Demand response programs in selected US markets

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

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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.

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1 LEI scope of work

London Economics International LLC ("LEI") was retained to assist Ontario Energy Board ("OEB") staff by providing context around demand response ("DR") resource participation in a selection of US markets at the Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") level, as well as the applicability of Federal Energy Regulatory Commission ("FERC") Order 745 to programs offered by these markets.

LEI's scope of work included the provision of a summary of Order 745 and its scope, as well as the net benefits test methodology. The research was to focus on how DR resources are compensated in US markets, including consideration for energy, capacity or other kinds of payments. OEB staff also asked LEI to identify key contextual differences between the Ontario electricity sector and the US electricity markets subject to FERC Order 745. Other key areas to be described included how load customers participate in the respective electricity markets, how the energy they consume is priced, and how US markets reconcile wholesale market dispatchability with fixed retail rates.

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.

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.

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

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

3.2 Net benefits test

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

3.2.1 Generalized approach

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

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

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

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

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

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

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

3.2.2 Net benefits test methodology

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

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

Figure 3. Methodology to determine the Net Benefits Test price

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

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

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

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

Figure 4. Illustrative application of net benefits test

		Scenario 1 MWh	Scenario 1 LMP, $/MWh	Scenario 2 MWh	Scenario 2 LMP, $/MWh	Scenario 3 MWh	Scenario 3 LMP, $/MWh
Demand	Regular load	10,000		10,000		10,000	
	DR load	100		100		100	
Supply	Suppliers A - R	9,000	$ 50	9,000	$ 50	9,000	$ 50
	Supplier S	800	$ 60	800	$ 60	800	$ 60
	Supplier T	100	$ 70	100	$ 70	100	$ 70
	Supplier U	100	$ 100	100	$ 100	100	$ 100
	DR resource	**100**	**$ 1,000**	**100**	**$ 1,000**	**100**	**$ 1,000**
	Supplier V	100	$ 1,001	100	$ 1,062	100	$ 1,100

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

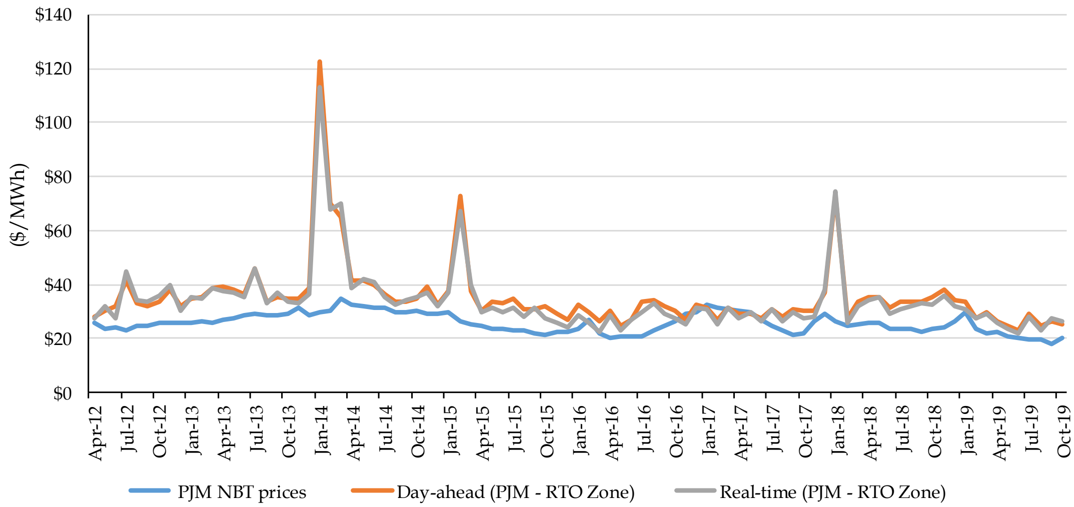
Source: *LEI calculations based on FERC Order 745*

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

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

(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

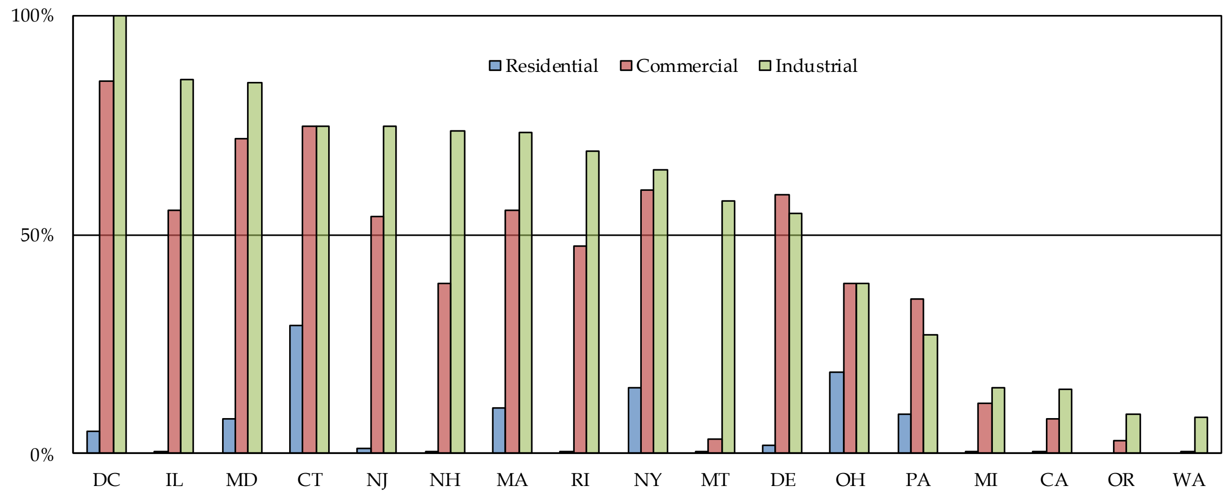
Wholesale electricity prices are dynamic. When retail customers pay for their consumption based on rates that do not reflect volatile potentially higher electricity prices in a given hour, for the hour in which their consumption occurs, this leads to a disconnect. For example, as customers on fixed price 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 provider other than their default) was low, commercial and industrial participation was much more active, with a number of states mostly in the geographic Northeastern US (and part of either ISO-NE, NYISO, and PJM) having a majority of retail load served by competitive suppliers.

Figure 6. % of retail sales from competitive suppliers by state and customer class (2010)



Notes: Texas is not shown since "participation is mandated" for all customers served by investor-owned utilities located within ERCOT, but according to the EIA around 60% of all customers (residential, commercial, and industrial) buy electricity from competitive retailers; Maine had retail choice, but is not included because of "reporting issues"; the District of Columbia only had one industrial customer.
Sources: US EIA. *State electric retail choice programs are popular with commercial and industrial customers*. May 14, 2012; US EIA Form EIA-861 data for 2010.

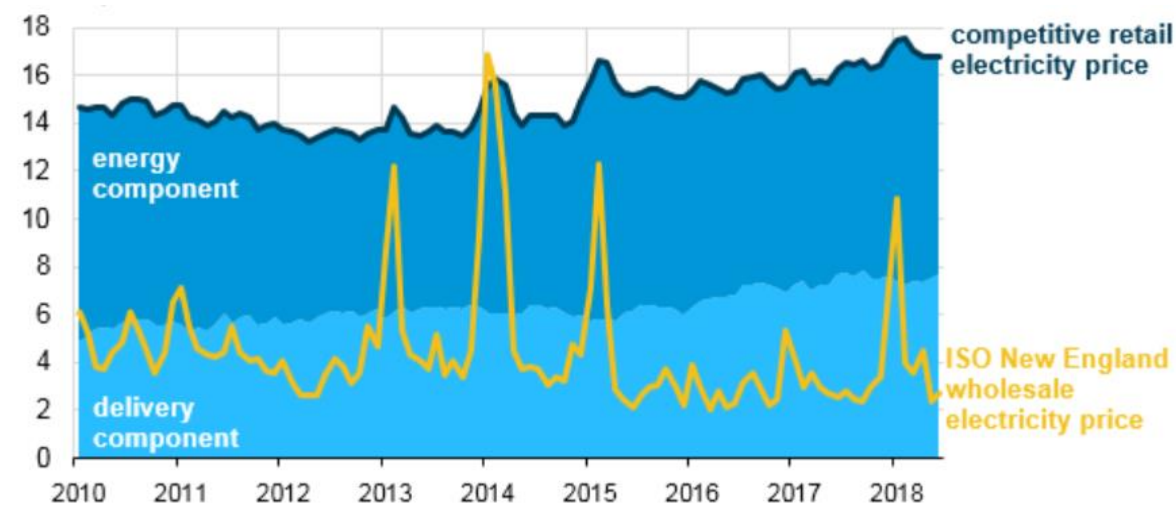
While there is a linkage between participation in a wholesale market and allowance of retail electricity choice, it is not direct; some states that are part of restructured wholesale markets do not have full retail choice, while other states that have retail choice may not be part of wholesale markets.[11] For example, although Georgia is not part of an organized wholesale market, retail electricity choice is available for large industrial and commercial customers, and according to the Southern Company CEO, around 40% to 50% of Georgia Power (the largest provider in the state) industrial and commercial load is subject to the utility's real-time pricing schedule.[12]

Within states that are both part of a wholesale market and allow retail electricity choice, there can still be a disconnect between the retail rates and the wholesale price volatility at the hourly and even monthly level. This can be seen in Figure 7, which shows the monthly competitive retail rates (with the energy component in the dark shaded blue) along with the monthly wholesale price in ISO-NE from 2010 to 2018. While the energy component of competitive retail rates is mostly higher than wholesale prices, periods of large price spikes in the wholesale market do not cause price spikes in the retail rates of close to the same magnitude.

[11] US National Renewable Energy Laboratory. *An Introduction to Retail Electricity Choice in the United States*. August 2017.

[12] S&P Global. *Hot temperatures, heavy loads drive Southern Company earnings growth*. October 30, 2019.

Figure 7. Monthly competitive retail and wholesale electricity prices in NE (¢/kWh)



Taken directly from: US EIA. *New England's competitive electricity markets lead to less price volatility*. October 31, 2018.

Issues around wholesale and retail rates were a key part of Order 745 (discussed in the upcoming Section 3.3.2). Even before Order 745 however, some US ISOs and RTOs had already implemented rules around the compensation of demand response resources participating at the wholesale level, to deal with the issue of wholesale – retail disconnect. For example, from November 2007 until March 2012 PJM compensated economic DR based on the difference between the LMP and the generation and transmission portions of the retail price. According to PJM, this "LMP-G&T" structure was developed precisely to "foster customers with fixed retail prices to reduce load when wholesale prices were high", as "without a price signal, retail customers have minimal financial motivation to reduce or shift their load since it may not result in a reduction in electricity costs for the customer."[13]

3.3.2 Discussion within Order 745 of the wholesale – retail disconnect and perceived barriers to DR

This section isolates some of the arguments made in Order 745 and Order 745-A related to retail rates, the disconnect between these rates and wholesale prices, and the impact this disconnect had on the Commission's decision.[14]

One of the main arguments against Order 745 as established related to the full payment of LMP to dispatched DR. An alternative suggestion, made by a number of parties and supported by FERC Commissioner Moeller in his dissenting view, was to subtract the cost associated with the avoided load from LMP (LMP minus G, with G referring to the generation component of retail

[13] PJM Interconnection. *2012 Economic Demand Response Performance Report: Analysis of Economic DR participation in the PJM wholesale energy market after the implementation of Order 745*. March 25, 2013.

[14] The focus here is only on certain aspects of the retail discussion contained in Order 745 and Order 745-A, and is not intended to be a comprehensive exposition of every question that arose with respect to the FERC proceeding.

rates). The argument in favour of this approach was that paying full LMP could result in over-payment as DR resources both avoid paying G and receive the LMP for dispatched load curtailments. Without the G offset, the payments fail to account for savings associated with the DR resource responding to curtailment.[15]

The Commission noted that incorporation of retail rates into wholesale payments made to dispatched DR resources would be "perhaps feasible" but would "create practical difficulties for a number of parties, including state commissions and ISOs and RTOs." The Commission ultimately disagreed with this LMP minus G position, in part because arguments in its favour "fail to acknowledge the market imperfections caused by the existing barriers to demand response."[16]

> *"Paying LMP to demand resources will help address the lack of a direct connection between wholesale and retail prices and the lack of dynamic retail prices by providing those customers that can respond to price signals with the accurate market price signal for such response."*
>
> Order 745-A

Some of the barriers that the Commission identified include a lack of direct connection between wholesale and retail prices, and a lack of dynamic retail prices (retail prices that change as the marginal wholesale costs change). According to the Commission, this demonstrates that customers "do not have the ability to respond to the often volatile price changes in the wholesale market and demonstrate the need for including demand response as part of wholesale market design." It is under these circumstances the Commission found that, in order to establish just and reasonable prices, demand response that can participate in the wholesale market should be paid the marginal value of its contribution. Given the barriers, the payment of LMP is "appropriate as it represents the value of the contribution of demand to the market during those periods in which demand response provides net benefits."[17]

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

[16] Ibid.

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

4 Demand response in selected US markets

This section covers two US ISOs and one RTO: PJM, ISO-New England, and New York ISO, all of which are in reasonable proximity to Ontario. All three of these ISOs (hereafter the term ISO should be assumed to encompass PJM as well) have both energy and capacity markets. Compensation from the energy market is paid in $/MWh terms (for utilization), while compensation from the capacity market is paid in $/kW-month or $/MW-day terms (for reservation, which pays resources for their availability to be utilized if needed). The demand response programs in these three ISOs, and the revenue streams available to them, are first covered in: Section 4.1 for PJM; Section 4.2 for NYISO; and Section 4.3 for ISO-NE. Once a background into the demand response programs in these three ISOs has been established, cross-cutting analysis and observations are presented in Section 4.4.

4.1 PJM

Currently there are two main categories of demand response programs in PJM, and one new category that becomes effective in 2020:

- economic DR;
- emergency DR; and
- (new category) Price Responsive Demand ("PRD").

The ***economic DR*** can participate in:

- energy markets (day-ahead and real-time);
- ancillary services:
    - day ahead scheduling reserve (30 minutes);
    - synchronized reserves (10 minutes); and
    - regulation.

The economic DR bids on a voluntary basis into real-time and day-ahead energy markets, and if it clears the market, it is to be dispatched along with generating resources, and as such its curtailment (when cleared in the marketplace) is termed as "dispatchable curtailment." Energy payments to economic DR resources are paid by loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[18]

The ***emergency DR*** includes both emergency and pre-emergency DR resources, and the registration options include:

- load management capacity only resources;

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

- load management capacity and energy resources; and
- emergency energy only DR resources.

DR resources under the first two registration options can be curtailed in emergency conditions (further details below) on a mandatory basis, while emergency energy only DR resources can be curtailed only on a voluntary basis.

DR resources under the load management capacity-only registration are paid the capacity prices, and when activated are not paid energy payments. Only 1.2% of DR load management resources were registered as capacity-only for the 2018/19 delivery year.[19] The remaining two (load management capacity and energy, and emergency energy only) allow DR resources to get paid the higher of the "minimum dispatch price" or LMP for when they are curtailed. The minimum dispatch prices are set once for the delivery year. The energy payment for curtailment is the minimum dispatch price or LMP, whichever is higher and is calculated on a $/MWh basis, plus shutdown costs, which are one time payments for each curtailment instance per nominated MW. For delivery year 2018/2019, only 7.2% of nominated capacity for resources had minimum dispatch prices below $1,100, as can be seen in Figure 8. The majority of nominated capacity (53.4%) had minimum dispatch prices at or close to the maximum price ($1,849).

Figure 8. Distribution of registrations and associated MW in the full option across ranges of minimum dispatch prices: 2018/2019 delivery year

Range of minimum dispatch price ($/MWh)	Locations	Percent of total (%)	Nominated MW (ICAP)	Percent of total
$0 - $1,100	383	2.8%	637.5	7.2%
$1,100 - $1,275	2,235	16.4%	3,069.9	34.6%
$1,275 - $1,550	325	2.4%	380.6	4.3%
$1,550 - $1,849	10,695	78.4%	4,776.1	53.9%
Total	**13,638**	**100.0%**	**8,864.1**	**100.0%**

Source: Monitoring Analytics LLC. *2018 PJM State of the Market Report,* March 14, 2019

A **DR resource may be registered as either** program participant (**economic DR** or **emergency DR**) **or both**, depending on circumstances and eligibility.[20]

PRD is an annual capacity resource nominated by a PRD provider (e.g. a Load Serving Entity or "LSE"). The customer load behind PRD must be on dynamic retail rates and a PRD provider must have capability to remotely reduce load at customer locations. There are no capacity market payments as PRD reduces the capacity that must be purchased by an LSE, and thus reduces the LSE's capacity payments (additionally, there are no energy payments for activation). Instead the

[19] *Monitoring Analytics. 2018 State of the Market Report for PJM: Section 6 – Demand Response.*
[20] PJM End Use Customer Factsheet. *Demand Response and Why It's Important*.

PRD provider receives a Daily PRD Credit,[21] which is applied to the LSE's Locational Reliability Charge (capacity payments).[22] PRD meets its obligation when LMPs are at or above the price threshold specified in its PRD plan and only when PJM declares a maximum emergency event, i.e. when emergency/pre-emergency DR resources and emergency energy DR sources are fully utilized and additional load reductions are required ("Deploy All Resources" emergency action in Figure 10 covered later). PRD is a new product that first cleared the Reliability Pricing Model ("RPM", the name of PJM's capacity market) for the 2020/2021 delivery year. Figure 9 compares different DR programs for dispatch requirements and sources of revenue.

Figure 9. PJM DR programs

	Economic DR	Emergency and pre-emergency DR			Price Responsive Demand
		Load management capacity only	Load management full (capacity and energy*)	Emergency energy* only	
Can be compensated for	Energy, ancillary services	Capacity only	Capacity and Energy*	Energy* only	Capacity only
Capacity market participation	No	RPM	RPM	No	RPM
Curtailment type	Dispatched curtailment	Mandatory curtailment	Mandatory curtailment	Voluntary curtailment	Price threshold specified in PRD plan
Capacity payments	No	RPM clearing price	RPM clearing price	No	Avoided capacity costs
Energy payments	Full LMP	No energy payments for activation	Higher of ***minimum dispatch price*** or LMP (paid for declared Emergency Event mandatory curtailment)	Higher of ***minimum dispatch price*** or LMP (paid only for voluntary curtailment)	No energy payment for activation

*Energy payments when activated
Source: Monitoring Analytics LLC. *2018 PJM State of the Market Report.* March 14, 2019.

4.1.1 DR deployment in PJM

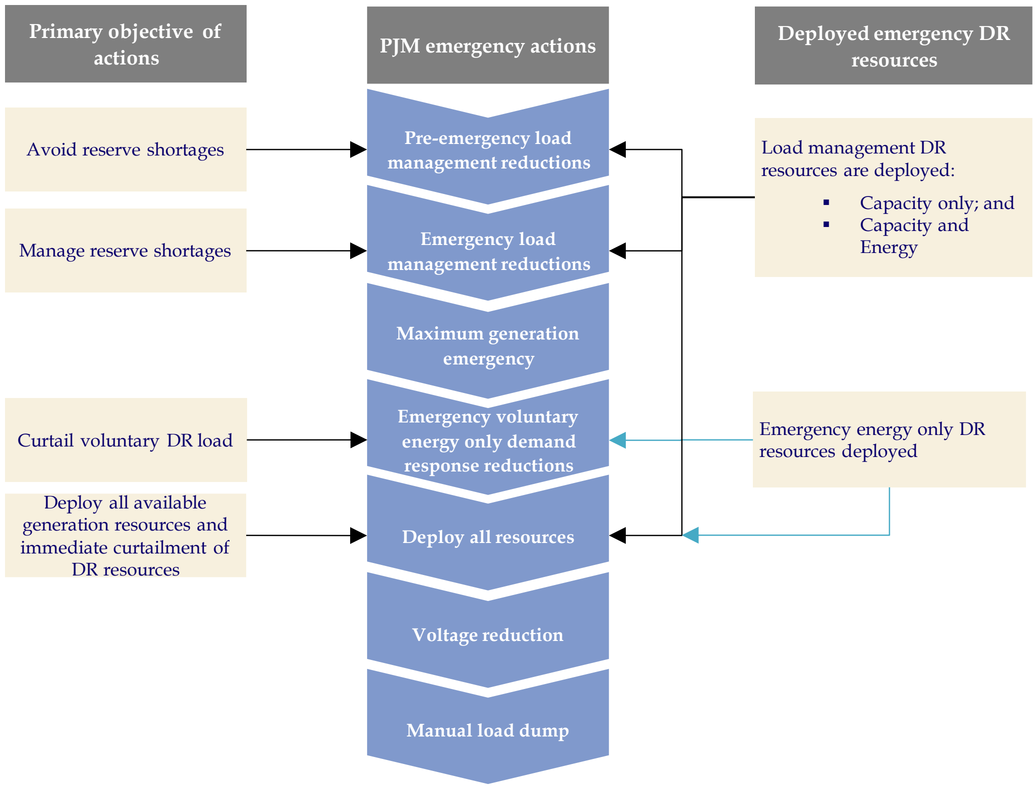
The economic DR resources are deployed along with generation resources in the energy markets, both real-time and day-ahead, i.e. dispatched curtailment.

The emergency DR resources are deployed in the order of severity of emergency conditions. There are seven actions that PJM can take in emergency conditions, and emergency DR is

[21] Daily PRD Credit is a product of final zonal capacity prices (in $/MW-day) and PRD nominal value (in MW).
[22] Locational Reliability Charge ($/day) is equal to the Unforced Capacity Obligation (in MW) of the LSE multiplied by the final zonal capacity price (in $/MW-day). After the Daily PRD Credit is applied, the LSE owes Net Load Charge ($/day), i.e. Locational Reliability Charge minus Daily PRD Credit.

deployed in four of these. The actual sequence of PJM actions may vary and can be implemented in any order that is required. Figure 10 shows PJM's emergency actions (in nominal order of severity), types of emergency DR deployed along with the corresponding objectives of the actions that are applicable to DR.

Figure 10. Current emergency actions and DR deployment in PJM



Source: PJM. *Demand Response Overview*. October 8, 2019

4.1.2 DR statistics in PJM

Since 2010, enrollment in economic DR programs in PJM has fluctuated but stayed above 2,000 MW, while enrollment in emergency DR programs also fluctuated but stayed above 8,000 MW. Combined, these resources accounted for between 6% and 9% of PJM's peak demand between 2012 and 2018 (based on unique DR capacity, as resources can be registered as both emergency and economic DR). Figure 11 shows enrollment statistics over the 2010 to 2018 timeframe.

Figure 11. DR enrollment MW statistics (2010-2018)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Economic DR program	2,441	2,252	2,204	2,660	2,955	3,456	2,597	2,269	2,512
Emergency DR (emergency and pre-emergency)	1,091	3,091	8,552	8,967	9,360	11,635	8,749	9,123	8,946
Emergency Interruptible Load for Reliability	7,961	8,731	*discountinued - - -*						
Total unique DR capacity	n/a	n/a	8,781	9,901	10,437	12,952	9,836	9,520	9,294
Total DR capacity as percent of PJM peak demand			6%	6%	7%	9%	6%	7%	6%
PJM peak demand	136,465	158,016	154,344	157,508	141,673	143,697	152,177	142,387	147,042
PJM installed capacity	154,074	170,481	173,414	183,095	183,724	177,683	182,449	183,882	185,952

Notes: ATSI transmission zone was integrated into PJM in 2011, accounting for the majority of increase in peak demand and installed capacity from 2010 to 2011; installed capacity refers to average offered capacity as reported by the Independent Market Monitor; Emergency Interruptible Load for Reliability was discontinued in 2012 and merged with the Emergency DR program; PJM's DR activity reports did not report unique DR capacity for 2010 and 2011.

Source: Monitoring Analytics LLC. *2010-2018 PJM State of the Market Reports;* PJM. *2010-2018 Demand Response Operations: Markets Activity Reports*

Among the sources of revenue for DR resources in PJM, capacity market payments remain by far the largest, accounting for on average 95% of all DR resource revenues over the 2010 to 2018 timeframe. Emergency energy revenues have been the second largest source of revenues over this period, averaging 2.3%, but there have been no emergency energy revenues reported in annual data from 2015 to 2018. DR revenues in PJM are discussed in greater detail in Section 4.4.3.[23]

Economic DR is paid the energy market price (LMPs) when its offers clear the energy markets alongside generation resources: real time and day-ahead. The combined revenues of the economic DR averaged $6.4 million annually (or 1.1% of all DR resource revenues) from 2010 to 2018 for reducing demand by an average of 92,104 MWh annually. Economic DR reductions (in MWh) and revenues over the 2010 to 2018 timeframe are provided in Figure 12.

Figure 12. Economic DR reductions and revenues

	2010	2011	2012	2013	2014	2015	2016	2017	2018
MWh reduction in real-time market	60,522	17,161	85,210	77,360	93,546	87,469	53,503	41,801	33,384
MWh reduction in day-ahead market	13,548	237	59,810	56,593	52,755	33,659	26,714	19,865	15,802
Total MWh reduction	**74,070**	**17,398**	**145,020**	**133,953**	**146,301**	**121,128**	**80,217**	**61,666**	**49,186**
Revenue, real-time market, $ mln	2.7	2.0	5.5	4.6	10.6	5.8	2.4	1.8	1.7
Revenue, day-ahead market, $ mln	0.4	0.0	3.8	4.1	7.2	2.2	1.0	0.8	0.9
Total revenues, $ mln	**3.1**	**2.0**	**9.3**	**8.7**	**17.8**	**8.0**	**3.4**	**2.6**	**2.6**

Source: PJM. 2010-2018 *Demand Response Operations: Markets Activity Reports*

[23]Monitoring Analytics. *2010-2018 PJM State of the Market Reports*

Key takeaways from these programs: PJM

FERC Order 745 only applies to DR participating in PJM's economic program, but actual dispatch of DR resources under this program has been low. The majority of DR participating in PJM programs fall under emergency-based programs (not the subject of the FERC Order). Under these programs, the vast majority of DR resources would receive activation payments ($/MWh) if required to reduce their load by PJM in an emergency/pre-emergency situation. However, here too emergency events are not common, and there have been no emergency energy payments since 2015. Capacity payments are by far the main source of revenues for DR resources in PJM.

4.2 New York ISO

NYISO demand response programs currently include reliability- and economic-based demand response programs.[24]

Reliability-based demand response programs compensate load reduction during periods when the grid is expected to see stress in high-demand periods, such as in anticipation of reserve margin shortages or during extreme weather events. NYISO has two such programs, the Special Case Resource ("SCR") program and the Emergency Demand Response Program ("EDRP").[25] These resources are not capable of responding to real-time NYISO directions, and these programs were not directly impacted by Order 745, as it "does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions."[26]

Economic-based demand response programs involve load reduction being offered into the NYISO markets directly. Currently, there are two such programs, the Day Ahead Demand Response Program ("DADRP") and the Demand-Side Ancillary Services Program ("DSASP"). According to the NYISO, the issuance of Order 745 impacted these two programs.

Selected characteristics of these four DR programs are presented in Figure 13. According to the NYISO, participants may participate simultaneously in one reliability- and one economic-based demand response program.[27] Once the NYISO's dispatchable Distributed Energy Resource participation model is implemented, the NYISO intends to retire these two economic-based programs, with resources that currently participate in the DADRP and DSASP transitioning to participation as dispatchable DERs (while the two reliability-based DR programs will remain).[28]

[24] NYISO Website. Demand Response. <https://www.nyiso.com/demand-response>

[25] EDRPs and SCRs participate through Curtailment Service Providers and Responsible Interface Parties ("RIP") respectively, which serve as the interface between the NYISO and the resources. Source: NYISO. *2018 Annual Report on Demand Response Programs*

[26] FERC Order 745

[27] NYISO. *NYISO Demand Response Programs: Frequently Asked Questions (FAQs) for Prospective Resources*. September 12, 2018.

[28] NYISO. *Distributed Energy Resources Market Design Concept Proposal*. December 2017.

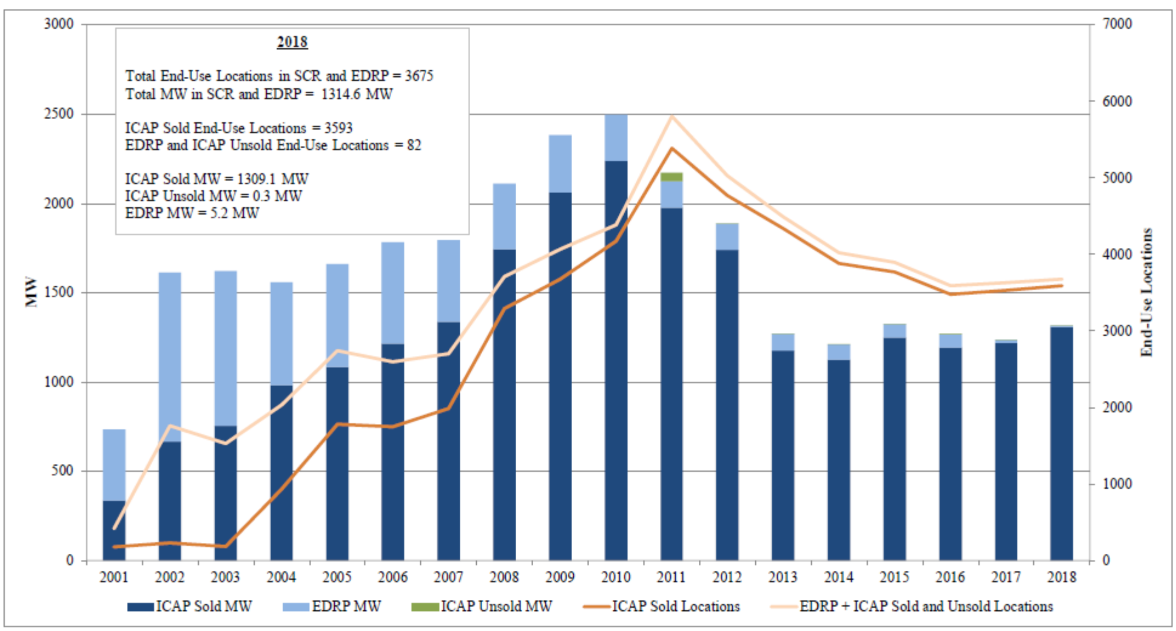
Figure 13. NYISO's DR programs

Type	DR Program	Dispatchable?	Performance obligation	2018 participation (MW)	Directly impacted by Order 745?
Reliability	**SCR**	No, manually activated	Mandatory for NYISO reliability event	1,309	No
Reliability	**EDRP**	No, manually activated	Voluntary for NYISO reliability event	5	No
Economic	**DSASP**	Yes	Mandatory if scheduled	*	Yes
Economic	**DADRP**	Yes	Mandatory if scheduled	**	Yes

*DSASPs represented 116.5 MW of capability over the May to October 2018 period, and provided on average over 100 MW of 10-minute spinning reserve over the entire 2018 period (nearly 15% of the 10-m spinning reserve requirement).
**No bidding activity
Sources: NYISO. *NYISO Demand Response Programs: Frequently Asked Questions (FAQs) for Prospective Resources*. September 12, 2018; Potomac Economics. *2018 State of the Market Report for the New York ISO Markets*. May 2019; NYISO. *2018 Annual Report on Demand Response Programs*.

As is visible in Figure 14, capacity enrolled in the two reliability programs has grown since 2001, (SCR shown in the darker blue column, EDRP shown in the lighter blue column). In 2003, participation in the EDRP and the SCR program became mutually exclusive (i.e. resources could no longer participate in both), leading to a reduction in participating MWs in the EDRP program. A large drop in SCR capacity and locations can be seen starting from 2010, which according to the NYISO was at least in part due to changes in market rules related to estimation of DR capability under peak conditions (moving in 2011 from a methodology based on average peak monthly demand, to average coincident load).[29]

Figure 14. Enrollment in NYISO reliability programs by MW and number of locations (2001-18)



Source: Taken directly from NYISO's *2018 Annual Report on Demand Response Programs*

[29] NYISO's Report on Demand Response Programs for 2011, 2013, and 2018.

Payment for operation in the different DR programs consists of: [30]

- **EDRP:** a voluntary curtailment program, where resources are paid the higher of $500/MWh or the real-time LMP if they choose to curtail when called upon by the NYISO.
- **SCR:** can participate in the NYISO capacity market. Resources can sell their capacity, and are obligated to reduce their load when deployed.[31] In such an event, they are also paid the higher of their strike price (which can go up to $500/MWh) or the real-time LMP. In 2018, EDRP and SCR were activated on three days (between 480 and 495 MW) to prevent potential capacity deficits in New York City.
- **DADRP**: can participate in the NYISO day-ahead market, and are paid the same market clearing prices as generators. However, **there has been no bidding activity in this program between 2011 and 2018** (based on last full-year state of the market report for 2018).
- **DSASP:** can participate in the NYISO ancillary services market (operating reserves and regulation services), are paid the same market clearing prices as generators, and receive the real-time LMP if actually dispatched.

Key takeaways from these programs: NYISO

FERC Order 745 only applies to DR participating in NYISO's economic programs (DADRP and DSASP). No resources have bid into NYISO's economic DADRP program between 2011 and 2018. The vast majority of NYISO's DR resources participate in reliability programs (specifically the SCR) which are not the subject of the FERC Order. They receive capacity payments for their availability and activation payments if actually deployed (in $/MWh terms). However, actual activation of SCRs is low, and the capacity market remains their main source of revenues.

4.3 ISO-New England

ISO-NE has two general groupings for demand-side resources:

1. active (**dispatchable**) demand resources (also referred to as demand response resources or active demand response resources); and
2. passive (**non-dispatchable**) demand resources (also referred to as passive demand response resources).

Active demand resources are activated upon dispatch instruction from ISO-NE, through for example ramping down on-site consumption or activating on-site generation. These resources are fully integrated into the wholesale market, and can participate in the day-ahead and real-time energy markets (dispatch is determined economically based on their offers), as well as the

[30] Sources: Potomac Economics. *2018 State of the Market Report for the New York ISO Markets*. May 2019; NYISO. *2018 Annual Report on Demand Response Programs*

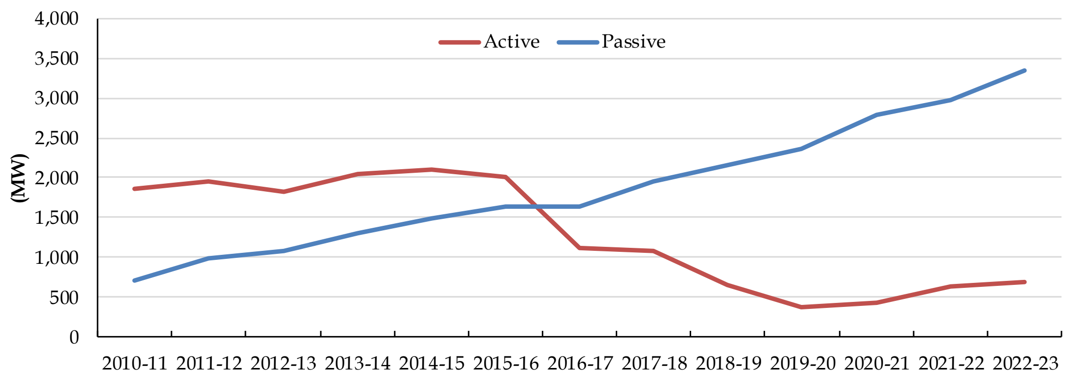
[31] Load reduction for SCRs is mandatory provided the NYISO gives notification a day before the event and two hours before the event. Source: NYISO. NYISO Demand Response Programs: *Frequently Asked Questions (FAQs) for Prospective Resources*. September 12, 2018.

operating reserve ("OR") markets. Active demand with capacity supply obligations ("CSO") also participate in the Forward Capacity Market ("FCM") as active demand capacity resources ("ADCR").[32, 33]

Passive demand resources reduce their consumption during predetermined periods. Examples of passive demand resources include energy efficiency and passive distributed generation (e.g. distributed solar). These resources differ structurally from the reliability- and emergency-based demand response resources in NIYSO and PJM, in that they cannot reduce their load upon instruction from the ISO. While passive demand resources have been fully integrated into the Forward Capacity Market,[34] they are **not eligible** to participate in energy or ancillary services markets.[35]

Passive demand resources make up the bulk of total demand resource participation in the New England Forward Capacity Auction ("FCA"), as shown in Figure 15. Passive demand resources have grown significantly since the 2010-2011 FCA commitment period, driven mainly by state-sponsored energy efficiency programs, while active demand resources have declined noticeably.

Figure 15. FCA capacity of passive and active demand response by commitment period



Source: ISO New England. *NEPOOL Participants Committee Reports: September 2019.* September 13, 2019

32 To participate in the FCM, one or more demand response resources are mapped into ADCRs, which holds the CSO. ADCRs have a "must offer" obligation whereby they are required to offer into energy markets all physically available capacity up to their CSO. Source: ISO-NE. *2018 Annual Markets Report*. May 23, 2019.

33 ISO New England. About Demand Resources. <https://www.iso-ne.com/markets-operations/markets/demand-resources/about>

34 Passive DR resources that can participate in the FCM are on-peak and seasonal resources. On-peak resources offer their reduced consumption during peak hours, while seasonal resources offer reduced consumption during periods of specific months.

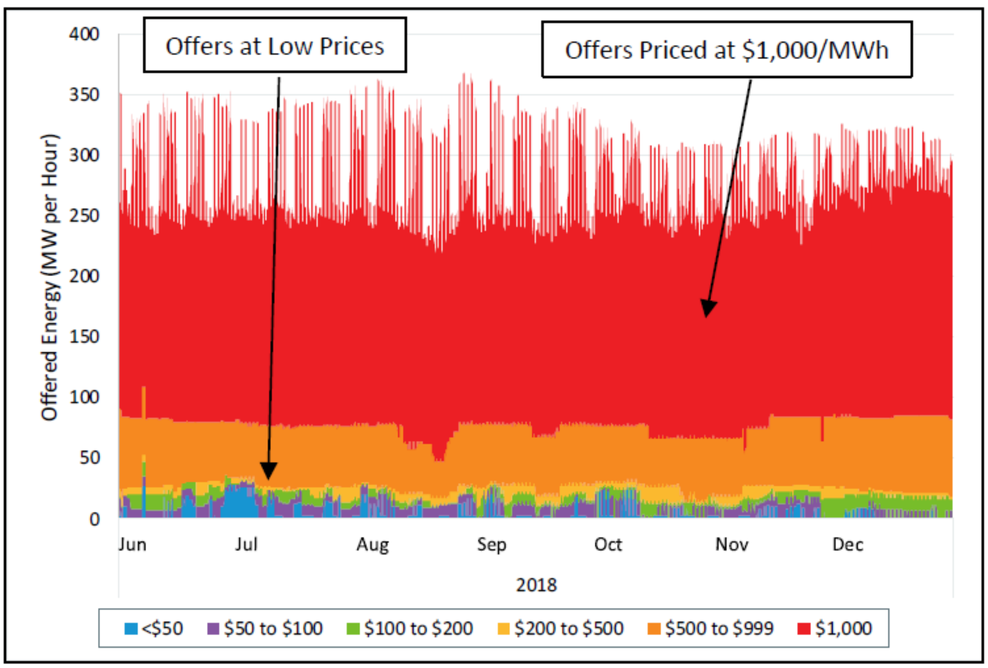
35 Source: ISO New England. "About Demand Resources". <https://www.iso-ne.com/markets-operations/markets/demand-resources/about>

From the June to December 2018 period,[36] around 350 MW of active demand resources participated in ISO-NE's wholesale energy markets (day-ahead and real-time). In terms of pricing, on average:[37]

- 72% of offered capacity was priced at the energy market cap ($1,000/MWh); and
- 7% of offered capacity was priced in the 'lower-priced tier' of $200/MWh or less, and did not exceed 20% of offered demand reduction capacity in any hour.

As according to ISO-NE only lower-priced tiers ($200/MWh or less) have a "reasonable likelihood of being dispatched in the day-ahead energy market," active demand resources participating in the wholesale energy market were dispatched at low levels and functioned predominantly as "capacity deficiency resources." From June to December 2018, the highest hourly amount of DR dispatched in the day-ahead market was 31.2 MW, and averaged just 7.7 MW in the hours when they were dispatched (which was 46% of hours over this period). This can be seen in Figure 16 (which shows the total DR resource participation in the day-ahead energy market along with their offers) and Figure 17 (which shows the total DR resource participation in the day-ahead energy market, the amount dispatched, and the corresponding day-ahead prices).[38]

Figure 16. DR resource offers in day-ahead energy market



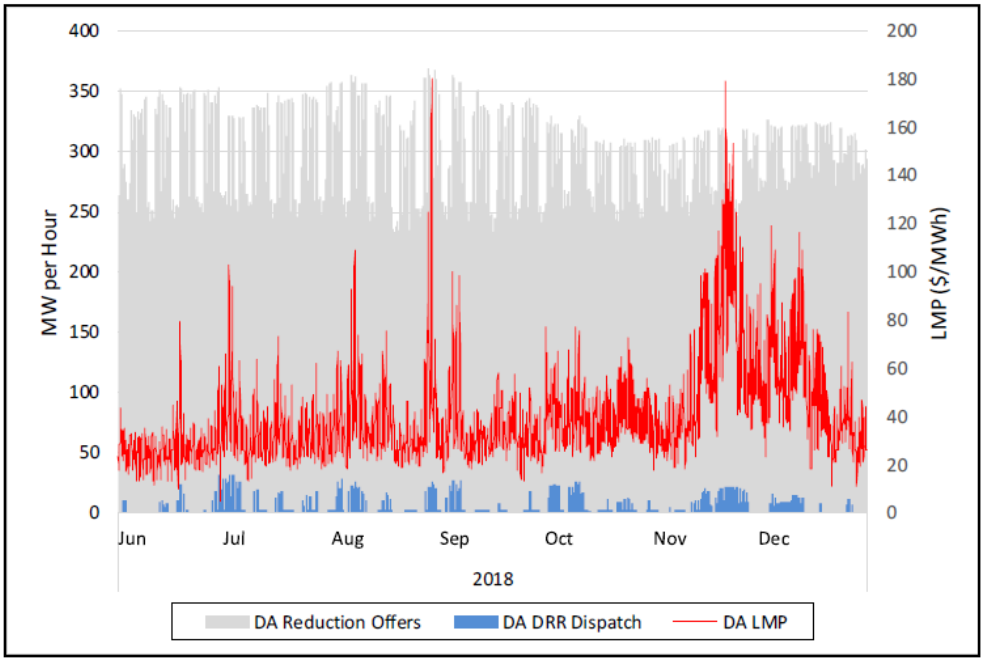
See source and note in Figure 17

[36] Demand response resources were fully integrated into the wholesale energy market on June 1st 2018, in compliance with Order 745, and DR resources with a CSO now have must-offer rules in the energy market. Prior to this, while DR resources were capable of actively participating in wholesale energy markets, most chose not to, and instead participated as emergence response resources providing dispatchability during capacity deficiency events. However, their behaviour in 2018 after their full integration into the energy markets did not change, most continued to serve as capacity deficiency resources (i.e. bidding at the offer cap in the energy markets).

[37] ISO-NE. *2018 Annual Markets Report*. May 23, 2019.

[38] Ibid.

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.

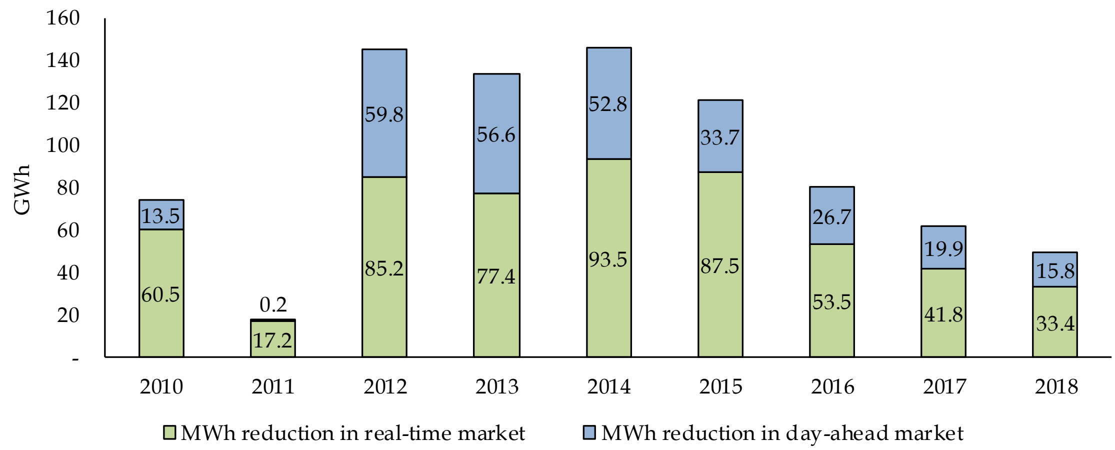
Based on the ISO programs for the US markets reviewed by LEI, and data LEI was able to gather:

- 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.

and real-time dispatch of economic DR for the historical period from 2010 to 2018 is shown in Figure 19.[40]

Figure 19. Real-time and day-ahead reductions to economic DR in PJM



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

Based on this information and the information on revenues to be covered in Section 4.4.3, it is not common for DR resources eligible to participate in ISO energy markets to only participate in ISO energy markets. The provision of capacity, and compensation from this provision, has tended to be the focus for DR resources in these markets.

4.4.3 DR resource revenue streams

DR resources participating in ISO programs for the US markets reviewed by LEI are compensated through different revenue streams, as shown in Figure 20.

Figure 20. ISO programs and markets available through the programs

ISO	NYISO				ISO-NE		PJM	
Demand side resource program	SCR	EDRP	DADRP	DSASP	Passive	Active	Emergency/ pre-emergency	Economic
Can participate in market as	Capacity*	Emergency*	Energy	OR and regulation services	Capacity	Capacity, energy, OR	Capacity*	Energy, OR

*can also receive activation payments

Capacity-related payments, or payments related to their load being made available for reduction (not the actual activation of this load reduction), are their main source of revenues. Ancillary services (operating reserves and regulation in certain markets) are another source of revenues

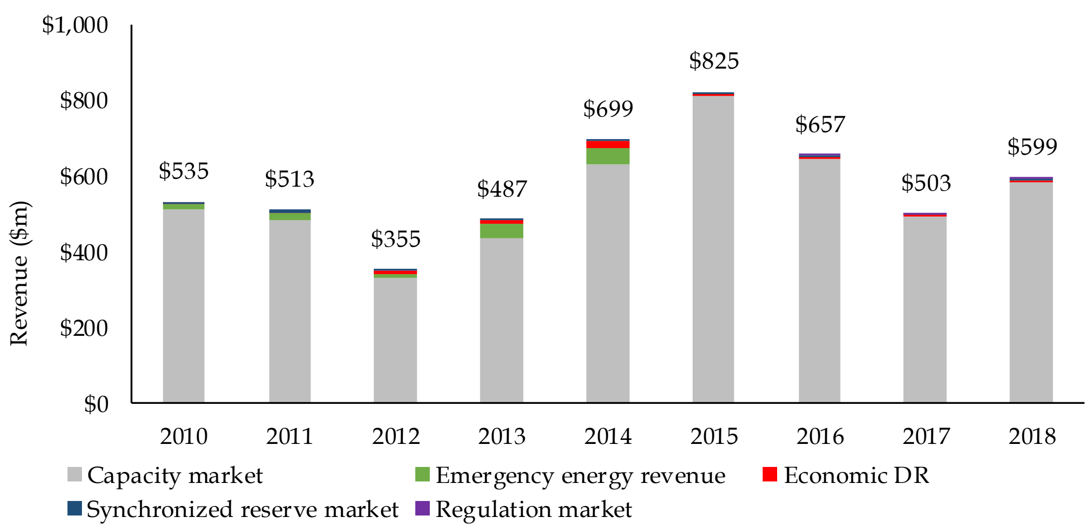
[40] An alternative approach would be to look at the difference between total unique DR capacity and total emergency DR capacity in PJM (shown in Figure 11), which would give an indication of the amount of DR capacity that participates as only economic. In 2018, this difference was 348 MW, which was just 3.7% PJM's total unique DR capacity.

made available to dispatchable DR resources. Energy market revenues are available to dispatchable DR resources participating in ISO-run markets. Compensation for activation of non-economic DRs also occurs in NYISO and PJM (reliability and emergency/pre-emergency DRs in these two markets respectively).

In terms of actual compensation, as mentioned previously, for NYISO economic demand response hasn't been dispatched through the DADRP between 2011 and 2018. Additionally, SCR and EDRP resources only saw three event-related activations in 2018, and total payment for these activations was $2.3 million.[41] In ISO-NE, total energy market payments to DR resources over the June to December 2018 period were $2.8 million. For reference, based on the CSO of demand response resources over that same period and the capacity price of $9.55/kW-month, total implied revenues for demand response resources over the June to December 2018 period were $197.6 million (broken down into $23.9 million for active resources and $173.6 million for passive resources).[42]

Information from PJM provides more granular breakdowns over longer periods of time. As shown in Figure 21, capacity payments have historically made up by far the largest portion of revenues for DR resources. In 2018, capacity market revenues for DR resources were $587 million, compared to total DR revenues of $598.6 million (i.e. 98.1% of total revenues were related to capacity). The remainder was made up of revenues from ancillary services (regulation and synchronized reserves) which totaled $9 million in 2018, and energy market revenues for economic demand response which totaled $2.6 million. There were no emergency energy revenues in 2018 (payments to emergency and pre-emergency demand response during a load management event).

Figure 21. PJM demand response revenues by market ($ million)



Source: Monitoring Analytics. *2018 State of the Market Report for PJM: Section 6 – Demand Response.*

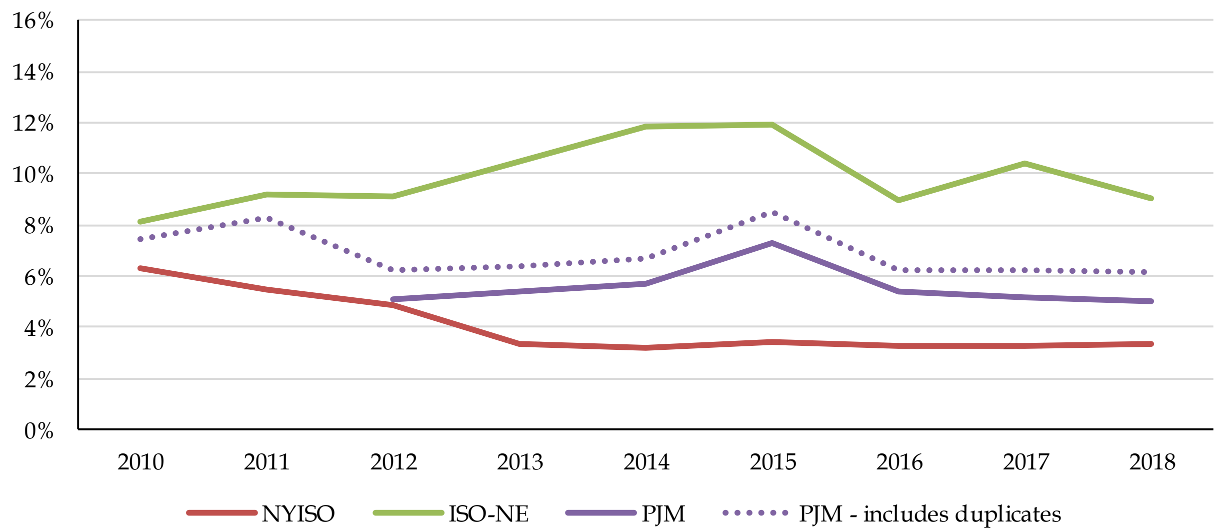
[41] NYISO. *2018 Annual Report on Demand Response Programs*

[42] LEI estimate for illustrative purposes, based on the CSOs from ISO-NE's NEPOOL Participants Committee Reports for the months of June to December 2018, and the capacity market clearing price for FCA 9.

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

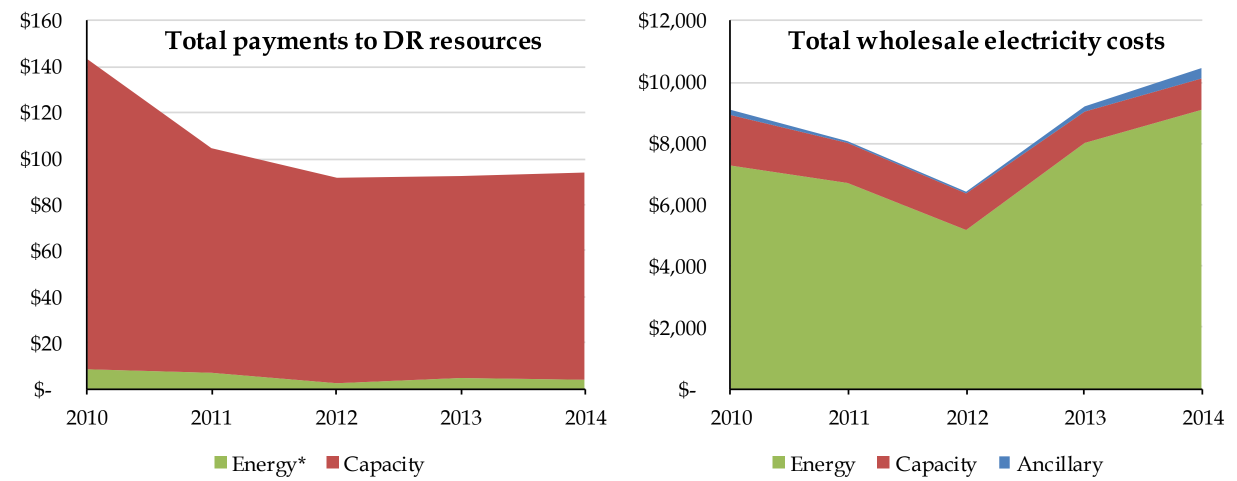


Demand response shown: NYISO shows the sum of EDRP and SCR ICAP; ISO-NE shows sum of active and passive resources with CSOs for commitment periods starting in 2010/2011; for PJM the solid line uses unique DR capacity. As PJM's DR activity reports did not report unique DR capacity for 2010 and 2011, the 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.

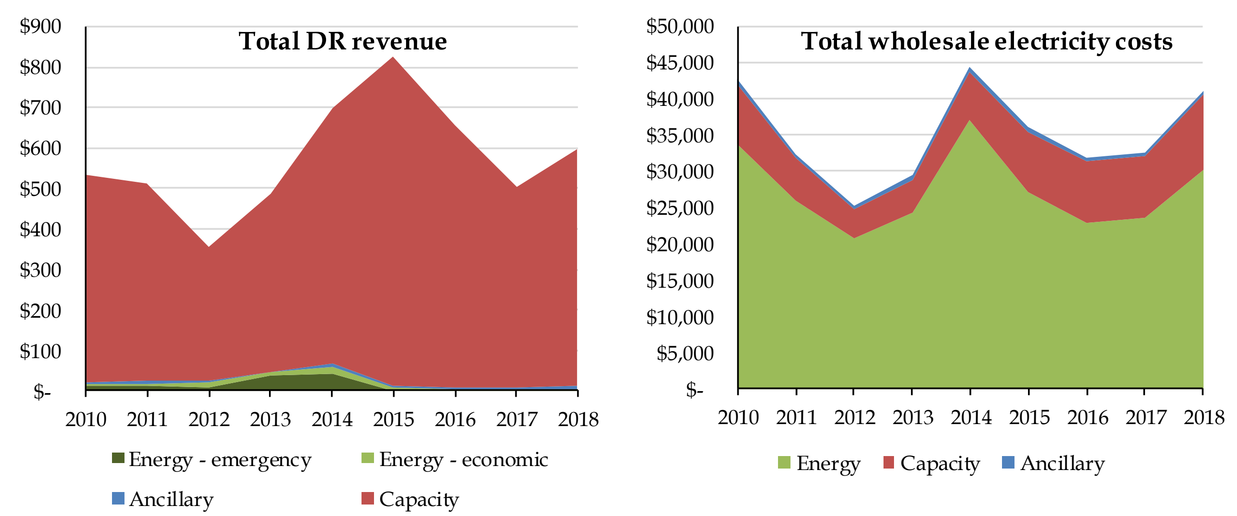
Based on these figures, and as discussed in Section 4.4.3, it is clear that **capacity payments make up the vast majority of compensation for demand response resources**, while payments for their activation or dispatch are a very small proportion of their total revenues (on average 5% of total payments 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

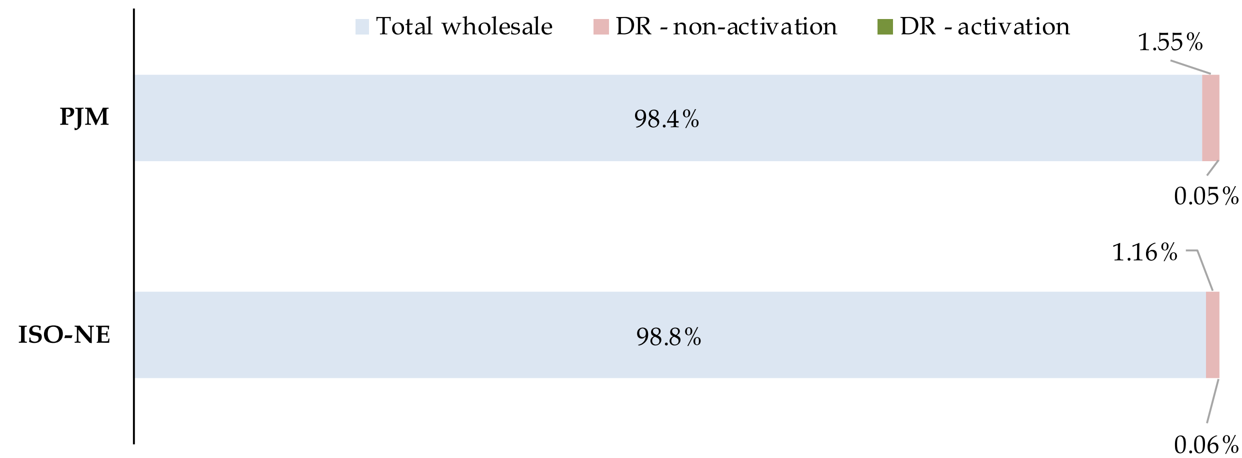
Figure 24. DR and total wholesale system revenues in PJM ($ million)



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 and emergency), and those related to non-activation (capacity in ISO-NE, capacity and ancillary services in PJM). Total DR payments made up around 1.2% of wholesale electricity costs in ISO-NE between 2010 and 2014, and 1.6% in PJM between 2010 and 2018. Activation-related DR payments were a fraction of this fraction, at only 0.06% of wholesale electricity costs in ISO-NE and 0.05% in PJM.

Figure 25. Total payments made to DR relative to total wholesale payments (%)



Sources: See Figure 23 and Figure 24

4.4.5 Degree of connection between energy payments for DR activations and capacity markets

While, as discussed previously, both the total revenues and total dispatch/activation from participation on the energy side directly or through emergency/reliability activations is low, there is still a **strong practical linkage** in these markets between participation on the capacity side and payments for activation or dispatch.

Most DR resources in the markets reviewed by LEI **participate through the provision of capacity**, in emergency or reliability-related programs in PJM and NYISO, and as active DR in ISO-NE. In NYISO and PJM, although Order 745 does not apply to these programs, when resources that participate in them are called upon to curtail, they are paid (in $/MWh terms) for this curtailment.[43] This activation payment is therefore directly linked to participation on the capacity side.

In ISO-NE, active DR with capacity obligations have must-offer rules in the energy market, therefore energy market participation is directly linked to capacity participation for DR resources in New England.

[43] In PJM, a small fraction of emergency and pre-emergency demand response is registered as capacity only, meaning they do not get payments for activation. There was 1.8% of emergency and pre-emergency demand response registered as capacity-only for the 2017/2018 delivery year, and 1.2% for the 2018/2019 delivery year. Source: Monitoring Analytics. *2018 State of the Market Report for PJM: Section 6 – Demand Response*.

Symbiotic nature of energy and capacity payments

Theoretically, a market participant's bid into the capacity market will reflect the residual revenue need that is required after all other sources of revenue or cost reductions have been considered. In the case of load, there are two potential 'revenue' sources: payments, if allowed, at LMP or some other level when dispatched, and the cost avoided by not operating. Note that failure to operate is not "free"; the cost to load of not operating in the period is equal to its lost profit for the period when it has been dispatched plus any shut down and restart costs. In a functioning market, the capacity payment would be expected to equal the desired revenue minus expected activation payments (at LMP or some other level) minus expected avoided costs. Allowing for an activation payment would not necessarily increase consumer costs; rather, it would shift the means by which they are paid out, and delineate between the "reservation payment" embodied in the capacity payment and the "utilization payment" embedded in the activation payment.

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.

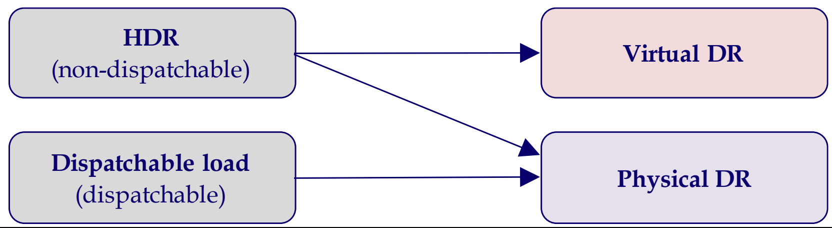
[46] Based on availability window for when the DR resource is expected to be available to provide demand response. The availability window is hours between 12:00 and 21:00 for the summer obligation commitment period, and 16:00 and 21:00 for the winter period, for business days. Sources: IESO. *Introduction 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.

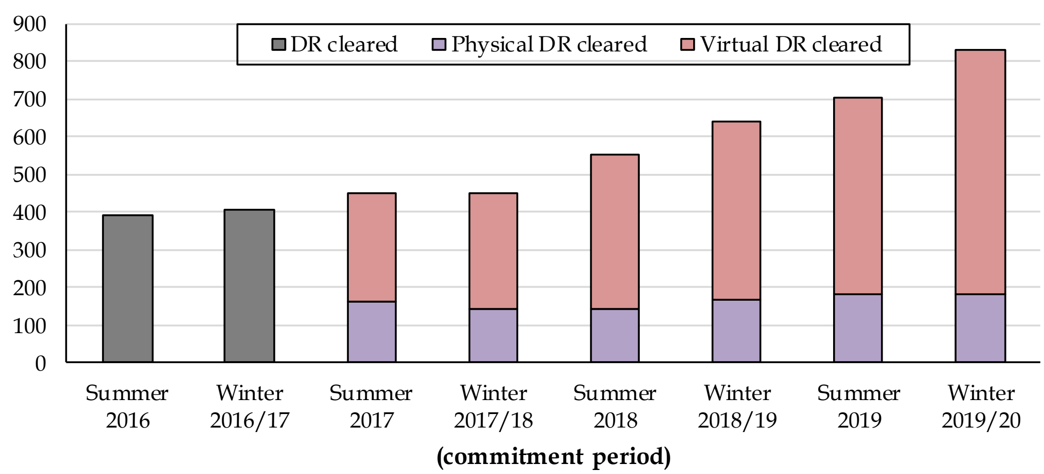
Cleared capacity within the auction is broken down into physical and virtual demand response. Physical DR resources are those that have IESO-registered revenue metering, while virtual DR resources are those that do not. All dispatchable loads are physical resources, and all virtual resources are HDRs, 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'.

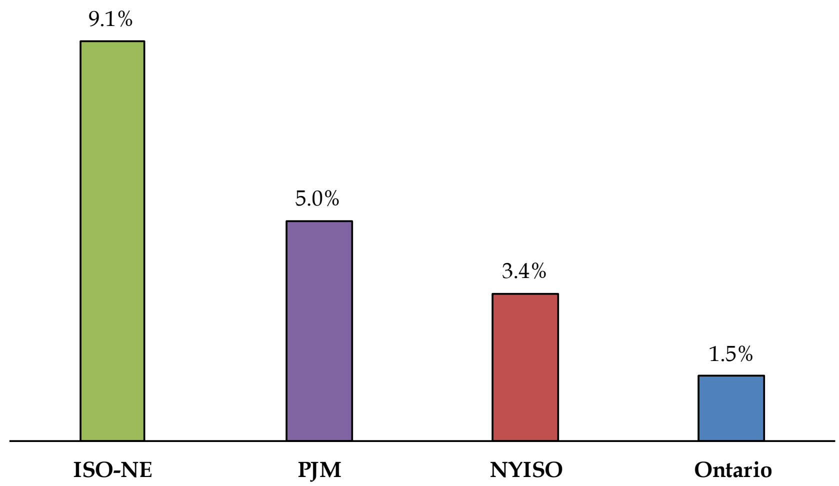
PJM currently has two broad categories of DR resources: economic DR and emergency DR. The economic DR participates in energy markets (real-time and day-ahead) on a voluntary basis, and when it clears the market, it is committed and dispatched by PJM. The reductions achieved through the deployment of 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

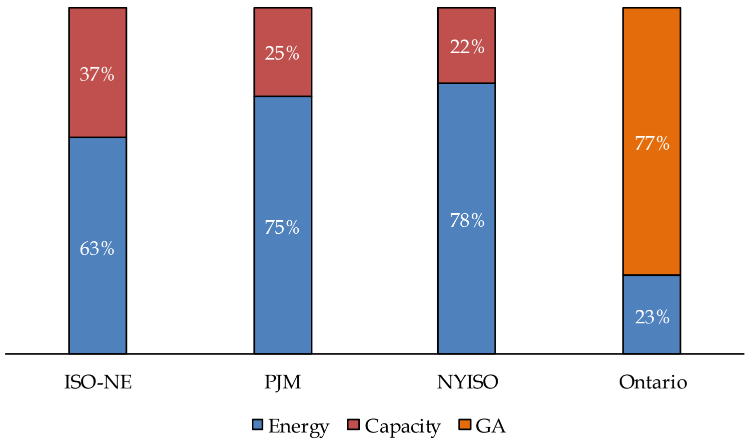
An alternative metric for consideration is DR capacity as a percentage of peak load, which averaged 5.6% across **all** US ISOs and RTOs in 2017 (and is depressed by the lack of DR participation in Southwest Power Pool);[53] again, Ontario is below this average at 2.4% for 2018. Worth re-emphasizing 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.

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

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

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

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

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

- DR resources serve primarily by the provision of capacity (in terms of total resource participation);
- when they have access to both capacity- and 'energy'-related compensation, capacity revenues still form the bulk of their revenues; and
- compensation for dispatch of economic DR resources or activation of emergency/reliability resources is the common approach; but the actual dispatch (in aggregate) of economic DR resources is low and activation of emergency/reliability resources is very infrequent (meaning, again, that actual dispatch or activation is a very small proportion of revenues for most DR resources).

Ontario has several key differences from US ISOs:

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

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

6 Appendix A: List of acronyms

ADCR	Active Demand Capacity Resources
CA	California
CELT	CELT and Transmission
CEO	Chief Executive Officer
CSO	Capacity Supply Obligations
CT	Connecticut
DADRP	Day Ahead Demand Response Program
DASR	Day Ahead Scheduling Reserve
DC	District of Columbia
DE	Delaware
DER(s)	Distributed Energy Resource(s)
DR	Demand Response
DRA	Demand Response Auction
DSASP	Demand-Side Ancillary Services Program
EDRP	Emergency Demand Response Program
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FAQs	Frequently Asked Questions
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
GA	Global Adjustment
GWh	Gigawatt-hours
HDR	Hourly Demand Response
HOEP	Hourly Ontario Energy Price
ICAP	Installed Capacity
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
IL	Illinois
ISO(s)	Independent System Operator(s)
ISO-NE	ISO-New England
kW	Kilowatt
LEI	London Economics International LLC
LLC	Limited Liability Company
LMP	Locational Marginal Price
LSE	Load Serving Entity
MA	Massachusetts
MCP	Market Clearing Price
MD	Maryland
MI	Michigan

MT	Montana
MW	Megawatt
MWh	Megawatt-hour
NBT	Net Benefits Test
NEPOOL	New England Power Pool
NH	New Hampshire
NJ	New Jersey
NY	New York
NYISO	New York ISO
OEB	Ontario Energy Board
OH	Ohio
OR	Operating Reserve
OR	Oregon
PA	Pennsylvania
PRD	Price Responsive Demand
RI	Rhode Island
RTO(s)	Regional Transmission Organization(s)
SCR	Special Case Resource
WA	Washington

7 Appendix B: List of works cited

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