Association of Major Power Consumers of Ontario

OEB Staff Cross-Examination Compendium

Panel 4 – Dr. Brian Rivard

EB-2019-0242

November 28, 2019

OEB Staff Compendium for EB-2019-0242 Oral Hearing

Index

TAB 1

Market Rules

Chapter 7
System Operations and Physical Markets - Appendices

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Public

Issue Date: March 1, 2017

g. *period of steady operation*; and

h. forecasts of *energy* for the *facilities* of *variable generators* that are *registered market participants* produced by the *forecasting entity*.

2.2.1.16 imports or exports between the *IESO-control area* and other control areas required by the *IESO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* including but not limited to inadvertent *intertie* flows and simultaneous activation of reserve. These shall be represented as an increase or decrease in *non-dispatchable load*.

2.3 Optimisation Objective

2.3.1 The *dispatch* scheduling and pricing process shall be a mathematical optimisation algorithm that will determine optimal schedules for each time period referred to in section 2.1.1, given the *bids* and *offers* submitted and applicable constraints on the use of the *IESO-controlled grid*. Marginal cost-based prices shall also be produced and, for such purpose, *offer* prices shall be assumed to represent the actual costs of suppliers and *bid* prices shall be assumed to represent the actual benefits of consumption by *dispatchable load facilities*.

2.3.2 The *dispatch* scheduling and pricing process shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as described in sections 4.3.2 and 4.3.3 of Chapter 7.

2.3.3 In respect of the *real time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall have as its objective function maximizing the weighted sum of the economic gain from trade among *market participants*, as described in section 4.3.2 and 4.3.3 of Chapter 7, for the *dispatch interval* and for advisory intervals within the study period. Critical intervals are those selected from the study period to be used as input to the objective function. The first critical interval is always the *dispatch interval*. The remaining critical intervals are advisory intervals.

2.4 The IESO-Controlled Grid

2.4.1 The *dispatch* scheduling and pricing process shall represent power flow relationships between locations on the *IESO-controlled grid* and between the *IESO control area* and adjoining *control areas*.

TAB 2

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MR. MONDROW: Thank you, Mr. Anderson.

And one final topic from Dr. Rivard's evidence. He discusses the industrial conservation incentive program. I think that is referred to commonly as the ICI program. And I would like you to, if you could, open Dr. Rivard's evidence and turn to paragraph 52, and Madam Chair, this is Dr. Rivard's report. It is dated November 8th, 2019. It was revised and refiled on November 21st, 2019, and obviously Dr. Rivard will speak to that. That may be the appropriate time to give it an exhibit number, but Mr. Anderson did want to comment on one passage from that evidence. It is page 29, paragraph 52.

MR. ANDERSON: Yes, thank you for that. I believe --

MR. MONDROW: Sorry, it is actually over at the top -- just for the record, Mr. Anderson, it is -- paragraph 52 continues on page 29, and I just want to orient us with the passage.

The passage reads, at the top of page 29 -- it is the third -- second full sentence, and it reads:

> "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."

TAB 3

LEI responses to interrogatories

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

November 20th, 2019

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London Economics International LLC
390 Bay Street, Suite 1702
Toronto, ON M5H 2Y2
www.londoneconomics.com

contact:
AJ Goulding/Adam Hariri
416-643-6617
adam@londoneconomics.com

1.4 KCLP-4

Interrogatory

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

Rivard Affidavit, Paragraphs 56-58

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

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

Questions:

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

Response

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

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

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

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

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

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

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

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

TAB 4

OEB STAFF INTERROGATORY 4

INTERROGATORY

Please provide the following data about the participation of various demand response provider categories in the Demand Response Auction and Real Time Energy Market.

HDR Participants	• Number of Participants • Total MW Capacity for this group • Average hourly consumption for both 2018-2019 Commitment Periods* • Average hourly consumption for High 5 Hours in 2018	• Number of Participants • Total MW Capacity for this group • Average hourly consumption for both 2018-2019 Commitment Periods* • Average hourly consumption for High 5 Hours in 2018
Dispatchable Load Participants	Same Information as above	Same Information as above

* Average hourly consumption is to be defined as Total MWh consumed in all availability window hours for the 2018 Summer Commitment period and the 2018-2019 winter commitment period, divided by the total number of hours in those two commitment periods.

RESPONSE

The IESO has made best efforts to present the data in the format requested. Note that HDR participants can be physical or virtual resources; physical resources are wholesale revenue metered by the IESO and virtual resources are not. Virtual HDR resources meet their capacity obligations through a portfolio of contributors. Virtual HDR resources are not classified as Class A or Class B consumers, and thus are excluded from the data table. Therefore, the data table shows only the HDR participants with physical capacity obligations. Please note that this categorization does not apply to dispatchable loads, which are all physical resources.

	Class A	Class B
HDR Participants	Number: 2 Total MW Capacity for this Group: 31.4 MW (summer and winter) Average Hourly Consumption for both 2018-2019 Commitment Periods*: 19.8 MWh Average Hourly Consumption for High 5 Hours in 2018: 63.1 MWh	Number: 0 Total MW Capacity: 0 Average Hourly Consumption for both 2018-2019 Commitment Periods*: n/a Average Hourly Consumption for High 5 Hours in 2018: n/a
Dispatchable Load Participants	Number: 3 Total MW Capacity: 112 MW (summer) 137 MW (winter) Average Hourly Consumption for both 2018-2019 Commitment Periods: 31 MWh Average Hourly Consumption for High 5 Hours in 2018: 72.9 MWh	Number: 0 Total MW Capacity: 0 Average Hourly Consumption for both 2018-2019 Commitment Periods*: n/a Average Hourly Consumption for High 5 Hours in 2018: n/a

*Where average hourly consumption is defined as per OEB Staff 4

TAB 5

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Demand Response Auction: Post-Auction Summary Report

Created at May 03, 2019 13:24:13

DR Auction Results

Zone	Summer Commitment Period (May 01, 2018 - Oct 31, 2018)			Winter Commitment Period (Nov 01, 2018 - Apr 30, 2019)		
	Physical DR Cleared (MW)	Virtual DR Cleared (MW)	Auction Clearing Price ($/MW-day)	Physical DR Cleared (MW)	Virtual DR Cleared (MW)	Auction Clearing Price ($/MW-day)
EAST	-	57.5	318.01	-	71.2	317.46
ESSA	-	13.2	318.01	-	21.4	317.46
NIAGARA	-	20.2	318.01	-	20.2	317.46
NORTHEAST	40	26.2	200	40	26.2	200
NORTHWEST	29	1	318.01	29	0	317.46
OTTAWA	-	23.3	318.01	25	24	317.46
SOUTHWEST	2.4	74.1	318.01	2.4	121.8	317.46
TORONTO	72	151.7	318.01	72	146.9	317.46
WEST	-	39.8	318.01	-	40.3	317.46
Ontario Total	143.4	407		168.4	472	

DR Auction Results - Participant Details

ZONE	Demand Response Auction Participant	Summer Commitment Period (May 01, 2018 - Oct 31, 2018)	Winter Commitment Period (Nov 01, 2018 - Apr 30, 2019)
		Cleared DR (MW)	Cleared DR (MW)
EAST	ENEL X CANADA LTD.	26.7	29.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	5.4	4.6
	RODAN ENERGY SOLUTIONS INC	25.4	37.4
ESSA	ENEL X CANADA LTD.	5.7	9
	GC PROJECT LP	2.5	2.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	2.2	2.1
	RODAN ENERGY SOLUTIONS INC	2.8	8.1
NIAGARA	ENEL X CANADA LTD.	16.7	14.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1	1
	RODAN ENERGY SOLUTIONS INC	2.5	5
NORTHEAST	ENEL X CANADA LTD.	1.7	-
	RODAN ENERGY SOLUTIONS INC	24.5	26.2
	TEMBEC ENTERPRISES INC.	40	40
NORTHWEST	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1	0
	RESOLUTE FP CANADA INC.	29	29
OTTAWA	ENEL X CANADA LTD.	5.4	4.9
	GC PROJECT LP	1.1	1
	IVACO ROLLING MILLS 2004 L.P.	-	25
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1.8	1
	RODAN ENERGY SOLUTIONS INC	15	17.1
SOUTHWEST	ENEL X CANADA LTD.	35	31.8
	GC PROJECT LP	3.4	3
	GERDAU AMERISTEEL CORPORATION -CAMBRIDGE	2.4	2.4
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	14.3	46.5
	NRSTOR C&I L.P.	-	4.5
	RODAN ENERGY SOLUTIONS INC	21.4	36
TORONTO	ALECTRA UTILITIES CORPORATION	1	-
	AMP SOLAR GROUP INC.	-	0
	EMERA ENERGY LIMITED PARTNERSHIP	-	0
	ENEL X CANADA LTD.	41.7	34.4
	GC PROJECT LP	6	5
	GERDAU AMERISTEEL CORPORATION	72	72
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	27	34
	NRSTOR C&I L.P.	-	2.5
	OHMCONNECT, INC	2	0
	RODAN ENERGY SOLUTIONS INC	64	71
	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	10	-
WEST	ENEL X CANADA LTD.	17.1	20.2
	GC PROJECT LP	2.5	2.3
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	7.4	2.5
	NRSTOR C&I L.P.	-	1.2
	RODAN ENERGY SOLUTIONS INC	12.8	14.1

DR Qualified Capacity - Participant Details

ZONE	Demand Response Auction Participant	Summer Commitment Period (May 01, 2018 - Oct 31, 2018)		Winter Commitment Period (Nov 01, 2018 - Apr 30, 2019)	

		Total DR Qualified (MW)	Surplus Total DR Qualified (MW)	Surplus Virtual DR Qualified (MW)	Total DR Qualified (MW)	Surplus Total DR Qualified (MW)	Surplus Virtual DR Qualified (MW)
BRUCE	ENEL X CANADA LTD.	5	5	5	5	5	5
EAST	EMERA ENERGY LIMITED PARTNERSHIP	1	1	1	1	1	1
	ENEL X CANADA LTD.	50	23.3	23.3	50	20.8	20.8
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	6.6	1.2	1.2	4.6	0	0
	OHMCONNECT, INC	3	3	3	3	3	3
	RODAN ENERGY SOLUTIONS INC	33.4	8	8	38.4	1	1
ESSA	ALECTRA UTILITIES CORPORATION	1	1	1	0	0	0
	AMP SOLAR GROUP INC.	0	0	0	3.7	3.7	3.7
	EMERA ENERGY LIMITED PARTNERSHIP	1	1	1	1	1	1
	ENEL X CANADA LTD.	15	9.3	9.3	15	6	6
	GC PROJECT LP	2.5	0	0	2.5	0.3	0.3
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	2.7	0.5	0.5	2.7	0.6	0.6
	RODAN ENERGY SOLUTIONS INC	6.7	3.9	3.9	11.1	3	3
NIAGARA	ENEL X CANADA LTD.	20.2	3.5	3.5	20.2	6	6
	GC PROJECT LP	0	0	0	1.2	1.2	1.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1	0	0	1	0	0
	RODAN ENERGY SOLUTIONS INC	12.5	10	10	16.8	11.8	11.8
NORTHEAST	ENEL X CANADA LTD.	10	8.3	8.3	10	10	10
	RODAN ENERGY SOLUTIONS INC	35.6	11.1	11.1	35.6	9.4	9.4
	TEMBEC ENTERPRISES INC.	40	0	0	40	0	0
NORTHWEST	ENEL X CANADA LTD.	2	2	2	2	2	2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	2.1	1.1	1.1	1	1	1
	RESOLUTE FP CANADA INC.	54	25	0	54	25	0
OTTAWA	ENEL X CANADA LTD.	15	9.6	9.6	15	10.1	10.1
	GC PROJECT LP	2.3	1.2	1.2	2.5	1.5	1.5
	IVACO ROLLING MILLS 2004 L.P.	0	0	0	25	0	0
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1.8	0	0	1	0	0
	OHMCONNECT, INC	5	5	5	5	5	5
	RODAN ENERGY SOLUTIONS INC	15.1	0.1	0.1	42	24.9	24.9
SOUTHWEST	AMP SOLAR GROUP INC.	0	0	0	1.1	1.1	1.1
	EMERA ENERGY LIMITED PARTNERSHIP	6	6	6	6	6	6
	ENEL X CANADA LTD.	52	17	17	65	33.2	33.2
	GC PROJECT LP	4.9	1.5	1.5	4.6	1.6	1.6
	GERDAU AMERISTEEL CORPORATION -CAMBRIDGE	2.4	0	0	2.4	0	0
	GREAT CIRCLE POWER CORPORATION	4	4	4	3.2	3.2	3.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	22.3	8	8	47.4	0.9	0.9
	NRSTOR C&I L.P.	12.2	12.2	12.2	12.2	7.7	7.7
	OHMCONNECT, INC	5	5	5	5	5	5
	RODAN ENERGY SOLUTIONS INC	64.3	42.9	42.9	79.6	43.6	43.6
TORONTO	ALECTRA UTILITIES CORPORATION	9	8	8	0	0	0
	AMP SOLAR GROUP INC.	0	0	0	12	12	12
	EMERA ENERGY LIMITED PARTNERSHIP	6	6	6	6	6	6
	ENEL X CANADA LTD.	85	43.3	43.3	85	50.6	50.6
	GC PROJECT LP	9.3	3.3	3.3	8.3	3.3	3.3
	GERDAU AMERISTEEL CORPORATION	72	0	0	72	0	0
	GREAT CIRCLE POWER CORPORATION	0	0	0	4	4	4
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	31	4	4	38	4	4
	NRSTOR C&I L.P.	5	5	5	5	2.5	2.5
	OHMCONNECT, INC	15	13	13	15	15	15
	RODAN ENERGY SOLUTIONS INC	72.8	8.8	8.8	82	11	11
	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	15	5	5	0	0	0
WEST	EMERA ENERGY LIMITED PARTNERSHIP	6	6	6	6	6	6
	ENEL X CANADA LTD.	35	17.9	17.9	35	14.8	14.8
	GC PROJECT LP	3.5	1	1	3.5	1.2	1.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	7.4	0	0	6.7	4.2	4.2
	NRSTOR C&I L.P.	2.4	2.4	2.4	2.4	1.2	1.2
	OHMCONNECT, INC	3	3	3	3	3	3
	RODAN ENERGY SOLUTIONS INC	15.3	2.5	2.5	18.6	4.5	4.5

TAB 6

EB-2019-0242

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

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

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

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

November 8, 2019
Revised: November 21, 2019

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

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

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

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

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

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

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[14] *Ibid.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B.9 Q: What is horizontal equity?

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

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

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

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

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

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

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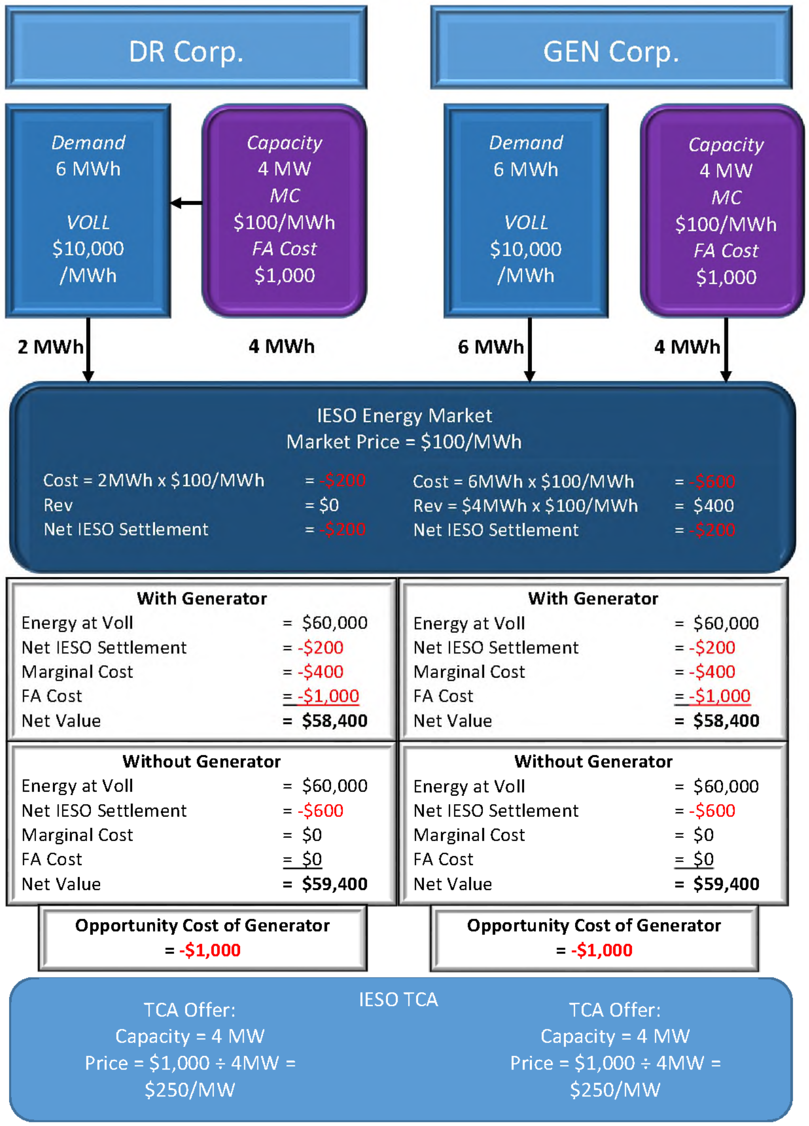
[17] IESO Presentation to Demand Response Working Group on Utilization Payments Discussion, dated March 1, 2018, being Exhibit "J" to the Affidavit of David Short, sworn October 25, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/656576/File/document at 10-14 ["IESO March 1 Presentation"].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

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

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

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

Figure 1.A: No Energy Payments for DR Resources



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

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

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

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

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

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

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[24] *Ibid* at para. 58.

[25] *Ibid* at para. 3.

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

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

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

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