

The NSERC Energy Storage Technologies Network (NEST) Project

Working Paper

Distributed Energy Resources (DER) and Energy Storage in Capacity Markets: Experience from the US and Implications for Ontario's Incremental Capacity Auction

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Executive Summary

A Capacity Market (CM) is a market that procures electricity generation capacity through a competitive bidding process. They initially arose as a solution to reliability and revenue sufficiency concerns in the late 1990's in the U.S. as part of liberalized electricity market designs. Their primary purpose being to secure long-term resource adequacy based on forecasted gross demand with the intention to create a more predictable, stable revenue stream that replaces a portion of the less predictable energy-only market.

CMs are a response to market failures prevalent in electricity markets that are rooted in "demand-side flaws". The primary demand-side flaw of concern is inelastic demand. As a result of electricity infrastructure constraints such as a lack of real-time metering, price signals that would cause consumers to reduce consumption during times of scarcity are not received. Because prices do not always affect usage, there may be times of insufficient supply to meet demand resulting in rolling blackouts.

Concerns over revenue sufficiency problems arise from the implementation of price caps in many markets in order to mitigate market power, reduce investment costs and avoid unpopular price spikes, as well as out of market interventions from regulators and system operators that would suppress market prices. The primary goal of a CM is therefore to optimize the duration of blackouts and to meet administratively set resource adequacy goals which are usually expressed as a required reserve margin, through procuring the lowest cost firm capacity. The other approach to these problems is energy-only markets with no price caps that rely on very high prices (\$9,000/MWh) to recover investment costs. The ability of both these approaches to facilitate the clean energy transition are currently being called into question and are sources of much debate.

CMs have been successful in maintaining system adequacy targets despite fleet retirements, with clearing prices generally below the net cost of new entry (net CONE) while still attracting new merchant investment, retaining existing capacity and procuring cost-effective resources such as demand response (DR) and uprates which has deferred the need for costly new generation. However, CMs are not without their challenges and as constructs constantly evolving with market conditions and regulations, since their inception they have been subject to much debate and questioning as to their effectiveness.

A major current challenge in CMs is a result of increasing shares of VRE in the electricity system and persistently low natural gas fuel prices that have raised resource adequacy and revenue sufficiency concerns particularly as many ISOs are seeing retirement of conventional generating units such as nuclear and coal plants that have reached the end of their lifetime or can no longer recover their costs as a result of suppressed market prices. VRE has low operational

costs and therefore bid in near zero in the energy market resulting in the "merit order effect" where conventional higher operating cost generators are pushed out of the market. This can occur as well in CMs where VRE's can bid in artificially low due to out of market subsidies and in the US State Renewable Energy Portfolios. Citing reliability concerns many ISOs have proposed changes to CM design that in effect limit the participation of VREs in CMs through mechanisms such as minimum offer price floors and two stage auction mechanisms that keep CM prices high enough to ensure conventional generators are not pushed out of the market. However, the purpose of keeping CM prices high is called into question if CMs are supposed to be able to send price signals for resources to exit the market when it makes economic sense and without sacrificing reliability, especially if additional capacity is already being procured through state renewable energy portfolios and this leads to oversupply¹. Furthermore, it is rarely recognized that fossil fuel generators also receive out of market subsidies from upstream subsidies provided for the development of the fracking industry for example.

It has also been recognized by some that due to the strong connection between natural gas and electricity prices that natural gas enjoys a natural hedge in CMs as both their capital costs and their operational costs are de-risked, whereas low operational cost generators only receive a partial derisk on their capital costs as a result of capacity payments. At the same time, there is no consensus on how the qualifying capacity of VRE should be determined, or if VRE should be subject to performance penalties when there is no wind or sun, which is evidence by the wide range of approaches employed across ISOs and depending on design may negatively impact the business case of VRE generators. As more VRE begin to be paired with energy storage systems, how these systems are to be properly valued also need to be considered.

Distributed energy resources (DER) can deliver a wide range of benefits in terms of carbon reductions, local economic benefits, efficiency of the grid, grid infrastructure asset deferral, and other grid services. However, DER provide a challenge to CMs due to a lack of 'visibility' on the extent of BTM resources in distribution grids which creates difficulties in accurately forecasting demand which forms the basis of CM procurement targets.

Market rules and electricity infrastructure have been designed for centralized generators to deliver a one-way flow of electricity to consumers. As a result, DERs have seen limited participation in CMs in the US to date. This is in part due to technology barriers that are characteristic of DER in general such as the need for grid infrastructure investments that allow bidirectional flow of electricity, metering at higher granularity and improved communication and telemetry between facilities and the distribution and transmission grid operators. However, existing market rules and regulations designed around centralized generators also do not account for the different operational characteristics of DERs which have prevented technologies such as energy storage from providing their full value to the grid. DR and energy efficiency (EE) have seen more success in CMs, having steadily grown since participation in CMs

¹ Byers, C. Levin, T., and Botterud, A. (2018). Capacity market design and renewable energy: performance incentives, qualifying capacity, and demand curves. *The Electricity Journal*, 31. 65-74

began in the early 2000's. Although, recently there has been a decline due to increasingly stringent measurement and verification rules, as well as uncertainties around ongoing rule changes.

As behind-the-meter generation (BTMg) is generally not allowed to participate in CMs due to their small capacity and lack of direct connection to the transmission grid, DR has been the primary avenue for participation of DER. While much of this has been through load reduction methods, the contribution of BTMg to DR has been primarily from onsite fossil fuel generators. FERC orders that have mandated the integration of DR and energy storage into all markets (capacity, energy and ancillary) should allow for increased participation of DERs going forward. Although, this ultimately depends on the design of the market rules, with many concerns already being raised by the Energy Storage Association around the proposed designs in each ISO.

The key policy question now is not whether market revenues are sufficient to allow conventional generation to survive but whether those revenues are sufficient to maintain some form of capacity that is capable of supporting a reliable electricity system². In order to ensure resource adequacy while achieving a low carbon energy system alternative market designs need to be considered that can provide emerging system quality needs in the face of highly variable net demand forecasts as a result of higher shares of VRE. How to value flexibility is gaining increased attention in market designs, however very few have developed concrete mechanisms, and those that have only procure short-term flexibility. Following the same lines of argument for a capacity market to procure long-term firm, a mechanism to ensure flexible resources are in the system for the long-term may also be needed. Some proposals already exist that adapt CM designs to value flexibility and other system qualities rather than just firm capacity. Furthermore, CMs currently lack any means of valuing carbon and a more economically efficient way to deal with out of market subsidies and to transition to a low carbon energy system would be to integrate carbon pricing into the market rather than redesign the CM to neutralize the impact of the subsidies.

² Bushnell, J. Flagg, M., and Mansur, E. (2017). Capacity markets at a crossroads. Energy Institute at Haas.

Introduction to Capacity Markets

Capacity markets (CM) initially arose as a solution to reliability and revenue sufficiency problems in liberalized electricity markets that were based on concerns around low spot markets prices being insufficient to attract new generation and meet reliability goals. This is often termed the “missing money problem”. These resource adequacy problems are rooted in what are called “demand-side” flaws in electricity markets.

Demand-side Flaws and the Resource Adequacy Problem

A common premise across many electricity market designs is that a large number of competitive generators deliver electricity supply while regulatory measures act to eliminate or limit the exercise of market power and the associated price distortions they can cause³. In these markets, marginal cost pricing results in cost-effective dispatch and compensation for generator’s operational costs. As generators bid in their marginal cost of generation, which is closely related to their operations costs, they primarily rely on scarcity events in order to recover their fixed and operational costs. Scarcity events occur when market clearing prices rise above their marginal cost as demand increases and supply becomes limited.

According to theoretical free-market principles, when supply become scarce, the price should rise until there is enough voluntary load reduction to absorb scarcity⁴. However, electricity markets deviate from these principles causing what are known as “demand-side flaws”. Chief among these are that consumers do not receive price signals that would normally cause them to reduce their consumption to a level that the market would always clear. This is mainly caused by a lack of real time meters, and billing and other equipment that would allow consumers to see and respond to price signals⁴. As a result of this inelastic demand, prices do not affect usage, which can potentially result in times of insufficient supply to meet demand no matter how high the price for electricity is, resulting in rolling blackouts. During rolling blackouts there is no competitive market price so the price must be set administratively. These demand-side flaws have led to policy-based reliability requirements and administratively set pricing rules such as price caps that give rise to revenue sufficiency problems³. Price caps are instituted in many markets to help alleviate market power, price gouging concerns, reduce investment costs and limit unpopular price spikes. However, they also exacerbate the revenue insufficiency or the so-called “missing money problem”⁵.

One of the primary goals of electricity markets has to be to ensure resource adequacy at cost-effective prices. Resource adequacy seeks to ensure that the level of installed capacity results in a very low probability, size and duration of blackouts. Loss of load probability (LOLP) is often used to calculate the common loss of load expectation (LOLE) of 1 day/10 years, however, this

³ Frew., et al. (2016). Revenue sufficiency and reliability in a zero marginal cost future. NREL.

⁴ Cramton, P., Ockenfels, A., and Stoft, S., (2013). Capacity market fundamentals. *Economics of Energy & Environmental Policy*, 2 (2).

⁵ Levin, T., and Botterud, A. (2015). Electricity market design for generator revenue sufficiency with increased variable generation. *Energy Policy*, 87. 392-406

reliability target is set by policy and can be higher or lower⁶. Ontario adheres to the Northeast Power Coordinating Council (NPCC) requirement of 0.1 days per year⁷. If higher reliability targets are desired extra capacity needs to be built, however this capacity may only be needed for a short time during the year and must recover both operational and capital costs in a small number of hours during the day, therefore not having the opportunity to earn sufficient revenue to remain in the market.

Market Approaches to the Resource Adequacy Problem

There are two main approaches to solving the resource adequacy and missing money problem so as to incentive the correct mix of generation technologies: 1.) the price-based approach (energy-only markets), and 2.) the quantity-based approach (capacity markets).

Energy-Only Markets

By setting a high price cap the energy-only market approach relies on scarcity prices reaching very high levels so that generators can recover their costs. The price cap is set at the value of lost load (VoLL), which is the amount that consumers would pay to avoid having power supply interrupted, and the market builds capacity up to the point where it can recover its costs from being paid the VoLL times the duration of the scarcity event⁸. Unless reliability is already included as a component of electricity prices, energy-only markets do not ensure that these reliability targets are met while simultaneously balancing supply and demand and providing sufficient revenue to all resources. Therefore, in practice these markets are accompanied by operating reserve markets to ensure that reliability goals are achieved.

The Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) are the two energy-only markets in the US. ERCOT is more prominently discussed in the literature due to the interactions of high shares of variable renewable energy (VRE) in the market. In ERCOT price caps have been raised to \$9,000 per MWh, and to address the growing resource adequacy concerns an Operating Reserve Demand Curve (ORDC) was implemented in 2014 based on a proposal by Hogan (2012). The ORDC automatically increases electricity prices through a real-time price adder, which reflects the VoLL, as operating reserves get tighter (**Figure 1**). One of the main challenges with this model are that it relies on having sufficient scarcity pricing events, which are optimized at a lower reserve margin of around 11%⁹. With wind buildout reaching 18 GW, reserve margins have reached 17% in ERCOT and more low-marginal cost generation has reduced the amount of scarcity events. As energy efficiency and VREs continue to be added to the system, combined with cheap NG, there are concerns over the future sustainability of this model as low prices may discourage generators from building new plants. The impact of the

⁶ Frew., et al. (2016). Revenue sufficiency and reliability in a zero marginal cost future. NREL

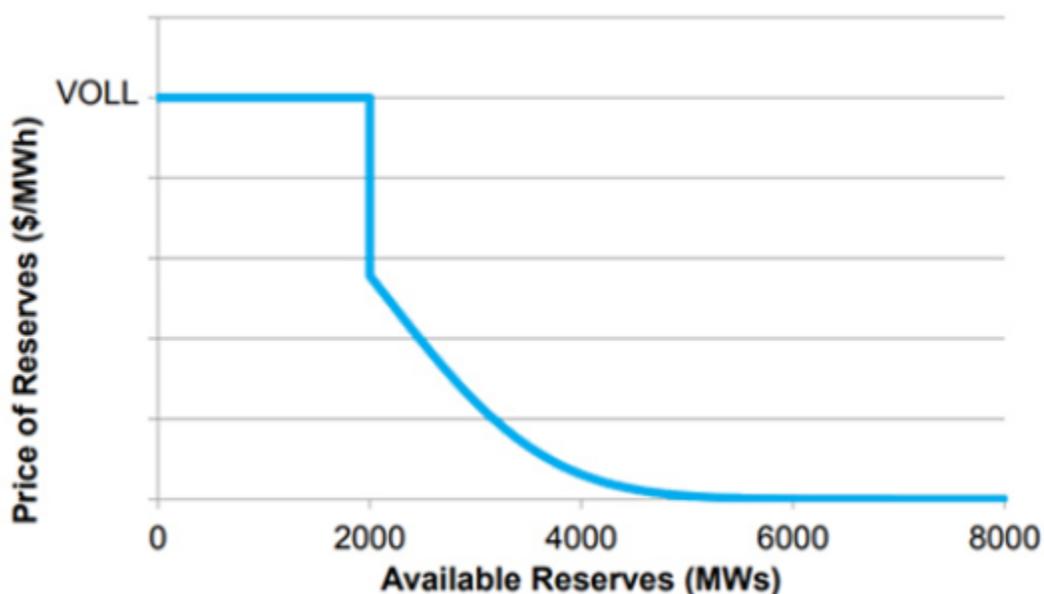
⁷ IESO. (2017). Incremental Capacity Auction: Stakeholder engagement phase 1 – Fundamentals. Meeting #2.

⁸ Cramton, P., Ockenfels, A., and Stoft, S., (2013). Capacity market fundamentals. *Economics of Energy & Environmental Policy*, 2 (2).

⁹ Bade, G. (2017). The great capacity market debate: Which model can best handle the energy transition? *The Utility Dive*.

Federal Renewable Electricity Production Tax Credit which provides a value of \$23/MWh for wind, has been blamed by the Commissioner of the Public Utilities Commission of Texas for suppressing market prices, although it should be noted that low NG prices also contribute to the price suppression problem¹⁰. What seems to be absent from these discussions, however, is that in the absence of a carbon pricing mechanism the tax credit can be seen as valuing the market externality of carbon emissions that are avoided by renewably produced electricity. Furthermore, upstream subsidies provided to the NG industry as contributing to artificially low fuel costs for NG plants are rarely mentioned.

Figure 1. ERCOT Operating Reserve Demand Curve



Capacity Markets

The fundamental purpose of a CM is to provide the amount of capacity that optimizes the duration of blackouts¹¹. The basic idea behind CMs are to secure long-term resource adequacy based on forecasted gross demand by holding auctions where new and existing generation bid for capacity payments that would induce generators to remain in or enter the market. The CM essentially tops up the energy price to a level of capacity that results in the optimal duration of blackouts¹¹. In the US, CMs have been used beginning in the mid-2000's by the New England

¹⁰ Bade, G. (2017). The great capacity market debate: Which model can best handle the energy transition? *The Utility Dive*.

¹¹ Cramton, P., Ockenfels, A., and Stoft, S., (2013). Capacity market fundamentals. *Economics of Energy & Environmental Policy*, 2 (2).

ISO (NE-ISO), the Pennsylvania New Jersey Maryland Interconnection (PJM), the mid-continent ISO (MISO) and the New York ISO (NYISO).

In general, capacity products are designed to meet the reliability objective of the grid operator, to be technology agnostic or neutral, and taking into consideration of locational constraints if transmission constraints limit deliverability between locations. Key features of market design include capacity procurement methods, auction procedures and products, the demand curve, the forward and commitment periods, and the supply curve. **Table 1** outlines some of the key features of CMs between ISOs. In centralized CMs the ISO establishes a resource adequacy requirement that sets a target amount of capacity to be procured from the market. The buyers in capacity markets are those who hold the resource adequacy obligation. In the US these are load-serving entities (LSE) who are responsible for securing energy and transmission services and related interconnected operations services to serve the electrical demand and energy requirements of its end-use customers. The ISO either acquires the capacity and then allocates costs to the LSEs as in the ISO-NE, or the LSEs can choose to self-supply with the approval of the ISO, as in the PJM, and the ISO procures the required capacity net of the self-supply. In the NYSIO the auction is voluntary and is used to assist LSEs in making incremental adjustments to their self-supplied capacity.

Table 1. Key features of US CMs.

	PJM	MISO	ISO-NE	NYISO
First Auction	2007/2008	2013/2014	2010/2011	2006/2007
Forward Period	3 years	Short term (~2 months)	3 years	Short term (~2-30days)
Commitment Period	1 year	1 year	1 year	6 months or for a specific month
Procurement	<ul style="list-style-type: none"> • Bilateral • Mandatory Auction 	<ul style="list-style-type: none"> • Bilateral • Voluntary Auction 	<ul style="list-style-type: none"> • Bilateral • Mandatory Auction 	<ul style="list-style-type: none"> • Bilateral • “Back stop” capacity at fixed price

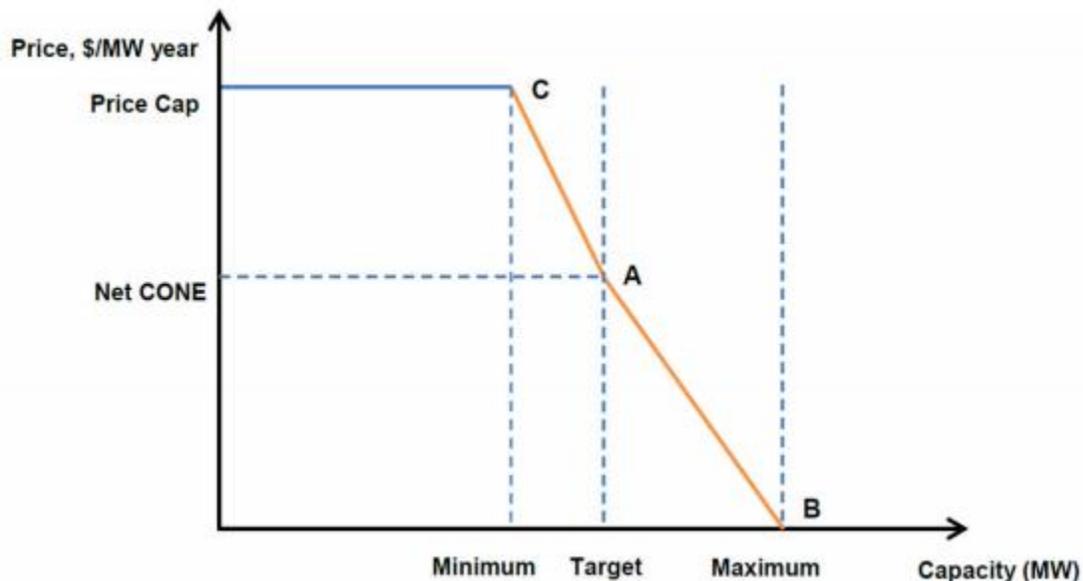
To determine the amount of capacity to be procured in each zone ISOs implement administratively set demand curves which reflect estimated demand at associated price levels and reflect the buyer’s willingness to pay for various levels of capacity ¹² (**Figure 2**). Demand curves are based on the net cost of new entry (net CONE) for a specified reference technology (typically a gas-fired simple-cycle combustion turbine, which is equal to the difference between investment costs and variable profits, and is the estimated capacity revenue that would be

¹² Jenkin, T., Beiter, P., and Margolis, R. (2016). Capacity payments in restructured markets under low and high penetration levels of renewables. NREL.

necessary for the investment to be profitable. Suppliers then make bids until the supply curve and the demand curve meet which sets a uniform clearing price that is paid to all resources that cleared the market.

The timing parameters of CMs are determined by the commitment period the forward period, delivery period and rebalancing auctions. The commitment period is the length of time which sellers are required to deliver their capacity obligations. Longer commitment periods are favourable for entry of new builds as it provides better price certainty and therefore makes obtaining financing easier. On the other hand, longer commitment periods rely on longer demand forecasts and therefore increase the risk of building capacity that ends up not being used. Seasonal commitment periods are important to properly value assets that have seasonal variability such as demand response aggregators that can cycle air conditioner loads in the summer, and VRE resources that vary output between seasons.

Figure 2. Demand Curve Concept¹³



The forward period is the length of time between the auction and the start of the commitment period. PJM and the ISO-NE have 3 year forward periods. The NYISO uses a spot auction that clears two to four days prior to the start of the month. Longer forward periods allow more time for new builds to be constructed, while resources such as demand response (DR) prefer shorter forward periods to reduce difficulties in securing individual customer far in advance. Longer periods also create greater potential for demand forecast errors¹⁴. To mitigate uncertainties

¹³ London Economics International LLC. (2017). Issues related to demand curves in capacity markets. Prepared for the AESO Adequacy & Demand Curve Working Group.

¹⁴ Charles River Associates. (2017). A case study in market design and considerations for Alberta.

with longer forward periods rebalancing auctions are typically employed that adjust capacity commitments according to changes in supply and demand. This enables suppliers to buy out of forward positions due to unforeseen circumstances and can facilitate participation of resources that did not participate in the forward auction or resources that cannot as easily make forward obligations such as DR¹⁵.

Two other important aspects of CMs are performance obligations and market power mitigation measures. Performance obligations ensure that capacity that has cleared the auction is available when needed and performs as required¹⁶. This commonly takes the form of must-offer provisions that requires suppliers with performance obligations to offer a quantity of energy or ancillary services at least as great as the qualified capacity that cleared the capacity auction into the day-ahead, real-time or ancillary markets. The qualified capacity is usually based on the unforced capacity (UCAP) which is the installed capacity (ICAP) of a resource derated for the expected level of outages. Since UCAP values are based on prior-period availability, this acts as an indirect performance incentive¹⁷. Markets may also employ performance penalties for those resources that fail to meet their obligations.

Market power concerns arise when there are few competitors in a constrained delivery area which can lead to a situation where one supplier becomes pivotal in that the demand in that areas cannot be met without their supply. Buyer market power can arise if there a large buyer of capacity that can depress prices by offering its required capacity below its cost¹⁶. Pivotal Supplier Tests (TPS) are often used by independent market monitors to measure the potential for seller market power, which can impose offer caps on those that fail the test. Other mechanisms include mandatory participation by existing facilities with price caps or price-taker requirements, and minimum offer price rules (MOPR) which limit a buyer's ability to depress clearing prices through its qualified capacity offers¹⁶.

The main challenges associated with CMs are the uncertainties involved with predicting demand, determining the amount and location of capacity needed many years in advance, and integrating diverse products that blend capacity and energy¹⁸. CMs can also be susceptible to manipulation by generators and loads due to their preset procurements, which leads to the need for regulations on offers and performance, bid mitigation, and other complications. For example, in 2018 the PJM independent market monitor found that energy markets have been workably competitive, while CMs have failed the three pivotal supplier tests (TPS), finding that structural market power is endemic to the CM¹⁹.

¹⁵ The Brattle Group. (2017). Capacity auction forward-period. Pros and cons of spot vs. forward auctions. Prepared for IESO ICA Fundamentals and Concepts Stakeholder Meeting.

¹⁶ Charles River Associates. (2017). A case study in market design and considerations for Alberta.

¹⁷ Byers C., Levin, T., and Botterud, A. (2018). Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves. *Electricity Journal*, 31. 65-74.

¹⁸ Hogan, W. W. (2012). Electricity scarcity pricing through operating reserves: An ERCOT window of opportunity.

¹⁹ Independent Market Monitor for PJM. (2019). State of the market report for PJM. Section 5: Capacity Market

Both of the energy-only and CM approaches can solve the resource adequacy problem, and both require regulatory intervention, so the choice between the two comes primarily comes down to factors such as risk, market power and coordination of investment²⁰.

The Impact of Unconventional Resources- Demand Response, Energy Efficiency, Behind-the-meter-generation, and Variable Renewable Energy

Unconventional resources present some challenges for CMs. DR and energy efficiency (EE) can be difficult to measure and evaluate and have resulted in complicated rules and processes that can increase the difficulty of participation²¹. A concern around DR and EE, particularly in the PJM, is that if LSEs implementing DR or EE receive a benefit from the corresponding reduction in their obligation to pay capacity costs then they should not also receive a capacity payment from the CM for making those reductions²².

Because of the intermittent production of VRE nameplate capacities are derated when determining their qualifying capacity. **Table 2** shows the variety of qualifying capacity values assigned to new resources across ISOs. As energy storage penetration increases, qualifying capacity calculations will need to evolve to properly credit a mix of VRE and storage that can be used to ensure delivery during peak demand hours²³.

Table 2. Qualifying Capacity Values of new VRE resources in US capacity markets.

ISO	Wind	Solar
PJM	14.7–17.6%	38%–60%
ISO-NE	9–18% (summer)	27–33% (summer)
MISO	15.6%	50%
NYISO	10% (summer) 30% (winter) 38% (offshore, both seasons)	26–46% (summer) 0–2% (winter)

The increasing shares of VRE has reignited concerns around the revenue sufficiency problem. VRE is characterized by near-zero marginal costs and variable output. This allows VRE to make near-zero bids into energy markets, or in the case of out of market subsidies such as the Federal Renewable Electricity Production Tax Credit (PTC), VREs can bid negative prices. This has the effect of suppressing market prices and reducing energy sales for other generators, by displacing generators at the top of the dispatch stack. This is referred to as the “merit order effect” where more expensive resources are pushed up or off of the dispatch stack. Out of market subsidies also include corporate and State Renewable Portfolio Standards (RPS) that

²⁰ Cramton, P., Ockenfels, A., and Stoft, S., (2013). Capacity market fundamentals. *Economics of Energy & Environmental Policy*, 2 (2).

²¹ Bushnell, J. Flagg, M., and Mansur, E. (2017). Capacity markets at a crossroads. Energy Institute at Haas.

²² Charles River Associates. (2017). A case study in market design and considerations for Alberta.

²³ Byers C., Levin, T., and Botterud, A. (2018). Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves. *Electricity Journal*, 31. 65-74.

mandate utilities to obtain a set capacity or percentage of production from RE through the purchase of renewable energy credits (REC), which provides out of market revenue to the generators. This applies mainly to investor-owned utilities; however, some States also include municipalities and rural electric co-ops in these mandates.

Concerns over low CM prices as a result of VREs and partly exacerbated by subsidies have led to some market design proposals to mitigate these impacts. Most prominently, the ISO-NE has introduced a proposal for a two-settlement capacity auction, the Competitive auction with Subsidized Resources (CASPR), which came into effect in 2018 after a split FERC decision. The first auction clears according to the current market rules but removes the minimum price offer (MOPR) exemption for VREs which has the effect of limiting the participation of most VRE resources. The second stage is a substitution auction where existing capacity resources with retirement bids that retained capacity obligations in the primary auction may transfer their obligations to subsidized resources that did not clear in the first stage. The transferring resources pay the subsidized resources for accepting the capacity obligation and then must retire from the CM²⁴. PJM has also made similar proposals to FERC to deal with subsidized resources by removing subsidized resources from the market and raising clearing prices for remaining resources such as coal and gas plants. However, the proposals were rejected. Two new proposals have been submitted that are still pending²⁵. Such proposals seek to maintain higher capacity prices; however, it is unclear what purpose this serves when additional capacity has been procured through state subsidies, especially if this leads to over capacity²⁶.

Stakeholders opposed to these approaches are calling for more granular capacity products instead of deciding what resources should dispatch for an entire year²⁷. NYISO is an example of this where seasonal capacity auctions prior to the start of each six-month season are followed by monthly secondary auctions. This means that prices change to account for shifting needs in reliability during peak seasonal times of demand. On the other hand, shorter term seasonal markets require more complicated design, reduce investor uncertainty due to difficulties forecasting price outcomes, require higher price caps which increases volatility and consumer risk and seasonal resource adequacy targets are more difficult to create due to the distribution of probabilities over a shorter period of time²⁸. Despite these potential drawback, studies on moving NYISO away from a spot CM to a forward CM have concluded that while longer forward

²⁴ ISO-NE. (2017). Competitive auctions with subsidized policy resources. Retrieved from: https://www.iso-ne.com/static-assets/documents/2017/04/iso_caspr_highlights_april_2017.pdf

²⁵ Patel, S. (2019). PJM will hold capacity auction under current rules in August. Retrieved from: <https://www.powermag.com/pjm-will-hold-capacity-auction-under-current-rules-in-august/>

²⁶ Byers C., Levin, T., and Botterud, A. (2018). Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves. *Electricity Journal*, 31. 65-74.

²⁷ Gheorghui, I. (2018). Capacity pricing changes: How each power market plans to account for resource adequacy. Retrieved from: <https://www.utilitydive.com/news/capacity-pricing-changes-how-each-power-market-plans-to-account-for-resour/542449/>

²⁸ AESO. (2017). Seasonality Reliability Requirements. Retrieved from: <https://www.aeso.ca/assets/Uploads/Seasonality-Discussion-Narrative-Final.pdf>

periods may provide better reliability and resource development incentives, moving to a forward CM would increase costs to loads and was not warranted given the relative success of the existing market structure in part as a result of a well-functioning energy market and the NYISO biannual Comprehensive System Planning Process²⁹.

Concerns in the NYISO are that without investment into the transfer capability of the bulk power system, increasing shares of VRE in upstate load zones may bring diminishing returns in terms of carbon emissions as nearly 90% of energy in upstate New York is from carbon free sources. Because load in the region is not projected to grow new VREs would displace other carbon-free sources such as nuclear and further suppress market prices for them³⁰. However, rather than limit the ability of subsidized VREs to enter the market NYSIO has put forward a proposal to integrate carbon pricing into the energy markets³¹. Integration of carbon pricing into the market is another option to deal with out-of-market subsidies, which would provide a more economically efficient approach to incentivizing clean energy investment than technology specific subsidies and redesigning CMs to accommodate such subsidies³².

VREs also increase variability and uncertainty in the system which increases the need for flexible resources that can adjust output so that power output ranges, power ramp rates, and energy duration sustainability are able to meet the needs of balancing supply and demand and allow of maximum utilization of VREs³³. The increase of behind-the-meter generation (BTMg) also presents problems for the CM in the ability to correctly predict demand. Much BTMg is not visible to system operators and is registered only as demand reduction. How much BTMg that is expected to be added during a CM forward period in a specific region is also very difficult to predict. These factors will have important implications for what the appropriate method for setting demand curves should be.

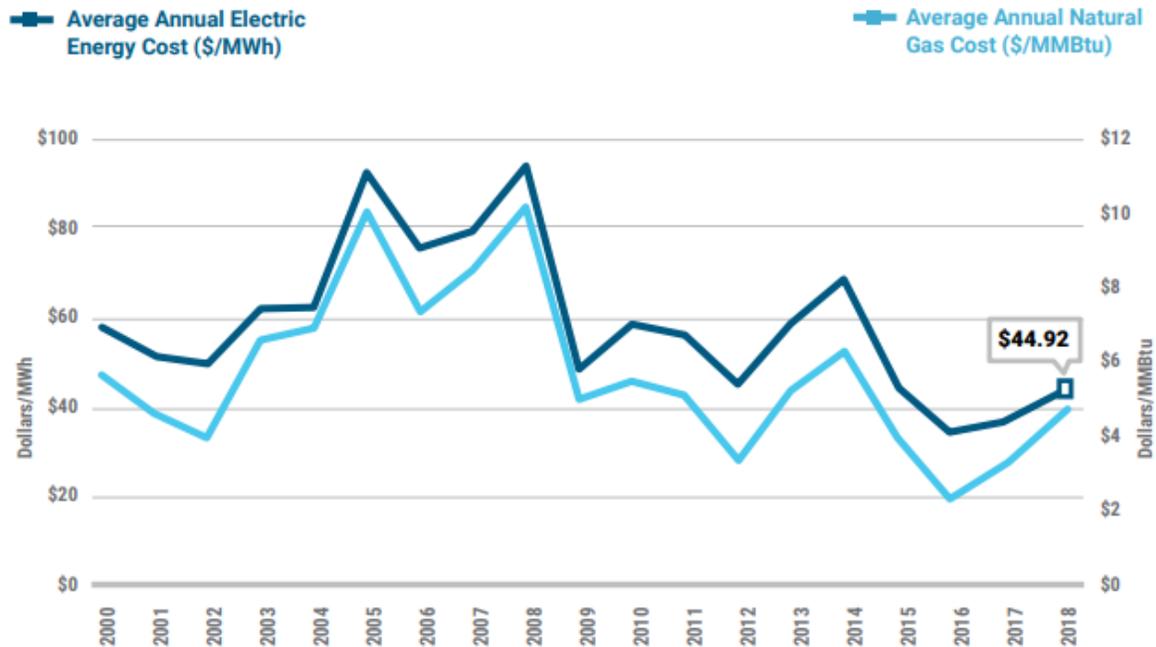
²⁹ Analysis Group. (2015). NYISO capacity market evaluation of options. Retrieved from: https://www.analysisgroup.com/uploadedfiles/content/insights/publishing/nyiso_capacity_market_evaluation_of_options.pdf

³⁰ ISO-NE. (2019). State of the grid. Retrieved from: <https://www.nyiso.com/documents/20142/2223020/2019-Power-Trends-Report.pdf/0e8d65ee-820c-a718-452c-6c59b2d4818b>

³¹ NYISO. (2018). IPPTF Carbon Pricing Proposal. Retrieved from: <https://www.nyiso.com/documents/20142/3911819/Carbon-Pricing-Proposal%20December%202018.pdf>

³² Byers C., Levin, T., and Botterud, A. (2018). Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves. *Electricity Journal*, 31. 65-74.

³³ Hsieh, E. and Anderson, R. (2017). Grid flexibility: the quiet revolution. Retrieved from: <https://www.osti.gov/servlets/purl/1352338>



Performance of Capacity Markets in the US

Reliability as the main goal of competitive electricity markets is a function of two dimensions: resource adequacy - enough firm resources to meet system peak demand - and resource security -the right resources deployed at the right time to balance supply and demand³⁴. With energy market prices declining as a result of low NG fuel prices and increasing shares of VRE, conventional baseload generators such as nuclear and coal are facing retirement in many markets across the US. This has led to many different proposals and market design changes to ensure resource adequacy can cost-effectively be maintained across US ISO regions. However, the key policy question now is not whether market revenues are sufficient to allow conventional generation to survive but whether those revenues are sufficient to maintain some form of capacity that is capable of supporting a reliable electricity system³⁵. CMs have been successful in maintaining system adequacy targets despite fleet retirements with clearing prices generally below net CONE, while still attracting new merchant investment, retaining existing capacity and procuring cost-effective resources such as DR and uprates which has deferred the need for costly new generation³⁶. However, many are not happy with CMs and CMs as the appropriate mechanism in facilitating the clean energy transition has been the source of much

³⁴ Hogan, M. (2012). What lies beyond capacity markets? Delivering least-cost reliability under the new resource paradigm

³⁵ Bushnell, J. Flagg, M., and Mansur, E. (2017). Capacity markets at a crossroads. Energy Institute at Haas.

³⁶ The Brattle Group. (2018). Recent trends and experience in US capacity markets. Retrieved from: <https://solarontarioconference.ca/wp-content/uploads/2018/11/Solar-Ontario-Walter-Graf-FUTURE-CAPACITY-MARKET.pdf>

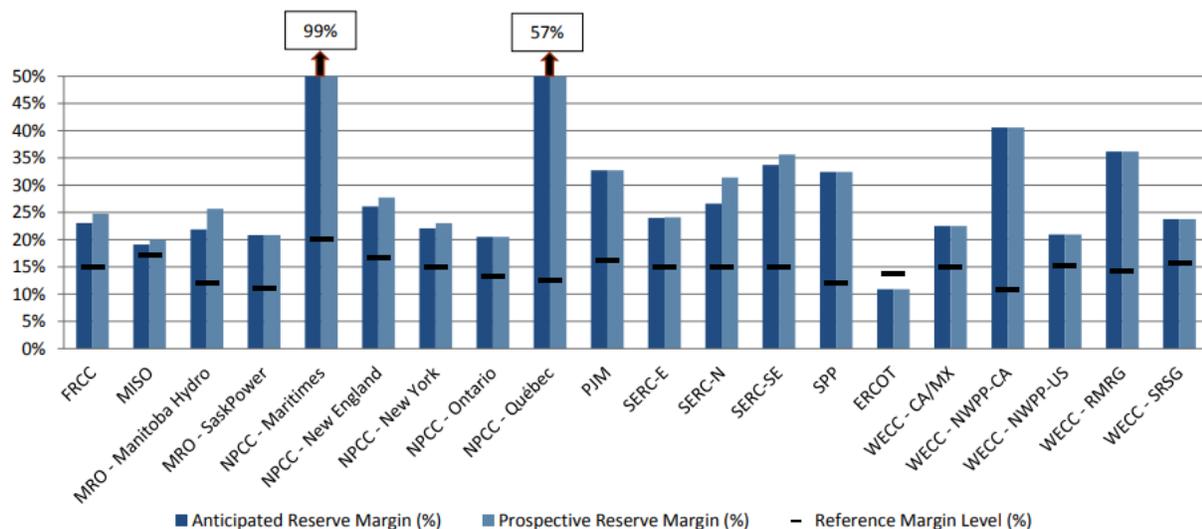
debate³⁷. This section will provide a brief overview of the ongoing challenges in CMs and then seeks to provide some context to the question of the suitability of CMs in the clean energy transition by reviewing the ability of distributed energy resources (DERs) to participate in CMs in the PJM, ISO-NE and NYISO.

In a survey of US electricity sector experts on CMs the main concerns raised by respondents in order of frequency, were:

- The differing designs and timing of neighbouring capacity markets,
- Continuous administrative rule changes that increase regulatory risk for investors
- Exercise of market power, including bidding above marginal cost and then double dipping by selling capacity credits, and then exporting power from the same generator to a neighbouring market
- Uncertainty around the availability of generation capacity that has been committed in terms of meeting reliability goals³⁸

CMs have been successful with implementing regions meeting their reserve margin targets. However, many argue that they have done so in an economically inefficient way, which has resulted in excess generation capacity at the cost of consumers³⁸. Indeed, most regions end up procuring substantially larger reserve margins than required³⁹ (**Figure 3**).

Figure 3. Comparison of anticipated and prospective reserve margins to a reference level*



³⁷ RTO Insider. (2018). 'Almost nobody is happy' with capacity markets at conference. Retrieved from: <https://rtoinsider.com/capacity-markets-frr-mopr-99362/>

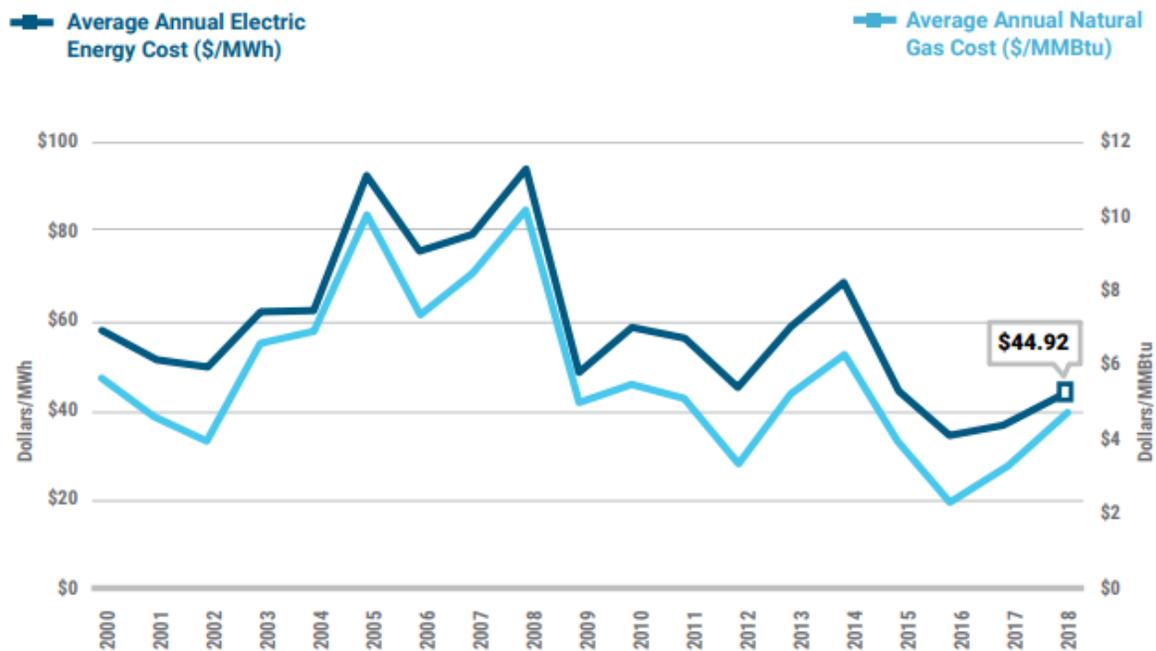
³⁸ Bhagwat, P. C., de Vries, L. J., and Hobbs, B. F. (2016). Expert survey on capacity markets in the US: Lessons for the EU. *Utilities Policy*, 38, 11-17.

³⁹ NERC. (2018). Summer reliability assessment

*Anticipated reserve margin is existing certain capacity plus capacity under construction. Prospective reserve margin is generating units that are expected to be available. The reference margin is the required reserve margin for that area.

Some have also recognized the natural hedge conferred by CMs to NG generators. Since the inception of liberalized electricity markets in the late 1990s the majority of merchant investment for new generation capacity has been in NG generation and has been the dominate form of capacity procured in CMs. Improvements in the efficiency of combined cycle plants as well as low NG prices as a result of the shale revolution have contributed to this⁴⁰. However, NG has a natural hedge in electricity markets. The price in electricity markets have been historically set by the short-run marginal cost of generation. Since NG is characterized by low capital costs and high operating costs, NG is often the price maker. Electricity market prices are therefore effectively tied to NG fuel prices as the marginal cost of generation for a NG plant depends on the efficiency of the plant and the fuel price (**Figure 4**). As price makers, NG plants therefore enjoy a natural hedge in electricity markets as fuel prices are passed through to consumers making them less exposed to market risks⁴¹. This can make investment in RE technologies less attractive⁴².

Figure 4. Natural Gas and Electricity Prices in the NYISO



⁴⁰ Mays, J., Morton, D. P., and O'Neill, R. P. (2019). Asymmetric risk and fuel neutrality in capacity markets. USAEE Working Paper No. 19-385

⁴¹ Gross, R., Blyth, W. and Heptonstall. (2010). Risks, revenues and investment in electricity generation: Why policy needs to look beyond costs. *Energy Economics*, 32(4). 796-804.

⁴² Guo, X., Beskos, A., and Siddiqui. (2016). The natural hedge of a gas-fired power plant. *Computational Management Science*, 13(1). 63-86.

Mays et al. (2019), argue that this hedge only confers an advantage when combined with CMs. In energy-only markets NG peaker plants with high operating costs rely on scarcity events to recover their fixed and operating costs. A CM removes risk related to the frequency of scarcity events, while only partially derisking variable and baseload generation. Therefore, the introduction of a CM has a stronger impact on the risk profile of technologies with higher operating costs.

Participation of Distributed Energy Resources

Demand Response and Energy Efficiency

Distributed energy resources (DER) have primarily participated in CMs through mechanisms for the inclusion of demand response (DR) programs, with the PJM and NYISO markets both allowing participation since the beginning of their CMs⁴³. ISO-NE has allowed participation of active and passive DR, which includes energy efficiency (EE) since 2010⁴⁴. PJM also allows participation of EE, while NYISO does not as it supported through other state programs. For clarity DR will be used to refer only to active DR. Passive DR is only used in the ISO-NE and is defined as any load reduction that can't respond to a dispatch instruction, which is primarily EE and BTMg such as solar.

As a result of these programs the share of DR in CMs has steadily grown. In PJM for example, the biggest ISO in the US and the biggest market for DR, DR grew more than 400% between 2007 and 2010 from 2,000 MW to 4,000 MW, and since 2009 DR has accounted for 4-6% of overall capacity commitments⁴⁵. Almost all revenue for DR comes from the CM in PJM (**Figure 5**). EE constitutes a smaller market share in PJM accounting for only 1.7% of cleared capacity in the latest auction, which was the highest since EE began participating in the 2012 delivery year. Similar trends are seen in ISO-NE, although with significantly less capacity at 400 MW of active DR and 2,000 MW of EE with obligations in the forward CM as of 2019⁴⁶. The Summer 2019 enrolled DR capability in the NYISO is 1,309 MW⁴⁷.

DR product definitions and participation rules continue to evolve with the goal of providing incentives for DR to participate, while setting stricter rules for deliverability and performance during emergency events⁴⁸. However, DR resources clearing the CM have seen a decline

⁴³ Walawalkar, R. et al. (2010). Evolution and current status of demand response (DR) in electricity markets: Insights from PJM and NYISO. *Energy*, 35. 1553-1562.

⁴⁴ ISO-NE. (2019). New England Power Grid Profile. Retrieved from: https://www.iso-ne.com/static-assets/documents/2019/01/new_england_power_grid_regional_profile_2018-2019.pdf

⁴⁵ PJM. (2017). Demand Response Strategy. Retrieved from: <https://www.pjm.com/~media/library/reports-notices/demand-response/20170628-pjm-demand-response-strategy.ashx>

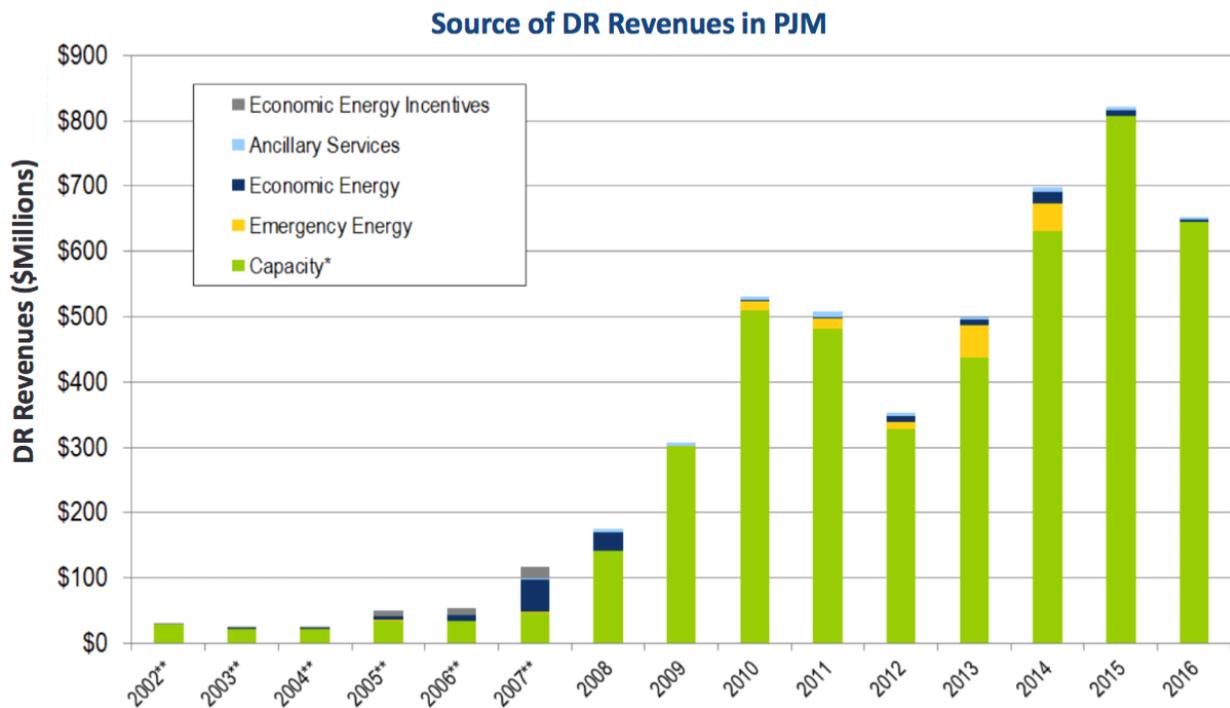
⁴⁶ ISO-NE. (2019). State of the grid. Retrieved from: https://www.iso-ne.com/static-assets/documents/2019/02/20190220_pr_state-of-the-grid_presentation_final.pdf

⁴⁷ NYISO. (2019). Reliability and a greener grid: Power trends 2019. Retrieved from: <https://www.nyiso.com/documents/20142/2223020/2019-Power-Trends-Report.pdf/0e8d65ee-820c-a718-452c-6c59b2d4818b>

⁴⁸ The Brattle Group. (2017). Review of PJM's Independent Market Monitor's Criticism of Demand Response Participation in PJM's Capacity and Energy Markets.

particularly in the PJM since 2012. This is largely due to increasingly stringent rules that have increased compliance costs, as well as uncertainty around a court challenge to FERC Order 745, which mandated that all ISO's must fully integrate DR into their wholesale markets such that they are paid at the same rate as generators. Prior to this some, regions paid a lower DR rate by subtracting either the generation portion or the entire retail rate from the wholesale energy market payment rate⁴⁹. The order was eventually upheld in 2014 which helped to restore confidence in the DR industry.

Figure 5. Source of DR Revenues in PJM



Primarily of concern have been rule changes in the PJM that have begun to slow the growth of DR in recent years through increasingly stringent measurement and verification requirements and the introduction of PJM's Capacity Performance rule⁵⁰. The Capacity Performance rule was implemented in 2016 in response to outages during the Polar Vortex of 2014, inciting concerns around reliability. In order to encourage investment in better year-round performance the rule removes the products for seasonal DR procurement, leaving only two types of Emergency DR: 1.) Capacity Performance (CP) resources which must be able to sustain delivery throughout the year; and 2.) Base Capacity resources with a seasonality component. As of 2017 the Base Capacity resource has also been removed. The requirement for full annual availability is a

⁴⁹ Synapse Energy Economics Inc. (2016). State of demand response in New England.

⁵⁰ The Brattle Group. (2017). Review of PJM's Independent Market Monitor's Criticism of Demand Response Participation in PJM's Capacity and Energy Markets.

problem for DR as certain DR resources only perform in the summer, such as air conditioner rotation programs, although they provide high value by reducing summer peaks and demand volatility. CP is also impacting the ability of seasonal VRE to participate. PJM has addressed this by allowing summer and winter resources to aggregate in order to meet the year-round requirements. However, this is contingent on resources being able to find the matching resource they need. 2017 auction results have shown a drop in DR cleared capacity from 10.3 GW to 7.8 GW from 2016, and total committed capacity falling from 6% to 4.7%⁵¹. However, the 2018 auction showed an increase of DR by 42% and EE by 60% from 2017, with 715 MW clearing as aggregated annual capacity, up 80% from last year. This has surprised analysts as many expected the downward trend to continue as a result of the CP rule and increasingly stringent performance rules.

Behind-the-Meter Generation

While definitions of BTMg vary it can generally be defined as generating units located on the host's property (behind-the-meter) and primarily used to meet their own loads, with excess generation often being exported to the distribution grid. However, transmission operators have little visibility into the distribution grid as historically, visibility has been unneeded due to the centralized generation model of one-way electricity flow from power plants to consumers through the transmission-distribution (T-D) interface of the substation. For this reason, BTMg is only registered by system operators as demand reduction. Therefore, in order for BTMg to participate in wholesale markets substantial improvements to connection and communication technology are needed, and as the share of DER rises further, enhancements to overcome grid constraints will be needed⁵².

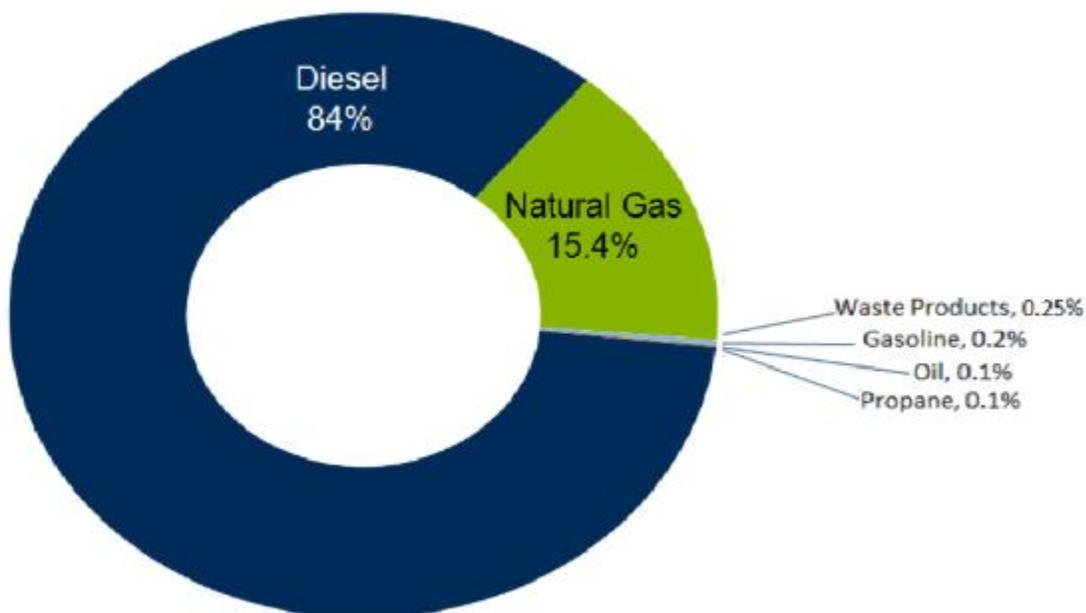
As a result of these constraints BTMg is typically not allowed to participate in CMs as generating units under current rules. Therefore, the primary means of participation in CMs for BTMg has been through aggregated DR products. Very little if any energy storage or solar plus storage are participating in these markets. In the PJM for example, BTMg that participates in the CM as DR is dominated by fossil fuel generating units (**Figure 6**). Similarly, DR BTMg in the ISO-NE are solely Real Time Emergency Generator Resources (RTEG). However, ISO-NE allows solar PV to participate in CMs as passive DR. Passive DR has been exceeding active DR in ISO-NE markets in recent auctions, however it is unclear how much of this is solar and how much is energy efficiency. No data could be found for NYISO⁵³.

⁵¹ St. John, J. (2017). PJM's latest capacity auction: A tough market for nuclear and demand response. *Greentech Media*.

⁵² More Than Smart. (2017). Coordination of transmission and distribution operations in a high distributed energy resource electric grid. Retrieved from: https://www.caiso.com/Documents/MoreThanSmartReport-CoordinatingTransmission_DistributionGridOperations.pdf

⁵³ Synapse Energy Economics Inc. (2016). State of demand response in New England.

Figure 6. PJM 2018/2019 BTMg DR MW capability fuel mix⁵⁴



However, the 2019 auction in the ISO-NE was the first in the US to clear aggregated demand resources with 20 MW of aggregated home solar and battery storage in 5,000 homes to be delivered by Sunrun in the 2022/2023 delivery year amongst 145 MW of other solar they successfully bid into the auction. Sunrun partnered with the unregulated arm of the utility National Grid which was a key enabler to win the auction by helping Sunrun navigate the market participation process. Massachusetts state incentives for energy storage also have helped to lower the costs of storage enabling them to clear the CM. Massachusetts is the first in the nation to allow BTM energy storage to qualify for EE incentives and have also included storage in the Solar Massachusetts Renewable Target (SMART). The SMART program gives an additional compensation rate if they pair with energy storage⁵⁵. The asset is registered as an on-peak demand resource in the CM which must meet its obligation to discharge the required amount of power within designated winter and summer peak hours. The biggest challenge going forward for Sunrun will be securing the customers to install the resources, although the

⁵⁴ PJM. (2018). Distributed energy resources (DER) that participate in the PJM markets as demand response.

⁵⁵ <https://www.utilitydive.com/news/massachusetts-multipronged-policy-approach-spurs-distributed-energy-storage/554208/>

CM payments will likely reduce the capital costs for customers making it an easier sell. An algorithm is also being developed to balance customer use with grid participation⁵⁶.

This was the first auction under the new price-responsive demand (PRD) rules initiated in response to FERC Order 745 making ISO-NE the first to fully integrate active DR into all wholesale markets. These changes allow active DR resources such as energy storage to:

- Receive wholesale market payments comparable to that of generating resources for providing energy, operating reserves, and capacity to the New England electric system
- Are able to submit offers to both Day-Ahead and Real-Time Energy Markets
- Can be committed by the ISO a day ahead and dispatched in real time
- Are co-optimized to provide energy and/or reserves in the most economically efficient manner
- Are able to set the price for wholesale electricity

Energy Storage

With FERC order 841 directing ISOs to clarify how storage can participate in the energy, capacity, and ancillary markets a variety of different approaches have been proposed to integrate energy storage into markets. How the market rules are designed will ultimately determine if participation will still be hindered. The Energy Storage Association (ESA) initial assessment of filings, while commending the ISOs for their efforts has not endorsed the proposals with the exception of CAISO, which was found by ESA to already be in compliance with the order. Key concerns by the ESA included⁵⁷:

- **PJM-** Lack of state of charge (SOC) parameters and the ten-hour duration requirement.
- **ISO-NE-** Lack of SOC parameters and a clear expansion of a mechanism to allow storage to deliver services in all markets. Clarification on must-offer rules are also needed.
- **NYISO-** While changes in sub-hourly dispatch enable flexible use of storage however storage would be prohibited from participating in both wholesale and utility programs

Prior to Order 841 storage could theoretically participate in all markets but rules have not recognized the unique physical characteristics of energy storage. In CMs DR appears to have been the primary path for energy storage to participate, although it is unclear how much energy storage is used in these programs. In terms of capacity pumped hydro has been the dominant form of installed storage capacity. In PJM, out of 5,300 MW of installed electric storage capacity 96% is pumped hydro and 4% is battery storage. PJM and CAISO currently have

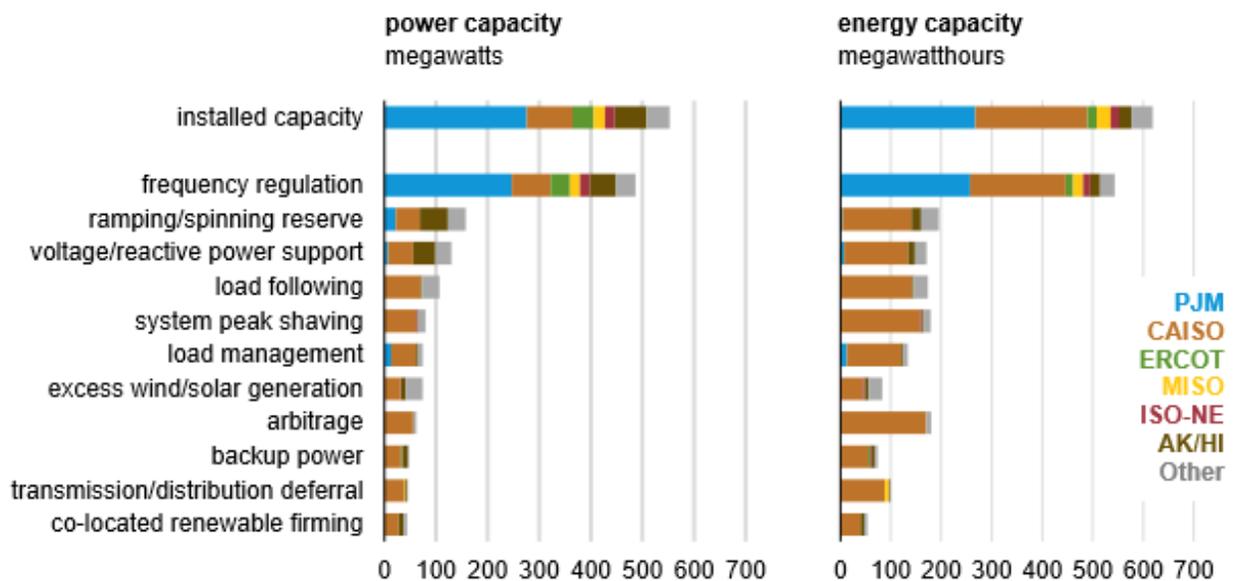
⁵⁶ Greentech Media. (2019). Sunrun wins big in New England Capacity Auction with home and solar batteries. Retrieved from: <https://www.greentechmedia.com/articles/read/sunrun-wins-new-england-capacity-auction-with-home-solar-and-batteries#gs.bhiwp7>

⁵⁷ Energy Storage Association. (2018). Energy Storage Association unveils initial assessment of regional grid operator compliance with FERC Order 841. Retrieved from: <http://energystorage.org/news/esa-news/energy-storage-association-unveils-initial-assessment-regional-grid-operator>

the most installed battery capacity in the US. The primary application is however frequency regulation accounting for 88% of all large-scale BES in the US⁵⁸ (**Figure 7**). This has largely been driven by the development of the fast-ramping frequency regulation product in the PJM which accounts for the majority of installed BES capacity in the US⁵⁸.

In terms of small scale battery storage, 90% of all installed capacity is located in CAISO. Outside of California New York, Hawaii and Georgia have the most installed capacity primarily for commercial applications. Uses of these batteries were not available due to difficulties around the visibility of these resources to grid operators and inconsistencies in reporting.

Figure 7. Applications served by large scale battery storage



IESO Market Renewal Objectives and Drivers

The IESO Market Renewal is being driven by a number of challenges with the status quo model.

These are:

- Uncertainty for developers
- Resource specific procurements do not maximize competition or foster innovation
- Lack of flexibility to respond to evolving needs through lock-in of specific resource types
- Price of capacity co-mingled with other value drivers
- Contractual incentives are not always aligned with system needs

Key drivers for a CM in Ontario are similar to what has driven CMs in other jurisdictions. Chief among these is the missing money problem, which previously had been addressed in Ontario through the use of long-term procurement contracts. A switch to CMs in Ontario also hopes to

⁵⁸ Energy Information Administration. (2018). U.S. battery storage market trends.

achieve flexibility in meeting capacity requirements, transparent price signals, the ability for all resource types to participate, and shift of investment risk away from ratepayers to the supplier.

The primary drivers of benefit from market renewal are expected to be:

- Fuel, emissions, and O&M cost savings
- Reduced curtailments/spilling of non-emitting resources
- Increased export revenues and reduced import costs
- Investment cost savings
- Reduced gaming opportunities, administrative complexity and unwarranted transfer payments
- Supporting competition and innovation
- Alignment with provincial policy goals

The expected benefit to customers compared to a continuation of long-term contracting scenario is in the range of \$120-\$200 million/year as a result of surplus capacity exports and reduced contracting, and \$290-610 million in later years based on the IESO's 2016 Planning Outlooks⁵⁹. However, it should be noted that these benefits are based on the assumption that the CM will procure the exact amount of supply needed. This is not realistic based on results from other jurisdictions. Furthermore, it should be noted that while a CM is a mechanism for procuring the lowest-cost capacity, benefits are not necessarily a result of the CM but are a result of procuring low-cost capacity which could also be procured through a different mechanism.

A CM could lead to reduced need for contractual support of new investment and lower contract prices due to a clearer view of post contract revenue. More efficient resource entry, exit and upgrade signals is expected to be provided by the CM so that customers will no longer have to pay for unneeded excess capacity due to lower prices during periods of excess capacity, which encourages suppliers to mothball, export or retire unneeded and higher cost resources.

Capacity auctions also only procure the amount of capacity predicted for a single year, reducing the risks of oversupply associated with long-term supply and demand forecasting. Use of one-year commitment periods reduces risk that customers will be locked into high price contracts for many years. Stable capacity payments also reduce uncertainty, making investment more attractive.

Efficiency and cost effectiveness goals can also be met through the provision of correct price signals: the supplier specifies prices and the auction clears the most cost-competitive resources. Flexibility to adapt to rapid energy sector changes may also be provided through short commitment periods and the long-term certainty of market mechanisms as auctions allow demand forecasts to update regularly, allowing procurement of the correct amount as forecasts

⁵⁹ The Brattle Group. (2017). Benefits Case Assessment of the Market Renewal Project.

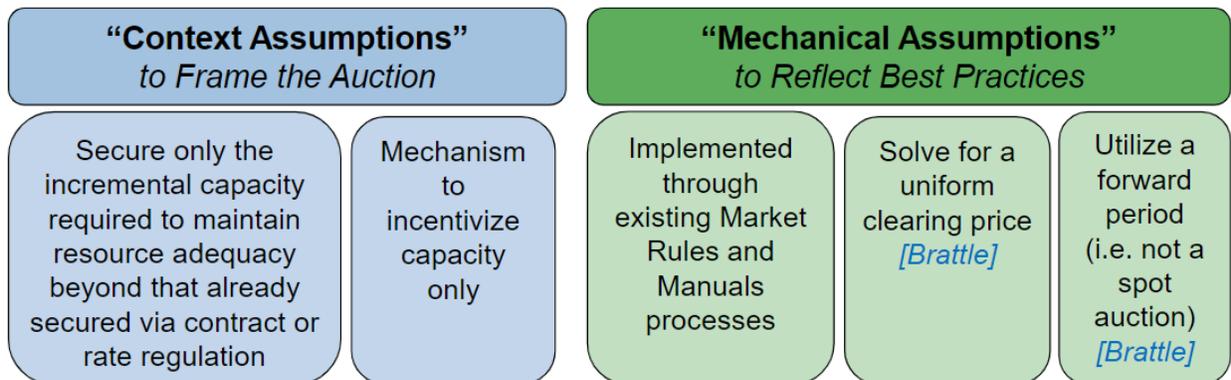
change and procurement of the most cost effective resources, while considering what is necessary to support particular resource types.

Experience from other jurisdiction have shown that low cost non-traditional resources are procured first such as DR and uprates to existing assets with new merchant generation only procured when price signals are high enough to attract that investment. A CM also aims to level the playing field for different technologies.

The CM design is based on five fundamental assumptions (**Figure 8**). First, rather than a centralized CM as in other regions, the CM will be an incremental capacity auction (ICA) meaning it will seek to procure capacity that is incremental to what is already under contract and rate regulation. Incremental capacity will come from merchant capacity which are resources that are not under contract and resources that have the ability to generate capacity in excess of what has been contracted. Incremental need in MW fore each commitment period and zone will therefore be established through the forecasted peak demand plus the reserve margin less the MW contribution from contracted and regulated facilities.

Second, the CM will seek only to achieve resource adequacy, as any approach that would focus on maintaining more than resource adequacy would reduce the expected benefits of the auction by not sending clear price signals for the value of capacity and would require some degree of centralized and administrative decision-making that would reduce the ability of the private sector to find innovative solutions to meet system needs. The approach is to have clear and distinct price signals for each product and services needed to meet system needs. Resources that maximize revenue from other markets while minimizing their cost of supply are therefore expected to be the most competitive in the auction.

Figure 8. IESO capacity market design assumption



The next three mechanical assumptions are based on international best practices. Implementation through existing market rules and manuals is expected to maximize benefits of the market design by increasing stakeholder confidence in the mechanism and reducing uncertainty that the opportunity to earn capacity payments will not be available over the useful life of the resource. A uniform clearing price has been shown to achieve the most efficient

results in the short and long run by incentivizing suppliers to offer at the lowest acceptable price to maximize their likelihood of clearing the market. This approach also minimizes costs as the market will clear the low-cost mix of resources and recognizes equal value of the same product purely by their ability to deliver MW of capacity. A forward period was chosen as opposed to a spot market as spot markets can limit competition between new and existing resources and increase price volatility and resource shortages as there is little recourse to correct for shortages through rebalancing auctions for example. The exact length of the forward period has yet to be determined.

Implications for the IESO Incremental Capacity Auction

Despite the apparent success of CMs in meeting resource adequacy goals, overcoming the missing money problem and shifting risk away from ratepayers in recent years significant debate has emerged around whether or not CMs are the appropriate mechanism to facilitate the clean energy transition with markets constantly under review and rules being changed to adapt to the shifting landscape⁶⁰. CMs at their core have always been about ensuring grid reliability at the lowest cost through technology neutral competition. As the market share of alternative resources increases, new challenges for measuring their reliability benefits are arising, creating legitimate differences in opinion and tensions between local regulatory authorities and regional transmission operators⁶¹. As VREs continue to suppress market prices suppliers will increasingly rely on capacity payments for their revenues placing even more importance on design parameters. In order for energy-markets to reach long-run competitive equilibrium extended periods of low prices will need to be offset by less-frequent highly priced scarcity events. For this reason, current bid-caps and pricing penalties may need to be raised. Key elements of CMs that have been debated and periodically revised include⁶¹:

- Should qualifying capacity be limited to resources that can be made available on demand, or evaluated based upon a probabilistic expectation of performance?
- How location specific should capacity procurement be?
- What performance characteristics should be required?
- What are the performance obligations of participating capacity?
- Should those obligations be applied uniformly or adapted to specific resources such as energy-limited storage, and variable energy resources?

Whether or not a market is truly technology neutral is ultimately determined by the market rules, and in practice market rules have favoured certain types of resources. The prime example of this is PJM's Capacity Performance rules that require annual availability, and minimum duration rules that derate energy storage capacity. The natural hedge of NG also confers an advantage. Uncertainties involved with valuing the capacity of VRE years in advance of their

⁶⁰ Heidorn, R. (September, 2018). 'Almost nobody is happy' with capacity markets at conference. *RTO Insider*.

⁶¹ Bushnell, J. Flagg, M., and Mansur, E. (2017). Capacity markets at a crossroads. Energy Institute at Haas.

actual production can also negatively impact the revenues they receive from the CM. A concern raised by the Consortium of Renewable Generators, Energy Storage Providers and Industry Associations in response to the High-Level Design is that due to the methodology for calculating unforced capacity (UCAP) (i.e. the actual capacity that can qualify in the market after accounting for forced outages and other derates) VRE will receive less capacity revenues from the CM and will therefore rely proportionately more on wholesale market revenues to ensure cost recovery and rate of return on investments⁶². Non-performance penalties contemplated in the High-Level Design also present more risk for VRE than other resources do not have. This also needs to be balanced with the natural hedge that NG generators have in CMs and energy markets as described above.

As capacity prices are planned to be set net of revenue from other markets in the ICA it becomes more important that energy market prices accurately reflect demand and supply and are not distorted or suppressed as a result of CM payments and are able to accurately reflect scarcity and shortage conditions.

What can be agreed on is that markets need to provide resource adequacy and reliability as the share of VRE and BTM and FTM DERs continue to increase, and as costs continue to fall rapidly. This adds a new dimension to the conventional resource adequacy question: flexibility. Flexibility solves the emerging system quality problem of ensuring that the right mix of resources are in place to ensure supply can be balanced with demand. This is in the context of increasing variability in net demand forecasts. Traditionally, ancillary markets have been used to ensure flexibility options are available to the system. However, short-term markets such as these may not suffice when integrating higher shares of VRE. CMs in terms of how they have been traditionally designed do not address this either as they only value firm capacity, therefore devaluing other resource attributes, and favouring low cost, and therefore likely less flexible capacity⁶³.

As the IESO's High-Level ICA design largely reflects conventional design based on the experience of CMs in the US it is doubtful that it will be able to address these needs. Although, the IESO does expect that system flexibility will be an area for future market evolution as the share of DERs in the system continues to rise and recognizes the need to adapt future market designs to integrate DERs into the system and allow them to participate in wholesale markets⁶⁴. However, it should be noted that the IESO does not expect a large level of load defection from DERs in the near-term due to the current lack of out of market subsidies and out of market payments.

⁶² Power Advisory LLC. (2019). Stakeholder feedback on the IESO draft Incremental Capacity Auction High-Level Design.

⁶³ Hogan, M. (2012). What lies beyond capacity markets? Delivering least-cost reliability under the new resource paradigm.

⁶⁴ IESO. (2019). Participation in Ontario's future electricity markets. A Non-Emitting Resource Subcommittee report to the Market Renewal Working Group.

Barriers to DER in the ICA High-Level Design

Current barriers to further DER integration were identified by the recent Non-Emitting Resource Sub-Committee (NERSC) report to the Market Renewal Group. In order to overcome revenue streams gaps NERSC identified the need to unbundle ancillary services and for the creation of new ancillary services such as flexibility and ramping products in order to respond to the growth of VRE and DER. The lack of demand-side bilateral contract counterparties was also identified as a barrier, citing the ability of LSEs in the US to contract with customers to meet system needs. In terms of market participation key market barriers included the 1 MW minimum size threshold, costs related to metering and communication, and barriers to energy storage that prevent them from delivering their full value to the grid, such as the many regulatory and load-related charges that energy storage is subject to as both a generator and a load.

Furthermore, stakeholder feedback to the High-Level Design has pointed out a number of challenges to new resource investment in Ontario that may prevent them from entering the market due to the high risks involved⁶⁵. These include the high amount of regulatory and political risk, the high share of government owned and rate regulated supply, lack of bilateral contracting opportunities between LDCs and suppliers, as well as the current governance, decision-making and market participant recourse framework in the IESO Administered markets. Regulatory and political risk is evidenced by recent cancellations made to renewable Feed-in Tariff contracts and may impact lenders decisions to finance generation projects in Ontario. The high share of government-owned supply owned by OPG has market power implications and will also be considered by lenders. The short one-year commitment period, while conferring adaptability to resource adequacy needs as they develop also reduces longer-term investment certainty. This may be mitigated by the proposed multi-year commitments, although the specifics of this mechanisms are to be determined during the detailed design phase.

While the IESO has acknowledged these concerns expressed by stakeholders and looks to develop the needed policies, rules and tools needed for DER integration through their working groups and stakeholder engagements, the High-Level Market Design, having come out prior to the release of the NERSC report, leaves some uncertainties on how DERs will be able to participate. Ultimately, this will depend on the ability of market rules to capture the operational characteristics of different resources. This may mean setting different participation rules for different resources. This approach has drawn criticism particularly in regard to DR in PJM markets, where concerns were raised that DR resources were not being treated in a manner comparable to generation resources suggesting that DR should be subject to a must-offer requirement in the energy market as well as an offer cap. However, FERC ruled that functional

⁶⁵ Power Advisory LLC. (2019). Stakeholder feedback on the IESO draft Incremental Capacity Auction High-Level Design.

and operation differences between DR and generation are justification to accommodate unique operational characteristics of DR⁶⁶.

Rules that favour participation of DERs include seasonal auctions that would allow the seasonal value of resources such as solar and summer DR to be captured, allowing aggregation, and attempting to find a balance between methods for valuing VRE. However, the final details will determine how well these resources will be able to participate. Variables that can impact participation of DERs include the minimum duration requirement, the minimum participation threshold, and the forward period.

The High-level design contemplates a minimum duration threshold of between 2 to 4 hours. Where this number ends up will heavily impact the business case for energy storage as requiring that storage resources are able to deliver for a four-hour period will increase costs in order to reach the required capacity. In addition, if a state of charge capable of delivering for four hours is required at all times, then this may prevent the storage resource from being able to provide other grid services. In terms of the 3.5 year forward period, some DR resources will have difficulties in securing individual customers so far in advance, however new builds, particularly hydroelectric resources will have difficulty with a short forward period, preferring longer forward periods to have enough time for construction⁶⁷.

It may also be difficult for aggregators to reach the 1 MW minimum capability requirement as eligibility is limited to those DERs that are connected to a single transmission node. This concern has been raised in regard to participation in NYISO's ancillary markets as part of their DER integration proposal⁶⁸. In recognition that individual resource capability is not necessarily a marker of value, NYISO has lowered this threshold to 100 kW for their energy and CMs. Another challenge of DERs in CMs is the decline in capacity value as net peak shifts.

Allowing DR resources participating in the Transitional Capacity Auction to participate in and receive payments from the energy market in the same way other eligible generation resources do is also imperative to ensuring fair competition with the other resources. Other eligible generators should be subject to the same performance penalties as DR.

A lack of a mechanism for behind-the-meter generation to participate other than through DR products will also restricts the ability of these resources to provide their full value that they are capable of to the system and ratepayers

There is also an ongoing debate as to what the appropriate reference technology should be to determine the net cost of new energy (net CONE), which serves as the basis of the demand curve and is one factor in determining the market clearing price which occurs at the intersection of the demand curve and the supply curve. Gas-fired simple-cycle CT is often used

⁶⁶ The Brattle Group. (2017). Review of PJM's Independent Market Monitor's Criticism of Demand Response Participation in PJM's Capacity and Energy Markets.

⁶⁷ Charles River Associates. (2017). A case study in market design and considerations for Alberta.

⁶⁸ NYISO. (2017). Distributed energy resource 2017 market design concept proposal

as the reference technology. Concerns over this are that a reference technology based on the lowest capital cost of capacity might lead to overpayment of other technologies with lower net CONE and the approach may favour selection of one technology when a larger technology mix would be desirable.

While the details of the market rules will be a large determining factor on whether or not DERs will be able to participate, and compete on an even footing with other resources, the ability of DERs to provide their full value will require proper grid upgrades to allow the needed visibility and bidirectional flow associated with DERs. For energy storage, a key problem that needs to be overcome is that the IESO system sees a storage resource as two separate entities, a load and a generator with no storage capacity and no relationship to each other. The result is a risk of conflicting dispatch instruction between the two facility components and an inability to optimize storage capacity through the Dispatch Scheduling and Optimization (DSO) algorithm⁶⁹.

As lessons are learned from the current fleet of dispatchable storage facilities in Ontario key questions around market design include:

- Can market participants adequately manage state of charge on their own? Is this the most efficient solution?
- Is the mandatory window for bid/offer changes too restrictive?
- Can storage facilities feasibly offer reliable operating reserve without state of charge monitoring in the DSO algorithm?
- Will conflicting dispatch between generator and load segments become a significant problem?

It is clear that how these questions are answered will significantly affect the business case for energy storage. If market participants are not allowed to manage their own state of charge through for example requirements that a minimum state of charge be required at all times for participation in a particular market then the ability to value stack will be diminished. Questions also remain as to if performance penalties in CMs will be sufficient enough incentive to avoid a situation where there is insufficient state of charge to meet a performance obligation.

Alternative Designs

Due to the existing bilateral contracts with nuclear and RE suppliers forming the majority of generation, who will not be allowed to participate in the CM, the ICA is intended to procure additional capacity beyond what is met by these resources. However, a number of NG generation units will soon be reaching the end of their contracts enabling them to participate in the auction (**Figure 8**). While the CM claims to be technology neutral, it is clear from the context of the electricity sector that existing NG generators that have already recovered their fixed costs will be able to make the lowest bid into the auction. This effectively makes the CM a

⁶⁹ Energy Storage Advisory Group. (2018). Ontario energy storage context.

method for determining which existing NG generators are the most cost-effective and should be allowed to operate and which ones should retire.

Market designs are stable and long-lasting constructs. Rather than commit to a design that will likely have to be changed in the near future due to the rise of DERs, the IESO should consider alternative market designs that will allow proper integration of DERs and address the flexibility needs of increasing shares of VRE. At the very least alternative CM market designs should be considered that value the quality of the service provided such as flexibility rather than just procuring the lowest cost firm capacity resources.

Flexibility

The ability to value flexibility is gaining increased attention in electricity markets, although few have yet developed concrete mechanisms to do so. CAISO and MISO seem to be the first in developing products to ensure up and down ramping capabilities. The CAISO Flexible Ramping Product allows sufficient ramping capability to be procured through economic bids in the 15- and 5-minute markets. Two products, the Flexible Ramp Up and Flexible Ramp Down provide additional capability to account for uncertainty due to demand and renewable forecasting errors as well as real-time interchange schedules⁷⁰. MISO is developing a product that issues payments to resources cleared for ramp capability regardless of real-time dispatch instructions⁷¹.

These approaches are short-term mechanisms that work alongside the energy and ancillary markets. However, to ensure flexible resources are available over the long-term, price signals may be needed similar to the basis that CMs were developed on. In order to do this Hogan proposes mechanisms to integrate net demand forecasts into investor's revenue models⁷². A separate capability market that would seek to balance greater resource flexibility at least cost, taking into account the costs of curtailing VRE generation or committing back-up generation would be ideal. However, as few markets have the time or capacity to do this Hogan proposes an enhanced services market and an apportioned forward capacity mechanism.

The enhanced services market would utilize a long-term services market to procure resource capabilities derived from the net demand forecast with value being set by periodic forward auctions. Capabilities to be procured would likely be already existing functions such as ten-minute spinning and non-spinning reserves, and operating reserves. This would most likely operate in the absence of a CM, although it conceivably could operate alongside one if the CM

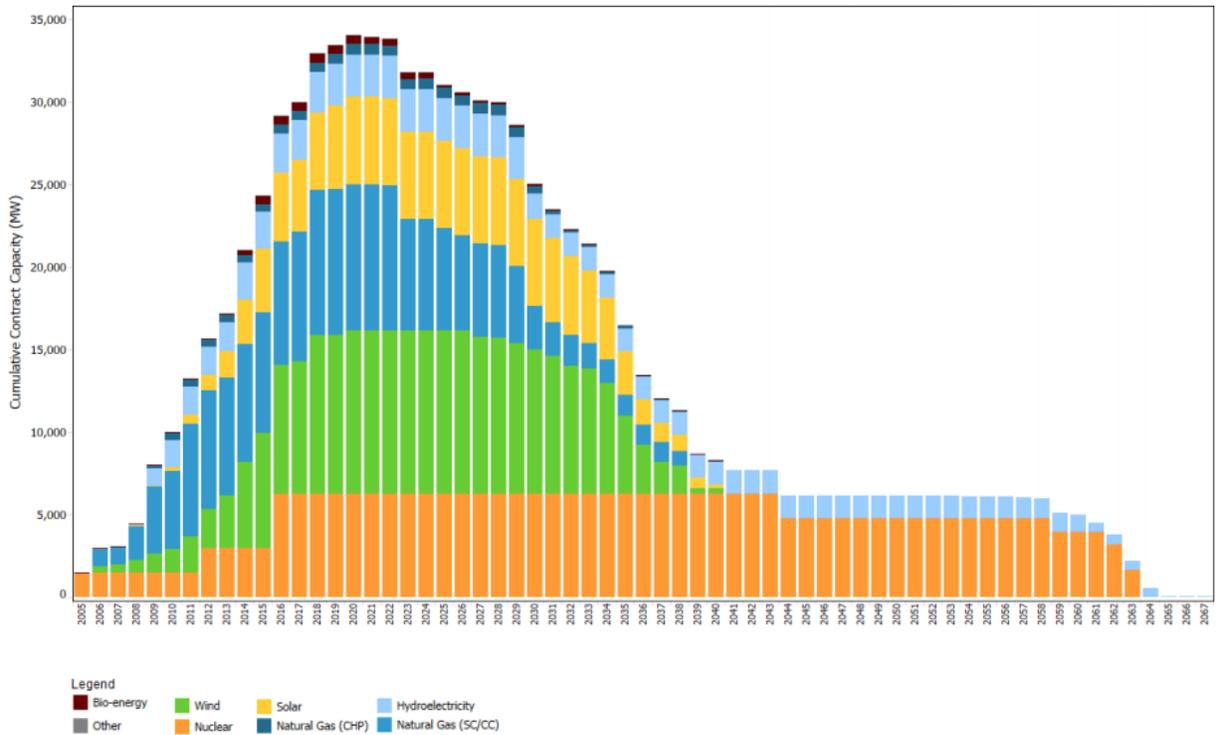
⁷⁰ CAISO. (2019). Flexible Ramping Product. Retrieved from: <http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/FlexibleRampingProduct.aspx>

⁷¹ MISO. (2019). Ramp capability product development. Retrieved from: <https://www.misoenergy.org/stakeholder-engagement/issue-tracking/ramp-capability-product-development/>

⁷² Hogan, M. (2012). What lies beyond capacity markets? Delivering least-cost reliability under the new resource paradigm.

was strictly to address resource adequacy. The benefit of this approach is to unbundle the long-term procurement of system services from processes to procure firm production capacity.

Figure 8. Expected lifetime of IESO contracts⁷³



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The apportioned forward capacity mechanism would apportion the existing CM into tranches based on the target mix of resource capabilities derived from the net demand forecast. This takes existing resource adequacy mechanism and breaks the quantity of firm resources

⁷³ IESO. (2017). A progress report on contracted electricity supply

required into tranches based on specific resource attributes. Resources would then bid into the highest-value tranche they could qualify for and tranches would clear starting with the most flexible one. The original PJM CM design in fact contemplated a design similar to this but was dropped in the final design in response to stakeholder concerns around complexity and market liquidity. The tranches specified in this design were dispatchable, flexible cycling, supplemental reserves, and tranche that included all other products. The market then cleared in stages based on the desired amounts in each category. One of the advantages of this approach is system operators can differentiate the value of capacity payment streams based on operation capabilities rather than on criteria that have no tangible reliability rationale such as new versus existing resources or strategic reserves versus other firm capacity.

Enabling DER

No matter the CM design, a sustained buildout of DER will be constrained until the needed upgrades to grid communication, controls and metering to allow bi-directional flow and sufficient visibility are addressed. As the role of LDCs as enablers of DER continues to grow and address the challenges through enabling platforms such as Hydro Ottawa's GREAT DR Protocol and the Alectra's Power.House a bottom-up model resembling load-serving entities (LSEs) in the US could be an attractive model. Such an approach was outlined in a discussion paper prepared for the Ontario Energy Association in 2018 and has the potential to provide significant benefits through increased efficiencies in planning and resource procurement⁷⁴. The proposed model would give LDCs the responsibility to secure resources from third-party providers as well as the ability to meet their own supply needs through owning and operating their own assets. Any additional capacity needed could then be procured through an IESO procurement process.

Stakeholder feedback to the High-Level Design also calls for the IESO to reconsider the use of contracts for procurement given declining contract prices in other jurisdiction such as Alberta where results of the AESO REP program saw average prices of \$37/MWh in 2017, \$38.9/MWh in Round 1 of 2018, and \$40.14/MWh in Round 2 of 2018⁷⁵.

Work in the NYISO to integrate DERs into the energy, capacity and ancillary markets also provides a promising way forward⁷⁶. The proposal sets a broader definition of DERs and distinguishes between different types of DER: dispatchable, non-dispatchable and front of the meter. Also key to the proposal is developing more granular pricing in conjunction with distribution utilities which would offer more locational pricing points on the transmission system. Currently, prices are calculated and published on a zonal basis every five minutes which does not provide the necessary level of granular pricing needed to determine the most cost-

⁷⁴ Power Advisory LLC. (2018). Policy Case: Recommendations for an Ontario Load-Serving Entity Model. Retrieved from: <https://energyontario.ca/wp-content/uploads/2018/09/OEA-LSE-Report-September-2018-Final.pdf>

⁷⁵ Power Advisory LLC. (2019). Stakeholder feedback on the IESO draft Incremental Capacity Auction High-Level Design.

⁷⁶ NYISO. (2017) Distributed energy resources market design concept proposal. Retrieved from: <https://www.nyiso.com/documents/20142/1404696/Distributed%20Energy%20Resources%202017%20Market%20Design%20Concept%20Proposal.pdf>

effective locations within a zone to invest. The new approach publishes intra-zonal prices that identify where on the grid DERs would be most beneficial. The NYISO also recognizes that as more BTM solar is added this could lead to more dynamic load particularly in concentrated communities like New York City, which will require sufficient resources to be available to respond to unexpected load increases. To address this the NYISO is developing additional reserve requirements for New York City that will provide location-specific market signals consistent with any reliability need⁷⁷.

⁷⁷ NYISO. (2019). State of the grid. Retrieved from: <https://www.nyiso.com/documents/20142/2223020/2019-Power-Trends-Report.pdf/0e8d65ee-820c-a718-452c-6c59b2d4818b>