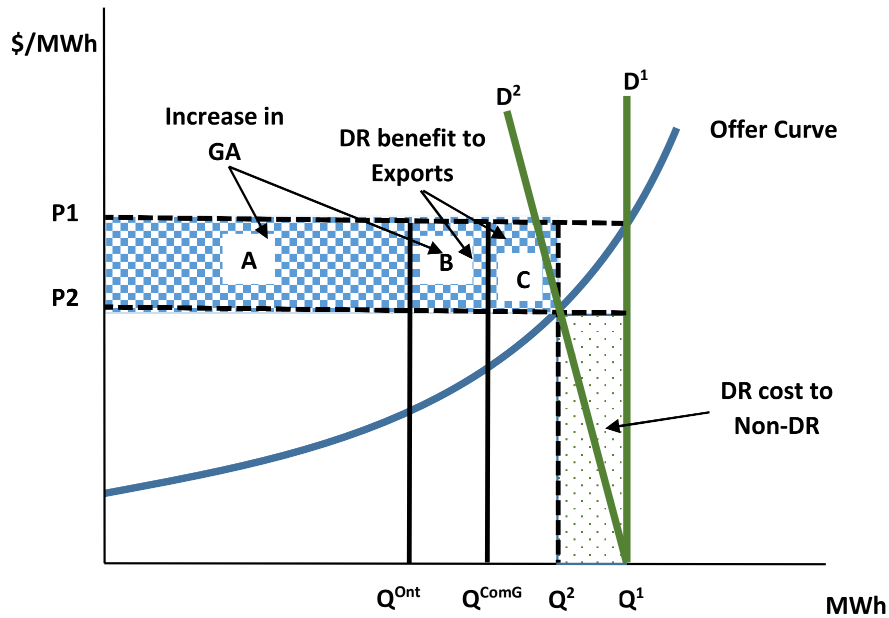
63. In Figure 6, the amount of supply provided by committed generators is Q^{COMG}. When lower energy bid prices of DR resources cause the energy market price to fall from P^1 to P^2, the amount of net revenues earned by the committed generators falls in proportion to the price decrease (the area marked 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,



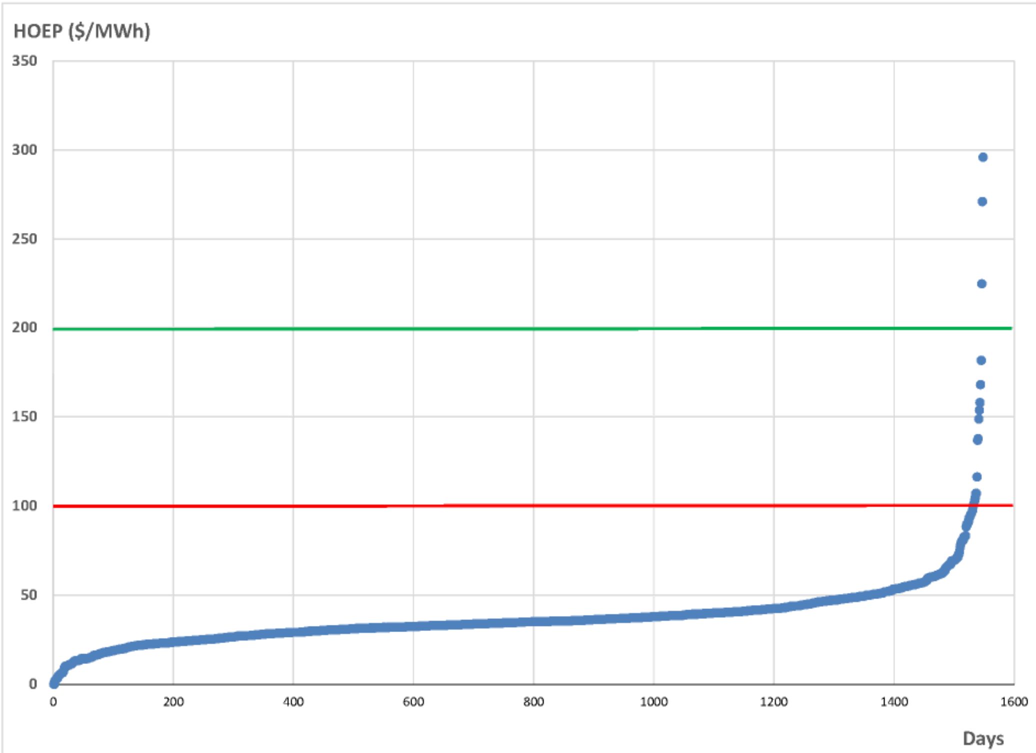
65. In Figure 7, the Ontario non-DR consumers' demand is Q^{ONT}. The difference between Q^2 and Q^{ONT} is export demand. The amount of energy produced by committed generators is Q^{COMG}, which is greater than the Ontario non-DR consumers' demand. The benefit that non-DR consumers realize from the 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

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[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.

Demand response programs in selected US markets

prepared for the Ontario Energy Board staff by London Economics International LLC ("LEI")

November 8th, 2019

Federal Energy Regulatory Commission ("FERC") Order 745 established that demand response resources participating in organized wholesale energy markets (day-ahead and real-time) would be compensated through the payment of the locational marginal price for curtailing their load if dispatched. However, Order 745 did not directly impact the majority of demand response resources participating in programs administered by the two US Independent System Operators ("ISO") and one Regional Transmission Organization ("RTO") that LEI reviewed, as these demand-side resources tended to serve more as capacity providers. Demand response resources as capacity providers make up the majority of demand-side participation in the ISO and RTO programs that LEI reviewed, and capacity payments make up the bulk of their total compensation (although additional payments are made if these resources are actually activated). In contrast, the total dispatch of demand response resources through ISO and RTO programs reviewed by LEI was low, as were revenues associated with dispatch.

Table of contents

3 Overview of FERC Order 745

The Federal Energy Regulatory Commission ("FERC") Order 745 amended regulation under the *Federal Power Act* in relation to the compensation of demand response ("DR") resources participating in organized wholesale energy markets (i.e. day-ahead and real time markets) administered by ISOs or RTOs. According to Order 745, demand response resources participating in organized wholesale energy markets **must** be compensated when providing services to the energy market at the market price for energy (the locational marginal price or "LMP"), but **only** when the following two conditions are met:

1. the DR resource has the capability to balance supply and demand as an alternative to a generation resource; and
2. the dispatch of that DR resource, and the payment of LMP for this dispatch, is cost-effective as determined by the 'net benefits test'.[3]

3.1 What Order 745 applies to

> "***Demand response*** *means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy*"
>
> "***Demand response resource*** *means a resource capable of providing demand response*"
>
> Definitions contained in Order 745

According to information contained in Order 745, demand response can generally take the following two forms:

1. customers reduce demand by responding to retail rates that are based on wholesale prices; and
2. customers provide demand response that acts as a resource in organized wholesale energy markets to balance supply and demand (the focus of this proceeding).

Order 745 only applies to demand response resources participating in day-ahead or real-time energy markets administered by US ISOs or RTOs, that can balance the system through load reduction when dispatched, with this load reduction being compared to an expected level of consumption and undertaken in response to price signals.[4] The FERC Order[5] therefore applies to DR resources that can be viewed similar to generation resources, and as discussed in FERC Order 745-A (and originally covered in FERC Order 719), such DR resources must be "technically capable of providing the ancillary service" and "submit a bid under the generally-applicable bidding rules."[6]

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[3] FERC. *Demand Response Compensation in Organized Wholesale Energy Markets [Docket No. RM10-17-000; Order No. 745].* Issued March 15, 2011.

[4] Ibid.

[5] Usage of 'the FERC Order' in LEI's report refers to Order 745.

[6] FERC. *Order No. 745-A: Order on Rehearing and Clarification*. Issued December 15, 2011.

The FERC Order **does not** apply to:

- **state-level efforts**, including state and/or utility retail-level price-responsive demand initiatives based on dynamic and time-differentiated retail prices and utility investments in demand response enabling technologies;
- DR participating in RTO and ISO programs administered for **reliability or emergency** conditions;
- compensation in **ancillary services** markets (which the FERC has addressed elsewhere); and
- **capacity** markets.[7]

3.2 Net benefits test

A DR resource participating in a wholesale energy market would theoretically be dispatched when it is the incremental resource with the lowest bid. However, under certain situations, dispatching this DR resource could result in a higher cost per unit for all remaining load (compared to a situation where the next-lowest-bid incremental resource was dispatched), and therefore dispatching the DR resource would not be cost-effective.[8] In an attempt to deal with such situations, Order 745 requires each RTO and ISO to implement and perform a **net benefits test**, to determine whether the dispatch of a demand response resource is cost-effective.

3.2.1 Generalized approach

According to FERC, a DR resource can be considered cost-effective compared to alternative generation resources under the conditions that:

- LMP is reduced (due to the dispatch of the DR resource) and the remaining market load achieves cost savings due to this LMP reduction; and
- the cost savings from dispatching the DR resource are greater than the total cost to consumers for paying the DR resource the LMP, as well as the effect of the reduction in load paying for the purchased supply resources.

To establish cost-effectiveness, a price threshold must therefore be estimated, where the overall benefit from the LMP reduction due to the DR resource dispatch is greater than the cost of dispatching that DR resource, and a net benefit occurs. With this in mind, Order 745 requires each RTO and ISO to approximate conditions under which it is cost-effective for demand resources to be dispatched and receive the LMP. More specifically, ISOs and RTOs were directed to approximate, updated on a monthly basis, the "*threshold price corresponding to the point along the supply stack at 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.*"[9] This

[7] As some US RTOs and ISOs do not have capacity markets, and for those that do DR resources are not always obligated or able to participate in wholesale energy markets.

[8] This potential result is referred to as the 'billing unit effect' of dispatching DR.

[9] In Order 745, the FERC acknowledges that this monthly price threshold method may be less precise than a more dynamic approach that integrates a determination of the cost-effectiveness of demand response resources into the dispatch of the ISOs and RTOs, but also acknowledges that modification to ISO and RTO dispatch algorithms to incorporate the costs related to demand response may be difficult in the near term.

approximation would be done through analysis based on historical data and updates for condition changes (e.g. supply-side availability and fuel prices).

3.2.2 Net benefits test methodology

Conceptually, the net benefits test methodology requires RTOs and ISOs to calculate the pricing point on the supply curve where price elasticity of supply changes from greater than one to less than one (i.e. the point where percent changes in the prices result in same percent changes of supply).

An RTO/ISO's typical approach in determining the net benefits test price levels involves six steps as shown in the Figure 3 below.

Figure 3. Methodology to determine the Net Benefits Test price

Steps	Details
Step 1	Retrieve generation offers from the corresponding month of a previous year (reference month)
Step 2	Apply fuel cost adjustment (year-on-year change by using futures price of fuel and average spot price of fuel in a reference month) to the portion of the offers that typically represents fuel costs
Step 3	Build daily supply curves for the month
Step 4	Build monthly average supply curve
Step 5	Use non-linear least squares estimation technique to calculate an equation that smooths the supply curve
Step 6	Calculate the price level at which the elasticity is equal to 1

Source: *PJM Manual 11: Energy & Ancillary Services Market Operations, Section 10: Overview of the Demand Resource Participation.* Dec 20, 2018

An intuitive way to view the net benefits test ("NBT") is that it enables determination of the price level where the cost of the next generating unit after the DR is not high enough to offset the billing unit effect of the demand response resource dispatch would have on the remaining load. Figure 4 demonstrates the billing unit effect of DR and the circumstances when:

- the dispatch of DR resources results in net benefit to consumers (Scenario 3, when the next marginal generating unit is sufficiently more expensive than the DR resource to offset the billing unit effect of reduced load paying for supply);
- such dispatch would result in net costs to consumers (Scenario 1, because the next marginal generating unit's cost is too close to the DR's offer and does not offset the increased cost of electricity per MWh of load); and
- when there is a zero net benefit from dispatching the DR resources, i.e. the price point target of the Net Benefits Test (Scenario 2).

Figure 4. Illustrative application of net benefits test

			Scenario 1		Scenario 2		Scenario 3	
			MWh	LMP, $/MWh	MWh	LMP, $/MWh	MWh	LMP, $/MWh
Demand	Regular load		10,000		10,000		10,000	
	DR load		100		100		100	
Supply	Suppliers A - R		9,000	$ 50	9,000	$ 50	9,000	$ 50
	Supplier S		800	$ 60	800	$ 60	800	$ 60
	Supplier T		100	$ 70	100	$ 70	100	$ 70
	Supplier U		100	$ 100	100	$ 100	100	$ 100
	DR resource		**100**	**$ 1,000**	**100**	**$ 1,000**	**100**	**$ 1,000**
	Supplier V		100	$ 1,001	100	$ 1,062	100	$ 1,100
			No DR deployment	DR deployment	No DR deployment	DR deployment	No DR deployment	DR deployment
Cost of supply	Suppliers A - R	= 9,000 MWh * $50	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000
	Supplier S	= 800 MWh * $60	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 48,000
	Supplier T	= 100 MWh * $70	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000	$ 7,000
	Supplier U	= 100 MWh * $100	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
	DR resource	**= 100 MWh * $1,000**	**$ -**	**$ 100,000**	**$ -**	**$ 100,000**	**$ -**	**$ 100,000**
	Supplier V	= 100 MWh * LMP	$ 100,100	$ -	$ 106,200	$ -	$ 110,000	$ -
	Total cost of supply for the hour ($)		$ 615,100	$ 615,000	$ 621,200	$ 615,000	$ 625,000	$ 615,000
	Total load to be supplied in the hour (MWh)		10,100	10,000	10,100	10,000	10,100	10,000
	Zonal price for the hour, i.e. cost of electricity paid by load ($/MWh)		**$ 60.90** <	**$ 61.50**	**$ 61.50** =	**$ 61.50**	**$ 61.88** >	**$ 61.50**

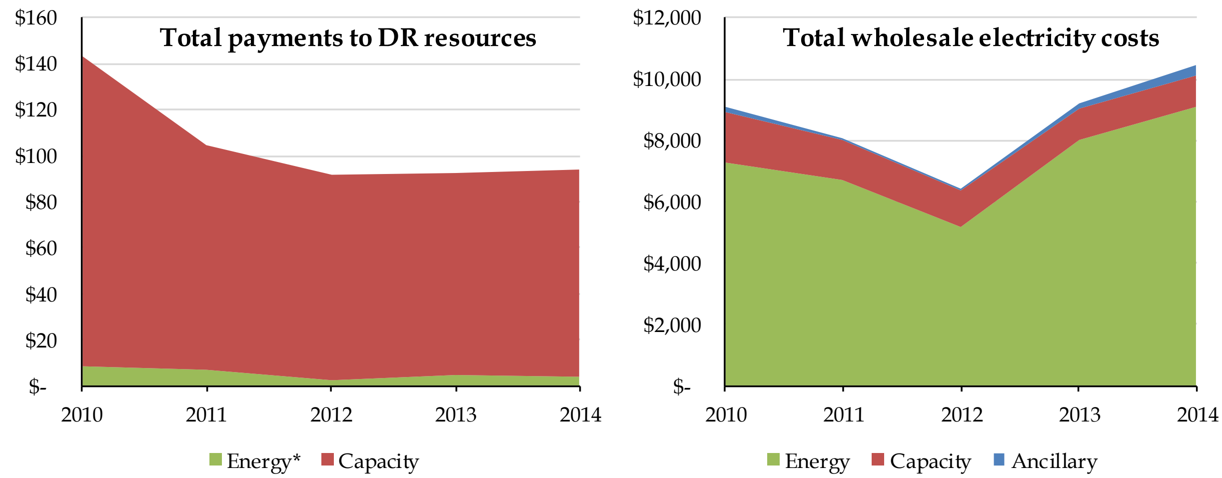
Source: *LEI calculations based on FERC Order 745*

Using PJM as an example, Figure 5 presents for illustrative purposes PJM's monthly NBT prices from April 2012 to October 2019, along with the monthly average prices for PJM – RTO Zone (this chart is illustrative as the test is actually applied to each applicable zone on an hourly basis). Dispatched DR resources are paid LMP times MWh of reduced load only for the hours where the applicable zonal LMP is greater than or equal to the month's NBT price.[10] Based on this figure, real-time and day-ahead prices were almost always higher than PJM's NBT price, and it is likely that across the RTO in most months, on average, DR resources were economic to dispatch

[10] PJM Manual 28: Operating Agreement Accounting," § 11.2.2 Economic Load Response Program, Rev. 81 (Oct. 25, 2018).

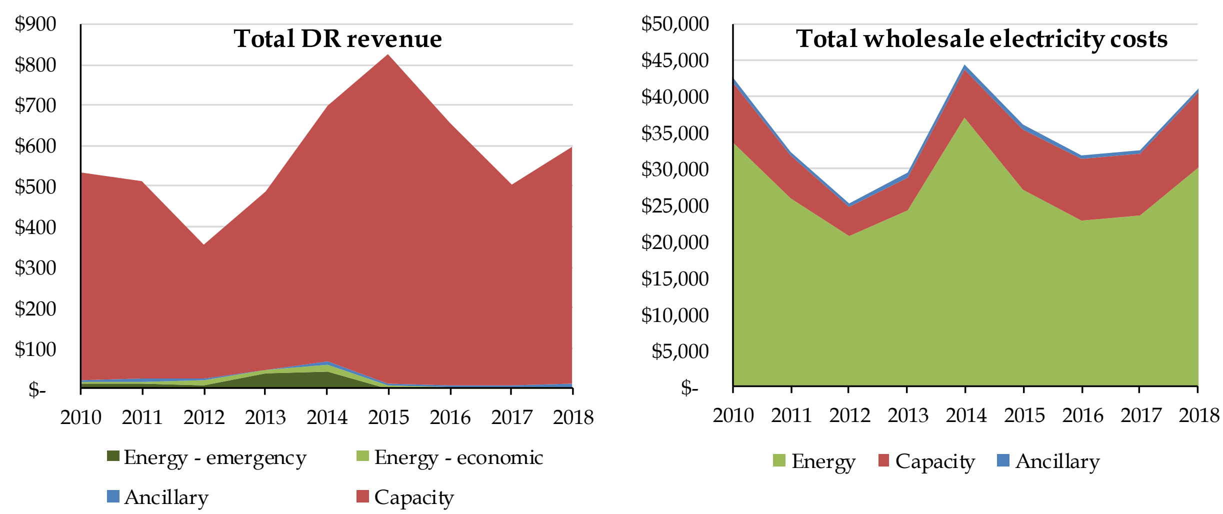
activation or dispatch are a very small proportion of their total revenues (on average 5% of total payments to DR resources in ISO-NE and 3% in PJM using this data). This is in stark contrast with total system costs, which are majority energy-related in these two markets (84% energy in ISO-NE and 78% in PJM).

Figure 23. Total payments to DR and total wholesale electricity costs in ISO-NE ($ million)



* Energy values shown consist of the Day-Ahead Load Response Program, Transitional Price-Responsive Demand program, and the Real-Time Price-Response Program.
Sources: ISO-NE Annual Markets Reports for 2010 to 2014; ISO-NE. *2018 Report of the Consumer Liaison Group*. March 12, 2019

Figure 24. DR and total wholesale system revenues in PJM ($ million)



Sources: Monitoring Analytics LLC. *2010-2018 PJM State of the Market Reports*

It is also clear that **total revenues earned by DR resources are a very small proportion of total system commodity-related costs** (energy, capacity, and ancillary services). This is illustrated in Figure 25, which show the percentage of total costs that are attributable to wholesale electricity costs and the percentage attributable to just DR resources, based on the average of data shown in Figure 23 and Figure 24. DR here is broken down into those related to activation (both energy

5 Contextual differences between Ontario and the markets covered

Starting with an overview of demand response procured by the IESO in Ontario, this section covers at a high level some of the differences between the three US markets discussed in this report and Ontario related to: differences in dispatchability from the ISO perspective; the amount of demand response in these markets procured at the ISO level; differences in total commodity costs; and structural considerations.

5.1 Demand response in Ontario

Demand response in Ontario takes two forms, dispatchable loads and Hourly Demand Response ("HDR") resources.

According to the IESO, **dispatchable loads** are those large consumers that actively participate in the energy market. Dispatchable loads submit bids into the energy market, and if prices exceed their bid, these loads will receive dispatch instructions to reduce consumption. Settlement price for dispatchable loads is the 5-minute Market Clearing Price ("MCP").[44]

Dispatchable loads:

- are not paid the MCP for this load reduction, but do avoid paying the MCP on the portion of load that was reduced;
- can participate in the IESO's capacity auctions;
- are able to offer and receive payments for operating reserves; and
- may receive Congestion Management Settlement Credits under certain conditions.[45]

HDR resources are those demand response resources that cannot respond to 5-minute schedules from the IESO (non-dispatchable).

Within the current Demand Response Auction ("DRA"), demand response market participants must be registered as either dispatchable loads or HDR resources. These resources fulfill their capacity obligations by making cleared capacity available in the energy market, through submission of bids that are greater than $100 and less than $2,000.[46] Activation of both dispatchable loads and HDRs can therefore occur in market, but these resources are not paid for reducing their consumption if activated.[47] Demand response resources that clear the auction

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[44] Non-dispatchable loads are those that are not able to respond to 5-minute signal. Non-dispatchable loads cannot offer operating reserves, and settlement prices for these loads is the HOEP. Source: IESO. *Quick Takes - Dispatchable Loads*. April 2017; IESO Website. Real-time Energy Market. <http://www.ieso.ca/sector-participants/market-operations/markets-and-related-programs/real-time-energy-market>

[45] Sources: IESO. *Quick Takes - Dispatchable Loads.* April 2017.

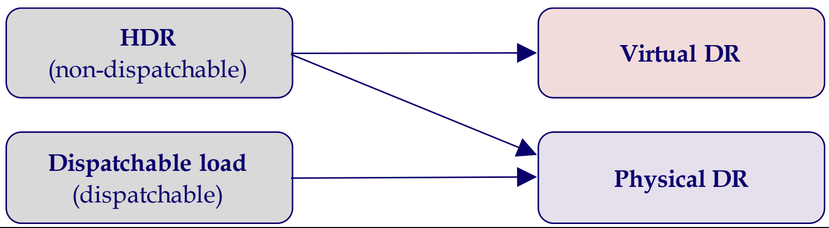
[46] Based on availability window for when the DR resource is expected to be available to provide demand response. The availability window is hours between 12:00 and 21:00 for the summer obligation commitment period, and 16:00 and 21:00 for the winter period, for business days. Sources: IESO. *Introduction to the Demand Response Auction*. May 2017; IESO. *Market Manual 12: Capacity Auctions - Part 12.0: Capacity Auctions - Issue 7.0*. October 15, 2019.

[47] Out-of-market activation can also occur for HDRs, under emergency or test situations. Source: *IESO. Energy Payments for Economic Activation of DR Resources.* October 10, 2019.

receive compensation for being available (through $/MW-day term payments) regardless of whether or not they are activated.

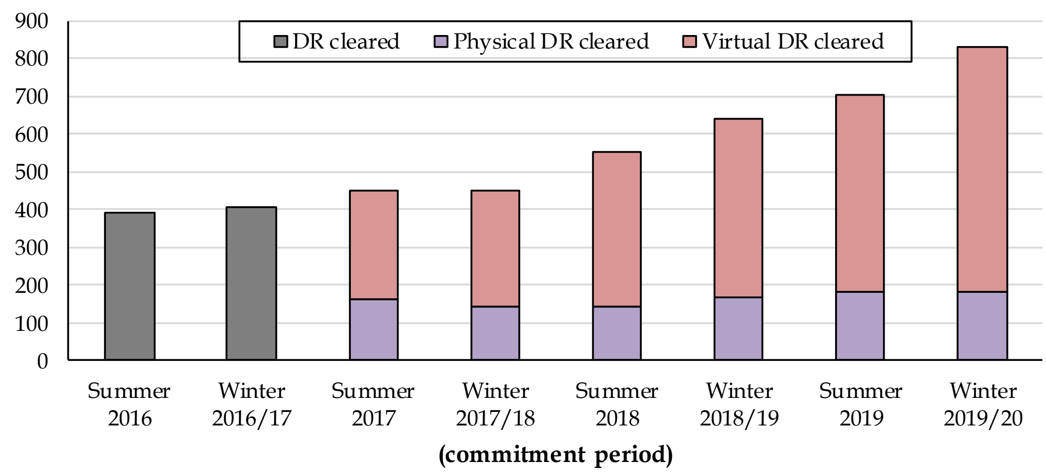
Cleared capacity within the auction is broken down into physical and virtual demand response. Physical DR resources are those that have IESO-registered revenue metering, while virtual DR resources are those that do not. All dispatchable loads are physical resources, and all virtual resources are HDRs, but HDRs can also be physical resources.[48] The linkage between physical/virtual and dispatchable loads/HDRs is shown visually in Figure 26.

Figure 26. Linkage between physical/virtual resources and dispatchable loads/HDRs



As shown in Figure 27, the amount of capacity procured through the DRA has grown since its first commitment period in 2016. Breakdowns for cleared capacity between virtual and physical DR were reported from the summer 2017 commitment period onwards. Based on this, it is also clear that most DR resources procured through the auction are HDRs (as all virtual resources are HDRs).[49]

Figure 27. DR auction cleared capacity (MW)



Note: breakdowns between physical and virtual DR capacity were reported from the summer 2017 period onwards
Sources: IESO Demand Response Auction Post-Auction Summary Reports

[48] IESO response to OEB interrogatories under case EB-2019-0242 filed on November 6, 2019.

[49] Further, according to the IESO for the Winter 2018/19 commitment period 112 MW of physical DR was dispatchable load, and for the Summer 2018 commitment period 137 MW of physical DR was dispatchable load (with physical HDR capacity at 31.4 MW for both these commitment periods). Source: IESO response to OEB interrogatories under case EB-2019-0242 filed on November 6, 2019.

Although full data on utilization of DR resources was not readily available, according to an IESO presentation in 2016 activation of dispatchable load resources procured through the DR auction totaled just 1,431 MWh. [50] Further, according to the IESO HDRs have only been economically activated once (in July 2019 for a three hour period) since the introduction of the DRA, and dispatchable loads have been dispatched less than 1% of time over the same timeframe.[51]

5.2 Differences between load dispatchability in Ontario as compared to the US markets

For the demand-side resources in ISO programs LEI reviewed, dispatchability of the resource is centered around the ability of the ISO to schedule the resource in-market, based on economic considerations (resource dispatchability by program is summarized in Figure 28). Dispatchable resources are scheduled economically and in-market, while non-dispatchable resources, if activated, are done so in anticipation of emergency or reliability events and scheduled manually (out-of-market and not 'economically dispatched'). In contrast, LEI's understanding is that dispatchability of DR in the Ontario context is centered around whether the resource can respond to 5-minute schedules from the IESO; HDRs, while 'non-dispatchable', can still be economically activated in-market.

Figure 28. Dispatchability of selected demand response resources from ISO perspective

ISO	NYISO				ISO-NE		PJM		Ontario	
Demand side resource	SCR	EDRP	DADRP	DSASP	Passive	Active	Emergency/ pre-emergency	Economic	HDR	Dispatchable load
Considered dispatchable by ISO?	No	No	Yes	Yes	No	Yes	No	Yes	No	Yes

In ISO-NE, demand-side resources include "passive" resources (including energy efficiency) that can participate in the capacity market by providing on-peak and seasonal load reduction. However, this load reduction is provided across multiple hours, and is non-dispatchable from the ISO's perspective as load cannot be reduced in response to a dispatch instruction. DR resources in ISO-NE, referred to as active DR, are dispatchable from the ISO's perspective, as they are energy market participants and reduce their load when economically dispatched by the ISO.

For the NYISO, DR programs include reliability- and economic-based demand response programs. Reliability (SCR and EDRP) resources are non-dispatchable from the ISO's perspective, and, although they have the capability to reduce their load with adequate lead-time from the ISO, they must be **manually activated** by the ISO based on expectations of reliability events (i.e. not part of NYISO's dispatch algorithm).[52] Resources participating in economic-based demand response programs in NYISO (e.g. DADRP) are considered dispatchable as they are active

[50] IESO. *Demand Response Working Group: Notification and Activation of Hourly DR Resources*. May 11, 2017.

[51] IESO response to OEB interrogatories under case EB-2019-0242 filed on November 6, 2019.

[52] Manual activation uses load and generation forecasts, as well as forecasts of transmission availability, to determine whether a reliability DR resource may be needed in order to maintain reliability. As this is a manual activation based on forecasted conditions, it is less efficient than an automated commitment and dispatch in the wholesale market. Source: NYISO. *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets*. January 2017.

participants in the NYISO's energy markets. These resources determine when they participate through supply offers, and are scheduled by the ISO and dispatched when they are 'economic'.

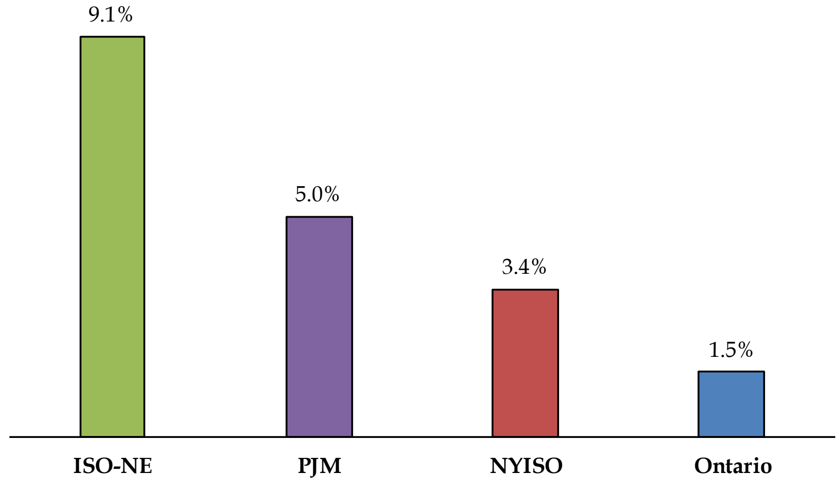
PJM currently has two broad categories of DR resources: economic DR and emergency DR. The economic DR participates in energy markets (real-time and day-ahead) on a voluntary basis, and when it clears the market, it is committed and dispatched by PJM. The reductions achieved through the deployment of the economic DR are known as dispatched curtailment. The emergency DR, on the other hand, are not dispatchable directly by PJM. When these resources are needed (as pre-emergency or emergency load reduction), PJM contacts these resources via email/web portal or telephone to curtail the load. This type of curtailment is known as mandatory curtailment. Once these sources of DR are exhausted, PJM may call on emergency energy only DR resources, but their curtailment is voluntary.

In the IESO market, dispatchable and non-dispatchable DR resources participating in the auction make their cleared capacity available in the energy market through submission of bids above $100 and below $2,000. Activation for **both** dispatchable and non-dispatchable DR resources can therefore occur in market, through the ISO's dispatch. This is in contrast to the other markets reviewed by LEI, where non-dispatchable resources either cannot reduce their loads even with instruction (e.g. passive resources in ISO-NE), or are activated by the ISOs but out-of-market (e.g. SCR in NYISO).

5.3 Comparing Ontario's DR resource supply to other markets

Total demand response resources relative to total installed generating capacity in 2018 for each of the three US markets is shown in Figure 29, along with Ontario's demand response resources procured through the DRA (see figure note for what is included). ISO-NE's demand response resources are made up mostly of passive resources, PJM's demand response resources are mostly emergency (non-dispatchable), and Ontario's are mostly HDRs; NYISO's demand response in this figure only includes reliability-based resources, as there was no bidding activity in the DADRP in 2018. For the three US markets, DR relative to total installed capacity was between 3.4% and 9.1% in 2018; Ontario's DR procured through the DR auction was below this range, at 1.5% for 2018.

Figure 29. Demand response relative to installed generating capacity (2018)



Demand response shown: NYISO shows the sum of EDRP and SCR ICAP; ISO-NE shows sum of active and passive resources with CSOs for commitment period 2018/2019; PJM is sum of economic and emergency DR; Ontario uses demand response capacity from the Summer 2018 DR auction.
Sources: See sources from Figure 22 and Figure 27; IESO's December 2018 Reliability Outlook

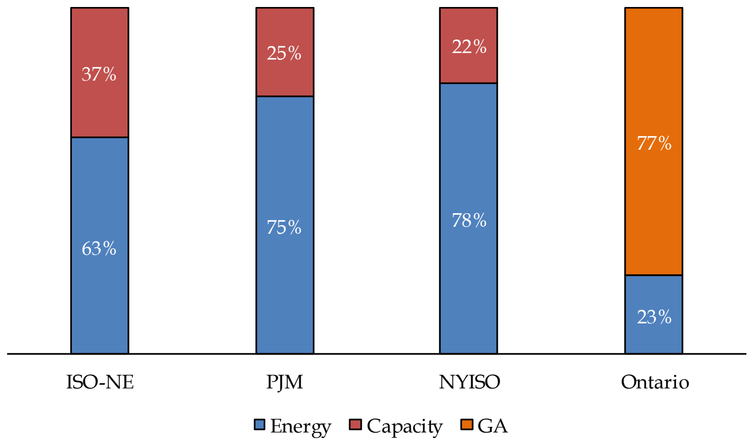
An alternative metric for consideration is DR capacity as a percentage of peak load, which averaged 5.6% across **all** US ISOs and RTOs in 2017 (and is depressed by the lack of DR participation in Southwest Power Pool);[53] again, Ontario is below this average at 2.4% for 2018. Worth re-emphasizing however, and as discussed in Section 4 and Section 5.1, based on data LEI could gather actual utilization of DR resources has been minimal in all markets reviewed when compared to total load, and DR resources in the US markets are compensated primarily for their provision of capacity.

5.4 Impact of the Global Adjustment

Total system costs for energy and capacity in the three US markets, and for wholesale energy and the Global Adjustment ("GA") in Ontario, are shown in Figure 30 (for 2018). In the three US markets covered by LEI in this report, the energy component made up the bulk of total costs, ranging from 63% in ISO-NE to 78% in NYISO. In contrast, Ontario's wholesale energy component constituted only 23% of the combined total wholesale energy and GA. The main component, the GA, relates to a number of items including regulated and long-term contracted generation, and captures aspects related to capacity, as well as internalized Renewable Energy Credits (in contrast to the three US markets, which have standalone renewable energy compensation products at the state-level), among others.

[53] FERC Staff Report. *2018 Assessment of Demand Response and Advanced Metering*. November 2018.

Figure 30. Total system costs for energy and capacity/GA (2018)



Notes: NYISO system costs estimated by LEI using regional average all-in prices and regional load data; energy costs for Ontario estimated using weighted average Hourly Ontario Energy Price ("HOEP") and Ontario market demand. Total costs shown are: $9.6 billion for ISO-NE; $40.5 billion for PJM; $8.3 billion for NYISO; and Canadian $14.5 billion for Ontario. For reference, when included, AS made up between 1.5% and 2% of total system costs for energy/capacity/AS in the three US markets for 2018.
Sources: ISO-NE's 2018 Report of the Consumer Liaison Group; NYISO's 2018 State of the Market report and 2019 Gold Book; PJM's 2018 State of the Market report; IESO monthly market report for December 2018 and IESO year-end data for 2018.

While not part of the DRA program, larger customers in Ontario can be eligible to participate in the Industrial Conservation Initiative ("ICI"). The ICI is a powerful demand response tool that incentivizes qualified customers to reduce their load at peak periods through lower Global Adjustment ("GA") costs (which as visible from Figure 30 are the largest portion of commodity costs in Ontario).[54] The ICI is estimated to have reduced peak demand in Ontario by around 1,300 MW in 2016 and 1,400 MW in 2017 (similar data for 2018 was not readily available, although participation in the ICI has grown from 20% of Ontario's annual consumption in 2016 to 29% in 2018).[55, 56]

5.5 Distinctions and implications

As discussed in Section 3.3.2, in the US the FERC has jurisdiction over the wholesale markets, states have jurisdiction over the retail situation, and ISOs and RTOs can span multiple states.

Whereas Ontario was able to simultaneously develop its wholesale and retail markets, in the US, given this split between federal and state jurisdictions, state retail market designs were developed over a different timeframe from wholesale market designs, without substantial coordination.

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[54] As they pay for the Global Adjustment based on their percentage contribution to the top five peak demand hours in Ontario over a 12-month period.

[55] Peak demand reduction estimate for 2016 taken from the IESO's Industrial Conservation Initiative Backgrounder (August 2019); estimate for 2017 taken from the Q1 2019 Ontario Energy Report.

[56] Based on consumption by customer class from the IESO's "GA components plus costs and consumption by customer class" datasheet.

The existence of multi-state ISOs, state-level regulators, and the FERC mean there are additional actors attempting to address potentially overlapping issues (in this case demand response) that are not present in Ontario. For example, the presence of multi-state ISOs means that states may have additional DR programs which may or may not complement those at the ISO level.

Based on the demand response resource programs in the three US markets LEI reviewed, the following conclusions can be drawn:

- DR resources serve primarily by the provision of capacity (in terms of total resource participation);

- when they have access to both capacity- and 'energy'-related compensation, capacity revenues still form the bulk of their revenues; and

- compensation for dispatch of economic DR resources or activation of emergency/reliability resources is the common approach; but the actual dispatch (in aggregate) of economic DR resources is low and activation of emergency/reliability resources is very infrequent (meaning, again, that actual dispatch or activation is a very small proportion of revenues for most DR resources).

Ontario has several key differences from US ISOs:

- a number of states in the geographic Northeast (including most states in PJM, ISO-NE, and NYISO) allow retail electricity choice, with Load Serving Entities being more prevalent, a large portion of industrial and commercial load being served by competitive suppliers, and greater access to competitive fixed-price contracts or hedging without the use of physical assets;
- demand response procured through the IESO's DRA in Ontario is presently a smaller share of capacity and peak than in other markets. Additionally, this auction is still in its early stages of development (compared to the other three markets), and procurement is limited to a small proportion of Ontario's total capacity;
- the fact that over 90% of all generation in the province is under regulated rates or contracted impacts the price signal provided by the HOEP and increases the influence of the GA on bills to final consumers; and
- although fewer DR resources are procured through the IESO's auctions compared to the US ISOs, outside of the DRA, the incentives embedded within the ICI provide significant avoided costs for those Class A customers capable of curtailing their loads during critical peak periods (with around 29% of load being Class A in 2018).

Overall, when assessing compensation mechanisms for DR, the impact on the transparency of the energy price signal needs to be considered, balanced against the practical reality that across the three US markets covered in this report DR is rarely activated, and receives the bulk of its revenue from capacity-like mechanisms.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to Staff #1

Reference: AMPCO Application, Paragraph 22 (page 6); Affidavit of Colin Anderson, page 4, para. 15, 17.

Preamble:

AMPCO's application states that under the Transitional Capacity Auction (TCA) rules generators will offer into the auction at prices that take into account their anticipated energy payments. DR resources will have to compete against these bids without an equivalent energy payment stream, putting DR resources at a competitive disadvantage to generators in the capacity market.

The Affidavit refers to an IESO proposed "work-around" that 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 generators.

The Affidavit also states "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."

Questions:

(a) Please provide a detailed list of the cost elements or cost categories that DR Resources include in their capacity offer prices for the Demand Response Auction (DRA). Please also provide an approximate percentage value that each element would account for in the total auction offer price. Please respond for a typical dispatchable load Demand Response Auction Participant (DRAP), and a typical Hourly Demand Response (HDR) resource DRAP.

(b) Does the above-mentioned utilization payment proxy sometimes used by DR Resources also relate to costs of being activated? If so, please identify what these costs are. Please also identify, for a typical dispatchable load and HDR participant, an approximate breakdown of these costs and all other elements that form part of these participants' Demand Response Energy Bids.

(c) Please explain the circumstances under which the partial proxy "work-around" is used, and the circumstances under which it is not used.

(d) To what degree does the "work-around" reflect a capitalization of energy market costs borne by demand responders with DRA capacity obligations into their offer prices for the DRA? Are these costs always present for a demand responder with a DRA capacity obligation, or are they only present when the demand responder is activated?

(e) A dispatchable load with a commitment in the DRA must make Demand Response Energy Bids into the Day Ahead Commitment Process (DACP) and the real time energy market (RTEM), and these bids must cover all hours in its availability window. A dispatchable load that does not have a commitment from the DRA may enter bids in DACP and the RTEM if it wants to consume energy. If these two dispatchable loads are in all other respects the same, please:

  i. explain how their energy bids into the DACP and the RTEM would be different. In providing this explanation please identify all significant elements that comprise the energy price bid for a given quantity of energy demanded.

  ii. Identify any other differences in the situation of a dispatchable load with a commitment from the DRA and one without.

  iii. Explain whether and how these differences will cause the behaviour of these two participants to differ.

Response:

(a) A Demand Response Auction Participant (DRAP), when determining its bid parameters ($/MW and Quantity of MW) for the DRA/TCA, needs to consider both the cost of providing the availability, as well as the potential costs associated with curtailment when asked to do so in the real time energy market. This second set of costs requires a DRAP to make an estimate of the number of activations they may experience.

The cost elements associated with curtailment are specific to each individual participant based on a number of business and operational factors and no two participants are likely to have the same characteristics, inputs or outcomes. Accordingly, AMPCO is not in a position to provide an approximate percentage value that each element would account for in the total auction price and that would be reflective of the cost elements of a class of resources.

Factors that may be considered in determining capacity auction offers include:

1. <u>Cost per Curtailment</u>:

- Lost opportunity
  - Forecast production schedule and flexibility (i.e. is the plant's output completely sold out, or can lost production be made up later?)
  - Product type being made at the time
  - Product margins at the time
  - Product energy intensity
  - Foreign exchange rates
  - Business Reputation Risk (i.e. will curtailments affect the DR resource's high value customers, thereby damaging DR resource's reputation, future business opportunities, prices, etc.?)
  - Inventory Costs

- Semi-variable cost recovery
  - Labour costs
  - Other Overhead costs for production facility

2. <u>Number of Curtailments</u>:

- Entity's Risk Tolerance (could change seasonally or could be variable depending on market conditions)

- Weather Impact (Frequency of activations)
  - Winter Forecast
  - Summer Forecast
  - Unusual weather events (e.g. polar vortex)

- Length of Curtailment Risk
  - HDR risk is between 1 to 4 hours of curtailment
  - DL could be 5 minute to full availability window (9 hrs)
  - Curtailment costs increase as duration increases

- Natural Gas/power price forecast

- Market Price Risk (i.e. the potential for changes in the electricity market supply that could have impacts on price)

3. <u>Other Considerations</u>:

- Availability Risk
  - Possibility of penalties

- Administration costs
  - Contract management
  - Metering
  - Daily Bidding

- Individual Department risk
  - Energy Intensity of upstream and downstream operations that are impacted
  - Equipment wear and tear

- Shut down/Start up risk (for all impacted equipment)

(b) Yes, the above-mentioned utilization payment proxy sometimes used by DR Resources also relates to costs of being activated. See part a) for a listing of potential costs.

In the DRA, participants can only recover their costs in their auction offer, while assuming the risk that they may be activated for more hours than they have forecast.

The costs above refer to a typical Dispatchable Load ("DL") or an Hourly Demand Response Resource ("HDR"). The difference to consider is DL's may be activated for as short a period as 5 minutes or as long as 9 hours with no limit on the number of activations per day, whereas HDR activations are currently 4 hours in length (and could be as short as 1 hour), and they can only be activated once per day.

(c) As set out in AMPCO's evidence (Affidavit of Colin Anderson, paragraphs 15-20) DR resources may or may not incorporate utilization amounts in their capacity offers.

The circumstances in which a specific resource will incorporate these elements are driven primarily by the entity's risk tolerance, and its perspective on activation probabilities. For example, a DR resource that feels it will likely be activated will probably include utilization amounts in its capacity offers. A resource that feels the probability of activation is very low may not incorporate such elements.

The decision on whether to include or not is entity specific and driven by its approach to offers and one or more of the various factors listed in response to part (a) and any other factors or considerations relevant for that entity.

(d) Costs associated with curtailments typically increase the entity's operating, maintenance and administration (OM&A) costs and are therefore not typically capitalized. Capital costs would generally be included by DR resources in their capacity offers exclusive of any "utilization payment" proxy workaround.

(e) In general, any individual load is going to have the same approach to offering, unless its costs change between the two different timeframes (DACP vs real time (RT)). For example, a load facility's production schedule could (theoretically) change between the DACP and RT time horizons, which could fundamentally change the entity's desire to consume – which would manifest itself in different offers between the two time horizons.

In regards to a DR resource that has a DRA position versus one that does not, offer strategy is participant specific. It is possible that, all other things being equal, the entity with the DRA position could have a lower bid, but this is not necessarily the case since no two participants have identical cost profiles.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to Staff #2

Reference: (FERC) Order No. 745 Demand Response Compensation in Organized Electricity Markets, March 15, 2011, paragraphs 24, 25, 28, 42, 43, 57, 60, 63, 103, 104, footnote 199, paragraphs, 105, 107, 108, footnote 208, paragraphs 110, 111, 114.

Reference Commissioner Moeller's dissenting opinion page 4, paragraph 3; page 4, footnote 11; page 5, paragraph 2; page 5, footnote 12; page 7, paragraph 1; page 7, footnote 21, page 8, paragraph 1, page 8, footnote 26; page 8, footnote 27; page 8, footnote 29; page 9, paragraph 1; page 9, footnote 33; page 10, paragraph 1.

Preamble:

The paragraphs and footnotes listed in the reference above deal with how FERC's decision relating to the payment of LMP for demand response activations interacts with the fact that many potential demand responders in the electricity markets under FERC's jurisdiction pay state-level regulated retail rates for the energy they consume. This appears to be quite different as compared to the Ontario electricity market where potential demand responders typically pay either the market clearing price determined in the Real Time Energy Market (for Class A loads), or the Hourly Ontario Energy Price (HOEP) plus a volumetric charge for Global Adjustment (for Class B loads).

The contrast between the U.S. discussion and the Ontario discussion suggests differences in how demand responders participate in the IESO-administered markets in Ontario as compared to similar demand responders in U.S. FERC-regulated electricity markets.

Questions:

(a) What differences between demand response participation in energy markets in the U.S. and in Ontario are you aware of?

(b) Are any such differences relevant to the question of energy payments for the economic dispatch of demand response resources in Ontario? If so, why?

Response:

AMPCO does not have particular expertise in the nuances of energy markets, and DR resources participation within those markets, in the various FERC regulated US jurisdictions (which are PJM Interconnection (PJM), New York Independent System Operator (NYISO), New England ISO (ISO-NE), Midcontinent ISO (MISO), Southwest Power Pool, (SPP) and California ISO (CAISO)). Questions on particular market differences between one or more of these markets and the Ontario electricity market might be best addressed by the IESO.

There are two issues discussed by FERC in the various paragraphs referenced in connection with this question in respect of which AMPCO can contribute its view:

1. The relevance of the fact that some of in the U.S. jurisdictions considered large electricity customers pay retail rather than wholesale market rates.

2. Whether DR resources would be overcompensated by receiving energy payments set at what FERC refers to as the full “locational marginal price” (LMP), rather than receiving energy payments of LMP-G where G is the retail electricity cost avoided by the DR resource operator.

Related to these two issues is the importance, in AMPCO’s view, of the “net benefits test” adopted by FERC in order to ensure that compensation of DR resources with energy payments provides a benefit to electricity consumers (i.e. reduces overall electricity costs).

In respect of the first issue – the relevance of the fact that in some of the U.S. jurisdictions considered large electricity customers pay retail rather than wholesale market rates – the implication of this difference that has been suggested in the context of considering energy payments for DR resources is that, in these U.S. jurisdictions, but for the energy payments the DR resource operators would not be responsive to wholesale market prices. In Ontario, where large electricity customers pay real time energy market prices, they have direct price signals which influence their consumption choices and behaviours, even without energy payments.

The second issue – the impact of avoided energy costs on appropriate energy payments to DR resources – relates to theoretical optimization of economic efficiency.

FERC addressed both of these issues in examining the appropriateness of energy payments for DR resources from the perspective of the market, not the individual customer. At paragraph 62 of its March 15, 2011 decision FERC stated:

> *In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for individual resources participating as supply resources in the organized wholesale electricity markets and will not here, as*

> *requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of LMP to supply resources clearing in the day-ahead and real-time energy markets encourages "more efficient supply and demand decisions in both the short run and long run," notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.*

In the result, FERC found [paragraph 47, page 39] it appropriate to pay demand response resources *LMP "in order to compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO"*, and thus in order to *"result in just and reasonable rates for ratepayers".*

FERC went on to qualify its finding by requiring that two conditions be met to establish the appropriateness of compensating DR resources at the wholesale energy price (LMP in those jurisdictions) for the service provided [page 39, paragraph 42]. These two conditions are that;

1. the DR resources have the capability to provide the service, i.e. to displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand; and

2. payment of the LMP for the provision of the service by the DR resources must be cost-effective, as determined by the net benefits test described.

A properly constructed net-benefits test was required by FERC in order to [page 3, paragraph 3]:

> *… ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources*. *When the net benefits test described herein is satisfied and the demand response resource clears in the RTO's or ISO's economic dispatch, the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.*

From AMPCO's perspective a properly constructed and applied, Ontario specific, net benefits test is required in order to ensure that a demand response resource will only be paid for energy in a situation where it is cost-effective from the market's perspective (i.e. the consumer's perspective) for that resource to be utilized. This means that the interests of all consumers are served by implementing energy payments because the utilization of the specific demand response resource in question is the most economically efficient action that can be taken to satisfy the need. A properly constructed net-benefits test would take into account any Ontario specific considerations to ensure such a result (such as, for example, out of market settlements and the Global Adjustment).

If the net-benefits test is not passed, no energy payment is made.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to SEC #1

Reference: Notice of Appeal, para. 24, 51.

Preamble:

AMPCO states that the Market Rules amendments at issue are "inimical" and "contrary" to many of the objectives of the [*Electricity Act*] including 1(f).

Question:

Please explain how AMPCO believes the Market Rules amendments at issue are inconsistent with the objective "to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".

Response:

AMPCO believes that more competition results in lower prices and higher levels of adequacy, reliability and quality of electricity service. AMPCO further believes that inviting generation resources which receive energy payments upon activation to compete against DR resources which do not will undermine competition for the provision of capacity resources, replacing one set of resources (DR resources) with another (generation resources).

AMPCO also believes that proceeding with a broadened capacity auction prior to addressing the availability of energy payments for DR resources is a step backwards in evolving towards a more competitive capacity auction process in particular, and a more competitive wholesale electricity market in general. Taking such a step creates unnecessary uncertainty and displacement of resources from their traditional market role, thus undermining confidence in the market and thus competition and better (i.e. lower) pricing in the longer term.

As stated by the IESO in evaluation of the success to date of its Demand Response Auction (DRA) program [as excerpted at AMPCO Application, page 5, paragraph 19, emphasis added];

> *As the electricity system moves toward competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand*

> *response will <u>increase competition leading to overall lower prices for Ontario Consumers</u>.*

Similarly, in its ruling on Order 745, FERC noted [as excerpted at AMPCO Application, page 10, paragraph 38, emphasis added];

> *In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets <u>"expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability</u>".*

The overall objective of the IESO's Market Renewal Program is to encourage and enhance competition [IESO Transitional Capacity Auction: Phase I Design Document, April 11 2019, page 1];

> *Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues.*

In respect of capacity auctions in particular, the IESO has stated [IESO Incremental Capacity Auction High-Level Design: Executive Summary, March 2019, page 1]:

> *The [Incremental Capacity Auction] will help us to prepare for [a future period of capacity requirement] by allowing more resource types to compete to provide future capacity, enabling the IESO to flexibly meet the province's adequacy needs.*

The success of a capacity auction hinges on expanding participation in competition for the provision of capacity [IESO Incremental Capacity Auction High-Level Design: Executive Summary, March 2019, page 3]:

> *One of the advantages of the [Incremental Capacity Auction] is that all eligible sources of capacity – new and existing, on both the supply and demand sides – compete with each other, regardless of resource type. …From the perspective of meeting adequacy needs, there is no functional difference between a megawatt of power from an electricity generating facility and a megawatt of reduced consumption from demand response.*

As related at paragraphs 25 and 26 of AMPCO's application, requiring DR resources to compete against generators without resolving the issue of fair and non-discriminatory compensation for DR resources for the value they provide to the energy market would undermine the current success of the Demand Response Auction and handicap DR resources from successfully competing within their own existing platform, because;

a. generators will bid into capacity auctions taking into account their anticipated energy payments; and

b. DR resources will have to complete against these bids without an equivalent energy payment stream, putting DR resources at a competitive disadvantage to generators in the expanded capacity market.

The IESO has recognized just such an issue in the context of compensating DR resources for "out of market" (i.e. test) activations. In a presentation provided on this issue to the Demand Response Working Group on June 19, 2019 [pages 36 *et seq.*], the IESO noted that *"[o]bserved bid prices and stakeholder feedback indicate that activation costs (explicit and opportunity) can be significant for HDR [hourly demand response] resources"*. The IESO further noted:

- When other resource types (dispatchable load, generator, import) are dispatched out-of-market they are eligible for some form of "make whole payment"

- *HDR resources do not receive a make-whole payment for out of market activiations*

- *These costs may be reflected in their capacity offers potentially increasing the cost of the capacity*

- *In the context of the proposed capacity auctions, where HDR will be competing against other resource types, how these costs are recovered will potentially impact market efficiency*

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to SEC #3

Preamble:

SEC wishes to better understand the impact on ratepayers of the Market Rule amendments at issue, and AMPCO's position that Demand Response providers should be eligible for energy payment.

Question:

Please provide AMPCO's views, including copies of any analysis that it has undertaken or is aware of, regarding impact on costs that will ultimately be borne by Ontario ratepayers of providing energy payments to Demand Response providers.

Response:

AMPCO has not undertaken any analysis on this issue.

In AMPCO's view which includes consideration of the perspectives of the majority of AMPCO's members who are not DR resource providers and for whom the lowest possible electricity costs are of paramount importance, the interests of Ontario consumers would be fully and appropriately protected by the development and application of an Ontario specific "net benefits test", as was required by FERC as a pre-condition to energy payments for DR resources. Please see AMPCO's response to OEB Staff interrogatory 2.

In AMPCO's view, this is the primary issue which the IESO's now launched [Affidavit of David Short dated October 25, 2019, paragraph 21-27 and Exhibit K] stakeholder engagement on energy payments for DR resources should be focussed on.

OEB STAFF INTERROGATORY 3

INTERROGATORY

Ref: Memorandum of Michael Lyle, Vice-President, Legal Resources and Corporate Governance; Chair, IESO Technical Panel to IESO Board of Directors, dated August 20, 2019

Preamble:

On page 3, paragraph 2 of the above noted Memorandum, Mr. Lyle states:

> *The IESO takes the position that the proposed Phase I market rules do not unjustly discriminate against DR resources. Phase I initiates a process that will allow more market participants to access a capacity auction, thereby increasing competition and providing the greatest value for ratepayers while meeting a growing reliability need.*

Question:

Please explain how the IESO has come to the conclusion that the TCA Phase I market rules do not unjustly discriminate against DR resources.

RESPONSE

The TCA market rule amendments introduce new competition to the IESO's capacity auction, which will enhance economic efficiency. The IESO is unaware of any reason to conclude that such competition from new resource types would result in unjust economic discrimination against any class of market participants in form or effect.

The TCA rules are built upon the existing, underlying design of the IESO energy market, in which demand side resources do not, and have never received, energy payments for load reduction. The TCA market rule amendments do not deviate from the underlying design, nor do they introduce new differences in treatment between demand-side and generation resources.

If the IESO were to adapt a FERC-style "net benefit test" for determining when energy payments to DR resources may be warranted, it is unclear that it would demonstrate any net benefit to Ontario consumers. The only Ontario specific evidence before the Board on this point comes from Navigant who concluded that "more DR activations (as a result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced cost to consumers since generators have their compensation guaranteed". In other words, any reductions in the IESO market price may simply be offset by out of market Global Adjustment payments which are ultimately paid by consumers.

Moreover, based on the historical infrequency of DR resource activation in the DRA, and the IESO's short-term forecast for capacity need, the IESO estimates a very low probability of economic DR resource activation during the TCA commitment period. Given this low probability of DR resource activation, theoretical access to energy payments should have no material impact on DR auction offers, and so should have no effect on their competitiveness in the auction.

OEB STAFF INTERROGATORY 8

INTERROGATORY

Ref: Presentation to IESO Board - IESO Market Rule Amendments: Transitional Capacity Auction, August 28, 2019, p.6

Questions:

(a) IESO staff notes at slide 6 in the presentation that "Access to energy payments for DR resources with a capacity obligation has not been material historically nor is it expected to be material under the TCA rules for the December 2019 auction". Please explain this statement, including the meanings of "access" and "material" in this context.

Further on slide 6, IESO staff also notes "Economic activations of DR resources have been very limited to date, and we do not expect the likelihood of economic activation to increase appreciably in 2020".

(b) Please clarify the number of economic activations of DR resources in each year since the DRA was introduced in 2015 for: (1) HDR resources; and (2) Dispatchable load resources.

(c) Please describe the IESO's expectations for 2020 in relation to the number of economic activations of DR resources under the current TCA design. Please describe the anticipated market conditions (such as total load, MCP and/or HOEP) at times when activations, if any, would be expected.

(d) Would IESO expect the frequency of activations to change if DR resources received an energy payment and, if so, how?

RESPONSE

(a) In the referenced statement, the term "access" means an opportunity for a DR resource to receive an energy payment if activated. The IESO stated that access has not been historically "material" because HDR resources have only been economically dispatched on one occasion since the introduction of the DRA in 2015 and dispatchable loads have been dispatched less than 1% of the time over that same time period.

Based on the historical infrequency of DR resource activation in the DRA, and the IESO's short-term forecast for capacity need, the IESO estimates a very low probability of economic DR resource activation during the December 2019 TCA commitment period. Given this low probability of DR resource activation, theoretical access to energy payments should have no material impact on DR auction offers, and so would have no effect on their competitiveness in the auction.

(b) The number of activations under the DRA by year are shown on the table below for DL resources only.

	Activation (Interval Based)	Percentage of All Intervals within hours of availability (Interval Based)	Activation (Hourly Based)	Percentage of all hours within hours of availability (Hourly Based)
2016 (Since May 1st)	244	0.40%	74	1.45%
2017	142	0.20%	44	0.72%
2018	79	0.10%	34	0.49%
2019 to date	64	0.09%	23	0.38%
Total	529	0.18%	175	0.72%

Where:

- Activation (Interval Based) – Occurrences (count of intervals) that DLs were activated
- Activation (Hourly Based) – Occurrences (count of hours) that DLs were activated

Percentage of all hours within hours of availability - percentage of all hours within the availability window of the mentioned period

There has only been one activation for three hours of an HDR resource, this occurred in July, 2019.

(c) The IESO does not anticipate any change in the frequency of activations for the December 2019 commitment. There has been no material change in the target capacity for the December 2019 commitment period (675 MW for summer and winter commitment periods) as compared to the December 2018 commitment period (611 MW for summer and 606 MW for winter). The total target capacity is negligible in the context of total system need.

The IESO does not anticipate any activations of HDR resources during the December 2019 commitment period.

The IESO does not anticipate any activations of HDR resources and anticipated a similar historical activation of DL resources during the December 2019 commitment period.

(d) No. For the reasons described in paragraph (a), the IESO would not expect any energy payments to be material in respect of the December 2019 commitment period. Therefore, the IESO does not expect that the availability of an energy payment would influence frequency of activations of DR resources. As Navigant stated in section 3.1.5 of its report (Exhibit "I" to the Affidavit of David Short sworn October 25, 2019, "[l]arge commercial and industrial customers with a high value of lost load are not likely to change their bids into the energy market because of utilization payments".

OEB STAFF INTERROGATORY 10

INTERROGATORY

Ref: Reasons of the IESO Board in respect of an amendment to the market rules, August 28, 2019, p.4

Ref: IESO stakeholder engagement web page – Energy Payments for Economic Activation of Demand Response Resources[1]

Preamble:

The document containing the reasons of the IESO Board decision on the TCA market rule amendments discusses FERC's decision to require energy payments to DR resources when they are dispatched subject to the condition that they meet a "net benefit requirement". It also notes that it is not clear that the FERC analysis and conclusion is applicable to Ontario given the differences between the Ontario and U.S. electricity markets. As a result, further analysis was required and the IESO had committed to completing that analysis and engaging stakeholders.

The document further notes that AEMA and AMPCO believe it is appropriate to delay implementation of the auction until the analysis is completed. However, the IESO concluded that a delay was not warranted and would be detrimental to the market overall. According to the IESO website, the stakeholder engagement process discussed above that is analyzing the issue of energy payments to DR resources will be completed in June 2020, with a final IESO decision issued at that time.

Questions:

(a) Please describe the IESO's expectations of the detrimental impact to the Ontario electricity market overall in the event of a delay to the implementation of the TCA.

(b) Please identify the "the differences between the Ontario and U.S. electricity markets" that were taken into consideration by the IESO Board.

RESPONSE

(a) The potential impact to the Ontario electricity market in the event of a delay to the implementation of the TCA is described in the affidavit of David Short sworn October 25, 2019.

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[1] http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Energy-Payments-for-Economic-Activation-of-DR-Resources

(b) The IESO Board was advised of Navigant's conclusion that the arguments for and against the provision of energy payments to DR resources are "nuanced and prudent" (see slide 5 of Market Rule Amendments: Transitional Capacity Auction, August 28, 2018). As reflected in the IESO Board's reasons, the IESO Board considered whether any reductions in the IESO market price resulting from payments to DR resources would meet the net benefit test in Ontario given the effect of Global Adjustment payments. The Board recognized that further analysis of the issue was required.

OEB STAFF INTERROGATORY 14

INTERROGATORY

Reference:

IESO Evidence, November 8, 2019, Tab A, p.8; OEB Staff IR #8, p.2

In the IESO evidence, the IESO noted that dispatchable loads have been economically dispatched less than 1% of the time since the DRA was introduced. Based on the table provided by the IESO in the response to OEB Staff interrogatory #8, the actual number of "interval based" activations of dispatchable load resources is 525, since May 2016, and the chart below, prepared by OEB staff using the data in the IESO's table referenced above, shows the number of economic activations in each year.

Questions:

(a) Please explain why there has been such a significant (i.e., four-fold) and consistent decline in dispatchable load activations since 2016 -- from 244 to 64 – as part of the IESO's DRA.

(b) IESO stated in its response to OEB-Staff-8 that it expects 2020 DR economic activation frequency not to differ from 2019 levels. Please describe the currently expected frequency of economic activations in 2021, 2022, and 2023.

(c) Is any change in DR economic activation frequency upcoming years (relative to prior years) to be attributed to the procurement of both generation and demand response resource commitments via the same auction process?

RESPONSE

(a) As Board staff notes, dispatchable loads participating in the DRA have rarely been economically dispatched since the DRA was introduced. Dispatchable load activations are a function of the participant's bid relative to the market price. The IESO has not conducted any analysis to assess the reasons for the decline in activations.

(b) Based only on historical bids of dispatchable loads, the IESO would expect little change to the frequency of economic activations for DR resources in 2021, 2022, or 2023.

(c) See (b), above.

IESO'S RESPONSES TO SEC INTERROGATORIES

SEC INTERROGATORY 1

INTERROGATORY

SEC wishes to better understand the impact on ratepayers of the Market Rules amendments at issue, and AMPCO's position that Demand Response providers should be eligible for energy payment, Please provide the IESO's views, including a copy of all analysis that is has undertaken or is aware of, regarding impact on costs that will ultimately be borne by Ontario ratepayers of providing energy payments to Demand Response providers.

RESPONSE

The IESO has not yet performed analysis of the impact on Ontario ratepayers of making energy payments to DR resources. In its report, Navigant noted that any reductions in the IESO market price may simply be offset by out of market Global Adjustment payments. As described in the response to OEB Staff 5, the IESO has initiated a consultation with stakeholders and will be undertaking a study on this issue.

SEC INTERROGATORY 2

INTERROGATORY

Please provide a copy of all analysis that IESO has in possession regarding potential energy payments to Demand Response providers.

RESPONSE

See the Demand Response Discussion Paper dated December 18, 2017 prepared by Navigant and the associated PowerPoint presentation (attached as Exhibits "I" and "H" to the affidavit of David Short sworn October 25, 2019).

IESO RESPONSES TO SCHOOL ENERGY COALITION SUPPLEMENTAL INTERROGATORY

SEC INTERROGATORY 7

INTERROGATORY

Reference**:**

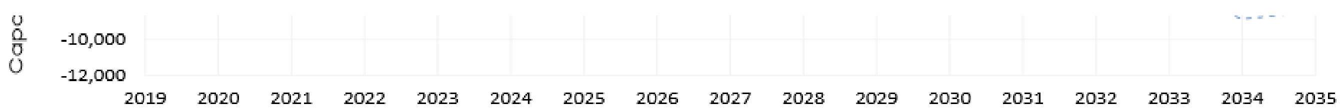
IESO Evidence, para. 1

Question:

Is there a forecast capacity gap before the summer of 2023? If so, please provide details.

RESPONSE

Yes. Refer to IESO Evidence, Tab 15 "Technical Planning Conference Presentation September 13, 2018", slide 51. See row on "Summer Adequacy: Reference Outlook Without Existing Resources" :



Capacity Surplus (+)/Deficit (-) (MW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer Adequacy: Reference Outlook	1,454	81	622	433	-1,377	-1,673	-3,711	-3,099	-2,536	-2,330	-2,118	-2,065	-2,192	-1,729	-1,895	-1,625	-1,566
Summer Adequacy: Reference Outlook Without Existing Res.	847	-811	-335	-583	-3,844	-4,686	-6,878	-6,736	-6,292	-6,018	-8,689	-9,096	-10,077	-10,418	-10,475	-10,724	-11,273
Winter Adequacy: Reference Outlook	2,091	1,364	1,408	1,698	435	-192	-1,229	-1,770	-1,343	-366	47	825	184	-2	983	-176	523
Winter Adequacy: Reference Outlook Without Existing Res.	2,060	710	1,143	1,410	-1,085	-2,263	-4,063	-5,124	-4,838	-3,675	-4,833	-5,451	-7,344	-7,921	-7,306	-8,834	-8,419

Connecting Today.
Powering Tomorrow.
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SEC INTERROGATORY 11

INTERROGATORY

Reference**:**

IESO Evidence, para. 77

Question:

Using the most recent DR Auction clearance price as a proxy the TCA auction clearance prices, please provide an estimate of the total amount expected to be paid through the TCA.

RESPONSE

The IESO does not believe it is appropriate to use the most recent DR Auction clearing price to determine the value of the upcoming TCA.

However the IESO can provide the total estimated cost of the DR Auction conducted in December, 2018, which will be approximately $44M. The total amount of capacity cleared was:

1. Summer Commitment Period (May 01, 2019 - October 31, 2019) – 818.4 MW
2. Winter Commitment Period (November 01, 2019 - April 30, 2020) – 854.2 MW

The estimate does not consider the actual performance of the DR resources.

SEC INTERROGATORY 12

INTERROGATORY

Reference:

IESO Evidence, para. 92(b)

Question:

The IESO has provided its view on its expectation regarding the frequency of economic activation of DR resources. On a comparative basis, what is its view on the forecast quantity of energy that the generators who have capacity obligations as a result of the TCA will produce.

RESPONSE

The IESO's expectations with respect to economic activation of DR resources is informed by four years of successful DR auctions and stable demand and supply conditions forecasted for 2020. The IESO and the MSP have had an opportunity to examine DR resource bids and their associated economic dispatch frequency. By contrast there is no energy market history for generators with capacity auction obligations relative to which the IESO can form a comparable view.

SEC INTERROGATORY 14

INTERROGATORY

Reference:

KingstonCoGen, Evidence of Brian Rivard, para. 73

Question:

Please provide the IESO's views on the information that Mr. Rivard says is required for the IESO to develop a net benefits test.

RESPONSE

The IESO is in the process of studying the issue of energy payments and the possibility of developing a net benefits for Ontario. The IESO has not yet determined what additional information would be required to develop an Ontario-specific net benefits test. The IESO will consider the comments of Dr. Rivard as part of its work

OEB STAFF

KCLP-Staff-1

INTERROGATORY

Ref: Evidence of Brian Rivard, p.34

Ref: IESO Evidence, p.17

Preamble:

In the evidence of Brian Rivard, it states:

> "When lower energy bid prices of DR resources cause the energy market price to fall …. the amount of net revenues earned by the committed generators falls in proportion to the price decrease … 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."

Question:

> According to the IESO, the amount of generation coming off contract will be "significant" in 2023 at "approximately 4,000 MW" and the amount of off-contract generation will continue to grow thereafter. Under the scenario described above (i.e., lower energy bid prices of DR resources cause the energy market price to fall), would the net benefit get larger over time and would it become more likely that the net benefits test condition will be satisfied in Ontario (i.e., less affected by the GA)?

RESPONSE:

As contemplated under FERC Order 745, the net benefits test compares the "***benefit***" that non-DR consumers realize from the lower market price, against the "***cost***" they incur to compensate the DR-resources to curtail demand. When benefit exceeds cost, FERC Order 745 concludes that there is a net benefit to non-DR consumers and hence it is cost-effective to compensate DR resources to curtail demand.

In Ontario, the size of the benefit is lower because of the Global Adjustment. The ***benefit*** to non-DR consumers from the lower market price represents a ***loss*** to those generators that earn lower net revenues from the lower market price. The lost net revenues reduces the amount of fixed cost that the generators can recover through the IESO wholesale market. These include the capital costs the generators incurred to build generation capacity and the costs they must continue to incur to maintain generation capacity in the province. The province compensates these generators for the lost net revenues through payments made under IESO contracts or rate regulation. Ontario consumers make these payments through the Global Adjustment. As a result, the monthly benefits that non-DR consumers realize from lower market prices are offset by a higher monthly Global Adjustment charge. The IESO data provided to me indicates that, at least historically, the benefits to non-DR resources from the lower monthly market prices would have been more than offset by the higher monthly Global Adjustment charges had FERC Order 745 been implemented in Ontario.

As generators come off contract, the relationship between the monthly market prices and the Global Adjustment will change. However, I am unable to say exactly how this change will impact the net benefits test. As existing generation resources come off contract, if the IESO wishes to rely on that capacity in its system planning, the IESO will need to identify a mechanism to compensate those generators for their fixed operating costs required to maintain their facilities as a going concern. Historically, in Ontario this has been done using long-term contracts funded through the Global Adjustment mechanism. If the IESO elects to re-contract with existing or new generation resources to meet the forecasted capacity gap starting in 2023, then the chances that the net benefits test is passed in Ontario may in-fact get smaller in the future.

The IESO has already commenced a separate stakeholder engagement initiative entitled *Energy Payments for Economic Activation of Demand Response Resources*, and has engaged the Brattle Group to study the issue further.[1] The Brattle study is due to be published Q1 2020, and the IESO is targeting June 2020 for its rationale and final decision on energy payments for DR resources. This will be completed long before the forecasted 2023 capacity gap arises.

Finally, in my view, the FERC Order 745 net benefit test is problematic in that it is a static test that does not properly capture the longer-term costs and benefits to consumers. In particular, existing generators will still need to recover their fixed operating costs if they are going to maintain their generation capacity, and new generators investing in the province will need to cover their capital investment costs. Furthermore, if the IESO is to maintain reliability (i.e., satisfy its resource adequacy reliability requirement) it will need to compensate generators for these costs (the IESO cannot maintain reliability with only non-generation resources, such as Demand Response). To do so, the IESO will have to either re-contract with generators, provide generators with higher payments through the TCA or compensate generators through some other means. Ontario consumers will be responsible for covering these costs. In this way, the

[1] Affidavit of David Short at paras. 84-88.

payments Ontario consumers currently provide generators through the Global Adjustment will have to be made through some other means.

In my opinion, if the intent of the FERC Order 745 net benefits test is to compensate DR resources for curtailing demand, only when it is to the benefit of non-DR consumers, it should factor in the longer-term implications of ensuring a reliable amount of generation capacity in the province.

<u>WITNESS</u>: Brian Rivard

1.2 KCLP-2

Interrogatory

Reference: LEI Report, section 3.2.2, pp. 10-11

Preamble: The LEI Report states that Figure 5 presents for illustrative purposes PJM's monthly NBT prices from April 2012 to October 2019, along with the monthly average prices for PJM – RTO Zone. It states that the chart is illustrative as the test is actually applied to each applicable zone on an hourly basis.

Questions:

(a) Can you confirm that the net benefits test price threshold in PJM is calculated monthly using a system-wide monthly supply curve that is smoothed using non-linear estimation techniques?
(b) Can you confirm that this singular system-wide threshold is compared to the various locational marginal prices (LMPs) on an hourly basis to determine DR resources are eligible for compensation?
(c) In your opinion, are there any shortcomings of applying this system-wide threshold to hourly LMPs for determining a net benefit to consumers from compensating DR resources?
(d) Would you recommend the same approach be applied to Ontario? If yes, why and if no, why not?

Response

(a) As laid out in PJM's *Manual 11: Energy & Ancillary Services Market Operations, Revision: 107,* Section 10.3.1 (effective September 26, 2019), the aggregate supply curve for PJM is smoothed using a non-linear least squares estimation technique.

(b) The system-wide threshold is compared to applicable LMPs; this can be on an hourly basis (e.g. in the case of the day-ahead market) or on a five-minute basis (e.g. in the case of the real-time market).

(c) Yes. Comparing the LMPs to a system-wide threshold poses a degree of administrative burden on market institutions, while potentially oversimplifying net benefit calculations given the possible diversity in how load to customers is priced and the nature of their financial hedges, among other factors.

(d) No. We do not believe that Order 745 is relevant to the specifics of the Ontario market. Any test developed for Ontario should at a minimum take into account Ontario-specific conditions, including the Global Adjustment and how it is recovered, as well as more generally how supply is priced to various types of load in Ontario and over what time period, and the expected evolution of the Ontario market.

1.4 KCLP-4

Interrogatory

Reference: LEI Report, Section 3, Pages 7-14

Rivard Affidavit, Paragraphs 56-58

Preamble: At section 3 (pages 7-14) of the LEI Report, LEI provides an overview of FERC Order 745 and the net benefits test.

At paragraphs 56-58 of the Rivard Affidavit, Mr. Rivard draws a distinction between the net benefits test and economic efficiency.

Questions:

(a) Please identify any points on which LEI is in agreement with, or disagrees with, Mr. Rivard's assessment of the net benefits test and economic efficiency. If LEI generally agrees with Mr. Rivard, please confirm this.
(b) If LEI disagrees with any aspect of Mr. Rivard's assessment, please explain the basis of this disagreement.
(c) Based its research conducted, has LEI formed an opinion regarding the economic impacts of providing energy payments to DR resources? If yes, please state the opinion.
(d) Is LEI of the opinion that providing energy payments to DR resources could lead to economically inefficient outcomes both during the TCA, and in the event that a DR resource is dispatched? Please explain.

Response

(a) LEI's disagreement with the assessment of the net benefits test lies primarily with regards to its relevance to the Ontario situation. With regards to economic efficiency, LEI's concern is with regards to the fidelity of the price signal and the need for a more nuanced approach to the concept of horizontal equity.

However, LEI agrees that any consideration of whether and how market rules are developed to incorporate an activation payment must take into account the incentives Class A customers receive under the ICI to adjust their consumption.

(b) LEI believes that the discussion of horizontal equity is over-simplified. Fossil generators are not expected to guess how many times they will operate and at what fuel price, and to incorporate those assumptions into their capacity bids because they will not be paid an energy price when run. While the theoretical premise is that generators will reduce their capacity bids by the margin above fuel costs that they expect to achieve, generators do expect to receive at least their short run marginal costs when dispatched, and configure their bids accordingly.

A framework in which DR receives only capacity payments but no activation payments will drive DR participants to set high activation price thresholds. This may dull the effectiveness of the price signal at relatively high price periods (such as periods when the market price is high, but remains below the DR activation threshold). Short run costs of activation include process wastage (for example disposing of unfinished and unfinishable products) and staff inefficiencies; allowing compensation for these costs rather than expecting companies to factor them in to their activation threshold (i.e. the price trigger at which load would be curtailed) is more consistent with horizontal equity in that it is equivalent to generators being paid for fuel and other short run variable operating costs through their energy bids.

(c) Given the short time period in which to develop its analysis and respond, LEI's opinions are preliminary and subject to change. With that caveat in mind, LEI's views are as follows:

Based on the markets and programs LEI reviewed in its report, actual activation of DR resources has been relatively limited, and DR resource revenues from this activation have also been limited (as compared DR capacity revenues, see Section 4.4 of LEI's report). This implies that, from a practical perspective, the benefit or harm arising from whether DR resources are provided energy payments may not be material in the near term.

LEI's understanding is that the IESO's proposed design is the subject of this proceeding and alternative approaches are not within the scope of the case. Nevertheless, LEI believes that, conceptually, there is merit in separating the reservation payment embodied in a capacity payment from an activation payment which occurs when the resource is actually deployed. In such a market design, bidders into the capacity auction need not consider the frequency of deployment or build in a risk premium when submitting their capacity bid. Were market rules devised which allowed a two part bid from DR resources in which they set forth both their required activation payment and the activation price threshold, DR resources would receive a payment, and their DR activation bids would reflect both the benefit of avoiding a cost and the cash payment required to address specific costs of activation. LEI believes that such an approach would result in greater variation of DR activation bids leading to a more robust price signal. LEI also notes that behavior responses to avoidance of cost versus those to receipt of a benefit may differ; creating a hybrid of the two may produce more economically efficient outcomes.

(d) LEI believes that any assessment of economic efficiency needs to be based on the specific market rules being applied, and the period of time being analyzed. Furthermore, the fact that something ***could*** happen does not mean that it ***will*** happen; analysis needs to take into account probability, frequency, the degree of harm, safeguards, and net benefits before coming to a determination.

1.6 KCLP-6

Interrogatory

Reference: LEI Report, Section 5, pages 33-39, Rivard Affidavit, Paragraphs 58-71

Preamble: At Section 5.4 (pages 37-38) of the LEI Report, LEI identifies the impact of Global Adjustment in Ontario, which according to Figure 30 accounts for 77% of the total electricity wholesale costs (excluding transmission and distribution costs) in Ontario.

At paragraphs 58-71 of the Rivard Affidavit, Mr. Rivard provides an analysis of the impact of Global Adjustment on the calculation of the net benefits test in Ontario.

(a) Does LEI agree with Mr. Rivard that 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 in Ontario?
(b) Does LEI agree with Mr. Rivard that as a result of the Global Adjustment, the net benefits test will be satisfied less frequently (if ever) than in the US markets?
(c) With specific reference to paragraphs 58-71 and Figures 5, 6 and 7 of the Rivard Affidavit, please explain whether LEI generally agrees or disagrees with Mr. Rivard's analytic approach and Mr. Rivard's findings?

Response

(a) Yes; however, as Ontario is not under FERC jurisdiction, and the market framework has significant differences, the test is not relevant.

(b) LEI does not believe that the net benefits test as configured for US markets is appropriate for developing market rules in Ontario. Due to the generally inverse correlation between Ontario wholesale market prices and the Global Adjustment, there are some changes to Ontario market rules which could improve transparency and change wholesale price outcomes without having an immediate bill impact. However, such rule changes could still incentivize changes to investment and operating behavior which over the long run would still provide benefits to consumers.

(c) Because LEI questions whether the net benefits test as configured for US markets is relevant to Ontario, LEI regards the analysis as largely academic. LEI nonetheless has the following observations:

1. The analysis is largely static; it does not assess how the behavior of various market players would change as a result of the changes in market conditions.
2. Using historical data is a beginning, rather than an end, to the analysis; consideration of future changes in price dynamics is helpful in exploring the impact on final consumers.
3. Changes that impact even a very small number of overall hours may nonetheless be worthwhile, to the extent that they improve the value of the price signal during super-peak hours.

4. The analysis may be targeted at the wrong question: a better question is, under what circumstances would providing energy payments to demand response be beneficial for Ontario, and what tests should be designed to confirm that those circumstances prevail at the time?
5. LEI believes that Ontario should pursue a pragmatic approach based on sustained incremental improvements to market rules, which where appropriate is substantiated by dispatch modeling and scenario analysis.

Energy Payments for Economic Activation of Demand Response Resources

Comments on the Stakeholder Engagement Plan presented on October 10, 2019

Don Dewees

Market Surveillance Panel

18 November 2019

On October 10, 2019, the IESO presented its stakeholder engagement plan to determine whether it will provide energy payments to Demand Response (DR) resources when they are economically activated. The IESO invited stakeholders to provide comments on the scope of the analysis to be undertaken by a third party and any insights or analysis on the appropriateness of providing energy payments to DR resources. The Market Surveillance Panel (MSP) appreciates the opportunity to submit comments.

1. What are the objectives of providing energy payments to loads?

The study should provide one or more objectives that might be achieved by providing energy payments to loads. It is not clear what role energy payments for DR resources would promote – i.e. for spare energy, greater system flexibility, increased participation in the energy market or emergency response, among others. In contrast, FERC Order 745 – in which the U.S. regulator ordered system operators to provide energy payments to DR resources – provided a clear objective that it was attempting to achieve. In that Order, FERC argued that providing energy payments would help "remove barriers to participation of demand resources" in the wholesale market, among other benefits.[1] FERC stated that its aim was to increase the participation of DR resources in the wholesale market. However increased participation, in itself, is not an appropriate goal. Would increased participation lead to increased market efficiency, greater reliability, lower costs or more effective competition? The consultant should identify the objectives of using DR in the Ontario market and assess the ability of energy payments to promote these objectives in a manner consistent with the principles governing the Ontario market. Similarly, it can review whether the objectives and outcomes should be applied equally to Dispatchable Loads and Hourly Demand Response (HDR) resources, given their distinct characteristics.

It is not clear whether the Order 745 approach is necessary in the wholesale market in Ontario. The MSP notes that a number of DR resources already participate in the wholesale market as Dispatchable Loads. HDR resources also participate in the wholesale market via bidding and many loads currently pay the wholesale price for energy, not a retail rate as is common in the U.S. markets. Loads not paying the wholesale price was seen as a barrier to fully participating in the wholesale market in Order 745. The study should determine what market benefit, if any, would be achieved by expanding energy payments to loads, as it is not evident that the stated goal laid out in Order 745 is appropriate or necessary in Ontario. In the present situation, a DR resource that is activated saves the spot price on its demand reduction, analogous to a generator being paid the spot price for its production. On this basis, an energy payment to DR resources looks like double payment. A number of stakeholders appear to be urging the IESO to accept Order 745 as the definitive ruling on this issue, but the Ontario situation is different and we may not share the same objectives as FERC.

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[1] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

2. What principles will be used to evaluate energy payments for DR resources?

The study should also identify the core principles it will rely on when evaluating whether to provide energy payments to DR resources. In its Market Renewal Program (MRP), the IESO laid out five core principles that would guide the program – efficiency, competition, implementability, certainty and transparency. The principles applied to making energy payments to DR resources should be consistent with the principles applied to the Ontario electricity market in general.

3. Are energy payments necessary to achieve those objectives and principles?

Once the study has articulated its objectives and the principles that will be applied, it can determine if energy payments to DR resources are necessary. As it currently stands, the IESO appears to be asking stakeholders – many of which would benefit from energy payments – to provide reasons why it should or should not provide energy payments, with 'increased participation' appearing to be a goal without assessing the costs and benefits of such an increase. The consultant should assess the costs and benefits of energy payments that might increase participation and determine the net impact that mere "increased participation" would yield.

VT INCEPIT FIDELIS SIC PERMANET

Ontario

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**

the otherwise DRA, demand response auction, when it becomes a transitional capacity auction.

That is the whole issue at play here today, is the issue of the discriminatory nature of the amendments. That is why I included it in my affidavit. That is why I understood that the IESO would understand it. And I hope that clarifies what it was that I was trying to state.

MR. MONDROW: Thank you, Mr. Anderson. I am going to just identify for you, again, Exhibit K1.1, which was the letter dated November 22nd, 2019, the CV which you have already spoken to, and a one-page witness statement which we provided, Madam Chair, to parties in advance just so they would have an indication of two issues connected to Dr. Rivard's evidence that Mr. Anderson wished to address in his direct testimony. And so that is why I identify that and filed it.

Mr. Anderson, just to those two issues, in his evidence Dr. Rivard goes through a number of scenarios involving a demand response resource consisting of a behind-the-meter generation facility which allows the load customer to displace a portion of its own demand for energy from the market, and Dr. Rivard compares that facility to a load customer who is also a directly connected generator, market participant.

And you wanted to address the aptness of that comparison in Dr. Rivard's evidence.

MR. ANDERSON: I did, thank you. Dr. Rivard's example is very specific. He uses an example of a demand response resource with a behind-the-meter generator, so in that case when activated the demand response resource simply ramps up its generator.

This is, by far, the minority example of what actually happens in a demand response activation. Typical demand resources don't have behind-the-meter generators. The majority of them do not.

And what they do, in terms of responding to activation notices, is they dial back their processes. They shut down equipment. They stop making whatever widgets that they would rather be making.

These operations incur real costs to do this, beyond the cost of lost production, as highlighted by Dr. Rivard. And I will give you some examples of this. I will take the steel industry as an example, because it is probably easier to understand than some of the others.

In a situation where demand response is activated, typically steel manufacturing entities would take out of service called an electric arc furnace. If that electric arc furnace happens to still have molten steel inside it, you're no longer putting electricity to it to keep it that way. It will eventually harden up. That is a very bad thing. So they do fire on gas.

In addition to that, there's a downstream process where billets are loaded into a furnace for further processing. Those furnaces are full of refractory, which is basically industrial grade insulation, for lack of a better term.

That refractory, if it is subjected to temperature fluctuations, will crack, break, and fall off. It is very expensive. So they also have to fire that furnace with natural gas, which they otherwise would not have to do. These are costs that are avoidable in a situation where they have been told to activate.

Another example -- and again it is a gas-firing example -- steel melts at somewhere around 2,500 degrees Fahrenheit. Generally speaking, the facilities that make steel don't have building heating. They don't need it. But in a situation in the middle of winter where you have shut down and stopped your process, it starts to get cold, and things inside that facility can freeze up, and they do have to bring in gas-fired heaters to keep that facility warm. Again, another situation where, but for the activation, you wouldn't be burning that gas and you wouldn't be incurring that cost.

So for those customers there is a much broader range of costs beyond the value of the lost load and a broader range of risks to consider.

And I think one final point that Dr. Rivard makes is an implication based on -- I think it is based on some of his other studies from other jurisdictions that you can simply shift that production, you can make those widgets later. And some DR resources can actually do that. Many cannot. When you lose the production of those widgets, you lose it for good. You don't just shift it into the off-shift, because you don't have that spare capacity. And I

So they will not stop consuming unless it reaches a price point where it would cost them to -- they're not willing to pay the cost to consume.

So there is a benefit in a voiding the energy cost in in-market activation. Do you agree with that?

MR. ANDERSON: Sorry, can you run that one past me again? I am not sure what you said.

MS. DJURDJEVIC: Well, in the context of an in-market activation, a demand resource will only be willing to be curtailed when there is a benefit to doing so, i.e. the cost of electricity is now $2,000 and does not want to incur that cost. Like, it is an avoided cost. They're avoiding the cost of energy. That --

MR. ANDERSON: I can agree that they're looking for benefit in terms of their curtailment, yes.

MS. DJURDJEVIC: Now, if they are -- you have this benefit of an avoided energy cost and in addition to that an HDR resource received an energy payment for activation, which is the basis of the application, would you agree that there at least appears to be a double benefit or that the resource is even better off financially?

MR. ANDERSON: No, I would not. And I think the error in your logic link was that if they get activated at 1999 that that covers their costs. And I can guarantee you that at times it absolutely will not cover their costs.

The value of the lost load is set out in response to Board Staff 1, but all of the additional costs that get incurred as a result of that activation can easily put it well north of 1999.

So where you're saying they're covered off by 1999 and then they get this gravy on top of that, I wouldn't agree with that.

MS. DJURDJEVIC: Okay. Those are all of my questions, thank you, Mr. Anderson.

MR. ANDERSON: Thank you.

MS. SPOEL: Mr. Rubenstein.

CROSS-EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Thank you very much. I don't have a compendium, but the documents that I will refer to are actually in the IESO compendium. So if maybe we could use that --

MS. SPOEL: Thank you.

MR. RUBENSTEIN: -- as a guide. I just have a few questions for issues that haven't been dealt with.

Mr. Anderson, I want to just understand AMPCO'S position better. If I can ask you to turn to SEC, which is -- your response to SEC, which is located at tab 3, behind the blue page.

MS. DJURDJEVIC: Sorry, Mr. Rubenstein, can you give us a document reference again so we can put it on the screen.

MR. RUBENSTEIN: Sorry, this is AMPCO's response to SEC 3. It's behind tab 3 of the IESO cross-examination compendium. Behind the blue page in tab 3.

MR. ANDERSON: I have that.

MR. RUBENSTEIN: Now...

MS. SPOEL: Mr. Rubenstein, I think -- I know they're having trouble putting it up on the screen. But I think most -- do you -- have you located it, Mr. Anderson?

MR. ANDERSON: Yes, I have.

MS. SPOEL: And we have got it, and I think most parties do, so you can proceed even though -- the screen is nice to have, not need to have.

MR. RUBENSTEIN: So Mr. Anderson, we had asked you in this interrogatory if AMPCO's views, including any analysis it had undertaken regarding the impact on costs that ultimately would be borne by Ontario ratepayers providing energy payments to demand response providers. Do you see that?

MR. ANDERSON: I do.

MR. RUBENSTEIN: And in the response say that you haven't done the analysis, but the next paragraph:

> "AMPCO's view, which includes consideration of perspectives of majority of AMPCO's members who are not DR resource providers and whom the lowest possible electricity costs are of paramount importance, the interests of Ontario consumers would be fully and appropriately protected by the development of the application of an Ontario-specific net benefits test as required by FERC as a pre-condition to energy payments for DR resources."

Do you see that?

MR. ANDERSON: I do.

MR. RUBENSTEIN: So do I understand that in AMPCO's view, if the IESO is to provide energy payments to demand response providers, as a pre-condition there must be a net benefits test that is put in place and ultimately I guess would be passed in any given situation before an energy payment is made?

MR. ANDERSON: That's absolutely correct, and I believe we say that in AMPCO's response to Board Staff number 2. In fact, in the very, very last line of that interrogatory response it says: "If the net benefits test is not passed, no energy payment is made."

MR. RUBENSTEIN: So conceptually, as I understand it, at a high level the intent of the net benefits test would ensure that in any given situation that a DR resource would only receive an energy payment if it's economically activated, if its activation in the payment of that energy payment would reduce the overall cost to customers as compared to if it wasn't activated. Is that your understanding, or can you help me understand what your view at a high level of what the net benefit test is attempting to do?

MR. ANDERSON: Let me try to paraphrase it slightly differently, counsel.

My understanding is that the net benefit associated with activating the demand response resource is a direct result of reducing the provincial load.

Let's say the demand response resource is 100 megawatts, so it takes you from 25,000 megawatts down to 24,900. That reduction in overall load may drop you down through some price laminations of what the energy has built up to. So your market price will drop consistent with that drop in load.

Multiply that delta through the entire rest of the 25,000 megawatts, you're going to incur a benefit, which is incurred for all consumers. Your market price is now lower.

So unless that amount is greater than the amount you pay the DR resource, you don't pay the DR resource. That's my paraphrasing of it.

MR. RUBENSTEIN: So I take it in your view the fact that you think there should be a pre-condition that there be a net benefits test, that there would be situations where DR resources who receive energy payments may actually increase costs to customers?

MR. ANDERSON: There would be situations where they -- where, sorry, they increased costs?

MR. RUBENSTEIN: Would increase costs. Thus you believe there should be a net benefits test to ensure that in those situations energy -- there is no payment of energy payments through a DR resource.

MR. ANDERSON: The amount of benefit that accrues to the market must exceed the amount of payment to the DR resource or there is no payment.

MR. RUBENSTEIN: But as I understand, the reason you believe that there should be a net benefit test and there should be a condition on paying energy payments is that there are going to be situations where, without the net benefits test, a payment of energy payments to DR resources would actually increase costs to consumers.

MR. ANDERSON: Okay, my apologies. I didn't understand that last clarification, but, yes.

MR. RUBENSTEIN: Now, as I understand the -- in your application, because a transitional capacity auction market rules amendments don't include provisions of compensation of energy payments to DR resources, it is unjustly discriminatory.

MR. ANDERSON: The market rules as currently crafted result in discriminatory impacts.

MR. RUBENSTEIN: Because there is no -- there's not the possibility of energy payments to DR resources who are activated?

MR. ANDERSON: Because of the difference in treatment between the two classes of participants, yes.

MR. RUBENSTEIN: And your application as you talked about in your direct is you're seeking to revoke -- you're asking the Board to revoke the amendments and send it back to the IESO for further consideration?

MR. ANDERSON: We are seeking the relief as specifically contemplated in section 33 of the Act, yes.

MR. RUBENSTEIN: Would the market rules be unjustly discriminatory regardless of the lack of an inclusion of a net benefit test?

MR. ANDERSON: I believe they would still be discriminatory. Mr. Rubenstein, the reason why I can so adamantly support the notion of energy payments is because of the net benefits test.

In the absence of a net benefits test, I would be here advocating only for DR resources, and I don't do that.

My association represents DR resources and people who don't provide DR, and those people still pay bills. With the inclusion of the net benefits test I can sit up here and say, I think this is a really good thing for the market because it will overall reduce costs. That is why I can be here and push hard, because I am representing 100 percent of my members instead of a smaller percentage who provide DR.

MR. RUBENSTEIN: Imagine that you are successful in this application, the Board revokes the amendments and sends it back to the IESO for further consideration.

Ultimately in their further consideration they decide, based on what they have heard in this application, that they believe that providing energy payments to DR resources is appropriate. But they are unable to, for reasons of complexity or technical ability, are unable to create a net benefits test.

Would those amendments be unjustly discriminatory?

MR. ANDERSON: You're in a hypothetical area I really haven't considered. Let me just be sure that I am hearing what I think you're saying.

There would be new rules that would be crafted. Those rules would contemplate similar treatment between the two.

But it was impossible to come up with a net benefits test because of the complexities of the Ontario market? Is that...

MR. RUBENSTEIN: Yes, yes.

MR. ANDERSON: I think that would deal with the discriminatory piece.

I would be less comfortable than what we're currently considering because of the reasons I just set out. I want to represent all of my members and, in fact, any load customers in the province to ensure that what we are doing here doesn't result in increased prices.

MR. RUBENSTEIN: Thank you very much. Those are my questions.

MS. SPOEL: Thank you, Mr. Rubenstein.

QUESTIONS BY THE BOARD:

DR. ELSAYED: I just have a couple of questions. Can you hear me?

MR. ANDERSON: I'm sorry, I can't.

DR. ELSAYED: Is this better?

MR. ANDERSON: That is better, thank you.

DR. ELSAYED: Okay. Just to clarify, I think it was something you said at the direct start of the hearing.

The objective of your application is to -- for the OEB to send these amendments back to the IESO for reconsideration. Is that basically what you are...

MR. ANDERSON: Yes, that was part of my direct, and there has been some question -- or we perceived there was some questions amongst the intervenor community what us, in your examination-in-chief, to page 39 of your report, which is at tab C of my compendium, where you discuss a number of bullet points that describe the primary differences between the Ontario energy market and US ISOs.

And in particular, you discussed how 90% of all generation in the province is under regulated rates, and you also discussed the GA. Correct?

MR. GOULDING: Yes.

MS. KRAJEWSKA: Is there anything else that you would like to highlight as significant differences between the Ontario and the US ISOs?

MR. GOULDING: No.

MS. KRAJEWSKA: And so in terms of the second point, the existence of the global adjustment in Ontario, would you agree that the benefits that large consumers of energy, so-called class A consumers, receive under the global adjustment is a form of demand response in Ontario?

MR. GOULDING: Yes.

MS. KRAJEWSKA: And would you agree that if the ISO were to consider the FERC order 745, the calculation of the net benefits test would need to be adapted to take into account the ICI program and the global adjustment?

MR. GOULDING: So my concern is that a focus on 745, in and of itself, I think obscures the question of what is right both theoretically and for Ontario.

And so while I agree with the premise that we should, in looking at any market rule, consider costs and benefits and consider them both from the perspective of the impact on consumers and on the economy as a whole.

I am not convinced that 745, in and of itself, is completely relevant to circumstances in Ontario today, seven years after the order and the order being in another jurisdiction entirely, nor am I convinced that the net benefits test, as set out by FERC for US markets, would be the way that I would seek to design a test today.

MS. KRAJEWSKA: And, Mr. Goulding, if I could ask you to elaborate on each of those point. Why do you say it is not relevant to Ontario, and that you would not recommend or see it as beneficial to transplant the analysis from FERC order 745 to Ontario?

MR. GOULDING: Well, there have been a number of instances in the past two decades around the world where folks have more or less cut and pasted, in some cases literally cut and pasted market rules from other jurisdictions. There are almost always unintended consequences.

So I would want to start with an analysis of the Ontario situation specifically and of the general concept and then use 745 as one piece of the overall analysis.

So I think that we need to look at the specifics of how load actually pays for power. We need to look at the specifics of the providers of DR. We need to have a strong understanding of the supply curves, both for the capacity mechanism and the energy markets. And we need to have some understanding of not just where we are today, but where we would like to get to tomorrow with regards to the market design.

So I worry that 745 becomes imprisoning rather than empowering with regards to the analysis.

MS. KRAJEWSKA: And Mr. Goulding, as part of your retainer in this proceeding, you haven't had an opportunity to review the supply curves for demand response or the energy response in this proceeding? There has not been that kind of evidence filed.

MR. GOULDING: That's correct that there has not been that kind of evidence filed.

MS. KRAJEWSKA: Mr. Goulding, then similarly, I assume with respect to the net benefits test as it is discussed in FERC order 745, would you also have some hesitancy about importing that type of analysis to the Ontario market?

MR. GOULDING: I would have a similar set of hesitancy. I think that conceptually it is important, as I have said previously, to do cost-benefit analysis on any market rule and to understand its implications from the perspective of all stakeholders.

But the net benefits test itself, as it is structured for U.S. markets, I don't believe would produce meaningful results in the Ontario context.

MS. KRAJEWSKA: And Mr. Goulding, if I could just take you to tab D of my compendium. This is more of a point of clarification with respect to one of your responses to interrogatories.

Question A was:

"Please identify any points on which LEI is in

"...agreement with or disagrees with Mr. Rivard's assessment of the net benefits test and economic efficiency. If LEI generally agrees with Mr. Rivard please confirm this."

And then in response you provided:

"LEI's disagreement of the assessment of the net benefits test lies primarily with regards to its relevance to the Ontario situation."

And my question of clarification is, it is -- you are not disagreeing with Mr. Rivard, I understand. You are disagreeing with the application of the net benefits test to Ontario. Is that correct?

MR. GOULDING: Yes. That's correct. We're not disagreeing about the way in which the net benefits test is described.

MS. KRAJEWSKA: Right. Thank you. And Mr. Goulding, at tab F of my compendium is a brief filed by Amicus to the United States Federal Court of Appeals, and the Amicus here are leading economists.

Are you familiar -- have you had -- are you familiar with this brief?

MR. GOULDING: Yes.

MS. KRAJEWSKA: Thank you. And if I turn you to page 8 of 44 of that brief -- yes. This is the first paragraph of the brief, and it simply describes who the Amici Curiae are, and that they're the leading economists and educators who have designed, studied, and taught, and written about electricity markets affected by the FERC.

And you would agree with that description of the -- who the clients or the Amici were in this brief?

MR. GOULDING: I would agree that they are some well-known economists and educators. I would question whether they are the leading economists and educators.

MS. KRAJEWSKA: Okay. Well, I guess you -- fair enough. That's fair enough. But you would agree that in some sense they represent certain renowned economists in the United States who work in this area?

MR. GOULDING: I think they're well-known people who spend a lot of time thinking about these issues.

[Laughter]

MS. KRAJEWSKA: Okay. And Mr. Goulding, in this brief they provide a general criticism of the FERC order and the kind of economic underpinnings of that order. And in particular they raise concerns about the economic incentives that the order creates.

Would you generally agree with some of the comments that they've posited in their brief?

MR. GOULDING: So there are some comments that I would agree with, some not. But I think that in general the most challenging concept for anybody to get their mind around is whether or not there is a double payment and whether that results in a reshuffling of the merit order in either the energy or the capacity mechanism auctions.

And I think that what we've seen, first of all, is that eminent economists have been on either side of this. Certainly no one would doubt that the late Dr. Kahn is also eminent and well-known.

And I think that is why I try and focus on thinking about what are the true short-run marginal costs that are incurred by a DR provider.

So I think that, you know, as we go through here, it's important to recognize that there is not a consensus among all noted economists as to the conclusions, and I think it is important to focus on what the key challenge is, which is figuring out what are the short-run marginal costs of DR participants.

MS. KRAJEWSKA: Okay. But today -- and that's fair enough. Can I take you to page 20 of that decision.

MR. MONDROW: Page 20 of the brief?

MS. KRAJEWSKA: Yes, sorry, it's 20 --

MR. MONDROW: Or the decision?

MS. KRAJEWSKA: I haven't -- so just to be clear, I haven't page-numbered this part of the brief, because it was overlapping with the page numbers of the decision. So I am referring to page numbers of the decision. So I am referring to page 20 of 44.

Page 20 of 44, the last paragraph there talks about incentives and the danger that sometimes excessive incentive payments can be deeply problematic.

And this is, I think, a general statement, but would you agree that if the incentive is not properly calibrated, it may have -- cause damage in terms of incentivizing some forms of production while decreasing others?

MR. GOULDING: Well, I think it is a fairly generic specific information or data? Or would you just want a general category of here's the type of cost?

MR. GOULDING: Well, understanding that my answer is not intended to be exhaustive, I would want to look at different categories.

I would want to have an understanding of what is truly avoidable in the moment. In other words, if I continue producing my widgets, what cost do I avoid versus the cost that I incur when I shut down. And I would want to have an understanding generally of how this varies across industries.

So I think there is a variety of ways of obtaining that, but I would want to understand what is avoidable in the short term and what the drivers are of those particular costs.

MR. BARZ: And in your experience, is that information easy to connect -- or collect, sorry, with -- if parties are forthcoming in that regard?

MR. GOULDING: Well, I think that the information can be collected, and it doesn't necessarily need to be collected directly from the widget manufacturer. Right? You could certainly collect similar information from the world's leading expert on widget manufacturing processes, for example.

So I think that the information can be gathered without necessarily requiring proprietary processes to be exposed in a general proceeding.

MR. BARZ: Okay, thank you very much. Those are all of my questions.

MS. SPOEL: Thank you, Mr. Barz.

Mr. Mondrow.

MR. MONDROW: Thank you, Madam Chair. I do have a few questions.

MS. SPOEL: Great.

CROSS-EXAMINATION BY MR. MONDROW:

MR. MONDROW: Good afternoon, gentlemen. Mr. Goulding, I can refer you if you wish to page 31 of your report. In Staff's compendium it has come out as page 60 of 86. It might be easier to find it there.

And I just -- you mentioned off the top I think in your direct examination some of your primary or basic conclusions.

Am I correct that one of your conclusions is that there is a strong practical linkage between capacity market participation by DR resources and activation payments?

MR. GOULDING: I would like to recharacterize that a bit if I could, which is, first of all, resources are not going to participate in any form if they don't perceive it to be remunerative.

And the part of what they're seeking compensation for is the risk of being activated and the costs that will be incurred.

So when we look at the market rules specific to the capacity mechanism and the energy market, the market rules need to enable the DR participant to recover the total of their need across the multiple product streams.

So conceptually, if we're recovering nothing in the energy market, we need to recover everything in the capacity market. And consequently as we bid into the capacity market, we need to guess how often are we going to be activated and what are the consequences of that and make sure that we have a margin, if we guess wrong, that is built into our capacity bid.

So I would say that an understanding of the potential for activation and the financial consequences is critical for the DR resource to determine their bid in the capacity mechanism.

MR. MONDROW: So if you look at the page I referenced in your report under heading 4.4.5, you see the highlighted strong practical linkage language, which is where I took that phrase.

But I think at the bottom of the next paragraph you sum up what you just explained, which is you say:

> "This activation payment is therefore directly linked to participation on the capacity side."

And I think you just explained that. Is that -- my understanding of that sentence correct?

MR. GOULDING: Yes.

MR. MONDROW: Thank you. And am I correct that another one of your primary conclusions is that demand response participation in Ontario is proportionately lower than demand response participation in the U.S. FERC jurisdictional -- U.S. FERC jurisdictional -- jurisdictions that you looked at?

MR. GOULDING: That's correct, with a caveat, which is you -- it depends, again, on how narrowly we're defining demand response.

So I think that as we look at that we need to make sure that we take into account properly participants in the ICI program, even if they're not directly registered in the DR auctions. But generally speaking, obviously I just stated it, I would agree with that conclusion.

MR. MONDROW: Fair enough. And if you could turn maybe to page -- again in Staff's compendium it's page number 68 of 86. I think in your paper it is actually page 39. And you see the -- sorry, the fifth bullet on the page. It starts with "demand response procured".

And there, as you just corrected me, you're talking about the proportion of demand response, but you were specifically referring to the demand response option as the vehicle in that bullet.

MR. GOULDING: Yes.

MR. MONDROW: Okay. And you do conclude that bullet by saying:

> "Procurement is limited to a small proportion of Ontario's total capacity."

And you are referring there to demand response procurement?

MR. GOULDING: Yes.

MR. MONDROW: Okay, thank you.

And one more question. Do you think that it is conceptually appropriate to pay demand response resources for the energy services they provide to the energy market?

MR. GOULDING: I want to be careful about terminology, in that I believe that it is appropriate for there to be some sort of payment upon activation.

I think that the actual market rule -- you know, I would need to look at how it was configured and whether that is at an Ontario equivalent of locational-based marginal price, whether it is some kind of a two-part bid. My scope was not to come to a conclusion with regards to that, and doing so would require further analysis.

MR. MONDROW: Fair enough. You said earlier in response to one of my friends that market rules should be product base. And I assumed by that you were referring, for example, to energy services as a product. Is that what you meant? Is that an example of the product when you referred to --

MR. GOULDING: Yes. That would be an example generally of the product. I mean, there is many different ways that we can slice and dice that, but, yes, generally.

MR. MONDROW: Understood. Thank you very much. Thank you, Madam Chair.

MS. SPOEL: Thank you, Mr. Mondrow.

Mr. Zacher, are you next, or Mr. Duffy, are you...

MR. DUFFY: Yes, I will take the questions.

MS. SPOEL: Thank you.

CROSS-EXAMINATION BY MR. DUFFY:

MR. DUFFY: Good afternoon, gentlemen. With respect to FERC order 745, you will agree with me that it was looking at barriers to entry for DR in the energy market. Correct?

MR. GOULDING: Yes.

MR. DUFFY: And it specifically wasn't looking at DR in capacity markets, correct?

MR. GOULDING: Yes.

MR. DUFFY: And it made no conclusions about DR participation in capacity markets for that reason, correct?

MR. GOULDING: Yes.

MR. DUFFY: And at the time of FERC order 745, other markets in the United States had capacity markets in them. Correct?

MR. GOULDING: Some did. Some didn't. The geography -- simplistically, we'll call it about half, maybe 60 percent by geography of the U.S. is covered by organized markets, or was at the time. And, you know, those organized markets themselves differ with regards to whether they have some form of capacity mechanism.

MR. DUFFY: What about the three markets that you identified in your paper?

MR. GOULDING: Yes. They had capacity mechanisms.

MR. DUFFY: Thank you. So earlier you said that Ontario was in an earlier stage than these markets and that is because Ontario is still developing its capacity mechanism, correct?

MR. GOULDING: That's correct.

MR. DUFFY: Thank you.

Can I get you to turn up your report, page 39. It is tab 3 of the Staff brief.

And I am going to...

MS. SPOEL: Mr. Duffy, is that page 39 of the report?

MR. DUFFY: Of the report.

MS. SPOEL: Can you tell us what page it is?

MR. DUFFY: In the actual brief?

MS. SPOEL: In the actual brief, because we don't have the report page numbers in our copies.

MR. DUFFY: Okay. Oh, I see, okay. I don't have the actual --

MS. SPOEL: We have something of 86 pages.

MR. DUFFY: Page 68.

MS. SPOEL: Oh, already on it. Thank you. Perfect. Thank you.

MR. DUFFY: Thank you. Yes, we can stop right there. So at the top of the page, you have three bullets there and you say:

> "Based on the demand resource programs in three US markets that I reviewed, the following conclusions can be drawn."

I want to ask I awe fie questions about your conclusions.

The first conclusion is that DR resources serve primarily by the provision of capacity in terms of total resource participation.

Can you just explain that briefly for us?

MR. GOULDING: Sure. So there are a variety of ways in which DR resources can be compensated, not all of them involve payment of capacity.

But our assessment of, when we look at how the funds actually flow, what people are getting paid for, the greatest proportion of what people are being compensated for was capacity.

MR. DUFFY: Okay. When you say "people" in that sentence, you are referring to DR resources, correct?

MR. GOULDING: Correct, absolutely.

MR. DUFFY: If we look at the next bullet, the conclusion is when they - and that would be DR resources in these three markets, correct?

MR. GOULDING: Yes.

MR. DUFFY: "When they have access to both capacity and energy related compensation, capacity revenues still form the bulk of their revenues," correct?

MR. GOULDING: Yes.

MR. DUFFY: Okay. Then in the third bullet, you state: "Compensation for dispatch of economic DR resources or activation of emergency/reliability resources is the common approach."

I will stop there. So there's payment made in these three markets to DR resources in the energy market for activation, correct?

MR. GOULDING: Yes.

MR. DUFFY: And you then go on to state:

> "But the actual dispatch (in aggregate) of economic DR resources is low, and activation of emergency/reliability resources is very

infrequent."

Then you state: "Meaning again that actual dispatch or activation is a very small proportion of revenues for most DR resources," correct?

MR. GOULDING: Yes.

MR. DUFFY: Earlier you stated -- I believe you used the term extremely infrequent activations, is that accurate?

MR. GOULDING: Yes. I would have to look up the exact place, but that sounds correct.

MR. DUFFY: And that would mean that as a proportion of revenues for a DR resource, what they're getting from the energy market would be likewise very small.

MR. GOULDING: Yes.

MR. DUFFY: Thank you. And can I next have you turn to your IR responses, which will be tab 4 of Staff compendium. And I would like to go to the response to IR number 4, which is page 79 of 86 of the brief.

And if we can just scroll up so we can all see the question, just so we set some context.

The question you were asked was:

"Based on its research conducted, has LEI formed an opinion regarding the economic impacts of providing energy payments to DR resources? If yes, please state your opinion."

And if we turn to the next page, I'll read the first bit here for you. It says:

"Given the short time period in which to develop

its analysis and respond, LEI's opinions are
preliminary and subject to change. With that
caveat in mind, LEI's views are as follows..."

And in the first paragraph you state:

"Based on the markets and programs LEI reviewed in its report, actual activation of DR resources has been relatively limited, and DR resource revenues from this activation have also been limited as compared to DR capacity revenues," and you reference section 4.4.

So that ties to those bullets we were looking at in your report, correct?

MR. GOULDING: Yes.

MR. DUFFY: You then state:

"This implies that from a practical perspective,
the benefit or harm arising from whether DR
resources are provided energy payments may not be
material in the near term."

Correct?

MR. GOULDING: Yes.

MR. DUFFY: And am I right to take from that that whether or not there are energy payments made to DR resources, you view them as immaterial because the likelihood of being activated is so infrequent?

MR. GOULDING: So I want to be clear over what time period we're talking about, and as to whether I view this as an important issue over the long run.

So over the long run, I believe it is an important issue and may become more material over time.

Over the short run, based on the historical participation, with the acknowledgement that one of the reasons that I'm concerned over the long run is that I do expect there to be change.

But over the short run, if we actually went and calculated the amount of money that is at stake, and that amount of money would be at stake only for this particular auction period, I believe that amount to be relatively small and perhaps absolutely small.

MR. DUFFY: Right. So if I were to put to you, for instance, that if dispatch is going to be extremely infrequent, then the risk premium that one needs to build into their capacity auction bid would be negligible or almost zero, correct?

MR. GOULDING: I don't believe it would be zero. And we can imagine circumstances where the market conditions could change quite suddenly, right.

And so if I were a DR resource, I don't think that I would be wise to assume zero.

MR. DUFFY: But if you were a DR resource and the historical activations in Ontario are extremely infrequent, and even activations in other markets where payments are made is extremely infrequent, you will agree with me that in either scenario, you would treat your bid the same way. No?

MR. GOULDING: I think that the historical information would cause my risk perception to be low and perhaps biased. But it would certainly cause my risk perception to be low.

MR. DUFFY: Thank you. Those are all of my questions.

MS. SPOEL: Mr. Rubenstein?

CROSS-EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Good afternoon, panel. My name is Mark Rubenstein. I am counsel for the School Energy Coalition. I was wondering if you could first pull up -- actually, before you do that, I would like to follow up with some questions you were just being asked, where you were asked -- you caveated your answer about what the definition of short or long-term, what you're talking about.

I just want to be clear and very specific. When you were talking about in the short term, are you specifically talking about the commitment period for the auction that is supposed to take place in December?

MR. GOULDING: Yes.

MR. RUBENSTEIN: But you are not talking about necessarily -- or let me ask you. What type of time period, is it short term or long-term would we talk about in, say, 2023 where there is a forecasted capacity gap, I think we heard this morning, of somewhere between 3500 to 4,000 megawatts.

Is that closer to the short term or to the long-term, in your view?

MR. GOULDING: So my answer was intended to relate solely to the auction at hand, with the understanding that there will be the opportunity for further review before the next auction takes place.

MR. RUBENSTEIN: But let's put aside that there may be further review for a moment. I just want to understand from your perspective, because I understand that TCA auction is leading up to the -- the intent of it is to lead up ultimately to the larger capacity gap that will exist in 2023.

So I am just trying to understand your view. In 2023, do you think it makes sense then to provide energy payments? Or is it more likely that because it would be more likely to be activations by then?

MR. GOULDING: So what I believe is that a process for further study is necessary soon with regards to these issues, so that we can come to a clear understanding of consequences prior to 2023.

MR. RUBENSTEIN: I was wondering if we could turn up your response to KCLP number 4. And this is on page 79 of 86 of the Staff compendium. Sorry, KCLP number 6. Page 83 of 86. Number 6.

So you were asked in part B:

> "Does LEI agree with Mr. Rivard that as a result of the global adjustment the net benefits test will be satisfied less frequently, if ever, than in the U.S. markets?"

Do you see that?

MR. GOULDING: Yes.

MR. RUBENSTEIN: And in your response you say:

> "LEI does not believe the net benefits test as

configured for U.S. markets is appropriate for developing market rules in Ontario."

And then you go on to explain why you have that view. Do you see that?

MR. GOULDING: Yes.

MR. RUBENSTEIN: So I understand your view that the net benefits test, as set out in FERC order number 745, you don't agree has much application in Ontario.

But do you agree at a high level that some form of a net benefits test should be incorporated?

MR. GOULDING: So I believe that I said earlier that I believe that any market rule should be subjected to a cost-benefits analysis.

Now, we want to be careful when we talk about a net benefits test to make sure that we understand net benefits to whom, whether we are talking about two customers, or whether we're talking about something that looks on a more generalized basis to society.

We need to determine the terms of this test. I am not sure I would necessarily call it a net benefits test. But I agree that undertaking any market rule change without considering the impact on final consumers would not be best practice.

MR. RUBENSTEIN: So I understand -- and you can correct me if I am wrong -- in FERC 745 the net benefits test there is looking at, in any given moment, if a certain payment should be authorized because --

MR. GOULDING: Yes.

MR. RUBENSTEIN: And I want to compare that to what I would call an overall cost-benefit analysis which looks at over some period of time are -- the benefits outweigh the costs, but not at any specific moment.

MR. GOULDING: I understand your distinction, yes.

MR. RUBENSTEIN: All right. When you talk about cost-benefit analysis are you talking about the former or the latter?

MR. GOULDING: So among my concerns about the net benefits test as described in 745 is whether it actually produces meaningful results at all in the moment.

And so -- and again, I highlight that my mandate was not to design a net benefits test for Ontario. But what I would say is that if there is a way to design a meaningful, dynamic analytic approach that determines whether or not a DR bid should be accepted, then conceptually I would support that.

However, I want to highlight that we should not -- we should not place too much faith in these tests, because by necessity they oversimplify the situation of each individual consumer, depending upon the market design.

So if we are looking at putting together a dynamic -- we can figure out what the time period is, whether it is hour by hour or five-minute interval by five-minute interval -- I think that what we would want to do is make sure that it is meaningful and assess periodically whether it remains meaningful as market arrangements evolve.

MR. RUBENSTEIN: Now, as I understand AMPCO's position in this application, that in their view a net benefits test is a pre-condition to energy payments to be made. Are you familiar with that view of theirs?

MR. GOULDING: So I would want to be taken to the point in the record that says specifically that that is a pre-condition for energy. I heard some discussion of this this morning --

MR. RUBENSTEIN: I can do that if you want.

MR. GOULDING: Yes.

MR. RUBENSTEIN: If we can turn to AMPCO's response to Staff number 2. So this was, for ease, this was in the K1.6, the IESO cross-examination compendium, tab 3. Or actually, a better reference for you is SEC 3, their response to SEC 3, which is behind the blue page in that tab.

MS. SPOEL: Sorry, which tab, Mr. Rubenstein?

MR. RUBENSTEIN: Tab 3 in the IESO compendium. 1.6.

MS. SPOEL: Thank you.

MR. RUBENSTEIN: If we can go to SEC 3, which is in that tab, but a little further down, I guess. Further down. A couple of pages. SEC 3, yes. Further. Two more IRs. Yes. So this is the first reference I will give you. And this is in the second paragraph where they say:

> "In AMPCO's view, this includes consideration of the perspective of the majority of AMPCO's members who are not DR resource providers in whom the lowest possible electricity costs are of paramount importance. The interests of Ontario

consumers would be fully and appropriately
protected by the development and application of
an Ontario-specific net benefits test as required
by FERC as a pre-condition to energy payments for
DR resources."

Do you see that?

MR. GOULDING: Yes.

MR. RUBENSTEIN: And so I take it you see that, you agree with their position?

MR. GOULDING: Yes. Well, I agree that that is their position. I am not agreeing it is my position.

MR. RUBENSTEIN: No. And so my question to you on that line is, would you believe that that should be a pre-condition for the payment of -- ultimately the payment of energy payments?

MR. GOULDING: So I believe that before we implement the payments we need to understand what the consequences are. Now, whether that entails doing an increment-by-increment net benefits test as envisioned by FERC or whether it envisions something else, and this response to the IR envisions an Ontario-specific net benefits test, I think it all depends on what that test would look like.

We can certainly imagine trade-offs between the administrative costs of doing a five-minute by five-minute test against, perhaps, some test that took place over a broader period that would, on average, produce results that are beneficial to consumers.

So I don't want to foreclose the nature of the net benefits test, but I do generally agree that we shouldn't do something before analyzing whether there are going to be benefits.

And if there are ways of putting in place breaks, if you will, that would highlight specific instances where it may not be beneficial and sort of excising them from the market rule, I think that would be sensible.

But the specifics of what those would be I think have yet to be determined.

MR. RUBENSTEIN: And if we could go up now to AMPCO's response to Staff 2. So a few pages up on that.

If we can just go a little bit down that page. Sorry, the next page.

I just want to ask you about AMPCO's definition of what a net benefit is, and ask for your opinion about this.

In the last paragraph, it says:

"From AMPCO perspective, a properly constructed and applied Ontario specific net benefits test is required in order to ensure that demand resources will be paid for energy in a situation where it can cost-effective from the market's perspective, i.e. the consumers' perspective, for the resources to be utilized. This means that the interests of all consumers are served by implementing energy payments because the utilization of the specific demand response resource in question is the most economically efficient action that should be taken to satisfy the need."

Do you agree with that? Anything you want to add to that, or quibble with?

MR. GOULDING: Well, I think again, we need to look at the terms, and we need to think about short term versus long-term impacts.

And so when we assess the impact on consumers, we may want to think about not just how this affects the five-minute price, but how it affects long-term investment patterns in the industry.

We need to figure out over what time period we're doing the assessment, because one can imagine circumstances in which the test may be satisfied on a five-minute basis, but that the implications for the market as a whole may be potentially problematic over time.

MR. RUBENSTEIN: Thank you very much for your assistance. Those are my questions.

MS. SPOEL: Thank you, Mr. Rubenstein. Ms. Djurdjevic, do you have any re-examination -- sorry. Does the panel have questions?

MS. FRANK: I have some questions.

MS. SPOEL: Sorry.

QUESTIONS BY THE BOARD:

MS. SPOEL: I am getting ahead of myself.

MS. FRANK: I do have questions for you, Mr. Goulding. I was interested in your description of technology-neutral capacity markets. And then I wondered if technology-neutral meant that indeed, the nature of the compensation

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**

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 dissent -- Commissioner Moeller, I believe was his name is -- his view was that if you were going to pay demand response resources the wholesale price -- so in essence give them an energy payment -- you needed to subtract their avoided energy cost. Correct?

DR. RIVARD: Yes.

MR. RUBENSTEIN: And I understand, in the US demand response providers for the most part, unlike in Canada or Ontario specifically, are not exposed to the market price. They pay retail rates.

DR. RIVARD: That was the -- at the time that was the problem that they were encountering, that's right.

MR. RUBENSTEIN: And so the dissent's view was that if you were going to provide demand response energy payments, you had to subtract out the retail price that they would be paying.

DR. RIVARD: Correct.

MR. RUBENSTEIN: So if we were translating that into Ontario, that logic, would you be subtracting out the entire wholesale price, ergo you would pay them nothing? Is that the logic?

DR. RIVARD: Yes, because you don't -- that's how the Ontario market works. You pay whatever that market price is and hence, as long as it exceeds what you are willing to pay, you will not consume.

There's no barrier to that kind of demand response in Ontario. That could have been happening at the time in the US, where consumers weren't facing that market price, but instead were facing a retail price.

MR. RUBENSTEIN: So in the decision, it uses the sort of for market prices locational marginal price and it uses for retail price G, and it uses the formula L M P minus G.

Would I be correct then the Ontario version of that theory of the dissent would be HOEP minus HOEP?

DR. RIVARD: Yes.

MR. RUBENSTEIN: Okay. Now, you discussed at paragraph 58, "Yes" -- the question is:

> "Do you see any implications for the IESO or Ontario consumers of the IESO required to apply a net benefits test in order to pay DR resources the market clearing price?"

And you say:

> "Yes, if the intent of FERC net benefit test is to compensate DR resources only when it results in a reduction from the bills of non-DR resources -- non-DR consumer surplus -- then 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."

Do you see that?

DR. RIVARD: Yes.

MR. RUBENSTEIN: And as I understand the impact of the

GA that we're talking about, or one of the impacts that we have to take into consideration, is that most generators in Ontario are under contract or are rate-regulated, and they're guaranteed a certain amount of revenue regardless of the market clearing price. Correct? I can provide by way of an example if it would be helpful.

And using something the Board may be most familiar with is Ontario Power Generation's rates, which are rate-regulated by the Board. The Board sets a payment amount per megawatt hour of generation by its facilities.

And regardless of what the actual market clearing price is, if it is lower than that payment amount, through the global adjustment it receives that amount. Do I have that correct?

DR. RIVARD: Yes, yes.

MR. RUBENSTEIN: And so what could potentially happen is that, as I understand it, is if you provide energy payments to demand resources and that lowers the market clearing price, customers end up paying that difference in the global adjustment. Correct?

DR. RIVARD: To those resources that had a contract or were under regulation, yes.

MR. RUBENSTEIN: And so potentially customers are worse off, because not only are they paying energy payments to the DR resources if activated -- that's, I guess, the benefit -- but -- that they receive as the lower clearing price -- but they're -- essentially that benefit is clawed back by way of increased global adjustment costs. Correct?

DR. RIVARD: Yes. In the extreme, if all of the generators were under contract or regulation, if the intent is a net benefit test is to induce demand response, causing the energy price to fall, with the concept that energy consumers will benefit, in Ontario this dynamic effect that I was talking about before is almost instantaneous within that month. Those payments go right back to the generators. So the consumers in that month never really realize that benefit.

MR. RUBENSTEIN: And that's why -- and I think AMPCO recognizes it in their view -- is that is why we should have a net benefit test, so that you are only paying that energy payment if it passes a net benefits test. Is that your understanding as well?

DR. RIVARD: I think I have heard in the evidence that -- from Mr. Anderson that he would only want payment if it was in the interests of consumers, because he represents two types of members. Yes.

MR. RUBENSTEIN: Now, if we look back at paragraph 58, it is your view, as I understand it, that, all else held constant, the net benefit test will be satisfied less frequently, if ever, than in the United States market. You discuss this throughout the evidence, that in your view the net benefits test may never be -- rarely, using your language, if ever, be satisfied. Correct?

DR. RIVARD: Well, certainly I think later on I try and explain why that is. I mean, at that point I kind of set up what the issue is and I go on and explain it.

And the data, the historic data -- and that is probably the best data we have at this point -- says that it would never have been satisfied.

MR. RUBENSTEIN: Let me just focus on a couple of things in the language here. First you say "all else held constant". Can I just ask what things may not be held constant that would change your view?

DR. RIVARD: That's a good question. I just want to think about that. I think my use of "all else held constant" was that -- in the sense of trying to deliver what FERC was looking at versus what would actually happen here. So maybe it wasn't the -- what you're getting at, but I think that is kind of what I had in mind.

MR. RUBENSTEIN: Well, your evidence discusses that in your view -- and you can take me to it if you want -- you have some numbers that you provided at -- let me pull it up here -- paragraph 68 through 71, where essentially you take the view based on the analysis that you have undertaken that paragraph 71 concludes:

> "Overall, the recent historical data suggests that the net benefits test would rarely, if ever, be satisfied in Ontario because..."

In your view, I think what you're saying is that best 0.019 percent of the time the DR resources would clear the market clearing price. Correct?

DR. RIVARD: Yeah, what the data shows is that you would never activate these resources; that's right.

MR. RUBENSTEIN: Well, so then I guess going back to my question, what are the factors that would actually change that?

DR. RIVARD: Okay. I see. So if suddenly there was a large loss of supply, of generation supply, then that would put upward pressure on the prices and it could induce activation more often. That could -- you know, that's -- all else held constant, I think I am saying in the context of what we have seen in recent past and what evidence suggests is going to happen next year, we don't see this likely to happen. But I can't say that if there wasn't this loss of all the nuclear plants or something that you wouldn't see more activation, and I can't say definitively how often. Yes.

MR. RUBENSTEIN: Can you give us a view, would it have to be a material -- like, a significant -- material may not be a lot -- a material or significant change? What is the magnitude we're talking about that would -- that there would be factors that would change that would make it that the net benefit test could be satisfied more often? Materially more often.

DR. RIVARD: Yeah, I don't -- I didn't really -- that really requires forecasts, modelling. Certainly in the time period that I had I didn't think I could offer that with any rigour. The best I could do was use the recent history.

MR. RUBENSTEIN: That's fair enough. I was just wondering if on the screen they could pull up KCLP Staff 1.

And in this you were asked by Staff -- they posed a question to you, and at a high level essentially they were asking you to essentially give us your views when the -- when this capacity gap in 2023 occurs, how this is going to change directionally.

And you respond on the second page, second paragraph. You say:

> "As generators come off contract the relationship between the monthly market price and the global adjustment will change. However, I am unable to say exactly how this change will impact the net benefits test. As existing generation resources come off-market, if the IESO wishes to rely on the capacity in its system planning, the IESO will need to identify a mechanism to compensate those generators for their fixed operating costs required to maintain their facilities as a going concern. Historically in Ontario this has been done using long-term contracts funded through the global adjustment mechanism. If the IESO elects to recontract with existing or new generation resources to meet the forecast capacity gaps starting 2023 then the chances of a net benefit test is passed in Ontario may in fact get smaller in the future."

Do you see that?

DR. RIVARD: Hmm-hmm.

MR. RUBENSTEIN: Now, and we can ask the IESO this tomorrow, but my understanding of moving to the transitional capacity is that IESO is moving away from long-term contracts to a capacity mechanism to secure capacity, essentially, the option mechanism to secure capacity.

So assume that is correct. Does that -- can you help explain, does that change your view about what in 2023 if this more or less is less likely directionally that the net benefits test will be met?

DR. RIVARD: Hmm-hmm. I think the point is still the same, right? With the global adjustment today we have a direct mechanism that says we've already committed to pay those generators what that fixed -- you know, make a payment to those generator covers that fixed cost to make sure that they are available. That is how the contracts work.

And so there is a direct mechanism that if you were to compensate demand response with the hope of lowering the energy price and benefiting consumers, that, you know, within the month that benefit would be offset by a higher payment.

As contracts expire that specific mechanism goes away, but there's still a presumption that those generators are likely still to be needed.

So how will that -- those generators be secured? How will they make sure that they can continue recovering any of their costs going forward? That could be through a contract. It could be through a capacity auction. Either way, I still think that the shortcomings of the net benefit test is it doesn't capture that longer term payment.

It focuses only on the short term energy payment and the short term savings that consumers may get by having a lower energy price. But it doesn't factor in will that lead to the lowest cost overall for both capacity and energy.

And I don't have the answer to whether that net benefit test would be passed more often. But I do know that that net benefit test has to somehow factor that in.

MR. RUBENSTEIN: Can we go back to your report. The premise in your report as we talked about is this in your view, the net benefits test based on your analysis will rarely, if ever, be satisfied. Am I correct with that?

DR. RIVARD: Yes.

MR. RUBENSTEIN: So if that's the case and that energy payments would be -- you would have to pass the net benefits test before any energy payments are made, who is worse off? It seems ultimately it seems the bidding would be exactly the same if a demand resource -- if your analysis is correct that a demand resource is never going to be activated, or it's never going to pass the net benefits test and never receive energy payments, then it is in the essentially in the exact same situation we are with the proposed amendments.

DR. RIVARD: I think that's the logical effect, right, that if -- if you truly do a net benefits test that captures this, which means that that threshold price at which you compensate demand response is so high that it still never happens, the net effect is nothing.

MR. RUBENSTEIN: Now, obviously there is two ways to look at it. One way from the demand response providers is, they're in the same boat than if they were with the amendments or with the way they would like the amendments to look.

DR. RIVARD: Correct.

MR. RUBENSTEIN: But I guess the flip side I am trying to understand is what is the harm in providing them energy payments if they meet the net benefits test?

DR. RIVARD: I think your first point is correct, that if there's -- if the change is superfluous based on the factors of the market, that is even though you properly apply that net benefits test, nothing happens, there should be no harm either.

Now, I think the situation here though is -- I think that's likely the case, but now we have a situation where we're proceeding with a demand response auction that doesn't have an opportunity to have generators participate in that, to the extent that those generators say that, you know, going forward, I just can't recover my costs, and they shut down we might be in a worse situation.

So your hypothesis is true in that if the effect of providing a payment, if you properly have captured the global adjustment is that no payment would have been applied at all, it's true no harm in that respect happens. But unfortunately, we ended up here and we now have a DRA auction that we don't even have an opportunity to have that competition. That is kind of unfortunate.

MR. RUBENSTEIN: But that is an issue -- in six months if the decision comes out in either direction, and either the TCA amendments are come in force as proposed or there is a new amendment that comes in because AMPCO has won and ultimately the results is there will be energy payments, it seems to me your analysis is nothing actually changes.

DR. RIVARD: Well, I agree that if the net benefit test says we never pay anything, that in that sense, nothing happens. That's true.

But there have been real implications, right, of following through with this potentially if a generator -- generators that aren't eligible to compete in the next auction -- which they're not now -- decide they have to shut down.

MR. RUBENSTEIN: You're talking about today. I am talking about in six months where you have two scenarios. TCA has proposed. TCA with energy payments.

DR. RIVARD: Hmm-hmm.

MR. RUBENSTEIN: It seems to me, based on your analysis, practically it actually makes no difference.

DR. RIVARD: If the historic data plays out that even if you applied the net benefit test, factored in global adjustment, such that the threshold is never at a level that you dispatch demand response, then the practical effect is that nothing happens.

MR. RUBENSTEIN: Right. Thank you very much. Those are my questions.

Ontario

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**

MR. SHORT: Yes, that's correct.

MR. MONDROW: And the forward period, which is the period between the auction and the commitment period -- am I right? That's what the forward period is?

MR. SHORT: Between the end of the auction and the start of the commitment period, yes.

MR. MONDROW: Was six months, was to be six months?

MR. SHORT: I believe it's roughly five months, but...

MR. MONDROW: Okay. And the target capacity, do we have that on the record somewhere? What was that?

MR. SHORT: I believe 675 megawatts was the target capacity.

MR. MONDROW: And you said generation registered was how much? Four generators, but do we have the capacity?

MR. SHORT: I'm not entirely sure if I should divulge That, because that indicates the supply mix for the upcoming auction. So I can tell you how many folks registered.

MR. MONDROW: Four, we know that.

MR. SHORT: It's five now, actually. It was five; we have now taken them out.

MR. MONDROW: Okay. But you can't give us the --

MR. SHORT: I would like to be able to, I will just throw this out there. The amount of people that are participating in terms of the quantities, it may give folks an unfair or more information, and maybe it could influence the outcome of the auction. So I am not sure that's the right thing to do is to give out that information.

MR. MONDROW: These fine. Can you tell me if it was more than 600 or less than 600 megawatts? Would that compromise...

MR. SHORT: I can say for certain it was less than 600 megawatts. Are you going to keep going down until I say I can't -- sorry.

MR. MONDROW: No, no, no. I thought about it but I am not going to.

MR. SHORT: I appreciate that, thank you. I am going to start to sweat at some point.

MR. MONDROW: It's not important enough for me, and I don't want to compromise your position, thank you.

So new auction number one, subject to the outcome of this process perhaps, is scheduled to be held June 2020. Again a one-year period and in that respect, commencing May 2021.

MR. SHORT: Yes.

MR. MONDROW: Two commitment periods, summer and winter?

MR. SHORT: That's correct.

MR. MONDROW: An 11-month forward period for that auction?

MR. SHORT: I agree with that math, yes.

MR. MONDROW: Thank you. Do you know what the target capacity is likely to be?

MR. SHORT: As far as how we develop the target capacities at this point, because we are transitioning from a process where the DRA was -- so the demand response document number 1 is essentially the K3.1, which is simply the examination compendium from the IESO which has the IESO's evidence.

MS. SPOEL: Great, thank you.

MR. RUBENSTEIN: As well as, I have a compendium, if we can mark that short compendium, just a few documents, on the record.

MS. DJURDJEVIC: That very large tome of a few pages will be Exhibit K3.5.

EXHIBIT NO. K3.5: SEC COMPENDIUM FOR IESO PANEL 5.

MR. RUBENSTEIN: And the last thing is -- and I -- just from some discussions that were brought up, I may refer to -- I told my friend, so it may come up on the screen, but it's from K1.6. This was that -- IESO's cross-examination compendium of Mr. Anderson, but it's a very short amount, and if I do refer to it, it will be brought up on the screen, so you don't need to --

MS. SPOEL: Okay, thank you, because I am not sure we have that --

MR. RUBENSTEIN: -- dig that out.

MS. SPOEL: -- in the room any more, thank you.

CROSS-EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: I just have a couple of sort of grab-bag of areas that haven't been addressed from the cross-examinations today, so bear with me, please.

I just want to understand the intent of the TCA as it relates to your evidence and the issue before us. And if we turn -- as I understand it -- you don't need to, I guess, turn up the evidence -- the TCA is the first step in evolving the DRA auction to a more competitive capacity auction; correct?

MR. SHORT: That's correct.

MR. RUBENSTEIN: And the intent is to -- where historically you've relied on long-term contracts to secure capacity -- is to move it to more of an auction mechanism; correct?

MR. SHORT: It's twofold, I think you have said that accurately, about trying to not necessarily sign long-term contracts. We've seen challenges with the -- ultimately the competitiveness, the lack of transparency and the flexibility.

The other thing, just a slight suggestion, is we are evolving the DRA to something else, because we're looking to introduce other resources in the next, so demand response auctions, DRs essentially had their own area to -- their own kind of exclusive auction, and we are trying to add other resources to the mix to make it more competitive and to broaden the participation so we can meet our 2023-plus needs.

MR. RUBENSTEIN: And as I understand, you had a DR-only auction for a number of years, correct?

MR. SHORT: Correct, since 2015.

MR. RUBENSTEIN: It is the IESO's view that it's been a success.

MR. SHORT: In terms of broadening its original intent was to get folks ready for future participation we have certainly increased the level of participation, the megawatts and -- that are acquired and offered into the auction, and as well the price that ultimately consumers would pay has been -- gone down. I think it's just over 40 percent since 2015. So you would check the box on a lot of successes.

MR. RUBENSTEIN: And I understand from the evidence you have a DR auction, so you have secured demand response capacity over the last few years. But they have been activated very infrequently, correct?

MR. SHORT: Correct. As Ms. Trickey indicated, it's -- when we acquire that additional level of capacity, it's usually more of an assurance so we can comply with our standards and make sure we have got sufficient capacity for those the worst -- what planners look for is kind of the worst hour of the worst day of the entire year, and we are trying to plan for that, because that's part of our job, to worry about the what ifs.

MR. RUBENSTEIN: If we go to page 2 of our compendium, this is K3.5, we asked -- you had provided some information in the question, not exactly what we asked.

But ultimately, as I understand the last auction, the December 2018 auction, which covered a year -- which would cover from May 1st, 2019, to April 30th, 2020, you're expected to ultimately spend on capacity payments $44 million. Do I have that right, that number right?

MR. SHORT: Yes, approximately, assuming resources meet their capacity obligations.

MR. RUBENSTEIN: So even with the limited activation, it's your view that that $44 million provided the value that you've talked about, correct?

MR. SHORT: Yes.

MR. RUBENSTEIN: All right. If we can go now to your evidence, you can pull this up at K3.1, paragraph 3. So it's on page -- paragraph 3. You have three bullet points -- sorry, I will just wait until you have it.

MR. SHORT: Yes.

MR. RUBENSTEIN: I take it you lay out three bullet points, and I read these three bullet points as really the reason why you think that TCA is important. That's the best place I could find ...

MR. SHORT: Yes.

MR. RUBENSTEIN: So I want to first ask about part A. So the first thing you say is it's important for reliability purposes to launch a TCA in December 2019 to progress in the TCA in a phased manner, and ultimately to get to the 2023 capacity gap, correct?

MR. SHORT: Correct.

MR. RUBENSTEIN: And you talk about the 2023 capacity gap in the evidence and in a lot of the excerpts. And we had asked you in an interrogatory, in SEC number 7 which is on page 11 of our compendium, and the question was, is there a forecast capacity gap before the summer of 2023, if so, please provide details, and your answer is yes. Do you see that?

MR. SHORT: Yes, that's the -- if you look at the line that refers to summer adequacy reference outlook without existing resources for 2020, the number there at the time is indicated at 811 megawatts.

MR. RUBENSTEIN: Okay. So my first question is: Is the TCA necessary to meet the capacity gap before 2023, or is it only at 2023?

MR. SHORT: It's before 2023 as well. We are also preparing for the bigger gap in 2023.

MR. RUBENSTEIN: Now, you provided a number of -- you had a long exchange with Mr. Mondrow about the capacity gap. And when I flipped to this while you were having the discussion, the numbers didn't seem to be the same.

And I took it -- and I know there's an undertaking about some more updated numbers, but I was just trying to understand the relationship between your response to this specific question and what the actual capacity gap is in, say, 2020, '21, '22.

Is this just an outdated table and you are going to provide the updated numbers in response to undertaking showing different things?

MR. SHORT: Yeah, this is the information we published in September 2018. And we will look to see if we can find updated information with respect to a reliability outlook that was published maybe a little bit more recently.

MR. RUBENSTEIN: Well, you talk about being published. Like is there a more updated number that you have?

MR. SHORT: Yes, there is.

MR. RUBENSTEIN: And are you only going to provide it if it's published? Sorry, I didn't fully understand.

MR. SHORT: So I think we took an undertaking to provide that information.

MR. RUBENSTEIN: If it's published or if you have a more updated and you just haven't published it.

So I guess the question I asked in this interrogatory -- and I am trying to understand what the actual capacity is, not what information you have published, but what ultimately is the IESO's best view of the gaps in these years are.

MR. SHORT: So the information provided in the interrogatory is the best long-term view of information that we have. We also produce short term information as well, and maybe a better response for this interrogatory could have been that reliability outlook information.

MR. RUBENSTEIN: And that's what you are going to be providing in that undertaking. All right.

MR. ZACHER: We will update. I just noticed one -- I think in this interrogatory response, should it referenced at September 13, 2019? I just want to make sure that it's correct. No, I am wrong; sorry, I apologize.

MR. SHORT: 2018.

MR. ZACHER: 2018, just wanted to make sure there wasn't a mistake.

MS. SPOEL: That's fine, thank you.

MR. RUBENSTEIN: So if we go back --

MR. SHORT: Sorry, we are trying to answer the question here as succinctly as possible when it comes to the IR response.

And so the information was a gap before 2023, and so we provided the latest. So we have long term information which is -- which was that the September 2018 information. So that's what we are trying to provide you, you know, as simplistic as possible.

We do update numbers on a more regular basis and that reliability outlook shows, but it might only just show for September, and I would have to look for the information – sorry, it might only show for 2020, and I would have to look at that information.

MR. RUBENSTEIN: But even if we looked at the numbers here with respect to that information, so in 2019 essentially you are in a surplus. There's no capacity gap, correct?

MR. SHORT: Yeah, that's correct.

MR. RUBENSTEIN: But you still ran the DR auction in 2019 to secure capacity?

MR. SHORT: Again, consistent with trying to get ready for 2023, we have viable DR resources and we are looking to continue to support them being available for that future capacity in 2023

So no different than generators, we are trying to ensure there's an opportunity for folks to participate, ideally more broadly than just demand response.

MR. RUBENSTEIN: And is it your view like --

MS. SPOEL: Mr. Rubenstein, I am having some trouble hearing some of your words. If you can sit a little closer to the microphone, it might -- you are soft spoken and sometimes it's hard to hear.

MR. RUBENSTEIN: I apologize. This ties into my question on part B of paragraph 3. So in part B you say -- and this is essentially, as I understand, what Kingston Cogen's evidence has been, that ultimately as contract -- existing generators come off contract, they need some sort of payments to stay in operation until that 2023 when the large capacity gap occurs, correct?

MR. SHORT: We are looking for the opportunity to provide that capability --

MR. RUBENSTEIN: The opportunity to earn some revenue.

MR. SHORT: Yeah, and to supply capacity that we need.

MR. RUBENSTEIN: Okay. And then the third thing you talk about is it will increase competition and benefit consumers by allowing participation of new capacity resources and increasing the supply of capacity.

I take it what you mean is more bidders in the auction, more capacity that's bid in the auction is likely to lower the clearing price of the auction, correct?

MR. SHORT: Yeah. Typically increased competition leads to opportunities for innovation, for maybe better risk management, all sorts of -- it tends to put pressure on price and so it may not result in a lower price, but it usually results in the lowest capacity price.

MR. RUBENSTEIN: All right. If I can you to turn to page 9 of our compendium? We asked you: The IESO has provided its view on the expectation regarding the frequency of economic activation of DR resources. On a comparative basis, what is the view of the forecast quantity of energy that generators have capacity obligations as a result of the TCA will produce?

So just stopping there, your evidence talks about what your expectation on the activation of DR resources are with energy payments, correct?

MR. SHORT: Just give me a second to read it. Sorry, my apologies. Could you repeat the question again now that I have read it?

MR. RUBENSTEIN: The first part of that question is in your -- relating to your evidence where you talk about how you just don't expect there's going to be much activation of the DR resources regardless of the energy payment.

MR. SHORT: I think we've looked at the history over the first four years, yes, and we think the probability is extremely low.

MR. RUBENSTEIN: Essentially, SEC is asking in this question, well, what about at the flip side? How does this work about generator activation? Do we expect in a TCA they are going to be activated very often or not? And your response, as I take it, is we don't really -- paraphrasing -- we don't know, we don't have the history; correct?

MR. SHORT: It's up to the participant to provide energy offers, you know, economic for them, and so it depends on how they offer into the market. That will judge -- that will ultimately be how often they get dispatched is based on their economics in the -- under the energy market.

MR. RUBENSTEIN: So we don't know -- we don't have a comparative basis then to say if we provide energy payments to DR resources that have a capacity obligation, they may be activated at a certain level. We can't do the exact same thing with respect to the generators who may have a capacity obligation.

MR. SHORT: Yeah, it becomes challenging, because we don't know what generators will be successful in the auction -- well, I guess, there won't be any right now, but in June, for example, if we run another auction, we won't know who's successful. Every generator has a different cost profile. It could be a different type of generator, different steam/gas mix, could be a storage facility. We don't know the specifics of their facility.

MR. RUBENSTEIN: All right. If you can go to page 10 of the SEC compendium. So in this interrogatory -- I will paraphrase, but essentially we were asking your views or analysis regarding the impact on costs that will be borne by consumers by providing energy payments to demand response providers.

And your response was you haven't done any analysis, and you essentially pointed us to the comments in the Navigant study; is that correct?

MS. TRICKEY: That's correct.

MR. RUBENSTEIN: And in the Navigant study that we've talked about they talk about the effect of the global adjustment; correct?

MS. TRICKEY: Correct.

MR. RUBENSTEIN: And there was some -- I had some discussion yesterday with Dr. Rivard about this, and there's been some others who have had this discussion, and it was essentially that because certain contracts -- certain generation that exists already in the system are on long-term contracts or through regulated rates, a reduction that you may get in the market price, HOEP, because of a DR resource is being activated may be essentially clawed back through the global adjustment; do you recall those discussions?

MS. TRICKEY: Correct, yes, I do.

MR. RUBENSTEIN: And I used OPG as an example, a utility I know well, but essentially they are provided a certain payment amount for their megawatt-hour, and if HOEP is less than that amount then they -- and they are producing, they get essentially a payment from the global adjustment; correct?

MS. TRICKEY: Correct.

MR. RUBENSTEIN: And I understand similarly, for example, through the FIT -- some of the FIT contracts, wind generators, it's very similar. They are guaranteed essentially a price on a production basis, and they get the difference from the global adjustment, correct?

MS. TRICKEY: I am not an expert on all the different contract types, but generally there are different contract types that do provide that top-up if the energy market doesn't provide enough.

MR. RUBENSTEIN: I was wondering if there is also the other situation which people have -- feel like I have heard about, and I am not sure is correct, where certain generators are guaranteed an overall revenue, not just a revenue on a per megawatt basis if they produce. And so if a demand-side resource essentially outbids a certain -- one of these generation facilities and thus they are not producing, they still would get a payment from the global adjustment?

MS. TRICKEY: I am not an expert. There are so many different contract types that -- and I can't say that I know all of them. I know there are a few types that I have some information on, but I wouldn't want to comment on that.

MR. RUBENSTEIN: Fair enough.

And as I understand, the problem with the clawback is that -- or the -- what Navigant talks about and what's been talked about is ultimately the benefit that you may get from paying the energy payment may actually be clawed back and customers could be potentially worse off, correct?

MS. TRICKEY: Correct.

MR. RUBENSTEIN: And that's an issue you are going to be addressing in the context of your engagement, the possibility of a net benefits test, high level.

MS. TRICKEY: Correct.

MR. RUBENSTEIN: Now, you were asked -- let me ask you about your response. I know your view is ultimately -- if I could take you to your evidence. You mention at paragraph 87 -- my apologies, paragraph 108. You're asked

-- or you answer your own question, I guess, in the evidence, where it says:

"Will the IESO consider energy payments to DR resources?"

And you say:

"Yes. While DR resources will not be entitled to receive energy payments if activated under the DCA during the December 29th commitment period, IESO has not made a final determination on the issue."

Do you see that?

MS. TRICKEY: Yes.

MR. RUBENSTEIN: And I know you haven't made a final decision, but does the IESO have any preliminary views on the appropriateness of this?

MS. TRICKEY: Yeah, I think that we do have concerns, and that's why we wanted to take the time to do a proper study. If we thought it was an obvious answer, I think we would have proceeded. But as there's been lots of discussion with the various types of concerns and -- but, you know, that doesn't mean that we haven't missed something, so, you know, yes, we have concerns and, yes, we intend to complete the study to make a final determination.

MR. RUBENSTEIN: Is that the same concern about why you would launch a study or in the context of all the discussions that you have had since the filing of the AMPCO application, the sitting here listening to us, I assume the discussions you internally have about the issue -- is there any concerns that you have that -- or you have learnt that you just -- simply hasn't been brought out during these discussions? And by discussions, sorry, I mean in the coon text of this hearing.

MS. TRICKEY: It's certainly been very informative, helpful in our deliberations. I can't say that I've learned anything brand-new, but it's certainly helped deepen understanding of the various positions and considerations.

MR. RUBENSTEIN: Now, my understanding from a document that was included in your counsel's cross-examination compendium to Mr. Anderson -- and this is in K1.6, tab 12, if that can just be -- and I hadn't seen this document before, so I apologize. If it can just be put up, and this is tab 12, sorry.

And my understanding is this is a submission from the market surveillance panel to inside the engagement that you're undertake -- stakeholder engagement on energy payments, correct? Is that your understanding of what this document is?

MS. TRICKEY: Yes.

MR. RUBENSTEIN: And as I go down the page on this, to the last paragraph here on that page, it talks about order 745, and then further down it talks about:

> "Loads are not paying the wholesale price but seen as a barrier to fully participating in the wholesale market in order 745. The study should determine what market benefit, if any, would be

achieved by expanding energy payments of loads. It is not evident that the stated goal laid out in order 745 is appropriate or necessary in Ontario. In the present situation a DR resources that is activated saves the spot price on its demand reduction analogous to a generator being paid the spot price for its production. On this basis an energy payment to DR resources looked like a double payment and a number of stakeholders appear to be urging the IESO to accept order 745 as a definite ruling on this issue, but the Ontario situation is different, and we may share the same objectives as FERC."

Do you see that?

MS. TRICKEY: Yes.

MR. RUBENSTEIN: And so I take it this is -- I don't want to overstate this, but as I understand, the MSP had some similar initial views, I will say, than what we heard yesterday from Mr. Rivard?

MS. TRICKEY: I think that's fair to say. I mean, my interpretation of the MSP's concern here is that they are raising a point that the -- one of the concerns that was raised under FERC order 745 was the lack of an incentive for some types of resources to really respond to the wholesale electricity market price.

So if you're a small consumer and you're on a retail rate, or like you would be in Ontario, you are on the regulated price plan, if you avoid consuming because we dispatch you off, you're not avoiding that wholesale price.

So if the wholesale price is a thousand dollars in some hour, that retail price or the RPP price is still going to be, you know, 7 cents or whatever -- I won't do the conversions, but a lot lower. If an aggregator take as whole bunch of those small loads and aggregates them to participate in the demand response auction, as I have said, our model is that, you know, avoiding the energy price should be the appropriate incentive for them to be dispatched off in the energy market.

Well, if you are not actually paying that price, you are not avoiding it and therefore, there's a mis-matched incentive.

So one of, I think, the goals for FERC's order was to provide the energy payment to those loads, so that they now had an incentive to respond to the price, which is very different from what we're talking about here.

But I think -- and I am not saying that that was the whole concern that FERC was looking at, but it was one of them and it has come up in various discussions on the issue. I believe it was brought up in the LEI paper, it was brought up in the Navigant paper. I don't recall if Dr. Rivard brought it up, but it is one of the underpinnings of why FERC wanted to introduce that and it is different than what we're talking about here.

So I don't know if that's what you are getting at, or is that answering your question?

MR. RUBENSTEIN: Sure. Yes.

MS. TRICKEY: One of the additional complications of this exciting issue.

MR. RUBENSTEIN: Lastly, I just want to understand just the practical implication of what happens.

So assume that AMPCO is successful on this review. The Board essentially revokes the transitional capacity auction provisions and says essentially, for the reasons that AMPCO had put forward, that there's no -- it's discriminatory, because you're not providing some sort of compensation activation or energy payments, that's why we're doing it.

So the matter goes back, as I understand it, to the IESO for reconsideration. I just want to understand the timeline of how this is going to work.

So I understand you're undertaking a consultation on this issue with the results, and based on what you said in paragraph 87 of your evidence, you expect that you'll finish that consultation in June 2020. Do I have that correct?

MS. TRICKEY: Yes, and I believe I corrected Mr. Mondrow earlier with May. I think the stakeholder engagement page indicates May, but June, July, it's all pretty close. So yes, we will say that time next year.

MR. RUBENSTEIN: So sometime in June and July, so that's already -- there's another auction that would have expected to be undertaken, correct, that you will not -- that will not be at least in the trance -- will not be a transitional capacity auction, correct?

MS. TRICKEY: I think that that's a bit premature to say definitively.

MR. RUBENSTEIN: Well, I don't understand. If ultimately the plan is to at last complete this, I guess. How would you -- how would you run the auction?

MS. TRICKEY: Can I just look for something quickly?

MR. RUBENSTEIN: Sure.

MS. SPOEL: Mr. Rubenstein, how much longer do you think you're likely to be?

MR. RUBENSTEIN: This is my last, a minute or two.

MS. SPOEL: Okay, fine, thank you. So we want some time for Board questions later.

MS. TRICKEY: There are a range of outcomes, I think is the short answer really. It depends to some degree on what the Board decides and what's included in that decision to some degree on how, you know, whether we can get to, get this study and what the outcomes of the study are. And I am talking about the decision on the energy payments and how that may be factored into the next auction or not.

And I think -- is that answering your question?

MR. RUBENSTEIN: I am just trying to understand the practicalities, because as I understand, your evidence is you need to run these auctions so we can get ready for 2023 and I just want to practically understand how this will play out if AMPCO is successful, because I don't fully understand.

MR. SHORT: Just to reiterate, we do have concerns. We want to run a June 2020 auction, just so we are clear, and we're obviously concerned about anything that would prevent us from doing that.

MR. RUBENSTEIN: As I understand, in June 2020 or July 2020, you will be completed the stakeholder engagement. And if ultimately the output of that is we should have some sort of payment, energy payments, just to be clear, as I understand, it's then at that point then you start the process of amending the market rules to include that, correct?

MS. TRICKEY: If we were to proceed in a typical orderly way, absolutely, then, you know, what -- I guess some of the dates I have been getting tripped up in my mind is it says in our stakeholder engagement that we would present a draft decision to stakeholders in May 2020. That's the disconnect I have had over those different dates.

But at any rate, we would present a decision, we would move forward. If that decision was to move forward, then if we were to move forward in an orderly way, yes, then we would start the process of figuring out how to do that and implementing that.

And I think if that's the case, then the June 2020 auction that we're talking about would proceed under the same basis as today, that there wouldn't be an energy payment in that.

MR. RUBENSTEIN: And if one of the outcomes of that is that you need to have a net benefits test, would I expect that that may take additional time to determine how to do that with all the contracts and all the complexities of the Ontario market, correct?

MS. TRICKEY: Correct.

MR. RUBENSTEIN: And so after the June 2020, the December 2020 is the next auction after that?

MS. TRICKEY: Correct.

MR. RUBENSTEIN: And there was some discussion with Mr. Mondrow that the forward period is increasing over time, correct?

MR. SHORT: Yes, that's correct.

MR. RUBENSTEIN: But the 2019 auction was going to be five months. Do I take it that that is really the minimum amount of time you need? I know that these are longer auction time periods, the forward periods are longer.

But it's really the five months. That's the minimum amount of time you need from having the market rules -- from running the auction to the commitment period. Is that fair?

MR. SHORT: I believe that's part of the stakeholder process that we have had to determine to develop the DRA, and we are looking to transition that to the TCA, which could mean longer, which our plan is to increase the forward periods.

MR. RUBENSTEIN: Well, under the original -- under the market rules that have been stayed, it was going to be five months, correct?

MR. SHORT: That's correct, yes.

MR. RUBENSTEIN: That was a TCA auction?

MR. SHORT: That was the first one transitioning from the DRA to the TCA, yes. So again, we aren't looking to do a big change when it came to the forward period. That was going to wait until the June 2020 auction.

MR. RUBENSTEIN: Can I take from that that the minimum amount of time that the IESO and participants say they need as the forward period is five months?

MR. SHORT: I think for the December 2019 auction, that's correct.

MR. RUBENSTEIN: But we can't say that for some of the Others?

MR. SHORT: I think that's part of the stakeholdering conversations we are have having right now.

MR. RUBENSTEIN: So we don't know if the June one gets pushed off, you can still run a transitional capacity auction if the market rules are passed to meet the May 1st, 2021, commitment period, if it gets pushed off.

MR. SHORT: So it -- there's a combination of the two I guess, as to engaging what stakeholders are interested -- what's feasible. But it's also again our plan to essentially try and solve the 2023 problem by 2021. In order to do that, we start to -- have to start moving up the forward periods.

MR. RUBENSTEIN: I know you are going to stakeholder. But just with the best information we have today, it's the last day of the hearing, so it's last time we will.

In my understanding, so for the May 1st, 2021, to April 2022, you had produced June 20th as the auction date.

Do I take it that really, at worst case scenario, you could actually run that in December, similar to what your plan was for this year?

MR. SHORT: So I am trying to be helpful.

MS. SPOEL: Mr. Short, can I make a suggestion? We are getting -- Mr. Rubenstein, you are a good ten minutes or so over your estimated time.

MR. RUBENSTEIN: I have no more questions.

MR. SMITH: I am going to suggest that we take our break now. You can think about the answer to that question, and then when we come back you can answer the question and we can move on to the next party, and that will maybe save us all some time, and given the time of day and the fact it's Friday afternoon and we all want to get out of here, can we resume at 3:25 and just really have a short break. Thank you.

--- Recess taken at 3:13 p.m.

--- On resuming at 3:27 p.m.

MS. SPOEL: Thank you, please be seated. All right, Mr. Short. I think we left it that you were going to think about the answer to the question that Mr. Rubenstein posed to you, which was how long do you need? Could you delay the start of the transitional capacity auction currently scheduled for June 2020 if you needed more time to implement things like any changes that might be made as a result of our decision, or not, or any other changes that might be required.

MR. SHORT: And if I've also got a five months kind of the minimum.

MS. SPOEL: Yes.

MR. SHORT: I think it got it now. Sorry, it's getting late.

So I think from our perspective right now, five months, give months or take a few weeks, is the minimum time. As we add new resources, that time may change.

What we also have -- we've lost essentially an iteration right now, and we have laid out a plan to get to where we think we need to be. So the combination of those two items is of what stakeholders we think need, and our plan to move the forward period to be ready in 2021 for 2023. We think the time frames are accurate, give or take, you know, maybe a few weeks here or there.

Did I relatively answer the question, please?

MR. RUBENSTEIN: It's enough.

MR. SHORT: It's enough, okay. I appreciate your indulgence.

MS. SPOEL: I think now it's your turn, Ms. Djurdjevic.

CROSS-EXAMINATION BY MS. DJURDJEVIC:

MS. DJURDJEVIC: Thank you, Madam Chair. Staff has a few questions and I want to sort of give you a bit of context.

We have had a lot of in evidence the hearing about DR resources, and we have been using the example of physical dispatchable load. For example, the steel mill that Mr. Anderson discussed and has been put to other witnesses.