EB-2009-0242

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 ("IESO")

COMPENDIUM OF EVIDENCE FOR THE FINAL ARGUMENT OF THE IESO

December 11, 2019

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INDEX

TABLE OF CONTENTS

TAB NO.	DOCUMENT DESCRIPTION	SOURCE
16.	AMPCO Submission, IESO Stakeholder Engagement on Energy Payment for Economic Activation of DR Resources, dated October 25, 2019	Exhibit K1.6, Tab 11
17.	Market Surveillance Panel, Energy Payments for Economic Activation of Demand Response Resources, Comments on the Stakeholder Engagement Plan, dated on November 18, 2019	Exhibit K1.6, Tab 12
18.	DRWG Presentation on Out of Market Activations, dated June 19, 2019 (Excerpts)	AMPCO Notice of Appeal, dated September 26, 2019 at Footnote 14

TAB 1

EB-2019-__________

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

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

NOTICE OF APPEAL

Nature of the Appeal and Relief Sought

1. The Association of Major Power Consumers in Ontario (AMPCO) applies to the Board for review of the Independent Electricity System Operator's (IESO) amendments of the Ontario Electricity Market Rules (Market Rules) for implementation of a transitional capacity auction (TCA).

2. On September 5th, 2019 the IESO published, pursuant to *Electricity Act, 1998* (*EL Act*) section 33(1), a package of Market Rule amendments[1] (the Amendments) to facilitate expansion of the existing Demand Response Auction (DRA) platform that has been operative in the IESO Administered Market (IAM) since 2015 into a Transitional Capacity Auction (TCA) platform. The Amendments will allow electricity generators to participate in future capacity auctions alongside Demand Response (DR) resources.

3. Generators receive payments for energy services provided to the IAM. DR resources do not (though the IESO has recently indicated that it intends to review the issue of DR resource eligibility for energy payments for services that they provide to the IAM).

4. The effect of implementing the Amendments to broaden the DRA to a TCA without first addressing the inequity in treatment between generation resources and DR resources in

[1] MR-00439-R00-R05.

the IAM energy market is to unjustly discriminate against DR resources, and in favour of generation resources. This is because the Amendments would allow the latter to effectively and unfairly displace the former in the capacity auction platform which was developed for DR resources and through which such resources have been successfully and competitively participating in the IAM since 2015.

5. AMPCO seeks an order from the Board revoking the Amendments effective the date of the Board's decision herein, and referring the Amendments back to the IESO for further consideration, all pursuant to section 33(9) of the *EL Act*.

6. The first TCA facilitated by the Amendments is currently scheduled for early December, 2019. The Amendments were passed in order to allow the first TCA to proceed. Should the first TCA proceed prior to determination by the Board of this application, generators that participate in the new TCA will be provided with an unfair competitive advantage, and DR resources which have historically participated actively and effectively in the DRA will be unduly and unjustly disadvantaged and potentially irreparably harmed.

7. AMPCO will thus also seek an order of the Board, by way of a motion pursuant to *EL Act* sections 33(7) and 33(8) and Rule 8 of the Board's *Rules of Practice and Procedure* (*Rules*), staying the operation of the Amendments pending completion of the Board's review of the Amendments.

8. AMPCO further relies on section 19(4) of the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Sched. B (*OEB Act*), and Rule 17 of the OEB's *Rules*.

Summary of the Grounds of the Appeal

9. The Amendments adopt rules to implement the first phase of a TCA. The IESO explains that Phase 1 of the TCA, *"enables non-committed dispatchable generators to participate in the TCA alongside dispatchable loads and hourly demand response resources. The*

TCA represents an evolution of the demand response auction into a more competitive capacity acquisition mechanism."[2]

10. The Phase 1 December, 2019 TCA was initially proposed as a first step towards transition to an Incremental Capacity Auction (ICA) to be implemented in 2022 in order to address what had been an identified need for capacity following that date. In July 2019 the IESO announced suspension of work on the ICA in light of an updated forecast indicating sufficient baseload and other resources to ensure reliability for the foreseeable future[3]. As such, the first TCA will simply be the first in potentially a series of capacity auction evolutionary steps without any defined end state or particular timing need.

11. While the IESO has indicated that it will address the issue of compensation of DR resources for the value that they provide to the IAM, resolution of this issue is not anticipated prior to the proposed December 2019 implementation of TCA Phase 1. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators will unnecessarily damage the existing, highly successful DRA market mechanism, which would be unfair to DR resources and counterproductive to robust evolution of the Ontario electricity market.

12. Without ensuring just and reasonable compensation to DR resources, on a comparable basis with other resources which bring similar value to the IAM, the TCA could result in replacement of one set of capacity providing resources with another. This would not enhance competition, but it may well stifle it.

13. The IESO's proposal for developing a broadened capacity auction is part of its overall Market Renewal Program (MRP). The overall objective of the MRP is to encourage and enhance competition[4]:

> *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.*

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[2] IESO Memorandum to the Board of Directors of the IESO, from Michael Lyle, Vice President, Legal Resources and Corporate Governance Chair, IESO Technical Panel, dated August 20, 2019 re: Recommendation from the Technical Panel on Market Rule Amendment Proposal.
[3] IESO, Energy Payments for Economic Activation of Demand Response Resources, September 25, 2019.
[4] IESO Transitional Capacity Auction, Phase 1 Design Document, April 11, 2019, page 1, 2nd paragraph.

14. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

a. Undermine competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

b. Introduce unjust discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of the eligibility of such resources for energy payments.

15. Because they discriminate against DR resources and are likely to stifle (not enhance) competition, the Amendments are not only unjustly discriminatory, they are also inconsistent with various of the *EL Act*'s purposes, including:

a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

c. promoting 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;

d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

16. Pursuant to subsection 33(9) of the *EL Act*, the Board must revoke and refer back to IESO amendments to Market Rules that are: (i) inconsistent with the purposes of the *EL Act*, or (ii) unjustly discriminatory against a market participant or class thereof. Because the Amendment is both inconsistent with the *EL Act*'s purposes and unjustly discriminatory to DR Resources, the Board must exercise that power in this case.

Background to the Appeal

A. Historical Demand Response Auctions.

17. DR is the changing of electricity consumption patterns by end use consumers in response to market prices.[5]

18. Since 2015 the IESO has held annual DRAs to acquire DR capacity from market participants that are able to provide that capacity to the market in exchange for an availability payment (which is for present purposes essentially a "capacity payment" - i.e. a payment to ensure that capacity is available to supply energy services as and when called upon).

19. Four successful DRAs have been held in Ontario, the most recent in December 2018. The IESO's report on the most recent DRA underscores the success of the DRA program:

> *This year, 38 organizations were registered as auction participants, the highest number since the auction began in 2015. The successful proponents included four new participants who represent a mix of commercial and industrial consumers.*
>
> *The average annual clearing price for availability payments of $52,810/MW represents a 30% decrease from last year, and a 42% decrease since the first auction in 2015. The auction cleared 818 megawatts (MW) for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period.*
>
> *Moving in to its fourth year, the auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases. Lower capacity prices benefit all Ontario consumers, while auction participants benefit by offsetting their energy costs and improving their competitiveness.*
>
> *As the electricity system moves towards competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand response will increase competition leading to overall lower prices for Ontario consumers.*[6]

[5] IESO Market Manual, Part 12.0: Demand Response Auction, Issue 6.0, page 4, paragraph 1.
[6] IESO, IESO Announces Results of Demand Response Auction, December 23, 2018.

B. Transition to TCA Without Addressing Compensation for DR Resources Inimical to IESO Objectives and to *EL Act*'s Purposes.

20. Starting in December, 2019 the IESO intends to "transition" the DRA into a broader auction by opening participation to other resources. The TCA will permit non-committed dispatchable generators to participate in the auction alongside dispatchable loads and hourly demand response resources.

21. Generation resources, unlike DR resources, have other revenue opportunities in the IAM, including payments for energy services provided. DR resources do not currently have commensurate revenue opportunities for the energy services which they provide to the market.

22. If the TCA is implemented now (through the Amendments), generators will bid into capacity auctions taking 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.[7]

23. As long as this is the case, commandeering the currently successful DRA into a TCA will not broaden the existing auction platform, it will only result in driving the DR resources that have successfully participated in that DRA out of the fledgling IESO capacity market, and replacing one set of capacity auction participants (DR) with another (generators). This would actually be a step backward in evolution of the IAM, not a step forward.

24. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform. This result is contrary to various of the *EL Act*'s purposes, including:

[7] Energy payments avoided by the load are <u>not</u> economically equivalent to energy payments for provision of demand reduction to the market, and are not adequately compensatory for the value provided by DR resources to the energy market: 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 62.

a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

c. promoting 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;

d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

25. This result is also inimical to the IESO's own objectives of enhancing competition for the benefit of consumers.

26. As noted above, the overall objective of the IESO's MRP is to encourage and enhance competition[8]:

> *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."*

27. The IESO's proposal to evolve the DRA into a broader based capacity auction is to the same end[9]:

> *The ICA 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.*

28. The success of a broadened capacity auction hinges on expanding participation in competition for the provision of capacity:

> *One of the advantages of the ICA 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*

[8] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.
[9] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 1, last paragraph.

generating facility and a megawatt of reduced consumption from demand response. [10]

29. The TCA would start with the DRA, and add non-committed dispatchable generators as eligible capacity auction participants. The IESO's stated intent in so doing is to *"enable competition between additional resource types"*.[11]

30. At the same time the IESO has acknowledged concerns that there are barriers to DR participation in the IESO markets, and that one of these barriers is the unavailability to DR resources of energy payments.[12]

31. The IESO proposes to study the introduction of energy payments for DR resources (i.e. to determine *"whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations"*). The study proposed is to be concluded *"before the end of 2020"*, with a next step proposed to be to *"[o]btain input from stakeholders on the approach to conducting the analysis required to make this determination"*.[13]

32. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform.

33. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

   a. Undermine competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

   b. Introduce undue discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of their eligibility for energy payments.

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[10] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 3, 3rd paragraph.
[11] *Transitional Capacity Auction Phase I Design Document*, April 11, 2019, p.2, para. 8.
[12] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 54 *et seq.*
[13] IESO Demand Response Working Group Meeting Materials, June 19, 2019, page 7.

(The IESO has recently recognized just this sort of issue in respect of DR compensation for out of market (i.e. testing or emergency) Hourly DR resource activations.[14])

34. Premature introduction of a TCA such that it undermines the ability of DR resources to compete in Ontario's competitive electricity market would be a regressive step in the quest for enhanced competition and innovation.

35. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators and other sources of capacity would unnecessarily damage a highly successful existing market mechanism, which would be unfair to DR resources, counterproductive to robust evolution of the Ontario electricity market, and irresponsible on the part of the IESO.

C. Failing to Compensate DR Resources is Unjust and Unreasonable.

36. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services is unjust and unreasonable. In a Final Rule issued in March, 2011 the United States Federal Energy Regulatory Commission (FERC) determined that:[15]

> *... when a demand response resource participating in an organized wholesale energy market... has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective... that demand response resource must be compensated for the service it provides to the energy market at the market price for energy... This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.*

37. In the course of its consideration of the equivalency of DR resources and generation resources in providing energy services, the importance of recognizing and compensating this equivalency appropriately, and the importance of thus reducing barriers to DR

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[14] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 36 *et seq*.

[15] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 1.

participation in wholesale markets, FERC cited an earlier order which included a finding that[16]:

> *A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.*

38. FERC went on to find that:

> *Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy.*[17]
>
> ...
>
> *In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."*[18]

39. In its rulemaking deliberations FERC also considered arguments that DR resources are "compensated" by avoiding energy costs when responding to requests to curtail consumption, and accordingly paying such resources for energy thereby effectively supplied would amount to double compensation. On these arguments FERC found as follows:[19] [emphasis in original]

> *Furthermore, Dr. [Alfred E.] Kahn argues that paying demand response [marginal price] sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but one is no more a [case of overcompensation*] than the other: the one delivers electric power to users at marginal costs – the other – <u>reductions in cost</u> – both at competitively-determined levels [*Insert in original].*
>
> *... In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the 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 [marginal price] to supply resources clearing the day-ahead and real-time energy markets encourages "more efficient supply and demand decisions in both the short*

[16] Ibid, paragraph 57, citing FERC Order No. 719.
[17] Ibid, paragraph 59.
[18] Ibid, paragraph 61.
[19] Ibid, paragraph 62.

run and long run," notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

40. FERC also recognized in its rule making findings the interrelationship between just and reasonable compensation to DR resources in energy markets and the fairness of associated capacity markets. FERC noted *"how the increased participation by demand resources [in energy markets] could actually increase potential suppliers in capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down"*, and the need to *"examine the way in which capacity markets already may take into account energy revenues".*[20]

41. The FERC's conclusions on this topic followed a comprehensive rule making process during which opposing positions on the issue were thoroughly represented (with supporting expert evidence), canvassed and considered.

42. Moreover, the IESO itself has recognized the value DR Resources provide by indicating that it will address the issue of compensation of DR resources for the value that they provide to the IAM.

43. Just and reasonable compensation for DR resources must be addressed, and it must be addressed before the implementation of the TCA so that DR resources are not unfairly driven out of the fledgling capacity market.

D. Instituting a TCA without resolving issues regarding just and reasonable compensation to DR resources is discriminatory.

44. As outlined above, the pre-eminent North American energy regulator – FERC - has carefully and thoroughly considered the role of DR resources in wholesale energy markets, and the issue of just and reasonable compensation of those resources for their participation, and has concluded that:

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[20] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 67, footnote 167.

a. Failure to compensate DR resources for the value they provide to energy markets in the same manner as compensation is afforded to generation resources for the value which they supply to energy markets results in wholesale prices that are unjust and unreasonable.

b. The fairness of compensation of wholesale energy market participants for energy services provided influences the fairness and efficiency of capacity markets.

45. It follows that expanding the current DRA platform to allow generation resources eligible for energy market compensation to participate in the broadened capacity auction without addressing just and reasonable compensation for DR resources providing energy market services would result in a capacity market that is unfair and inefficient, and effectively anti-competitive and discriminatory.

46. Without resolution of payment to DR resources for energy services that they can and do provide to the IAM in a manner that fairly recognizes the value of these services provided, inviting generators to compete with DR resources in a capacity auction, which will be the effect of the Amendments, will unduly and unfairly prejudice the ability of those DR resources to compete, and would thus be unjustly discriminatory.

E. Market Rule Amendments which, in the result, are unjustly discriminatory or contrary to the purposes of the *EL Act* must be rejected.

47. The *EL Act* governs the authority of the IESO to make Market Rules, and the manner in which the Board oversees that IESO authority.

48. Subsection 33(9) of the *EL Act* requires the Board to consider whether a Market Rule amendment *"unjustly discriminates against or in favour of a market participant or class of market participants"*. If the OEB so finds, it <u>must</u> make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

49. For the reasons articulated above, Market Rule amendments which have the effect of allowing generation resources to unjustly and unfairly compete against DR resources for the provision of capacity to the IAM would *"unjustly discriminate against a class of market participants"* – i.e. DR resources currently active in the very successful DRA – and <u>must</u> be revoked by the Board.

50. Furthermore, subsection 33(9) of the *EL Act* requires the Board to consider whether a Market Rule amendment "*is inconsistent with the purposes of this Act*". If the Board so finds, it must make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

51. For the reasons articulated above, Market Rule amendments which implement the TCA without first addressing the unfairness and anti-competitive impact of requiring DR resources to compete with generation resources, but without the assurance of compensation for energy services provided to the IAM, is inimical to fostering competition. Consequently, it is inimical to many of the objectives of the *EL Act*, including:

   a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

   b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

   c. promoting 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;

   d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

   e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

Relief Sought

52. For all of the foregoing reasons, AMPCO submits that;

   a. the Board should find that the Amendments are;

      i. inconsistent with the objectives of the *EL Act*; and/or

      ii. unduly discriminatory to DR resources; and

   b. having so found, it must to revoke the Amendments and refer them back to the IESO for reconsideration.

53. In addition to the materials filed with this Notice of Appeal and any additional relevant materials from those required to be filed by the IESO in response to this Notice of Appeal,

in support of this application AMPCO proposes to file affidavit material as and when permitted by the Board.

54. AMPCO also requests eligibility to seek recovery from the IESO of AMPCO's reasonably incurred costs of this application.

September 26, 2019

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Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00439-R00		
Subject:	Transitional Capacity Auction		
Title:	Changes to Market Rule Definitions		
Nature of Proposal:	☒ Alteration	☒ Deletion	☒ Addition
Chapter:	11	Appendix:	
Sections:	NA		
Sub-sections proposed for amending:			

PART 2 – PROPOSAL HISTORY

Version	Reason for Issuing	Version Date
1.0	Draft for Stakeholder Review and Comment	May 15, 2019
2.0	Draft for Technical Panel Review	June 18, 2019
3.0	Posted for Stakeholder Review and Comment	June 27, 2019
4.0	Submitted for Technical Panel Vote	August 6, 2019
5.0	Recommended by Technical Panel; Submitted to IESO Board	August 14, 2019
6.0	Approved by IESO Board	August 28, 2019
Approved Amendment Publication Date:	September 5, 2019	
Approved Amendment Effective Date:	October 15, 2019	

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The IESO proposes to amend the market rules to evolve the Demand Response Auction (DRA) into the Transitional Capacity Auction (TCA) to address capacity needs in Ontario.

Over its four auctions, the DRA has proven successful in driving down capacity costs and increasing competition. Enhancing the IESO's approach to capacity auctions this year by opening participation to other resources is another step toward a more competitive electricity marketplace; it moves Ontario's electricity marketplace down the path of efficiency, competition, and transparency – the key principles of the market renewal efforts.

This proposal will be discussed as part of the Transitional Capacity Auction stakeholder engagement initiative before consideration by the Technical Panel.

Further information on the Transitional Capacity Auction stakeholder engagement is found here.

Background

The changes to Chapter 11 – Definitions outlined below are being made to clearly define key aspects of the Transitional Capacity Auction, differentiate from previous demand response programs, and to retire definitions that will no longer be in use.

Discussion

Most of the proposed changes to the market rules to enable the TCA are to add, change or delete defined terms. This approach was taken to minimize process changes for existing market participants. The proposed market rules for the TCA are based on newly defined terms with the 'capacity auction' prefix which encompasses both the existing DRA commitment period which ends on April 30, 2020 and the TCA, expected to commence in December, 2019. Because of the overlap of the two auction constructs, the new capacity auction definitions will cover both auctions.

Some 'demand response' definitions remain in the proposed ruleset because they are required to facilitate the existing DRA. It is anticipated that most of the remaining demand response definitions will be removed from the market rules after the DRA commitment period has concluded. This will be a further discussion in phase 2. In the same manner, some 'transitional capacity auction' definitions were added only to help facilitate the first TCA and may change in future phases. Managing any overlapping auction rules within the TCA will be a key consideration for the upcoming phases of change.

This market rule amendment proposal was first circulated to stakeholders and market participants who are participating in the Transitional Capacity Auction stakeholder engagement. In response to feedback received, changes were made to the Capacity Auction Zonal Constraints, Capacity Auction Eligible Generation Resource and Qualified Capacity definitions. Additionally, the definition for Demand

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Response Direct Participant has been removed as that definition was used exclusively for the Capacity Based Demand Response Program.

All new defined terms are listed below, and fully defined in the next section.

<u>Chapter 11</u>

- New definitions
    - *auction capacity*
    - *auction period*
    - *availiability window*
    - *capacity auction*
    - *capacity auction deposit*
    - *capacity auction eligible generation resource*
    - *capacity auction offer*
    - *capacity auction participant*
    - *capacity auction zonal constraints*
    - *capacity generation resource*
    - *capacity market participant*
    - *capacity obligation*
    - *capacity prudential support*
    - *capacity prudential support obligation*
    - *capacity transferee*
    - *capacity transferor*
    - *capacity zonal constraints*
    - *demand response resource*
    - *forward period*
    - *non-committed resource*
    - *obligation period*
    - *qualified capacity*
    - *target capacity*
    - *transitional capacity auction*
    - *transitional capacity auction clearing price*
    - *transitional capacity auction reference price*

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

- Updated definitions
  - *capacity auction deposit*
  - *commitment period*
  - *demand response auction*
  - *demand response capacity*
  - *demand response contributor*
  - *demand response energy bid*
  - *demand response market participant*
  - *demand response prudential support*
  - *demand response prudential support obligation*
  - *demand response transferor*
  - *demand response transferee*
  - *hourly demand response*

- Deleted definitions
  - *capacity based demand response program*
  - *demand response aggregator*
  - *demand response auction clearing price*
  - *demand response auction offer*
  - *demand response capacity obligation*
  - *demand response direct participant*
  - *demand response pilot program*
  - *demand response security*
  - *demand response target capacity*
  - *demand response zonal constraints*

Specific changes to the definitions are listed below. There are five additional rule amendment packages that form the entirety of the proposed rule changes for the TCA.

PART 4 – PROPOSED AMENDMENT

Chapter 11

auction capacity means an amount in megawatts of electricity available to be provided to the *IESO-controlled grid*, by *capacity market participants* pursuant to obligations related to a *capacity auction*;

auction period means, with respect to a *capacity auction*, the length of time commencing with the opening of the window during which the IESO receives *capacity auction offers*, and finishing at the time at which the *IESO publishes* auction results;

availability window means the hours in an *obligation period* during which resources associated with *capacity obligations* are required to be available to provide *auction capacity*;

capacity auction means a *transitional capacity auction* or a *demand response auction;*

capacity auction deposit means the deposit required to be made by a *capacity auction participant* in accordance with section 18 of Chapter 7, as a condition of participating in a *capacity auction;*

~~*capacity based demand response program* means the temporary program used by the *IESO* to transition the former *OPA's* contract based DR3 program into the *IESO-administered market;*~~

capacity auction eligible generation resource means a *non-committed resource* that is a *generation facility*, which is also a *connected facility* at the commencement of the capacity qualification process for a given *capacity auction*, and which is registered as dispatchable with the *IESO* from at least the time a *capacity obligation* is allocated to it;

capacity auction offer means an *offer(s)* from a *capacity auction participant*, in the form of a *price-quantity pair(s)*, to provide *auction capacity* for an applicable *obligation period*, reflecting the amount of *auction capacity* that the *capacity auction participant* can reliably and responsibly provide if received as a *capacity obligation*, and which *offer* amount is no greater than the *capacity auction participant's qualified capacity;*

capacity auction participant means a person that is authorized to participate in a *capacity auction*;

capacity auction zonal constraints means the minimum or maximum amount of *auction capacity* that a *capacity auction* seeks to secure for a specific electrical zone as detailed by the *IESO* in each pre-auction report;

capacity generation resource means a *capacity auction eligible generation resource* with respect to which a *capacity market participant* has allocated a percentage of a *capacity* *obligation* received in the given *capacity auction* in accordance with the applicable *market manual*;

capacity market participant means a *capacity auction participant* that has registered with the *IESO* as a *capacity market participant*, and who satisfies requirements contemplated in Chapter 7, section 18;

capacity obligation means the amount of *auction capacity* that a *capacity market participant* is required to provide during the *availability windows* of an *obligation period*;

capacity prudential support means the collateral provided by a *market participant* with a *capacity obligation in* accordance with the requirements contemplated in Chapter 2, section 5B;

capacity prudential support obligation means the dollar amount of collateral required as specified by the *IESO* as a condition of delivering on a *capacity obligation*;

capacity transferee means a *capacity auction participant* who is willing to accept all or a portion of a *capacity obligation* from a *capacity transferor;*

capacity transferor means a *capacity auction participant* who intends to transfer all or a portion of its *capacity obligation* received through a *capacity auction* to a *capacity transferee;*

commitment period means the ~~length~~period of time for ~~which a *demand response market participant* is required to fulfill its *demand response*~~each *capacity auction* over which it secures *capacity*. It consists of two *obligation* ~~by making its *demand response capacity* available for *dispatch* through the day-ahead commitment process and *energy market*;~~*periods;*

~~*demand response aggregator* means a person that is not a *demand response direct participant* and aggregates at least one *demand response contributor* to provide a portion of the aggregator's monthly contracted MW for the contracted *dispatch* period as outlined in the aggregator's *demand response schedule;*~~

demand response auction means ~~the~~an auction operated by the *IESO* prior to December 31, 2018, to ~~procure~~acquire *demand response capacity,* in accordance with section 18 of Chapter 7;

~~*demand response auction clearing price* means the price at which the *demand response auction* clears for a commitment period and will be quoted in $/MW-day;~~

~~*demand response auction offer* means an offer(s) , submitted by a *demand response auction participant*, in the form of a *price-quantity pair(s)* to provide *demand response capacity* in a *demand response auction*;~~

demand response capacity means the expected ~~quantity of~~*auction capacity* a *dispatchable* *load* ~~reduction a~~or an *hourly* *demand response resource* can provide during a specified *availability window* and ~~*commitment*~~*obligation* *period* ~~for~~following a ~~*demand response*~~*capacity* *auction*, and excludes *energy* transacted through the *energy market*;

~~*demand response capacity obligation* means the amount of *demand response capacity* that a *demand response market participant* is obligated to provide during the applicable availability window and *commitment period*, following a *demand response auction*;~~

demand response contributor means an interruptible load or behind the meter *generator* that is owned by a *demand response direct participant,* or with whom a *demand response aggregator* has enforceable rights, and in either case, who will provide a portion of the monthly contracted MW for the contracted *dispatch* period as outlined in the *demand response schedule.* A *demand response contributor* also means the delivery of a ~~*demand response*~~ *capacity obligation* with an *hourly demand response resource,* in which case a monthly contracted MW is replaced by a ~~*demand response*~~ *capacity obligation*;

~~*demand response direct participant* means a person who is not *a demand response aggregator* and whose *demand response contributors* are owned by the *demand response market participant* and the *facilities* in which the *demand response contributors* reside are controlled by the *demand response market participant;*~~

demand response energy bid means a *bid* in the day-ahead commitment process and the *real-time energy market,* greater than the *demand response bid price threshold* and less than the *MMCP,* by a *demand response market participant* entered for either a *dispatchable load* or an *hourly demand response resource* to fulfill a ~~*demand response*~~ *capacity obligation* availability requirement;

demand response market participant means a ~~person who is a~~ *capacity* *market participant* ~~that participates only in the *capacity based*~~with a *dispatchable load* or an *hourly* *demand response* ~~*program,* the *demand response pilot program,* or is a person with a *demand response capacity obligation;*~~*resource;*

~~*demand response pilot program* means a demonstration project, or projects for a *demand* response service referred to in section 16 of Chapter 7;~~

demand response prudential support means ~~the collateral~~*capacity prudential support* provided by a *capacity* *market participant* in connection with a *demand response* ~~*capacity obligation*~~*auction*;

demand response prudential support obligation means the dollar amount of collateral required as specified by the *IESO* as a condition of delivering on a ~~*demand response*~~ *capacity obligation* received through a *demand response auction*;

demand response resource means, in a *capacity auction,* either an *hourly demand response* resource or a *dispatchable load* and with respect to which a *capacity market participant* has allocated a percentage of a *capacity obligation* received in the given *capacity auction* in accordance with the applicable *market manual;*

~~*demand response security* means the obligations owed to the *IESO* by a third party and other forms of security for the financial obligations of a *demand response market participant,* in the form set forth in section 5A of Chapter 2;~~

~~*demand response target capacity* means the amount of *demand response capacity* which the *IESO* seeks to clear through the *demand response auction*;~~

demand response transferor means a ~~*demand response*~~*capacity auction participant* who intends to transfer all or a portion of its ~~*demand response*~~ *capacity obligation* received through a *demand response auction* to a *demand response transferee*;

demand response transferee means a ~~*demand response*~~ *capacity auction participant* who is willing to accept all or a portion of a ~~*demand response*~~ *capacity obligation* from a *demand response transferor*;

~~*demand response zonal constraints* means the minimum or maximum amount of *demand response capacity* that the *demand response auction* seeks to clear for a specific electrical zone as detailed by the *IESO* in each pre-auction report;~~

forward period means the period of time immediately following a *capacity auction*, to the commencement of an *obligation period*;

hourly demand response means the resource type described in section 19 of Chapter 7, that is a registered facility and used by the *IESO* as a delivery type, on an hourly basis, for a ~~*demand response*~~ *capacity obligation;*

non-committed resource means a *registered facility* that is neither - in whole or in part - rate-regulated, contracted to the *IESO*, contracted to the *OEFC*, or obligated as a resource backed capacity export to another jurisdiction during the entire duration of a given *obligation period;*

obligation period means the period of time for which a *capacity market participant* is required to fulfill its *capacity obligation* through the day-ahead commitment process and *energy market;*

qualified capacity means a quantity in megawatts representing the maximum *capacity auction offer* that a *capacity auction participant* may provide for an applicable *obligation period*, and which corresponds to an amount submitted to the *IESO* by the *capacity auction participant* for qualification during the pre-qualification period of a relevant *capacity auction;*

target capacity means the amount of *auction capacity* which the *IESO* seeks to acquire through *a capacity auction*;

transitional capacity auction means an auction operated by the *IESO* after January 1, 2019 to acquire *capacity,* in accordance with section 18 of Chapter 7;

transitional capacity auction clearing price means the price at which *a capacity auction* clears for an *obligation period* and will be quoted in $/MW-day;

transitional capacity auction reference price represents the price at which resources would be incentivized to enter the market and recover the necessary costs to make their capacity available, recognizing their revenue opportunities and avoided costs in the *energy market*. The reference price is directly associated with the *target capacity* as another key reference point in the demand curve;

PART 5 – IESO BOARD DECISION RATIONALE

Documents presented to the IESO Board of Directors as well as the reasons for adopting the amendments are available online.

TAB 2

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

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

AFFIDAVIT OF COLIN ANDERSON

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

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

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

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

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

The Amendments.

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

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

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

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

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

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

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

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

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

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

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

Implications of the proposed TCA.

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

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

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

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

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

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

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

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

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

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

Harm to DR Resources can be Avoided.

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

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

SWORN BEFORE ME at the City of Toronto, in the Province of Ontario on October 11, 2019	
Commissioner for Taking Affidavits LSUC 55408S	COLIN ANDERSON

This discriminatory treatment must be remedied now - during Phase One Design of the project - not at some undetermined future date. Accordingly, AMPCO cannot support the TCA in its current form and looks forward to working with the IESO and other stakeholders to correct this flaw as part of Phase One activities.

DISCUSSION OF THE DISCRIMINATORY DESIGN ELEMENT

1. The Core of the Discriminatory Design Element

The subject of just and fair treatment and non-discriminatory competition is a major area of concern for AMPCO within the context of the TCA Design Document.

In general terms, the Design Document sets out, among other things, the process by which participants will offer their available capacity into the TCA. Those offers will be evaluated against the target capacity and each other, and successful capacity providers will be determined based on offer price, with the result being that some participants will be successful in their offers (i.e. they will clear the market, and be eligible to provide capacity during the commitment period) and some will be unsuccessful (they do not clear the market and will not be eligible to provide capacity during the commitment period). Successful participants will receive capacity payments during the commitment period, where unsuccessful participants will not.

For clarity, entities that offer lower prices will generally be more successful in clearing the TCA than those that offer higher prices. This is intuitively obvious.

Entities that provide capacity during the commitment period will be obligated to provide corresponding energy offers, for that capacity amount, to allow for the activation of that capacity in the energy market. Should such activations occur, a TCA participant that is a generator will receive energy payments for that portion of its capacity that is activated. A TCA participant that is a DR provider will not. This gets to the core of the discriminatory design element. AMPCO submits that demand response resources must be compensated for the service they provide to the energy market at the market price for energy, in the same way that generators are compensated.

While this subject has been raised before within the context of the Demand Response Working Group, it has not been resolved. Arguably, one could take the position that since currently (i.e. "pre-TCA"), the only providers of demand response are load customers, the issue is not as explicitly unfair as it will be in the future, since all loads are currently being treated similarly (i.e. equally unfairly). There is no discrimination today, since none of the providers receives an energy payment. However, as soon as the pool of DR providers is expanded to include generators, a very real discriminatory element is introduced. Two classes of participants will be created - one that is eligible for energy payments and one that is not. This separation of participant classes is what gives rise to the issue of discriminatory treatment.

If the current IESO design allows for both generators and loads to secure a capacity payment for provision of DR, but only allows a generator to receive an energy payment in the event that its DR is activated, this is unacceptable discrimination that cannot be permitted.

2. Utilization Payments and Energy Payments are Not the Same Thing

In the current Demand Response Auction (DRA) process, it has been possible to avoid having to address this issue by using "Utilization Payments". Since the only participants in the DRA are on the load side (i.e. no generators currently participate) it has been possible to include amounts in capacity offers that act as a proxy for an energy payment, in a situation where capacity is activated. These amounts are referred to as utilization payments. Since all participants would include these amounts in their capacity offers, the issue of discrimination is avoided.

In the design contemplated within the Design Document, this proxy approach no longer works. Because the TCA will allow for two distinct classes of participant - one who receives an energy payment and one who does not - any participant that includes a utilization payment amount in its capacity offer (as a proxy for the non-existent energy payments) will move itself up the offer stack and no longer be competitive with those entities that do not include such costs elements in their capacity offers. Those participants who include utilization payments in their capacity offers are unlikely to clear the capacity market since they will be including cost elements that other participants (i.e. generators) will not be including, because those other participants will cover those costs in their energy payments that they will receive when activated.

It is also not a viable solution for loads to simply omit utilization payment amounts from their capacity offers, since they have no other means of recovering those costs in the event that they are activated in the energy market. In effect, loads are in a no-win situation. If they include utilization amounts, they cannot compete in the capacity market and if they do not include them they may clear the capacity market, but cannot recover legitimate costs if they are activated to provide energy.

For these reasons, it is clear that the topic of utilization payments does not solve the discriminatory treatment that is inherent within the Design Document. DR providers who only receive capacity payments (either with or without utilization payments) are not competing on a level playing field with generators who receive capacity and energy payments.

3. Other Jurisdictions

Ontario is not the only jurisdiction that has contemplated this issue. In the U.S., the Federal Energy Regulatory Commission (FERC) issued Order 745 in 2011. In the Summary of that Order, the following text appears:

> "In this Final Rule, the Federal Energy Regulatory Commission (Commission) amends its regulations under the Federal Power Act to ensure that when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource 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)."[1]

The FERC Order specifically references two conditions that must apply in situations where DR energy payments will take place. First, the resource in question must have the capability to balance supply and demand, and second, the DR resource must be deemed to be "cost-effective". Some form of these conditions could be adopted for use in Ontario to ensure that appropriate resources are paid and that overall value to the system is achieved.

Further, FERC's Order 745 was upheld in January, 2016 by a decision of the Supreme Court of the United States[2]. The following is an excerpt from that ruling:

> "FERC's decision to compensate demand response providers at LMP—the same price paid to generators ... is not arbitrary and capricious. ... this Court's important but limited role is to ensure that FERC engaged in reasoned decision making—that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that decision. Here, FERC provided a detailed explanation of its choice of LMP and responded at

[1] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf
[2] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf

TAB 3

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.

EVIDENCE OF THE INDEPDENENT ELECTRICITY SYSTEM OPERATOR

November 8, 2019

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INDEX

INDEX

17.	North American Electric Reliability Corporation (NERC), *2018 Long Term Reliability Assessment*	December 2018
18.	Northeast Power Coordinating Council, *2018 Ontario Comprehensive Review of Resource Adequacy (Issue 3.0)*	December 2018
19.	*Hourly Demand Response (HDR) Testing Update*	April 25, 2019
20.	Remarks by Peter Gregg at Ontario Energy Network Luncheon	January 28, 2019
21.	Demand Response Working Group Meeting Notes for February 12, 2019,	February 12, 2019
22.	Meeting Ontario's Capacity Needs Presentation, "Evolving the DR Auction to Transitional Capacity Auction"	March 7, 2019
23.	*Demand Response Working Group – Meeting Notes*	April 25, 2019
24.	*Energy Payments for Economic Activation of DR Resources*	October 10, 2019
25.	AEMA and AMPCO Joint Brief, "IESO Proposed Capacity Auctions and Demand Response Resources"	July 2019
26.	*Technical Panel Rationale*	August 13, 2019
27.	*Resolution of the IESO Board of Directors*	August 28, 2019
28.	Reasons of the IESO Board in Respect of an Amendment to the Market Rules	August 28, 2019
29.	*DRA Pre Auction Report*	September 26, 2019

TAB A

TABLE OF CONTENTS

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.

7. The IESO's authority under Part II of the *Electricity Act* includes making market rules: (1) governing the IESO-controlled grid; (2) establishing and governing markets related to electricity and ancillary services; and (3) establishing and enforcing standards and criteria relating to the reliability of electricity service or the IESO-controlled grid.

B. What is the IESO's process to amend the market rules?

8. The IESO's Board has ultimate authority and responsibility to amend market rules.

9. The IESO has developed a stakeholder engagement processes to consult with individuals and organizations for the purpose of informing the IESO's decision-making, including proposed market rule amendments. The IESO's stakeholder engagement processes are designed to promote transparency, efficiency and consistency.[2]

10. All proposed market rule amendments are considered by the IESO's Technical Panel, whose members are appointed by the IESO Board of Directors. The IESO's Technical Panel is composed of stakeholders that represent a broad range of electricity resources and constituencies in the IESO-administered markets. The Technical Panel provides advice to the IESO Board on proposed market rule amendments.

11. Each member of the Technical Panel casts a vote as to whether they are in favour of, or opposed to, proposed rule amendments along with the reason for their position. This information is then communicated to the IESO Board for its consideration in determining whether to approve proposed market rule amendments.

12. After the IESO Board has adopted or rejected a proposed amendment, information on the Board's decision with reasons is posted to the IESO's public website along with the approved amendments as applicable.

13. The IESO is also required to provide a copy of any adopted amendment, along with prescribed information, to the Board before the IESO publishes the amendment and the Board may, not later than 15 days after the amendment is published, revoke the amendment.

[2] The IESO guides its engagement processes in accordance with its Engagement Principles to ensure that the engagement activities follow an efficient and effective process which is conducted with integrity. Attached at **Tab "1"** are the IESO's Engagement Principles, undated.

PART III - THE TRANSITIONAL CAPACITY AUCTION

A. What is the Transitional Capacity Auction?

14. The purpose of the Amendment is to implement the TCA in Ontario. The TCA is the first step in evolving the IESO's existing capacity auction – the demand response auction ("**DRA**") – into a more competitive capacity auction that includes additional resource types and enhanced auction features that will improve reliability. The DRA was limited to dispatchable load and hourly demand response ("**HDR**") resources. The Amendment enables non-contracted and non-regulated dispatchable Ontario generators to participate in a capacity auction alongside dispatchable loads and HDR resources.

15. The Amendment largely leaves the foundation of the DRA in place and begins the transition to a broader capacity auction by expanding eligibility to participate in the TCA to resource types other than DR resources.

B. What does capacity mean in the context of the IESO-administered market?

16. In the context of the IESO-administered markets, "capacity" represents the need to have sufficient resources available to ensure that the demand for electricity in Ontario can be met at all times.

17. At a high level, capacity can be provided by supply resources through energy injections or from loads in the form of demand response.

C. What is the IESO's plan for the TCA?

18. The TCA is the first step in evolving the DRA into a more competitive capacity auction that includes additional resource types and enhancing auction features that will improve reliability. Whereas in the past, most capacity in Ontario has been procured through long-term contracts, the TCA will be a market-based mechanism for securing needed incremental capacity.

19. The TCA will run on December 4, 2019 for a one-year commitment period of May 1, 2020 to April 30, 2021. The commitment period will consist of two seasonal obligation periods.

20. The successful participants in the TCA auction will be required to become authorized as Capacity Market Participants, which will enable them to register resources with the IESO to deliver on their capacity obligations. TCA participants will receive availability payments for providing auction capacity, subject to non-performance charges.

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

22. The IESO plans to increase the forward period[3] for future capacity auctions. The IESO's intention is to run future capacity auctions in June 2020 (for a May 1, 2021 to April 30, 2022 commitment period), December 2020 (for a May 1, 2022 to April 30, 2023 commitment period) and in 2021 (for a May 1, 2023 to April 30, 2024 commitment period).

PART IV - THE DEMAND RESPONSE AUCTION

A. What is demand response?

23. Demand response refers to the change in end-user electricity consumption patterns due to fluctuating market prices. DRA participants who are called upon by the IESO provide capacity by refraining from consuming energy from the IESO-administered grid rather than, as in the case of generators, supplying energy to the grid.

B. What is the DRA?

24. The IESO introduced the DRA in 2015 as a means of securing demand-side capacity for the IESO-administered grid. The DRA differs from former Ontario Power Authority (**"OPA"**) DR programs in that it is a market-based program administered under the market rules and DRA participants are integrated into the IESO-administered market, as opposed to the former OPA contract based DR programs.

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[3] A forward period is the time between the execution of the auction and the first day of the commitment period.

25. DR participants in the DRA (**"DRA participants"**) participate in the energy markets either (1) dispatchable loads that responds to a five-minute schedule, or (2) as Hourly Demand Response (**"HDR"**) participants where participation limited to hourly blocks (up to 4 hours per day) with activation notice required at least two hours in advance of the need.

26. The DRA procures capacity for (1) a summer commitment period which occurs from May 1 to October 31 and (2) a winter commitment period which occurs from November 1 to April 30.

C. What are the mechanics of the DRA?

27. DRA participants are required to submit offers in the DRA for quantities between 1 MW and the DR capacity for which they were qualified in the DRA pre-auction process and are allowed to use offer laminations reflecting the prices of providing various levels of capacity. The prices offered must represent the minimum prices at which the participant is willing to provide each incremental quantity of capacity.

28. DRA participants must be willing to provide DR capacity – by reducing their consumption – starting on the first day of the commitment period, failing which they are subject to non-performance charges.

29. After DRA participants submit their offers, the offers are stacked against the demand curve to determine the clearing price for each zone and for each commitment period. The process of determining the auction clearing price is summarized in Market Manual 12.0.

30. After running the auction, the IESO communicates a Public Post-Auction Report to the public and a private Post-Auction Participant Report to market participants.

31. All successful DRA participants in a zone receive the same availability payment per MW day for their capacity obligation. This is referred to a "price as cleared"[4] where all successful participants are paid the same availability payment. As such, assuming resources offer into the auction at or near their costs, lower priced resources would

[4] *Price as cleared* is a standard auction and energy market mechanism where all successfully scheduled resources are essentially paid the highest price for that zone.

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

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[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.

generators receive energy payments, but loads do not. Dispatchable loads bid prices in the energy market represent the point at which the load does not wish to consume electricity.

C. Did DR resources receive energy payments under the former OPA programs?

44. No, they did not. Starting in or about 2005 the former Ontario Power Authority (**"OPA"**) commenced a number of demand-side programs. The OPA held yearly procurement processes in which qualified participants bid for contracts to curtail their electricity consumption during periods of high system demand. These programs paid participants a monthly availability payment in return for the commitment to reduce load when called upon.

45. The final OPA DR program, called the Demand Response 3 (**"DR3"**) program, included utilization payments for activations. These payments, however, were not energy payments. They were contract payments set at a fixed rate of $200/MWh.

46. After the merger of the OPA and IESO on January 1, 2015, the IESO developed a transitional demand response program, governed by the market rules, called the Capacity Based Demand Response (**"CBDR"**) program. The CBDR program bridged the period from the DR3 contract expiration to the commencement of the DRA. For this period, the CBDR program continued some of the features of the DR3 program for the purpose of facilitating the transition to the DRA market-based structure under the market rules. For instance, the fixed rate $200/MWh utilization payment was included in the CBDR program until the expiration of DR3 contracts.

D. Do DRA participants receive energy payments?

47. No, they do not. As stated above, under Ontario's market design and the market rules, only generators are entitled to energy payments. DRA participants are solely entitled to monthly availability payments for the duration of their applicable commitment periods.

E. Will TCA DR participants receive energy payments?

48. No, the Amendment does not change the market rules governing payments in the IESO energy market. DR participants in the TCA will not receive an energy payment in the energy market because, as detailed above, loads are not entitled to receive energy payments under the market design and the market rules that have been in place since market opening.

F. Has the IESO previously studied the issue of energy payments for DR Resources?

49. Yes, the IESO previously commissioned a study of the merit of utilization payments for DR resources through its Demand Response Working Group ("**DRWG**").[7]

50. In the lead up to the launch of the DRA, some stakeholders had inquired about energy payments or utilization payments in the DRA, however, the immediate priority was to implement the DRA.

51. In early 2017, some DRWG members again raised this issue on the basis that "[o]ther jurisdictions (ISO-NE, NYISO, PJM) provide both energy and availability payments to DR [resources]" (p. 19). The IESO therefore agreed to further look into this matter (p. 22).[8]

52. In July 2017, the IESO, in consultation with the DRWG, engaged Navigant, an independent consultant with expertise in DR and electricity markets, to study and prepare a discussion paper on the merits of utilization payments.[9] Stakeholders were invited to provide submissions to inform the scope of Navigant's analysis, which included:

(a) Jurisdictional review - A summary of practices adopted in other markets;

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[7] The IESO established the DRWG in April 2014 to assist in the evolution of DR from a contracted resource into the energy market, as well as to inform the development of pilots and the DRA stakeholder engagement.

[8] Attached at **Tab "4"** is *DR Stakeholder Priorities for 2017*, Demand Response Working Group, dated January 31, 2017.

[9] Attached at **Tabs "5", "6", "7"** respectively are *Utilization Payments for DR Activations*, Demand Response Working Group, dated May 11, 2017; *Utilization Payments – 2017 Work Plan Item*, Demand Response Working Group, dated May 30, 2017; and *Utilization Payments – 2017 Work Plan Item*, "Scope of Discussion Paper", dated July 21, 2017.

(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

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[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

needs. The ICA, which was to be a competitive auction open to participation by a broad range of supply and demand resources, was intended to replace the DRA. The IESO planned to launch the ICA in 2022.

60. On September 13, 2018 the IESO released an updated Electricity Planning Outlook that forecasted a capacity deficit in summer 2023 of 3844 MW (p. 51).[14] Shortly after this, the IESO came to the realization that it was not feasible to launch the ICA in time to address the projected 2023 capacity gap (the **"2023 capacity gap"**) and that alternative measures were required.

61. The IESO determined that the best solution for addressing the 2023 capacity gap was to evolve the DRA into the TCA, for reasons which included the following:

(a) the DRA was directionally aligned with the ICA in that there would be a demand curve based auction that would be executed at regular intervals for a future one-year long capacity need (with two 6-month seasonal periods);

(b) the DRA was a proven mechanism governed by an existing set of market rules;

(c) the DRA provided a platform that could be incrementally evolved into a broader-based and more competitive capacity auction, which would provide the IESO and market participants with opportunities to learn, adapt and make improvements; and

(d) a TCA was preferable to contractually procuring new capacity, which was a less flexible mechanism and risked higher costs for consumers.

62. The IESO also determined that the TCA would provide opportunities for existing off contract generators, which might otherwise decide to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario consumers. In particular, the IESO was concerned with the risk of permanently losing these existing generation facilities and not having them available when the 2023 capacity gap

[14] Attached at **Tab "15"** is a Technical *Planning Conference Presentation*, dated September 13, 2018, p. 51.

emerged, since these facilities may be able to more cost-effectively satisfy future capacity gaps compared to other alternatives, including the construction of new generation facilities. In addition, these existing resources offer an additional measure of certainty as compared to unknown future alternatives.

63. The TCA was also established to enable the future participation of capacity imports from other jurisdictions. Capacity imports are likely to play an important role in the future and the TCA would establish auctions as a credible and certain mechanism that would entice economic external resources to supply capacity to Ontario.

B. Can the IESO rely upon the DRA to fill the forecast 2023 capacity gap?

64. The IESO cannot rely upon the existing DRA to provide sufficient capacity to satisfy the 2023 capacity gap.

65. The DRA in December 2018 attracted a qualified capacity of over 1000 MW. This is insufficient to meet the 2023 capacity gap, which is now forecast at approximately 4000 MW.[15]

66. HDR resources have also had a history of poor performance during test activations. Between February 2018 and January 2019, HDR resources had a 58% failure rate for test activations which were four hours in duration.[16] These results suggest that the actual capacity available to the IESO under the DRA may be substantially less than the results of prior DRA auctions suggest.

67. HDR resources, which comprise the large majority of DRA participants, are also, unlike dispatchable generators or loads, not dispatchable on a five-minute basis. This presents operability and reliability challenges as compared to relying on capacity from supply or dispatchable load resources. Given the IESO's need to maintain a diverse supply mix of resources to meet system needs, both HDR and DL resources are part of the total solution in meeting Ontario's capacity needs – mixed with other resources that

[15] Attached at **Tabs "16" "17" "18"** respectively are the Stakeholder Advisory *Committee Presentation*, August 14, 2019, p.4 (**"*SAC Presentation*"**); and North American Electronic Reliability Corporation, *2018 Long-Term Reliability Assessment*, dated December 2018 (**"*NERC Report*"**); Northeast Power Coordinating Council, *2018 Ontario Comprehensive Review of Resource Adequacy* (Issue 3.0), dated December 4, 2018 ("***NPCC Report***").

[16] Attached at **Tab "19"** is the *Hourly Demand Response (HDR) Testing Update*, dated April 25, 2019.

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.

PART VII - THE IMPLEMENTATION OF THE TCA

A. When did the IESO announce its decision to proceed with the TCA?

78. On January 28, 2019, Peter Gregg, the president and CEO of the IESO, announced that the IESO's plan to expand the DRA to include generators in order to meet immediate resource adequacy needs in Ontario:

> This transition to a capacity auction will start to take shape later this year. As you know, in September we produced a new planning report which indicated a potential capacity gap emerging in 2023. This gap would emerge at a time when Pickering units are closing, as nuclear refurbishments are underway and as some of our generation contracts expire.
>
> While the forecasted gap is relatively small at the moment, our ability to continue to rely on existing resources such as conservation, could affect both the timing and the size of any potential gap.
>
> ...[W]e expect to have a clearer picture of our more immediate capacity needs in the third quarter of this year.
>
> We will meet those capacity needs by leveraging the competitive mechanisms we have in place right now such as the annual demand response auction.
>
> [...]
>
> In December, we will run an auction to meet capacity needs for 2020. Our goal is to have that auction and subsequent auctions build on the current demand response auction including allowing more resource types to compete. This would provide generators whose contracts are expiring over the next few years an opportunity to compete in our electricity market and help meet emerging capacity needs. It is a staged approach to a much more competitive marketplace ... one that we at the IESO and others are striving for. It allows us to realize efficiency, competition and transparency ... the key principles of our market renewal efforts – as quickly as possible.

> It's also a sensible approach, allowing both the IESO and market participants to continue to learn and improve our processes as capacity needs increase[19].

B. What stakeholder engagement did the IESO undertake on the TCA?

79. In February 2019, the DRWG convened to discuss the IESO's plan to evolve the DRA to meet Ontario's capacity needs after 2019. At this time, some DRWG members renewed their interest in DR resources receiving utilization or energy payments. The IESO agreed to further consider this issue.[20]

80. In late February 2019, the IESO initiated a stakeholder engagement to inform IESO decision-making in the design and the implementation of the TCA. The first TCA engagement session was held on March 7, 2019 and included representation from generators, consumers, DR resources and other interested stakeholders. At this meeting, the IESO introduced its "Stakeholder Engagement Plan", which set out the following objectives:

(a) understand the changes involved in the development of the TCA;

(b) understand how proposed changes to the DRA may affect stakeholders; and

(c) gather stakeholder feedback on any significant issues and potential solutions associated with the proposed design features[21] (pp. 16-19).

81. Most participants in the stakeholder engagement were generally supportive of the decision to transition the DRA to the TCA, however, some DR representatives, including AMPCO, objected to launching the TCA without first resolving the issue of energy payments for DR resources. AMPCO and other DR representatives said DR participants would be at a competitive disadvantage vis-à-vis generators in the TCA if they were not entitled to energy payments.

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[19] Attached at **Tab "20"** is *Remarks by Peter Gregg at Ontario Energy Network Luncheon*, dated January 28, 2019, pp. 8-9.

[20] Attached at **Tab "21"** is *Demand Response Working Group Meeting Notes for February 12, 2019*, dated February 12, 2019, p. 11.

[21] Attached at **Tab "22"** is *Meeting Ontario's Capacity Needs*, "Evolving the DR Auction to Transitional Capacity Auction", dated March 7, 2019.

82. The IESO advised participants in the stakeholder engagement that the IESO intended to proceed with the TCA in December 2019, which would serve as an important learning experience for the IESO and market participants in preparation for the 2023 capacity gap, including allowing for price discoverability. The IESO, however, advised stakeholders that the issue of energy payments would be further considered as part of DRWG, including prioritizing the issue as part of the 2019 DRWG Work Plan, and that the IESO would follow up on the Navigant Paper and consider a "made-in-Ontario rationale supported by a good business case" [22]

83. In May 2019, The IESO posted the draft TCA design documents and draft market rule amendments, which were thereafter discussed by stakeholders at a stakeholder engagement session on May 22, 2019.

C. How else did the IESO respond to AMPCO and other DR representatives concerns?

84. In response to AMPCO's and other DR representatives' concerned about energy payments, the IESO decided to commence a separate stakeholder engagement initiative entitled *Energy Payments for Economic Activation of Demand Response Resources* ("***Energy Payments Stakeholder Engagement***"). The IESO commissioned a third-party consultant, Brattle Group, to support the research and analysis and sought stakeholder feedback on the inputs and outputs of third party research and analysis to inform the IESO's decision on the energy payment issue. This engagement and the Brattle study will follow up on some of the important matters identified for further consideration in the Navigant Paper.

85. On October 10, 2019, IESO issued the proposed reference question for consideration in the Energy Payments Stakeholder Engagement – "Should demand response resources receive energy payments when they are activated in-market?" (p. 17) – followed by the proposed scope for the engagement and associated Brattle third party study:

(a) What is the relevant Ontario context and history?

[22] Attached at **Tab "23"** is *Demand Response Working Group – Meeting Notes, dated April 25, 2019*, pp. 4, 11.

(b) What are the economic first principles that drive the activation decision for demand response resources?

(c) How are in-market activations compensated in other jurisdictions and what are the key takeaways for Ontario?

(d) If compensation is provided, what could the compensation model look like in Ontario?

(e) What are the benefits, risks, and implications of a) the status quo, and b) providing DR with energy payments in the near and longer terms?[23]

86. Stakeholders were invited to provide written feedback by October 25, 2019 on the proposed study scope which will inform the final study scope, which the IESO intends to publish in December 2019. AMPCO is participating in this engagement and provided input on the final study scope.

87. The IESO anticipates that the Brattle study will be completed by Q1 of 2020 and the IESO is targeting June 2020 for its rationale and final decision on energy payments for DR resources. The IESO will then commence the market rule amendment process for any changes that are needed to implement the decision.

88. The IESO does not have an estimated timeline as to when any necessary market rule amendments could be put in place to implement its final decision on the energy payments. The timeline would, among other things, depend on the findings of the study and the scope of implementation.

PART VIII - THE ADOPTION OF THE AMENDMENT

A. What was the recommendation of the Technical Panel on the Amendment?

89. On June 18, 2019, the proposed Amendments were submitted to the Technical Panel for review and comment. At the Technical Panel's meeting, on June 25, 2019, the Technical Panel voted to submit the proposed Amendments for stakeholder review and comment.

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[23] Attached at **Tab "24"** is *Energy Payments for Economic Activations of DR Resources*, dated October 10, 2019, pp 23-24.

90. AMPCO, along with the Advanced Energy Management Alliance ("**AEMA**") submitted a joint legal brief[24] that referenced FERC Order 745 and argued that the failure to compensate DR resources with energy payments in a manner equivalent to compensation provided to generation resources for similar services is unjust and unreasonable, unjustly discriminatory, and anti-competitive. The brief further argued that there exists "no rationale for implementing the TCA prior to the resolution of the issue of just and reasonable compensation for DR resources...."

91. Following further stakeholder review and feedback, the proposed Amendments were submitted to the Technical Panel on August 6, 2019. On August 13, 2019, the Technical Panel voted 11-1 to recommend the proposed Amendments for consideration to the IESO Board.[25] Three of the four consumer representatives on the Technical Panel voted in favour of recommending the Amendment.

92. The Technical Panel recommended the Amendments for approval by the IESO Board for reasons, which included the following:

(a) more competition in the TCA, which will put downward pressure on auction clearing prices and will benefit consumers;

(b) supports the development of a reliable capacity market to address future resource adequacy needs;

(c) implementing the TCA in phases, and making changes and accommodations in the future is a helpful step to gaining experience and developing an efficient and competitive electricity market;

(d) TCA helps to ensure that the power system is adequately prepared to meet future needs by providing additional mechanisms to address capacity and energy requirements;

(e) due consideration will be given to DR resource's concerns about fair and reasonable compensation as part of the planned study;

[24] Attached as **Tab "25"** is AEMA/AMPCO Joint Brief, "IESO Proposed Capacity Auctions and Demand Response Resource", dated July 2019.

[25] Attached as **Tab "26"** is the *Technical Panel Rationale*, dated August 13, 2019.

(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.

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[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.

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[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

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[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.

* *

July, 2019

IESO PROPOSED CAPACITY AUCTIONS & DEMAND RESPONSE RESOURCES

AEMA/AMPCO BRIEF

Summary of Concerns and Recommendation.

1. The Ontario Independent Electricity System Operator's (IESO) proposal for developing a broadened capacity auction is part of the IESO's overall Market Renewal Program (MRP). The overall objective of the MRP is to encourage and enhance competition[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.*

2. Proceeding with a broadened capacity auction, in the form of the "Transitional Capacity Auction" (TCA) currently proposed, without first resolving how demand response (DR) resources are compensated for the value that they provide to the IESO administered market (IAM) would not only fail to further this objective, it would undermine this objective.

3. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services in a manner equivalent to compensation provided to generation resources for similar services is unjust and unreasonable.

4. Without ensuring just and reasonable compensation to DR resources, on a comparable basis with other resources which bring similar value to the IAM, the TCA proposal could result in replacement of one set of capacity providing resources with another. This would not enhance competition, but it may well stifle it.

5. While the IESO has indicated that it will address the issue of compensation of DR resources for the value that they provide to the IAM, resolution of this issue is not anticipated prior to the proposed December 2019 implementation of TCA Phase I.

6. Fortunately there appears to be no urgency to proceeding with the TCA. On July 16, 2019 the IESO indicated that it would suspend further work on an "Incremental Capacity Auction" (ICA), the mechanism towards which the TCA was to evolve, in light of an imminent forecast indicating sufficient baseload and other resources to ensure reliability for the foreseeable future. The IESO indicated that work on the TCA would continue as currently planned. The current plan is for an initial TCA by the end of 2019.

7. As there is currently no time frame within which a full ICA program is required, there is no rationale for implementing a TCA prior to resolution of the issue of just and reasonable

[1] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

compensation for DR resources in the IAM, and all the more reason for getting the TCA right initially so that it will facilitate, rather than undermine, competition.

8. ***Implementation of the TCA should be deferred. It would be more appropriate and more equitable, and it would better achieve the IESO's stated objectives, to forego the proposed "Phase I" TCA implementation in December, 2019 and instead focus on getting the proposed TCA right from its initiation.***

Background and Current Status.

9. DR is the changing of electricity consumption patterns by end-use consumers in response to market prices.[2]

10. Since 2015 the IESO has held annual demand response auctions (DRAs) to acquire DR capacity from market participants that are able to provide that capacity to the market in exchange for an availability payment[3] (which is for present purposes essentially a "capacity payment" - i.e. a payment to ensure that capacity is available to supply energy services as and when called upon).

11. Four successful DRA's have been held in Ontario, the most recent in December 2018. The IESO's report on the most recent DRA underscores the success of the DRA program[4] [emphasis added]:

> *This year, 38 organizations were registered as auction participants, the highest number since the auction began in 2015. The successful proponents included four new participants who represent a mix of commercial and industrial consumers.*
>
> *The average annual clearing price for availability payments of $52,810/MW represents a 30% decrease from last year, and a 42% decrease since the first auction in 2015. The auction cleared 818 megawatts (MW) for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period.*
>
> *Moving in to its fourth year, the auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases. Lower capacity prices benefit all Ontario consumers, while auction participants benefit by offsetting their energy costs and improving their competitiveness.*
>
> *As the electricity system moves towards competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand response will increase competition leading to overall lower prices for Ontario consumers.*

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[2] IESO Market Manual, Part 12.0: Demand response Auction, Issue 6.0, page 4, paragraph 1.
[3] IESO News and Updates page; http://www.ieso.ca/en/Sector-Participants/IESO-News/2018/12/IESO-Announces-Results-of-Demand-Response-Auction
[4] *Ibid*

12. Starting in December, 2019 the IESO is proposing to "transition" the DRA into a broader auction by opening participation to other resources.[5] While the "Phase 1" December, 2019 auction was initially proposed as a first step towards transition to an ICA to be implemented in 2022, with the recently announced suspension of work on the ICA, the first TCA will simply be the first in potentially a series of capacity auction evolutionary steps without any defined end state timing.

13. While AEMA/AMPCO support broadening of the DRA into a more robust and competitive capacity auction mechanism, they are concerned that in the current state of the market for DR such broadening will not only fail to enhance competition for the benefit of Ontario consumers, it will have the opposite effect.

14. Generation resources have other revenue opportunities in the IESO administered markets, including payments for energy services provided. DR resources do not currently have commensurate revenue opportunities for the energy services which they provide to the market.

15. As long as this is the case, commandeering the currently successful DRA into a TCA will not broaden the existing auction platform, it will only result in driving the DR resources that participate in that DRA out of the IESO administered market, and replacing one set of capacity auction participants (DR) with another (generators). This would actually be a step backward in evolution of the IESO administered markets, not a step forward.

16. ***AEMA/AMPCO urge the IESO to match the timing for evolution of capacity auctions with resolution of the issue of how to justly and reasonably compensate DR in the broader IESO administered market.***

17. Given that the IESO now does not anticipate in the foreseeable future a period of significant system need, the current proposal to implement the first TCA in December, 2019 cannot be said to be driven by an imminent need to secure capacity. There is no apparent driver for a rush to implementation of a broadened capacity auction this year.

18. ***AEMA/AMPCO urge the IESO to reschedule the first TCA to allow for sufficient time to ensure just and reasonable and non-discriminatory compensation for DR in the broader IAM, thus preserving the ability of the TCA to enhance, rather than restrict, competition.***

Enhancing competition, for the benefit of consumers.

19. As noted above, the overall objective of the IESO's MRP is to encourage and enhance competition[6]:

> *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."*

[5] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 2.
[6] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

20. The IESO's proposal to evolve the DRA into a broader based capacity auction is to the same end[7]:

> *The ICA 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.*

21. The success of a broadened capacity auction hinges on expanding participation in competition for the provision of capacity:

> *One of the advantages of the ICA 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.* [8]

22. The TCA would start with the DRA, and add non-committed dispatchable generators as eligible capacity auction participants. The IESO's stated intent in so doing is to *"enable competition between additional resource types"*.[9]

23. At the same time the IESO has acknowledged concerns that there are barriers to DR participation in the IESO markets, and that one of these barriers is the unavailability to DR resources of energy payments.[10]

24. The IESO proposes to study the introduction of energy payments for DR resources (i.e. to determine *"whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations"*. The study proposed is to be concluded *"before the end of 2020"*, with a next step proposed to be to *"[o]btain input from stakeholders on the approach to conducting the analysis required to make this determination"*.[11]

25. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform.

    (a) Generators will bid into capacity auctions taking into account their anticipated energy payments.

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[7] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 1.
[8] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 3.
[9] *Transitional Capacity Auction Phase I Design Document*, April 11, 2019, p.2.
[10] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 54 *et seq.*
[11] IESO Demand Response Working Group Meeting Materials, June 19, 2019, page 7.

(b) 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.[12]

26. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

(a) Undermine competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

(b) Introduce undue discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of their eligibility for energy payments.

(The IESO has recently recognized just this sort of issue in respect of DR compensation for out of market Hourly DR resource activations.[13])

27. Premature introduction of a TCA such that it undermines the ability of DR resources to compete in Ontario's competitive electricity market would be a regressive step in the quest for enhanced competition and innovation.

28. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators and other sources of capacity would unnecessarily damage a highly successful existing market mechanism, which would be unfair to DR resources, counterproductive to robust evolution of the Ontario electricity market, and irresponsible on the part of the IESO.

Failing to recognize and compensate the value of DR resources to the energy market is unjust and unreasonable.

29. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services is unjust and unreasonable.

30. In a Final Rule issued in March, 2011 the United States Federal Energy Regulatory Commission (FERC) determined that:[14]

> *... when a demand response resource participating in an organized wholesale energy market... has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective... that demand response resource must be compensated for the service it provides to the energy market at the market price for energy...*

[12] Energy payments avoided by the load are not economically equivalent to energy payments for provision of demand reduction to the market, and are not adequately compensatory for the value provided by DR resources to the energy market: 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 62.

[13] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 36 *et seq.*

[14] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 1.

This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

31. The FERC's conclusions on this topic followed a comprehensive rule making process during which opposing positions on the issue were thoroughly represented (with supporting expert evidence), canvassed and considered.

32. On January 25, 2016, the Supreme Court of the United States issued a determination that in making the foregoing determination FERC was within its jurisdiction to regulate wholesale power markets. While expressly eschewing making a finding on the correctness of FERC's determination as outside of the Court's legitimate area of inquiry, following a detailed 33 page review of the evidence and arguments placed before FERC in the rule making process, the Court commented:[15]

Our important but limited role is to ensure that the Commission engaged in reasoned decision making – that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that choice. FERC satisfied that standard.

33. FERC's determination that establishing just and reasonable wholesale power market rates requires that a DR resource must be compensated for the service it provides to the energy market at the market price for energy was subject to satisfaction of a "net benefits test" to assess the appropriateness of that DR compensation. The "net benefits test" condition was applied to address what was referred to in the FERC's rule making proceeding as the "billing unit effect" of dispatching DR resources in the energy market. Essentially, the concern is that as the volume of energy consumed declines when DR resources actually reduce demand (i.e. avoid consuming energy), the reduction in the costs to meet overall energy demand by dispatching competitive DR is offset in end-user rates to some extent by the fewer units consumed, resulting in an upward pressure in the price for each unit. Whether the reduced costs of supply outweigh the upward pressure on unit rates determines whether there is a "net benefit" for end-users from participation of the DR resource in the market. If there is, then it is in the interest of consumers that DR resources be dispatched when they require a lower energy payment than other resources bidding into the market.

34. On this point FERC concluded as follows[16]:

For this reason, the billing unit effect associated with dispatch of a demand response resource in an energy market must be taken into account in the economic comparison of the energy bids of generation resources and demand response resources. Therefore, rather than requiring compensation at [marginal price] in all hours, the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of reduced [marginal price] that results from dispatching demand response resources exceeds the cost of

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[15] Federal Energy Regulatory Commission v. Electric Power Supply Association Et Al., 577 U.S. (2016), page 33.

[16] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 53.

dispatching those resources. When the above-noted conditions of capability and of cost effectiveness are met, it follows that demand response resources that clear in the day-ahead and real-time energy markets should receive the [marginal price] for services provided, as do generation resources.

35. In the course of its consideration of the equivalency of DR resources and generation resources in providing energy services, the importance of recognizing and compensating this equivalency appropriately, and the importance of thus reducing barriers to DR participation in wholesale markets, FERC cited an earlier order which included a finding that[17]:

> *A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.*

36. FERC went on to find that:

> *Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy.*[18]
>
> ...
>
> *In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."*[19]

37. In its rulemaking deliberations FERC also considered arguments that DR resources are "compensated" by avoiding energy costs when responding to requests to curtail consumption, and accordingly paying such resources for energy thereby effectively supplied would amount to double compensation. On these arguments FERC found as follows:[20] [emphasis in original]

> *Furthermore, Dr. [Alfred E.] Kahn argues that paying demand response [marginal price] sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but one is no more a [case of overcompensation]*[21] *than the other: the one delivers electric power to users at marginal costs – the other – <u>reductions in cost</u> – both at competitively-determined levels.*
>
> *... In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here,*

[17] Ibid, paragraph 57, citing FERC Order No. 719.
[18] Ibid, paragraph 59.
[19] Ibid, paragraph 61.
[20] Ibid, paragraph 62.
[21] Insert in original.

as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of [marginal price] to supply resources clearing 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 be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

38. FERC also recognized in its rule making findings the interrelationship between just and reasonable compensation to DR resources in energy markets and the fairness of associated capacity markets. FERC noted *"how the increased participation by demand resources [in energy markets] could actually increase potential suppliers in capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down"*, and the need to *"examine the way in which capacity markets already may take into account energy revenues"*.[22]

Instituting a TCA without resolving issues regarding just and reasonable compensation to DR resources is discriminatory.

39. As outlined above, the pre-eminent North American energy regulator – FERC – has carefully and thoroughly considered the role of DR resources in wholesale energy markets, and the issue of just and reasonable compensation of those resources for their participation, and has concluded that:

    (a) Failure to compensate DR resources for the value they provide to energy markets in the same manner as compensation is afforded to generation resources for the value which they supply to energy markets results in wholesale prices that are unjust and unreasonable.

    (b) Fair compensation of wholesale energy market participants for energy services provided influences the fairness and efficiency of capacity markets.

40. It follows that expanding the current DRA platform to allow generation resources eligible for energy market compensation to participate in the broadened capacity auction without addressing just and reasonable compensation for DR resources providing energy market services would result in capacity markets that are effectively anti-competitive and discriminatory.

41. Without resolution of payment to DR resources for energy services that they can and do provide to the energy market in a manner that fairly recognizes the value of these services provided, inviting generators to compete with DR resources in a capacity auction would unduly and unfairly prejudice the ability of those DR resources to compete, and would thus be discriminatory.

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[22] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 67, footnote 167.

Market Rule Amendments which, in the result, are discriminatory, must be rejected.

42. The Ontario *Electricity Act, 1998* (*EL Act*) governs the authority of the IESO to make Market Rules, and the manner in which the Ontario Energy Board (OEB) oversees that IESO authority.

43. Subsection 33(9) of the *EL Act* requires the OEB to consider whether a Market Rule amendment *"unjustly discriminates against or in favour of a market participant or class of market participants"*. If the OEB so finds, it must make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

44. For the reasons articulated above, Market Rule amendments which have the effect of allowing generation resources to unjustly and unfairly compete against DR resources for the provision of capacity to the IAM would *"unjustly discriminate against a class of market participants"* – i.e. DR resources currently active in the very successful DRA – and would have to be revoked by the OEB.

45. The IESO should refrain from instituting Market Rule amendments which would co-opt the current DRA platform to a broadened capacity auction prior to addressing the currently unjust and unreasonable wholesale energy market compensation structure under which DR resources are not fairly and properly compensated for the energy services which they provide to the IAM.

46. To proceed with the TCA related Market Rule amendments proposed without first addressing this unfairness would have the effect of unjustly discriminating against DR resources competing to provide capacity to the IAM. Such amendments would not withstand regulatory review.

Recommendation.

47. The unjust discrimination outlined above would be particularly objectionable where there is no need to rush to ICA implementation prior to resolution of the issue of just and reasonable compensation for DR resources in the wholesale energy market. With the suspension of work on the ICA as a result of an updated forecast which sees no resource constraints for the foreseeable future there is no justification for rushing to TCA implementation.

48. AEMA and AMPCO support expansion of the current DRA into a broader capacity auction platform, and the use of a broadened capacity auction platform along with other competitive procurement options to address future capacity needs.

49. While AEMA/AMPCO recognize that the IESO has now proposed a study, to be completed by the end of 2020, to determine *"whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations"*, as outlined above the FERC has already exhaustively considered this issue as recognized by the U.S. Supreme Court, and has unequivocally concluded "yes". Repeating this comprehensive examination is unnecessary and wasteful. That work has already been done, and concluded.

50. A more appropriate, and considerably more focussed, inquiry to validate the "net benefits" to consumers should not take until the end of 2020.

51. In order to enhance competition and market confidence, both to the ultimate benefit of Ontario's electricity consumers, **AEMA and AMPCO urge the IESO to:**

(a) **Recognize and respect both its own overall MRP objectives and its capacity auction specific objectives of *"[c]reating a stable and efficient marketplace that produces value for consumers"* by *"encouraging competition and innovation among suppliers"* and *"resolv[ing] long-standing market design issues"*[23].**

(b) **Proceed expeditiously with a more focussed study to validate the "net benefits" to consumers of energy payments for DR resources, so that the study can be concluded as soon as feasible and its results implemented.**

(c) **Defer implementation of a TCA from December, 2019 and instead focus on getting the proposed TCA right from its initiation, following resolution of the issue of compensation of DR resources for the value that they provide to the IAM.**

(d) **Thereby avoid a result which would unfairly and unjustly discriminate against DR resources in the IAM.**

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[23] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

TAB 4

EB-2019-0242

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

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

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

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

November 8, 2019
Revised: November 21, 2019

INDEX

INDEX

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

TAB 1

TABLE OF CONTENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B.9 Q: What is horizontal equity?

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

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

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

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

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

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

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

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

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

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

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

Figure 4: Effects of the Global Adjustment

Figure 4.A: No Energy Payments for DR Resources

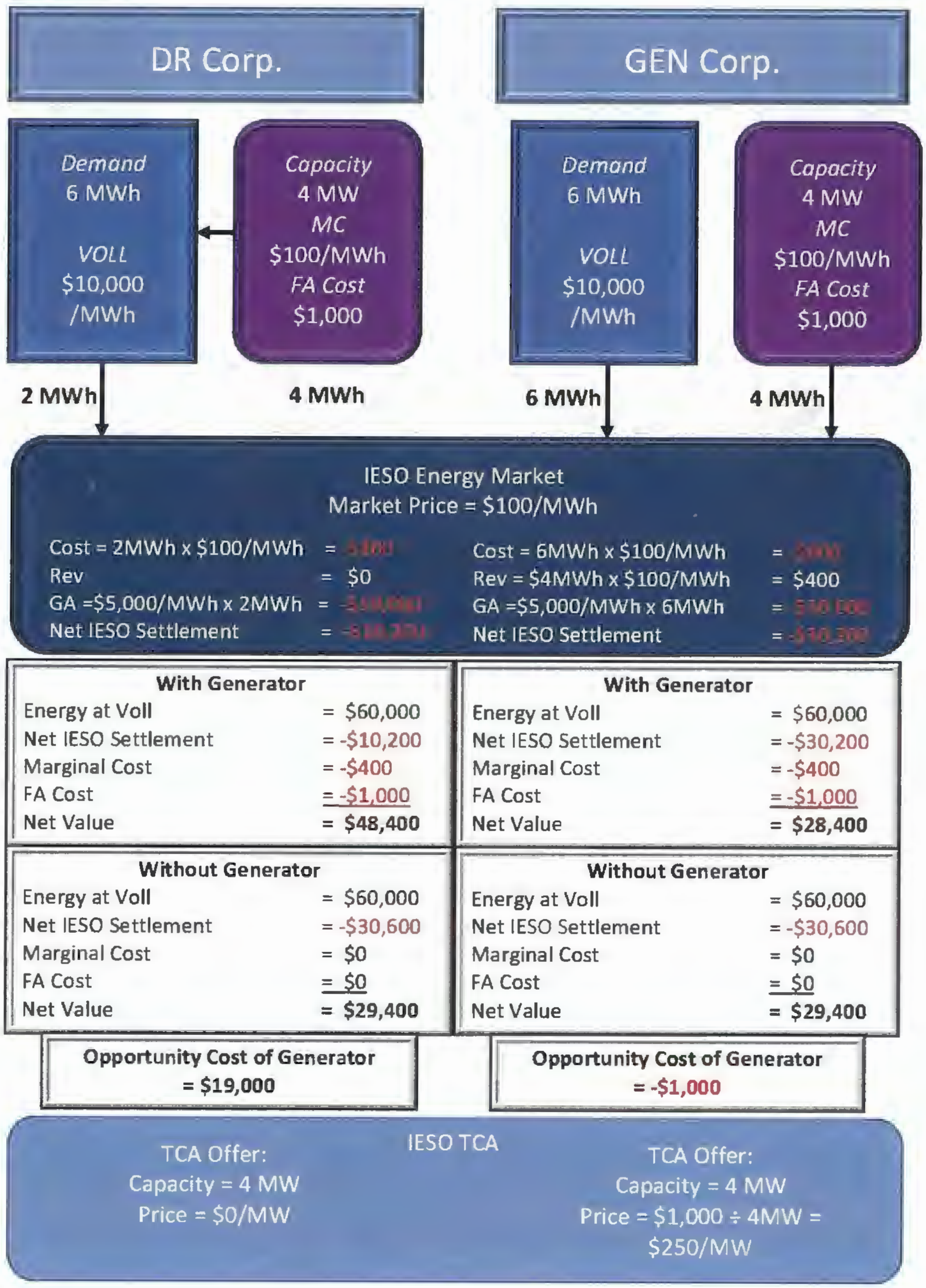
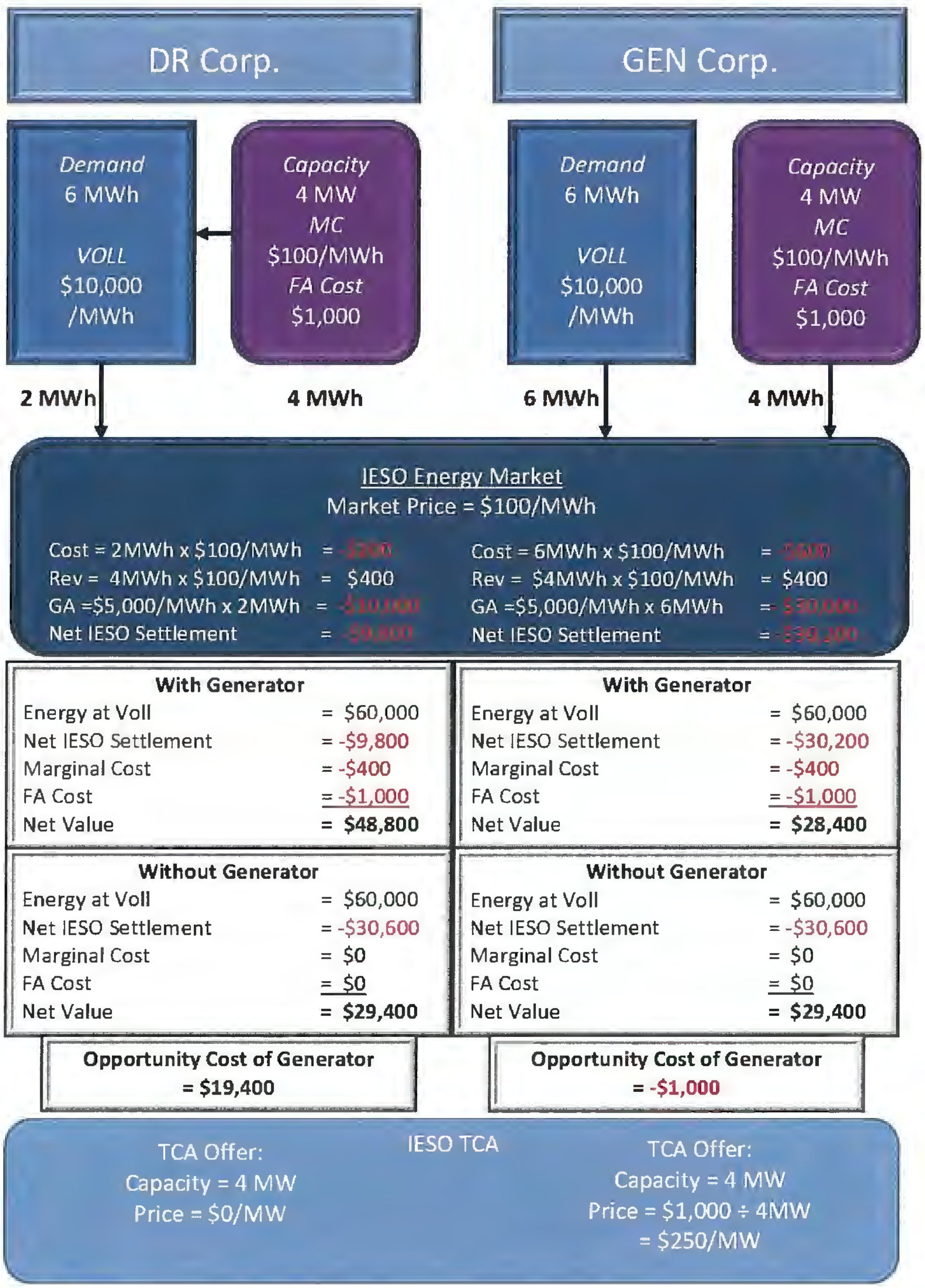


Figure 4.B: Energy Payments for DR Resources



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

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

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

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

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

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

[19] *Ibid* at para. 2.

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

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

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

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

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

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

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

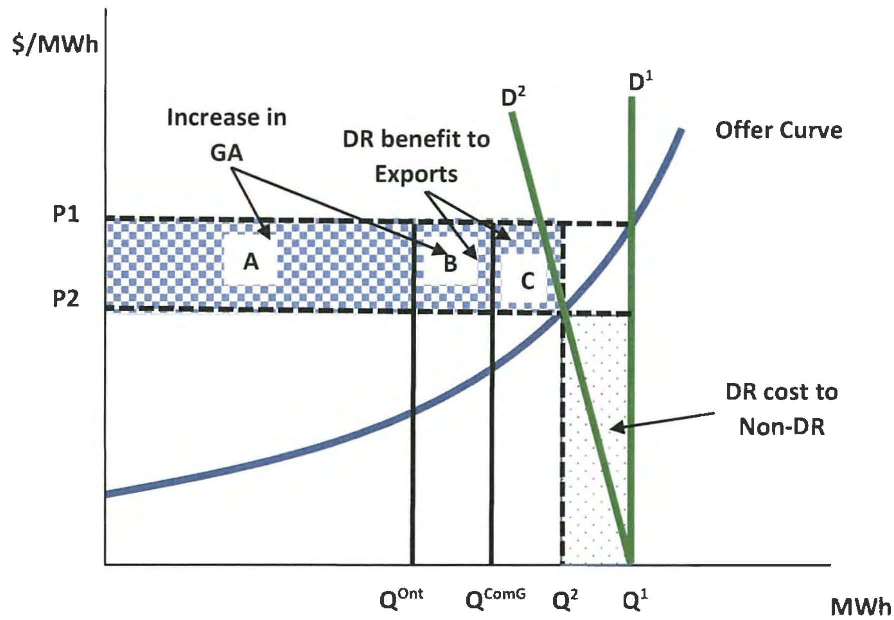
[21] *Ibid* at para. 9.

[22] *Ibid* at para. 8.

[23] *Ibid* at para. 57.

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,



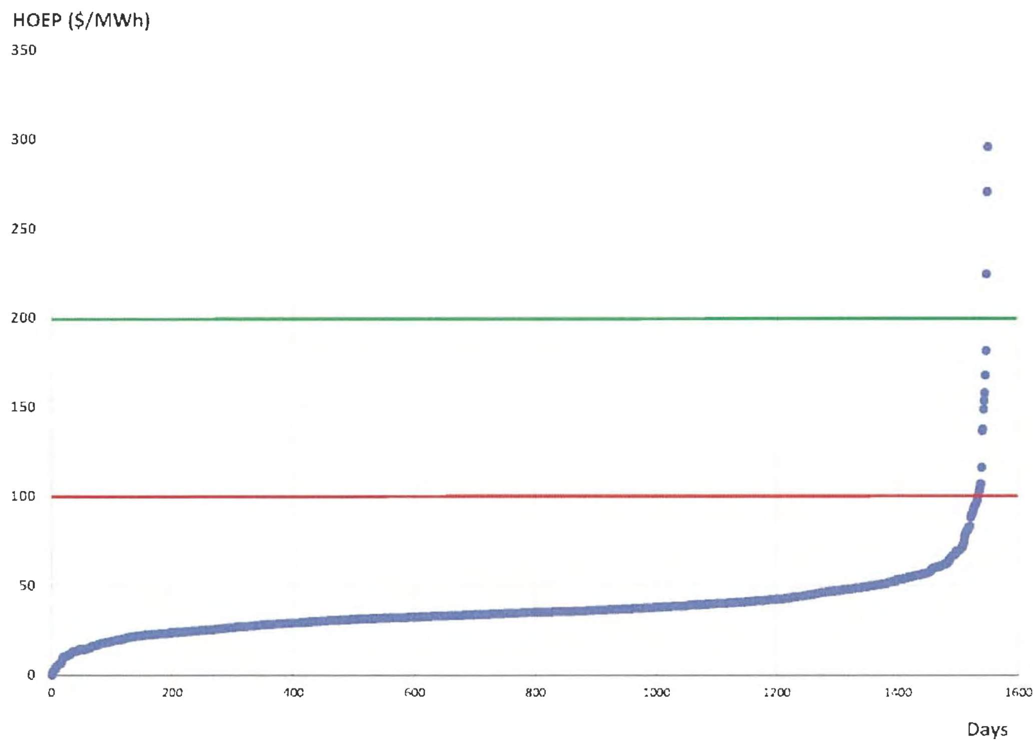
65. In Figure 7, the Ontario non-DR consumers' demand is Q^{ONT}. The difference between Q^2 and Q^{ONT} is export demand. The amount of energy produced by committed generators is Q^{COMG}, which is greater than the Ontario non-DR consumers' demand. The benefit that non-DR consumers realize from the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

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

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

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

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

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

TAB 5

134 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-17-000; Order No. 745]

Demand Response Compensation in Organized Wholesale Energy Markets

(Issued March 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) amends its regulations under the Federal Power Act to ensure that when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource 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). This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

EFFECTIVE DATE: This Final Rule will become effective on [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. Dates for compliance and other required filings are provided in the Final Rule.

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SUPPLEMENTARY INFORMATION:

134 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets — Docket No. RM10-17-000

ORDER NO. 745

TABLE OF CONTENTS

(Issued March 15, 2011)

Paragraph Numbers

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Demand Response Compensation in Organized Wholesale Energy Markets — Docket No. RM10-17-000

FINAL RULE

ORDER NO. 745

(Issued March 15, 2011)

I. Introduction

1. This Final Rule addresses compensation for demand response in Regional Transmission Organization (RTO) and Independent System Operator (ISO) organized wholesale energy markets, i.e., the day-ahead and real-time energy markets. As the Commission has previously recognized, a market functions effectively only when both supply and demand can meaningfully participate. The Commission, in the Notice of Proposed Rulemaking (NOPR) issued in this proceeding on March 18, 2010, proposed a remedy to concerns that current compensation levels inhibited meaningful demand-side participation.[1] After nearly 3,800 pages of comments, a subsequent technical conference, and the opportunity for additional comment, we now take final action.

[1] Demand Response Compensation in Organized Wholesale Energy Markets, Notice of Proposed Rulemaking, 75 FR 15362 (Mar. 29, 2010), FERC Stats. & Regs. ¶ 32,656 (2010) (NOPR).

2. We conclude that when a demand response[2] resource[3] participating in an organized wholesale energy market[4] administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described herein, that demand response resource 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).[5] The Commission finds that this approach to compensation for

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[2] 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. 18 CFR 35.28(b)(4) (2010).

[3] Demand response resource means a resource capable of providing demand response. 18 CFR 35.28(b)(5).

[4] The requirements of this final rule apply only to a demand response resource participating in a day-ahead or real-time energy market administered by an RTO or ISO. Thus, this Final Rule does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions, such as, for instance, Midwest ISO's Emergency Demand Response, NYISO's Emergency Demand Response Program, and PJM's Emergency Load Response Program. This Final Rule also does not apply to compensation in ancillary services markets, which the Commission has addressed elsewhere. See, e.g., Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719).

[5] LMP refers to the price calculated by the ISO or RTO at particular locations or electrical nodes or zones within the ISO or RTO footprint and is used as the market price to compensate generators. There are variations in the way that RTOs and ISOs calculate LMP; however, each method establishes the marginal value of resources in that market. Nothing in this Final Rule is intended to change RTO and ISO methods for calculating LMP.

demand response resources is necessary to ensure that rates are just and reasonable in the organized wholesale energy markets. Consistent with this finding, this Final Rule adds section 35.28(g)(1)(v) to the Commission's regulations to establish a specific compensation approach for demand response resources participating in the organized wholesale energy markets administered by RTOs and ISOs. The Commission is not requiring the use of this compensation approach when demand response resources do not satisfy the capability and cost-effectiveness conditions noted above.[6]

3. This cost-effectiveness condition, as determined by the net benefits test described herein, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit ($/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill. This is the case because customers are billed for energy based on the units, MWh, of electricity consumed. We refer to this potential result as the billing unit effect of dispatching demand response. By contrast, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load. To address this billing unit effect, the Commission in this Final Rule requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced

[6] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

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.

4. To implement the net benefits test described herein, we direct each RTO and ISO to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective. The RTO or ISO should determine, based on historical data as a starting point and updated for changes in relevant supply conditions such as changes in fuel prices and generator unit availability, 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. This price level is to be updated monthly, by each ISO or RTO, as the historic data and relevant supply conditions change.[7]

[7] In its compliance filing an RTO or ISO may attempt to show, in whole or in part, how its proposed or existing practices are consistent with or superior to the requirements of this Final Rule.

5. This Final Rule also sets forth a method for allocating the costs of demand response payments among all customers who benefit from the lower LMP resulting from the demand response.

6. The tariff changes needed to implement the compensation approach required in this Final Rule, including the net benefits test, measurement and verification explanation and proposed changes, and the cost allocation mechanism must be made on or before July 22, 2011. All tariff changes directed herein should be submitted as compliance filings pursuant to this Final Rule, not pursuant to section 205 of the Federal Power Act (FPA).[8] Accordingly, each RTO's or ISO's compliance filing to this Final Rule will become effective prospectively from the date of the Commission order addressing that filing, and not within 60 days of submission.

7. In addition, we believe that integrating a determination of the cost-effectiveness of demand response resources into the dispatch of the ISOs and RTOs may be more precise than the monthly price threshold and, therefore, provide the greatest opportunity for load to benefit from participation of demand response in the organized wholesale energy market administered by an RTO or ISO. However, we acknowledge the position of several of the RTOs and ISOs that modification of their dispatch algorithms to incorporate the costs related to demand response may be difficult in the near term. In

[8] 16 U.S.C. 824d (2006).

light of those concerns, we require each RTO and ISO to undertake a study examining the requirements for and impacts of implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm to determine when paying demand response resources the LMP results in net benefits to customers in both the day-ahead and real-time energy markets. The Commission directs each RTO and ISO to file the results of this study with the Commission on or before September 21, 2012.[9]

II. Background

8. Effective wholesale competition protects customers by, among other things, providing more supply options, encouraging new entry and innovation, and spurring deployment of new technologies.[10] Improving the competitiveness of organized wholesale energy markets is therefore integral to the Commission fulfilling its statutory mandate under the FPA to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[11]

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[9] We note that this report is for informational purposes only and will neither be noticed nor require Commission action.

[10] See, e.g., Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281, at P 1 (2008) (Order No. 719); see also Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at P 1 (1999), order on reh'g, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607, 348 U.S. App. D.C. 205 (D.C. Cir. 2001).

[11] 16 U.S.C. 824d (2006); Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 1.

9. As the Commission recognized in Order No. 719, active participation by customers in the form of demand response in organized wholesale energy markets helps to increase competition in those markets.[12] Demand response, whereby customers reduce electricity consumption from normal usage levels in response to price signals, can generally occur in two ways: (1) customers reduce demand by responding to retail rates that are based on wholesale prices (sometimes called "price-responsive demand"); and (2) customers provide demand response that acts as a resource in organized wholesale energy markets to balance supply and demand. While a number of states and utilities are pursuing retail-level price-responsive demand initiatives based on dynamic and time-differentiated retail prices and utility investments in demand response enabling technologies, these are state efforts, and, thus, are not the subject of this proceeding. Our focus here is 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.

10. As the Commission stated in Order No. 719,[13] and emphasized in the NOPR,[14] there are several ways in which demand response in organized wholesale energy markets

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[12] See Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 48.

[13] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, at P 48 (2009).

[14] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 4.

can help improve the functioning and competitiveness of those markets. First, when bid directly into the wholesale market, demand response can facilitate RTOs and ISOs in balancing supply and demand, and thereby, help produce just and reasonable energy prices.[15] This is because customers who choose to respond will signal to the RTO or ISO and energy market their willingness to reduce demand on the grid which may result in reduced dispatch of higher-priced resources to satisfy load.[16] Second, demand response can mitigate generator market power.[17] This is because the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high.[18] Third, demand

[15] For example, a study conducted by PJM, which simulated the effect of demand response on prices, demonstrated that a modest three percent load reduction in the 100 highest peak hours corresponds to a price decline of six to 12 percent. ISO-RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets, found at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf.

[16] Id. ("Demand response tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy.").

[17] See Comments of NYISO's Independent Market Monitor filed in Docket No. ER09-1142-000, May 15, 2009 (Demand response "contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power.").

[18] Id.

response has the potential to support system reliability and address resource adequacy[19] and resource management challenges surrounding the unexpected loss of generation. This is because demand response resources can provide quick balancing of the electricity grid.[20]

11. Congress has recognized the importance of demand response by enacting national policy requiring its facilitation.[21] Consistent with that policy, the Commission has undertaken several reforms to support competitive wholesale energy markets by removing barriers to participation of demand response resources. For example, in Order No. 890, the Commission modified the pro forma Open Access Transmission Tariff to

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[19] See ISO-RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets at 4, found at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf ("Demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings . . . .").

[20] For instance, in ERCOT, on February 26, 2008, through a combination of a sudden loss of thermal generation, drop in power supplied by wind generators, and a quicker-than-expected ramping up of demand, ERCOT found itself short of reserves. The system operator called on all demand response resources, and 1200 MW of Load acting as Resource (LaaRs) responded quickly, bringing ERCOT back into balance. OAK RIDGE NAT'L LAB., NAT'L RENEWABLE ENERGY LAB., TECH. REP. NREL/TP-500-43373, ERCOT EVENT ON FEB. 26, 2008: LESSONS LEARNED (JUL. 2008).

[21] See Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005) ("It is the policy of the United States that . . . unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be eliminated.").

allow non-generation resources, including demand response resources, to be used in the provision of certain ancillary services where appropriate on a comparable basis to service provided by generation resources.[22] Order No. 890-A further required transmission providers to develop transmission planning processes that treat all resources, including demand response, on a comparable basis.[23]

12. In Order No. 719, the Commission required RTOs and ISOs to, among other things, accept bids from demand response resources in their markets for certain ancillary services on a basis comparable to other resources.[24] The Commission also required each RTO and ISO "to reform or demonstrate the adequacy of its existing market rules to ensure that the market price for energy reflects the value of energy during an operating reserve shortage,"[25] for purposes of encouraging existing generation and demand resources to continue to be relied upon during an operating reserve shortage, and encouraging entry of new generation and demand resources.[26]

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[22] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 887-88 (2007), order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g and clarification, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228 (2009), order on clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[23] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216.

[24] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 47-49.

[25] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 194.

[26] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 247.

13. Additionally, in recent years several RTOs and ISOs have instituted various types of demand response programs. While some of these programs are administered for reliability and emergency conditions, other programs allow wholesale customers, qualifying large retail customers, and aggregators of retail customers to participate directly in the day-ahead and real-time energy markets, certain ancillary service markets and capacity markets.[27]

14. To date, the Commission has allowed each RTO and ISO to develop its own compensation methodologies for demand response resources participating in its day-ahead and real-time energy markets. As a result, the levels of compensation for demand response vary significantly among RTOs and ISOs.[28] For example, PJM Interconnection, L.L.C. (PJM) pays the LMP minus the generation and transmission portions of the retail

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[27] Other demand response programs allow demand response to be used as a capacity resource and as a resource during system emergencies or permit the use of demand response for synchronized reserves and regulation service. See, e.g., PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006); Devon Power LLC, 115 FERC ¶ 61,340, order on reh'g, 117 FERC ¶ 61,133 (2006), appeal pending sub nom. Maine Pub. Utils. Comm'n v. FERC, No. 06-1403 (D.C. Cir. 2007); New York Indep. Sys. Operator, Inc., 95 FERC ¶ 61,136 (2001); NSTAR Services Co. v. New England Power Pool, 95 FERC ¶ 61,250 (2001); New England Power Pool and ISO New England, Inc., 100 FERC ¶ 61,287, order on reh'g, 101 FERC ¶ 61,344 (2002), order on reh'g, 103 FERC ¶ 61,304, order on reh'g, 105 FERC ¶ 61,211 (2003); PJM Interconnection, L.L.C., 99 FERC ¶ 61,227 (2002); California Independent System Operator Corp., 132 FERC ¶ 61,045 (2010).

[28] See New England, Inc., Docket No. ER09-1051-000; ISO New England, Inc., Docket No. ER08-830-000; Midwest Indep. Transmission Sys. Operator, Inc., Docket No. ER09-1049-000.

rate.[29] ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) pay LMP when prices exceed a threshold level, with the levels differing between the RTOs.[30] The Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) demand response programs[31] pay LMP for demand response resources in the day-ahead and real-time energy markets.[32] The California Independent System Operator Corporation (CAISO) pays LMP at pricing nodes, or sub-load aggregation points (Sub-LAP) in its Proxy Demand Resource program that allows qualifying

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[29] See sections 3.3A.4 and 3.3A.5 (Market Settlements in the Real-Time and Day-Ahead Energy Markets) of the Appendix to Attachment K of the PJM Tariff.

[30] For example, under ISO-NE's Real-Time Price Response Program, the minimum bid is \$100/MWh and a demand response resource is paid the higher of LMP or \$100/MWh. For the Day-Ahead Load Response Program, the minimum offer level is calculated on a monthly basis and is the Forward Reserve Fuel Index (\$/MMBtu) multiplied by an effective heat rate of 11.37 MMBtu/MWh. The maximum offer level is \$1,000/MWh. See sections III.E.2.1 and III.E.3.2 of Appendix E of the ISO New England Transmission, Markets and Services Tariff. NYISO implements a day-ahead demand response program by which resources bid into the market at a minimum of \$75/MWh and can get paid the LMP. See section 4.2.2.9 ("Day-Ahead Bids from Demand Reduction Providers to Supply Energy from Demand Reductions") of NYISO's Market Services Tariff.

[31] Midwest ISO FERC Electric Tariff characterizes Demand Response Resources (DRR) as either DRR-Type I or DRR-Type II. DRR-Type I are capable of supplying a specific quantity of energy or contingency reserve through physical load interruption. DRR-Type II are capable of supplying energy and/or operating reserves over a dispatchable range. See sections 39.2.5A and 40.2.5 of the Tariff.

[32] See Charges and Payments for Purchases and Sales for Demand Response Resources. Midwest ISO FERC Electric Tariff, section 39.3.2C.

resources to provide day-ahead and real-time energy.[33] CAISO also provides for demand response resources to participate in its Participating Load program, which enables certain resources to provide curtailable demand in the CAISO market. CAISO pays nodal real-time LMP for its Participating Load program. The Southwest Power Pool, Inc. (SPP) has filed revisions to its tariff to facilitate demand response in the Energy Imbalance Service Market.[34]

III. Procedural History

15. As noted above, the Commission issued the NOPR in this proceeding on March 18, 2010.[35] The NOPR proposed to require RTOs and ISOs to pay the LMP in all hours for demand reductions made in response to price signals. The Commission sought

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[33] See section 11.2.1.1 IFM Payments for Supply of Energy, CAISO FERC Electric Tariff. CAISO notes that for a Proxy Demand Resource that is made up of aggregated loads, the Resource is paid the weighted average of the LMPs of each pricing node where the underlying aggregate loads reside. See CAISO, 132 FERC ¶ 61,045, at P 26 n.14 (2010).

[34] The Commission has directed SPP to report on ways it can incorporate demand response into its imbalance market. Southwest Power Pool, Inc., 128 FERC ¶ 61,085 (2009). As of September 1, 2010, SPP has submitted seven informational status reports regarding its efforts to address issues related to demand response resources. In orders addressing SPP's compliance with Order No. 719, the Commission also directed SPP to make another compliance filing addressing demand response participation in its organized markets. Southwest Power Pool, Inc., 129 FERC ¶ 61,163, at P 51 (2009). On May 19, 2010, SPP submitted revisions to its Open Access Transmission Tariff in Docket Nos. ER09-1050-004 and ER09-748-002 to comply with the Commission's requirements established in Order Nos. 719 and 719-A. These filings are pending before the Commission.

[35] NOPR, FERC Stats. & Regs. ¶ 32,656.

comments on the compensation proposal and, in particular, on the comparability of generation and demand response resources; alternative approaches to compensating demand response in organized wholesale energy markets; whether payment of LMP should apply in all hours, and, if not, any criteria that should be used for establishing hours when LMP should apply; and whether to allow for regional variations concerning approaches to demand response compensation.[36]

16. After receiving the first round of comments, the Commission issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference (Supplemental NOPR) in this proceeding on August 2, 2010.[37] The Supplemental NOPR sought additional comment on: whether the Commission should adopt a net benefits test for determining when to compensate demand response providers, and, if so, what, if any, requirements should apply to the methods for determining net benefits; and what, if any, requirements should apply to how the costs of demand response are allocated. The Commission further directed Staff to hold a technical conference focused on these two issues, which occurred on September 13, 2010.[38]

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[36] See Appendix for a list of commenters.

[37] Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference, 75 FR 47499 (Aug. 6, 2010), 132 FERC ¶ 61,094 (2010) (Supplemental NOPR).

[38] See Notice of Technical Conference (Aug. 27, 2010).

IV. Discussion

17. Based upon the record in this proceeding, the Commission herein requires greater uniformity in compensating demand response resources participating in organized wholesale energy markets. This Final Rule also addresses the allocation of costs resulting from the commitment of demand response, directing that such costs be allocated among those customers who benefit from the lower LMP resulting from the demand response.

A. Compensation Level

1. NOPR Proposal

18. The NOPR proposed to require RTOs and ISOs to pay the LMP in all hours for demand reductions made in response to price signals. The NOPR sought to provide comparable compensation to generation and demand response providers, based on the premise that both resources provide a comparable service to RTOs and ISOs for purposes of balancing supply and demand and maintaining a reliable electricity grid.[39] Also as stated in the NOPR, the proposed compensation level was designed to allow more demand response resources to cover their investment costs in demand response-related technology (such as advanced metering) and thereby facilitate their ability to participate in organized wholesale energy markets.[40] The Commission sought comments on the

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[39] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 15.

[40] Id. at P 16.

compensation proposal and, in particular, on the comparability of generation and demand response resources; alternative approaches to compensating demand response in organized wholesale energy markets; whether payment of LMP should apply in all hours, and, if not, any criteria that should be used for establishing hours when LMP should apply; and whether to allow for regional variations concerning approaches to demand response compensation.

19. In the Supplemental NOPR, the Commission sought additional comments and directed staff to hold a technical conference regarding various net benefits tests. In particular, the Commission sought comment on: whether the Commission should adopt a net benefits test applicable in all or only some hours and what the criteria of any such test would be; how to define net benefits; what costs demand response providers and load serving entities incur and whether they should be included in a net benefits test; whether any net benefits methodology adopted should be the same for all RTOs and ISOs; proposed methodologies for implementing a net benefits test and the advantages and limitations of any proposed methodologies.[41] The September 13, 2010 Technical Conference included an eleven-member panel discussion of net benefits tests representing

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[41] Supplemental NOPR, 132 FERC ¶ 61,094 at P 8-9.

a wide range of interests and viewpoints.[42] The Commission subsequently received additional written comments addressing these issues.

2. Comments

a) Capability of Demand Response and Generation Resources to Balance Energy Markets

20. Various commenters address the comparability of demand response and generation resources for purposes of compensation in the organized wholesale energy markets. To begin, numerous commenters address the physical or functional comparability of demand response and generation, agreeing that an increment of generation is comparable to a decrement of load for purposes of balancing supply and demand in the day-ahead and real-time energy markets.[43] Equating generation and demand response resources, Dr. Alfred E. Kahn states:

> [Demand response] is in all essential respects economically equivalent to supply response . . . [so] economic efficiency requires . . . that it should be rewarded with the same LMP that clears the market. Since [demand response] is actually—and not merely metaphorically—equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proffered to system operators, and be treated equivalently to generation in competitive power markets. That is,

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[42] See Sept. 13, 2010 Tr.

[43] DR Supporters Aug. 30, 2010 Comments (Kahn Affidavit at 2); Verso May 13, 2010 Comments at 3-4; Occidental May 13, 2010 Comments at 11; Viridity June 18, 2010 Comments at 5.

> all resources—energy saved equivalently to energy supplied— . . . should receive the same market-clearing LMP in remuneration.[44]

Indeed, some commenters believe that, from a physical standpoint, demand response can provide superior services to generation, such as providing a quick response in meeting system requirements and service without having to construct major new facilities.[45] Occidental asserts that the fungibility of demand response and generation output creates greater operational flexibility that, in turn, offers RTOs and ISOs multiple options to solve system issues both in energy and ancillary service markets, and that the fungible nature of demand response and generation supports comparable compensation for each as proposed in the NOPR.[46]

21. Viridity states that attempts to distinguish the physical characteristics of generation and demand response ignore bid-based security-constrained economic dispatch as the foundation for LMP and are based on the assumption that the value of load management on the grid is limited to periods when the system is stressed, i.e., traditional "super peak shaving." Viridity states that, while these arguments might have been valid 15 years ago, today competitive markets can offer proactively-managed load control and comparable and non-discriminatory treatment of load-based energy resources.

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[44] DR Supporters August 30, 2010 Reply Comments (Kahn Affidavit at 2 (footnote omitted)).

[45] Verso May 13, 2010 Comments at 3-4; Alcoa May 13, 2010 Comments at 9.

[46] Occidental May 13, 2010 Comments at 11.

in markets that start with a market-based level of compensation and then reduce it by the generation portion of a customer's retail rate (LMP – G).[110]

44. Other commenters caution against standardizing the compensation level for demand response, pointing to regional differences in market structure, state regulatory environment, and resource mix.[111]

3. **Commission Determination**

45. The Commission acknowledges the diverging opinions of commenters regarding the appropriate level of compensation for demand response resources. As discussed above, commenters are split on this issue, with some in favor of paying the LMP for demand reductions in the day-ahead and real-time energy markets in all hours, others arguing that paying the LMP for demand reductions under any conditions will result in over-compensation or distortions in incentives to reduce consumption, and still others arguing that paying the LMP for demand reductions is only appropriate when it is reasonably certain to be cost-effective.

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[110] Viridity Energy May 13, 2010 Comments at 4.

[111] See, e.g., May 13, 2010 Comments of: ConEd at 3-4; Consumers Energy at 2; California Commission at 9; CMEEC at 2-3, 14-15; Detroit Edison at 3-5; Dominion at 8; Duke Energy at 4; EPSA at 6; Hess at 4; Indicated New York TOs at 3; Maryland Commission at 5; Midwest TDUs at 2, 6; Midwest ISO TOs at 16; National Grid at 5-6; 11-12; New York Commission at 4, 11; NCPA at 3; NYISO at 2-3; ODEC at 27; PJM at 5-6; SPP at 1.

46. In the face of these diverging opinions, the Commission observes that, as the courts have recognized, "'issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission.'"[112] We also observe that, in making such judgments, the Commission is not limited to textbook economic analysis of the markets subject to our jurisdiction, but also may account for the practical realities of how those markets operate.[113]

47. As discussed further below, the Commission agrees with commenters who support payment of LMP under conditions when it is cost-effective to do so, as determined by the net benefits test described herein.[114] We have previously accepted a variety of ISO and RTO proposals for compensation for demand response resources participating in

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[112] Elec. Consumers Res. Council v. FERC, 407 F.3d 1232, 1236 (D.C. Cir. 2005) (quoting Pub. Util. Comm'n of the State of Cal. v. FERC, 254 F.3d 250, 254 (D.C. Cir. 2001)); see also Town of Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992).

[113] See Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 872 (D.C. Cir. 1993) ("It is the FERC's established policy to consider equitable factors in designing rates, and to allow for phasing in of changes where appropriate. . . . It is hardly arbitrary or capricious so to temper the dictates of theory by reference to their consequences in practice."); Vermont Dep't of Pub. Serv. v. FERC, 817 F.2d 127, 135 (D.C. Cir. 1987) ("Indeed, 'the congressional grant of authority to the agency indicates that the agency's interpretation typically will be enhanced by technical knowledge.'" (quoting Nat'l Fuel Gas Supply Corp. v. FERC, 811 F.2d 1563, 1570 (D.C. Cir. 1987))); Columbia Gas Transmission Corp. v. FERC, 750 F.2d 105, 112 (D.C. Cir. 1984) ("the Commission is vested with wide discretion to balance competing equities against the backdrop of the public interest").

[114] See generally May 13, 2010 Comments of NYSCPB; NECA; Capital Power; NECPUC; Maryland Commission; New York Commission; NSTAR; National Grid; NE Public Systems.

organized wholesale energy markets. We find, based on the record here 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 test described herein, 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.[115] As stated in the NOPR, we 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.[116]

48. The Commission emphasizes that these findings reflect a recognition that it is appropriate to require compensation at the LMP for the service provided by demand response resources participating in the organized wholesale energy markets only when two conditions are met:

- The first condition is that the demand response resource has the capability to provide the service , i.e., the demand response resource must be able to displace a

[115] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

[116] NOPR at P 12.

generation resource in a manner that serves the RTO or ISO in balancing supply and demand.

- The second condition is that the payment of LMP for the provision of the service by the demand response resource must be cost-effective, as determined by the net benefits test described herein.

49. With respect to the first, capability-related condition, we note that a power system must be operated so that there is real-time balance of generation and load, supply and demand. An RTO or ISO dispatches just the amount of generation needed to match expected load at any given moment in time. The system can also be balanced through the reduction of demand.[117] Both can have the same effect of balancing supply and demand at the margin either by increasing supply or by decreasing demand.

50. With respect to the second cost-effectiveness condition, the record leads us to alter the proposal set forth in the NOPR in this proceeding. As various commenters explain, dispatching demand response resources may result in an increased cost per unit to load

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[117] Andrew L. Ott Sept. 13, 2010 Statement at 1.

> Economic and Capacity-based demand response clearly provides benefits to regional grid operation and the wholesale market operation. . . . These demand resources provide benefits by providing valuable alternatives to PJM in maintaining operational reliability and in promoting efficient market operations.

Id. at 1; see also CDRI May 13, 2010 Comments at 10; CDWR May 13, 2010 Comments at 5; NJPBU May 13, 2010 Comments at 2.

TAB 6

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**

EB-2019-0242

THE ONTARIO ENERGY BOARD

Association of Major Power Consumers of Ontario (AMPCO)

Application to Review Amendments to the Market Rules made by the Independent Electricity System Operator

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Monday, November 25, 2019,
commencing at 9:02 a.m.

VOLUME 1

BEFORE:

CATHY SPOEL	Presiding Member
EMAD ELSAYED	Member
SUSAN FRANK	Member

A P P E A R A N C E S

LJUBA DJURDJEVIC	Board Counsel
DAVID BROWN CHRIS CINCAR MICHAEL BELL CIERAN BISHOP CHERIDA WALTON LILLIAN ING	Board Staff
IAN MONDROW LAURA VAN SOELEN	Association of Major Power Consumers in Ontario (AMPCO)
GLENN ZACHER DANIEL GRALNICK PATRICK DUFFY	Independent Electricity System Operator (IESO)
EVAN BARZ	Association of Power Producers of Ontario (APPrO)
EWA KRAJEWSKA GIAN MINICHINI	Kingston Cogen Limited Partnership (KCLP)
MARK RUBENSTEIN	School Energy Coalition (SEC)

INDEX OF PROCEEDINGS

E X H I B I T S

Description	Page No.
EXHIBIT NO. K1.1: LETTER FILED WITH THE BOARD DATED 22 NOVEMBER 2019 CONTAINING A COVERING LETTER, MR. ANDERSON'S CV, AND A ONE-PAGE WITNESS STATEMENT.	6
EXHIBIT NO. K1.2: MR. ANDERSON'S AFFIDAVIT SWORN 11 OCTOBER 2019.	7
EXHIBIT NO. K1.3: DOCUMENT ENTITLED STAKEHOLDER ADVISORY COMMITTEE (SAC) MEETING MINUTES DATED APRIL 24TH, 2019	12
EXHIBIT NO. K1.4: ASSOCIATION OF POWER PRODUCERS OF ONTARIO COMPENDIUM FOR AMPCO PANEL 1.	20
EXHIBIT NO. K1.5: KINGSTON COGEN LP COMPENDIUM FOR AMPCO PANEL 1	40
EXHIBIT NO. K1.6: IESO COMPENDIUM FOR AMPCO PANEL 1	63
EXHIBIT NO. K1.7: STAFF COMPENDIUM FOR AMPCO PANEL 1.	116
EXHIBIT NO. K1.8: KINGSTON COGEN LP COMPENDIUM FOR AMPCO PANEL 2	132

U N D E R T A K I N G S

your CV which was filed with that package, please, and I will ask you to adopt that as accurate.

MR. ANDERSON: It is accurate. Adopted.

MR. MONDROW: Thank you. And that CV contains the balance of your work experience which began in 1988 at what was then Ontario Hydro?

MR. ANDERSON: That's correct.

MR. MONDROW: And you have since and continue to work in the energy sector?

MR. ANDERSON: Correct.

MR. MONDROW: Thank you. And Mr. Anderson, I would like to take you to your affidavit which was sworn October 11th, 2019. And that document, because it's been sworn, is already evidence technically, but I would like to ask you whether you are prepared to adopt that evidence in support of AMPCO's application in respect of which you are here today?

MR. ANDERSON: I am.

MR. MONDROW: And perhaps we could get an exhibit number for that affidavit, please.

MS. DJURDJEVIC: That will be K1.2.

EXHIBIT NO. K1.2: MR. ANDERSON'S AFFIDAVIT SWORN 11 OCTOBER 2019.

MR. MONDROW: Thank you. And Mr. Anderson, you were asked a number of interrogatories on that evidence, responses which have been filed, and these are responses from AMPCO to Board Staff interrogatories 1 through 3 and School Energy Coalition interrogatories 1 through 4.

Were those interrogatory responses prepared by you or under your direction and control?

MR. ANDERSON: They were.

MR. MONDROW: And do you adopt them as your evidence in support of AMPCO's application?

MR. ANDERSON: Yes, I do.

MR. MONDROW: Thank you. Now, Mr. Anderson, various of the materials filed since AMPCO's application was filed have suggested various motivations for the application. The IESO has posited that what AMPCO is seeking is relief in respect of energy payments. KCLP has suggested AMPCO is seeking to limit competition in future capacity auctions.

Can you please reiterate for the Hearing Panel why AMPCO has brought this application?

MR. ANDERSON: I can. AMPCO consists of members who provide demand response, but we also have many members who do not provide demand response. And I represent them all by being here today.

On behalf of the DR resource members, I am here to remedy an inequity created as a result of the market rule amendments that are in question. And on behalf of the other AMPCO members, I am here in support of a properly competitive market in which prices are as low as reasonably possible.

MR. MONDROW: Mr. Anderson, is AMPCO asking the Board to direct that payments be made to demand response resources for energy services provided to Ontario's real time market?

MR. ANDERSON: No, we're not. This application was brought pursuant to section 33 of the Electricity Act, and looking at that section, it asks the Board to revoke amendments and to remand them pack to the IESO for further consideration if they find them to be discriminatory in nature or counter to the objects of the Act.

That is clearly set out at paragraph 52 of AMPCO's appeal.

We would expect that the issue of energy payments will be dealt with in due course.

MR. MONDROW: Mr. Anderson, your evidence has been challenged on the basis that it is brought on behalf of AMPCO members, rather than AMPCO members providing their own evidence.

I would like to take you, please, to your October 11th affidavit. If you could open that to paragraph 3, please?

MR. ANDERSON: Okay.

MR. MONDROW: And in paragraph 3 of that affidavit, you say in the second sentence:

> "I am providing this evidence in my role as president of AMPCO and because of reticence that I perceived among my members to do so themselves."

Can you explain what you meant by that, please?

MR. ANDERSON: I can. In theory, any time an entity takes its regulator or its system operator to task, it potentially exposes itself to some form of retribution.

AMPCO provides an additional layer of cover against any such retribution.

Now, do I think retribution is going to happen here in this case? No, I absolutely do not. But quite frankly, that doesn't matter, because what I am dealing with is the perceptions, the perceptions of my members, and the perceptions of my members' senior management team who, quite frankly, are uncomfortable being out front of this application, and would request that I would do so on their behalf.

So a lot of those senior management team members don't even necessarily deal with the IESO on a daily basis. But it is just that perception of potential liability that they are uncomfortable with.

So as part of my role as president of the association, here I am today.

MR. MONDROW: Madam Chair, I wonder if you want to give the affidavit an exhibit number at this point since it's been identified.

MS. DJURDJEVIC: Is this another affidavit?

MR. MONDROW: No. This is the affidavit that Mr. Anderson was --

MS. SPOEL: It was given K1.2 at the beginning.

MR. MONDROW: I apologize. Yes, I did, thank you. Good. I'm more organized than I thought.

MS. SPOEL: Ahead of the curve, Mr. Mondrow.

MR. MONDROW: There you go. Mr. Anderson, where you state in your affidavit, which is Exhibit K1.2, that you have been informed by AMPCO members, can you describe the signed anything yet and I am not going to tell my Board, who I already convinced that I was going to file some additional evidence, yes, we got the evidence done, it's very good. Unfortunately, we couldn't file it. That was a conversation I didn't want to have.

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

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

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

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

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

MR. ANDERSON: That's correct.

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

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

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

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

MR. BARZ: I said quantifiable evidence.

MR. ANDERSON: I understand that.

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

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

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

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

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

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

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

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

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

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

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

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

MR. ANDERSON: That's correct.

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

MR. ANDERSON: Also correct.

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

MR. ANDERSON: Yes, we are.

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

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

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

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

MR. ANDERSON: They are.

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

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

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

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

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

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

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

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

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

MR. BARZ: I was about to go --

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

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

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

The quote you use:

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

Is that the correct reference in your affidavit?

MR. ANDERSON: It is.

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

MS. KRAJEWSKA: Correct. And they're going to use these factors that you have listed in order to come up with their offer price.

MR. ANDERSON: Correct.

MS. KRAJEWSKA: And these are going to be very specific to each entity?

MR. ANDERSON: Yes.

MS. KRAJEWSKA: And so, Mr. Anderson, I feel like you have moved away from a position that compensating DR resources with the market clearing price will compensate them for these very factors.

MR. ANDERSON: Oh, I think that is a logic leap I can't follow you on.

What I have said is that each one of the demand response resources has to frame its own offers, both for capacity and for energy, based on its risk tolerance, its costs, all of the factors that I have listed in AMPCO's response to Board Staff 1.

At some point, if a decision is taken in regard to will energy payments be made for DR resources, there has to be some structure to that.

And I think if I can pause for just one moment, and take you to Exhibit B from my affidavit -- it's Exhibit B, page 22 of 40.

The IESO listed potential approaches for consideration of out-of-market activation of DR resources, and it talks about using energy bids as representative costs, historical precedence such as CBDR, which is a program that predates the demand response auction...

MS. KRAJEWSKA: I'm sorry, can you slow down. I think it is being pulled up on the screen. Your page 22 of 40 of your affidavit?

MR. ANDERSON: Exhibit B of my affidavit.

MS. KRAJEWSKA: Okay.

MR. ANDERSON: Sorry, my apologies.

MS. KRAJEWSKA: Are you under number 2, out-of-market activation of DR resources?

MR. ANDERSON: I am, yes.

MS. KRAJEWSKA: You are going through those bullets.

MR. ANDERSON: I am looking at those three bullets, because those three bullets represent what the IESO put forward as potential options for payments.

The first was using energy bids as representative costs. The second was historical precedent, which is just a somewhat arbitrary number, as was done with the CBDR program. The third is identify costs on individual or type of resource basis.

I think what you are suggesting is that because all resources are different, that that third bullet would be the most accurate way to do it, and you may not be wrong. But it would also be an administrative nightmare for the IESO. I wouldn't wish that on anyone.

So you can see...

MS. KRAJEWSKA: But --

MR. ANDERSON: Sorry, I wanted to finish. You can see there were three options that were advanced by the IESO.

there are costs associated with that. Wear and tear on equipment is a very real cost, and the other thing to think about is in a number of these process-oriented facilities, when start up and shut down, you've gone outside your quality boundaries for a period of time.

So you are wasting, whether it is pulp and paper or whether it is steel, or whatever the widget is that comes out the back end of that facility, you have wasted a chunk of it. So those are very real costs.

MS. KRAJEWSKA: But in each of those circumstances, the DR resource would factor that cost into their bid price, correct?

MR. ANDERSON: Each resource would factor it in in the way it saw as appropriate.

MS. KRAJEWSKA: Mr. Anderson, I would like to -- in your witness statement, you take issue with Mr. Rivard's evidence with respect to his models that look at DR resources that have a behind-the-meter generator. That's correct?

MR. ANDERSON: Yes, that's correct.

MS. KRAJEWSKA: And, Mr. Anderson, you have not filed any evidence with respect to how many of your members have behind-the-meter generators.

MR. ANDERSON: I have not, no. But as I said in my -- I believe in my direct, those who have behind-the-meter generation are in the far minority to those who do not.

MS. KRAJEWSKA: But that information is also - how many, or which demand response resources or consumers of energy have behind-the-meter generators? That's not a matter that is known publicly.

MR. ANDERSON: I don't expect it would be.

MS. KRAJEWSKA: And you said that the majority of your membership, however, is -- are class A consumers under the GA.

MR. ANDERSON: That's true.

MS. KRAJEWSKA: And Mr. Anderson, if I can take you to -- this is tab G of the compendium. This is a further extract from the Market Surveillance Panel Report prepared by the OEB.

And the second paragraph -- or the full first paragraph there reads:

> "The ICI creates an incentive for class A consumers to invest in new generating of storage capacity located at their facilities. On-site generation offsets consumption from the transmission or distribution..."

Do you see that?

MR. ANDERSON: I do.

MS. KRAJEWSKA: And the second paragraph, the second sentence reads:

> "In 2017 and 2018, three Class A consumers made a combined 33 applications to the Ministry of Climate Change to build a total of 44 megawatts of natural gas-fired capacity."

Do you see that?

MR. ANDERSON: I do.

advanced initiatives in this direction. Capacity auctions for demand response is a first stage in the development of capacity auctions for other resources and the consideration of capacity exports."

Then at the bottom of the page:

"The DR capacity auction is intended to be the first phase of the IESO's efforts to introduce capacity markets for all resources. The IESO conducted several information sessions over 2014."

So this is 2015. It's known at that time, Mr. Anderson, that the DRA is a step towards a broader capacity auction. Do you agree with the MSP?

MR. ANDERSON: To be clear, I am not disputing that that was the direction in 2014-2015, Mr. Zacher.

What I'm saying is I am not sure what the status is today.

So up until the point where it was cancelled, absolutely, this is the direction that was being pushed by the IESO publicly.

I don't know what the status of the ICA is completely right now; that's all I am saying.

MR. ZACHER: If you look on to the next page, the same Excerpt, page 93, you will see that it is also signalled -- this is sort of two-thirds of the way down the page: "The IESO also recommended that the development of the capacity auction and capacity export markets be continued, with consideration given to facilitating broad participation including by non-utility generators."

So it was again signalled in early 2015 that off-contract generators were also to be provided with an opportunity to participate in a broader capacity auction. You agree?

MR. ANDERSON: I see that, yes, I agree with it.

MR. ZACHER: And so it was never intended that the DRA, as you suggested in your evidence, was to be exclusive to demand response, that it was to evolve of into an auction that was to include all potential capacity resources.

MR. ANDERSON: I think AMPCO has been remarkably clear that we have no issue with the demand response auction transitioning to a transitional capacity auction, which includes off-contract generators.

What we have an issue with is what we believe is discriminatory impacts of the amendments that have been put forward to effect that.

We have no issue with the increased participation. We just want to participate on a level playing field.

MR. ZACHER: Fair enough. So I am going to come back to that first point. But you have been supportive of evolution towards a larger more competitive capacity auction?

MR. ANDERSON: Hmm-hmm.

MR. ZACHER: Right. And again, just for a little bit of context, I would like to refer you to tab 6 of the IESO's compendium, and this is a May 2017 report of the market surveillance panel.

complaint, Mr. Anderson, is the fact that generators receive energy payments in the energy market and loads don't.

MR. ANDERSON: That, in my mind, Mr. Zacher, is the illustration of the discriminatory nature of the amendments that have been put forward to the market rules.

MR. ZACHER: So the amendments concern the conversion of the DRA into a transitional capacity auction, effectively a capacity auction that includes some supply resources. Right?

MR. ANDERSON: They do.

MR. ZACHER: And you don't take issue in your evidence anywhere with any of the mechanics of the TCA.

MR. ANDERSON: Sorry, can you reframe that? I am not following you.

MR. ZACHER: Well, you don't -- correct me if I'm wrong, but nowhere in your evidence do you identify any deficiencies in the TCA rules.

MR. ANDERSON: The submissions that we've made were made at a high level and did not go into the specific markups of the market rules that are being changed.

The submissions we made, each and every one of them reference the discretionary impact of those specific changes to the market rules.

MR. ZACHER: So let me drill down. So in the TCA, generators and -- those generators that can participate at this stage and demand response resources will both bid in. Right? They bid in capacity.

MR. ANDERSON: Correct.

MR. ZACHER: And the rules with regards to bidding are roughly commensurate or equivalent for both?

MR. ANDERSON: For capacity.

MR. ZACHER: And both generators and loads will receive availability payments?

MR. ANDERSON: They will.

MR. ZACHER: And the rules with regards to settlement are equivalent. You haven't identified any deficiencies or any differences in that respect?

MR. ANDERSON: I am going to actually take you to the market rules, if we want to go there. Do you mind? To answer your question?

MR. ZACHER: Sure.

MR. ANDERSON: Okay. I would like to -- it is -- the market rules themselves are shown at AMPCO's notice of appeal, footnote 1, page -- starting at page 6 of 60. Can we get that put up? It is actually page 7 of 60, my apologies. No, sorry, it is the actual notice of appeal, so the initial document that was filed by AMPCO to start this application. And it has a number of attachments at the back of it by footnote number. One of them is footnote 1, page 7 of 60.

MR. MONDROW: That's the correct tab. And if you look at the top of the page, each page has a header on it with a page number. So you see that is page 1 of 60, so six pages forward should be page 7 of 60.

MR. ANDERSON: Thank you, Mr. Mondrow. That's it.

So page 7 defines a number of new definitions, definitions that had not previously existed. And just at the very bottom of the screen right now -- thank you for that -- you will see -- yes, that's good -- "capacity auction eligible generation resource". That is a new definition. And CAEGR is now allowed to participate.

And if we scroll back up again, it is now allowed to participate in the capacity auction, which you will see in the middle of the page means a transitional capacity auction or a demand response auction. It was previously just a demand response auction. Now it is both.

Those changes in definition introduced a new type of participant into what was the demand response auction, but is now the capacity auction, or the TCA. That new participant has a new and different revenue structure than all of the previous DRA participants.

These two participant types now share the TCA, which had been exclusively, I think as you have said, the demand response auction, which had only one type of participant.

So if we can go down further to Chapter 7, section 19.1 -- sorry, I will try to find that and tell you what page it is. Page 18 of 21. I am not sure what footnote it was.

MR. MONDROW: So that would be I think still footnote 1 --

MR. ANDREW: It should be 1, I think.

MR. MONDROW: Page 29 of 40 at the top of the page. Is this what you are referring to, Mr. Anderson?

MR. ANDERSON: I am trying to get to Chapter 7, section 19.1, which combines all of the above and sets out the generators now qualify for the amended auction.

MR. MONDROW: Sorry, bear with me. I gave you the wrong -- a different reference. Ms. van Soelen I think may have found it. Try footnote 1 still. Page 44 of 60. Try footnote 1 still, page 44 of 60.

MS. SPOEL: Mr. Mondrow, our copies -- the top of the page was cut off, so we don't have the page numbers. If you can give us the page number at the bottom of the page as well, that will help us to navigate.

MR. MONDROW: I will certainly do that.

MR. MONDROW: Sorry, Mr. Anderson, what section are you trying to refer to? There should be a section number, and then I can get a page number.

MR. ANDERSON: It was supposed to be section 19.1, according to my notes.

MR. MONDROW: 19.1. Okay, I have it.

MS. SPOEL: Mr. Mondrow --

MR. ANDERSON: Sorry. The page number at the bottom is 18 of 21. At the top, it is 29 of 60 in footnote 1. My apologies.

MS. SPOEL: Is that the one that starts with 19.1, purpose?

MR. ANDERSON: Yes. That's it, thank you. My apologies for that. I didn't mean to torture you.

MS. SPOEL: Thank you.

MR. ANDERSON: The combination of the new definitions for capacity auction, the new definitions that set out the CAEGR generation definition, and this section 19.1, which permits in 19.1.2.3 generators to now participate, is sufficient to change the landscape from a DRA that was exclusive to loads to a CA that now includes a second class of participant, who has a very different payment structure than the existing loads that were in the DRA.

So from my perspective, the amendments do in fact have a discriminatory impact in the changes that are contemplated within those amendments, and that impact is what AMPCO has objected to. And the reason it has chosen now to object to it so strongly is that this is the point where the generators have formally been introduced, creating that second class of market participant, who gets a different payment stream than the DR proponents that were in it before.

MR. ZACHER: Okay. Well, listen, I don't want to belabour it, but effectively you're saying the TCA rules have fundamentally changed because a new class of participants can now participate in the auction. Do you agree with that?

MR. ANDERSON: I agree that a new class of participant is participating, yes.

MR. ZACHER: Right. It used to just be demand resources. Now certain generators can participate.

MR. ANDERSON: That's correct.

MR. ZACHER: And the rules, not surprisingly, have created a new definition to recognize the new class of generator participants, yes?

MR. ANDERSON: Not surprising.

MR. ZACHER: And you don't object to any of that? You are fine with having a broadened capacity auction with more participants?

MR. ANDERSON: I am absolutely fine, as I have said a number of times now, with a broadened auction as long as the rules permit for non-discriminatory treatment of the different classes of participant who take place or who participate in those auctions.

MR. ZACHER: If you just return to paragraph 14 of the legal brief we were earlier looking at, you say: "Generation resources have other revenue opportunities in the IESO markets, including payments for energy services provided DR resources do not," right?

MR. ANDERSON: I see that.

MR. ZACHER: And generators entitlement to energy payments is a right that they've enjoyed under the market rules since the market was opened in 2002, correct?

MR. ANDERSON: That's correct.

MR. ZACHER: And loads not being entitled to energy payments in the IESO markets is equally something that has been included in the rules since the market opened in 2002. Agreed?

MR. ANDERSON: I agree with that.

MR. ZACHER: And there is nothing in the TCA rules that change any of that, or add to any of that. Agreed?

MR. ANDERSON: I don't agree with you, sir.

MR. ZACHER: Well, I think you're saying that the impact, Mr. Anderson, of the TCA rules is what you take issue with, not with the content of the TCA rules themselves.

MR. ANDERSON: The amendment allows generators into what was previously a demand response auction. Those generators get a different treatment than the demand response proponents. That is what I disagree with.

MR. ZACHER: I am not going to belabour it, but the -- you don't object to generators participating in the auction.

MR. ANDERSON: I don't object.

MR. ZACHER: And generators' entitlement to energy payments is something that pre-existed the TCA, and the TCA rules have not changed that.

MR. ANDERSON: I have no objection to fair competition, Mr. Zacher.

MS. SPOEL: Mr. Zacher, I wonder if this would be a convenient time to take a morning break?

MR. ZACHER: Fine, absolutely.

MS. SPOEL: And we will come back at 11:20.

MR. ZACHER: Thank you.

--- Recess taken at 11:00 a.m.

--- On resuming at 11:21 a.m.

MS. SPOEL: Thank you. Please be seated.

Okay. Mr. Zacher. Mr. Anderson.

MR. ZACHER: Thank you.

Mr. Anderson, if you could turn to your affidavit, which is at tab 2 of our compendium, and go to paragraphs 13 and 14. Could I have that?

And so under the heading -- or just before paragraph 14, "implications of proposed TCA" -- and I take it that this is where you explain what you say are the unfair or unjust implications of the TCA. Is that right?

MR. ANDERSON: That's correct.

MR. ZACHER: And in particular that the implications of the TCA are that they impose a competitive disadvantage on DR resources in the TCA auction. Is that right?

MR. ANDERSON: Correct.

MR. ZACHER: And just so that I understand, your position is that because DR resources, unlike generators, do not receive energy payments in the real-time energy market, that they are required to factor in the cost of economic activation into their DR auction bids. Is that it?

MR. ANDERSON: I wouldn't say "require", Mr. Zacher, and I think I tried to get at that in paragraphs 15 and then again in paragraph 18, where it says it can be problematic to simply omit.

I think the way I framed it between paragraphs 15 and about 19 in the affidavit was, some DR members do in fact include what I call the utilization payment, which is a proxy for an energy payment, and some do not.

And if you look back at our response to Board Staff number 1, there's a very clear indication that each one of those DR proponents considers its own risk profile very include or sometimes do include, but it can change --

MR. ZACHER: Right. And --

MR. ANDERSON: -- depending on their specific circumstances or their perceptions.

MR. ZACHER: And you said:

> "The cost elements associated with curtailment are specific to each individual participant based on a number of business and operational factors and no two are alike. AMPCO is not in a position to provide an approximate percentage value that each element would account for."

And again, that is because you don't have any cost information from your participants who wouldn't provide it to you?

MR. MONDROW: Sorry, Mr. Zacher, could you take Mr. Anderson to the passage you are reading to him?

MR. ZACHER: I'm sorry, page 3 of 5, first paragraph at the top.

MR. ANDERSON: I do not have the cost profiles of all of my members.

MR. ZACHER: And you said in response to --

MR. ANDERSON: Neither does the IESO --

MR. ZACHER: Right. And you said in --

MR. ANDERSON: -- in response to AMPCO Board Staff number 2.

MR. ZACHER: And you said in response to cross-examination questions by my friends that you have no insight into your members' bidding behaviour?

MR. ANDERSON: That's correct.

MR. ZACHER: And so you are not able to provide, in response to this question, any cost information specific to any person that has ever participated in the DRA or who might participate in the TCA. However, in your answer to question 3(c) you provide I guess what could be characterized as conceptually your views as to how participants would make determinations as to whether to include such costs in their bids, is that right?

MR. ANDERSON: Notwithstanding that I haven't provided specific cost information, I will take you back to what was discussed, I believe in direct evidence or perhaps it was with APPrO's counsel, where we talked about a number of different things conspiring to ensure that this was no longer a level playing field: lower prices, more participants, upward pressure on one class of participant offers and the same capacity requirement as last year.

I don't need to have numbers to know that all four of those things push it in one direction, and one direction only, Mr. Zacher.

I don't have the numbers. You don't have the numbers. The IESO doesn't have the numbers. The only people that have the numbers are the demand response proponents, and they're not sharing.

MR. ZACHER: Right. So I think you agree. You're telling me that directionally, this is your view.

MR. ANDERSON: Absolutely.

MR. ZACHER: Okay. And if you look at your answer to quantified evidence, I would reframe that to historically, there have been very few activations. And I would absolutely agree with that.

What happens tomorrow or next year? You don't know that and neither do I.

MR. ZACHER: The IESO's evidence says, and it is at paragraphs 36 and 38, this is at tab 13 of our compendium - I don't think it is necessary to go to it -- that HDR resources have been activated on a single occasion since the introduction of the DRA in 2015. And the dispatchable load has been economically activated less than one percent of the time.

I take it you don't disagree with that data?

MR. ANDERSON: I have agreed with that more than once this morning.

MR. ZACHER: Okay. And the MSP has made the same comment in multiple reports?

MR. ANDERSON: Can you take me to that and show me before I have to agree to it?

MR. ZACHER: I will take you to it in a moment. Let me park that for a moment. The reason, Mr. Anderson, and I don't think there is any issue with this, the reason that DR resources are not activated is because they bid at extremely high levels into the energy market, right?

MR. ANDERSON: Yes, they do.

MR. ZACHER: And the IESO's evidence, again at paragraphs 36 to 38, is that since the launch of the DRA in late 2015, dispatchable loads have bid in at average prices of $1,500 a megawatt hour. HDR resources have bid in at averages of approximately $1,700 a megawatt hours, and the average Ontario energy price during that time was $25.

Do you agree with all of that?

MR. ANDERSON: I do. And historically, if I got paid zero to be activated, I would leave my energy offer very high. If I actually was going to get paid for it, I may reconsider that.

MR. ZACHER: I will come back to that. If I can take you to tab 6 of our compendium, which is the MSP's May 2017 report, and this is a report where the MSP did a fairly deep dive into the issue of activation, starting at page 98.

But I will actually ask you to flip over to page 100. And under the heading "prospect of being activated", the MSP says: "Given the activation criteria described above, the likelihood of an activation is remote."

And the MSP then goes on in the next paragraph to explain that DR resources have to offer-in at prices between $100 and $2,000. You agree with that?

MR. ANDERSON: Yes.

MR. ZACHER: And that since the start of the first commitment period, 82 percent of all DR capacity has been bid-in at the maximum allowable price, which is $1,999. You don't disagree with that?

MR. ANDERSON: I don't disagree with that, Mr. Zacher.

MR. ZACHER: And in fact - and this is the last sentence on that page -- bids at any price over $220 a what the MSP, the IESO, and Navigant have all said?

MR. ANDERSON: I have already agreed that utilization -- or, sorry, that activation numbers have been low and that energy offers have been high.

MR. ZACHER: And do you agree with me that DR offers into the energy market since its inception have averaged between $1,500 a megawatt hour and $1,700 a megawatt hour?

MR. ANDERSON: And if I am not getting paid for something I am providing, I wouldn't be dropping my offer either.

MR. ZACHER: And do you agree with me that if DR participants continue to do that, they will eliminate or render negligible any risk of being activated?

MR. ANDERSON: If they continue to do that, it will be a low probability that they will be activated.

MR. ZACHER: Thank you.

MR. ANDERSON: It's not zero.

MR. ZACHER: Thank you. Just one moment.

Those are all of my questions. Thank you, Mr. Anderson.

MR. ANDERSON: Thank you.

MS. SPOEL: Thank you, Mr. Zacher.

Ms. Djurdjevic, is it your turn now?

CROSS-EXAMINATION BY MS. DJURDJEVIC

MS. DJURDJEVIC: I believe it is, from looking at the schedule, unless someone tells me otherwise.

Good morning, Mr. Anderson.

MR. ANDERSON: Good morning.

MS. DJURDJEVIC: So if we understand correctly, the basic proposition behind AMPCO's application is the expectation that DR resources will be treated comparatively or commensurately in the energy -- in terms of getting energy market revenues, simply, you know, generation gets paid when they're dispatched, so DR should get paid when it is dispatched as well. Do I have that correct, basically?

MR. ANDERSON: Essentially what we're saying is we want a level playing field, and with the introduction of a second class of market participant, that playing field is no longer level.

I would even go as far as to say it wasn't as bright an issue before this change to the market rules, for the following reason. All the participants were DR providers. So you could say because none of them gets an energy payment they are all equally disadvantaged. It is not discriminatory. It may not be exactly what they wanted, but it's not discriminatory, but introduce a new class that does have a different revenue stream and all of a sudden you do --

MS. DJURDJEVIC: But it's the fact that this other class has another revenue stream that is problematic from AMPCO's perspective; is that right?

MR. ANDERSON: That results in the discriminatory impact, correct.

MS. DJURDJEVIC: So you would agree that -- well, I think functionally everybody can agree that both demand and supply serve a load balancing function in organized of the report.

Now, what we noted was that FERC 745 relates to the compensation of DR resources participating in organized wholesale energy markets. And furthermore, that 745 requires the payment of a locational margin price, or LMP, for curtailing their load if dispatched.

Now, the reason for 745 was a number of perceived barriers to participation of DR resources, particularly a disconnect between the price that load pays to consume and the wholesale price in any one hour. Ultimately, I think we should say in any one time period, because sometimes we're talking about periods shorter than one hour.

So the objective of 745 was to try and address this disconnect between what load was paying for supply and the way in which the wholesale energy market valued that supply.

So we then looked at what had happened in various independent system operators and regional transmission operators at the time of and after 745.

And so we focussed specifically on PJM ISO New England and the New York Independent System Operator. And I won't go through all of figure 1, which looks at the specifics of the various resources, the various programs, and what you will see is that each market has slightly different names for things that are more or less the same thing, but that doesn't mean that the rules are absolutely identical.

Now, what we saw was that when we see what these resources ultimately have as their primary source of compensation, the bulk of compensation came through capacity payments. Actual dispatch on the energy side for those participating in those programs was quite low.

We found as well -- although it wasn't the focus of our report -- that there were a few other revenue streams like ancillary services, and we saw that activation across the various programs was also low.

And so if we then move to section 5.5, pages 38 and 39, there were a few conclusions that we drew, and these were with regards to some of the similarities and differences between Ontario and the various US markets.

One key difference, of course, is jurisdictional. In the US, the structure, generally speaking, is that the US Federal Energy Regulatory Commission, or FERC, has jurisdiction over intrastate matters. And this leads them to have jurisdiction over wholesale energy markets.

States retain jurisdiction for what happens within their borders. Clearly distribution happens exclusively within their borders, and retail happens within their borders.

And so what we see is a somewhat ambiguous seam between federal and state jurisdiction when it comes to retail, in that the States set the rules for access or lack thereof. But because those retail customers are ultimately depending on the state's structure supplied by the wholesale market, and because FERC has jurisdiction over the wholesale market, we see -- when it comes to demand response -- a degree of overlap in jurisdiction.

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 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 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 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 should also be similar.

I am looking at the split between payments for capacity and payments for energy.

So if it didn't matter what technology would be, would a fair competitive market result in it didn't matter who bid in, they would likely get the same kind of payment for the capacity and the energy. Would that result in fair competition?

MR. GOULDING: I think this is challenging because we can look at this question two ways, right.

One is should they get the same amount, right. And so what we have today, and I think rightfully so, are not, you know, what you bid is what you get markets, but we have a market clearing price that is based on the marginal cost of the last unit dispatched.

I should say the marginal bid rather than cost, depending on the market and whether you have audited costs or not.

And so under those circumstances, you might say, well, what's fair is that everybody gets the same energy payment. They're providing the same service; they get the same energy payment.

The challenge is that when we go back to this question of price equals marginal cost, then we have this challenge as to how do we think about an avoided cost. Do we think about that as a payment, or not.

So as I think about it, I think that the -- and I want to caveat this by saying that our mandate didn't allow us

[Laughter]

DR. ELSAYED: Is this better?

MR. GOULDING: Yes.

DR. ELSAYED: My question is similar to one I asked before, but there may be some overlap with what Ms. Frank just talked to you about.

Again, we heard quite a bit today about the historical fact that DR resources in the Ontario market have not been economically activated very frequently.

Based on your knowledge of other markets, under what circumstances can that change in the Ontario market going forward?

MR. GOULDING: Well, I think that -- again looking short term and long-term -- over the short term, a sudden supply shock would produce a sort of an all hands-on-deck-type situation under which DR, I think, would be called upon much more frequently.

And so for me, I believe that the most likely scenario is something goes dramatically wrong with a nuclear program over a time frame that is too quick to respond, right, you know, that in that period before you can bring every barge-mounted simple cycle gas turbine on the planet to float in Lake Ontario, you have to meet the short term needs of the system -- and look, in this day and age, you would probably meet that with a mix of batteries and other things, but you probably would be bringing in some short term resources.

I think under those circumstances, the system operator is going to be calling, where appropriate, as much DR as possible.

So if we imagine a hot summer, a higher than expected number of nuclear outages, a hot summer might mean that wind doesn't produce what you would expect, you might have poor hydrology as well. So, you know, annoying though the phrase perfect storm is, we can nonetheless imagine a not completely I implausible set of circumstances that could occur over the near term that would cause DR to be activated much more than anybody expected, but consistent with the market rules.

DR. ELSAYED: And the longer term.

[Laughter]

MR. GOULDING: So in the longer term -- I shouldn't say I have visions, right.

[Laughter]

MR. MONDROW: Not on the record.

MR. GOULDING: Not on the record, yes.

[Laughter]

MR. GOULDING: Yes. We can imagine a market that -- getting back to what I said about an increasing number of intermittent resources, if we believe that demand response participation can provide a highly flexible, valuable way of balancing supply availability, we can imagine a circumstance where it becomes a much more active part of the energy market.

And so and -- look, I mean we have, you know, some projections that show batteries serving this role and ultimately the market will determine the relative costs of

TAB 7

Ontario

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**

EB-2019-0242

THE ONTARIO ENERGY BOARD

Association of Major Power Consumers of Ontario (AMPCO)

Application to Review Amendments to the Market Rules made by the Independent Electricity System Operator

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Thursday, November 28, 2019,
commencing at 9:34 a.m.

VOLUME 2

BEFORE:

CATHY SPOEL	Presiding Member
EMAD ELSAYED	Member
SUSAN FRANK	Member

A P P E A R A N C E S

LJUBA DJURDJEVIC	Board Counsel
DAVID BROWN CHRIS CINCAR MICHAEL BELL CIERAN BISHOP CHERIDA WALTON LILLIAN ING	Board Staff
IAN MONDROW LAURA VAN SOELEN	Association of Major Power Consumers in Ontario (AMPCO)
GLENN ZACHER DANIEL GRALNICK PATRICK DUFFY	Independent Electricity System Operator (IESO)
EVAN BARZ	Association of Power Producers of Ontario (APPrO)
EWA KRAJEWSKA GIAN MINICHINI	Kingston Cogen Limited Partnership (KCLP)
MARK RUBENSTEIN	School Energy Coalition (SEC)

I N D E X   O F   P R O C E E D I N G S

E X H I B I T S

U N D E R T A K I N G S

That's the problem?

DR. RIVARD: The perceived value that electricity consumers might get in this situation may not be a long term sustainable value, if those generators that they still need also need those revenues.

MR. MONDROW: If they still need them. But what if more DR resources come forward under this structure because they're more efficient at providing this stuff. Then consumers would be better off, right?

DR. RIVARD: Well, at some point, you know, we'll have no generation. And I don't know any market where consumers are not consuming and we still -- sorry, I don't know any market where we have no generation output and consumers can continue to consume. So you have to be very careful with that analogy.

And, you know, I think this is where the net benefits test, in my mind, kind of -- is suspect in that it looks at very short term, a very short term savings to consumers, but not recognizing that it comes at the expense of generators to recover those net revenues and can lead to, over the long-term, a higher cost for consumers.

MR. MONDROW: Let's if to paragraph 56 of your evidence, if we could. Paragraph 56 is -- or you talk about the net benefits test, Dr. Rivard. You ultimately explain that in the concluding sentence as follows - sorry, you don't explain the test in the concluding sentence.

In the concluding sentence, after talking about the test, you say:

"In this sense paying DR resources is deemed cost-effective if it leads to lower bills for all non-DR customers."

And maybe that is your encapsulation of the net benefits test. Is that what that sentence is? Is that essentially what the net benefits test was? Paying DR resources is deemed cost-effective if it leads to lower bills for all non-DR consumers? The FERC necessary benefit test, I should specify. Sorry.

DR. RIVARD: Yes. If you read the FERC order that is exactly how they describe it, right? They call it the billing effect.

MR. MONDROW: Right. And did they get that wrong? Do you think that is the wrong test?

DR. RIVARD: I think it's the wrong test to apply in the context of a market, yes.

MR. MONDROW: Okay.

DR. RIVARD: And I think I explain this in a response to one of the interrogatories, or it might be Mr. Anderson's witness statement.

What it does is it looks very short-term and says, we can save some energy payments here for all other consumers, essentially by paying one demand response to reduce instead of paying a generator. And it lowers the prices for sure in that moment for energy. But it is also clear that what that means is any other generator that is producing at that time, it also gets paid less revenue. And so its net revenues also decline.

And the thing that the FERC kind of failed to recognize is that if you want those generators to be available, if we need electricity to be produced at some point, we can't do it all by demand response resources. We will need those generators. They're going to have to recover their fixed costs through some other means. Capacity prices will go up eventually. We need those generators. Eventually they have to recover those revenues as rates go up.

My concern with the net benefits test is it is a very short-term test, a measure of what consumer benefit is. I think what we should be concerned more with is the long-term costs to consumers, which includes not just the cost of the energy but the costs of the capacity, the value of the reliability that we get from having those physical generators there.

MR. MONDROW: And the value of the widgets produced or not produced?

DR. RIVARD: Personally I think that is value that we want in the economy, for sure, yes, that is how we -- we strive to design our economies, to make sure that the value of resources are put to their best use, yes.

MR. MONDROW: And if you look at the last sentence in your paragraph 57, this is where you talk -- 57 is where you talk -- maybe this is what you were thinking about -- the societal optimization concept that you have mentioned, you mentioned a minute ago.

DR. RIVARD: Yes.

MR. MONDROW: In the last sentence in paragraph 57 you say:

"The net benefits test seeks to maximize the benefit to non-DR participants' or non-DR consumers' surplus and comes at the express of producers' surplus."

And then you say:

"That is contrary to the efficiency objective of the Electricity Act."

So your problem with the net benefits test is it produces allocative inefficiencies, it takes surplus from generators and gives it to DR resources, and in the long run you think that might not be good for the market.

DR. RIVARD: Yes. The net benefit test is in conflict with the concept of allocative efficiency, and it is true that you have to consider the dynamic effects. The whole idea of promoting allocative efficiency in the short-term is that it sends the right signals to investors in the long-term, and to the extent that we structurally have competition in that way it assures that we get the least cost way of meeting demand in the future.

MR. MONDROW: So again, this sentence at the bottom of paragraph 57:

"The net benefits test seeks to maximize the benefit to non-DR participants or non-DR consumers' surplus."

In Ontario that is electricity customers? Yes?

DR. RIVARD: It seeks to -- yes, it is all electricity

DR. RIVARD: Yes, capacity market to purchase what I call a stock variable; i.e., the ability or the potential to produce energy.

MR. DUFFY: And in that auction process, if the capacity auction evolves as intended, the same payment will be made regardless of whether someone wins as a load or as a generator, correct?

DR. RIVARD: Anybody successful in the auction receives the market clearing price, they get the same payment per megawatt of capacity made available.

MR. DUFFY: And you helped clarify for us that every participant who clears the auction gets the same price.

DR. RIVARD: That's correct.

MR. DUFFY: Right. And then the second thing we have is an energy market, which you called a flow measure, correct?

DR. RIVARD: Correct.

MR. DUFFY: Okay. And in the energy market of course what we have been talking about is that generators are paid for energy, but loads are not paid to not consume. Correct?

DR. RIVARD: That's correct.

MR. DUFFY: Okay. And that has been the structure of the energy market since market opening, correct?

DR. RIVARD: That's correct.

MR. DUFFY: And can you just again explain the rationale for why the market is configured in that manner, the real-time energy market?

DR. RIVARD: Hmm-hmm. The market was designed that way to recognize that we wanted to encourage generators that can produce electricity to meet demand to do so in the least cost fashion, and we recognize that they incurred a cost of actually producing that. They inputted the fuel.

So it is designed to say, tell us how much you need to recover that cost. We will stack up those generators at lowest cost to highest cost, and we will choose just the generators that we need to meet demand, and we will pay all of them the market clearing price. That will make sure that anybody that is accepted recovers their variable costs.

On the demand side, we wanted to set up a situation where the demand side had the ability to say that I am not willing to pay what it costs to produce, because my business is buying electricity as an input to continue to produce widgets or whatever it is.

So what was enabled was a bid option for the demand side that said at what price they would be willing to stop consuming, and if the price is below that they will continue to consume.

So from that standpoint the IESO kind of also analogously stocks up the demand-side bids from highest down to lowest, and the lowest bid, those who are not willing to pay the most, might be the first to ask to not consume.

MR. DUFFY: And one of the questions you were asked, and I believe you acknowledged, is things are changing and technology is changing or has changed since 2002, correct?

DR. RIVARD: Yes.

MR. DUFFY: Therefore, we may want to recover decisions that were made in 2002 or prior as part of the market design, correct?

DR. RIVARD: I think it is wise to continue to adapt, yes.

MR. DUFFY: And you will agree with me that through its energy payments stakeholder process, the IESO is conducting a study into that issue, correct?

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

MR. DUFFY: You also agree with me that issue of whether energy payments should be made, it's not the issue that you were asked to opine on, and it is not the issue before this Board today. Correct?

DR. RIVARD: Can you repeat that question?

MR. DUFFY: The issue of whether or not loads or DR resources should receive an energy payment is being studied by the IESO. It's not what you were asked to opine on and it is not part of what the Board has to decide today. Correct?

DR. RIVARD: I think I was asked to comment on whether the decision not to pay an energy payment would be discriminatory, could lead to competitive disadvantage, if I can clarify that.

MR. DUFFY: Yes. We will go to that in a second. And you will agree with me that the -- I think it's been pretty obvious the issue ever whether or not to pay DR resources an energy payment is a contentious and complex one?

DR. RIVARD: Yes.

MR. DUFFY: And we would have to consider Ontario factors, such as the ICM and the GA, as part of any assessment of that issue, correct?

DR. RIVARD: Yes.

MR. DUFFY: Okay. If I can ask you to turn to your witness statement or affidavit, and it is in the compendium at tab 1, in paragraph 17.

DR. RIVARD: Yes.

MR. DUFFY: So what you were asked to do in 17(a), Dr. Rivard, was to analyze the economic merit of AMPCO's assertions of inequitable and unfair treatment, competitive disadvantage, and negative impacts on competition and efficiency.

Correct, that was one of your mandates?

DR. RIVARD: Yes.

MR. DUFFY: Okay. The second part of your mandate was to identify similarities or differences basically between the United States and Ontario with respect to FERC order 745. Correct?

DR. RIVARD: Yes.

MR. DUFFY: Okay. And on 17(a), when we're talking about inequitable treatment, that's inequitable treatment in the capacity auction, not in the energy market. Correct?

DR. RIVARD: So I can tell you there's a -- it's a good question. And I can tell you how you might interpret this.

Do the amendments themselves, which essentially describe how a capacity market would work and enables generation to participate in it, are they discriminatory?

I don't think that's actually -- there's nothing in those rules that I would argue would be discriminatory one way or the other, no.

MR. DUFFY: The question is whether when you layer those on top of the existing market design, the interlinkages between the two creates some form of --

DR. RIVARD: Yes.

MR. DUFFY: -- inequity, is that right?

DR. RIVARD: That's my interpretation of what the issue is. It is not so much the rules themselves, but it is the fact that they have now come along and complemented existing rules around energy payments that is raising the concern.

MR. DUFFY: Okay. You were asked by Mr. Mondrow a series of questions regarding activation costs and lost load. Hopefully, I was following along and caught it.

But effectively, you've got for a DR resource, they get a capacity payment, and that covers their ability to -- whatever costs they would need in order to respond if activated. Correct?

DR. RIVARD: I think it covers anything that they need, say on an annual basis, to make sure they're available when called upon to reduce demand.

MR. DUFFY: Then you've got lost load, which is something they would factor into their energy bid. Correct?

DR. RIVARD: That's correct.

MR. DUFFY: Then they have these activation costs and three examples were given to you. Correct?

DR. RIVARD: Yes.

MR. DUFFY: Yes. And those, as I understood your evidence, could either go in the energy bid or could go in the capacity bid, whichever one was chosen by the participant. Correct?

DR. RIVARD: The -- yes. These are -- I interpret those as a one-time avoidable cost, much like a start-up cost for a generator, and it is up to the participant either to recover in the energy bid by raising its bid to avoid those costs, or recovering them in the availability payment.

MR. DUFFY: These costs only arise if the DR resource is actually activated, right?

DR. RIVARD: That's correct.

MR. DUFFY: So can I ask you to turn to paragraph 26 of your evidence, please?

DR. RIVARD: Okay.

MR. DUFFY: And the question you were asked here was: Does AMPCO provide evidence that DR resources are at risk of incurring this cost with an economic activation.

And maybe what you were -- you then refer to two types Resources, dispatchable loads and hourly demand response HDR.

Just before we go on, quickly what is the difference between a dispatchable load and a HDR?

DR. RIVARD: In the simplest way, a dispatchable load is someone that is capable of increasing or decreasing its consumption on a five-minute basis, when it receives a five-minute instruction from the IESO to do so.

Whereas an hourly dispatchable load is asked in advance to reduce demand on an hourly basis.

MR. DUFFY: And if we walk through paragraph 27, you note that a dispatchable load can manage the risk of activation, and I will read you the last sentence in that paragraph, which states:

> "As long as the price in the dispatchable load's energy bid reflects their value of lost load, they are not at risk of incurring a cost from an economic activation. They will only be economically activated when the market price exceeds their value of lost load."

Correct?

DR. RIVARD: Yes.

MR. DUFFY: Would the same also be true for their other activation costs that are not lost load. Could they manage those in the same manner?

DR. RIVARD: To the extent they have that kind of fixed one-time avoidable cost of maintaining the product by using gas, the way they would manage it is by bidding an energy price that is sufficiently high that they never get asked to do that.

MR. DUFFY: And the only way they would be at ribs of not being able to manage that is if those costs -- I think the example given to you by Mr. Mondrow is they bid at 1999, but that is not enough.

DR. RIVARD: That's correct.

MR. DUFFY: They get dispatched at 1999 and those costs -- when we add the activation costs is 3,000, I think you said, is that right?

DR. RIVARD: That's correct.

MR. DUFFY: Does the same apply as well for HDR resources, Dr. Rivard?

DR. RIVARD: Yes.

MR. DUFFY: You were asked this morning by the panel, I believe it was Member Frank, about is there anything we can learn from historical market prices. And I was wondering if we can revisit that quickly.

Is there anything that you think historical market prices can tell us or inform us about the ability of DR resources to manage this risk of activation?

DR. RIVARD: To manage the risk of activation? What I would say is I can observe two things.

In history, I have observed dispatchable loads deciding, without a capacity payment or any other payment, to -- when the price reached a certain level or above, they purposely and voluntarily said I'm not going to consume.

What that tells me is that there was an economic decision they were willing to avoid prices.

I think with the creation of the demand response auction and this concept of activation, the other evidence we have is that they've rarely been activated, and there is evidence there that there is a way to manage that.

MR. DUFFY: They have rarely been activated, Dr. Rivard, because they are bidding high at 1999 and the price -- the scenario Mr. Mondrow outlined for you where the market price gets to 1999 and they can't recover those costs. I mean, is that one that -- in your knowledge, is that something that happens in the market?

DR. RIVARD: That they bid high?

MR. DUFFY: No, no, sorry, that we get a market clearing price of 1999.

DR. RIVARD: On an hourly basis, I may be wrong, I -- I don't believe it has ever happened. I could be wrong. But I am certain that prices -- I think it's even in the evidence I gave, prices have really never reached that level.

MR. DUFFY: So one final question, Dr. Rivard. If a DR resource can manage the risk of these activation costs through its energy bid, you will agree with me there's no need then to factor them into the bid they're making in the capacity auction. Correct?

DR. RIVARD: So I can only speak of from the standpoint of what I think would be economically optimal in light of the conditions that you gave me.

MR. DUFFY: Hmm-hmm.

DR. RIVARD: If I was a DR resource that I knew that the probability of me being activated at a price of 1999 was as low as what the evidence suggests, then I wouldn't be too worried about bidding that -- any potential loss in my capacity payment. I think that is, as a kind of economist, that is how I think about it.

MR. DUFFY: And if you didn't as a DR resource have to include that in your capacity auction bid, you will agree with me you wouldn't be at a disadvantage as compared to a generator. Correct?

DR. RIVARD: I think the evidence on what prices have been and the risk to a DR resource incurring a cost that it can't recover is really minimal. And I can't see how it's truly at a disadvantage in the capacity auction.

MR. DUFFY: Thank you, Dr. Rivard. That is all of my questions.

MS. SPOEL: Thank you.

Ms. Djurdjevic, you're next.

MS. DJURDJEVIC: Thank you, Madam Chair. OEB Staff has a compendium which is on the dais for the panel, and it will be Exhibit K2.6.

EXHIBIT NO. K2.6: BOARD STAFF COMPENDIUM FOR PANEL 4.

MS. DJURDJEVIC: I am also going to be referring to a couple of documents on the screen that didn't make it into the compendium, and...

MR. MONDROW: Are there copies of the compendium available? Was it circulated?

MS. DJURDJEVIC: It was -- I believe it was sent out this morning by e-mail. So you will have a PDF of it that was sent by e-mail. And we will refer to it on the screen as well.

MS. SPOEL: Are there -- are there -- I mean, sending it PDF by e-mail in the morning when people are in the hearing room is perhaps not the most efficient way for people to actually be able to use it. Are there any extra printed hard copies available --

MS. DJURDJEVIC: I can ask Staff to go and make us some copies and the parties can have it available, if they need them.

MS. SPOEL: Well, let's look at the table. Are the items that are in here -- I see that Mr. Rivard's affidavit is in here, so I assume that that -- everyone has a copy of that at hand, because we have just been dealing with it.

The other materials that are in here, are they readily --

MS. DJURDJEVIC: Every single --

MS. SPOEL: -- available? I see the second item is the transcript from -- excerpts from the transcript, which I think Mr. Mondrow had in his compendium as well. Perhaps the other materials, if they aren't from today, maybe somebody could quickly make some photocopies of those materials --

MS. DJURDJEVIC: Yes, we certainly can.

MS. SPOEL: -- I think that is at what is at tab 2 -- sorry, tab 1, tab 3, tab 4, and tab 5. It is only a few pages, I realize, but I think it might be helpful if we could all operate from the --

MS. DJURDJEVIC: Sure, we can --

MS. SPOEL: It is only a few pages, so perhaps somebody could produce those quickly?

MS. DJURDJEVIC: Yes. We will get to that. And it's actually -- the only document that isn't already filed and been referred to many times is the item at tab 1. The item at tab 5 is actually not part of today's cross. It is for tomorrow.

So it is really only the one-page document at tab 1 --

MS. SPOEL: Anything you intend to refer to this afternoon that --

MS. DJURDJEVIC: Yup.

MS. SPOEL: -- could you please arrange to have copies of those pages reproduced and made available to the other counsel so we can all -- so everybody can follow along and perhaps make notes on their copy and not have to use a PDF on their computer?

MS. DJURDJEVIC: Sure. We will start on that, and --

MS. SPOEL: Meanwhile you can perhaps start with the things that people do have in front of them.

MS. DJURDJEVIC: Okay, thank you.

CROSS-EXAMINATION BY MS. DJURDJEVIC:

MS. DJURDJEVIC: So good afternoon, Dr. Rivard. I have a few questions, and I am going to start with a concept we've heard a lot of -- or discussion about, and that is the value of lost load, which is important for demand response and this proceeding generally.

I believe we talked about it, but I am wondering if you can sort of explain what it means in terms of in you don't think that has -- well, let me ask you.

Is there any correlation between the absence of activation payments and inefficiencies in the market?

DR. RIVARD: I don't believe not -- sorry, I have some double negatives. I don't believe not paying demand response a price per megawatt reduced is leading to any material inefficiencies in the market.

MS. DJURDJEVIC: Okay. I have a couple of questions, and I have five or six minutes to do it.

So you already had taken us to paragraph 57 of your report, where you express your view that maximizing allocative efficiency should be the desired outcome. Do we still have that on the screen? Okay, yes.

And you indicate -- you also state in that paragraph that promoting efficiency is also a purpose of the Electricity Act.

Would you agree that there's ten purposes identified in the Electricity Act and, subject to check -- they keep adding or taking them away -- but there's ten. And your expert opinion is primarily based on one of the purposes, and that's to promote economic efficiency. Is that a fair assessment?

DR. RIVARD: So I do agree there's many. I can't tell you the exact number, ten might be right, and efficiency is one of them.

MS. DJURDJEVIC: And I don't propose to go through all ten of the objectives, but there are a couple that seem -- that are quite germane to this proceeding.

One of them being, for example, to encourage electricity conservation and efficient use of electricity. And would you agree that that's a purpose of the Act that is relevant in this proceeding?

DR. RIVARD: I'm not sure I see exactly how it is relevant, but...

MS. DJURDJEVIC: Demand resources refraining from consuming electricity and electricity conservation is about reducing electricity consumption. So --

DR. RIVARD: Maybe it depends on what you mean by conservation. I kind of think about it that if there are ways that we are aware that we can reduce demand, and the cost of achieving that reduction is less than what it would be just to continue to consuming, then that could be conservation that is worthwhile.

MS. DJURDJEVIC: So you do agree that reduced demand response can serve a function of electricity conservation, like it is relevant. It is a relevant purpose of the Electricity Act in this proceeding.

Do you agree with me generally?

DR. RIVARD: If you are saying that consuming less of a megawatt by a demand response can be seen as -- I guess I am just not -- I can't say that that is actually conservation in the sense that that's a megawatt saved that was worth saving.

I just -- and in my examples, a couple I show it wouldn't be. There was actually from the perspective we shouldn't have reduced that megawatt of demand.

- and, you know, what the purpose of the Act is, call it the financial viability of the electricity industry.

So would making activation payments of DR resources negatively impact the financial viability of the electricity industry?

DR. RIVARD: So what I would say is, given the evidence that we have -- let me see if I can answer your question. I am trying to make sure I understand it -- given the evidence that we have, if we were to pay demand response per megawatt the market price, let's say, when it reduces, to reduce its demand, I think the effect would be for them to lower their bid prices, because there's an opportunity to get a payment that is greater than what the value they might get from continuing to consume, although I think the evidence suggests that is probably still pretty low, because prices are well below even what half of the market clearing price has been.

So from a material standpoint, I think it's not likely, but there is that potential. If prices were to fall then in terms of the financial viability, what I point out is that that means generators have less revenues, and that affects their viability, and that can affect the need for future payments in the capacity market.

I am not sure that they -- I think it could threaten that generator who is on the margin who no longer now qualifies for the capacity market, and their viability could be at risk.

MS. DJURDJEVIC: Going back again, I might be chasing my tail here, but the -- only because you mentioned it. If there was a new rule -- new rules in the game that would cause demand response participants to submit bids that are below value of lost load, would you say that that is consistent with maximizing gains from trade?

DR. RIVARD: I think that goes in the direction of not maximizing gains from trade.

MS. DJURDJEVIC: Okay. Lower bids that are below VoLL, and that would reduce the cost to consumers, and -- anyway, why don't you explain to me why that would not be consistent with the maximizing gains from trade which is the objective of the IESO rule.

DR. RIVARD: So maximizing gains from trade, remember, is maximizing the difference between what consumers are willing to pay, that demand curve -- sorry, I am drawing pictures with my hands -- and the supply curve, what sellers are willing to sell at.

MS. DJURDJEVIC: Let the record show that the witness is indicating an upward slope.

DR. RIVARD: Yes. Maximizing the gains from trade is to maximize that difference.

If you pay a market price per megawatt reduced to demand response, then they will bid lower than what their true willingness to pay is and the market will now maximize something that does not really reflect what the gains from trade are. It will lead to an outcome that maximizes something less than the gains from trade.

MS. SPOEL: Ms. Djurdjevic, you have kind of used up

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

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

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

Correct?

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

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

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

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

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

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

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

DR. RIVARD: Yes, certainly, yes.

MR. BARZ: Okay.

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

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

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

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

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

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

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

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

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

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

DR. RIVARD: Okay.

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

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

DR. RIVARD: Yes.

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

DR. RIVARD: Yes.

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

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

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

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

DR. RIVARD: Yes.

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

DR. RIVARD: Yes, yes.

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

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

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

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

DR. RIVARD: That's correct, yes.

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

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

Correct?

DR. RIVARD: Yes.

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

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

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

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

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

DR. RIVARD: It had that effect.

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

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

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

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

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

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

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

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

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

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

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

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

DR. RIVARD: I can't say factually, but my memory -- which by the way, my capacity for that is declining the older I get and the longer I sit here, but...

[Laughter]

MR. MONDROW: I have some more questions.

[Laughter]

DR. RIVARD: My memory is that, yeah, we started to see much more, and I will say innovative ways of providing demand response. We saw aggregators and dispatchable loads, yes.

MR. BARZ: Okay. So then arguably then, based on the number of resources that are involved and the types that became involved, aggregators that became involved in the demand response auction, these programs were successful in removing some of the barriers to demand response auction participants.

DR. RIVARD: I think from the perspective of, let's call it reveal preference, we saw what actually happened. It brought about demand response. That's right. So they were successful in that regard.

MR. BARZ: So arguably helping demand response resources at this early stage as Ontario did already addressed the key objective of FERC order 745, which was to get -- to remove barriers to demand response participants.

DR. RIVARD: To the extent that that's what FERC order 745 was hoping to do, bring about more demand response, those programs helped that, yes.

MR. BARZ: Beyond that specific issue of removing barriers, in your view how applicable is FERC order 745 to Ontario's market?

DR. RIVARD: How applicable? So I want to make sure I define what applicable is. Applicable in the sense that if the objective was to lower the cost for all other consumers, as FERC said, by inducing more response than would otherwise be there and lowering the price, I think my evidence shows that it's -- because of the global adjustment specifically, it really is not likely to have that effect.

MR. BARZ: So you mentioned the global adjustment, which is one of the distinctions between the FERC-regulated jurisdiction and Ontario. Can you elaborate on some of the differences between Ontario and those FERC-regulated jurisdictions which might distinguish and might make an impact in terms of the applicability of that order?

DR. RIVARD: Yes, again, I think what I wanted to point out in the evidence is that if your objective is to lower the cost for all other consumers and that you wanted to apply the FERC order as defined, paying demand response when capable, but also when lowering the price that has a net benefit to all other consumers, I think you have to factor the global adjustment in that. And the evidence, at least the historic evidence is that that is not likely to happen.

MR. BARZ: Okay. I just have a couple of more lines of questioning. You were present during Monday's hearing day, correct?

DR. RIVARD: I was.

MR. BARZ: And you would have heard some of the discussion with London Economics regarding designing market rule amendments that are technology neutral?

DR. RIVARD: Yes.

MR. BARZ: Can you describe what technology neutral means to you?

DR. RIVARD: I think when I hear technology neutral -- and I have used this term as well -- I think it is an attempt to kind of point out that we really want to let competition determine the outcome, and it's a sense of saying, and so we want to be not recognize technology per se. And it's got an aesthetic appeal to it.

I think it is often the raise when people are talking about, hey, you don't want to pick winners, and you don't want to give a subsidy to something just because you favour a technology. I think that is the context that I think about it.

What I would also say though is, I think -- I don't think you want to stop at that kind of principle. It seems like an admirable principle. But again, when you are designing markets, I think it is important to recognize that there are differences, economic differences in participants and when you design a market, sometimes you might have to recognize those technological differences and treat them in a way that brings about the best of them in the market. And I think that, you know, that is something that we see in the market today in Ontario even.

We have, just thinking when the generation fleet, there are certain situations where baseload nuclear facilities, when they may go off line, are treated in a way that other generators may not be, and that is to reflect kind of the economic situation of those plants.

We have hydro limited resources, we only have so many hours' worth of water to produce electricity. We allow them to put that information into the market about what their limitations are, to hopefully optimize when we use it.

We have quick-start fossil generators and non-quick start fossil generators, and the rules apply differently to those. But the idea, I think, is to try and recognize what it is that those technologies bring, and to make sure that we can bring about the best in those technologies to the benefit of whatever that objective is.

And I think the objective of the market rules and of the market itself is promoting competition, not so much to watch it happen, but because it leads to the most efficient outcome.

MR. BARZ: So in relation then -- with that in mind in relation to these market rule amendments that are before us, how do you believe that the concept of technology neutral should be considered, or how is it applied, or how should it be applied?

DR. RIVARD: Within the specific issue of should demand response be paid to an energy price to reduce its consumption?

MR. BARZ: Yes. In the context of these market rules, amendments and with that specific issue in mind.

DR. RIVARD: Right.

MS. SPOEL: Sorry, Mr. Barz, we're not actually here, as I understand it, on this application to determine how things should be compensated.

We're here to determine whether or not the amendments that have been put forward by the IESO, whether they will or will not lead to unjust discrimination or not be consistent with the objectives, the purposes of the Electricity Act.

So I don't think we need to spend time on how it should be fixed, because we actually don't have jurisdiction to say you should or shouldn't make certain kinds of payments.

What we're here to do is actually look at the amendments themselves and if the amendments -- if it goes forward as proposed, or as enacted by the IESO, then will the result be that there will be unjust discrimination. And of course the rules around who gets paid what for how much and when is a component of -- well, it's a component.

But we are not here to figure out how we would do it better, because we don't actually have the jurisdiction to do that.

MR. BARZ: Thank, you Madam Chair, I appreciate that. I think my line of questioning was going at -- and I think that might have been where Dr. Rivard was going.

But I guess then I could ask you just point blankly, then, do you think that these energy payments would result in -- sorry, the lack of an energy payment, would it result in unjust discrimination for a demand response resource?

DR. RIVARD: I would say no. Not paying the demand response, the market price for reducing demand will not have a discriminatory effect.

MR. BARZ: Okay. Then I guess my final question, which is somewhat related, a more general question related to the TCA is do you believe the TCA or market rule amendments will limit competition in Ontario?

DR. RIVARD: I don't see how they would, no.

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

MS. SPOEL: Thank you. Mr. Rubenstein?

CROSS-EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Thank you very much. Is this on? I will be referring to K2.5 as well, which is potentially one interrogatory response which Staff, as I understand, will pull up if need be.

Dr. Rivard, I want to follow up on something you talked about during your in-chief when you were providing the examples. One thing you talked about was the potential for what you called -- and what I believe was discussed in FERC 745 -- is the problem of potentially double compensation. A demand response resource is avoiding the HOEP, the market clearing price at a given time, and then is also being compensated for that market clearing price.

Do you recall that -- your comments from that respect?

DR. RIVARD: Yes.

MR. RUBENSTEIN: As I understand in FERC 745 -- which as I understand you are familiar with based on your affidavit -- that was a discussion which the dissent talked a lot about.

DR. RIVARD: Yes.

MR. RUBENSTEIN: And my understanding is that the

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 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.

QUESTIONS BY THE BOARD:

MS. SPOEL: Thank you, Mr. Rubenstein.

DR. ELSAYED: I have just one question. I think what I heard is a statement to the effect that participation by DR resources in the capacity market may affect generators, or a generator who is on the margin, and put their viability at risk.

Am I accurate in that statement?

DR. RIVARD: Do you mind just repeating that? Sorry.

DR. ELSAYED: That the participation of the DR resources for some generators who may be on the margin may put their financial viability at risk.

DR. RIVARD: Because they can't participate in the current --

DR. ELSAYED: Because they can't participate, because the DR resources can participate in the capacity market, I thought I heard you say. If they're allowed to participate, that that may put some generators who are on the margin, put their viability, financial viability at risk.

DR. RIVARD: Oh, I see. I think what I was saying is -- the question that was asked to me if we did pay -- I think the question was asked to me by Board Staff that if we did pay demand response for reducing demand, could that affect financial viability of the industry?

I think my response was to the extent that it leads to a reduction in demand at times when the actual value of that consumer consuming was greater than what the costs of, say, that marginal generator was and so they were no longer producing, that generator in particular, its financial viability could be at risk.

DR. ELSAYED: Okay. And in that -- can you address the flip side of this, in terms of what impact could the fact that the DR resources are not able to participate in the capacity market may have on the financial viability of some of those DR resources?

DR. RIVARD: So the DR resources are eligible to participate in the capacity auction. But I think the issue that's being raised here is that because they, unlike a generator, don't get an energy payment, that that would disadvantage them.

DR. ELSAYED: And what I am saying is by not getting an energy payment, what are your thoughts in terms of how that might impact for some of them their financial viability.

DR. RIVARD: I think what I, I would say is that -- and I think this came out in perhaps the IESO discussion -- not getting an energy payment right now, based on history seeing how often they would actually be activated is, in my words, de minimus in expectation, in which case they could offer in that capacity auction exactly the same that they would have had generators not been there. And then let's see what competition brings about.

DR. ELSAYED: But I thought what we heard is that history is not necessarily indicative of what might happen in the future, as far as the utilization of DR resources in such a market.

DR. RIVARD: I think I was asked a question about could history inform us about the merits of providing an energy payment, which is different from the question about can history inform us the likelihood that activation would happen.

DR. ELSAYED: What are your thoughts in terms of the likelihood in relation to history?

DR. RIVARD: I think the evidence says that based on recent history, and there's really no obvious evidence that things are going to change in the next year, the likelihood of activation is not going to increase beyond what has happened in the last year.

So the risk of being activated as a demand response resource and not being able to recover some costs is very low. Which means, again, I think to the point of your question, that means they can participate in that capacity auction and bid at a level they would have bid otherwise, had generators been part of it.

DR. ELSAYED: So what advantages can you think of -- like why would the DR resources be pursuing this in this case if there are no prospects of any benefits beyond what has been happening in the past?

DR. RIVARD: I am not sure I can explain their motive behind that.

DR. ELSAYED: No, I mean like based on your economic perspective.

DR. RIVARD: Yeah, maybe the best way I can answer that is if I, as an economist, and I was working for one of these DR resources, and I was asked, do you think this is going to put us at a disadvantage, I would say no, because I am not being activated often.

DR. ELSAYED: Okay. Thank you. That is my questions.

MS. SPOEL: Ms. Frank.

MS. FRANK: I would like to explore the conversation you had a little while ago about the activation costs, and we will start with, I think, the easier one with generation. There are activation costs that you have talked about, and they're standby type payments associated. So I think you said there was no harm, they got to recover their costs of the generators.

DR. RIVARD: So, yes. The non -- sorry, a quick -- sorry. A non-quick-start generator, someone that takes a while to start and has to use fuel to kind of warm up and get ready to start producing electricity, those types of generators are -- there's a program called the Cost Guarantee Program, I think I got that right, that says, lookit, if we -- if the IESO says if we need you, if in advance of real time we need you, and you tell us in advance what those costs you're going to incur, if the market price that you get paid for every megawatt that you produce is not high enough to cover your marginal costs of producing that electricity, plus those start-up costs, what we'll do is guarantee that you will at least be able to cover those start-up costs. If the price goes really, really high and you cover your marginal costs and your start-up costs, you will get no payment.

So it is really an insurance program. The intent of it really was -- and it was not there at the start of the market. It was something that was introduced, I think probably in the second year of the market.

And the intent was to try and help those generators manage the risk when the IESO's forecasting that we will need you, we will need you, but then we don't, and you come online and you take the risk that you are going to start, prices are really low, you didn't cover the costs.

What we're finding is to manage that generators were bidding -- offering, sorry, prices higher than their marginal cost because they had to manage that risk. This was an attempt to reduce that risk.

MS. FRANK: Right. So that what they were going to now offer would be truly their marginal costs, and they would know -- they would be confident if there were start-up type costs, they're going to get paid for it? And that would be true today as well. Right?

So when a generator bids into the capacity market, they do not have to include any of these start-up costs, because they know there's a mechanism to get paid. Is that fair?

DR. RIVARD: That's fair. The Cost Guarantee Program reduces the risk that they can't cover those costs, and therefore that's not something they have to bid in their energy offer, or put in their energy offer, or bid in the capacity market, yes.

MS. FRANK: Okay. Now we move over to the DR example. So I think there was enough conversation that indeed there was a recognition for some DR resources. There are equivalent start-up type costs. There is some bucket of costs that only occur if they get activated. We're good with that?

DR. RIVARD: Yeah. I think Mr. Mondrow walked me through Mr. Anderson's evidence, which -- and this was my interpretation -- was kind of helpful in explaining kind of similarity to a generator, in that when activated, when asked to reduce consumption, it is not just the value of lost load they might be at risk, but they may actually have to incur an out-of-pocket cost, burning gas to maintain a product to avoid waste.

MS. FRANK: And you seem to say there were two ways that these DR responses -- and this was really where -- what I am trying to get assistance on -- the one option was that they increase their bid price for the capacity to cover these potential costs. The challenge with that is they have now added a cost component that generators don't have to add. So that puts them at a disadvantage having to include another category of costs that generators don't have to, in terms of the capacity bid. Do I have that right?

DR. RIVARD: I think you do, yes. The demand response resource today has to factor that risk of incurring that fuel cost to maintain the product in its bid price.

MS. FRANK: Right.

DR. RIVARD: So it may bid something beyond just what its true value of lost load is or its willingness to pay to say, I want to avoid that.

MS. FRANK: Right.

DR. RIVARD: So -- and is at risk of that. Now, I will say -- I mean, the evidence here was about, and as a practical matter does that matter. And the evidence is, no, that prices never really get to that level that they would actually have to incur that cost.

But as a point of consideration, it is meritous (sic) to think that there is this analogy of cost, there might be some value in thinking about that specific type of cost guarantee in a future market design.

MS. FRANK: So it is about the design rather than the -- you know, it's the theoretical rather than the practical that we have to be concerned about, right?

DR. RIVARD: I believe so.

MS. FRANK: So I think you were suggesting there's another way that the DR customer -- the load could actually recover these costs. I was -- and this is my -- we're getting to what my lack of understanding is. So what was that other option? They're not going to raise their -- they want to be competitive with the generators so they're not going to add it into their bid price to try to be more competitive and therefore possibly get, you know, get selected for the capacity.

How else do they recover it? What else do they do?

DR. RIVARD: Right. Well, I realize the question you are asking me is probably considered outside of the scope of the hearing, and I will --

MS. FRANK: Well, I am looking for, you know, how do we avoid the discrimination.

DR. RIVARD: Yeah.

MS. FRANK: So this is all -- I see this as discriminatory treatment if indeed generators are allowed to get recovery for these start-up costs and DR are not. And the only mechanism they have is to inflate their capacity bid. If there's another mechanism, then they're not discriminated against.

DR. RIVARD: That's correct.

MS. FRANK: So I am looking for, how are they not discriminated against?

DR. RIVARD: Yes. I think that is fair. I think the way they're not discriminated against is to be eligible for a cost guarantee very much like the generator is in terms of the start-up.

And so what the IESO is looking to do going forward is to improve the way it makes decisions in advance to start generation by -- through the day-ahead market and what they call the enhanced real-time -- enhanced real-time start-up guarantee. Anyways, a real-time program similar to what they have now.

And what that would do is have generators in advance say how much they need to recover just as a start and provide them a guarantee that if they are scheduled, that if they don't incur -- recover enough revenues in the energy market, that they will at least be compensated as an insurance that they will cover that cost.

I think there is merit in considering if a DR resource has a very similar type of start-up cost when activated, why not allow them to bid that into the market and then compete against generators to decide, well, should the generator start to produce electricity, or should the demand response resource incur this cost to avoid a payment.

MS. FRANK: So that is all about what the future might hold. But today when we look at the rules that were proposed, that we're considering, there isn't a way to avoid this discrimination, is there? Today in what we've got. Just for this narrow piece. Just these...

DR. RIVARD: No, you're right, yeah. Well, I would say that the point that you raise is, I think there's merit to considering that. I would say that for sure.

But the material effect of it is not real. I think that is the question you are getting to.

MS. FRANK: Right, okay, thank you.

MS. SPOEL: Dr. Rivard, I just had one small area and I just want to make sure I understand this. You spent quite a lot of time talking about allocative efficiency, and essentially, if I can try to paraphrase it, that for societal benefit widget-makers should make widgets and generators should generate electricity, generally speaking, that that is a better allocative exercise because if the widget-maker stopped making widgets in order to do demand response resource can factor into its bid any activation costs, and you talked about how they can factor it into their capacity offer.

Are there other ways in which a demand response resource can factor those costs into its bidding strategy?

DR. RIVARD: Right. And I think Member Frank's question was really specific to these kind of activation costs that came out in Mr. Anderson's evidence about incurring an actual physical cost of maintaining a product.

So how could -- if a DR resource feels that it's at risk of incurring those costs if activated, what can it do about it? It could either factor it into its energy bid, which would reduce the chance that it would incur that cost and reduce the chance it would be activated. You can do that up to bidding 1999.99. Or it could try and bid it into a capacity market.

I think I was then asked what would I do if I was working for that company, and that is when I said, based on the evidence for this next auction, if I was advising my CEO, I would say we're not at risk. I can manage that in my energy bid. We'll be as competitive as we can in our capacity auction.

MS. KRAJEWSKA: Okay. Thank you.

And just, are you aware of the cost guarantee for generators? Are you aware about what the IESO is doing with respect to that in the near future?

DR. RIVARD: So my understanding is that it was kind of a program that was put in place back in 2002 or 2003 as almost a stop-gap program, and over the last several years it's been established that it's not the most efficient program. So it's part of the market renewal initiative the IESO is looking to transition from that program, which essentially says, tell us your costs in advance and we will pay you after the fact.

But there is really no competitive mechanism for generators to compete against each other to ensure that we're getting the least cost way of starting generators. That's transitioning to a much more sophisticated optimization that will factor that cost in and should lead to efficiency gains.

MS. KRAJEWSKA: Thank you. Those are all of my questions.

MS. SPOEL: Thank you. Before we rise I just wanted to address the -- I did want to address the order of cross-examination for tomorrow. First of all, Mr. Barz, you're not on the list. Are you not planning to cross-examine the IESO's witnesses?

MR. BARZ: Pardon me. Sorry. No, we are not planning on cross-examining IESO.

MS. SPOEL: It seems to me that given that KCLP is generally supportive of the IESO's position, that it would probably be better to cross-examine before AMPCO, just as a general matter of fairness. Is that --

MS. KRAJEWSKA: Yes. I appreciate that the custom is for friendly cross-examination to happen before adversarial cross-examination.

TAB 8

VT INCEPIT FIDELIS SIC PERMANET
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**

EB-2019-0242

THE ONTARIO ENERGY BOARD

Association of Major Power Consumers of Ontario (AMPCO)

Application to Review Amendments to the Market Rules made by the Independent Electricity System Operator

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Friday, November 29, 2019,
commencing at 9:34 a.m.

VOLUME 3

BEFORE:

CATHY SPOEL	Presiding Member
EMAD ELSAYED	Member
SUSAN FRANK	Member

A P P E A R A N C E S

LJUBA DJURDJEVIC	Board Counsel
DAVID BROWN CHRIS CINCAR MICHAEL BELL CIERAN BISHOP CHERIDA WALTON LILLIAN ING	Board Staff
IAN MONDROW LAURA VAN SOELEN	Association of Major Power Consumers in Ontario (AMPCO)
GLENN ZACHER DANIEL GRALNICK PATRICK DUFFY	Independent Electricity System Operator (IESO)
EVAN BARZ	Association of Power Producers of Ontario (APPrO)
EWA KRAJEWSKA GIAN MINICHINI	Kingston Cogen Limited Partnership (KCLP)
MARK RUBENSTEIN	School Energy Coalition (SEC)

I N D E X   O F   P R O C E E D I N G S

E X H I B I T S

U N D E R T A K I N G S

MR. SHORT: Sure. With regards to the first question of I guess how we secure capacity, essentially we have three ways today. We have got Ontario Power Generation's or OPG's rate-regulated fleet, which, the OEB manages that for cost recovery. We have contractor resources either through the Ontario Electricity or Electric Financial Corporation, OEFC, or the IESO. That's a bit of a mix of capacity and energy-type contracts. And the third is -- currently today is the demand response auction, and that is our first full attempt at a capacity-based market mechanism with certain obligations in the energy market.

And the second question, sorry, can you repeat that?

MR. ZACHER: Just generally the reasons for transitioning the DRA to a broader capacity auction.

MR. SHORT: So the IESO believes that one of the ways we can provide a cost-effective and reliable solution for consumers is to have an open, transparent, and competitive process that is technology-neutral. We had a plan with regards to the incremental capacity auction as kind of the ultimate product and, seeing the pending gap in capacity, we looked to resolve that by trying to figure out what's the most optimal solution. And we believe that an auction would be the best approach. And we looked around the -- we already had a demand response auction that was functioning. It had many of the core elements ultimately that we were looking for in an open and transparent competitive process.

And so in conversations with the DR community there was always this knowledge that the DR community and the DR auction would be transitioned to a more broader resource -- sorry, a broader auction where more resources would compete to supply capacity.

And so we thought we would start with the core fundamentals of the DRA, the demand response auction, and begin to add new features, new design features, and of course our plan was to add more resources to the mix to have them all compete to supply capacity to meet Ontario's needs.

MR. ZACHER: Mr. Short, was another reason that the IESO required additional resources other than demand resources to meet Ontario's capacity needs or would demand resources on their own have been sufficient?

MR. SHORT: If you look forward to the evidence that we have submitted, there's a 4,000 megawatt-plus gap for capacity in 2023. The demand response auction to date clears around just over 800 megawatts. There's about 1,000 megawatts of offered or I guess qualified capacity that can participate.

So simple math, 1,000 megawatts versus a 4,000 megawatt shortfall, DR on itself can't meet that future need, and so when we look forward we need a mix of different resources. We wanted to enable things like capacity imports from other jurisdictions like Quebec, New York, Michigan. We needed to look at what available generation was in Ontario. There's over 600 megawatts of contract generation that could be available for an auction.

And so when you add up things like -- even like storage, storage is a new product. Maybe it can help meet that need. So when you add up the capabilities maybe from all these other resources, that would meet our 4,000-megawatt need, but DR itself can't do that.

MR. ZACHER: Okay. And have you learned anything from either the previous, call them OPA-based contract DR programs, or the DRA in terms of integrating DRA's resources into an auction or into the IESO market more generally?

MS. TRICKEY: Yeah, I think there's been a few things that we've learned. The previous demand response 3 program, contract-based program, that was run by the OPA was taken over by the IESO and transitioned into what was called capacity-based demand response program.

That program really -- it required a certain number of activations, and it based activations not on the market price, it based activations on other factors, and I think you heard Dr. Rivard speak about this yesterday. What resulted was that we were activating those resources when it maybe wasn't the most efficient thing to do. There were other resources that would have been more cost-effective to activate.

I think, you know, again, we talked about at length yesterday, generators in the business to generate, loads are in the business to do something else, but when it makes sense they can be a really useful addition to the electricity market, but I think for that reason we'd rather see them doing their core business when that's the most cost-effective thing for them to do, and we found that in the DR3 program that wasn't always happening from an operational perspective.

So that's one thing that we looked to rectify by putting them into the market and having market prices activate or create the activation signal for them.

I think another piece that we -- I don't know if we learned or that we worked on through the transition was, so there was this demand response 3 program that was run, and we had a plan to move the demand response resources into an auction mechanism for much the same reasons Mr. Short described.

In doing so we wanted to make sure that we provided stability and certainty for those resources so that we knew that they had a pathway to move from a contract-based structure to a market-based structure.

So the first thing we did was we took the rules of the demand response 3 program and embedded them in the IESO market rules, so that we could operate those resources and that contract, but operate them under the market rules. So we're sort of creating a transition first to allow us to operate those contracts.

And that allowed us then to start to establish the rules and mechanisms for the demand response auction, give us time to set that up properly, give us time to let those resources know that that would be the next stage, when those auctions would happen, and give them an off-ramp so if they wanted to move from the contract to the auction, that they could. And if they're economic in that auction, that they had a smooth pathway from the contract mechanism to the auction mechanism. So that was something that we intentionally ensured was enabled so that they had certainty that again, if they wanted to and were economic to do so, they could move from one mechanism to the next without interruption.

And we staged the timing of the following auctions because not all of the contracts ended at the same point. They ended at different points in time, so we also looked at timing the auction so that again, they could move from one to the next, if that was their intent, smoothly.

MR. ZACHER: Thank you. Presently and moving forward as well, is are there any sort of notable differences in how demand response resources are treated relative to supply resources, in either the capacity market or the energy market?

MR. SHORT: So yes, there are differences. As Brian Rivard -- sorry, as Dr. Rivard noted yesterday, the IESO strives to treat all resources as equally as possible. You know, we think that we try and -- we recognize, as a former controller manager, in a perfect situation every resource is instantly flexible and has an infinite amount of fuel. But that's just not the case. It doesn't reflect reality, and that's okay.

We look at all the resources and try and optimize them and try -- again, as Dr. Rivard said, we try and extract, we think, the greatest value that we can out of them to make sure we can, you know, both be reliable and provide a cost effective solution ultimately benefiting ratepayers.

So we look to remove barriers. We may discover barriers as we go ahead and operate the market, and we'll try and remove those. But they may not be instantaneous. First you have to discover them, you have to validate, and then develop the plan over time to correct them. But it's not an instantaneous fix.

So when it comes to the question that was related to like HTR or DR, we recognize that -- and it's transitioned again from contract-based structures at the OPA through to the IESO for market-based structure. But we recognize there's certain limitations and it's okay, we account for that.

For example, they require a notification. So a standby notification has to be issued from the day ahead at about -- I think it's 3 o'clock in the afternoon up until 7 o'clock the day of. And so we can't just wait and phone them up an hour or five minutes ahead of time and say go ahead and reduce your load for some resources, which is HTR resources.

And so we have to give them that standby notice and once they're on standby, we have to give them a subsequent time to get activated. And so about two-and-a-half hours to three hours ahead of time, we will give them a signal to say you may need to reduce your load, or you will need to reduce your load and here's -- to meet your capacity obligation. And they require that time.

And when we dispatch them or schedule them, they are only scheduled for one-hour chunks, anywhere from one-hour, to four-hour. And once we use them for even just one hour, we can't use them again for the rest of the day.

There's things like -- because the loads also can be aggregated, they can be virtual loads. We call them virtual, but they're real. But that's the term the IESO uses; maybe not the best term, but that's the term we use.

It could be things like household air conditioners, hot water tanks. I am not sure how they do their business, but we don't have visibility to that. We don't have a meter that we can read in real time. If you're a physical resource, like a dispatchable load, we get five-minute telemetry.

And it's okay for us again. We looked at the program, we looked at the concept, and we thought it's an acceptable solution for these virtual resources not requiring real time telemetry going back to our control room. It's updated every six seconds, as an example.

So there's a number of things that we do accommodate for and plan for. And just like every other resource, for look for ways to optimize it as best we can.

MR. ZACHER: Just to be clear, are those accommodations unique to DR resources in particular, HDR, or would those apply to generators as well?

MR. SHORT: So the ones I just spoke about are specific to HDR, but there are other accommodations. So for example, if you are an import in another jurisdiction, there's scheduling protocols we have to adhere to between us and a neighbouring market.

If you're a generator in Ontario, sometimes you require more time to start up, or you may have to run for a particular period of time before you can shut down. So there are other accommodations we make.

MR. ZACHER: Okay. So I'd just like to turn now to some of the matters that are at issue in this case, and ask some questions.

Can you tell me how the IESO has responded to AMPCO's past concerns about energy payments, and its more recent request to resolve the issue of energy payments before moving ahead with the TCA, or any future capacity auctions.

MS. TRICKEY: Okay, yes. So as you mentioned, AMPCO and the demand response community did raise this issue a few years ago, the issue of, you know, a design to have energy payments when activated. It was raised through the demand response working group. At the time, I think, you know, likely largely related to what was going on in the US, the fact that decisions had been made, as we've discussed, to provide those types of payments.

So it was something we agreed to look at through the demand response working group. As provided in our evidence, we did initiate a study with Navigant to look at the issue. Essentially, we asked Navigant to do a jurisdictional scan, understand what other jurisdictions were doing, and to look at the arguments for and against. You know, understanding a lot of debate had happened in the

US markets on this, a lot of people on both -- good, smart people on both sides of the argument had articulated lots of different arguments. We wanted to understand what those arguments were on both sides of the question, and what that -- what are some of the implications if we were to do something like this in Ontario.

So that study was initiated, completed, provided in our evidence, and I would say at the end of the day it was inconclusive in that it did demonstrate there are a lot of good arguments on both sides, and that a lot of considerations to make. It also indicated that there wasn't -- that there were a lot of questions about whether there really would be a benefit in Ontario to providing this type of payment to demand response resources.

We completed the study, discussed those implications and findings with the demand response working group. From the IESO's perspective, it didn't appear to be something that would create a lot of benefit and it was a lot of work. So we asked stakeholders is this a priority at this time. The response we received at that time was that it was not a priority, so we set that aside to work on other issues.

And, you know, as we're well aware, the issue came up again when the IESO initiated the transitional capacity auction, so we -- understanding this was an important issue to stakeholders, we regrouped, took a look at our work plans again, and agreed to initiate more work on the question. So we've agreed to initiate another study following on the heels of the Navigant study, taking what it had found, going to the next stage to understand what would a benefit look like -- or how would this work in Ontario, is there a benefit, what would a net benefit test look like.

So we've currently engaged the Brattle Group to complete that study. We initiated stakeholder engagements in September, recognizing this a big question as we have discussed. This is a change to the fundamental underpinnings of our market, the fundamental design of our electricity market, not something we undertake lightly. So we needed to ensure that we talked to stakeholders about this, get their feedback on it.

So as I said, we initiated a stakeholder engagement in September, opened to all stakeholders to get their insights into it. We provided them with a proposed scope of study, and asked for feedback on that and we're just in the process of working through that at the moment.

MR. ZACHER: And just when is that to be concluded, and what ultimately will be the upshot of that study?

MS. TRICKEY: Right. So as I said, we asked for feedback on the proposed scope. We are meeting with stakeholders early next month to discuss their feedback, finalize the scope of the study, and we have Brattle starting the work on this, and then we will complete that and provide a decision on the matter by next May is the timeline that we've committed to.

MR. ZACHER: Okay, and then that will inform the

IESO's decision?

MS. TRICKEY: Yeah, so -- yes, the intent is to get the study, stakeholder feedback on the study, and the IESO needs to then make a decision as to whether we believe this is an appropriate change to make to our market structure. We will make that decision and discuss that decision with stakeholders by next May.

MR. ZACHER: Okay, and just a follow-up. So why not, Ms. Trickey, wait until the study's complete and the issue of energy payments for demand response resources, if at all, if any, is resolved before forging ahead with the TCA or ensuing phases of the capacity auction?

MS. TRICKEY: Right, okay. So I think there's two things to consider here. As I said, this is a fundamental change to our market, not something we want to -- we can implement without significant stakeholder engagement and study, and that does take time. And then the second piece is really, we do see this looming capacity gap coming, something that we need to address to ensure reliability in the province, and that's something that we need to get started on right away. I will talk a little bit more about the first one, and then I'll pass over to my colleague to talk more about the timing of the capacity gap and how we're addressing that.

So again, if we look at this issue, major change to our market, something that we are considering and talking to stakeholders with and are doing a study on. But in addition to it being a major change, we haven't really seen any evidence that indicates that it's a needed change, that it will result in benefits to the demand response participants or even benefits to the province, and I think there's even evidence to suggest that it could increase costs to consumers because of the unique structure of Ontario's market with the global adjustment, something we've talked about over the last few days.

Those are important considerations, so it's not something that we can undertake and just say, okay, we'll do it and move forward. So we do want to take our time. I believe we've put forward an aggressive schedule to get that work done and come to a decision, but nonetheless we are committed to working through that over the next number of months and coming to a decision by May.

So, again, that's the sort of schedule for the study and that question. The separate question is how do we proceed on the capacity market and address the capacity gap, so I will pass it over to Dave to talk to that.

MR. SHORT: Thanks. So TCA -- in our evidence we talked about this pending capacity gap in 2023. We needed to -- and we need to -- we still need to move forward with incremental changes in a phased approach to addressing that need. There are -- this is the first time we've run a capacity auction with supply side or at least we want to run an auction for the first time with supply side resources. The last four auctions have been demand response only.

So adding the resources introduces challenges and complexities to the mix. But overall there's a net benefit in terms of, again, increased competition and of course trying to get ready to meet that future need.

So if you think, if I can provide a couple examples, if somebody said, I want to add imports today to an auction that we're going to run tomorrow, the answer would be, I can't do that, because I don't have agreements from -- I need operating agreements between, say, New York ISO, the system operator in New York, and ourselves, and we are in the process of trying to have those conversations, but that takes time in trying to iron out the details on how to trade capacity.

That's not to say that New York State is supplying gas, it's just working out the mechanics of how we would transact that.

Conversely, once we have those agreements, there's nothing compelling New York State first of all to make this their number-one priority. There's also nothing compelling a generator in New York State to have to participate in our auction.

And so the intent is to run the auctions, prove they are a viable product as far as introducing new resources, because we want to attract those resources to the auction and get them to compete with everybody else. And so if you're a generator in New York State, once the agreements are reached, then it allows them and affords them the opportunity to compete, but it doesn't compel them to compete.

Another example can be storage. It's relatively new to the -- to Ontario. We have got a -- we have had pump storage at Beck for decades, but as far as the smaller storage it's relatively new product. We have plans to integrate it into our next auction, but there's nuances to it. It behaves differently. I talked earlier about, we want to be on a level playing field, but we have to respect their differences.

So we've got a load -- so a storage product behaves as a load and a generator, and so how do you effectively integrate that into a future capacity auction? We are not sure it's perfect yet, but we need to start, and so we are planning to start that with the June 2020 auction.

So when it comes to this auction -- sorry, the proposed December 2019 auction for the TCA, the intent was to simply add the first round of new resources, which was off-contract dispatchable generators.

MS. TRICKEY: Maybe I can add a few points to the complexity of something like this. I think one thing to recognize is that you don't know what you are going to get when you launch an auction. You know, you launch an auction, it takes time to set it up and get it out there and put it out there, and then you need to see who comes to market. And do a sufficient number of resources come to market? If you are not getting the kind of uptake that you expect or need through that, now you need time to enact something different or make changes to the auction.

But given the timelines we have, I think if an auction mechanism wasn't working, we would need time likely to do something different.

I think the other thing that's important to recognize with auctions, and this I can speak to from my experience in operating the demand response auction, is it's a long cycle time to make changes. So as we have talked about, it's an annual product typically. You need to -- it sort of works in a number of phases, so you announce that you're going to do an auction so that everybody can get ready to participate in it, you have the auction, and then you need to give people time between the auction and when they deliver on their obligation to get ready to deliver on their obligation, then they deliver on the obligation; while you are in the middle of delivering on that obligation we are running the next auction to get ready for the next period.

So it's cyclical, but it's a long cycle, so to test and make sure that it's going to work you need to give yourself a long lead time to incorporate learnings and changes, and from what we have seen in the DR auction it can be as long as three years just to make one change. Some things can happen more quickly, but recognizing there's sort of a stage of learning in each portion of the auction and you're only holding this thing on an annual basis, you do need to give yourself a long lead time to incorporate those types of things.

MR. ZACHER: Thank you. And can you just touch on the impact of the Board's recent stay decision earlier this week and how that impacts the IESO's plans if any, if at all?

MR. SHORT: So we announced, I think it was on Wednesday, that we've -- we will be running the demand response auction. We contemplated waiting and running the TCA until -- if there's an outcome of this decision -- potentially sometime in January, but the reality is we have a pending capacity gap for the summer of 2020, and so, given the time it takes participants to get ready post-auction to the first obligation, the start of the obligation period, there's not enough time for them to get ready, in our opinion.

And so we opted to run the auction, the DRA, essentially at the same time we would have run the TCA, which is December 4th. You know, we essentially, from a TCA perspective, we have lost a year of opportunity when it comes to the period from May of 2020 through 'til April of 2021 for generators, off-contract generators, to participate.

I think if we're -- you know, it's not -- we're still afforded opportunities, two more chances to continue to evolve the auction, assuming we are allowed to provide with TCA and capacity auctions in general, we need to get ready for that, the pending gap in 2023. It's not just 2023, I keep mentioning that, but it the gap continues and grows beyond 2023.

So I think -- next week, for example, we have our stakeholder session on the June 2020 auction. Another one we've -- actually, draft market rules and manual wills be posted this week for the June 2020 auction. So that's -- we need to keep moving forward; we can't lose time. It will be challenging, but we think we can still engage the community and engage other resources to get ready for that 2023 need.

MR. ZACHER: Just to clarify, Mr. Short, notwithstanding that you've lost some time, do you -- is the IESO still in a position to move forward with a capacity auction mechanism to address current needs, and ultimately the 2023 gap?

MR. SHORT: Yes, we are at this point, assuming we are allowed to continue and operate the auction, and the next planned auction is in 2023 -- sorry, the next planned auction is June of 2020.

You know, alternatives, if we are not able to execute the auction, then that creates some challenges for us. You know, we need to look at -- getting for 2023 and beyond is not as simple as waiting until 2022 and flipping a switch and saying we now have all the rules.

We now have, even if we have to go -- so if we can't run an auction, we have to look at alternatives -- or we can't run a capacity auction, we may have to look for alternatives and that could mean some, you know, smaller auctions where we run a DR-only auction, and a generator-only auction, and an importer-only auction.

It really doesn't make sense, though, because the whole point of a capacity auction is to get all those resources competing together to supply capacity. It's all in theory the same capacity product, and so we want them all running in an open, competitive process, not boxed off in mini-auctions.

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

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

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

Is that a fair characterization of the purpose?

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

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

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

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

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

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

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

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

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

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

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

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

What's the IESO's reasons for disagreeing with AMPCO's position?

MS. TRICKEY: As I have said, we have agreed to look at this issue. You know, it's something that the IESO will study and make a decision on whether or not there is a benefit to doing this in Ontario.

However, you know, given the situation we're in, the position we're in, we also think it's important to understand what are the implications of not doing that immediately.

And we ultimately do believe that there is an opportunity for loads to reflect their costs in both markets. As was described at length yesterday, the fundamental design is such that they're able to reflect their costs for providing capacity in the capacity auction, and in the energy market, they're able to manage their costs by reflecting that in their energy market bid. So there is an opportunity in both markets.

As I said, we are willing to look at the issue more closely, see if there's something we are missing. We will do that. But in the meantime, from a practical standpoint, we also look at what is the actual risk of activation. So what is the risk that they are going to have activation costs that they are unable to capture if we, you know, take it to that place where we say there is some sort of cost that they can't capture in the energy market, what is the risk that that cost is actually going to occur in the current market.

And given that they have rarely, if ever, been activated over the last number of years, we don't see that there's a risk that they are going to be activated and therefore not going to have -- they won't have those costs and won't need to reflect those costs in their capacity auction offer.

I think if we look at the other markets as well, the evidence from LEI and from our Navigant study also shows that even with an energy payment, demand response resources are rarely activated. We see that they have the opportunity to manage this risk, and so we don't see that there's a risk in this period for them to need to reflect that in their capacity auction offer, so that we can proceed carefully on both fronts at the same time.

MR. ZACHER: And just to pick up, what's the value -- what's the value of these resources, DR resources, if they are not being activated?

MS. TRICKEY: Yeah, that's a great question. They really are valuable to Ontario. It probably starts to sound like I am picking on them; given my job title, I probably shouldn't do that. But they are valuable to Ontario.

I think it's important to understand, though, that we have separate markets because we try to separate the value of each type of service that's provided.

So in the capacity market, they are very valuable because they, from what we've seen in the demand response auction, provide fairly inexpensive capacity, so the availability. They can provide that availability fairly inexpensively, compared to what some types of generators can, or other types of resources. And we have seen those prices come down over the last number of years.

So I think they have proven that they are valuable capacity resource, and they could be even more valuable if we enable them to compete against other resources, because they can demonstrate that in terms of providing capacity and that availability that they're able to help us manage those costs, keep those costs competitive.

The energy market is a separate matter and runs under separate economics. But I think actually, before I go to that, it's important to understand, as Dave mentioned, we have to buy certain amount of -- or we have to secure a certain amount of capacity for the province to meet our reliability standards.

That amount is over and above what we would typically use on a normal day. Even on a hot summer day when we expect to be at our peak, we still need to have more available because, as we see, you know, the typical hot summer day isn't always going to be what's going to occur. There will be extreme days. There will also be days where large resources are suddenly on outage unexpected, so we have to be able to prepare for those types of contingencies.

So there are reliability standards required that we secure enough capacity to meet those types of extreme situations, so that means we are buying more capacity than we need. You can think of it as insurance. We are buying that insurance. We hope not to have to use it, but we have to buy it nonetheless.

So that's the capacity market. When I look at the energy market, we only activate the resources that we need. You know, we have to meet that minute-to-minute, second-to-second demand for electricity, so we are only activating what we need, which means that a certain segment of the resources are rarely, if ever, going to be activated.

The way things work in Ontario, we try to use market economics to set who gets activated, as Brian talked about, so we're going to activate the least expensive resources first.

In the energy market, loads are typically the most expensive resources, and that's not a problem, that's just a fact. That's what they are. They are in the business to do something else. So it's expensive for them to interrupt that, so we accept that, give them the ability to bid as high as they need to to cover -- to manage their costs, and it just so happens, like I said, they tend to be the most expensive resources, so they are going to be the last ones to be activated, and in fact they are rarely if ever going to be activated, because we have to have that capacity for insurance purposes.

So they do provide value in both markets in the capacity. They help keep our capacity costs low, and I think I would rather -- if we are going to have resources that are sitting around and not activated very frequently, I would rather that be a demand response resource that has other things to do than a generator that has nothing else to do, so I think that's an important part of the whole picture. So I think that there is value there.

On the energy side, the value that they provide is if we really, really do need them, they can prove that they can be there and provide that emergency type of response.

So I think there is a lot of value, it's just understanding how that value fits into the different services that we need.

MR. ZACHER: Thank you. So I think this is my last question. Member Frank at the end of the day yesterday referenced out of market startup costs that some generators are eligible for under the IESO's generation cost guarantee program and expressed some concern that demand response resources, to the extent that they have the sorts of equivalent costs that were referenced by Mr. Anderson in the example he provided, don't have those same opportunities to recover those costs.

And I am wondering if you can just comment or shed, if you're able to shed any light on that.

MS. TRICKEY: So what I can do is explain you a little bit more about what the program is and what's intended, and I think Dave can talk a little bit more about why -- the sort of operational considerations for that type of program.

MR. ZACHER: You are talking about the GCG, or the generator cost guarantee program?

MS. TRICKEY: Yeah, so the real-time generation cost guarantee program is a program that we created to manage a reliability risk, and the risk was that generators wouldn't come to market because they wouldn't be able to recover sufficient costs to recover their costs in the market.

So we created this program that essentially provides them a make-whole payment or compensation for situations when they come to market and the market doesn't actually cover their minimum costs, they'd get this type of a payment.

I am going to come back to how that works and how it's relatable to some other things, but maybe it might help to understand why we need that kind of thing. So I will let Dave speak to that.

MR. SHORT: So not every generator is eligible to participate in the program. It's really been developed for what we call non-quick start. I think Dr. Rivard mentioned that yesterday. So if you're, for example, a combined-cycle gas plant, so you have, say, two or one or three gas turbines that run or generate electricity, and the wastes -- the exhaust is essentially then kind of captured and crated and moved to a steam turbine, where the waste heat creates more electricity, so basically you could have two steam -- sorry, two gas generators and one steam generator.

There's implications in start-up. You can't -- I talked earlier about in a perfect world you'd flip a switch and the generators would be online in a second. The reality is some of them take six, seven, eight hours to start up, so if you say six hours, just do some math here -- hope I get the math right -- if you need them at six o'clock at night and the market dictates -- says there's a signal here that we are going to hit the winter peak, they're economic at that point, so we need them online.

The challenge is if you're now having to start six hours ahead of time the market price may be low, and there's start-up costs associated with going from pushing the button to start to the point where you're at your -- we call it minimum loading point, but it's kind of your -- your lowest point where the unit's stable and ready to be dispatched, and that has to be done in advance of that six o'clock need.

And so there's costs associated with, you know, gas. I think it was talked about yesterday, gas costs to go to start the generator, there's wear and tear on the turbine to start the generator, and other costs, and those are -- that's part of the program, is to capture those types of things, but the fundamental component is that it's reliability need, because we need them online by dinner time, essentially. And so we have to look at the costs associated with getting them ready to be online at that time.

MS. TRICKEY: So how does this type of program relate to the market in general? There are a number of places where we provide this type of program, and I would generally characterize it as, there are certain circumstances where resources are required to operate in the market at a price which they've indicated is uneconomic, so where their costs aren't going to be covered.

When we see those types of situations it's typically our practice to provide some sort of compensation or make whole payment to ensure that the market ultimately -- where the market isn't sending the right signal or isn't enabling the right type of activation we can ensure that the resources still come to market.

So there are a number of situations where this can happen. Dave's explained the real-time generation cost guarantee example. For dispatchable loads, there are times in the market where they are asked to reduce when the market prices in their area or their particular market price isn't -- isn't the active price at the time, so we're activating them when it's uneconomic. In that case we provide them a payment that makes up the difference between their offer and -- or, sorry, their bid and the market price.

The same thing for generators. When generators are tested, we provide the same type of thing, because when we test them we may be bringing them on at a time when the market price is lower than what they need to recover, so we, again, we recover the differences.

This is also something we recognized was a problem for the hourly demand response resources. When we got into the most recent conversations about the energy payments issue, IESO stepped back to take a look at the issue and understand it a little bit better, and recognizing that because we were proceeding with the transitional capacity auction, we were actually creating a situation where hourly demand response resources wouldn't be able to always have the opportunity to manage their costs.

So as I said earlier, we need to make sure that all resources are able and ready when we call on them. Because demand response resources aren't typically called on often, we test them regularly to make sure that they are ready and able when we need them. So we typically test them once per obligation period or up to two times per period. So they can be tested two to four times a year.

And we recognize when we test them we are bringing them on at a price that's below what they've -- sorry, yes, below. It's confusing when we think generators versus loads, but we are bringing them on at a price that's uneconomic for them, where they said they would rather be consuming.

So in that case, we recognize that there are costs that they are not capturing or managing, so we have recently instituted rules and a process to enable us to provide them some compensation in those scenarios, so that when we test them, we can feel sure that they're -- they will come, they will be -- they will be tested, they will be -- can be activated and tested in that scenario, and then we will provide compensation to make up the difference, or provide some compensation for that scenario.

So there's lots of times when we do this type of thing. We recognize generally the market doesn't always do -- doesn't provide the signal we need, or we need to activate them at a time when the market is uneconomic to do so, and we think it's the right thing to provide compensation to manage that; so we have done that.

We started the process a few months ago. We've recently, I think just this week, had the market rules approved for that, and we will be implementing that prior to the next obligation period.

MR. ZACHER: And, Ms. Trickey, just to clarify, so those tests costs that -- test activation costs that HDR resources incur, those are costs that they cannot avoid, I gather, through their -- by including those costs in their energy market bids. Is that correct?

MS. TRICKEY: Correct. So they've offered in at, let's say, $1,500 in the energy market, saying I want to consume as long as the price is up to $1,500. When we test them, the prices aren't going to be $1,500. It's going to be, you know, probably likely a day -- sort of a normal day when we don't have anything going on, or no concerns for reliability, so the prices might be $20.

So we recognize they would rather be consuming in that circumstance. So we are activating them when it's not economic for them to do so. So we do -- we have settled on a compensation mechanism to provide them some top-up to recognize that they are not covering all their costs in that scenario.

MR. ZACHER: Okay. And how does that compare to the other costs that Mr. Anderson referenced in the example in his affidavit? Are those other costs, call them in-market costs, that they are able to avoid or manage through their energy offers -- energy bids, rather?

MS. TRICKEY: I think the concept is the same, in the sense that what they're asking for is to ensure that they are able to recover their costs, or manage their costs. In this case, we recognize a situation where we didn't believe that they could, we are providing that compensation.

I think in the case that we are talking about here under an economic activation, our market design is such that they can manage that through their energy offers. So they offer at the price that they think is the right price to be activated at, and if there's no real risk of being activated at that price, then there's no cost to be considered there in terms of adding something to a capacity auction.

MR. ZACHER: Thank you, those are my questions.

MS. SPOEL: Thank you, Mr. Zacher. I think you're next up, Ms. Krajewska.

CROSS-EXAMINATION BY MS. KRAJEWSKA:

MS. KRAJEWSKA: Thank you, Members of the Panel. Good morning, Mr. Short and Ms. Trickey. My name is Ewa Krajewska, and I am counsel to KCLP. I would like to start off by going back to the stay decision, and the IESO's decision to run a DRA auction on December 4th, 2019.

I think my client would like to understand whether it was open or possible for the IESO to wait to delay the TCA auction that was originally scheduled on December 4th until the -- sorry?

MS. SPOEL: Sorry, I am just wondering, I am conscious a bit of the time. We have to get through all of this today because some of us are in another hearing on Monday. I know your client's anxious to know about it, but I am not sure it's going to be relevant to the decision that the Board, the Panel has to make in this case.

So if it's something you can explore offline, perhaps that would be helpful.

MS. KRAJEWSKA: I was just going to have one question on this. I was not going to explore it at length.

MS. SPOEL: Fine, because we just don't really have time.

MS. KRAJEWSKA: I understand. Was it possible for the IESO to delay the TCA auction until February, until after this Board released its decision?

MR. SHORT: I will be brief as well. The answer is no, we couldn't. We have the pending reliability or capacity gap for the summer of 2020, if we wait until February to run an auction, it's not enough forward period between the completion of the auction results and the start of the obligation period on May 1st.

So could we have pushed it off maybe like a week or two, possibly, but we felt it was necessary to run a DRA to secure the capacity required, and to give participants enough time to be ready for the May 1st obligation period.

MS. KRAJEWSKA: Thank you. And you've spent some time in your evidence in-chief talking about the forecasted capacity gap for 2023. And I understand from your evidence that demand response resources are not going to be sufficient to meet that capacity gap, correct?

MR. SHORT: That's correct.

MS. KRAJEWSKA: And that one of the ways, in order to meet that gap, is to use off-contract generators?

MR. SHORT: It's to afford them the opportunity to compete, yes.

MS. KRAJEWSKA: And has the IESO considered other ways of ensuring that off-contract generators will be around by 2023 to be able to participate in that -- to provide that capacity, for example, by providing them with a fixed contract?

MR. SHORT: In short, no, other than the brief conversation I had just a few moments a go. The intent is to be able to run a capacity auction and enable that to be the mechanism to acquire capacity.

We believe auctions provide the open, transparent competitive process. It puts pressure on everybody to be as economic as possible, and it's not favouring one type of resource over another. It's allowing all the resources that we can enable to compete.

MS. KRAJEWSKA: So would your evidence be that from an economic or efficiency perspective, it's preferable to use a capacity auction rather than a fixed contract?

MR. SHORT: For the purposes of where we're trying to run the capacity auction, yes, there's -- I think that there's other opportunities for -- and the IESO has recently announced the stakeholder engagement for resource adequacy. That's a broader question of different types of resources.

But essentially, for the purpose of the design of the TCA and small evolution it was proposing to get ready for 2023, we think that's the right mechanism.

MS. KRAJEWSKA: And perhaps a more efficient mechanism than providing a fixed-term contract?

MR. SHORT: We believe so, yes.

MS. KRAJEWSKA: And I wanted to go back to the process for approving the amendments. I understand that the IESO has a technical panel that discusses proposed market amendments rules. Is that correct?

MR. SHORT: I believe they review the rules to assess whether the rules ultimately meet the intent of the design.

MS. KRAJEWSKA: And who sits, broadly speaking, on the technical panel?

MR. SHORT: Oh, you are going above my capabilities here. I believe there's a -- just generally, I will Generalize. If you need something more specific, I will report back.

But essentially, you've got, I think, a few generator reps, customer reps. There's a trader -- I think there's a trader rep. So we have got about -- I think there's 12 or 13 people that sit on the technical panel, and they represent a variety of stakeholder interests, as kind of a high-level comment.

MS. KRAJEWSKA: And would it be accurate to say that four of those panel members are energy consumers such as AMPCO?

MR. SHORT: I believe that's right.

MS. KRAJEWSKA: And that three of those four members voted in favour of the amendments?

MR. SHORT: That would be correct.

MS. KRAJEWSKA: And that the only member who voted against the amendments was AMPCO?

MR. SHORT: Correct.

MS. KRAJEWSKA: And I believe there was another organization, called AEMA, that were originally concerned about the proposed amendments and how they would treat demand response resources. Is that correct?

MR. SHORT: That's correct. And I believe, just for clarity, they represent -- I think they are in the "other" category. We have different categories of technical panel members. I believe they are in the "other" category. Again, I can confirm that if required.

MS. KRAJEWSKA: What do you mean by "other" category?

MR. SHORT: So again, we -- other service providers I believe is how we characterize that. There's certain people we try and entice on to the panel, but, yes, AEME was concerned about it and ultimately voted in favour of the -- to recommend the rule.

MS. KRAJEWSKA: And AEME represents other demand response resources?

MR. SHORT: Yes.

MS. KRAJEWSKA: And there's a question that came up yesterday from Board Staff about -- that discuss some of the purposes in the Electricity Act, and as you'll recall, one of the purposes of the Electricity Act is to promote energy conservation. And Dr. Rivard I think was kind of unable to speak to this, so I'd like to ask you, what is the difference between demand response and energy conservation?

MS. TRICKEY: That's the other half of my job. So for the purposes of, you know, how Ontario -- or how the IESO sort of manages things, we do look at demand response and energy efficiency or conservation as very different things.

I will start with energy efficiency. Really energy efficiency is acknowledging that there's ways to -- you know, everybody uses electricity, but there's always a better way to use it. You can always get more efficient, whether it's just changing out your lightbulbs or changing out your equipment, use more efficient equipment so that it uses less electricity. There's lots of things we can do to use less electricity so that we are using the province's resources more efficiently overall.

We have a number of programs that we run to help businesses, AMPCO's customers being, you know, users of this type of service, we help them review or implement measures and initiatives that help them use electricity more efficiently. So instead of using -- you know, they can use less on a consistent basis.

So energy efficiency or conservation is about sort of a consistent and -- a consistent change that lasts over time, not something that you need to operate or manage, it's just, you just use less. So it could be as simple as, like I said, changing a lightbulb to one that uses less electricity. That's energy efficiency or conservation.

Demand response is actually working within the market to provide a reduced -- to reduce your usage on a signal. So it's something that we activate and we operate, and it's part of the market. So it's saying that in a given hour if you need me to I can use less, but it's not about being overall more efficient, it's really about saying I can use less in this time period if you need me to. But there's a cost to doing that, and it typically may mean that they have to change something in their process. So it's more about activating and responding to a signal as opposed to just using electricity more efficiently.

MS. KRAJEWSKA: And Ms. Trickey, you mentioned in your evidence that the IESO considered a payment -- an energy payment to demand response resources and canvassed kind of the other jurisdictions and other markets and came to a preliminary conclusion that that may not be appropriate because of some of the unique features of the Ontario market, and in particular you noted the global adjustment in Ontario; do I have that right?

MS. TRICKEY: Correct.

MS. KRAJEWSKA: And do you agree with the evidence that was given earlier this week that the global adjustment covers about 80 percent of consumer electricity bills in the province?

MS. TRICKEY: That sounds about right.

MS. KRAJEWSKA: However, that as a result of the ICI program, class A consumers, which include demand response resources, are treated differently for the purpose of the global adjustment.

MS. TRICKEY: Class A consumers have an opportunity to manage the amount of the global adjustment that they pay by responding to peak. So by in essence being a demand response resource and when the system really is at its peak, they can reduce their consumption in those hours. And if they do so successfully and do it when we hit those peaks, they have an opportunity -- they will then reduce the amount of the global adjustment that they pay in the following year.

So it's in essence a similar type of thing as our demand response program, but it's got a different signal, a different purpose, and a different way of being activated, but it does -- it's the same type of response, and it does afford them the opportunity to lower the amount of global adjustment that they pay in a future period.

MS. KRAJEWSKA: And if I am a demand response -- Class A consumer demand resource and I am very good at figuring out which days are going to end up being the peak days, what does that mean in terms of my electricity bill the following year?

MS. TRICKEY: If you are successfully able to reduce your electricity usage to zero in those hours, in what turn out to be the top five hours for the province, then you will pay zero for the global adjustment in the following year.

MS. KRAJEWSKA: So you will only pay the other balance of the 20 percent of the electricity bill that is not the global adjustment?

MS. TRICKEY: If that's what the divide is, then, yes, you will only pay the remaining costs.

MS. KRAJEWSKA: Let me just -- I will just take a quick look at my notes. I think I am almost done.

Thank you, those are all my questions.

MS. SPOEL: Thank you. Mr. Mondrow?

MR. MONDROW: Thank you, Madam Chair. Good morning again. Madam Chair, I don't think Mr. Zacher in his fervour marked his compendium as an exhibit. Perhaps we should do that --

MS. KRAJEWSKA: He did.

MR. MONDROW: Oh, I am sorry. I keep missing that. My apologies, Mr. Zacher.

MS. SPOEL: Yes, K3.1.

MR. MONDROW: Thank you. In that case I would like to mark our compendium as an exhibit, which I assume will then be K3.2.

MS. DJURDJEVIC: Yes, that will be K3.2.

EXHIBIT NO. K3.2: AMPCO COMPENDIUM FOR IESO PANEL 5.

MR. MONDROW: Thank you. And Madam Chair, you have our compendium up on the dais, and in the back of the compendium there are two loose documents which I will --

which were integrated by me late last night and I didn't circulate them by e-mail or otherwise get them in time to be bound yesterday, but I will refer to them as I go. I did bring copies. Not everyone has a copy. I ran out of paper. But I have provided copies to the witnesses and the IESO and those of my friends that were early enough to get the worm, as it were, and I will refer to those as I get to them and mark them separately if I could.

MR. BARZ: Sorry to interrupt. I just saw this morning at around 10:00 an e-mail went across with some initial documents. Is that --

MR. MONDROW: Those are the same documents, so those documents have now been circulated by e-mail, but I don't have more copies in the hearing room. Thank you.

MR. BARZ: Okay.

MS. SPOEL: Okay. Perhaps at the break some copies could be -- extra copies could be made for those who need them. I'm assuming you'll be taking more --

MR. MONDROW: Sure. Sure. What --

MS. SPOEL: -- more than half an hour, I assume, Mr. Mondrow?

MR. MONDROW: Yes, I will --

MS. SPOEL: There will be a break and you can make --

MR. MONDROW: Happy to do that. Just --

MS. SPOEL: -- after the break.

MR. MONDROW: Just to remove the mystery, there are three letters which were submissions to the DRWG expressing concern about activation payments, and I am just going to

So paragraph 39 confirms that dispatchable loads have been economically dispatched less than 1 percent of the time, but they had been dispatched; is that right?

MS. TRICKEY: Correct.

MR. MONDROW: And how many hours is 1 percent of the time? Is that about 1,000 hours?

MR. SHORT: So if we look back over the last -- just give me just a second to find that --

MR. MONDROW: I am sorry. I should clarify this references the paragraph above, just so I am not misleading you. And the reference is actually, in fairness, 1 percent of the time between May and December 2016.

MR. SHORT: Just give me a second while I find the right reference.

Since May 1st, 2016. So first of all, HDR resources have not been economically dispatched except for, I think, one occurrence.

MR. MONDROW: One occurrence in 2019 for three hours, as I recall your evidence. Is that right? July 2019. I will take you to it in a few minutes. Why don't you finish your answer.

MR. SHORT: Okay, you can take me to it. So with respect to the number of activations for dispatchable Loads, if you average it out over since May of -- May 1st, 2016, it averages around ten hours a year. The -- it's about 3.8 years, so do the math; it's about ten hours a year, roughly.

MR. MONDROW: Do you have your full set of evidence before you there, Mr. Short, with all of the exhibits?

MR. SHORT: I am going to say I think so. If not, I will let you know.

MR. MONDROW: That's fine. Could you go to Exhibit 3? Exhibit 3 should be an OEB -- an IESO response to OEB Staff Interrogatory No. 8.

There we -- it's on the screen, I will just wait to make sure you have that. Do you have that?

MR. SHORT: Sorry, yes, I do.

MR. MONDROW: Could you go to page 2? There's a table on page 2.

MR. SHORT: Okay, I see it.

MR. MONDROW: And the table lists the activations under the DRA by year for dispatchable load resources.

MR. SHORT: Correct.

MR. MONDROW: Right?

MR. SHORT: Yeah.

MR. MONDROW: Okay. And then if you look at line 11 on that same page -- sorry, line 13 on that same page, that's the reference I referred to a minute ago. There was an activation for an HDR resource in July 2019.

MR. SHORT: Yes, I see that, thank you.

MR. MONDROW: So the point is these activations have Occurred, and you would agree with that, I assume?

MR. SHORT: Yeah, less than 1 percent of the time, yes.

MR. MONDROW: Okay. Now your evidence is that DR resources can manage their activation risk through their this is contentious.

On my assumptions -- I am not asking you to agree with the assumptions, I am asking you to take them and tell me if I have got the right energy bid in order to manage that risk.

MS. TRICKEY: I understand, and I don't think it's that simple. I think it's difficult to understand what in those costs can be captured in their capacity auction offer.

MR. MONDROW: They didn't capture any of them in their capacity offer auction.

MS. TRICKEY: So their capacity auction offer is zero?

MR. MONDROW: I don't know what it is, but they didn't capture any of it.

MS. TRICKEY: I don't think that I can comment on what's an appropriate bidding strategy. Again, as I have said, they have an opportunity in the energy market to reflect their costs and in all likelihood not get activated.

MR. MONDROW: You agree -- will you agree that a DR resource has a value of loss load, and if they're curtailed? The -- no, let me think about this for a minute.

I will come back to this. I have some time, so let me come back to this.

If energy prices go above the level at which generators have been contracted, for those periods of time -- first of all, does that happen? Do prices ever go above contract prices so that there's no debit to the GA? And by debit I mean charge. Maybe that's not the right term.

MS. TRICKEY: I think there was a time when the global adjustment actually resulted in payments to consumers. So a reverse from what we see today.

MR. MONDROW: Yeah, it was called the provincial benefit at the time. It took a while to change that name, but eventually it was changed.

MS. TRICKEY: Yes, not so much a benefit anymore. Remind me again your question?

MR. MONDROW: The IESO gets five-minute energy prices, right?

MS. TRICKEY: Correct.

MR. MONDROW: And in any of those five-minute intervals does the energy price go above the contract levels for generators?

MS. TRICKEY: So does the --

MR. MONDROW: Okay. This isn't that complicated, Ms. Trickey. I am really not trying to fool you here.

MS. TRICKEY: I --

MR. MONDROW: Let me break this down for you. Generators have contracts which guarantee them a certain amount of revenue when they run; right? And if energy prices are below the guaranteed revenue they get paid and the global adjustment gets a charge; right?

MS. TRICKEY: I think that's the basics of how some of those contracts work --

MR. MONDROW: And if energy prices are above the there's something different happening here that we've missed? There may be, and that's exactly why we are undertaking this study to see if there is something we are missing, is there another way to look at this, is there some element of cost that demand response resources aren't able to avoid and that would be better captured in a different way. What they asked for is energy payments as a way to manage that.

So two pieces; I think we need to look at, you know, what they're asking us and do a thorough study and understand what's missing, because there's clearly a disconnect or we wouldn't be here today. We are committed to looking at that.

But we also understand that what AMPCO has asked for is an energy payment as a solution. We have a lot of concerns with that as a solution, based on the evidence that we've seen so far.

MR. MONDROW: Would you have fewer concerns if AMPCO's request was for an activation payment, and we jettisoned the word energy?

MS. TRICKEY: That's not the question they've asked us to answer.

MR. MONDROW: I am not asking you what they asked you. I am asking you that question: Would you have fewer concerns?

MS. TRICKEY: We may, and we would be willing to undertake looking at that as a different option. But that's not what we have been asked to undertake.

MR. MONDROW: Well, sorry, asked by whom? By AMPCO? Is that your reference?

MS. TRICKEY: Correct.

MR. MONDROW: Okay. Thanks. Maybe this is Mr. Short, I am not sure. The topic of energy payments for DR resources was raised as early as -- I think your evidence says the lead-up to the DRA. Do you recall that evidence, Mr. Short?

MR. SHORT: If you can point me to where you're referring to, that would be helpful.

MR. MONDROW: Sure, yeah. If you look at your examination-in-chief compendium, which has your evidence, paragraph 50.

> "In the lead-up to the launch of the DRA, some stakeholders had inquired about energy payments or utilization payments in the DRA. However, the immediate priority was to implement the DRA."

So that would have been about 2014?

MR. SHORT: I think I can agree. I think that was related to transitioning DR3 participants and CBDR over to the capacity-based product solely, which was the DRA.

MR. MONDROW: And that was about 2014?

MR. SHORT: It's -- yeah I see the footnote, yes.

MR. MONDROW: And the topic was not given priority at the time?

MS. TRICKEY: I apologize, Mr. Mondrow. I'm sorry, what topic wasn't given priority at that time?

MR. MONDROW: Energy payments or utilization payments in the DRA.

MS. TRICKEY: Was not given priority? Was this -- I apologize. I am having a hard time following the timeline we are working on.

MR. MONDROW: Wow, paragraph 50.

"In the lead up to the launch of the DRA some stakeholders had inquired about energy payments or utilization payments in the DRA ..."

Good so far?

MS. TRICKEY: Yes.

MR. MONDROW: In and around 2014?

MS. TRICKEY: Yes.

MR. MONDROW: "However, the immediate priority was to implement the DRA," which I read as saying the energy payment or utilization payment topic was not given priority at the time. Fair?

MS. TRICKEY: Yes.

MR. MONDROW: Thank you.

MS. TRICKEY: This is a little before my time, so it was taking me a minute to catch up. So thank you.

MR. MONDROW: No problem. Paragraph 51:

"In early 2017, some DRWG, demand response working group, members again raised this issue on the basis that other jurisdictions provide both energy and availability payments."

So we see it was raised again in 2017, and your evidence footnotes a January 31st, 2017, DRWG presentation on DR stakeholder priorities for 2017.

In our compendium, Exhibit K 3.2, that's at tab 2. Could you turn that up, please? You'll see the first page behind our tab 2 is just the cover page for the DR stakeholder priorities for 2017.

And if you go to page number 12 -- I think we gave you the whole presentation, but if you go to page number 12, we see the context in which the issue was raised was preparation for future incremental capacity auction.

And then the issue itself is noted following that page at page 19, if you could turn to page 19. And you see point number 14 on page 19? You have to say yes.

MS. TRICKEY: Yes.

MR. MONDROW: Well, you don't have to say yes. You could say no, but you have to say something.

MS. TRICKEY: I'll say something.

MR. MONDROW: Okay, just to be clear. Point number 14 says: "Reinstate utilization payments for DR activations."

I gather, and there's been some evidence on this, that reinstate means there was some previous demand response programs that did include -- granted, not energy payments, but energy payments, some of which you testified about this morning, correct?

MS. TRICKEY: That is correct.

MR. MONDROW: Okay. And the distinction between activation payments and energy payments, as I understand it, is that activation payments when you refer to them are administratively or contractually determined. They are not necessarily what's paid to resources bidding into and

Just while we are on that, if we go to paragraph 53 of your evidence, so this is compendium Exhibit K3.1, paragraph 53. You will see following the preamble of the paragraph there is a table, and this table is inserted in the evidence, Ms. Trickey, I gather, to document the arguments for and the arguments against activation payments as reported by Navigant.

MS. TRICKEY: That's correct.

MR. MONDROW: And these are not Navigant's arguments, these are arguments that were raised by others in other jurisdictions that Navigant attempted to capture and catalogue, essentially; is that fair?

MS. TRICKEY: That's correct.

MR. MONDROW: Okay. And I think you might have already said this, but am I correct that no definitive conclusions were drawn by the IESO in respect of its work culminating in the Navigant report in respect of activation payments or energy payments?

You can look at paragraph 57 of your evidence if it helps you.

MS. TRICKEY: You are going to have to bear with me. Can you repeat your question? I apologize.

MR. MONDROW: Am I correct to say that following the consideration of the Navigant report, the IESO did not reach any definitive conclusions on the appropriateness of activation or energy payments for DR resources?

MS. TRICKEY: Our conclusion was that there were lots of arguments on either side and nothing definitive that said that this was -- this would be a benefit and that there were -- there was evidence that indicated that it might actually create a cost to consumers.

MR. MONDROW: But no definitive conclusions; fair?

MS. TRICKEY: Right. We didn't -- we -- what we articulated to stakeholders that we didn't see anything that indicated we should proceed and we asked stakeholders for feedback on that decision at that time.

MR. MONDROW: Can you go to paragraph 57(e) of your evidence. It's still on the same page, just a little farther down.

And you say in your evidence, the royal you, so Mr. Short, jump in when you feel it's appropriate:

> "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."

Now, one of the loose documents that will have been in the back of your compendium is a stapled package of paper, the cover page on which is a City of Toronto letterhead, and it says "comments to Independent Electricity System Operator, IESO, Stakeholder Engagement Working" -- sorry. "Stakeholder engagement for demand response working group on March 1st, 2018".

Do you have that in front of you, that package, small package?

there right on the surface at the moment. But I am not sure. Is that what you are asking?

MR. MONDROW: That's what I am asking.

MS. TRICKEY: I can't comment on that without taking a further look at this.

MR. MONDROW: Okay. In any event, you have now posted a draft engagement plan as of August 22nd, to look at energy payments for economic activation of DR resources. And you talked about that this morning, right?

That plan is now posted and active, correct?

MS. TRICKEY: Correct.

MR. MONDROW: Okay. And you testified already you anticipate a resolution of that by June 2020.

MS. TRICKEY: Yeah, actually May 2020, but yes.

MR. MONDROW: With an IESO decision by June 2020, I think. That's what the timeline says but.

MS. TRICKEY: Sure.

MR. MONDROW: May or June; it doesn't matter. We are going to get a resolution of that issue.

MS. TRICKEY: Yes.

MR. MONDROW: Okay. And will that study consider activation payments as distinct from energy payments?

MS. TRICKEY: Our understanding is that what stakeholders want us to address is energy payments specifically as per what has been implemented by -- or was requested by FERC. That's what our study is looking at.

MR. MONDROW: So all of these minutes we looked at, they actually refer to activation/energy payments, right?

You saw those references as we went through them.

MS. TRICKEY: Correct.

MR. MONDROW: And so do you think you should maybe look at activation payments as well as energy payments?

MS. TRICKEY: We don't have a concern with looking at that. But again, what we understand we have been asked to look at is energy payments.

MR. MONDROW: Asked by whom?

MS. TRICKEY: By stakeholders, and AMPCO in particular.

MR. MONDROW: Okay --

MR. SHORT: Sorry, if I could add, we in earlier conversations about utilization in the first concept, I guess, of energy payments was at a TCA stakeholder session. I remember the confusion with myself and some other folks in the IESO, because we had thought it was a utilization activation exercise. And it was at that point we realized that the conversation had shifted to an energy -- sorry, an energy utilization which is a more -- this is basically anybody, anybody who has load that responds and reduces consumption would be eligible for an energy payment as opposed to something that was specifically -- we had thought earlier was specifically related to a smaller class of participants.

So it was a bit -- you know we were -- so that's where we thought the tone changed from utilization to an energy-specific one.

MR. MONDROW: Do you think it would be wise to look at going to cause a problem say with system voltage --

MR. MONDROW: Problem by going off?

MR. SHORT: Yes, for example. And so if there's a local issue we can certainly continue conversations with the generator. But essentially, once they are have completed the deregistration process they can disconnect from the grid.

MR. MONDROW: Right --

MR. SHORT: And then I think the second question was is it reversible?

MR. MONDROW: They can reconnect subject to another assessment, I assume?

MR. SHORT: Yes, they can either not complete the process or they can reregister.

MR. MONDROW: Right. And how many generators have applied to do that? Can you tell me?

MR. SHORT: I don't have an answer off the top of my head. Like, again, our goal is to get ready for the 4,000-megawatt 2023 need. I know I have said it again. I will keep saying it, is that demand response alone can't do it, and so we are looking for other folks to provide -- to have that opportunity, and if you've got 600 megawatts of generation that's potentially economic, that seems to me like the right thing to try and do is to give them an opportunity to compete in auction, the same thing with imports, storage, so we are trying to be -- we are not picking generators, we are trying to give them an opportunity to solve the 2023 need and beyond.

MR. MONDROW: Can you go to paragraph 37 of your evidence, please. Actually, we will start at paragraph 36, obviously right above 37. And if you have that, you see in paragraph 36 you say:

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

In the next paragraph you say:

"During this period the hourly Ontario energy price, HOEP, has averaged approximately $25 per megawatt."

You contrast that to the load bid prices of $1,500 per megawatt to approximately $1,700 per megawatt. What does the average HOEP have to do with deactivation?

MR. SHORT: So the intent was to demonstrate -- again, this is on averages -- was to demonstrate that demand response, specifically dispatchable loads and HDR resources, bid into the energy market at relatively high prices. I think we talked about that a lot during the proceeding.

So when it comes to the probability of activation, again it's a demonstrative number. On average, HOEP sits around $25 and so there's quite a gap. The intent was to show there's quite a gap between energy prices and the bid prices of HDR and dispatchable load resources.

MR. MONDROW: Okay. Between average energy prices and 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.

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.

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

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 contractsand 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.

And Staff has some questions about the other type of DR participant, which is virtual DR resources. And I'd like to start by -- well, first of all, we have a compendium. The Panel has it on the dais, so we will make that Exhibit 3.6.

EXHIBIT NO. K3.6: BOARD STAFF COMPENDIUM FOR IESO PANEL 5

MS. DJURDJEVIC: And I am looking at tab 1, which is -- okay, it's the May 3rd, 2019, post auction report. And the very top box is you'll see -- I know it's very tiny, but basically it shows the amount of capacity that was committed for the summer and winter periods.

And then there's a breakdown if you look at the columns for each season, you'll see there's physical DR cleared and there's virtual DR for the summer commitment period. And then moving over to the right, you have the same information for the winter commitment period. Do you see that?

MS. TRICKEY: Yes.

MS. DJURDJEVIC: And you'll see that under the physical DR column for summer, the amount that cleared was 143.4 megawatts. And similarly for the winter commitment period, physical DR that cleared was 168.4-megawatt. Do you see that?

MS. TRICKEY: Yes.

MS. DJURDJEVIC: Now under the virtual DR that cleared, we have for the summer period 407, and for the winter period 472 megawatts. Do you see those numbers?

MS. TRICKEY: Yes.

MS. DJURDJEVIC: Now, would you agree, subject to check, these numbers indicate that virtual DR resources make up just 74 percent of the capacity in both the summer and winter commitment periods?

MS. TRICKEY: That sounds about right.

MS. DJURDJEVIC: And you spent a bit of time this morning during your examination-in-chief talking about virtual DR resources. And given that this is three quarters of the DRA market, Staff would like to understand those category participants a little better.

So we have a few questions and if you don't have the answer, but it is something you can find out, then this can all be done by way of an undertaking in order to keep things moving.

So starting -- what, for example, is a virtual DR? Could you give us an example?

MS. TRICKEY: Sure. A virtual DR resource is really simply a resource that's not -- it's typically a group of resources. So it's not a large physical resource connected to the grid that we see as sort of one big resource, like a big industrial plant. It's a collection of small resources typically connected at the distribution side of the grid and aggregated up to one larger resource by an aggregator.

So it could be, you know, a hundred different places all -- that are all in a similar area, all connected up and operated by an aggregator rather than directly by the IESO.

MS. DJURDJEVIC: And does the IESO have any kind of

Now, in the exchange with Mr. Zacher this morning, the IESO seemed to disagree with Dr. Rivard on whether DR resources should receive similar treatment to generators in relation to incremental cost beyond their value of lost load."

Is this IESO's position? Did I understand this correctly?

MS. TRICKEY: Sorry, are you referring to the discussion we had on the real-time generation cost guarantee or --

MS. DJURDJEVIC: Yes.

MS. TRICKEY: Yes, okay. My point there was that that program and the intent of that program is to enable -- when we have resources that are required to operate in the market at a price that they have said is not economic, that we enable them to recover some costs as a result of that.

That's the intent of the real-time generation cost guarantee program. And my point was that we have other similar programs or approaches that enable the same type of thing when we activate resources out of market, and that we have recently instituted some changes to hourly demand response participants in terms of how they're compensated when that type of situation occurs.

That was really the intent there.

MS. DJURDJEVIC: I understand that context of your testimony this morning. But I am now going to ask about in the context of the TCA, which is to enhance competition, can you comment on whether if generators have the GCG program and DR resources don't a similar program to recover costs that are similar in nature, how can they compete in the TCA on a level playing field?

I wonder if you have a comment on that.

MS. TRICKEY: I am not sure that that was the conclusion, and I think my point was that where we have a similar situation, all types of resources, as far as I could tell at this point, do receive similar compensation.

MS. DJURDJEVIC: Okay. Thank you very much. Those are all my questions.

MS. SPOEL: Thank you.

DR. ELSAYED: I want to understand an answer that was provided earlier about if you cannot do the first TCA auction in December as was originally planned, when is the next opportunity to do so, and why?

MR. SHORT: The next opportunity to run an auction is in June of 2020. Our plan is to execute an auction with a slightly longer forward period to cover the period starting in May of 2021 until April of 2022. The reason --

DR. ELSAYED: I am still not clear. Like the decision, the OEB's decision is going to be issued by the end of January 2020. So why can't you run the auction shortly after that?

MR. SHORT: Sorry, is your question related to the December 2019 auction and why we can't delay that?

DR. ELSAYED: Yes, why can't you delay it.

MR. SHORT: Okay, now I understand, sorry about that. So there's a number of activities that folks have to do once they've cleared the auction. So say we execute the auction in early February, its takes -- I believe it's ten business days to complete the auction, reporting participants and find out they have to actually meet their obligations -- or they have been successful, sorry, in the auction and there's work they have to do we believe that goes out and gets their -- essentially their end use customers ready to participate in the auction.

There's things like credentials they have to submit to the IESO, like a financial deposit so-to-speak as well to the -- so there's a number of activities that have to happen and we don't believe that if we wait until essentially to tell participants that are successful in mid-February that they will have sufficient time to be ready for May 1st, because the obligation begins May 1st and they have to be able to provide -- the expectation is they have to provide that full level of capacity obligation May 1st.

DR. ELSAYED: Okay. The Navigant study, when was that done?

MS. TRICKEY: Roughly 2017.

MR. SHORT: Yes, December 18, 2017.

DR. ELSAYED: December 18th?

MS. TRICKEY: Yes.

DR. ELSAYED: And I understood that the results were not conclusive.

MS. TRICKEY: That was our view.

DR. ELSAYED: I need to understand what that means.

MS. TRICKEY: What we asked Navigant to look at was there have been a lot of arguments for, saying that this could be a good thing, and there have been a lot of arguments against, saying no it's not a good thing, that there are problems with it.

So we asked Navigant to go look into those reasons and help us understand them, and see how those things may or may not change in Ontario.

As well, we asked Navigant to look at are there any unique considerations in Ontario, or implications for implementing something like this in Ontario that we need to understand.

And if you sort of walk through their review of each of the pros and cons, there wasn't any -- there was nothing that really stood out to say, yes, this really looks like a great idea. There was a lot of, well, if this happens, this might give you some sort of benefit. If this happens, this might give you some sort of negative impact.

Everything was -- there was really nothing you could hang your hat on to say this really sounds like this is a good thing to do. And on top of that, they did also look at this issue of if FERC's net benefit test was intended to ensure that the it wouldn't create additional costs for consumers to implement something like this, when you applied that in Ontario, it appeared that it's possible that that would not be the case in a lot of the hours.

So it really called into question whether this was worth doing or not. That's our perspective. I understand others see it differently. But from the IESO's perspective, when we looked at all those things, we didn't really see anything that was compelling to say this was something that we shouldn't move forward on.

DR. ELSAYED: Was there any stakeholder engagement associated with the Navigant study?

MS. TRICKEY: Yes, we engaged stakeholders in each stage of that study, as we would normally do, to say this is what we are going out to do. When Navigant presented the results of this study, we discussed those results with stakeholders as well.

DR. ELSAYED: So what leads you to believe that the one you are embarking on would be any different?

MS. TRICKEY: Excellent question. Well, I think what he have asked Brattle to do is to go a step further and to say, okay, if we apply this in Ontario, you know -- so we've asked them to look specifically at the net benefit test and how that might apply in Ontario, so we can inform ourselves on that. And we have also asked them to look at are there other considerations that in the specific Ontario market design, are there things that we're missing, are there elements of the design or sectors or types of resources within that that could benefit from something like this from an energy payment, or are there new learnings that we have received since the Navigant study was done that would inform us on maybe another way to look at this.

DR. ELSAYED: So that maybe answers my next question, which is why you waited for two years, I guess, before you embarked on the new study?

MS. TRICKEY: The delay, I think, was more so, you know, we had a discussion with stakeholders. It didn't appear at that time to be a priority to continue pursuing the energy payments discussion. When the TCA was introduced stakeholders made it very clear that that created -- put a higher priority on this issue for them because of the TCA coming. So they -- they requested, again very strongly, that we look into it, and as we've discussed, we agreed to do so.

DR. ELSAYED: Okay, and can you explain to me what the net benefit test is again? What does it mean?

MS. TRICKEY: So the net benefit test that FERC has prescribed is to say that -- so if you have a demand response participant set the market clearing price, presumably they are setting it -- you know, they are setting it because they are setting it lower than whoever would have been above them. Let's assume that was a generator. So they've lowered the energy market clearing price in a given hour. Right now we don't pay that demand response participant an energy payment, so you're adding a payment to the picture, so we are going to add a payment to that, to the market, so now we have to pay the load that energy payment, so does the size of that energy payment offset the savings in the energy price that would be applied to all the consumers in that hour.

So if that is a net positive, then they say in that

Conversely, if prices are higher we acquire less megawatts, so it's actually -- when we say "downward sloping", it allows flexibility in terms of more megawatts that we can acquire.

But essentially, where you cross that line, all the resources get paid that are successful, get paid the same price.

MS. FRANK: So it doesn't matter if you are a generator or load displacement. Per megawatt you are getting exactly the same price.

MR. SHORT: Correct.

MR. FRANK: Okay. Do you get paid anything else in the capacity market except for that price?

MR. SHORT: From a capacity market perspective that's the only payment that they would receive is an availability payment.

MS. FRANK: Okay. So there's no activation payment of any sort in the capacity market.

MR. SHORT: That's correct. There is none.

MS. FRANK: So we have to go over to energy market to find what else is happening; is that true?

MR. SHORT: That's fair, yes.

MS. FRANK: Okay. On the energy market there's -- the first thing, the simple thing, is that a generator gets paid at the market price for what they generate; right? That's -- that one's a straightforward, simple one; right?

MR. SHORT: Yes, that's correct.

MS. FRANK: Okay. And there's no payment to the load displacement group if they happen to consume any energy. There's nothing -- they get nothing paid.

MR. SHORT: They consume up to the point where their bid price is, and that's the point --

MS. FRANK: No, no, remember, I am assuming that they have both been activated and I am looking at who is getting paid what. The generator is not getting paid because they are putting --

MR. SHORT: Yes, they are supplying electricity to the grid --

MS. FRANK: However, the load displacement may well be using some other type of energy. They may be having their own, you know, behind-the-meter generator. Who knows what they have got, but they are using something in order to not take any load off the grid.

MR. SHORT: Or they could be not using something --

MS. FRANK: No, but my -- some are using something. We can go there.

MR. SHORT: Yes, that's true.

MS. FRANK: So some are using something. They get no payment for that.

MR. SHORT: Correct.

MS. FRANK: Or is there any way of them getting paid? I keep on thinking there's something else in the marketplace that I am not aware of, and what makes me think that is you recently said, Ms. Trickey, you said they have recently implemented changes to the hourly demand response, and I thought, oh, does that mean you are paying for something? The other thing you said earlier is that you have an availability payment.

MS. TRICKEY: Right.

MS. FRANK: So I thought, is that something in the energy market? Is there something else that people are getting paid when they are on the load side of the equation?

MS. TRICKEY: Okay. So let's stick with -- the energy market generator, as you have said, accurately -- yes, they get the energy price when they are producing. If the demand response participant is activated because the price gets too high for them, then, correct, they do not receive a payment. They are not paying for energy and they are also not receiving any payment.

However, what I was referring to earlier is there can be occasions when we test them -- we test to sure that they can do what they say they are going to do. When we do that we activate them at a price that's much lower than what their energy bid is.

So they're saying, I want to be consuming, and we are saying, I am sorry, I need to test you in this hour, so you are not going to consume. In those situations we do provide them a payment.

MS. FRANK: But that payment has nothing do with --

MS. TRICKEY: But that's not what we are talking about here.

MS. FRANK: -- activating them in the normal course of --

MS. TRICKEY: Correct. Yes, that's not what we are talking about here; that's correct.

MS. FRANK: And there's no expectation that that type of payment would actually start under the current market rules, that --

MS. TRICKEY: Correct. So we do not have any contemplation or any rule -- we have not created any rules that would allow an energy payment to a load for reducing their consumption in an hour based on the energy price. The availability payment you talked about, that's how we pay for the capacity market. So the capacity market says you cleared the capacity market, you have an obligation now for 10 megawatts. The way we pay for that is the availability payment, and the way we make sure that we are doing it only when they're actually available rather than saying, oh, we will just give you $50,000 for the year, we -- they bid into the energy market the amount that they have available. They say I have got 10 megawatts available this hour; I have only 5 megawatts available next hour. So we pay for the capacity through that availability payment in each hour based on the amount of megawatts that they bid in to say that this is how much I have got available for you.

MS. FRANK: Okay. So I am back to the capacity totally equal treatment.

MS. TRICKEY: Yes.

MS. FRANK: No difference there.

MS. TRICKEY: Correct.

MS. FRANK: On the energy, though, there is a difference.

MS. TRICKEY: There is a difference.

MS. FRANK: And the difference is more than just the payment for the energy that's being input into the system. There's also this notion of -- I am going to forget the term, the true-up if you're not getting enough money.

And my feeling is that that relates to the costs that it takes for the generator to participate.

MS. TRICKEY: Correct.

MS. FRANK: There might be a variety of items.

MR. SHORT: There is only some generators. For example, if you are a hydro-electric generator, you don't get that money because there's no startup cost. You just open the wicket gates and away you go.

MS. FRANK: I assume also with load displacement not everybody would get -- not everybody incurs some costs in order to participate, but some people do.

MS. TRICKEY: Yes, you probably all have some sort of cost. Just how big it is and how often it occurs probably varies greatly, like it does with generators.

MS. FRANK: So for generators, there's a way to recognize a difference in generators and the experience they are going to have once they get activated. There's a way to pay for those who need to be paid and not pay for those who don't need to be paid.

It's not uniform. It's a like originally you had the $200, and it didn't matter what their experience was. It's more specific for the generators.

MS. TRICKEY: Yes. But as I have tried to distinguish, that's really about the fact that there's something requiring them to be in the market when they're -- they're not economic. So I think it's -- I think it's a side issue is really what I am saying. It's a different thing and --

MS. FRANK: But if the load had costs, you've said repeatedly that what they have to do with those costs is to add them to their capacity bid, meaning that they're now less competitive because they have got a cost in there that a generator doesn't need to put in, right?

MS. TRICKEY: I believe that's what's at issue here, and I think what we're saying is that our market design looks at things a little bit differently. It's really trying to incent loads to consume when it makes the most sense for their business, rather than -- and I think that's what Brian's -- Dr. Rivard's testimony and examples was trying to walk us through, was that in this type of market design, it doesn't necessarily make sense to pay an additional amount to that load.

Now, I think that there were questions about is there some slice of cost that maybe don't fit perfectly into his examples and that maybe there's evidence of, but we haven't really been able to quantify or understand fully in this hearing.

That's a possibility and maybe that's something that we need to explore. But it's not something that's been quantified or verified, and I think going back to, you know, we have this design. The design is meant to create efficient participation from all types of participants, and I think what Dr. Rivard's examples show is that it typically does.

MR. SHORT: I think Dr. Rivard also said, too, that if he was the economist working for one of these companies, he would probably have -- I forget the adjective he used, but it was a very minuscule risk, and so he wouldn't be factoring that into the other opportunity -- like it was basically he wouldn't factor that into the capacity cost.

MS. FRANK: But then would you also say for a generator -- I assume it's the same minimal risk that a generator would be activated that it is that a load would be activated. It's the same minimal expectation.

MR. SHORT: I can't say that for certain. Generators tend to offer a little lower, and they may be activated more frequently than a load.

MS. TRICKEY: I think it's important to think about what a generator is in the business to do versus what a load is in the business to do, if we are talking about --

MS. FRANK: But if they are in the capacity market, I assume they are similar in terms of what they brought forward. They are there about the capacity market. They are not really playing in the energy market; they are playing in the capacity market.

That's what this is about, right? We are talking about the capacity market, and we are trying to figure out how do we have that capacity available and ensure that when we need it, it's there and we can call upon it.

It doesn't matter what we call upon, if it's a reduction in load or if it's generated -- it doesn't matter. It just matters that it's there when we need it.

MS. TRICKEY: I think the issue at hand is actually about the energy market. But I understand that for the demand response participant, they see -- every participant looks at all of the markets and all of their opportunities to get revenue, to provide a service and get a revenue for that. And they look across all of them and try to understand what the best way to manage their costs across those things is.

And I think what we're really talking about is how people participate in the energy market, and how they get paid in the energy market.

Now, I understand that AMPCO sees that because of the way they participate in the energy market, they feel it puts them at a disadvantage in the capacity market. Our point is that two things, I think, one, first that we don't see the disadvantage. We are willing to be convinced Otherwise. We will work through that with them.

But in the meantime, if there is some disadvantage that happens there, at the moment that disadvantage is not material.

MS. FRANK: But there is a disadvantage in the rules. Would you go there?

MS. TRICKEY: No, so --

MS. FRANK: I am not saying a large amount. I am just saying literally applied, there is a payment that happens -- and if you just for the moment we are trying to you keep saying, well, that's the energy market; it's not capacity market.

But in reality it's what do people get paid, and there's a difference in what people get paid depending upon what they have to offer. If they're a load or a generator, there's different payment streams.

MS. TRICKEY: I wish it were that simple, I really do.

MS. FRANK: Well, you'd better try to convince us it isn't, because it sure seems that simple to me. So you haven't done it yet, so give you another try.

And I am not focussing on the energy piece. am about the activation piece, because I do believe for some load customers, there are activation charges -- not for all, but for some. And for those where there is an activation charge, I don't understand how they get paid.

And if you say with the current rules, there's a way they get paid for it, you've convinced me that they are being fairly treated and there's no discrimination.

MS. TRICKEY: I think the only thing that I can provide you is that historically speaking, prior to the demand response auction, there were loads participating in the Ontario market without any capacity payment or any energy payment. They simply participated and provided -- they watched the market price and they reduced their load when it made sense for them to do so.

They also participated in an operating reserve market, but that was a different, a different mechanism different payment stream.

So I think, and I think is the point that Dr. Rivard was trying to make, was that there isn't necessarily a need for an additional payment stream to make this make sense, that the capacity auction payment alone should be sufficient to incent loads to do what makes sense for their business and to provide a service to the Ontario market.

MS. FRANK: Could there not also be a way for the capacity payment to make generators want to participate? If the generators included their -- I'll call them incremental costs upon activation in their capacity bid, that would do it.

MS. TRICKEY: There's different ways to structure the different markets and some places have an energy-only market. So you don't have capacity payments and energy payments for generators, and that can work as well. That's just not the design that we have here in Ontario.

MS. FRANK: The challenge is how can our design in Ontario under the current rules make sure that it doesn't matter who you are. You are going to be treated equitably.

MS. TRICKEY: Maybe another thing that I can point to is in the U.S. markets when FERC was debating this there were jurisdictions where there was both the exact same structure that we have here where generators and loads could participate in a capacity auction together, both received capacity payments, they can both operate in the energy market together, generators received payments, loads did not, so the same as what we have today here. That -- that was -- that went on for quite a number of years.

Now, FERC decided that they wanted to do something different to encourage more loads to participate, but as I tried to explain earlier, that was -- I am sure there were many reasons for it, but one of the reasons was about the fact that what you didn't see participating in those markets were loads that were paying something other than that wholesale price, they were paying some sort of retail rate, so they really didn't have an incentive to participate in the energy market. That was really what brought them to that decision.

Now, they applied it more broadly than that, but I don't think it was about creating some -- it wasn't about saying that every resource that participates in every auction or every market needs to receive a payment, that it did recognize that there is -- there is an efficient way to run the energy market, and that that is for generators to get paid and loads to pay or not pay when they don't consume.

I know that's not the answer you are looking for --

MS. FRANK: I am looking for this equity, the non-discrimination. That's what I am looking for, and I am just not hearing it. That's my -- I would like to hear it, because I do agree with you that having transmission -- having generation and load both participating in the auction is the way to go and it's the way to get the -- you know, you need to get there. The problem is you need to get there in a way that you don't discriminate, and that's what I haven't quite heard, how the current rules do that.

So no problem with the idea that not only generators and load but many, many other sources as well need to be all considered if we are going to have a viable market, you know, a decade from now.

MS. TRICKEY: There may be a sliver of costs here, a slice of costs there, a bucket of costs that we haven't accurately captured or understood, and there may be a way to deal with that --

MS. FRANK: But there isn't today. That's the bottom line.

MS. TRICKEY: There isn't today, but I would also argue that an energy payment is not the way to do it. So an energy payment --

MS. FRANK: You know what? I have no trouble -- I am not sold on an energy payment at all. I am just sold upon at the end of the day it doesn't matter who you are, this technology-neutral notion that we have heard that applies and people are treated equitably.

And I know the argument is always, well, it's not a material thing, but it becomes more material over time. It may not be material today, but it grows over time, so if we have a rule in place that is discriminatory today it becomes a more serious problem, you know -- I used a decade, but even shorter than that. Once you increase the number of parties that are participating, the quality changes. Nothing else?

MS. TRICKEY: We -- again, we don't feel that the current rules are discriminatory. We do believe that there is a fair and efficient market structure in place that's been used in many other places and continues to be used in many other places and is established in the same way, but it doesn't sound like I can convince you of that.

MS. FRANK: I think we will stop.

MS. SPOEL: I just have a couple of questions. One of the questions, just picking up, Ms. Trickey, on a point you just made about, that the loads should consume when it's best for their business and that from an economic perspective that's best for the economy and that, you know, that's the way things should operate, and I think you cited Dr. Rivard's evidence in support of that.

Isn't it really up to the businesses to decide when it makes sense for them to operate and when it maybe makes sense for them not to, as opposed to structuring the electricity market in a way to encourage, you know, manufacturers of widgets or whoever as to when it's the right time to manufacture and when it's the right time to not?

MS. TRICKEY: I would agree, absolutely, and I believe what Dr. Rivard's evidence was trying to show was that that is how it works, that is how the market works, that if loads are paying at a price at which they are willing to consume, then they are making the rational decision for their business.

What I believe he tried to show is that when you add an energy payment on to that you're providing some form of additional payment that isn't necessarily needed, so it's -- while it may look efficient in that one hour, it's not good for the whole. It's giving them an advantage over the generator.

MS. SPOEL: But is it good for the electricity. I think you also said earlier -- and I don't have the reference, but I think you did say that for capacity given that it's really to cover the -- help me here -- the gap -- not the gap, but the extra capacity you have to have beyond what you are actually going to use, that DR is a very inexpensive way to have that.

So if you, from the electricity market point of view, as opposed to broader economic considerations of the economy as a whole, is it not -- would it not be reasonable to assume -- sorry, too many double negatives. Is it fair that it would make sense to keep as many of those demand response resources available for that purpose, for that covering the gap if you happen to need it to make sure you have the adequate reserves, that you don't want to lose -- you don't want the lose them, any more than perhaps than you want to not have generators available when you need them. But because it's an inexpensive way to provide that coverage, it's in the interest of the market to have it there through the capacity option -- through capacity payments?

MS. TRICKEY: I think there's two things to consider there. First, demand response can only be available if they're consuming. So they have to stop doing something in order to provide that response. So --

MS. SPOEL: Yeah, fair enough.

MS. TRICKEY: -- typically that means they are going to stop producing their widgets or doing something in their business. If it doesn't mean that, then potentially it just means there is an inefficiency there, there's a better way to manage their electricity, so I think that's an important part.

The other thing is, I expect there is a limit to how much demand response is efficient in the market. I don't know what it is, but the more demand response we get as part of our capacity makeup, the more it will be activated.

So, you know, if it's a small sliver it can be that type of insurance and only -- and be rarely activated, and I could be wrong, but I think that most businesses, from what I hear from them, they are happiest when they are the insurance. They are really just there to be rarely activated, because they have better things to do. They want to run their business.

So the more that we get, it gets to a point where, well, now we actually have to start activating them more frequently, and their costs are going to go higher, and -- now, some may be willing and able to do that, and that's good, but what you are going to see is their prices are going to rise because they're going to be activated more frequently.

MS. SPOEL: And does that apply to the virtual resources as much as to the, let's say the steel mill that Mr. Anderson referred to --

MS. TRICKEY: I think everybody's set a limit. Like, even you and me, you know, we may be okay having our air-conditioner cycled off on a hot day every now and then -- well, first off, it's only going to work on a hot day, so there is a limit to when that's actually available to us, and second off, if every day was hot and we were getting cycled off every day, I think we would all get a little frustrated with that and say, enough of that. I just want my air-conditioning.

So I think in every case there's a limit to it. What that limit is, it depends on the type of resource it is, but ultimately there is a limit.

MS. SPOEL: Okay. I have a -- this is more -- this is really a question of curiosity. On the page that Ms. Djurdjevic took you to with the demand response auction post-auction summary report, which lists the resources, I wondered why the price -- the auction clearing price in the northeast is $200 per megawatt per day, whereas everywhere else it's 317 -- well, 318 in the summer and 317 in the winter. Is that because in effect, you're running -- I don't know how many regions. It looks like about eight or nine -- you are actually running a series of mini auctions because it's regional, and is that why the price is different. But somehow magically, in every region except for the northeast, they all turned out to be the same?

Like I just -- it was one of those anomalous numbers that popped out at me, and I wondered what that meant.

MS. TRICKEY: Always helpful to get the ops guy to help me with these things.

In essence, yes, we run the auction in every region because we can only -- each region we have to look at separately, and say how much demand response can we accommodate in this region, can we operate is how much is okay to have...

MS. SPOEL: Because it's a grid.

MS. TRICKEY: Yeah, and each region of the grid. So we run the auction in each region and it just so happens that there's only one region where the amount of demand response that's economic is more than we can accommodate. So it clears at a much lower price because of supply and demand.

MS. SPOEL: They have more than you need.

MS. TRICKEY: Exactly.

MS. SPOEL: I had a previous question, which was is demand response in Thunder Bay the same as in Windsor, and it's not. They are not interchangeable.

MS. TRICKEY: No, and we have to apply the DR resources to the region in which they're located, so that we can operate them and balance the system regionally as well.

MS. SPOEL: Okay, that's really helpful, thank you. Let me just look and see if I had anything else. I think those are all my questions. Thank you very much. Mr.

Zacher, do you have any re-examination?

MR. ZACHER: I am tempted to ask some questions arising from Member Frank's discussions, but I think Mr. Mondrow would object and it's Friday afternoon, so I will leave that to our submissions. I just have one quick line of questions.

Ms. Trickey, do you understand AMPCO's position to be that DR resources should be entitled to energy payments in the energy market, or some other form of activation payment?

MS. TRICKEY: My understanding is that they are looking specifically for energy payments.

MR. ZACHER: And do you recall when Mr. Mondrow suggested to you that the IESO's energy payment engagement should in fact be considering activation payments for demand response resources?

MS. TRICKEY: Yes, I do.

MR. ZACHER: And has AMPCO provided input on the proposed scope of the energy payments engagement and study to be done?

MS. TRICKEY: I believe they have, yes.

MR. ZACHER: Okay. And I have asked Staff if they could just put up on the screen what is tab 11 from the IESO's earlier cross-examination compendium of Mr. Anderson. And maybe if we could just go to the first page of that -- sorry, the cover page. I'm sorry, the cover page at tab 11. Okay.

Do you recognize that, Ms. Trickey, as AMPCO's submission?

MS. TRICKEY: Yes, I do.

MR. ZACHER: And if we could just scroll down to the top of the next page -- sorry, the page after that. Okay, right there.

And do you see what AMPCO -- what has AMPCO said about what the scope of the engagement should be beginning at the first full paragraph?

MS. TRICKEY: My understanding of what they're asking for is that we narrowly scope -- more narrowly scope the consultation to deal with how to implement energy payments consistent with other FERC and non-FERC jurisdictions -- it's too late for me to be reading -- rather than as to pay them.

So my understanding of what they are asking for there is that we maintain the scope of the consultation to look at energy payments specifically.

MR. ZACHER: Okay, and if we could just scroll down to the bottom of that same page -- stop there.

So you see number 1, it says "proposed problem statement".

MS. TRICKEY: Yes.

MR. ZACHER: And what was the problem statement?

MS. TRICKEY: The proposed problem statement -- when demand response resources are economically activated, they will be --

MR. ZACHER: No, what was --

MS. TRICKEY: Oh, what was our proposed...

MR. ZACHER: Yes.

MS. TRICKEY: Pardon me, give me one second. So our proposed problem statement was should DR resources receive energy payments for in-market activations.

MR. ZACHER: And what has AMPCO now proposed?

MS. TRICKEY: When demand response resources are economically activated, they will be compensated for the service provided to the energy market at the market price for energy, provided they have the capability to balance supply and demand as an alternative to a generation resource, and when dispatched if that demand resource is cost effective, as determined by the net benefits test. How should the net benefits test be constructed in Ontario to ensure cost effectiveness.

MR. ZACHER: Thank you, those are my questions.

MS. SPOEL: Thank you Mr. Zacher. We have set aside -- and thank you, Ms. Trickey and Mr. Short, for your very helpful comments. I know it's been a very long day, so I hope you have a more restful weekend.

We have set aside two days at the end of next -- not next week, the week after, I think it's the 12th and 13th of December for oral argument for all parties, so that we can proceed along this with in a timely manner.

I would suggest we leave it with the parties and Board Staff to work out scheduling of oral argument for those Days, recognizing that everybody's got to have time to fit it in, and respond to each other and respond appropriately and so on.

TAB 9

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. Cost per Curtailment:

- 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. Number of Curtailments:

- 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. Other Considerations:

- 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 Staff #3

Reference: Transitional Capacity Auction, Phase I Design Document, June 5, 2019, p.11.

Preamble:

The IESO's Phase I design document for the TCA describes the different approach in relation to the dispatch of dispatchable load resources and non-dispatchable load resources, which are referred to as Hourly Demand Response (HDR) resources. That document notes dispatchable load resources deliver energy by following the IESO's five-minute dispatch instructions. In contrast, HDR resources receive a "standby report" in advance of a potential activation between 15:00 EST day-ahead until 07:00 EST on the dispatch day, if they were scheduled to curtail. HDR resources would then be notified that they will be dispatched by receiving an Activation Notice about 2.5 hours before the start of the first dispatch hour. Dispatchable load resources are therefore subject to the same requirements as generators (i.e., 5 minute dispatch), while HDR resource requirements are not.

AMPCO does not distinguish between the different types of DR in the application (i.e., dispatchable and not dispatchable).

Questions:

(a) Is AMPCO's position that all DR resources should be eligible to receive an energy payment?

(b) If so, given the differences between dispatchable and non-dispatchable loads discussed above, please explain why HDR resources should receive the same treatment as dispatchable load resources in relation to receiving an energy payment.

Response:

(a) Yes.

(b) Demand side resources that are activated for energy will all incur costs, examples of which are provided in AMPCO's response to Board Staff Interrogatory 1. Those costs are not dependent on whether the load in question is dispatchable or is an hourly demand response resource. For this reason, they should all be considered eligible for energy payments in a situation where they are activated and providing the requisite service to the market and displacing a generation resource, provided the appropriately derived and applied Ontario specific net-benefits test is passed.

TAB 10

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.

TAB 11

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

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2 Executive summary

FERC Order 745 relates to the compensation of DR resources participating in organized wholesale energy markets (day-ahead and real-time). Order 745 requires that DR resources participating in these markets be compensated through the payment of the locational marginal price ("LMP") for curtailing their load if dispatched.[1] In Order 745, the Commission identified a number of barriers to entry for DR resources, which included a disconnect between the price that load pays to consume and the wholesale price in any one hour (e.g. load paying rates that are less dynamic than actual wholesale prices on an hourly basis). Payment of the LMP to DR was therefore meant, at least in part, to address this disconnect between wholesale and retail rates. Order 745 is not concerned with DR participation in capacity markets, compensation in ancillary services markets, DR programs administered at the state/utility level, nor ISO- and RTO-level programs administered for reliability or emergency conditions.

In responding to the questions posed by the OEB, LEI focused on ISO- and RTO-level programs in three markets: PJM, ISO-NE, and NYISO. A summary of selected information around these programs, participation, as well as system-wide peak demand and load (for context), are presented in Figure 1.

Figure 1. Summary of demand response programs and information by ISO/RTO

ISO/RTO	NYISO					ISO-NE			PJM			Ontario
Demand side resource program	Special Case Resource	Emergency Demand Response Program	Day Ahead Demand Response Program	Demand-Side Ancillary Services Program	System-wide data	Passive	Active	System-wide data	Emergency/ pre-emergency	Economic	System-wide data	DR Auction
Can participate in market as and receive compensation for:	Capacity[a]	Emergency[a]	Energy	Operating reserves and regulation services		Capacity	Capacity, energy, operating reserve		Capacity[a]	Energy, operating reserves		Capacity
Considered dispatchable by ISO?	No	No	Yes	Yes		No	Yes		No	Yes		
Does Order 745 apply?	No	No	Yes	Yes		No	Yes		No	Yes		
2018 enrollment/ participation (MW)	1,309	18	0	116.5[b]		2,580.1[c]	365.7[c]		8,946	2,512		550.4*
2018 dispatch (GWh)[d]			0				18.1[e]			49.186[f]		
2018 peak demand (MW)					31,861			26,024			147,042	23,240
2018 load (GWh)					161,114			123,306			791,093	137,400

[a] can also receive activation payments; [b] capability over the May to October 2018 period; [c] capacity supply obligation for August 2018; [d] DR dispatched through these programs; [e] day-ahead dispatch for June to December 2018; [e] in day-ahead and real-time; * For Summer 2018 commitment period. DR procured through the auction take two forms, virtual and physical. Virtual resources, which are non-dispatchable, made up 407 MW of cleared capacity; 31.4 MW of physical resources were non-dispatchable and 112 MW were dispatchable. Dispatchable loads in Ontario can also provide and receive compensation for the provision of operating reserves.

[1] LMPs differentiate the price of electricity at each production and consumption node on the system, based on locational supply and demand conditions as well as congestion and losses. This contrasts with the current system in Ontario which has a single system-wide market clearing price.

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In PJM and NYISO, DR programs are currently broken down into economic (energy and ancillary services, dispatchable) and reliability/emergency (capacity, non-dispatchable). The majority of DR in these two markets participate on the capacity side, in programs that Order 745 does not apply to.[2] Additionally, actual dispatch of economic DR on the energy side is extremely low. Noteworthy, however, is that DR participating on the capacity side can receive payments (in $/MWh) if actually activated (e.g. during an emergency or reliability event).

ISO-NE's structure differs from PJM and NYISO, in that its groupings are broken down into two 'demand resources' (also referred to as demand response). 'Passive demand resources' are non-dispatchable, and can only provide capacity. 'Active demand resources' are dispatchable, and active resources with a capacity obligation have must-offer rules in the energy market. Because of this, most active DR in the energy market submits at or close to the offer cap. Most demand-side capacity is provided by passive resources, and active demand resources are dispatched at very low levels in the energy market. Order 745 only applies to active demand resources.

While the three US markets do distinguish between dispatchable and non-dispatchable resources, there are some differences compared to the Ontario context. For PJM and NYISO, DR resources in emergency/reliability programs are non-dispatchable from the RTO/ISO's perspective as they are activated outside of the RTO/ISO's dispatch system (e.g. manual activation), even though these resources reduce their load upon instruction from the RTO/ISO given adequate lead time. In ISO-NE, non-dispatchable resources cannot reduce their load in response to dispatch instructions. 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.

As most DR resources participate on the capacity side, and actual dispatch on the energy side for those that participate in these programs is quite low, compensation for demand response participating in these RTO/ISO programs is mostly related to capacity payments, as can be seen in Figure 2 (all dollar values shown in this report are in US terms unless otherwise noted). Ancillary service payments for those demand-side resources that are capable of providing them can often form the next largest revenue stream, although this is low in aggregate. Payment from dispatch in the energy markets for demand response resources is also quite low, as are activation payments for reliability and emergency-related programs in NYISO and PJM.

Figure 2. Demand response resource revenues in ISO-NE and PJM ($ million)

Market	Capacity	Energy	Ancillary Services
PJM	$577.1	$2.9	$6.1
ISO-NE	$89.0	$3.6	n/a

Note: ISO-NE shows three-year average demand response revenues from 2012 to 2014; similar data for more recent years was not readily available, but as capacity prices have risen in ISO-NE, capacity would most likely make up a large proportion of total revenues. PJM shows three-year average total demand response revenues from 2016 to 2018. Comparable data for NYISO was not readily available.
Sources: ISO-NE's Annual Market Reports, PJM's state of the market reports.

[2] "... the Final Rule does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions." Source: FERC. *Demand Response Compensation in Organized Wholesale Energy Markets [Docket No. RM10-17-000; Order No. 745].* Issued March 15, 2011.

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

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).

> *"**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

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]

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

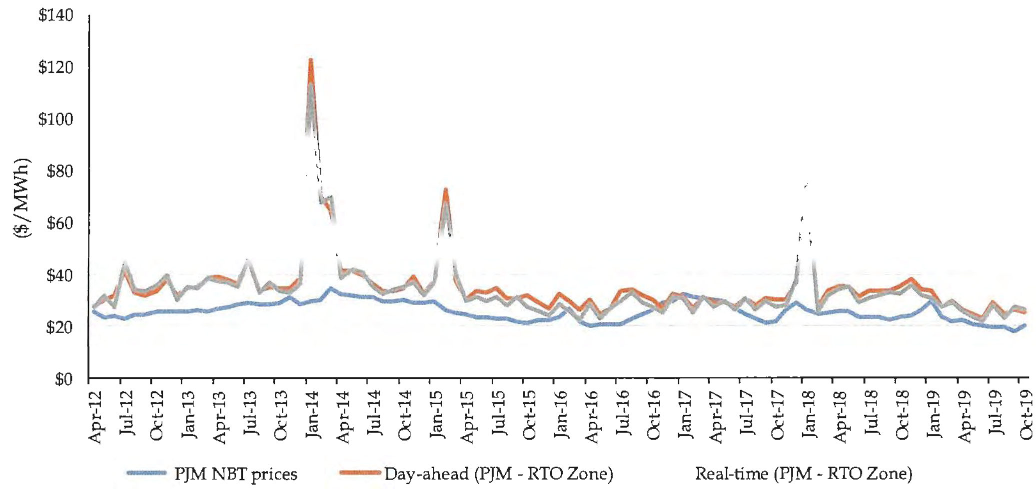
[4] Ibid.

[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.

(assuming, of course, that monthly PJM - RTO Zone prices are representative of hourly zonal prices).

Figure 5. NBT prices versus real-time and day-ahead prices in PJM



Source: PJM. *Historical results of net benefits test calculations; Energy Velocity*

3.3 Wholesale - retail disconnect

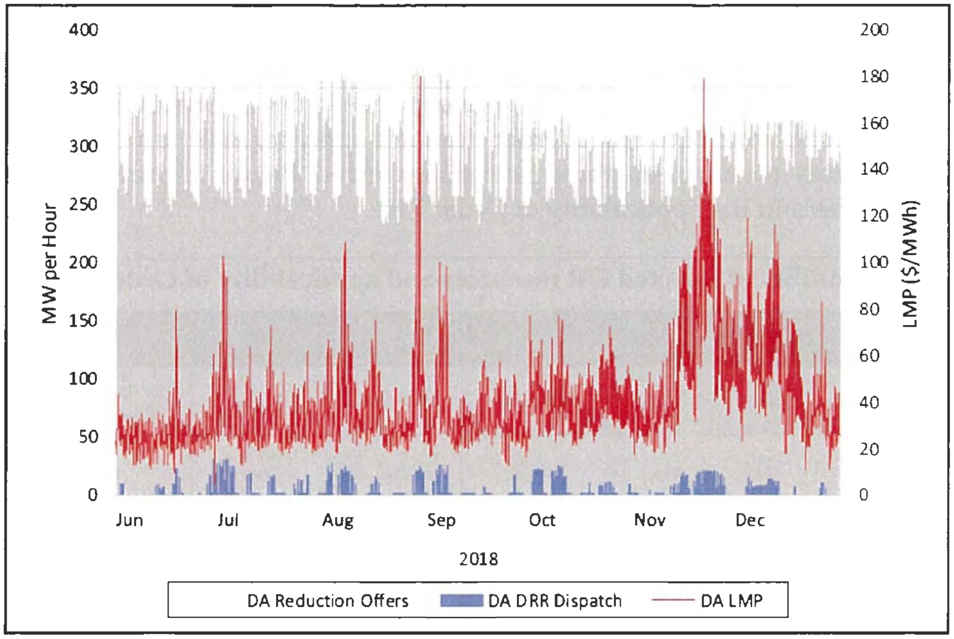
Wholesale electricity prices are dynamic. When retail customers pay for their consumption based on rates that do not reflect volatile potentially higher electricity prices in a given hour, for the hour in which their consumption occurs, this leads to a disconnect. For example, as customers on fixed price retail contracts are not impacted by the wholesale electricity cost for a given hour in which they are consuming, they are not incentivized to reduce consumption in the hours where large wholesale price spikes occur. As this was one of the key issues in the FERC proceeding, this section covers some of the matters around this disconnect. First, context around the retail choice situation in the US prior to the FERC Order is provided in Section 3.3.1. Then, discussion of the disconnect between retail rates and wholesale prices from within Order 745 appears in Section 3.3.2.

3.3.1 Contextual background: Retail choice situation in the US prior to the FERC Order

In the US, FERC's authority is at the wholesale market level (e.g. NYISO, PJM, ISO-NE), while the sale of electricity to end users ("retail") and their associated rates ("retail rates") are outside of FERC's jurisdiction. Retail rate design and retail electricity choice (i.e. allowing end-use customers to buy electricity from competitive retail suppliers instead of a default provider) falls under state-level jurisdiction. The demand response issue therefore creates additional layers of administrative complexity, as it encompasses both the retail and wholesale level.

According to the US Energy Information Administration ("EIA"), in 2010 (the year before FERC Order 745), 17 states and the District of Columbia had adopted electric retail choice programs. As shown in Figure 6, although residential participation in competitive retail (i.e. choosing a retail

Figure 17. DR resource dispatch in day-ahead energy market



Note: According to ISO-NE, real-time energy market dispatch would be similar to the day-ahead dispatch, with the exception of a single capacity scarcity period on September 3rd.
Figures taken directly from: ISO-NE. *2018 Annual Markets Report*. May 23, 2019.

Key takeaways from these programs: ISO-NE

FERC Order 745 only applies to active demand resources. Active demand resources with CSOs have must-offer rules in the energy market, leading most active DR resources to bid into the energy market at or around the offer cap. Actual dispatch of active demand resources is therefore low, and the capacity market remains their main source of revenues. Passive demand resources, which make up the majority of ISO-NE's total demand resources, are not the subject of the FERC Order.

4.4 Cross-cutting analysis

4.4.1 Applicability of Order 745 to the DR resource programs covered

FERC Order 745 relates to DR resources that participate in organized wholesale energy markets (real-time and day-ahead). It applies to those resources that are capable of balancing supply and demand as an alternative to generation through reducing load upon dispatch instructions (received in-market). The FERC Order also discusses that such DR resources must be technically capable of providing ancillary services, and states that it does not apply to DR participating in programs administered for reliability and emergency conditions.

For demand-side resources in the ISO programs LEI reviewed, the FERC Order therefore **only applies to those DR resources that are considered dispatchable from the ISO's perspective.**

These would be DR participating in economic programs run by PJM and NYISO, and active DR in ISO-NE.

The FERC Order **does not apply to DR** participating in ISO programs, **that from the perspective of the ISOs, are considered non-dispatchable**. These include: passive DR in ISO-NE; the SCR and EDRP in NYISO; and the emergency and pre-emergency DR resources in PJM. These 'non-dispatchable' resources, which the FERC Order does not apply to, make up the majority of total demand-side resources in each of the three markets reviewed. Figure 18 provides a summary of the covered programs and the applicability of Order 745.

Figure 18. Dispatchability of selected DR resources and applicability of Order 745

ISO	NYISO				ISO-NE		PJM	
Demand side resource program	SCR	EDRP	DADRP	DSASP	Passive	Active	Emergency/ pre-emergency	Economic
Considered dispatchable by ISO?	No	No	Yes	Yes	No	Yes	No	Yes
Does Order 745 apply?	No	No	Yes	Yes	No	Yes	No	Yes

4.4.2 Instances of Order 745 energy payments as the only source of DR compensation

The question of whether situations occur in which energy payments are the only source of DR compensation can be looked at from the perspective of actual load being dispatched by the respective ISOs, which is what Order 745 is focused on. From this perspective, because dispatch of DRs under any circumstance is infrequent, we can infer that situations when DR only receives an energy payment would be even more rare.

Based on the ISO programs for the US markets reviewed by LEI, and data LEI was able to gather:

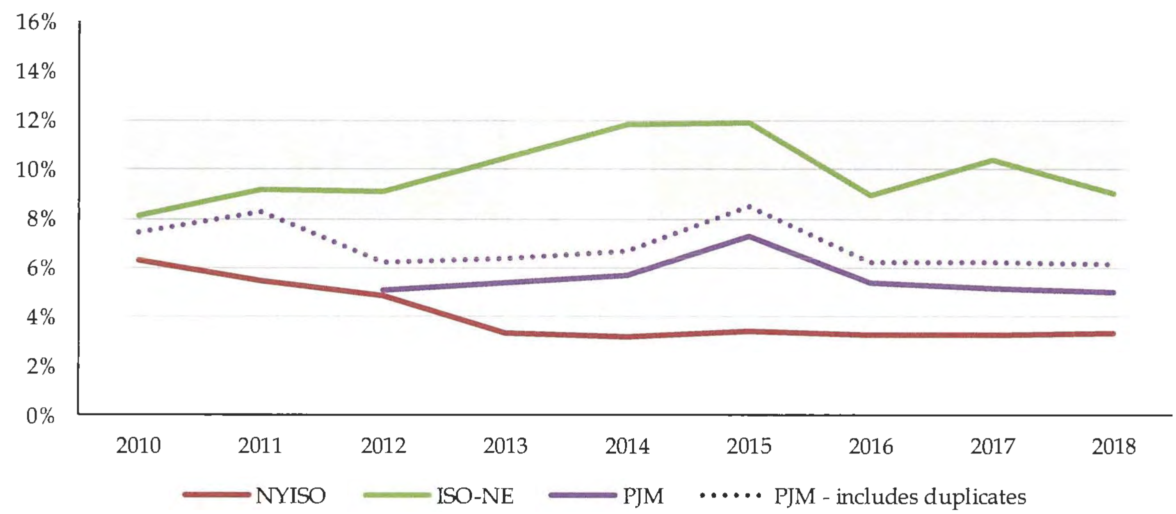
- for NYISO, as stated previously, there has been no bidding activity between 2011 and 2018 (i.e. no offers submitted in the program);
- for ISO-NE, in the 46% of hours when DR was dispatched in the day-ahead market over the June to December 2018 period, it averaged just 7.7 MW per hour (and was not dispatched in the remaining 54% of hours), implying a total DR dispatch of around 18.1 GWh in the day-ahead market over this timeframe (with real-time energy market dispatch generally being similar to day-ahead dispatch according to ISO-NE); [39] and
- in PJM, dispatch (i.e. load reduction) of economic DR in 2018 was around 33.4 GWh in the real-time market and around 15.8 GWh in the day-ahead market (these figures are additive), which is very low as a proportion of total load (791 TWh in 2018). Day-ahead

[39] ISO New England. *2018 Annual Markets Report.* May 23, 2019.

4.4.4 DR resource capacity and revenues relative to the total system

Figure 22 shows total demand response capacity relative to total installed generating capacity in each of the three markets. Total demand response in the three markets has not increased substantially since 2010, and NYISO has seen a noticeable decline in this ratio, due mostly to the drop in SCR capacity as discussed in Section 4.2. Still, DR procured through the various programs covered previously serve an important role through the provision of capacity during scarcity, reliability, and emergency events.

Figure 22. Demand response relative to installed generating capacity

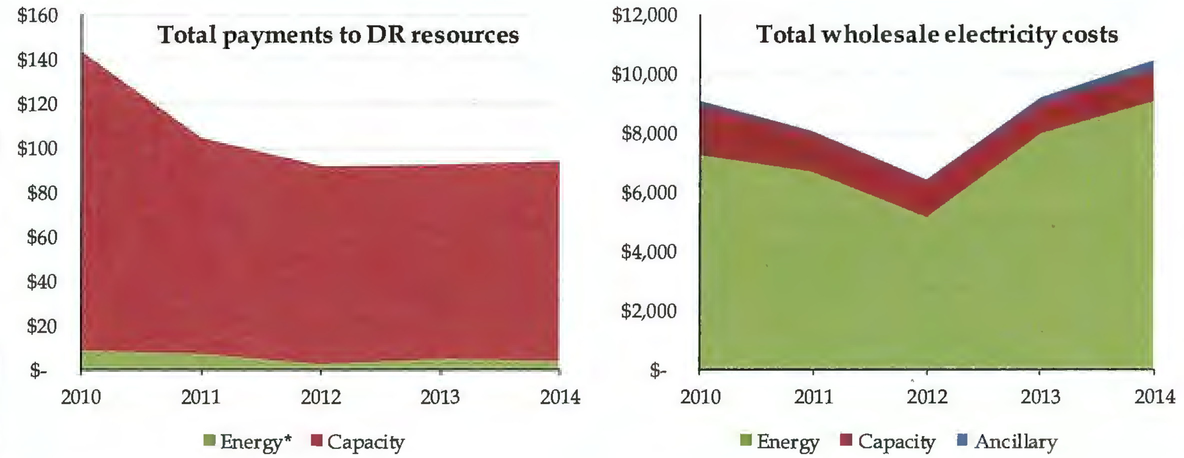


Demand response shown: NYISO shows the sum of EDRP and SCR ICAP; ISO-NE shows sum of active and passive resources with CSOs for commitment periods starting in 2010/2011; for PJM the solid line uses unique DR capacity. As PJM's DR activity reports did not report unique DR capacity for 2010 and 2011, the dotted line uses the sum of economic and emergency DR. This approach double-counts those resources that participate on both the emergency and economic side, but gives a visual indication of the trend over the 2010 to 2018 timeframe.
Installed capacity: NYISO shows summer capacity; ISO-NE shows capacity based on seasonal claimed capability
Sources: ISO-NE's CELT reports, ISO-NE's NEPOOL Participants Committee Reports, NYISO's annual reports on demand response programs, PJM's state of the market reports.

The importance of DR as a capacity resource specifically can be illustrated by looking at the total revenue breakdown between energy and capacity for DR, versus total system costs for energy and capacity. To this end, Figure 23 shows total payments made to demand response resources (consisting of energy and capacity) and total system costs for energy, capacity, and ancillary services in ISO-NE from 2010 to 2014 based on information contained in ISO-NE's Annual Market Reports (annual market reports from 2015 onwards stopped reporting the information on total payments made to demand resources). Similarly, Figure 24 shows payments made to demand response resources (consisting of economic energy, emergency energy, ancillary services, and capacity, as also shown in Figure 21) and total system costs for energy, capacity, and ancillary services in PJM.

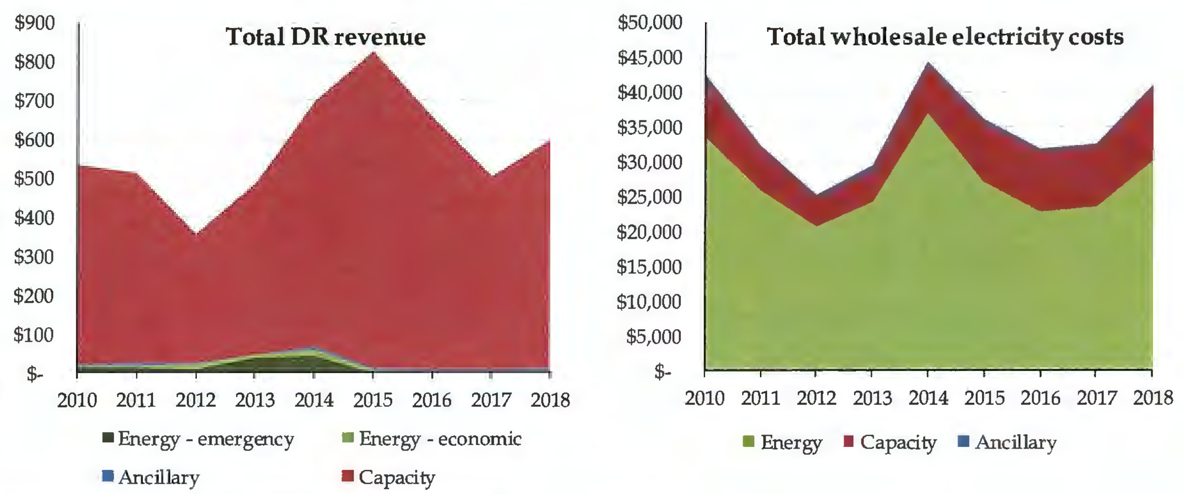
Based on these figures, and as discussed in Section 4.4.3, it is clear that **capacity payments make up the vast majority of compensation for demand response resources**, while payments for their activation or dispatch are a very small proportion of their total revenues (on average 5% of total payments 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

---

[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.

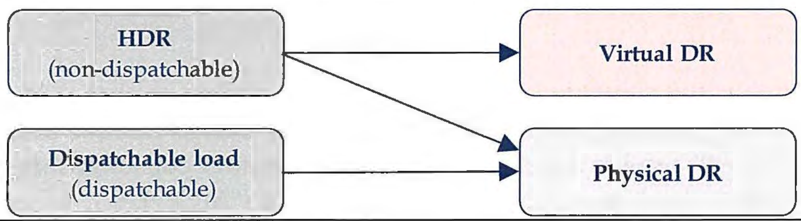
[46] Based on availability window for when the DR resource is expected to be available to provide demand response. The availability window is hours between 12:00 and 21:00 for the summer obligation commitment period, and 16:00 and 21:00 for the winter period, for business days. Sources: IESO. *Introduction 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.

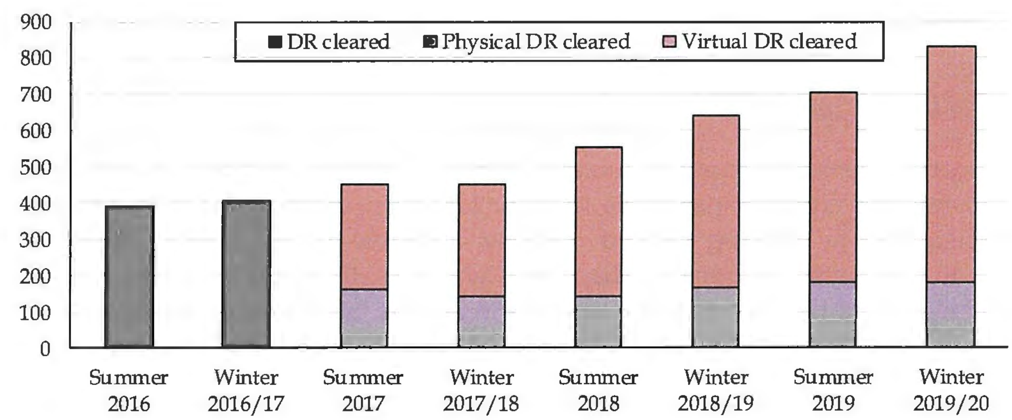
Cleared capacity within the auction is broken down into physical and virtual demand response. Physical DR resources are those that have IESO-registered revenue metering, while virtual DR resources are those that do not. All dispatchable loads are physical resources, and all virtual resources are HDRs, 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'.

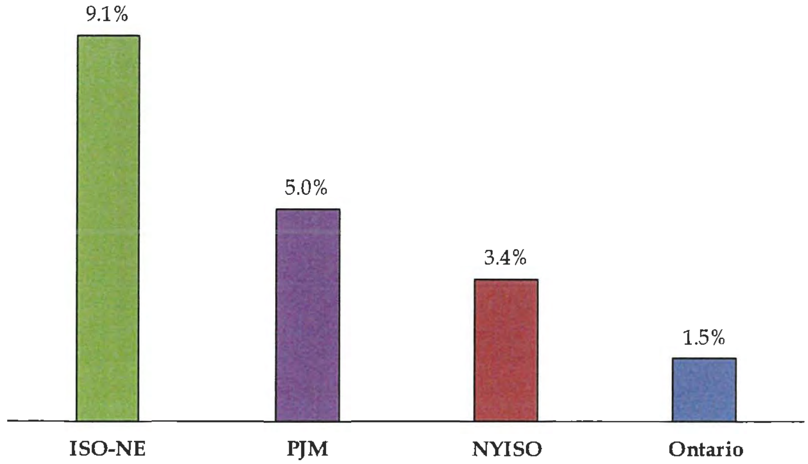
PJM currently has two broad categories of DR resources: economic DR and emergency DR. The economic DR participates in energy markets (real-time and day-ahead) on a voluntary basis, and when it clears the market, it is committed and dispatched by PJM. The reductions achieved through the deployment of 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

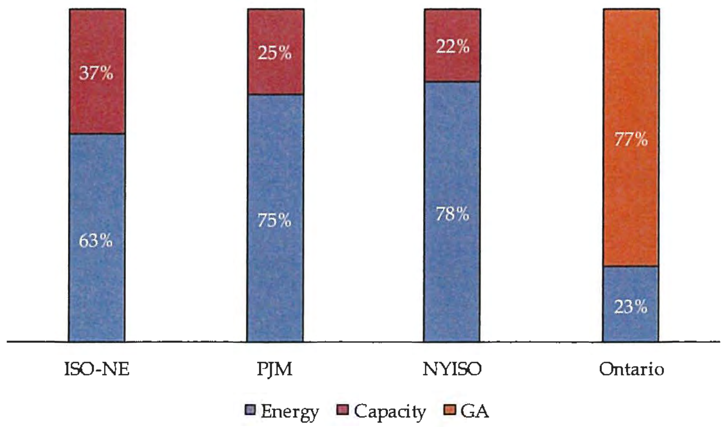
An alternative metric for consideration is DR capacity as a percentage of peak load, which averaged 5.6% across **all** US ISOs and RTOs in 2017 (and is depressed by the lack of DR participation in Southwest Power Pool);[53] again, Ontario is below this average at 2.4% for 2018. Worth re-emphasizing 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.

[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.

TAB 12

LEI responses to interrogatories

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

November 20th, 2019

Table of contents

Table of figures

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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.

1.6 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.

TAB 13

NAVIGANT

Demand Response Discussion Paper

Utilization Payments

Prepared for:

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Connecting Today.
Powering Tomorrow.

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December 18, 2017

1. INTRODUCTION

This paper was drafted to provide context and research on utilization payments and inform a dialogue on their possible merits to drive additional, economically efficient, curtailment of loads to meet a variety of electricity system needs. This discussion paper includes a review of practices in other jurisdictions, arguments for and against providing a utilization payment to demand response (DR) resources, a qualitative assessment of the potential impact of utilization payments on the dispatch frequency of DR resources in Ontario, and a qualitative assessment of the effect of any changes in payment structure on the wider market. ***This paper focuses solely on economic (i.e. energy) and reliability (i.e. capacity) DR that is linked to an organized wholesale power market and the question of economic efficiency relative to the status quo in Ontario.***

There is disagreement about the efficiency and fairness of allowing a single DR resource to capture both energy (utilization) and capacity (availability) payment streams.[1] At the broadest level, proponents of both payments for load resources argue that calling on a DR resource to curtail provides incremental value to the power system, and these load reductions should be compensated through utilization payments much like a generation resource participating in both capacity and energy markets. Opponents argue that the availability payment adequately compensates a DR resource for providing capacity and that utilization payments are a form of double payment as the DR provider receives a benefit in terms of its avoided cost of electricity when it is utilized. This paper will discuss these and other arguments for and against both availability and utilization payments.

DR has been part of the Ontario electricity system since the early 2000s. Dispatchable load resources were active in the IESO-administered market since the market open in 2002. In 2007, the IESO (former OPA) recognized that there was capacity value from demand-side resources and started the DR3 program. DR resources were procured through multi-year standard offer contracts in the DR3 program. The DR3 program included availability payments and utilization payments. In December 2015, the DR programs were integrated into the IESO-administered wholesale power market with the advent of the DR auction.

The DR auction procures DR resources as reliability/capacity resources. Participants offer into two seasonal DR auctions. Participants who clear the auction are required to be available to the IESO to meet peak demand. As part of this, they have a requirement to bid into the real-time energy market between a price floor of $100 and price ceiling of $1999.99 for each business day during the season. A DR resource is dispatched through the IESO's security constrained dispatch algorithm and is curtailed when economic in the seasonal activation window. Availability payments are made to DR resources that clear in the DR auction regardless of how often they are dispatched to curtail. DR resources participating in the DR auction do not receive an additional utilization payment when they are dispatched.

For some wholesale customers, the opportunity cost of curtailing load in any individual hour is higher than the IESO ceiling price. They participate in the market mainly to receive capacity payments. The main impact of this dynamic is that DR resources in Ontario tend to bid into the energy market at the ceiling price to minimize their utilization and are seldom called upon to curtail.

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[1] DR also participates in ancillary service markets in a number of jurisdictions, however, the use of utilization payments in these markets is widely accepted and outside the scope of this report.

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

3. ECONOMIC EFFICIENCY ARGUMENTS

This section presents the arguments for and against providing utilization payments to DR resources.

3.1 Against Activation Payments in Ontario

3.1.1 Wholesale Price Efficiency

The argument is as follows. Real-time wholesale energy prices are an efficient price signal because they match supply and demand based on bids and offers on a minute-by-minute, hour-by-hour basis.

When price responsive loads are exposed to real-time wholesale electricity prices they assess whether it is more cost effective for them to operate or curtail based on the real-time price signal. During high-price events a customer can choose to curtail and save the cost of electricity. This provides an economically efficient incentive to reduce consumption when prices are higher than a customer is willing to pay.

For example, large industrial customers such as pulp and paper pay for electricity based on the wholesale electricity price. These customers can determine on an on-going basis if it is more economically efficient for them to continue operating and producing pulp and paper given the required input costs of electricity than it would be to stop production leading to loss of production revenues but savings in electricity costs.

<u>Considerations for Ontario:</u> This argument only applies to loads that receive the wholesale energy price. Many large commercial and industrial customers in Ontario are already exposed to wholesale energy prices. These customers are already price responsive. They can determine based on real-time energy prices if it is more cost effective from them to operate or to curtail. These customers would not need an additional payment to be incented to curtail when they are needed by the system. There are some customers in Ontario who are not exposed to the wholesale electricity price. These customers are not exposed to price spikes that occur in the wholesale electricity prices. Since they aren't exposed to the price spikes they are not receiving the signal to curtail when needed by the system. The wholesale price efficiency argument is not relevant in those cases. In Ontario, 58% of the total load is exposed to the market price[6].

3.1.2 Disproportional Benefits

The argument is as follows. Providing a utilization payment compensates a DR resource disproportionally relative to a supply resource, because the DR resource did not incur a cost associated with the production of electricity. Under this argument, 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 a premise that a megawatt of electricity curtailed (negawatt) is not economically equivalent to producing a megawatt of electricity. This was the argument put forward by a group of economists in support of the Electric Power Supply Association's petition to US Court of Appeals

[6] http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170817-presentation.pdf?la=en

to overturn FERC Order No. 745.[7] This argument was supported by FERC Commissioner Philip D. Moeller, who argued that paying demand response resources full LMP overcompensates those resources because in addition to any incentive payments received, those resources also receive the benefit of not paying the cost of retail energy consumption that they otherwise would have incurred[8].

The underlying factor of this argument is the claim that DR is not a resource in the same way that generation is. A generating resource is providing a product and is paid for that. Opponents of DR utilization payments argue that since DR does not own the power they are not consuming, they should not be paid additionally for not consuming it. Despite this argument, FERC's final 745 ruling[9] was based on the premise that negawatts and megawatts are functionally and economically equivalent.

Considerations for Ontario: This argument is based on a premise that a megawatt of electricity curtailed (negawatt) is not equivalent to a megawatt of electricity. The argument assumes the cost of curtailment (or the value of lost load) for a DR resource is immaterial. Whether the disproportional benefits argument is considered valid in Ontario depends on whether this premise accepted.

3.1.3 Harm to Other Suppliers

The argument is as follows. Utilization payments can lead to greater levels of activation that put downward pressure on wholesale energy prices and negatively impact the profitability of other supply resources.

While initially a benefit to consumers, the argument is that this practice has the potential to harm suppliers in the long term to a point where existing or new generators, required to maintain system reliability, are not able to operate economically. This argument is based on the concept of dynamic efficiency.

The argument is that if more DR resources bid into the market at prices lower than traditional generation they will be dispatched rather than the generation. This is because the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high. This may make it difficult for the generators to recover their costs and ultimately to continue operating. In practice, the impact of providing a utilization payment has not been significant enough to affect generators ability to recover their costs.

Some FERC 745 commenters assert that a power system can function solely and reliably on generating plants and without any reliance on demand response, while the system cannot rely exclusively on demand response because demand response by itself cannot keep the lights on[10].

Considerations for Ontario: To have a material impact on energy prices, utilization payments would have to result in a considerable increase in activation. Also, under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence have a high degree of revenue or price certainty.

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

8 https://www.cleanenergylawreport.com/energy-regulatory/federal-appeals-court-vacates-ferc-order-no-745-on-demand-response-compensation/

9 https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

10 https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

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.

Considerations for Ontario: 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.

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[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

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[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.

TAB 14

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

Ontario

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2014 – April 2015

May 2016

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Table of Contents

List of Tables

List of Figures

amendment to accommodate other priorities, and that it would provide another update once new implementation timelines are established.[69]

4 New Market Mechanisms to Procure Capacity

The IESO is planning to introduce new market mechanisms for procuring additional capacity to meet future system needs. Over the course of 2015, the IESO has advanced initiatives in this direction: capacity auctions for demand response (DR), as a first stage in the development of capacity auctions for other resources, and the consideration of capacity exports to other jurisdictions.

The IESO held its first capacity auction for DR in December 2015 for delivery starting in the summer of 2016. This first auction had a target of 367 MW, equal to the capacity expiring from the IESO's current DR programs. The outcome of the auction was the award of DR capacity to seven of the seventeen registered participants, for 391.5 MW of capacity at a price of \$378.21/MW-day in the summer (May 1 to October 31) and 403.7 MW of capacity at a price of \$359.87/MW-day in the winter (November 1 to April 30).[70]

The IESO plans to hold DR auctions once each year to procure capacity for two six-month commitment periods— summer and winter. Registered DR auction participants will bid their capacity and the availability payment they will accept, and the IESO will clear the market (in several zones across the province) with a downward sloping demand curve for each commitment period.

Participants who clear the auction will be required to offer into the real-time market as DR resources, and will receive a monthly availability payment equal to their capacity times the clearing price times the number of business days in the month. Participants who respond to the dispatch will save the energy costs when they are activated to provide DR. Activations of these DR resources is expected to reduce peak demand.

The DR capacity auction is intended to be the first phase of the IESO's efforts to introduce capacity markets for all resources. The IESO conducted several information sessions on this

[69] For more information see the IESO's October 9, 2015 stakeholder communication, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20151109-Communication.pdf
[70] For more information see the IESO's Demand Response Auction webpage, available at: http://www.ieso.ca/Pages/Participate/Demand-Response-Auction/default.aspx

topic over the course of 2014, and published details of design elements in a September 18, 2014 Discussion Paper.[71] The Discussion Paper describes the role of a capacity auction as enabling "all resources to compete on a frequent basis to meet the province's future incremental resource adequacy needs". Although the IESO has not committed to firm implementation timelines for the capacity auction, the development of detailed design elements and the launch of the DR auction have set the groundwork for further market development in this area.

In November 2010, the Minister directed the IESO (then the Ontario Power Authority) to enter into negotiations with non-utility generators (NUGs) for new contracts. In December 2014, in light of changing supply conditions, the Minister directed the IESO (then the Ontario Power Authority) to suspend any pending negotiations with NUGs and prepare an assessment of the framework for NUG recontracting in the Province, having regard to a number of considerations including the IESO's work to develop a capacity auction in Ontario. The IESO's September 1, 2015 report to the Minister of Energy recommended that the current pause on recontracting with the NUGs be continued given the current strong supply outlook and pending clarification of evolving sector conditions.[72] The IESO identified the continued operation of the Pickering nuclear generating station, the development of the capacity auction and capacity export opportunities, and the introduction of cap-and-trade legislation as potential changes in the sector that would have a bearing on recontracting efforts. The IESO also recommended that the development of the capacity auction and capacity export markets be continued with consideration given to facilitating broad participation, including by the NUGs, as a more effective means of meeting future resource needs. By letter dated December 14, 2015, the Minister of Energy directed the IESO to discontinue negotiations for new contracts for NUGs and to continue engaging stakeholders in the IESO's development of an Ontario capacity auction and rules and protocols for Ontario-based capacity exports.[73]

Capacity markets in some other jurisdictions accept exports of capacity from neighbouring jurisdictions. Beginning in 2015, the IESO opened a stakeholder engagement on the subject of

[71] For more information see the IESO's September 18, 2014 Discussion Paper, available at: http://www.ieso.ca/Documents/consult/capacity-20140918-Design_Element_Discussion_Paper_Agenda.pdf
[72] For more information see the IESO's NUG Framework Assessment report, available at: http://www.ieso.ca/Documents/generation-procurement/NUG-Framework-Assessment-Report.pdf
[73] For more information on the Minister of Energy's December 14, 2015 Directive, see: http://www.ieso.ca/Documents/Ministerial-Directives/2051214-Directive-NUG_CHPSOP_ChaudiereFalls_WhitesandFirstNation.pdf.

capacity exports. This IESO continues to work towards establishing the market need for such a program, assessing the feasibility and timeline of implementation, and continues to engage with stakeholders.[74]

5 Developments Relating to Ontario's Interconnections

Several developments during this reporting period have had or will have an impact on the IESO's interconnections with other jurisdictions. These include a seasonal electricity capacity sharing agreement with Québec, discussions around enhancing trade in electricity products with Québec and Newfoundland and Labrador, and ongoing developments in the proposed interconnection between the Ontario and parts of the United States that fall within the jurisdiction of PJM.[75]

The capacity sharing agreement between the IESO and Hydro Québec Energy Marketing is in force from December 1, 2015 to September 30, 2025.[76] Ontario has an initial two year obligation to provide 500 MW to Québec during the first two winter periods (December to March), with an option to reduce the quantity after that time. Ontario may elect to receive up to 500 MW from Québec in any given summer period (June to September). Québec's obligation is to "repay in kind the equivalent amount of capacity it received in the winter periods to Ontario in the summer periods." The capacity is to be shared "like for like", with no monetary exchange. The jurisdiction receiving the power must make a "Reliability Declaration", which in Ontario will be made when there is a shortfall in the market. If Hydro Québec makes a Reliability Declaration, it will be responsible for scheduling an export transaction in the IESO-administered market, which will clear based on the economics of the bid.[77]

The IESO is also planning to study and provide reports on expanding trade in electricity between Ontario and Québec, and between Ontario and Newfoundland and Labrador. This is in response to the April 22, 2015 direction from the Minister of Energy to investigate "other opportunities to obtain electricity products from Hydro-Québec, and other Market Participants, where the

[74] For more information, see the IESO's stakeholder engagement webpage at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Capacity-Exports.aspx.

[75] PJM is a regional transmission operator that coordinates the movement of wholesale electricity in the USA in all or parts of 13 states and the District of Columbia. For more information on PJM, see: http://www.pjm.com/.

[76] For more information see the IESO's summary of the agreement, available at: http://www.ieso.ca/Documents/corp/Summary-Capacity-Sharing-Agreement-Ontario-Quebec.pdf

[77] For more information see the IESO's backgrounder, available at: http://www.ieso.ca/Documents/Ontario-Quebec-Capacity-Sharing-Agreement-Backgrounder-20151112.pdf

TAB 15

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

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Table of Contents

List of Tables

List of Figures

other jurisdictions have developed objective and open processes for assessing these competing priorities. A similar approach should be considered in Ontario.

Matters to Report in the Ontario Electricity Marketplace

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. 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.

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. DR 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 by uplift charges.

The resources procured through the DR auction are intended to help meet the Ministry of Energy's conservation policy goals. However, for the reasons explained in detail in Chapter 4 of this Report, 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.

Having said that, the Panel also questions the need for peak shaving DR capacity at this time as Ontario has sufficient resources to meet peak demand in the province for the foreseeable future.

<u>Recommendation 4-2:</u>

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

The Panel expands on the interdependencies between each component of the TR Clearing Account from section 3.1.1 to section 3.1.2 of Chapter 4.

Table 2-6: Demand Response Auction Results in December 2015 (MW, $/MW-day)

Description

Table 1-6 summarizes the results of the IESO's inaugural Demand Response (DR) Auction, completed in December 2015 for the subsequent summer (May 1, 2016 to October 31, 2016) and winter (November 1, 2016 – April 30, 2017) commitment periods. In general, DR consists of programs that encourage customers to reduce demand during times of tight supply conditions. DR is meant to reduce the total peak demand, or be used at other times to assist with maintaining reliability, as an alternative to calling on generators to produce more energy. As specified by the capacity obligation within each zone, resources committed through the DR auction are available to provide relief by reducing their consumption when called upon. Successful resources from the DR auction receive the auction clearing price for each MW of DR capacity.[36]

Zone	Summer Commitment Period (May 1, 2016 - Oct 31, 2016)		Winter Commitment Period (Nov 1, 2016 - Apr 30, 2017)	
	Capacity Obligation (MW)	Auction Clearing Price ($/MW-day)	Capacity Obligation (MW)	Auction Clearing Price ($/MW-day)
BRUCE	-	-	-	-
EAST	24.7	378.21	25.4	359.87
ESSA	13.7	378.21	13.8	359.87
NIAGARA	15.9	348.45	15.9	332.71
NORTHEAST	56.3	378.21	56.3	359.87
NORTHWEST	51	378.21	50	359.87
OTTAWA	10.8	378.21	11.2	359.87
SOUTHWEST	40	378.21	55.3	359.87
TORONTO	159.4	378.21	159.2	359.87
WEST	19.7	378.21	16.6	359.87
Total MW	**391.5**	-	**403.7**	-
Weighted Average Price	-	**377.00**	-	**358.80**

[36] See Chapter 3 for an in-depth explanation of the DR auction process.

Relevance

The DR Auction is part of the IESO's transitional program to migrate the procurement of demand response from previous multi-year, contracted programs into a more competitive, near-term market mechanism within the IESO-administered markets. Instituting the DR Auction is viewed by the IESO as a foundational step to introduce a market-based mechanism to procure capacity, with the aim to allow for the entry of new, cost-effective demand response providers, enable system flexibility, and evolve the demand response sector to eventually compete with conventional forms of capacity such as supply or import resources. The DR Auction is also one of the key instruments the IESO is using to work towards the policy goal set forth in the 2013 Long Term Energy Plan of reducing peak demand by 10% in 2025.

Commentary

As Ontario has 10 electrical zones with varying supply and demand conditions, the auction took place on a zonal level by creating limits for the amount of DR procured in each zone. Zones with more generation than load would require less DR, while zones with more load than generation can have DR playing a greater role in matching supply and demand. For these reasons, Toronto was the zone with the greatest capacity obligation, holding 40.7% and 39.4% of the total capacity obligation in the summer and winter commitment periods, respectively. There was no cleared capacity in Bruce because no participant submitted offers into the auction. See section 3.2 of Chapter 4 for an in-depth discussion of the DR auction.

2 *Demand*

This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

Figure 2-20: Monthly Ontario Energy Demand
May 2011 – April 2016
(TWh)

Description:

Figure 2-20 presents energy consumption by all Ontario consumers in each month in the past 5 years. The figure represents Ontario demand, which includes demand satisfied by behind-the-meter (embedded) generators.

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.

[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

TAB 16

October 25, 2019

IESO Stakeholder Engagement

Submitted via email

Re: AMPCO Submission – Energy Payments for Economic Activation of DR

AMPCO is the voice of industrial power users in Ontario. Our goal is industrial electricity rates that are competitive and fair.

Attached is AMPCO's submission made in response to the call for input as part of the newly constituted stakeholder engagement dealing with Energy Payments for Economic Activation of Demand Response as part of the IESO's Capacity Auction (formerly known as the Transitional Capacity Auction, and so referenced within this submission for consistency and clarity).

AMPCO appreciates the opportunity to provide such a submission, and looks forward to continuing the dialogue.

Best Regards,

[Original signed by]

Colin Anderson
President

Energy Payments for Economic Activation of DR:

Submissions of the Association of Major Power Consumers in Ontario (AMPCO)

INTRODUCTION

Ontario's electricity system is complex and always evolving. AMPCO provides Ontario industries with effective advocacy on critical electricity policies, timely market analysis and expertise on regulatory matters that affect their bottom line.

These submissions are made in response to the call for feedback issued by the IESO at its October 10 stakeholder session (Energy Payments for Economic Activation of Demand Response Resources). AMPCO's members are major power consumers, responsible for over 15 TWh of annual load in the province. A reliable and affordable energy supply is critical to the success of their businesses, which is why AMPCO has an interest in these discussions and in these discussions.

AMPCO appreciates the opportunity to provide this feedback and looks forward to continued discussions on this topic.

SUMMARY

AMPCO supports energy payments for economic activation of Demand Response. This has been well documented in AMPCO's previous 2019 submissions to the IESO made on March 27, May 2, June 5, July 5, July 9 and July 19 (jointly with AEMA). AMPCO will not reiterate those same comments and arguments here.

However, the pace of the stakeholder consultation constituted to directly address this issue does not match the IESO's speed for the movement of the remainder of the TCA project. Where the TCA project is aggressively moving towards the first auction in December of 2019, the consultation appears to be taking a leisurely stroll, content to revisit previously decided matters and to include within its scope tangential issues that are likely not required to advance the discussions at a reasonable rate.

Accordingly, AMPCO suggests that the IESO more narrowly scope the consultation to deal with ***how*** to implement energy payments (consistent with almost all other FERC and non-FERC jurisdictions, as reported by Navigant in the December 18, 2017 discussion paper commissioned by the IESO)[1], rather than ***if*** to pay them. The consultation could be dramatically streamlined by abandoning the exhaustive review of the FERC decision and all the evidence and argument brought to bear in that exercise, and simply accepting the decision and adjusting it for the relevant Ontario context. It should be remembered that this entire issue was thoroughly debated in front of and decided by the FERC in 2011[2], and the resulting decision upheld by the Supreme Court of the United States in 2016[3]. It seems unlikely that the IESO, in its stakeholder consultation, will do a more comprehensive job than was done by the FERC.

SPECIFIC COMMENTS ON THE OCTOBER 10 STAKEHOLDER SESSION

1. Proposed Problem Statement

   The proposed problem statement is too broad, for the reasons set out above. AMPCO suggests the following:

   "When Demand Response resources are economically activated, they will be compensated for the service provided to the energy market at the market price for energy, provided they have the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response

[1] http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Energy-Payments-for-Economic-Activation-of-DR-Resources
[2] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf
[3] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf

resource is cost-effective as determined by the net benefits test. How should a net-benefits test be constructed in Ontario to ensure cost-effectiveness?"

2. Proposed Criteria

The IESO has proposed the following criteria to guide the decision framework:

"Is there an overall net benefit to consumers over the long term?"

In AMPCO's submission, this is inadequate. The criteria dealing with the net-benefits test should be framed consistent with FERC Order 745. If the problem statement is modified consistent with AMPCO's recommendation above, no other criterion is necessary. However, if the scope of this consultation is maintained in its current broad form, then an additional criterion is required ensuring that the treatment afforded Demand Response resources pursuant to the TCA, or any other capacity auction, is fair and non-discriminatory in nature.

3. Scope of Research and Analysis

The scope of the research and analysis should be revised to reflect the recommended problem statement. Many of the items shown in the IESO's October 10 presentation materials (at slides 23 and 24) are unnecessary if the scope of the consultation is narrowed. Many of these items will already have been considered pursuant to the FERC proceeding, and other engagements such as the Navigant discussion paper dated December 18, 2017.

There is no need to reinvent the wheel in this consultation, and by streamlining the problem statement, the criteria and the scope of the analysis, a conclusion can be reached in a much more timely fashion.

TAB 17

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.

TAB 18

Demand Response Working Group Meeting Materials

Demand Response Working Group

June 19, 2019

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Cost Recovery for Out-of-Market Activation of Hourly DR Resources - Proposal

Demand Response Working Group

June 19, 2019

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Purpose

- Discuss a proposal to provide HDR resources cost recovery for out-of-market activations (i.e. testing or emergency activations) consistent with treatment of other resource types

HDR Activations

- There are two ways an HDR resource can be activated

In-Market

- Based on market economics
- HDR energy bids intended to reflect the maximum they are willing to consume at given price
- HDR will be "activated" when the price for electricity is greater than their willingness to consume

Out of Market

- HDR resources can be activated outside of market economics to respond to a:
  1. Capacity test, or
  2. Emergency Control Action
- HDR will be activated even if the electricity price is lower than their bid price

- Observed bid prices and stakeholder feedback indicate that activation costs (explicit and opportunity) can be significant for HDR resources

Out Of Market Costs

- When other resource types (dispatchable load, generator, import) are dispatched out-of-market they are eligible for some form of "make-whole-payment"
  - A make-whole payment may apply when a participant faces a shortfall between their resource bid/offer price and the revenue earned through market clearing prices
  - The payment restores the participant to the financial situation they would have been in as implied by their bids/offers
- HDR resources do not receive a make-whole payment for out of market activations
- These costs may be reflected in their capacity offers potentially increasing the cost of the capacity

Implications for ICA and TCA Participation

- In the Demand Response Auction, HDR participants could reflect the expected cost of out-of-market activations in DR Auction offer prices
  - Since the DR Auction was for DR only, all HDR resources were impacted equally
- 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

Proposal

- IESO's initial assessment concludes that providing HDR resources cost recovery for out-of-market activations is:
  - appropriate as testing or emergency activations can occur at a price below bid price of an HDR
  - consistent with energy market and existing design treatment of other resources (including dispatchable load)

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Potential Design Considerations/Issues

IESO requests feedback from stakeholders on potential design considerations, including:

- Most appropriate method for determining compensation; for example:
  - Using energy bids as representative costs
  - Historical precedents, such as CBDR activation payments
  - Identify costs on individual or type of resource basis
- Undue administrative burden of potential options
- Operational impacts on market participants, for example measurement data requirements
- Other considerations that should be assessed

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Next Steps/Timelines

- Stakeholders to provide feedback on concept and design considerations by July 5
- Work with stakeholders on design details of this concept and initiate market rule amendment process during Q3, 2019
- Timeline
  - Implement changes for May 2020 TCA obligation period to enable DR participants to incorporate change to offers in December TCA

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ONTARIO ENERGY BOARD

EB-2019-0242

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

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

COMPENDIUM OF EVIDENCE FOR THE FINAL ARGUMENT OF THE IESO

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