International Review of Demand Response Mechanisms in Wholesale Markets

PREPARED FOR

Australian Energy Market Commission

PREPARED BY

Toby Brown

Sam Newell

Kathleen Spees

Cathy Wang

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THE Brattle GROUP

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Executive summary

The Australian Energy Market Commission (AEMC) is currently assessing proposals that would change the way in which demand response participates in the National Electricity Market (NEM). The AEMC asked the Brattle Group to examine how demand response participates in electricity markets in six jurisdictions outside Australia, in order to draw on lessons learnt from other jurisdictions. This report updates an earlier Brattle study prepared for the AEMC in 2015.[1]

As the electricity industry transforms toward intermittent generation sources, demand response will become increasingly important for balancing the system. Demand response participation is already at least partly enabled within the NEM via a price signal to consume less when the price is high. Although most customers are not currently exposed to or responsive to spot prices, it is possible that more will respond in the future if prices became higher and more volatile or if technological advances enable more response. However, there are several design and regulatory factors that may continue to limit the level of demand response engagement in the NEM. For example, it is not currently possible for DR aggregators to act as a direct link between the NEM and end-use customers without also engaging with the retail provider. As another challenge, even customers that do respond to prices may not be visible to or controllable by the grid operator in such a way that maximizes the value of demand response to the system. For example, these customers cannot be dispatched to meet sudden shortages or to provide other grid services. And if the load is not bidding directly into the market, it can only influence prices but cannot *set* market prices, so its willingness-to-pay cannot fully inform efficient operating and investment decisions by other market participants.

Jurisdictions around the world have experimented with numerous ways to enable more demand response and to integrate it directly into wholesale markets. Demand response can participate in capacity markets where they exist and emergency response mechanisms where they do not; in wholesale energy markets; and in ancillary service markets. Demand response can participate on the demand side of the wholesale energy market, or on the supply side. On the demand side, a load can adjust its consumption in response to the wholesale energy price, but without submitting price-quantity bids and without being dispatched (we refer to this as "price-responsive load"). On the supply side, a load can "sell back" energy into the wholesale energy market; it submits offers, and is dispatched by the system operator like a generator. In capacity markets and emergency response mechanisms, demand response participates on the supply side.

- **Capacity market participation and emergency reserve mechanisms** resemble traditional (vertically integrated) utilities' interruptible load programs. They enable the system operators to "dispatch" load reductions to keep the lights on when supplies are limited. Like other capacity or emergency resources, demand resources'

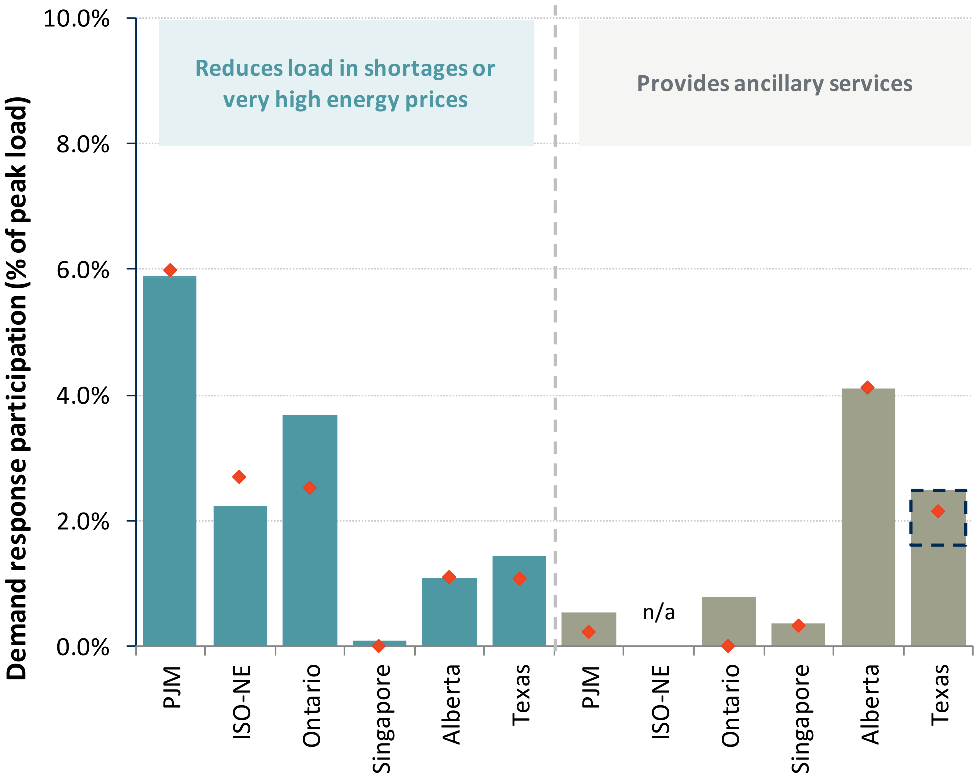
[1] Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015.

load reductions are treated and paid as supply. This has enabled a flourishing industry of specialized third parties that develop, aggregate, and sell load reductions. Capacity/emergency revenues are their biggest sources of revenue, but they can sell energy and ancillary services from the same assets.

- **Wholesale energy market participation** takes on three forms: simply purchasing less when the price is high (price-responsive load); submitting price-sensitive demand bids in day-ahead markets (but few or no loads do this in real-time markets); and selling load reductions from a hypothetical baseline back into the market as supply (most often from resources that are also earning revenues in the capacity market). The volumes of energy provided are trivial in normal periods, since energy prices will usually be below the willingness-to-pay of almost all loads.
- **Ancillary services markets** now admit demand response in numerous jurisdictions, particularly for contingency reserves and regulation. They are treated as "supply" just like generators. Participation continues to be quite high in PJM and ERCOT.

In Figure ES-1 we show estimates for the degree to which demand response participates by providing energy and ancillary services. The panel on the left represents all demand response that participates in the wholesale energy market by being available to be dispatched by the system operator, whether it is for reliability reasons (eg, capacity obligations from participating in capacity markets or emergency mechanisms) or economic reasons (eg, the economically dispatched demand response in PJM). Note that we show the quantity of demand response that is *available* to be dispatched. The actual quantity dispatched in any given year may be much lower, however, since the offer price or strike price for most loads is much higher than that of generation.

Figure ES-1: Demand response participation for the most recent year of available data



Notes: The red diamonds represent the demand response participation at the time of the 2015 Brattle Report. Alberta stopped publishing demand response data after 2011, so both the 2015 Brattle Report and this update reflect 2011 numbers.

ERCOT: The dotted box represents the range of contingency reserves throughout 2018, based on ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019, pp. 3-5. At the time of the 2015 Brattle Report, the procurement of demand response in the ancillary services market was capped based on a fixed hourly MW requirement for the entire year; following a rule change, ERCOT now allows the hourly MW requirement to be variable. Relative to the fixed level in 2014, there was an increase in DR providing ancillary services in some months in 2018, and a decrease in other months.

Figure ES-1 shows the participation of demand response, as a proportion of peak load in each of the six jurisdictions we have surveyed. Since the 2015 Brattle Report, each market has undergone several rule changes related to how demand response can participate in the markets; however, these rule changes have not resulted in substantial changes in participation.

Jurisdictions with capacity markets consistently attract the most demand response participation, and the demand response resources there earn the vast majority of their revenues from capacity. But there is a side-benefit for the energy market and ancillary services markets: capacity providers agree to be dispatchable, which can make them not only more reliable, but can also enable them to be dispatched and to *set* the energy price. Such resources submit offers to the dispatch process in the energy market, mostly at a very high price. These energy market offer prices reflect the customers' willingness-to-pay to avoid curtailments. Their offers can set energy prices at that level if they are marginal, as long as appropriate price formation mechanisms are in place. In these jurisdictions, increased participation of dispatchable demand response in wholesale energy markets results from a combination of capacity market revenues compensating for necessary infrastructure and the transfer of control to the system operator, and rules that require participation in the wholesale energy market in order to qualify in the capacity market.

In jurisdictions without capacity markets, there is little or no dispatchable demand response in the wholesale energy market (there may be significant amounts of load responding to price by voluntarily curtailing consumption in high-priced periods, though the amounts involved are not transparent because the loads are not being dispatched). In these jurisdictions, demand response is providing ancillary services and emergency reserves, but there tends to be very little load or demand response explicitly bidding into the energy market and being available to be dispatched on a regular basis.

A key question for the NEM, in assessing the current rule change proposals, which also faces other jurisdictions without capacity markets, is how to encourage demand response to participate explicitly by being available for dispatch in the wholesale energy market. Being available for dispatch requires that demand response incur costs to interface with the wholesale energy market systems, and manage risks associated with needing to follow dispatch instructions. At the same time, active demand response participation can bring reliability, efficiency, and price formation benefits to the system as a whole. Another policy question is whether to incorporate demand response on the demand side or the supply side of the energy market. The supply-side approach enables third-party aggregators to participate directly with loads but requires measuring load reductions from an inevitably imperfect baseline.

Ultimately, the participation of demand response in the wholesale energy market will depend on the value it is able to capture, which in turn depends on the participation mechanisms and the available mix of resources.

I. Introduction

The Australian Energy Market Commission (AEMC) is assessing three rule change proposals that consider mechanisms for demand response to participate in the wholesale energy market. These rule change proposals relate to one of the outcomes from the AEMC's *Reliability frameworks review*, which was to integrate more demand response into the wholesale market by enabling demand response to be recognized on an equal footing with generators.[2]

In 2015, the Brattle Group prepared a report for the AEMC on how demand response participates in wholesale markets in other jurisdictions ("2015 Brattle Report").[3] The 2015 Brattle Report was commissioned as part of the AEMC's assessment of an earlier rule change, and examined wholesale demand response participation in three energy-only jurisdictions as well as three jurisdictions with capacity markets. We previously examined the following jurisdictions:

- **Energy-only markets:** Singapore, Alberta Electricity System Operator (AESO), Electric Reliability Council of Texas (ERCOT); and
- **Capacity markets:** PJM Interconnection (PJM), Independent System Operator New England (ISO-NE), and Ontario Independent Electric System Operator (IESO).

The AEMC has asked us to update the 2015 Brattle Report, and to identify any recent developments that may be relevant to the AEMC's current work on demand response.

A. The 2015 Brattle Report

In our 2015 paper, the AEMC asked us to look at how demand response participates in wholesale markets in other jurisdictions, and how much demand response there is. We looked at three "energy-only" jurisdictions, with a market design more similar to the NEM, and three markets with "capacity mechanisms". We included the latter jurisdictions because demand response participation in capacity mechanisms has typically been greater than participation in energy markets.

We considered three routes for demand response to participate in electricity markets: the wholesale energy market; ancillary service markets; and the capacity mechanism or emergency reserve mechanisms (both of which involve demand response being available to be dispatched when the system is tight). All three routes are available to demand response in the NEM, although only participation via ancillary service markets (frequency control ancillary services (FCAS)) and the emergency reserve mechanism (the reliability and emergency reserve trader (RERT)) are directly visible to the market operator and other market participants.

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2 AEMC, *Wholesale Demand Response Mechanism*, accessed April 2019.

3 Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015.

In our 2015 paper, we found that there are three ways in which demand can respond to price in the wholesale energy market:

- **"Price-responsive load"** is customers that tend to consume less energy when the price is high, but these loads do so without submitting formal bids or offers in the wholesale market. Since these responses are not visible to the grid operator, their activity can only be estimated, and it appears to cut 1% to 2% of peak demand when prices are high, based on published estimates of price-responsive load;[4]
- **"Dispatchable load"** is customers that submit price quantity pairs to consume energy. From public data, there seems to be very limited amount of this type of load, perhaps because of high costs of complying with dispatch requirements (eg, telemetry, forecasting) and few benefits compared to operating as price-responsive load. Examples include the pumps in some pumped-storage hydro systems;
- **"Supply-side demand response"** is customers that participate on the supply side and "sell back" energy by submitting formal offers and being dispatched by the system operator. In the markets where the rules permit supply-side demand response, there can be a few percent of peak load directly dispatched in this way. The jurisdictions with supply-side demand response in the wholesale energy market were those where demand response is also able to participate in capacity markets.

B. This report

The AEMC has asked us to update the 2015 Brattle Report, and to document any major recent developments which might be relevant for the design of a new mechanism for demand response to participate in the NEM. The AEMC also asked us to summarize recent European legislative proposals that address demand response. We have looked for recent developments in each of the six jurisdictions covered in the 2015 report. The AEMC asked us to look specifically for developments that encourage demand response to contribute to transparent price formation in the wholesale energy market in these jurisdictions.

We continue to distinguish between three different ways that demand response can participate in wholesale energy markets: price-responsive load, which responds to high prices by reducing consumption but which is not dispatched by the system operator and is not directly visible to the system operator; dispatchable demand, which submits bids to the system operator and is dispatched; and supply-side demand response, which submits offers to the system operator and is dispatched on the supply side (like a generator). When we discuss demand response participating in the wholesale energy market as supply-side demand response, participating means submitting offers which the system operator can dispatch. Supply-side demand response may not be dispatched very often, but the fact that it is submitting offers means that it is available to be dispatched if needed, and is therefore providing value.

Where demand response is participating on the supply side and is selling back energy, a critical part of mechanism design is the definition of a "baseline" consumption of energy from which

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4 Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, p. iii.

the energy consumption can be reduced and sold back to the market. In most jurisdictions, the baseline is defined on a centrally-determined basis based on the load's historical demand. The arrangements in Singapore are unusual in that the baseline is a firm financial commitment: in periods where the demand response is available but not dispatched, it will be penalized if it does not consume at the baseline level. In this sense, the baseline can be considered decentralised. In both cases, the financial flows are settled centrally.

In most of the jurisdictions we examined, there is a greater value for demand response in capacity and/or ancillary services markets than in the wholesale energy market. Furthermore, in jurisdictions where loads can be dispatched we did not find any significant amounts of dispatchable demand (ie, demand response participating on the demand side in real time), presumably because much of the commercial benefits of responding can be captured by acting as price-responsive load, without the costs associated with being dispatched. For both wholesale energy and capacity, dispatchable demand response participates on the supply side.

Table 1 shows a high level description of the overall market design of the six jurisdictions studied in this report, as well as the NEM, focusing on aspects of market design that are relevant to demand response participation. Energy prices tend to be more volatile in the jurisdictions without capacity mechanisms.[5]

Table 1: High-level description of jurisdictions surveyed

	NEM	PJM	ISO-NE	Ontario	Singapore	Alberta	ERCOT
Market Model for Supporting Investment in Capacity	Energy-Only	Capacity Market	Capacity Market	Administrative Planning (now developing a Capacity Market)	Energy-Only	Energy-Only	Energy-Only (and a small emergency DR program)
Energy Market	Zonal Real-time	Nodal Real-time and day-ahead	Nodal Real-time and day-ahead	1 region with border pricing Real-time only (day-ahead scheduling but no market)	Nodal Real-time only	Single zone Real-time only	Nodal Real-time and day-ahead
Energy Market Price Cap	$14,700/MWh AUD	$3,700/MWh (AUD $5,317/MWh)	$5,050/MWh ($7,240/MWh AUD)	$2,000/MWh (CAD) ($2,132/MWh AUD)	$4,500/MWh ($4,726/MWh AUD)	$1,000/MWh (CAD) ($1,067MWh AUD)	$9,000/MWh ($12,938/MWh AUD)
Total Peak Demand	32.5GW	151.4GW	28.7GW	23.2GW	7.4GW	11.9GW	73.5GW
Fuel Mix[6]	Coal 60% Natural gas 19% Renewable 19% Oil products 2%	Coal 37% Nuclear 35% Gas CC 20% Renewable 3% Oil/Gas CT 2% Oil/Gas ST 1% Other 1%	Gas CC 47% Nuclear 29% Renewable 9% Coal 4% Oil/Gas CT 2% Oil/Gas ST 2% Other 8%	Nuclear 61% Hydro 25% Gas/Oil 7% Wind 7% Other 1%	Natural gas 95% Coal 1% Other 4%	Coal 47% Cogen 22% CC 15% Wind 7% SC 5% Hydro 3% Other 1%	Gas CC 47% Coal 26% Renewable 11% Nuclear 10% Oil/Gas CT 4% Oil/Gas ST 2%
Total Capacity	51.2GW	180.1GW	33.9GW	39.1GW	13.6GW	16.1GW	78.9GW

5 See Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, pp. 14-15.

6 Percentages calculated from MWh for NEM, PJM, ISO-NE, Ontario, and ERCOT; calculated from MW for Alberta; and pulled as percentages for Singapore. Percentages may not add up to 100% due to rounding.

Sources and Notes:

Ancillary Service products that DR is currently allowed to participate in are indicated in bold.

Fuel mix statistics for PJM, ISO-NE, and ERCOT are 2015 numbers from ABB Energy Velocity.

Australia: Australian Energy Market Commission, "National Electricity Rules Version 72," July 2015. Posted at http://www.aemc.gov.au/energy-rules/national-electricity-rules/current-rules; AEMC, "AEMC publishes the schedule of reliability settings for 2019-20," 21 February 2019. This market cap applies from 1 July 2019; AER, "Generation capacity and peak demand," 1 April 2019; AEMO, "Generation information page," 10 May 2019; Department of the Environment and Energy, "Australian Energy Statistics, Table O: Australian electricity generation, by fuel type, physical units," March 2019.

PJM: PJM, "PJM Manuals," July 2015. Posted at http://www.pjm.com/documents/manuals.aspx; PJM, "Day-Ahead Energy Market," 12 June 2017, p. 15; PJM, "Load Forecast Report January 2019," p. 4; PJM, "PJM at a Glance," p. 1

ISO-NE: ISO New England (2015), "Market Rule 1." July 2015. Posted at http://www.iso-ne.com/staticassets/documents/2014/12/mr1_sec_1_12.pdf and http://www.iso-ne.com/staticassets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf; ISO-NE, "Summer 2018 Weather Normal Peak Load," December 2018, p. 4; ISO-NE, "Seasonal Claimed Capability Monthly Report May 2019," 2 May 2019; Sam Newell, David Luke Oates, Pablo Ruiz, "Market Design for Winter Energy Security in New England," 6 February 2019, p. 4. While the offer cap is $1,000/MWh, it can increase to $2,000/MWh under special high gas-price conditions; combined with the Reserve Constraint Penalty Factors which can add up to $3,050/MWh, the market price cap for energy in ISO-NE is $5,050/MWh.

Ontario: IESO, "Overview of the IESO-Administered Markets," Jan. 2014; IESO, "2018 Electricity Data," 2019; IESO, "Market Power Mitigation and Load Pricing," 13 November 2017, p. 4; IESO, "2018 Ontario Comprehensive Review of Resource Adequacy," p. 14; IESO, "Yearly Energy Output by Fuel Type," 2019.

Singapore: EMA, "Implementing Demand Response In the National Electricity Market of Singapore: Final Determination Paper," Oct. 2013. Note that Singapore has an ancillary service DR program, but participation is only about 20 MW; Energy Market Authority, "Statistics: Monthly Peak System Demand," March 2019; Energy Market Authority, "Singapore Energy Statistics 2018," p. viii; Energy Market Authority, "Energy Transformation 02," 30 October 2018.

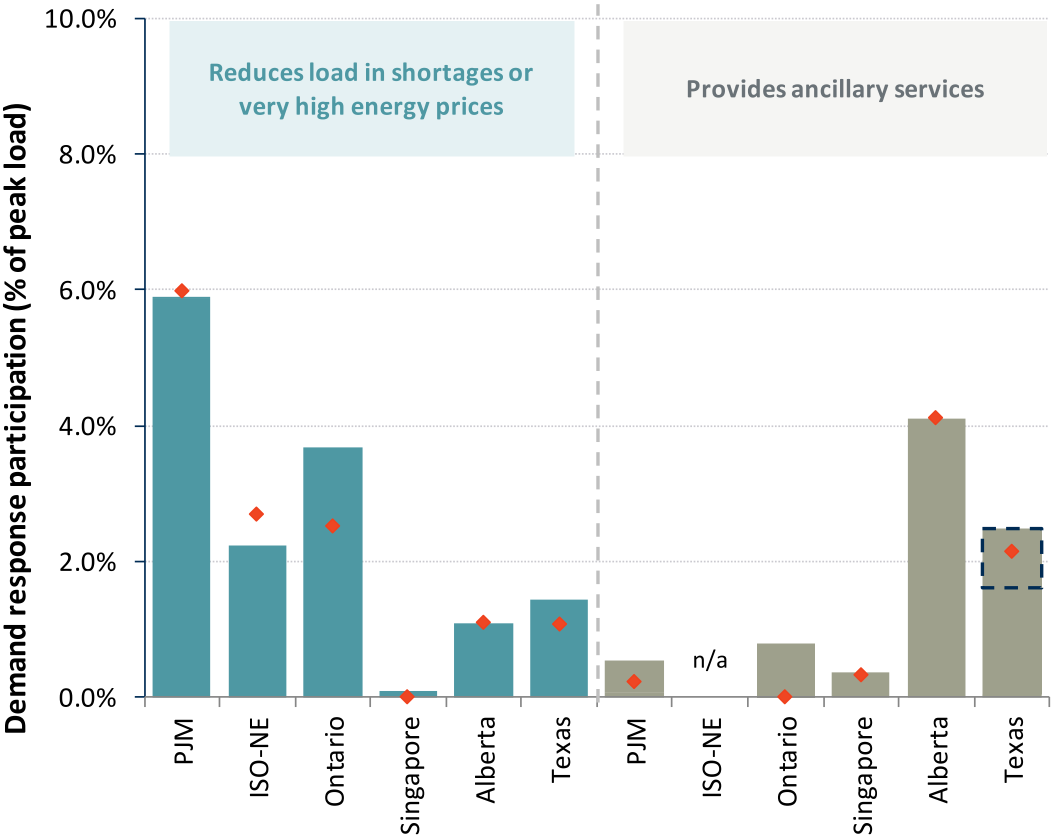
Alberta: AESO, "Guide to Understanding Alberta's Electricity Market," http://www.aeso.ca/29864.html. AESO, "Ancillary Services," http://www.aeso.ca/market/5093.html; AESO, "2018 Annual Market Statistics," 1 March 2019, pp. 4, 6, 9; AESO, "2018 Annual Market Statistics data file," 5 March 2019.

Texas: Electric Reliability Council of Texas, "Operating Procedures," 2015. Posted at http://www.ercot.com/mktrules/guides/procedures; ERCOT, "2019 ERCOT System Planning: Long-Term Hourly Peak Demand and Energy Forecast," 21 December 2018, p. 20.; ERCOT, "Demand and Energy Report 2018," 7 March 2019, [Demand] worksheet; ERCOT, "ERCOT expects record electric use, increased chance of energy alerts," 8 May 2019. Note that prices can rise up to an additional $5,000/MWh (to as much as $14,000/MWh) in constrained locations when transmission constraint penalty factors are binding.

II. Developments since the 2015 Brattle Report

In the 2015 Brattle Report, we showed the quantities of demand response (as a percentage of peak load) in each jurisdiction. Below, in Figure 1, we have updated that figure using the latest data available. In this new version, we have combined the capacity or emergency function with the energy function to indicate the overall amount of demand response available to be dispatched in tight supply conditions. This is because we understand that all demand response that supplies capacity has a "must-offer" obligation to participate in the wholesale energy market. Some resources may do so at the price cap to avoid being dispatched under regular circumstances; but they are available during tight supply conditions. We still find it helpful to distinguish between dispatchable demand response (visible and controllable by the system operator) and non-dispatchable price-responsive load (invisible in real-time and non-controllable by the system operator); however this is no longer shown in the participation charts because it is unclear how much overlap there is between the figures reported for each category. For ancillary services, we retain the same methodology. In the rest of this section, we elaborate on developments in each jurisdiction since the 2015 Brattle Report.

Figure 1: Demand response participation for the most recent year of available data



Notes: The red diamonds represent the demand response participation at the time of the 2015 Brattle Report. Alberta stopped publishing demand response data after 2011. Both the 2015 Brattle Report and this update reflect 2011 numbers.

ERCOT: The dotted box represents the range of contingency reserves throughout 2018, based on ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019, pp. 3-5. At the time of the 2015 Brattle Report, the procurement of demand response in the ancillary services market was capped based on a fixed hourly MW requirement for the entire year; following a rule change, ERCOT now allows the hourly MW requirement to be variable. Relative to the fixed level in 2014, there was an increase in DR providing ancillary services in some months in 2018, and a decrease in other months.

A. Updates in energy-only markets

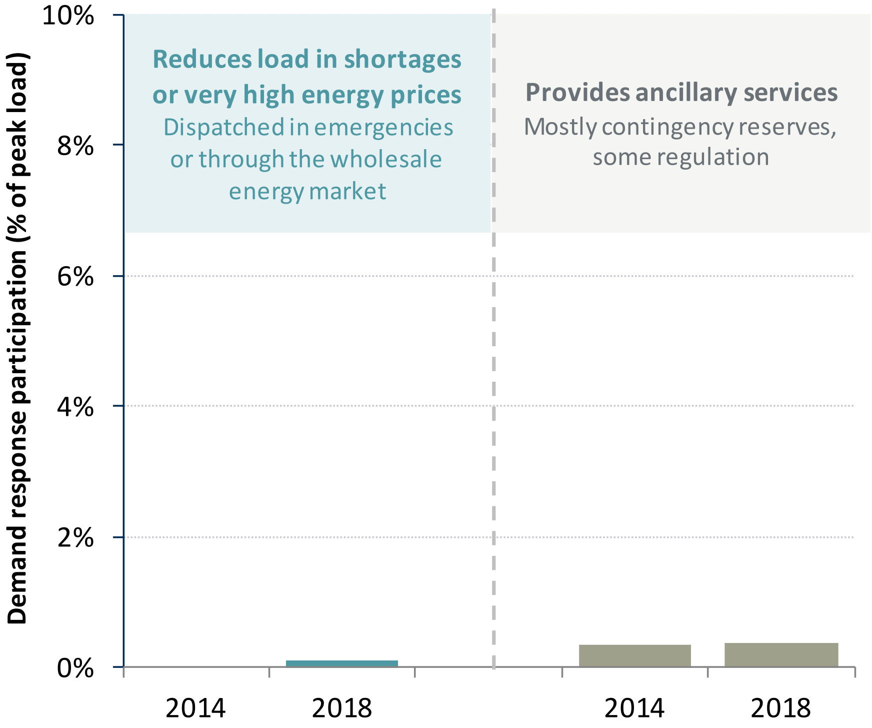
1. Singapore

Singapore has very limited demand response participation because of a combination of high penalty exposure (through its self-nominated baseline) and low prices (due to high reserve margins). The 2015 Brattle Report described a proposed demand response program for the wholesale energy market that has since been running since 2016. We discuss below some of its unique features and participation in the program to date. Overall, Singapore allows demand response resources to participate in the wholesale energy and ancillary services markets:

- **Wholesale energy**: The new Demand Response program, which was implemented after the publication of the 2015 Brattle Report is characterised by two distinct features: the use of a self-nominated baseline and a consumer surplus sharing mechanism. Participation to date has been limited (7.2 MW of registered capacity). We describe both of these features below.

– **Ancillary services**: Demand response resources can participate in the ancillary services market through the Interruptible Load scheme. Under this scheme, contestable consumers can offer interruptible load service by being available to curtail load as a substitute for spinning reserves. If scheduled to provide ancillary services, interruptible load providers are paid at the prevailing half-hourly contingency reserve price (like generating resources).[7]

Figure 2: Demand response participation in Singapore (2014 vs 2018)



Sources and notes:

2014 numbers from Figure 3 in the 2015 Brattle Report.

2018 numbers obtained through discussions with the Energy Market Authority.

We had discussed in the 2015 Brattle Report the finalisation of a new energy market Demand Response program, and reviewed the proposed implementation established in the Final Determination document.[8] Figure 3 shows how such a mechanism would work. The program is characterised by: (1) the use of a self-nominated baseline and (2) a consumer surplus sharing mechanism. At the time, due to concerns around gaming in the use of historical baselines that

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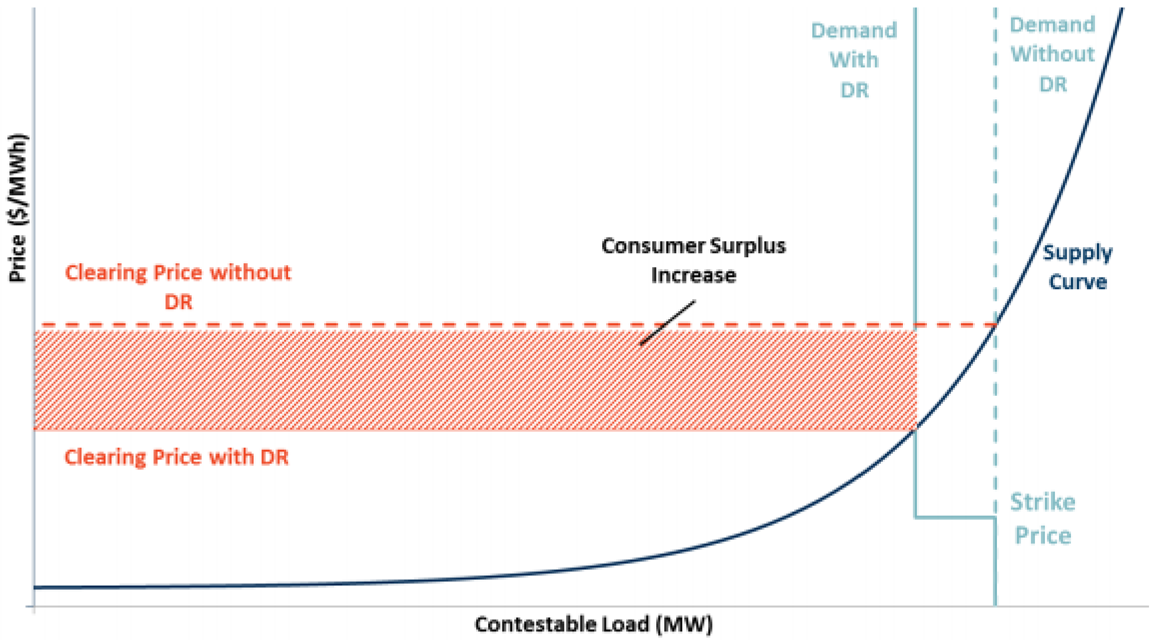
[7] Singapore's real-time market operates on a half-hourly basis. Every half-hour, the spot market determines the dispatch quantity, the required reserves and regulation capacity, and the corresponding spot prices for these products. See EMA, *Introduction to the National Electricity Market of Singapore*, October 2010, p. 2. EMA, *Enhancement to the Interruptible Load Scheme, Final Determination Paper*, August 2018, p. 3.

[8] EMA, *Implementing Demand Response in the National Electricity Market of Singapore, Final Determination Paper*, October 2013.

were centrally determined, the EMA had decided to adopt an approach where the demand response provider submitted its own baseline through a bidding process (instead of a centrally determined historical baseline), and penalizing the provider if the customer in fact uses less than the baseline when not called upon. Under this scheme, financial incentives are paid to load providers based on a demonstrated decrease in energy prices before and after the curtailment event. Cleared demand resources would be paid an amount equivalent to one-third of the additional consumer surplus (orange rectangle in Figure 3), which is capped at the existing price cap of SGD$4,500/MWh (AUD$4,658/MWh).[9] This is as opposed to the Locational Marginal Price (LMP) or LMP minus Generation compensation schemes elsewhere.

Figure 3: Singapore Demand Response program mechanics



Sources: Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, Figure 7.

To participate in the program, licensed load providers (aggregators and participating load) submit demand bids into the engine for the periods in which they intend to offer load curtailments (and comply with the baseline). The demand bids consist of: (1) the quantity of demand that will be taken if the resource is not dispatched (baseline); (2) a series of energy curtailment and price quantity tranches; and (3) the linear ramp rates (MW/min) of the resources.[10] If a demand response resource bid clears, the system operator subtracts the metered energy from the level that was bid at a price of $0/MWh to determine the volume of demand response supplied.

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9 EMA, *Implementing Demand Response in the National Electricity Market of Singapore, Final Determination Paper*, October 2013, p. 4. Conversion to AUD using an exchange rate of 1.04 AUD/SGD, current as of 23 April 2019.

10 See, for example, Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, p. 27. EMA, *Implementing Demand Response in the National Electricity Market of Singapore, Final Determination Paper*, October 2013, p. 13.

- **If the market clears below the strike price**, the DR provider is subject to a penalty if its load falls below 95% of its baseline bid (i.e. if its best guess of its but-for load were inaccurate by at least 5%). We note that there is no symmetric penalty for if actual load were greater than the baseline.
- **If the market clears above the strike price**, the provider is subject to a penalty if its load reduction falls below 95% of the reduction in its bid. If the provider provides less than 100% but more than 95% of the reduction in its bid, it is not penalized, but also does not receive the incentive payment. The provider only receives the incentive payment if it curtails 100% or more of the bid amount (though if the provider curtails more than 100%, it only receives the incentive payment based on its scheduled curtailment).

As historical baselines were said to be prone to gaming, this self-determined baseline was designed to alleviate concerns around artificially inflating baseline consumption (mitigated by the threat of being penalized for load falling below 95% of the baseline bid).[11] However, not all market participants supported the new approach. For example, Enel X (formerly EnerNOC) and Kiwi Power both thought that such an approach would have a side-effect of restricting participation to only the most predictable loads (given the penalties for not consuming at the baseline level).[12] Enel X also disagreed with the EMA's claim that such a methodology would reduce the potential for gaming. In fact, Enel X suggested that if a customer were to expect prices to be high during a specific interval, it could nominate an artificially high baseline. And if the price forecast turned out to be incorrect, it could remain compliant with the high baseline by starting unnecessary plant.

The Demand Response program was implemented in 2016, however participation in the program has been extremely limited. From public press releases, we understand that Diamond Energy became the first retailer to manage capacity (7.2 MW) under the new Demand Response program on behalf of contestable consumers.[13] Red Dot Power launched the eResponse pilot incentive scheme with Ngee Ann Polytechnic, Temasek Polytechnic and Institute of Technical Education (Central and West). The participating institutions were paid an incentive to voluntarily reduce consumption during peak periods.[14] But overall high reserve margins in

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11 This is referring to demand response participants' incentives to increase their baselines because the payment they receive is proportional to the difference between the baseline and actual consumption. Some real-life examples include: Lincoln Paper and Tissue LLC that intentionally reduced its use of on-site generation and drew additional power from the grid and the Baltimore Orioles baseball stadium that turned on stadium lighting despite not having a game in session, all in an attempt to artificially inflated their respective baseline. See, for example, Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, p. 64.

12 EMA, *Implementing Demand Response, Appendix 1 (Response to Stakeholder Feedback)*, October 2013, pp. 6-7.

13 Diamond Energy, *Diamond Energy Achieves Milestone in the Singapore Electricity Market with the First Demand Response Capacity*, December 2017.

14 EMA, *Demand Side Management*, December 2018.

Singapore reduce the frequency of energy price spikes and hence reduce the attractiveness of demand response and the economic value of curtailing load.[15]

On the ancillary services side, there are currently seven facilities registered to provide interruptible load services, with a total capacity of 27.5 MW. To encourage greater demand side participation, the EMA recently made two changes to the Interruptible Load scheme: (1) lower entry barrier by allowing aggregation of load facilities (to fulfil the participation size threshold of 0.1 MW); and (2) deter non-delivery of scheduled interruptible load services (by introducing a penalty for non-performance).[16]

KEY TAKEAWAYS FOR THE NEM

- Demand response participation will be low if penalties are high (and when energy prices are low);
- Energy participation on the supply side can be enabled through a baseline mechanism; the Singapore approach to self-supplied baseline has different vulnerability to gaming than historical baselines, but its enforcement with penalties discourages participation;
- Participation in ancillary services can be attracted by establishing qualification criteria and market mechanics for participation.

2. Alberta

Alberta has a significant amount of industrial loads that respond to real-time price signals without submitting bids into the market (and are therefore hard to monitor).[17] We are not aware of any dedicated emergency or capacity mechanism that gives availability payments to demand response resources to make them available for dispatch. Alberta allows for demand-side bidding in its wholesale energy market, but there is barely any participation there. So the main way for demand resources to formally participate is through the ancillary services markets:[18]

- **Wholesale energy**: Load resources can submit bids into the energy market, but do not currently do so. We had previously observed that large industrial loads respond

15 Plant (or capacity) margin is the proportion by which total expected generation capacity exceeds expected peak demand. Higher plant margins suggest greater flexibility to manage contingencies and higher than expected peak load.

16 EMA, *Enhancement to the Interruptible Load Scheme, Final Determination*, August 2018.

17 Alberta's Department of Energy noted that "Alberta has a significant amount of industrial demand response in comparison to other jurisdictions". See Alberta Department of Energy, *Alberta's Electricity Policy Framework: Competitive, Reliable, Sustainable*, June 2005, pp. 4–5.

18 Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, pp. 28-39. See also, Johannes Pfeifenberger and Attila Hajos, *Demand Response Review*, March 2011.

to price signals in the wholesale energy market, but it is hard to quantify how much since they do not formally participate through the market.

- **Ancillary services**: The main ancillary services product provided by demand response is the "Load Shed Service for imports", which is made up of load customers that agree to be quickly taken offline following the sudden loss of imports coming across the interconnectors. Demand response resources are also eligible to provide contingency reserves such as Spinning Reserves (though none currently do) and Supplemental Reserves.[19,20]

One interesting pathway for demand response participation in Alberta is through its Load Shed Services for imports (LSSi) product, which enables the AESO (the system operator) to restore system balance using load resources in the event of sudden loss of imports over its interconnectors. In particular, for a relatively small system such as Alberta (average load of 9,700 MW), losing the 700 MW interconnector from British Columbia can pose significant security threat (much like losing the Heywood interconnector in South Australia).[21,22] The LSSi product requires load shedding to activate within two seconds of reaching 59.50 Hz.[23,24]

LSSi providers are compensated through a three-step payment mechanism: (1) an availability payment when the resource makes its consumption available to be armed for LSSi; (2) an arming payment when the available consumption is actively armed for LSSi; and (3) a trip payment when the LSSi provider is tripped offline.[25] The AESO conducts a competitive tender to select the least cost portfolio of LSSi resources to maintain system reliability (based on bid in availability and arming prices). The trip price is not bid in during the RFP because it is intended to align with the energy price cap.[26]

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19 Loads do not currently provide Spinning Reserves. To do so, they must provide a minimum of 10 MW within 10 minutes of a directive and for at least 60 minutes following, and must also provide frequency support. AESO, *Ancillary Services – Offer Obligations for Operating Reserve Market*, n.d., pp. 2-3.

20 Loads providing Supplemental Reserves must provide a minimum of 5 MW within 10 minutes of a directive and for at least 60 minutes following the directive. AESO, *Ancillary Services – Offer Obligations for Operating Reserve Market*, n.d., pp. 2-3.

21 AESO, "2018 Annual Market Statistics: Alberta Internal Load," March 2019, p. 6.

22 See, for example, Spees, Kathleen, Samuel A. Newell, David Luke Oates, Toby Brown, Neil Lessem, Daniel Jang, and John Imon Pedtke, *Near-Term Reliability Auctions in the NEM, Lessons from International Jurisdictions*, August 2017, p. 8.

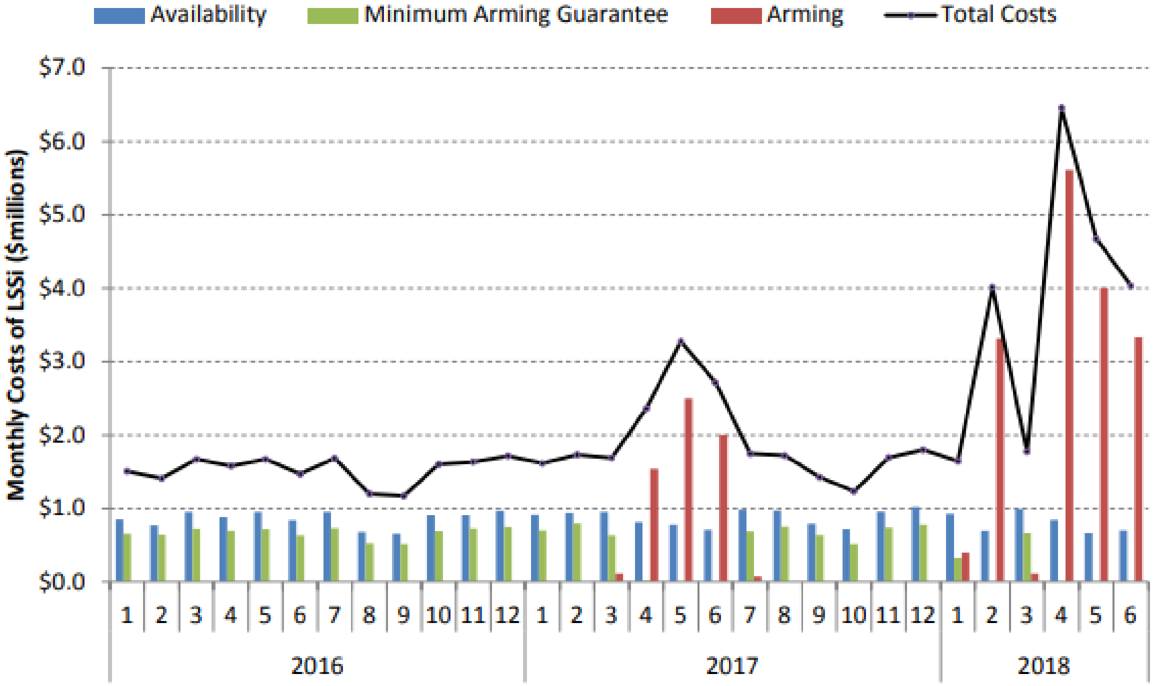
23 AESO, *Load Shed Services for imports, Information Session*, May 2018, p. 12.

24 This operating frequency is different from that in the NEM, which is 50 Hz. AEMO, *Power system requirements: Reference paper*, March 2018, p. 5.

25 Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, p. 38.

26 AESO, *Load Shed Services for imports, Frequently Asked Questions*, May 2018, p. 3.

Figure 4: LSSi costs in Alberta (January 2016 – June 2018)



Sources: MSA, Q2/18 Quarterly Report, Figure 31.

In 2012, Enel X (formerly EnerNOC) was the only demand response aggregator that participated in the LSSi program (along with other selected individual loads); it made up to 150 MW of demand response available to the AESO.[27] Its DemandSMART application automatically detects drops in system frequency and responds by reducing electricity consumption at participating sites in less than a second (well within the required response timeframe). In the latest round of LSSi procurement (June 2018 for delivery in 2019/2021), the AESO contracted 330 MW from seven market participants.[28] Between January 2012 and April 2018, there have been three trip events.[29]

In its review of the LSSi scheme in the second quarter of 2018, Alberta's Market Surveillance Administrator observed that LSSi does not provide as much value to the market, in terms of enabling additional imports when Alberta system prices are high, as expected because most of the LSSi providers already are price-responsive loads that monitor real-time price spikes. At high levels of energy prices, these providers would have already removed their offers to supply LSSi and curtailed their own consumption to avoid the high energy payments; this means that LSSi allows more imports to flow only when "there is a relatively modest differential between pool prices and power prices".[30]

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27 See for example, Enel X, Alberta Electric System Operator Selects EnerNOC To Provide 150 Megawatts Of Automated Demand Response, September 2011. Electric, Light & Power, Johns Manville selects EnerNOC demand response for Alberta, March 2012.

28 AESO, Load Shed Services for imports, accessed April 2019.

29 AESO, Load Shed Services for imports, Frequently Asked Questions, May 2018, p. 4.

30 MSA, Q2/18 Quarterly Report, p. 39.

Additionally, the AESO estimates that there is 200MW of price-responsive load. This includes a small number of large companies that are directly connected to the transmission network and respond to real-time prices.[31]

The Alberta energy market is currently transitioning to a capacity market. We understand that the final design of the capacity market will be similar to that outlined in the final Comprehensive Market Design (CMD) documents. As related to demand response resources, this means that they are eligible to participate on the supply side of the capacity market in order to displace the need for traditional generation resources. If taking on a capacity obligation, the demand response resources will also be required to make offers in the wholesale energy or ancillary services markets (likely on the supply side as negawatts). This wholesale energy market participation is anticipated to significantly increase the market operator's visibility into the quantity, type, location, and availability of demand response at different energy price levels under all system conditions and improve participation in energy price formation. However, since the capacity market will not be operational until 2021, success in this respect is yet to be determined.

KEY TAKEAWAYS FOR THE NEM

- Demand response, even in large MW volumes, can respond very fast if the system values this sufficiently to support the needed technology;
- Ancillary services products are most beneficial if procured and paid for in ways that are aligned with system value (i.e. maximum price paid = the value of the service provided at specific quantities), to avoid overpaying for programs;
- As with other energy-only markets, loads respond to high prices but do not tend to participate in a way that is visible to the system operator. This makes the demand response less valuable;
- Transition to a capacity market and the associated obligation for qualifying resources, including demand response, to participate in the energy markets creates an avenue for the resource to be fully visible and participate in energy price formation – success is yet to be determined in Alberta since capacity market has not yet been implemented.

3. ERCOT

The Electric Reliability Council of Texas (ERCOT) is the energy-only jurisdiction in the US, and is geographically contained within a single state (therefore not subject to the Federal Energy Regulatory Commission's (FERC's) purview).[32] The ERCOT market enables demand

[31] AESO, *24 Month Supply and Demand Forecast*, 6 May 2019; Alberta Direct Connect Consumer Association, *Re: Energy Intensive and Price Responsive Load Capacity Market Concerns*, 16 April 2018, pp. 1-2.

[32] FERC, *ERCOT*, accessed April 2019.

resources to participate through an emergency mechanism, the wholesale energy and ancillary services markets:[33]

- **Emergency**: The Emergency Response Service (ERS) is comprised of load and some generating resources that are paid an availability payment to be deployed in system shortages. ERCOT procures ERS through a competitive tender three times a year, and imposes an availability penalty on load resources consuming *less* than their historical baseline throughout the availability period, which serves to discourage ERS resources from curtailing before being activated, even if energy prices are high. This is similar to strategic reserves where reserves are prevented from reacting to energy prices and are activated only in times of scarcity.[34] When ERS resources *are* deployed, energy prices are adjusted to prevent artificial price suppression.
- **Wholesale energy**: Only "Controllable Load Resources" are currently allowed to participate in economic dispatch, and do so on the demand side. These resources submit demand bids, which create settlement outcomes equivalent to the LMP minus G methodology. These bids modify the economic dispatch demand curve and have the ability to set price.[35] Since dispatch is done every five minutes, these Controllable Load Resources must be able to move load incrementally in either direction every five minutes based on dispatch instructions. In addition, ERS resources are available for dispatch by ERCOT for reliability purposes, and some large loads in Texas are price-responsive, consuming less when prices are high, but their participation is not directly visible.
- **Ancillary services**: Demand response resources that can change their load in response to ERCOT instructions can qualify to participate as "Load Resources" to provide ancillary services. By far the main product that demand response resources provide in ERCOT is the Responsive Reserve Service (RRS), a contingency reserve. RRS loads are large industrial customers with under-frequency relays to curtail load within the first few seconds of a significant contingency. They are allowed to provide up to 60% of total RRS requirements, and the price is set by the highest generator offer accepted. Load Resources can also provide, though to a much lesser degree, regulation services (must respond to signals within five seconds) and non-spinning reserves (must respond within 30 minutes and be able to sustain a specified output level for at least an hour).[36]

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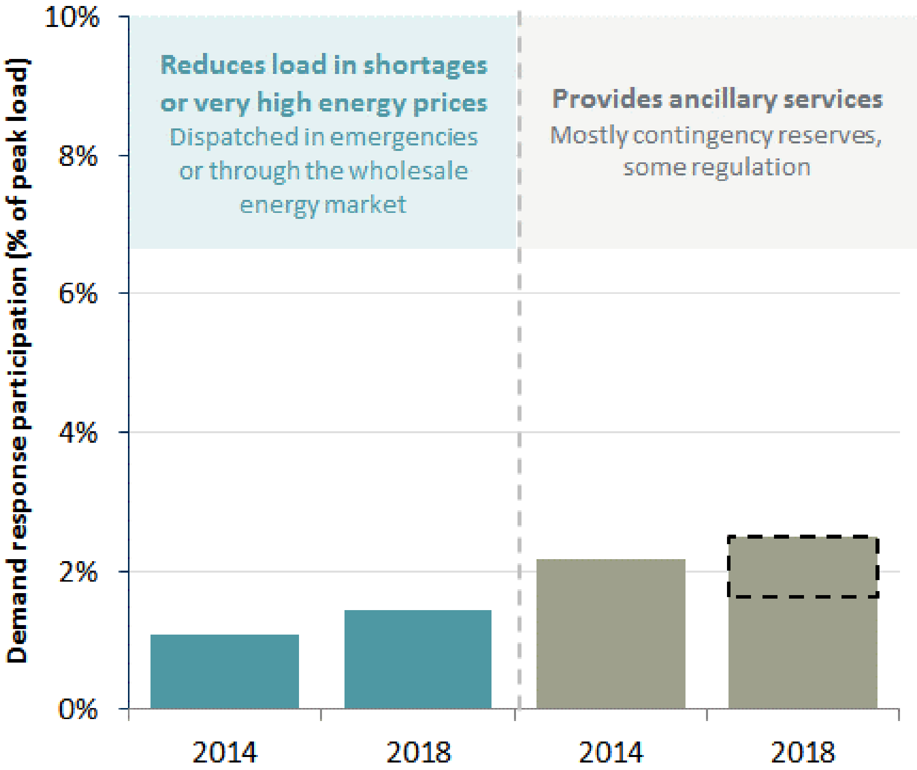
[33] Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, pp. 39-46.

[34] See, for example, Spees, Kathleen, Samuel A. Newell, David Luke Oates, Toby Brown, Neil Lessem, Daniel Jang, and John Imon Pedtke, *Near-Term Reliability Auctions in the NEM, Lessons from International Jurisdictions*, August 2017, pp. 6-8.

[35] ERCOT, *Scarcity Pricing in ERCOT, FERC Technical Conference*, June 2016, p. 13.

[36] ERCOT, *Current Protocols – Nodal: Section 2*, 1 May 2019, pp. 46, 58, and 71-72.

Figure 5: Demand response participation in ERCOT (2014 vs 2018)



Sources and notes: 2014 numbers from Figure 3 in the 2015 Brattle Report.

ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT Region," 4 December 2018, p. 9.

The dotted box represents the range of contingency reserves throughout 2018, based on ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019, pp. 3-5. At the time of the 2015 Brattle Report, the procurement of demand response in the ancillary services market was capped based on a fixed hourly MW requirement for the entire year; following a rule change, ERCOT now allows the hourly MW requirement to be variable. Relative to the fixed level in 2014, there was an increase in DR providing ancillary services in some months in 2018, and a decrease in other months.

Since the 2015 Brattle report, the amount of ERS to meet summer peak has increased substantially, from 432 MW forecast for 2015 to 773 MW of ERS forecast for 2019.[37] This upward trend is temporarily dampened by a minor rule change that has contributed to the decrease of demand response participation in the most recent procurement period. Traditionally, ERCOT's procurement mechanism for these emergency services involved allocating the annual expenditure limit of $50 million across the three annual auctions according to its assessment of the relative risk of an emergency event occurring in each of the three delivery periods. In October 2018, the Emergency Response Service (ERS) scheme was changed to add more granularity to the risk assessment process.[38] This means ERS would procure a similar quantity of demand response resources across the whole year, but focus procurements to the times of year when it is needed most (ie, June to September). As a result, the quantity procured in the period from October 2018 to January 2019 (shown in Figure 5)

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37 ERCOT, *Report on the Capacity, Demand, and Reserves in the ERCOT Region*, May 2014, p. 8; ERCOT, *Report on the Capacity, Demand, and Reserves in the ERCOT Region*, 4 December 2018, p. 9.

38 ERCOT, *2018 Annual report of demand response in the ERCOT region*, March 2019, p. 5.

underestimates the amount procured over a whole year. Excluding the the most recent procurement period, results were fairly consistent in 2018. [39]

Under the ERS (similar to the RERT), loads cannot curtail before being activated. This is enforced through the availability penalty, which is imposed on resources consuming less than their baseline throughout the availability period.[40] This approach is uneconomic because it causes sub-optimal energy consumption and pulls emergency demand response out of energy market merit order and price formation (unlike capacity type participation which allows for both capacity and energy participation). It also causes demand response to offer at higher prices in summer into the ERS since they have to face higher expected cost of consuming unwanted high-cost electricity above their natural strike price.

In June 2015, ERCOT implemented a reliability price adder to mitigate price reversals that occur when ERS or load resources are deployed. While this price adder was designed to prevent reliability deployments from depressing prices, in 2017 it had very little overall effect on market prices (annual average of US$0.16 per MWh) because ERCOT took few reliability actions in that year.[41]

No load resources were qualified to participate in economic dispatch for 2018. We think that this may be due to the high requirements for participation; for example, load resources must be able to respond at five-minute intervals, consistent with the economic dispatch model, and the load must be directly controllable.[42] Alternatively, as in other energy-only markets, loads respond to high prices but do not tend to participate in a way that is visible to the system operator (and the five-minute dispatch requirements increases the hurdle to participation even more than in other energy-only markets). ERCOT continues to work with and gather feedback from market stakeholders in the Demand Side Working Group (DSWG) to explore barriers to load resources in the energy market.[43]

Despite the absence of load resources in energy market dispatch, many customers are still exposed to, and respond to, wholesale market prices to various degrees. ERCOT estimates that up to 401 MW were deployed in 2018 by large commercial and industrial consumers with a "block and index" retail rate, in which they purchase a block of energy at a fixed price, with consumption above or below the block usually charged or credited at the market-index price,

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39 ERCOT, *2018 Annual report of demand response in the ERCOT region*, March 2019, p. 5.

40 See, for example, Spees, Kathleen, Samuel A. Newell, David Luke Oates, Toby Brown, Neil Lessem, Daniel Jang, and John Imon Pedtke, *Near-Term Reliability Auctions in the NEM, Lessons from International Jurisdictions*, August 2017, p. 7.

41 Potomac Economics, *2017 State of the Market Report for the ERCOT Electricity Markets: Independent market monitor for ERCOT*, May 2018, pp. iii and iv.

42 ERCOT, *Load participation in the ERCOT nodal market*, 2015, p. 11-13.

43 ERCOT, *2018 Annual report of demand response in the ERCOT region*, March 2019, p. 5.

and up to 57 MW were deployed in response to real-time pricing offered by retailers.[44,45] Participation more than doubled from a year earlier, in which ERCOT estimated up to 194 MW with a "block and index" product and up to 25 MW with real-time pricing response in 2017.[46]

Finally, load resources controlled by under-frequency relays continue to dominate the volume of demand response resources that participate in the ancillary services markets. The additional demand response participation in ancillary services can be in part attributed to the increase in the participation limit from 50% to 60% for under-frequency relays-type resources.[47] The limit change is coincident with a trend of increasing demand response participation in RRS, with 2018 RRS awards for load resources averaging 1,400 MW in January, and peaking in December at an average of 1,734 MW. More load resources are registered and offering to provide RRS than at any time in the past.

KEY TAKEAWAYS FOR THE NEM

- ERCOT has a large amount of load providing Responsive Reserve Service, some providing emergency response services, and some simply buying less energy when spot prices rise;
- The RRS product (for restoring frequency following large contingencies) is well-suited to large loads that are on under-frequency relays; they get paid regularly and know they will be deployed only rarely;
- ERCOT modified its market rules to ensure that deployment of ERS during shortages does not reverse prices from shortage levels;
- As in other energy-only markets, loads that simply buy less when prices are high are not fully visible to the system operator; market participants prefer this to being dispatchable / controllable by the operator on a real-time basis given that dispatchable participation comes at increased cost to the participant (without offering any greater commercial benefits to compensate for the additional system value of being dispatchable).

B. Updates in markets with capacity obligations

1. PJM Interconnection

The PJM Interconnection (PJM) has included some form of demand participation since 2000, through a pilot program that paid loads to curtail during emergency conditions. Since then,

44 ERCOT, *Price Responsive Load/Demand Response Data Collection: 2016 Version*, August 2016, p. 9; NRG Energy, *Balance your strategy: Block & Index*, 2019.

45 ERCOT, *2018 Annual report of demand response in the ERCOT region*, March 2019, p. 10.

46 ERCOT, *2017 Annual report of demand response in the ERCOT region*, March 2018, p. 8-10.

47 ERCOT, *2018 Annual report of demand response in the ERCOT region*, March 2019, p. 3.

PJM has continued to refine its market rules to enable more efficient and reliable participation in the wholesale markets. Most of the reforms have focused on supply-side participation. Supply-side participation enables demand response providers and aggregators to sell end-users' load reductions (from a baseline) without having to partner with utilities or retailers to capture the benefits of simply buying less on the demand side.

As discussed in our 2015 report, the PJM market enables the participation of supply-side demand response in the capacity, wholesale energy, and ancillary services markets:[48]

- **Capacity**: Loads that are curtailable by PJM are allowed to sell capacity into PJM's capacity market to help meet resource adequacy requirements. Participants must offer into the energy market (and may provide ancillary services), although most offer energy at only a very high "strike price" such that they are curtailable only in emergencies (and dispatched through administrative actions, although they can set the energy price).[49] Capacity payments account for the vast majority of revenues to demand response in PJM, at more than $500 million per year.[50]
- **Wholesale energy**: While the majority of cleared demand response capacity resources participate as load management (capacity commitment) and have high strike prices, less than a quarter participate in the energy market on an economic basis (called Economic DR). Because load management resources typically do not wish to be dispatched until all other resources are exhausted, if they participate in the Economic DR program at all, most submit offers at the price cap.[51] There is also a small number of demand response resources that participate in economic dispatch that do not have a capacity obligation. However, because compensation, despite being at full LMP, tends to be lower than that earned through the emergency program, only a small amount of demand response participates in this way.[52]
- **Ancillary services**: Demand response resources can also choose to participate in the ancillary services markets on an economic basis. Like PJM's emergency demand response products, ancillary service demand response products are dispatched outside of the market, and do not directly respond to or affect the spot price.[53]

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48 Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, pp. 47-58.

49 About 10,500 MW of the 11,000 MW registered as "load management" (demand response that participates by reducing its reliability requirement during emergency/pre-emergency conditions) have an offer price at or above $1,430 MWh (USD $1,000 MWh). See PJM, *Demand response strategy*, June 2017, p. 18.

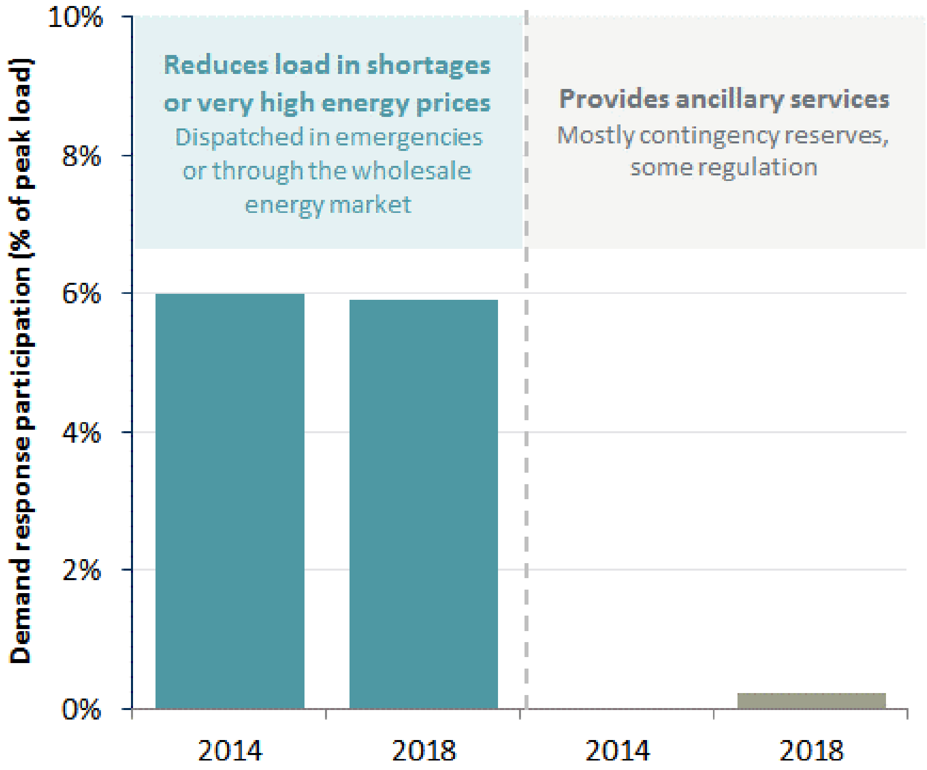
50 PJM, *Demand response strategy*, June 2017, p. 1.

51 While there are 3,495MW registered in the energy market, the amount of Economic DR that is dispatched on high-price days is less than 1,000MW. PJM, *Demand response strategy*, June 2017, p. 25.

52 PJM, *Demand response strategy*, June 2017, p. 18.

53 See, for example, Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, p. 57.

Figure 6: Demand response participation in PJM (2014 vs 2018)



Sources and notes:

2014 numbers from Figure 3 in the 2015 Brattle Report.

2018 numbers based on James McAnany, "2018 Demand Response Operations Markets Activity Report: March 2019," March 11, 2019, pp. 4, 11.

Since our last survey, PJM faced several major issues that could have significantly impacted the participation of demand response: the resolution of the contentious court case *EPSA vs. FERC*, the addition of price responsive demand (PRD), and the introduction of the Capacity Performance product. We discuss below the predicted and actual impacts from these developments.

First, *EPSA vs. FERC* was a case that questioned the jurisdictional authority of FERC (the Federal Energy Regulatory Commission, which oversees PJM's operation) to determine compensation for demand response. The case focused on energy market compensation, but it carried implications for capacity markets too. A ruling against FERC could have eliminated the participation of demand response directly in any of PJM's wholesale markets.

Originally approved in 2012, FERC Order 745 ensured that grid operators paid full Locational Marginal Price (LMP) to demand response resources in the energy market, the same price received by generation resources. In 2014, the DC Court of Appeals vacated FERC Order 745, stating that the FERC had overstepped its jurisdiction when enacting the order (EPSA decision). The DC Court of Appeals pointed out that demand response is not a wholesale sale of electricity, meaning the court did not view demand response as a resale of energy back into the wholesale energy market.[54] The decision then followed that FERC was outside its jurisdiction by regulating such transactions. GTM Research predicted that the appeals decision reduced projected annual growth rate of US demand response from 8.0% to 4.9% through 2023.[55]

In 2016, this decision was overturned by the US Supreme Court, which ruled that FERC had the authority to regulate demand response programs in wholesale markets and upheld FERC Order 745. The decision by the Supreme Court pointed to FERC's jurisdiction over wholesale rates and reliability, and determined that demand response resources affected both of these aspects of the market.[56] As a result, PJM and all other US RTOs retained their wholesale demand response programs; and they were all required to compensate demand response providers that provide energy with the full LMP for hours that pass a "net benefits" test. The net benefits test is intended to ensures that accepted demand response bids are actually saving consumers' money compared to if the load had not been curtailed.[57] As explained in the 2015 Brattle Report, paying customers at the full LMP overcompensates them since they never took title to the energy they are selling. They earn the LMP plus their retail savings from not consuming. This would result in economically inefficient outcomes, leading to greater-than-optimal curtailment and lower prices.[58]

The 2020/2021 Delivery Year has seen Price Responsive Demand (PRD) introduced into its capacity auction for the first time (shown in navy in Figure 7).[59] In PJM, PRD is load that will be offline when energy prices reach a certain strike price, usually above the market's price cap, meaning a PJM emergency event has been declared.[60] While PJM considers demand response to be a supply resource, PRD is considered a change to the demand curve as a demand resource that is factored into the load forecast, though the effect on the capacity market outcome is the same.[61,62] Once the PRD resource clears in an auction, it has a capacity commitment for the delivery year, similar to any other demand response or generation resource.

PJM does not dispatch price responsive demand, rather the Curtailment Service Provider (CSP) is required to have direct supervisory control to dispatch it remotely when conditions are met.

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54 United States Court of Appeals for the District of Columbia Circuit, *EPSA v. FERC*, September 2013, p. 7.

55 GTM Research, *Ruling Against FERC Order Could Cost US Demand Response Market $4.4B in Revenue*, September 2014.

56 Supreme Court of the United States, *FERC v. EPSA*, January 2016, Opinion of the Court p. 1.

57 Gavin Bade, "Updated: Supreme Court upholds FERC Order 745, affirming federal role in demand response," *Utility Dive*, January 2016.

58 Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, pp. 55-56.

59 We note that this product (fully dispatchable) differs from our definition of price-responsive load (non-dispatchable).

60 PJM, Price responsive demand education, May 2017, p. 7.

61 PJM, *Price responsive demand*, 2017.

62 PJM, *Demand response strategy*, June 2017, pp. 15-20.

These CSP are not compensated in the energy market, rather they receive the final capacity price multiplied by their committed capacity, to reflect the system's reduced capacity need.[63] To date, no CSP have participated in PRD due to the complex administrative requirements in maintaining supervisory controls, managing relationships and payments between Load Serving Entities (LSEs), as well as lack of payments from the energy market.[64] However, this will change in the 2020/2021 Delivery Year, when there is more than 500 MW of PRD committed capacity scheduled to become available (shown in navy in Figure 7).

PJM's other major development regarding demand response concerns the reliability of demand response, with PJM introducing more stringent participant rules to ensure reliability similar to generation, and demand response providers claiming that the rules are unnecessarily restrictive. PJM now requires year-round availability, rather than allowing demand response to participate with limited dispatched only in the summer. This change was stimulated by the 2014 Polar Vortex, which saw unprecedented cold-triggered generation outage rates, highlighting that supply shortages could occur outside of summer and that the performance of all resource types had to be solidified.[65] To better support reliability, PJM started the Capacity Performance product, which requires that capacity be available year-round, subject to strong penalties/incentives for performance during shortage events. These requirements will fully apply to demand response as well as traditional generation, starting in 2020 (a transitional, less-restrictive "Base Capacity Demand Resource" product is available until then).[66]

The annual requirement presents a significant barrier to participation for the large amount of summer-only demand response resources (mainly customer air conditioning programs), which now have to pair with an equal amount of winter-only capacity. This is inefficient to the extent that it excludes low-cost summer-only demand response from helping to provide resource adequacy in the summer when load is the highest.[67] Figure 7 shows the transition from Base CP (light blue) to Annual CP (dark blue) and the associated decline of demand response as a percentage of total PJM committed capacity. Other factors have also contributed to the declining demand response participation in PJM's capacity market in recent years, including: more robust measurement and verification requirements, the elimination of interruptible load for reliability, the implementation of a limited demand response cap, and increased operational flexibility requirements.[68]

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63 PJM, *Demand response strategy*, June 2017, Table 3 on p. 16.

64 PJM, *Demand response strategy*, June 2017, p.18.

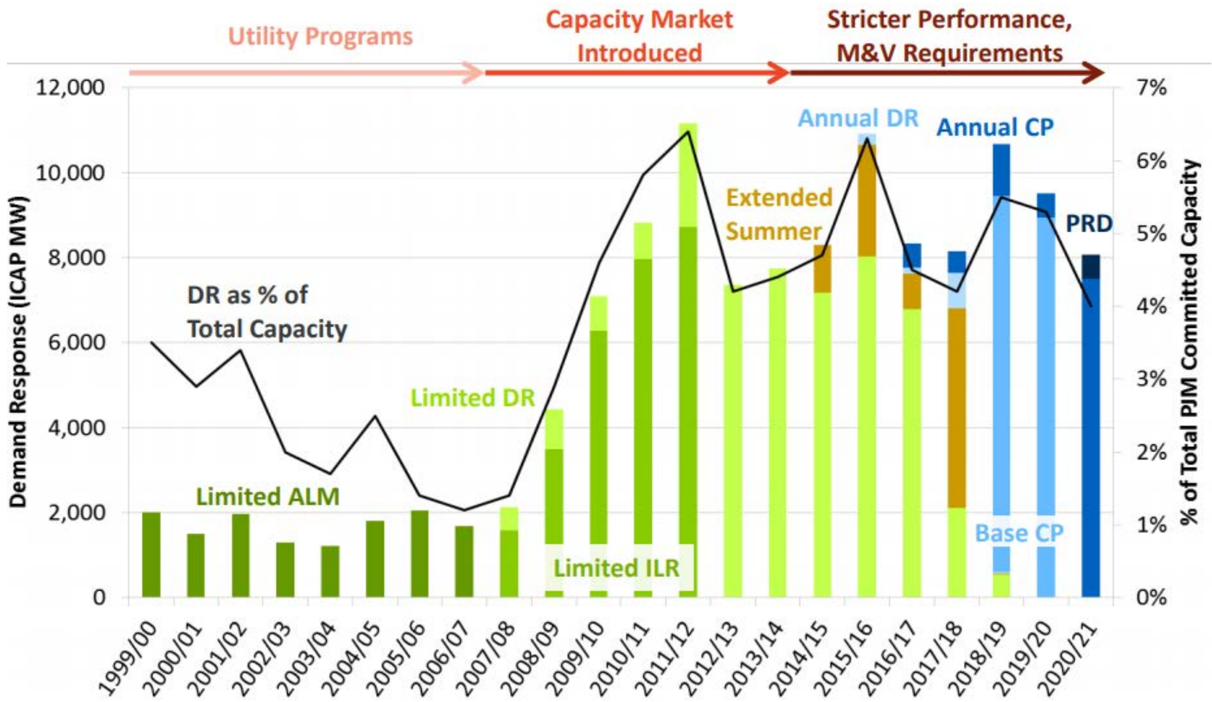
65 PJM, *Strengthening Reliability, An Analysis of Capacity Performance*, June 2018, p. 2.

66 BCDRs are defined as being available June to September for an unlimited number of calls, during the hours of 10 AM to 10 PM with a maximum length of 10 hours. See Toby Brown, Samuel Newell, David Luke Oates, and Kathleen Spees, *International review of demand response mechanisms*, October 2015, pp. 39-46.

67 See, for example, Newell, Sam, Kathleen Spees, Yingxia Yang, Elliott Metzler, and John Imon Pedtke, *Opportunities to more efficiently meet seasonal capacity needs in PJM*, April 2018.

68 PJM, *Demand Response Strategy*, June 2017, p. 15.

Figure 7: Demand response capacity commitment in PJM



Sources: Spees, Kathleen, Judy Chang, Hannes Pfeifenberger, Roger Lueken, and Tony Lee, *Demand response participation in PJM markets*, September 2017, p. 1. See also, PJM, *Demand Response Strategy*, June 2017, Figure 4.

In response to market participant concerns about the lack of seasonal demand response options, PJM set up the Summer-Only Demand Response Senior Task Force to help address the issue.[69,70] So far, the task force has proposed designs to provide emergency-only energy, include fewer non-performance penalties, and pairing of summer-only and winter-only resources.[71] Demand response resources and other market participants have also proposed alternative options, such as a comprehensive two-season capacity market with co-optimized auction clearing, though PJM has not announced any updates along these lines.[72]

In PJM, all of the demand response that is committed for capacity is also participating in the energy market in price formation (on the supply side). Some of it is directly and fully dispatchable in the wholesale energy market, and more participates on an emergency basis with a strike price that applies whenever it is called. There is a mechanism to allow demand resources to set prices in the day-ahead and real-time energy markets, but that it has not been extensively tested to date due to the high strike prices of most demand resources.

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69 Summer-Only Demand Response Senior Task Force, *Problem statement*, p. 1.

70 The Summer-Only Demand Response Senior Task Force was approved in August 2017, with the goal of providing recommendations to the Markets and Reliability Committee (MRC) within 12 months. As of September 2018, the Task Force voted on three proposals, and sent one to the MRC.

71 Summer-Only Demand Response Senior Task Force, *Proposal matrix*.

72 See, for example, Newell, Sam, Kathleen Spees, Yingxia Yang, Elliott Metzler, and John Imon Pedtke, *Opportunities to more efficiently meet seasonal capacity needs in PJM*, April 2018, p. 2.

PJM is exploring ways to move demand response's participation to the demand side of the wholesale electricity market in the long-term. This would avoid the use of baselines, the need for other customers to fund supply-side compensation, and distortions from over-compensating demand response at the full LMP.[73]

KEY TAKEAWAYS FOR THE NEM

- Demand response can be a significant resource in capacity markets;
- Jurisdictions with capacity markets can thereby enable higher demand response participation in the energy market if they require capacity resources to offer; this can contribute to efficient energy price formation if special provisions are in place to allow DR to set energy prices. However, demand response mostly offers at high prices and is not often dispatched, since energy prices are less volatile under the high reserve margins supported by capacity markets;
- Measurement and verification (M&V) can be contentious, but as long as the rules are consistent, demand response can meet the requirements. There is a trade-off between the need for robust M&V and rules that are so costly and onerous that they unnecessarily exclude demand response.

2. ISO New England

ISO-NE has long had substantial amounts of demand response as capacity. But demand response was less integrated into energy and ancillary services markets. As of last year, ISO-NE has "fully integrated" demand response resources across its capacity, wholesale energy, and ancillary services markets. The main effect of this is to bring capacity resources into the economic dispatch of energy and ancillary services, such that they can participate efficiently and set prices:[74]

- **Capacity**: All active demand capacity resources (ADCR) can receive obligations and compensation comparable to generating resources in the capacity market, now subject to the same performance penalties (also effective June 2018).[75] Participation has declined slightly because of that and other changes described in our prior report.
- **Wholesale energy**: Demand response resources can submit demand reduction offers into the day-ahead and real-time energy markets and be committed and dispatched according to the merit order. Participation includes all ADCRs that now must offer into the energy market (can be at the offer cap).

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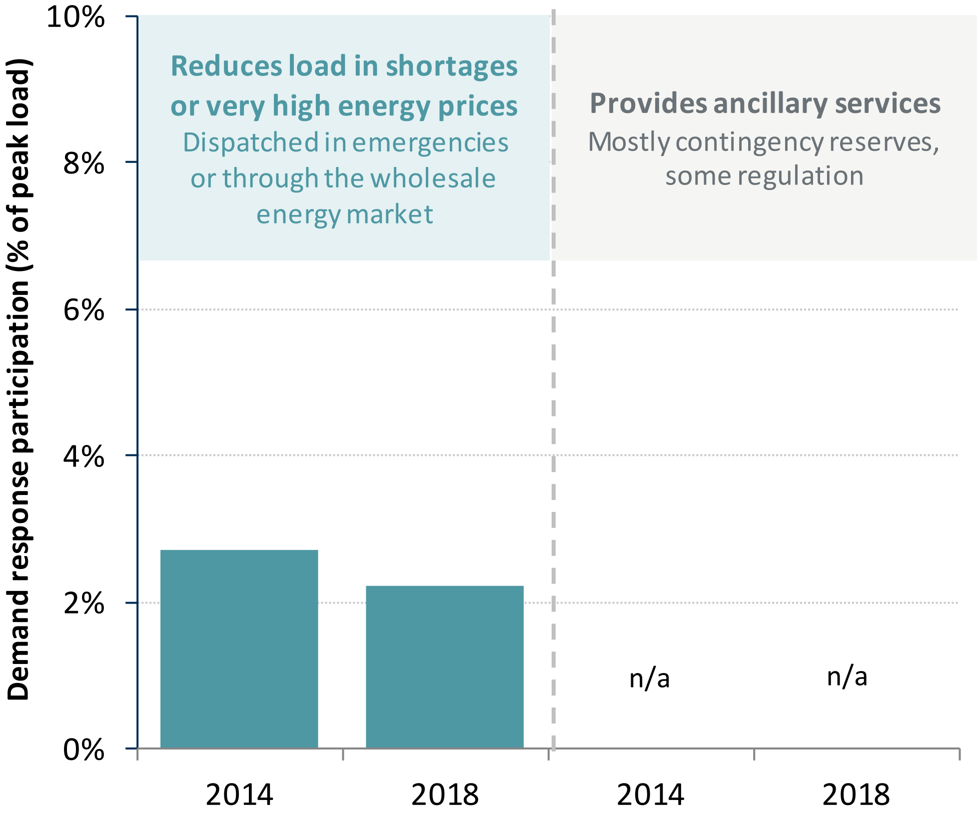
73 PJM, *Demand Response Strategy*, June 2017, p. 39.

74 ISO New England, *Price-Responsive Demand (PRD) Overview*, November 2017, p. 12.

75 "Active" resources respond to dispatch instructions from the ISO, whereas "passive" resources, which we do not discuss in this report, "cannot change the amount saved in response to a dispatch instruction" and include energy efficiency measures. ISO-NE, *About Demand Resources: Types of Demand Resources*, 2019.

– **Ancillary services**: Demand response resources can be co-optimised to provide energy and/or reserves to supply either type of requirement in the most economically efficient manner.

Figure 8: Demand response participation in ISO-NE (2014 vs 2018)



Sources and notes: No information found for ancillary services DR.

2014 numbers from Figure 3 in the 2015 Brattle Report.

2018 numbers based on ISO-NE, "Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the Thirteenth FCA," 6 November 2018, p. 21.

In July 2017, ISO-NE and New England Power Pool submitted market rule changes to fully integrate demand response into New England's wholesale electricity markets; this was approved by the FERC for an implementation date of 1 June 2018.[76] These changes address market participants' concerns that demand response was receiving the same capacity payment as dispatchable generation for capacity, but did not offer the same amount of reliability value. They were also concerned that demand response was only dispatched when called upon in capacity-constrained market conditions and was not part of the energy market's economic dispatch, and all demand resources received capacity payments. In the real-time energy market, this caused large price drops due to decreased demand at times when prices should have been highest.

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76 ISO-NE, Revisions to implement full integration of demand response, July 2017. The integration had been delayed several years due to uncertainty surrounding the status of FERC Order 745 (described in the PJM section, above) which regulates payments to demand resources for providing energy. As a result of this uncertainty, ISO-NE was unable to fully integrate demand resources into existing market structures in compliance with the Order until it was upheld by the Supreme Court.

Being "fully integrated" means that demand resources are also held accountable for failures to dispatch, like traditional resources. Moreover, demand resources now can and must submit economic offers into the day-ahead and real-time energy markets, and they can provide real-time ancillary services for which they are eligible. The market engine co-optimizes energy and ancillary services and sends dispatch signals for the least-cost solution. Like generation resources, demand resources can set prices at their offer price when they are marginal.[77] To incorporate into real-time optimization and price formation, ISO-NE had to accommodate some challenges and approximations unique to demand resources. Our understanding is that these include: for supply and demand to balance when demand response is being dispatched, the short-term demand forecast used in real-time has to be grossed up as if the demand response were not being dispatched; because demand response can involve a portfolio of resources at different nodes within a zone, the ISO assumes they are distributed throughout the zone; and load resources provide less continuous state information via telemetry than generators. Any resulting errors can presumably be accommodated via out-of-merit dispatch and side payments to other resources when necessary.

Integration into the day-ahead and real-time wholesale energy and ancillary service markets also required incorporating demand response resources (DRRs) into ISO-NE's eMarket system, with their own input parameters. Figure 9 lists out the various DRR offer parameters. DRRs may be committed by: (1) non-fast-start DRR clearing in the day-ahead market; (2) non-fast-start DRR committed via Resource Adequacy Assessment day-ahead or the day of; (3) fast-start DRR committed in real time based on optimization engines; (4) lead market participant or ISO requested audits; or (5) manually committed by the ISO control room operator via phone.[78] All commitments will abide by the most current offer parameters.

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77 ISO New England, *PRD conforming changes: demand response full integration*, February 2017.

78 ISO-NE, *Fully Integrated Price Responsive Demand, Detailed Project Overview*, October 2017, p. 46.

Figure 9: ISO-NE DRR offer parameters

Parameter	Description
Available/Unavailable	Flag to indicate if the resource is available to reduce load on the day/hour
Notification Time	Time needed between dispatch instruction and when load begins to reduce
Start-up Time	Time following Notification Time to ramp from zero to Minimum Reduction
Minimum Reduction	Minimum MW the DRR offers to reduce (must be at least 0.1 MW)
Maximum Reduction	Maximum MW the DRR offers to reduce
Price/Quantity Pairs	Up to 10 price/Demand reduction pairs (monotonically increasing)
Interruption Cost	Fixed amount required by DRR to be able to respond to a dispatch
Minimum Reduction Time	Minimum time the DRR must interrupt for if dispatched
Min. Time Between Reductions	Minimum time the DRR must be left in an non-dispatched state following the end of a dispatch
Ramp Rate	The MW/minute rate at which a DRR can vary its performance
Offered Claim 10	The demand reduction that can be achieved within 10 minutes of a dispatch
Offered Claim 30	The demand reduction that can be achieved within 30 minutes of a dispatch

Parameters in blue cannot be modified after the re-offer period

Sources: ISO-NE, *Fully Integrated Price Responsive Demand, Detailed Project Overview*, October 2017, p. 36.

The requirement that demand response be fully integrated in this way results in costs for demand response providers. Providers have said that the requirements are expensive to meet, and not necessary for efficient market outcomes.

KEY TAKEAWAYS FOR THE NEM

- As in PJM, capacity payments continue to attract substantial amounts of demand response. Participation has declined slightly, reflecting a trade-off between ensuring performance of demand response and encouraging participation;
- Demand response is now "fully integrated" into capacity, energy, and ancillary services markets and can contribute to price formation; how well it contributes to price formation has not been tested extensively due to continued high reserve margins.

3. Ontario

Ontario has a dedicated auction for demand response resources, which has cleared more than 150 MW of demand response annually. Though the Independent Electric System Operator (IESO) has found the prices for demand response to be attractive and declining, the Market Surveillance Panel (providing market oversight) is concerned that the demand response-only auction results in prices that exceed system value (because capacity is not needed in Ontario at present and demand response has not been required to compete with other supply technologies).[79] Part of the concern (about favouring a technology) will likely be resolved with the upcoming transition to a capacity mechanism (which will allow different technologies to compete). For now, Ontario enables demand response to participate through the Demand Response Auction, wholesale energy and ancillary services markets:[80]

- **Capacity**: In the past, demand response resources had been procured through long-term contracts between generation owners and the IESO, through Capacity-Based Demand Response (CBDR) contracts. In preparation for the transition to a capacity market, the IESO developed a separate market-based demand response program, called Demand Response Auction (DRA), which came into effect in 2015 (for delivery in 2016). Under this program, cleared resources are expected to be available to provide curtailment services during their availability window (a range of business days and hours during summer or winter).
- **Wholesale energy**: Participants that have a demand response capacity obligation must offer into the wholesale energy markets (day-ahead and real-time), either as a "hourly demand response resource" or a "dispatchable load". Each resource type has a unique set of requirements, with a main difference being the activation timeframe. While a dispatchable load is activated on a 5-minute basis, the hourly demand response product is activated in 4-hour blocks.[81] . The Ontario Market Surveillance Panel estimates that about 1,200 MW of large industrial customers also respond to spot market prices; though we do not know how much of that formally participates in price formation (through participating in dispatch).[82]
- **Ancillary services**: Load is allowed to provide operating reserves.

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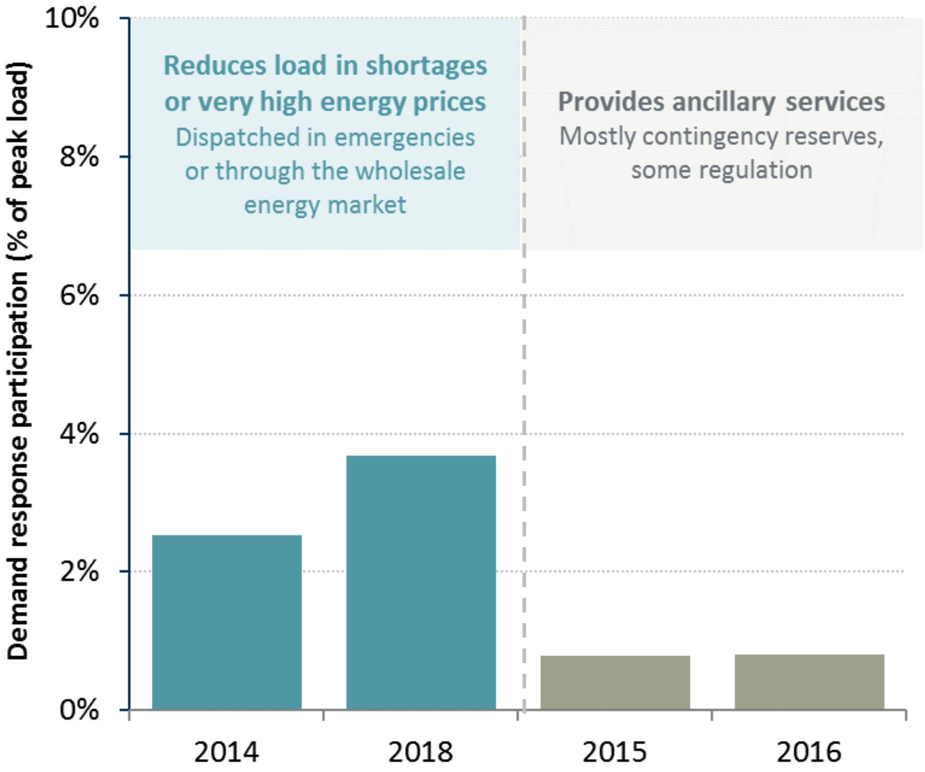
79 Ontario Energy Board, *Market Surveillance Panel Report for the Period from May 2016 to October 2016*, February 2018, p. 12.

80 ISO New England, *Price-Responsive Demand (PRD) Overview*, November 2017, p. 12.

81 IESO, *Market Manual 12: Demand Response Auction*, Issue 6.0, p. 23.

82 Ontario Market Surveillance Panel, "The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches," December 2018, pp. 8-10.

Figure 10: Demand response participation in IESO (2014 vs 2018 unless otherwise specified)



Sources and notes: 2014 and 2013 numbers from Figure 3 in the 2015 Brattle Report.

Demand response auction results for the Winter Commitment Period (2019/2020). IESO, *Demand Response Auction: Post-Auction Summary Report*, December 2018. Includes "virtual DR" (interruptible load and behind-the-meter resources).

2015 numbers for ancillary services from November 2014-October 2015, and 2016 numbers from November 2015-October 2016. Ontario Energy Board Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2016 -October 2016*, February 2018, pp. 53-54.

Since 2015, the IESO has been phasing out the Capacity-Based Demand Response (CBDR) contracts, to give way to a market-based auction procurement process. Each year, the IESO establishes a target demand response capacity level (typically based on MW of expiring previous demand response programs), and selects the least cost portfolio of resources to meet the target.[83] In 2018, the last of CBDR contracts expired, signalling a full transition into the market-based DRA program. So far, each demand response auction has seen growth in consumer participation and significant decreases in capacity costs. The latest one, conducted in December 2018, drew 38 participants and cleared 818 MW for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period for an average price of CAN$52,810/MW-year.[84] Going forward, the IESO proposes to transition this demand response auction into comprehensive incremental capacity auction that requires demand response and all technologies to compete on an equal footing to meet defined resource adequacy requirements. This includes equalising the contribution of 1 MW of capacity to resource adequacy from all resource types, defining a uniform capacity product, and reflecting deliverability considerations in the qualified capacity.[85] As with other capacity markets, we

83 IESO, *Transitional Capacity Auction Design, Phase I Design Document*, April 2019, p. 17.

84 IESO, *IESO Announces Results of Demand Response Auction*, December 2018.

85 IESO, *Incremental Capacity Auction, Participation Model – The Vision*, September 2018, p. 34.

expect that demand response providers will be required to offer into the wholesale energy market, contributing to improved energy price formation.

Alongside the DRA, the IESO is also exploring the potential for demand response to provide further benefits to the system through demand-side participation. Through a competitive process, the IESO procured 70 MW of demand response from Tembec Industries (pulping plant), EnerShift (aggregator), and HCE Energy (demand response participant) to assess the ability of these projects to help balance supply and demand by bidding their consumption in the day-ahead and real-time markets.[86] The IESO is specifically looking into demand response resources' ability to provide services that generating resources current provide, such as 5-minute and hourly load following (adjust consumption based on the 5-minute or hour-ahead market prices) and unit commitment (commitment to curtail a day or hour hours ahead of real-time).[87] The demand response resources in the pilot are expected to vary their consumption in response to IESO dispatch instructions for at least 100 hours per contract year; performance data and pilot results are yet to be released.

KEY TAKEAWAYS FOR THE NEM

- Procurement for capacity (whether through additional generation or load shedding) should be done on a technology-neutral basis;
- As with other markets with a capacity mechanism, must-offer requirements can encourage demand response participation in the wholesale energy markets;
- Ontario is exploring whether demand response can provide other services currently only provided by generators.

86 IESO, *Demand Response Pilot*, accessed May 2019.

87 IESO, *IESO Demand Response Pilot Program, Program Details*, April 2015.

III. European Union

The AEMC asked us to review recent European proposals for a revised Electricity Directive and a revised Electricity Regulation, and to include in this paper a summary of how these proposals might affect demand response. These legislative proposals address demand response specifically, in addition to proposing other reforms to energy market rules. As of March 2019, the European Parliament has adopted these proposals; if the Council of the EU approves them as well (expected May 2019), the Electricity Regulation will take effect on 1 January 2020 and Member States will have 18 months to transpose the Electricity Directive into national law.[88]

The policy rationale for the legislative proposals includes the goal of allowing businesses and households, enabled by technological developments, to participate in the electricity market via demand response solutions, in addition to electricity generation and storage.[89] With regard to demand response, the proposed Directive and proposed Regulation seek to remove existing barriers and encourage all customer groups to efficiently participate in "all organised energy markets, including ancillary services and capacity markets" in response to improved price signals.[90] Recognizing that price signals in most Member States are currently not passed on to customers, the proposed Directive and Regulation seek to make real-time (including day-ahead) price signals more transparent, thus "stimulat[ing] consumer participation, either individually or through aggregation, and mak[ing] the electricity system more flexible, facilitating the integration of electricity from renewable energy sources."[91] Customers should be able "to benefit from price fluctuations and … earn money."[92] The Commission also believes that price signals should "allow for adequate remuneration of flexible resources (including demand-response and storage), as these resources rely on rewards for shorter periods of time" as well as "ensure the efficient dispatch of existing generation assets."[93] As such, the proposed legislation addresses existing price distortions such as regulated prices below cost, which will be phased out, and ensures that "all market participants would bear financial responsibility for imbalances caused on the grid" and be "remunerated in the market on equal terms" in order to

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88 European Commission, *Clean energy for all Europeans*, April 2019, accessed 18 April 2019. See also, European Commission, *Clean Energy for All Europeans: Commission welcomes European Parliament's adoption of new electricity market design proposals*, Press release database, March 2019. Regulations are "directly applicable" and create rights that can be enforced immediately.

89 European Commission, *Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market for electricity*, 2016/0380, February 2017 ("EC Proposed Directive"), p. 3.

90 EC Proposed Directive, p. 31.

91 EC Proposed Directive, p. 5.

92 EC Proposed Directive, p.4.

93 EC Proposed Directive, p.4.

"activate and fully realise the flexibility potential that the demand side can offer."[94] In particular, the proposals seek to:

- **Improve price signals.** Market prices, which are currently distorted through caps, will be improved to reflect scarcity and adequately reward flexible resources such as demand response. The EC wants to phase out all regulated prices, or, at a minimum, those that are below cost.[95] Currently, most final customers are not exposed to real-time price signals; to incentivize active market participation, the proposals entitle final customers to a dynamic retail contract and a smart meter.[96]
- **Establish a framework for the role of aggregators in the system.** While the precise role of aggregators would be defined separately by each Member State, the proposals ensure that contracts between customers and aggregators can be made without the consent of the customer's retailer, and can be terminated within three weeks at the request of the customer.[97] Aggregators can "enter the market without consent from other market participants" and will not be required to compensate suppliers or generators, except in situations where they cause "imbalances to another market participant resulting in a financial cost."[98]
- **Improve data management.** The proposals clarify the role of data management and sharing between final customers and their retailers and other service providers. Final customers are also entitled to receive relevant demand response data from their aggregators at least annually.[99]
- **Raise efficiency in distribution networks.** The Regulation directs the establishment of a European entity of distribution system operators (EU DSO entity), which will coordinate the operation and planning of distribution networks, and assist with the development of demand response.[100]
- **Establish an annual resource adequacy assessment.** The European Network of Transmission System Operators for Electricity (ENTSO-E) is tasked with designing the methodology for an EU-wide assessment of resource adequacy, and conducting the assessment annually. The assessment must consider, among other things, the

94 EC Proposed Directive, pp. 5 and 15.

95 Price-setting intended to protect customers who are energy-poor or vulnerable shall be replaced by other forms of protection. EC Proposed Directive, Article 5.

96 EURELECTRIC, the European electricity industry association, recommended that the definition of "dynamic electricity price contract" be expanded to include time-of-use pricing, critical peak pricing, and real-time pricing. This recommendation was not adopted. EC Proposed Directive, Articles 11, 21. EURELECTRIC, *Dynamic pricing in electricity supply: A EURELECTRIC position paper*, February 2017, p. iii.

97 EC Proposed Directive, Articles 13.1-3.

98 EC Proposed Directive, Article 17.3-4.

99 EC Proposed Directive, p. 19 and Article 13.4.

100 European Commission, *Proposal for a Regulation of the European Parliament and of the Council on the internal market for electricity*, 2016/0379, February 2017 ("EC Proposed Regulation"), (38) and Article 51.1.

"contribution of all resources including existing and future generation, energy storage, [and] demand response."[101]

- **Ensure "equal footing" of all generation, storage and demand resources.** The dispatching and redispatching of generation and demand response resources must be efficient and carried out in a non-discriminatory manner, and network access charges cannot "discriminate between production connected at the distribution level and …at the transmission level" or create disincentives for demand response participation.[102] In the ancillary services market, demand response must be treated "in a non-discriminatory manner, on the basis of their technical capabilities."[103] A recurring theme in the legislative proposals is that different resources should be treated equally, although we do not know what kinds of changes will in practice result from this requirement.
- **Ensure access to the balancing market.** Balancing markets are operated even closer to real-time than intra-day markets, in particular to make sure cross-zonal capacity that is available after the intraday gate closure time is used.[104] "All market participants shall have access to the balancing market, be it individually or through aggregation. Balancing market rules and products shall respect the need to accommodate increasing shares of variable generation as well as increased demand responsiveness and the advent of new technologies."[105]
- **Deliver appropriate investment incentives.** Though market rules will differ in each Member State, they should "deliver appropriate investment incentives for generation, storage, energy efficiency and demand response to meet market needs and thus ensure security of supply."[106]

KEY TAKEAWAYS FOR THE NEM

- The proposed European legislative framework calls for demand response aggregators to be able to contract with customers directly without contracting with the retailer as intermediary;
- The model permits a backstop that requires demand response aggregators to compensate the retailers if curtailment creates a financial cost for them.

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101 EC Proposed Regulation, Article 19.2-4.

102 EC Proposed Regulation, Articles 3.1(i), 3.1(l). 11.1, 12.1, 16.1.

103 EC Proposed Directive, Articles 17.2.

104 EC Proposed Regulation, Articles 2, 5 and 15.

105 EC Proposed Regulation, Article 5.1.

106 EC Proposed Regulation, Article 3.1(f).

IV. Key takeaways for the NEM

We considered three routes for demand response to participate in electricity markets: the wholesale energy market; ancillary service markets; and the capacity mechanism or emergency reserve mechanisms. All three routes are available to demand response in the NEM, although only participation via ancillary service markets (FCAS) and the emergency reserve mechanism (RERT) are directly visible to the market operator and other market participants. Given this context, we think that the most important takeaways for the NEM from the jurisdictions we reviewed for this report are:

- Singapore: The new energy market Demand Response program has now been running for two years, but has seen very limited participation. The Singapore approach to a self-determined baseline, somewhat similar to dispatchable load participating on the demand side, sought to alleviate gaming concerns related to historical baselines. However, the program has seen very limited take-up.
- Alberta: Alberta continues to have significant industrial load that responds to wholesale price changes, however this is not dispatched by the system operator as it is not formally bid into the market. Demand response continues to play an important role in maintaining transmission system reliability, though we note that ancillary service products are most beneficial if procured and paid for in ways that are aligned with system value (Alberta's Shed Services for imports may not be exactly aligned, and be undercut by non-visible price-responsive load). Going forward, we expect that Alberta's transition to a capacity market and the associated obligation to participate in the energy markets will create an avenue for the demand response resource to be fully visible and participate in energy price formation.
- ERCOT: In ERCOT, demand response participation slightly increased from 2014 to 2018. Some of this growth is due to increased participation in the Emergency Response Service (ERS). In addition, in the ancillary services market, large industrial customers provide half of ERCOT's Responsive Reserves for contingencies. In the energy market, some customers respond to high spot prices, and perhaps more will as conditions tighten this summer. But as with other energy-only markets, loads that simply respond to high energy prices without bidding directly into the wholesale market are not visible to the system operator and can't set prices. (As for energy price formation when ERCOT deploys ERS, ERCOT has revised its rules so prices are not supposed to drop from shortage levels).
- PJM: In PJM, wholesale demand response participation remained relatively stable from 2014 to 2018. Capacity resources declined slightly, but ancillary service participation increased slightly. Recent experience shows that rules supporting demand response baselines can be contentious, and that there is a trade-off between the need for robust baselines and rules that are so costly and onerous that they exclude certain demand response providers (the most recent example being the introduction of the Capacity Performance product that precludes summer-only demand response resources from participating without pairing up with a winter-

only resource). But overall, the PJM experience shows that demand response can be enabled on the supply side at very high levels in the capacity market, which also serves to increase energy market participation as a dispatchable resource that can set prices (due to capacity resources' obligation to provide a strike price that can set prices when the resource is deployed during emergencies).

- ISO-NE: In June 2018, ISO-NE became the first US grid operator to fully integrate demand response resources within its dispatch system, imposing participation requirements that are very similar to those that generating resources have to meet. Previously, demand response was not directly incorporated into the DA or RT markets, although it could offer day-ahead and receive a payment if the DA price exceeded their offer. Now demand response is required to offer into both the real-time and day-ahead markets, and can set the price. As in PJM, this shows how the availability of capacity payments can induce participation in the wholesale energy market as a dispatchable resource. However, this development also created new requirements, which demand response participants claim are expensive, onerous, and unnecessary. As in PJM, this seems to be an exercise of finding the appropriate balance between ensuring performance and enabling widespread participation. It remains to be seen whether the benefits of opening up participation outweigh the burdens created by the new requirements.
- Ontario: Ontario currently procures demand response resources for capacity/emergency purposes through a separate market-based demand response program. Going forward, we foresee that this will be replaced by the IESO's technology-neutral capacity market (including both load and generating resources). As discussed before, a transition to a mechanism that requires cleared resources to participate in the energy markets can improve visibility of demand response and improve efficient price formation.
- Europe: The European Commission is considering new legislation, which, if approved (expected May 2019), will require Member States to ensure that demand response is given equal mention as generators and other market participants. It also requires Member States to establish a framework for aggregators in which they will be able to contract with customers without having to contract with the retailer, but they may be required to compensate retailers if the curtailment creates a financial cost. This is consistent with a desire to unbundle demand response from the retail function, but how this will be achieved in practice is not yet clear.

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