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Capacity Markets for Transactive Energy Systems

September 2022

Brittany Tarufelli
Brent Eldridge
Abhishek Somani

U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
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Summary

Capacity markets provide important incentives for resource adequacy in electricity markets and may become more important for providing sufficient revenue and generation capacity with changes to energy market prices driven by increasing levels of zero marginal cost resources. However, current capacity market designs also have important shortfalls that may limit the benefits they can provide to the future grid. Current capacity markets are primarily designed for participation from conventional thermal generators, but markets are evolving with increasing levels of variable renewable energy resources. However, further reforms may be necessary to enable more participation from distributed energy resources (DERs) and demand-side resources.

To understand the benefits and shortfalls of current capacity market design, we review the historical reasons electricity markets have needed capacity markets or capacity payments for resource adequacy, by first examining regulatory pricing policies, then exploring how current capacity market designs may create challenges for incorporating increasing levels of DERs and demand-side resources. We then consider how transactive systems—which allow the coordination of bids and offers for DERs and demand-side resources through a market interaction approach—administered by a distribution system operator (DSO), can address traditional resource adequacy problems due to inelastic consumer demand. We also consider the need for a DSO-level capacity market in helping to meet resource adequacy, reliability, and other electricity market objectives.

We find that because the missing money in electricity markets is largely driven by incentives to meet resource adequacy goals, and the bulk grid would always supply power to the DSO, that resource adequacy is unlikely to be a determining factor in the need for a DSO-level capacity market. Many current reliability problems could also be addressed by the incorporation of more flexible demand enabled with transactive energy systems. However, other DSO objectives, including resilience, reactive power, voltage control, environmental policies, and energy equity could lead to specific challenges that could be aided by a DSO-level capacity market. We consider the possibility of a DSO-level capacity market in addressing these challenges, as well as its potential role in coordinating with the independent system operator who operates the wholesale market. We conclude with suggestions for future research, including the need to develop analytical models of DSO-level capacity market designs to address these potential objectives and examine their implications for DSOs and consumers.

Acknowledgments

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Acronyms and Abbreviations

4CP	Four Coincident Peak
CAISO	California ISO
CLR	Controllable Load Resources
CONE	Cost of New Entry
CPUC	California Public Utilities Commission
DADRP	Day-Ahead Demand Response Program
DER	Distributed Energy Resource
DR	Demand Response
DRR	Demand Response Resource
DSASP	Demand-Side Ancillary Services Program
DSO	Distribution System Operator
DSO+T	Distribution System Operator with Transactive
EDR	Emergency Demand Response Resources
EDRP	Emergency Demand Response Program
ELCC	Effective Load Carrying Capacity
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Responsive Service
FERC	Federal Energy Regulatory Commission
HCAP	High-system-wide-offer Cap
ICAP	Installed Capacity
IRM	Installed Reserve Margin
ISO	Independent System Operator
ISO-NE	ISO New England
LEI	London Economics International
LMR	Load-modifying Resources
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LR	Load Resource
LSE	Load-serving Entity
MC	Marginal Cost
MRI	Marginal Reliability Impact
NCLR	Non-Controllable Load Resource
NICR	Net Installed Capacity Requirement
NYISO	New York ISO
ORDC	Operating Reserve Demand Curve
PDR	Proxy Demand Response

PJM	PJM Interconnection
PUCT	Public Utilities Commission of Texas
RAAIM	Resource Adequacy Availability Incentive Mechanism
RDRR	Reliability Demand Response Resource
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
UCAP	Unforced Capacity
VOLL	Value-of-lost-load
WECC	Western Electricity Coordinating Council

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1.0 Introduction

In today's electricity markets, prices, reliability requirements, and investment are governed by regulatory policies. Although market clearing prices are essentially determined by supply and demand, electricity has unique characteristics that introduce complications: there is a need for instantaneous balancing of supply and demand, market operators can't control the flow of power to specific consumers, and many consumers lack real-time metering and billing (Ruff, 1999; Stoft, 2002). Because market operators can't control the flow of power to specific consumers, any consumer can take power from the grid without a contract at any time. This requires a market operator be the supplier of last resort, buying sufficient power to meet demand. However, because of a general lack of real-time metering and billing, demand (for the most part) is unresponsive to price, meaning customers may not reduce consumption during high-price periods when supply is scarce. If demand exceeds supply, market operators must shed demand. For these reasons, reliability policies are currently needed to ensure that there is sufficient supply available to meet peak demand, requiring regulatory prices that induce the appropriate amount of capacity investment for resource adequacy. However, in theory, when sufficient demand becomes price-responsive—a situation that could be made possible with transactive energy systems—these flaws may be largely ameliorated through consumers responding to price increases by reducing demand, and power markets can function without today's reliability policies (Stoft, 2002).

Transactive energy systems are uniquely poised to address the demand-side unresponsiveness to price by dynamically balancing demand, supply, and storage. Transactive energy enables this dynamic balance through a set of economic and control mechanisms that use value as a key operational parameter (GridWise, 2019). With transactive energy systems, customers can automatically manage responsive demand-side assets by setting preferences for smart assets (such as smart thermostats) to respond to incentive signals that communicate price and grid conditions. By coordinating bids and offers for responsive demand assets through a market interaction approach, a distribution system operator (DSO) can engage large amounts of distributed energy resources (DERs) to reduce system peak demand, manage congestion, and better balance renewable resources (Hammerstrom et al., 2008; Hammerstrom et al., 2009; Lian et al., 2018).

To fully achieve the possibilities of responsive demand assets, their contributions to deferring or avoiding upgrades on distribution facilities, as well as the reliable operation of the distribution system, must be properly valued in the DSO marketplace. Current challenges in valuing responsive demand assets or DERs for their contributions to resource adequacy can be gleaned from wholesale capacity markets. Demand for new capacity in wholesale markets is administratively valued at the cost of building a new peaking generator—typically a natural-gas-fired combustion turbine—rather than determined by the value of new capacity to consumers. Further, valuing responsive-demand assets' contributions to resource adequacy have proven difficult due to their spatial and temporal variability. Resource adequacy policies designed to incentivize sufficient supply, such as regulatory price caps or price floors, may also limit responsive demand potential. Participation requirements in wholesale capacity markets—including complex rules over aggregation, minimum size, and availability constraints—may also limit potentially valuable DER contributions. Last, lack of access to enabling technology—such as real-time metering and controls that allow customers to respond to market price signals—can limit demand-side participation, muting their ability to set energy prices and reduce the need for additional capacity. With these challenges in mind, how to best represent and incentivize demand-side flexibility remains an open question in wholesale electricity markets.

To examine the reasons why a capacity market may be beneficial to a DSO, we review the historical reasons why electricity markets have required capacity markets or capacity payments to signal adequate investment for resource adequacy, and how these existing policies may create challenges for incorporating increasing amounts of responsive demand from transactive energy systems. We will then consider the possibility of a DSO-level capacity market in addressing these challenges, as well as its potential role in coordinating resource adequacy with the independent system operator (ISO) who operates the wholesale market.

In section 2.0, we examine why wholesale electricity markets have needed regulatory pricing policies to address “the missing money problem” and the impact of these policies on signaling sufficient supply-side investment for resource adequacy. We also provide examples of regulatory pricing policies existing in today’s wholesale electricity markets. Next, we turn to the transactive approach to “the missing money problem,” providing an overview of the potential benefits and limitations of transactive energy for ensuring resource adequacy and reliability. We close this section with some key takeaways from existing transactive energy demonstrations and simulations.

In section 3.0, we provide an overview of a common construct used to incentivize sufficient investment for resource adequacy: the capacity market and its design in wholesale markets. We discuss common elements of capacity market design, including mechanisms to incentivize generator availability, zonal definitions for resource adequacy, and methods for valuing the capacity contributions of renewable and demand-side resources. We also provide in-depth examples of capacity market design, pay-for-performance incentive mechanisms, and participation rules for existing capacity markets.

Section 4.0 then discusses the potential need and role of a DSO-level capacity market with a transactive approach to capacity markets.

2.0 The Impact of Regulatory Pricing Policies on Resource Adequacy

Wholesale electricity markets are traditionally planned around capacity reserve margins, so that each service region will have enough power generating capacity to supply the peak system demand with a sufficiently high probability. This results in the “missing money problem,” in which a handful of expensive resources are needed to maintain a desired capacity reserve margin but will rarely, if ever, earn enough profit from being dispatched to supply energy. Administratively determined operating reserve demand curves (ORDC) and price caps help address some of the incentive issues that create the missing money problem. The following section describes how energy markets compensate the resources needed for revenue adequacy.

2.1 The Missing Money Problem

Because ISOs can’t control the flow of power to specific consumers, anyone can take power from the grid, making it difficult to enforce contracts between consumers and generators. Instead, ISOs must act as the default supplier, buying sufficient power to balance the system, as well as (at times) determine the market-clearing price of power. The ISO can set a price by equating supply with demand. When demand can be met with sufficient supply, as shown in Figure 1, the price for electricity can be set by the market, rather than administratively by the ISO.

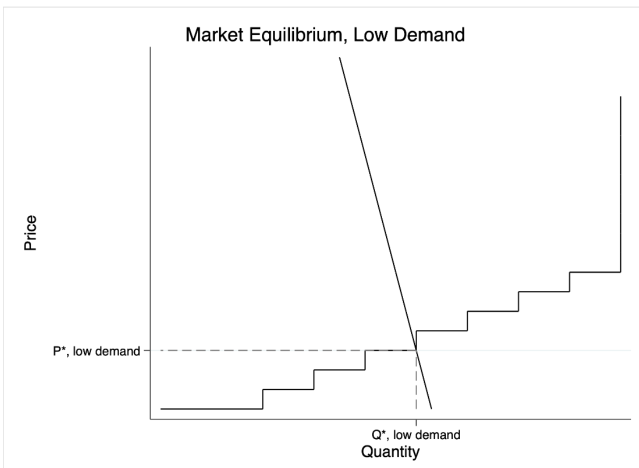

Figure 1. Market Equilibrium Price from Equating Supply and Low Demand

Historically, fluctuations in electricity demand were met with changes in supply, which resulted in little consideration of price-responsive demand when planning infrastructure investments or proposing changes in rate design. The associated lack of real-time metering and billing for electricity customers limits their exposure to wholesale price fluctuations, making demand unresponsive to price. Additionally, incentives from rate-of-return regulation encourage demand and asset growth,[1] limiting demand-reducing efforts unless through regulatory requirements

[1] Thirteen states and Washington, D.C., have restructured their electricity markets to allow for retail choice (where consumers can purchase power from third-party providers). Other states retain some form of rate-of-return (cost-of-service) regulation. However, both retail choice and rate-of-return regulated states can and do participate in ISOs and regional transmission organization (RTOs). See Rose et al. (2020) for further detail.

(Peskoe, 2016). With inelastic demand, in periods of high demand (such as a cold winter day or hot summer day), or periods of low supply (due to generator outages or maintenance), electricity prices can rise steeply, and a high-cost generator clears the market, as shown in Figure 2.

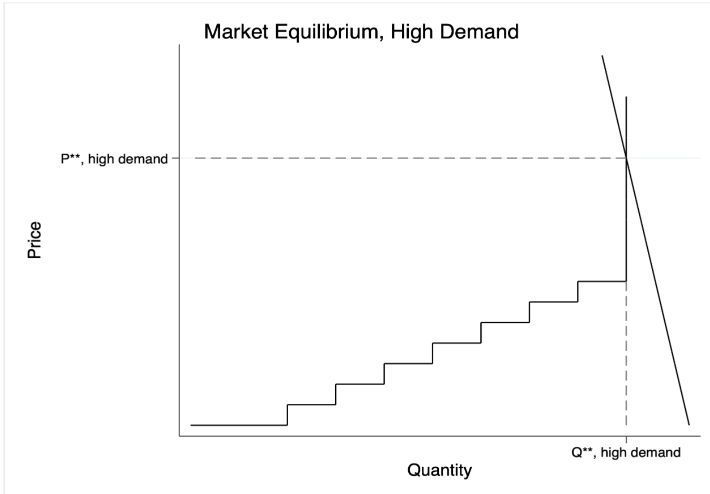

Figure 2. Market Equilibrium Price from Equating Supply and High Demand

However, periods of high demand can also lead to situations where demand exceeds supply. When this happens, the market will not clear, requiring operators to curtail demand and regulators to set the market-clearing price. The regulator determines both the level (height) of the regulatory price and the duration for which the price will last (Stoft, 2002). However, these regulatory prices (e.g., price caps) are, at best, a rough approximation to the value of curtailed demand and do not incentivize efficient changes in energy consumption. With inelastic demand, the regulator must incentivize new investment in generation capacity to address the supply shortfall. For this to occur, the regulatory price must cover the fixed costs of generators; if it is too low or set to the marginal cost of the last generator that cleared the market, underinvestment may occur (Stoft, 2002; Petitet et al., 2017). On the demand-side, underinvestment also may occur if the peak load requirement is incorrect.

Price spikes also create investment and political risks (if, for example, they lead to high prices for consumers), as well as the opportunity for generators to exercise market power. For these reasons, many markets have implemented price caps to limit the height of the price spike. A related issue is that market operators may also over-commit generators to artificially lower price volatility (Mays, 2020). Regulatory policies and price caps determine both the height and duration of price spikes, which affect risk; for example, infrequent, high-price spikes increase uncertainty and risk, whereas low and long duration price spikes reduce uncertainty and risk (Stoft, 2002; Newbery, 2016). However, price caps have the adverse effect of limiting the amount retailers are willing to pay for electricity, meaning they will not enter contracts with generators for more than the price cap, as they can always wait and purchase electricity on the spot market at the price cap, although buying electricity forward may reduce exposure to risk (Stoft, 2002; Newbery, 2016). This incentive to delay forward purchases of electricity can also create reliability issues if sufficient short-term supply is unavailable to meet demand (Wolak, 2021).

Further, as shown in Figure 3, with regulatory prices (e.g., price caps), all market-clearing generators lose out on potential revenue that could have contributed to covering their fixed costs, had the market cleared where supply equals demand, and the incentive to invest in new plants is distorted. When revenues earned in the electricity markets are insufficient to cover a generator's fixed and variable costs, this is known as the missing money problem in electricity markets. Although Figure 3 displays the missing money problem in a supply scarcity situation, generators can struggle with recovering fixed costs even in normal operating situations. This is because the market-clearing price is equal to the physical marginal cost of producing the last unit of electricity—typically, a marginal generator's fuel cost. If average energy prices aren't high enough, a generator will not recover its fixed costs—the missing money problem, as shown in Figure 4—signaling unprofitable generators to leave the market.

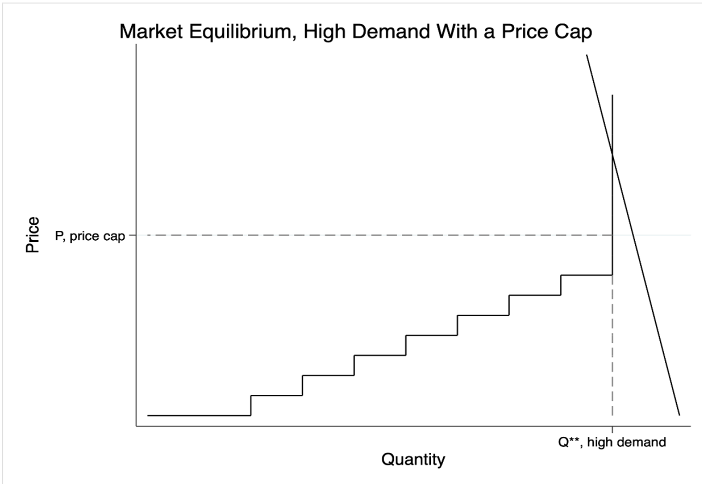

Figure 3. Market Equilibrium with a Price Cap

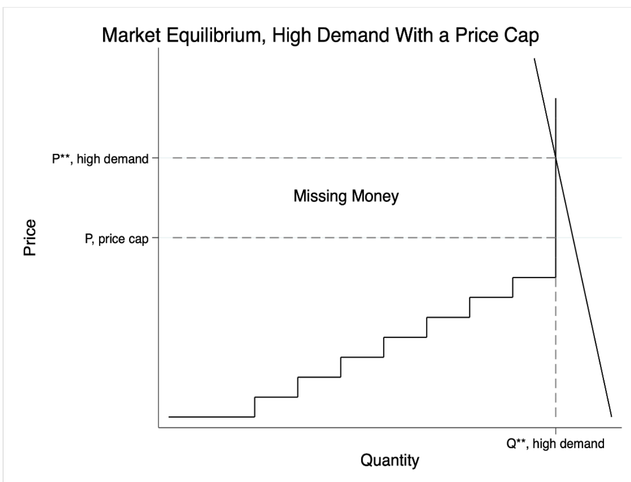

Figure 4. The Missing Money Problem in Electricity Markets

2.2 Regulatory Pricing

When setting the price cap in markets to induce resource adequacy and reliability, one option is value-of-lost-load (VOLL) pricing. With this approach, the regulator determines VOLL by estimating how much to offer for additional supply when some demand has been shed (for example, during a partial blackout). This requires estimating the value customers would be willing to pay to avoid their power being turned off and is difficult to determine because most customers do not respond to real-time electricity prices, making that data unobservable. Instead, an engineering approach is often taken, which calculates an implied VOLL on an acceptable duration of demand shedding for each year. In markets with capacity constructs, this is typically based on the cost of new entry (CONE) of a new peaking plant, as a proxy for consumers' willingness to pay for reliability (Parent et al., 2021). If the fixed cost of a typical peaking plant is $50,000/MW per year and the acceptable duration for demand shedding is 5 hours per year, the implied VOLL will be $50,000/MW-year divided by 5 hours per year or $10,000 per MWh (Stoft, 2002).

In theory, the VOLL should be equal to the reduction in consumer surplus caused by 1 MWh of curtailed load. To provide an intuitive example, in Figure 5, assume consumers' maximum willingness to pay for electricity is $18,000/MWh. If there was an emergency requiring a 10-percent reduction in load, the consumer demand function would scale back from the solid line to the dashed line, and 2,000 MW of load shedding would take place. The lost total surplus from the load shedding event is the light grey shaded area; however, there would also be avoided variable costs for producers, for example, avoided fuel costs, shown by the dark grey shaded area. To connect this example to the VOLL, let H be the average MWh of shed load and V_H the average consumer surplus of power consumption; dH is then the decrease in H and dV_H the increase in V_H for a small increase in installed capacity (i.e., $dH < 0$ and $dV_H > 0$ for a small increase in installed capacity). The VOLL (V_{LL}) is then:

$$V_{LL} = \frac{-dV_H}{dH}.$$

In our example, a 10-percent reduction in consumer surplus ($-dV_H$) is 18,000,000/h;[2] dividing this by 2,000 MW of lost load (dH) gives the VOLL (V_{LL}) of $9,000.[3] This example is based on Stoft (2002).

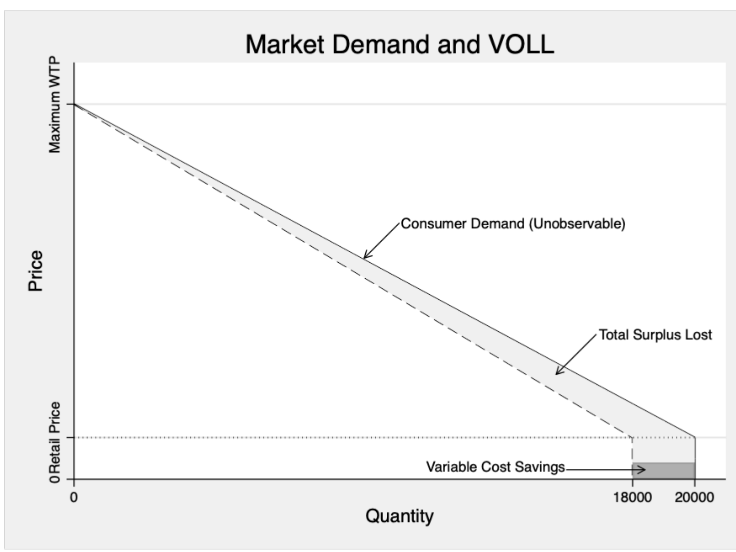

Figure 5. Market Demand and VOLL (Source: Based on Stoft, 2002)

[2] 1/2*(18,000 $/MWh * 20,000 MW)*10%.
[3] Note that because the value of consumer surplus is an uncertain value and much greater than the variable cost of power, the distinction between total and consumer surplus is ignored (see Stoft, 2002).

The ORDC approach is intended to incentivize responsive load and supply, when and where it is needed, by improving scarcity pricing; this is achieved by communicating the value of additional capacity during scarcity situations through energy and reserve prices (Hogan, 2012). Because electricity markets currently do not have sufficient price-responsive load to provide representative scarcity values, the ORDC approach is intended to serve as a proxy for the scarcity values that would arise from demand bidding, providing a variable value for different levels of operating reserves, rather than a fixed reserve requirement (Hogan, 2019). The value of the ORDC is determined by the loss of load probability (LOLP) at a particular reserve level, shown as LOLP(R) in Figure 6, multiplied by the VOLL (net of the variable cost of generation at the margin, the marginal cost, MC). This calculation (VOLL – MC)*LOLP(R) provides the expected cost of marginal load curtailment at particular level of reserves. Different from long-term resource adequacy planning, the LOLP is determined from a probability distribution of deviations from forecasted net load over the next hour rather than a longer time horizon (Hogan, 2019).

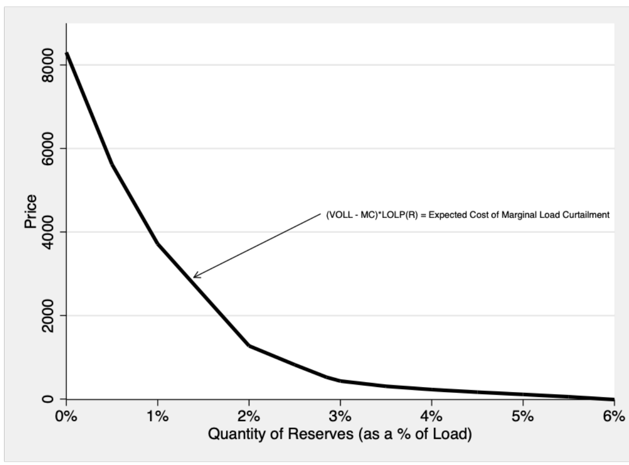

Figure 6. Operating Reserve Demand Curve (Source: Based on Hogan, 2019)

2.3 RTO/ISO Regulatory Pricing Examples

Setting the VOLL price to accurately reflect the cost customers are willing to pay for one more MW of demand is challenging, as it varies across customer segments and also can lead to political repercussions if customers are exposed to too much price risk. A case-in-point is the VOLL, or high-system-wide-offer cap (HCAP) used to set a ceiling on the Electric Reliability Council of Texas' (ERCOT's) scarcity pricing mechanism.

Case Study – VOLL Pricing in ERCOT

In 2012, the Public Utilities Commission of Texas (PUCT) commissioned The Brattle Group to analyze resource adequacy concerns—stalled investment and reserve margins expected to fall below 10% by 2014—in Texas. The Brattle Group benchmarked VOLL from other energy markets,[4] finding VOLL ranged from $3,000 to $12,000, depending on the market and customer segment. Although the VOLL estimates were not specific to the ERCOT market, and The Brattle Group recommended a study to determine the correct VOLL for ERCOT, the PUCT raised the HCAP to address immediate resource adequacy concerns from $5,000 in 2013, to $7,000 in 2014, to $9,000 in 2015, based on The Brattle Group's finding that a $9,000 HCAP could bring the reserve margin to 10% (PUCT, 2012).

[4] The 2012 Brattle Report VOLL estimates were based on Australia's National Energy Market and a customer survey conducted in MISO (Newell et al., 2012).

A subsequent study (Project Number 40000) was initiated by the PUCT to further address resource adequacy issues raised by The Brattle Group. As part of this project, in 2013, ERCOT hired London Economics International (LEI) to determine the VOLL for Texas customers. LEI used several macroeconomic approaches to calculate an implied VOLL, finding "accurately estimating VOLL for a region is a challenging task that ultimately requires a survey of affected customers" (LEI, 2013). LEI did not recommend a specific VOLL estimate for ERCOT due to the need for the customer survey, and the customer survey to provide an accurate estimate of VOLL was not performed.[5]

In February 2021, Texas experienced extreme winter weather, resulting in severe energy infrastructure failure and blackouts, leaving 4.5 million homes without power for several days and leading to loss of life. Although the power system failure had no single cause, during the crisis, the PUCT ordered the price of electricity to stay at $9,000/MWh, suspending market pricing rules to ration price-responsive demand and keep generators online (King et al., 2021). Following the crisis, LEI found that the market pricing rules would have resulted in average prices that were $6,578/MWh lower than those that resulted from the PUCT orders (LEI, 2021). In December 2021, following the February 2021 extreme weather and scarcity pricing event where customers were charged $9,000/MWh for nearly 77 hours (EIA, 2021)*, the PUCT lowered the HCAP to $5,000/MWh due to the price cap being a "liability on market participants and customers of ERCOT" (PUCT, 2021). However, recent research on the extreme winter weather event has estimated actual VOLL to be around $87,000 (Gruber et al., 2022).*

While targeting VOLL to achieve a certain level of reliability is a reasonable approach, given the challenges in estimating VOLL, the Texas case study clearly shows that VOLL is a regulatory construct, and the risk customers and other market participants face because of VOLL pricing is an important consideration to regulators. But the price cap in the ERCOT market is only one piece of its scarcity pricing mechanism. To uncover the full picture requires a discussion of operating reserves. Instead of (or in addition to) VOLL pricing, many markets in the United States use operating reserve requirements that are a fixed percentage of load.[6] If there is a shortage of operating reserves, scarcity pricing will be used to reduce load shedding. Scarcity pricing kicks in before demand needs to be shed, creating a lower and a longer duration—meaning less risky—price spike.

The ERCOT ORDC in Texas is a combination of both approaches, with scarcity pricing due to a shortage of operating reserves capped by the VOLL price.

Case Study – ORDC in ERCOT

The ORDC approach aims to improve scarcity pricing through operating reserves as the value of capacity scarcity is not always adequately reflected in energy and ancillary service market prices (Joskow, 2008). The ORDC is essentially an energy price adder to provide adequate incentives in short-term prices for generation investment, as well as participation of responsive demand. The underlying mechanics of the ORDC are that real-time energy prices (as determined by economic dispatch) are increased by a real-time price adder that is based on the remaining reserves in the system and the ORDC—to better reflect the value of scarce operating reserves.[7] *If reserves fall below a minimum threshold, the scarcity price will reach the VOLL. The PUCT implemented the ORDC as part of Project 40000 based on a proposal by Hogan (2012) and revisions with Hogan and ERCOT staff (Hogan and ERCOT Staff, 2013).*

[5] LEI did perform a macroeconomic analysis to calculate an implied VOLL for non-residential customers and a preliminary VOLL for residential customers based on the direct cost of electricity; however, LEI noted that these methods were not sufficient for ERCOT's needs and recommended a survey of end-use customers.

[6] For example, in the Western Electricity Coordinating Council (WECC) region, the North American Electric Reliability Council standard is 1) the loss of the most severe single contingency, or 2) the sum of three percent of hourly integrated load plus three percent of hourly integrated generation, whichever is greater (WECC, 2021).

[7] The value of the ORDC at any given level of operating reserves is determined by the LOLP at that reserve level multiplied by the VOLL; this represents the marginal value of that level of reserves (Surendran et al., 2016).

The ORDC's "price adder" curve is based on the probability that a rotating outage would occur (LOLP) and the expected consumer impacts if an outage were to occur (as measured by the VOLL). The ORDC reflects that, in situations when demand is high or there is not enough supply to reliably operate the grid, the amount of reserves would decrease and the possibility of an outage would increase, raising the LOLP and the ORDC. The value of the ORDC at any given level of operating reserves is determined by the LOLP at that reserve level, multiplied by the VOLL; this represents the marginal value of that level of reserves (ERCOT, 2014a; Surendran et al., 2016). Following the February 2021 extreme weather event and the PUCT's decision to lower the HCAP to $5,000/MWh, the PUCT also approved a redesign of the ORDC's parameters. This redesign allows price levels to increase earlier but to a lower HCAP level, with the aim of reducing volatility and increasing reliability. Comparing the 2021 ORDC to the new revised version, as shown in Figure 7, shows that the new revised version has a lower but longer duration price spike, which reduces risk to market participants.

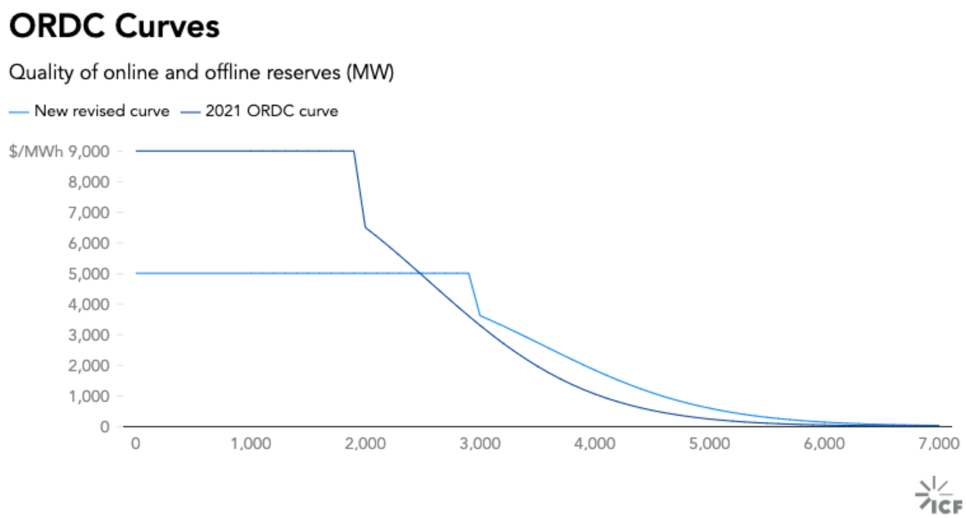

Figure 7. ERCOT Historical and Revised ORDC Curves (Source: ICF International, Inc.)

The ORDC is linked to short-term market conditions rather than long-term capacity requirements (or a forward market) but has been proposed as an alternative to ensuring long-term resource adequacy (Bajo-Buenestado, 2021). This approach has also been adopted in both PJM Interconnection (PJM) and MISO Energy to improve scarcity pricing (although both markets have a separate capacity payment mechanism). Better reflecting operating reserve value with scarcity pricing is also important for inducing demand-side flexibility. However, recent research has pointed out that short-run increases in wind generation may be problematic for creating long-run investment incentives for the ORDC. The issue is that, because the ORDC is a real-time price adder, price suppression from zero-marginal-cost renewable resources in the real-time market[8] also depresses ORDC prices, making the ORDC less effective as an investment incentive (Zarnikau et al., 2020; Bajo-Buenestado, 2021).

However, as exemplified in ERCOT, scarcity events cannot always be predicted with sufficient certainty to warrant investment. To address the missing money problem for generators and to properly signal investment, many markets instead use capacity payments, which pay generators

[8] The merit-order effect of zero-marginal-cost resources from both displacing conventional generation resources and lowering wholesale market prices is well-documented in the literature. See Tarufelli et al. (2022) for a recent survey.

small amounts regularly to cover their capital costs, or capacity markets, which set a generation adequacy target and then determine the amount of capacity needed to achieve the target (Kirschen and Strbac, 2018). But the need for capacity markets and capacity payments may change with transactive energy systems' incorporating more responsive demand assets in the market, addressing the demand-side flaw of inelasticity.

2.4 Transactive Approach to the Missing Money

As described above, regulatory pricing policies have developed in wholesale markets as a consequence of an inelastic demand-side, the desire for high levels of reliability, and the need for sufficient supply-side investment incentives. Transactive energy systems are uniquely poised to address the demand-side inelasticity by dynamically balancing demand, supply, and storage using a market interaction approach. To provide a brief overview of the potential benefits and limitations of transactive energy for ensuring resource adequacy and reliability, we will discuss some key economic principles for a transactive energy system and how this market design may interact with existing wholesale market features.

Transactive energy, instead, can coordinate responsive-demand assets through peer-to-peer negotiation or a market mechanism, such as a double auction mechanism. With the double auction market, the DSO orders demand bids by price and capacity, and clears demand bids against the price of supply from the wholesale market. To construct the supply curve, the DSO bids the distribution-level capacity limit (such as substation limits) at the uncongested market price, which is typically the locational marginal price from the wholesale market plus any necessary mark-ups, shown as the horizontal segment of the red supply curve in Figure 8. The supply curve forms a vertical line at the distribution-level capacity limit up to the price cap of the market, as shown in Figure 8. To construct the price-responsive demand curve, the DSO estimates the total demand on the feeder, and the price-responsive portion of demand from summing price-responsive demand bids. The nonresponsive portion of demand is found from subtracting price-responsive demand from total demand. Nonresponsive demand is bid into the market at the price cap, as shown by the horizontal portion of the green demand curve in Figure 8; the price-responsive portion of the demand curve is then downward sloping, based on the price-responsive demand bids. The intersection of demand and supply determines the market-clearing price (Widergren et al., 2022).

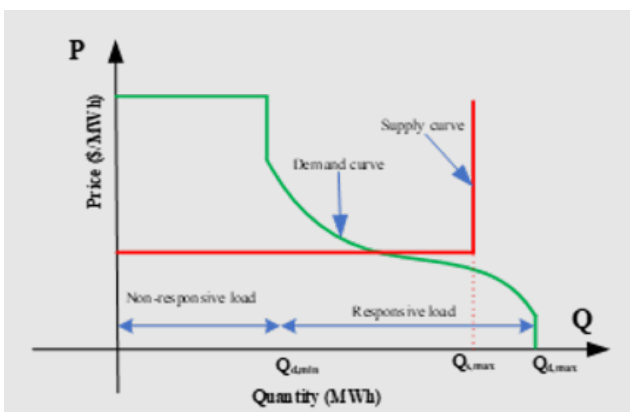

Figure 8. Retail Market Clearing in Transactive Energy Systems Source: DSO+T

Transactive energy systems encourage participation from electricity customers, which improves demand elasticity. However, it is evident from Figure 8 that price-responsive customer participation can be limited in two important ways from market design and system infrastructure: price caps and distribution-level capacity limits.

Price caps based on regulatory policies from the wholesale market could limit the participation of price-responsive demand. Price caps limit customer incentives to pay for (or conserve) electricity. Price caps can also affect customers’ investment in responsive-demand assets if potential savings from participating in transactive energy systems—which may be limited by the price cap—do not exceed the assets’ costs. Thus, the price cap can distort investment signals in the retail market, as well as the wholesale market.

Bohn et al. (1984) show that the optimal electricity spot price, $\dot{p_i}(t)$, for customer i at time t is equal to the social cost of additional demand at the swing bus at time t , plus the incremental losses caused by i , plus the incremental change in transmission constraints, summed over j lines, caused by i .

Mathematically,

$$\dot{p_i}(t) \;=\; \theta(t)\left[1+\frac{\partial L(t)}{\partial D_i(t)}\right]+\;\Sigma_k\left[\frac{\partial Z_j(t)}{\partial D_i(t)}\right]v_j(t),$$

where $D_i(t)$ represents i ’s demand for electricity, $L(t)$ represents transmission losses, $Z_j(t)$ represents power flow along each transmission line, and $v_j(t)$represents the shadow value of additional transmission capacity.

θ is the most important component of the spot price, as it represents the shadow price on demand

$$\theta \;=\; \lambda(t) \;+\; \mu(t),$$

or the short-run marginal generating cost, $\lambda(t)$, plus, a curtailment premium, $\mu(t)$, that is necessary to curtail demand back to meet available supply in times of shortage. This concept is shown graphically for different levels of supply from k generators with availability, α_k, and maximum output, K_k, in Figure 9.

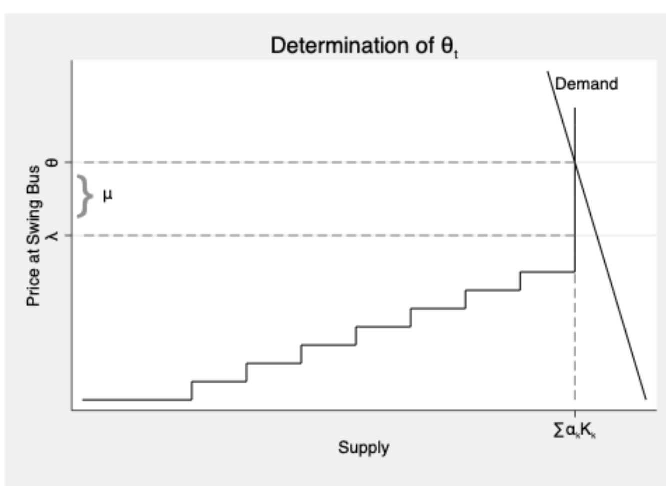

Figure 9. Determination of Theta (Based on Bohn et al., 1984)

This simple model from Bohn et al. (1984) demonstrates that customer i can affect transmission losses, transmission congestion, and potentially the curtailment premium, μ , depending on the consumer's willingness to accept payment for demand curtailment. Important for the curtailment premium is that research has found a disparity in an individual's willingness to accept a price for selling a service, versus their willingness to pay a price for that same service—that is, an individual requires more payment to sell a good than they would pay to buy that same good (Tunçel and Hammitt, 2014; Ganguli et al., forthcoming). This finding has important implications for consumers' demand response: if consumers perceive they are selling a service, they may require a higher price, increasing the cost of demand response.

How customer i affects transmission losses depends on the customer's location and voltage level. Customers whose demand increases cause larger losses should be charged a higher price (Bohn et al., 1984). How customer i affects transmission constraints depends on how much power flow on a critical or congested line is affected by i's demand.

With transactive energy, the curtailment premium, μ , should be determined by consumer demand bids in the DSO market. However, if wholesale market price caps exist, μ may instead be set administratively at a less than optimal level, reducing consumers' exposure to high prices and discouraging demand response.

Regulatory price caps contribute to the missing money problem in wholesale markets by limiting the revenues generators can earn during scarcity situations. A corollary for the DSO market is that price caps can blunt incentives for price-responsive demand. For these reasons, with transactive energy systems, an open question is: with high levels of demand-side participation, if wholesale markets retain price caps, will distribution-level capacity or resource adequacy mechanisms be necessary to incentivize and secure demand curtailment?

2.5 Transactive Demonstrations and Simulations

With dynamic control and incentives for consumers to reduce or shift energy consumption, transactive energy systems can manage responsive demand assets and incorporate variable renewable resources to flatten load and reduce operational constraints. Several transactive energy demonstrations have tested the system's ability to achieve these aims. The Olympic Peninsula Demonstration coordinated DERs through a double auction market, reducing system peak load, managing congestion, and saving energy costs (Hammerstrom et al., 2008; Hammerstrom et al., 2009). The American Electric Power-Ohio gridSMART demonstration also used a double auction market to coordinate DERS and demonstrate benefits (Widergren et al., 2014a; Widergren et al., 2014b). In 2016, the California Energy Commission funded a pilot program to evaluate customer response to dynamic price communications called the Retail Automated Transactive Energy System (RATES), which utilized TeMix's retail transactive energy platform to coordinate DERs for Southern California Edison customers (Samad and Bienert, 2020). A recent large-scale simulation of a market comparable to ERCOT, the Distribution System Operator with Transactive (DSO+T), showed how transactive energy mechanisms and principles could be used to integrate large numbers of DERs into electricity grid operations (Reeve et al., 2022). The important takeaway from recent demonstrations and simulations is that transactive energy systems have been implemented at the distribution level, successfully coordinating DERs to satisfy distribution-level constraints.

Although transactive energy can facilitate the participation of demand-side resources for reliable and efficient grid operations, the missing money problem may still occur due to a desire or need for higher levels of resource adequacy, reliability, and resilience than can be supported by a market with active participation from both supply and demand sides of the market. In section 3.0, we will discuss capacity markets designed for resource adequacy, as well as considerations for a DSO-level capacity market to remediate this problem.

3.0 Capacity Markets Designed for Resource Adequacy

Instead of relying exclusively on energy markets to incentivize resource adequacy, many organized electricity markets have developed frameworks to compensate resources for capacity and their contribution to resource adequacy goals, in addition to revenue from the energy and ancillary services markets. Resources that are cleared in the capacity market provide an obligation to offer their capacity into the energy market. Because these resources are paid for their availability rather than energy production, generators can receive capacity market payments even in years when they are not needed, which may improve price signals for resource adequacy needs.

in wholesale electricity markets:

> *Capacity represents a commitment of power from generators and other resources to deliver when needed, particularly in case of a grid emergency. A shopping mall, for example, builds enough parking spaces to be filled at its busiest time – Black Friday. The spaces are there when needed, but they may not be used all year round. Capacity, as it relates to electricity, means there are adequate resources on the grid to ensure that the demand for electricity can be met at all times. –PJM*[9]

This section first describes typical capacity market designs, including supply-side and demand-side participation models, as well as performance mechanisms and other enhancements, such as effective load carrying capacity (ELCC), that some market operators have implemented to further improve capacity market incentives.

3.1 Capacity Market Design

As explained in the previous section, the design and implementation of capacity markets has been guided by the investment incentives of conventional generators. That is, the capacity market is designed to create the investment incentives that will provide revenue sufficiency to a least-cost set of generators or demand-side resources that can meet resource adequacy goals. Conventional generators remain available essentially year-round, with the exception of planned maintenance or (typically rare) unplanned forced outages, and this corresponds well with annual capacity payments that compensate the reliability benefit provided by the resource's consistent availability. In contrast, renewable resources are weather-dependent, with geographic and temporal correlations among separate resources. Demand-side resources also vary in their availability throughout the day. The capacity contribution of renewable and demand-side resources is, therefore, not as straightforward as calculating an outage-adjusted capacity factor times the resource's nameplate capacity.

In contrast to a forward contract for energy (e.g., through a power purchase agreement or PPA), capacity markets only require energy availability, but they do not specify the price that the energy will be purchased. Capacity awards, therefore, provide an option-like payment to generators, and in return, consumers are less exposed to high energy prices due to the additional capacity that enters the market. Energy and capacity prices are linked because the implementation of capacity markets will tend to suppress the price spikes in the energy market that would have otherwise served as price signals for additional capacity. Unlike energy,

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[9] See PJM Learning Center: Capacity Markets, available at: https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx

capacity is inherently procured ahead of time, so the capacity resources will be able to contribute to system reliability during critical periods.

All capacity markets have some similar elements. Demand is based on a peak demand forecast that determines the need for future installed capacity. Price-responsive demand can participate in capacity markets, adjusting the demand curve. Capacity market participants who are willing to supply power submit capacity offers that reflect their capital costs and operational costs. The market is cleared with a competitive auction where ISOs order capacity offers from smallest to largest, then use the demand curve to determine the market clearing price of capacity.

Capacity market supply is determined by resources offering into the capacity market. Capacity offers are based on the avoidable costs to keep each resource available, for example, the ongoing maintenance costs of existing resources or capital investment costs of new resources or planned improvements. Since most resources will recover a significant portion of their capital costs through the energy market, capacity market offers are also reduced based on the resource's expected energy and ancillary services revenues by operators. Peaking plants will tend to offer the highest costs in the capacity market since they are only expected to operate a few times per year and will not receive as much energy market revenue as baseload resources, for example, but need to base their bid on the cost of keeping their plant available to operate when needed. Capital and operational costs can also be affected by state subsidies (for example, a subsidized plant can offer capacity at near zero-cost to clear the market, which has led to price suppression and some rule changes within capacity markets).

Capacity market demand is different than energy market demand because it's determined administratively by the ISO/RTO. First, the ISO/RTO calculates the required installed capacity, which is the capacity required to meet forecasted peak demand plus a capacity reserve margin. Next, the ISO/RTO calculates a price cap to anchor demand that is based on the CONE for a typical peaking plant—usually the cost of a new, gas-fired power plant. The CONE represents how much investors are willing to pay to add new capacity. The ISO/RTO also calculates net CONE, which is the CONE less energy and ancillary services market revenues. Net CONE estimates the "Missing Money" for the representative plant in the market. The ISO/RTO then uses a methodology to determine the downward sloping demand curve for capacity, which determines how much capacity the ISO/RTO will procure at each price point. Table 1 provides an overview of methodologies used to determine the shape of the demand curve by ISO/RTO.

In Figure 10, the flat part of the demand curve is set at net CONE. The curve is horizontal until the reliability requirement is met. In theory, the curve slopes downward because the ISO, on behalf of consumers, values the increased reliability provided by each additional megawatt less after the reliability requirement is met. In reality, the methodology to determine the downward sloping demand curve varies by market but is generally based on net CONE and the reliability requirement, rather than consumer's willingness to pay for reliability; see Byers et al. (2018) for further reading. The intersection of supply and demand determines the market clearing price. If the shape of the demand curve is wrong, the ISO/RTO will procure too much or too little capacity.

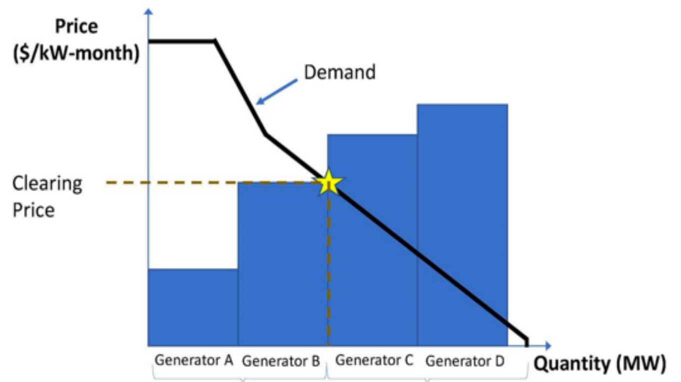

Figure 10. Capacity Market Clearing (Source: National Resources Defense Council)

In the United States, three ISOs/RTOs have mandatory capacity markets: ISO New England (ISO-NE), PJM, and the New York ISO (NYISO). The Midcontinent ISO has a voluntary capacity market. Table 1 provides details of the demand curve design and parameters used to determine the shape of the demand curve by ISO/RTO. While the California ISO does not have a formal capacity auction, it has a resource adequacy process to make sure that there is sufficient supply to meet demand in the near-term. ERCOT has no capacity market and, instead, has an energy only market with a higher price cap and ORDC approach to improve scarcity pricing.[10]

Table 1. Demand Curve Design and Parameters for Capacity Markets

RTO/ISO	Demand Curve Design	Demand Curve Parameters
PJM	System-wide and zonal demand curves that are downward sloping. The price cap is based on the CONE, net CONE, and pool-wide equivalent forced outage rate (PWEFORd). The downward sloping portion is defined by three points that are functions of net CONE and the reliability (“unforced capacity” [UCAP]) requirement.	Price Cap: $\frac{\max(CONE, 1.5 * Net\ CONE)}{1 - PWEFORd}$ Where CONE: Gross CONE is the is the levelized annual cost to build a new resource plus annual fixed maintenance and operation costs (PJM, 2020a).[11] Net CONE: is calculated as Gross CONE for the reference resource (combustion turbine, but PJM develops net CONE estimates for other technologies for its Minimum Offer Price Rule [MOPR]) minus its average ancillary and energy services revenues over the three years anterior to the auction delivery year (Newell et al., 2022). And PWEFORd: Equivalent Demand Forced Outage Rate (EFORd) is an estimate of the probability that a generating unit will be unavailable due to forced deratings or outages when in demand (PJM 2020b;

[10] ERCOT’s high system-wide offer cap was revised from \$9,000/MWh to \$5,000/MWh following severe weather events in Texas in February 2021 (PUCT, 2022). This price cap remains higher than in other centralized markets where caps range from \$2,000 to \$3,500.
[11] There are two approaches to levelized investment costs into annual costs. The first is the “level-nominal” approach that assumes that net revenues will be the same in nominal terms over the 20-year economic life of the plant. And the second approach is the “level-real,” which assumes lower revenues in the first year then an increase at the rate of inflation. Both approaches are calculated such that the NPV of the project is zero over the 20-year economic life of the plant (Byers et al., 2018).

RTO/ISO	Demand Curve Design	Demand Curve Parameters
		PJM, 2022a). Pool-wide refers to all generating units expected to be in service in a given delivery year. Downward Sloping Portion: Point A: $RR * \frac{100\%+IRM-0.2\%}{100\%+IRM}$ Point B: $RR * \frac{100\%+IRM+2.9\%}{100\%+IRM}$ Point C: $RR * \frac{100\%+IRM+8.8\%}{100\%+IRM}$ Where RR is the Reliability Requirement, the total amount of capacity large enough to meet peak loads plus a "reserve margin" to address plant outages and other unpredictable events. IRM is the Installed Reserve Margin, the percent of aggregate generating unit capability above the forecasted peak load that is necessary for meeting PJM's determined adequacy level (installed reserves needed to meet the reliability criteria for a loss of load expectation (LOLE) of one day, on average, in 10 years). It is expressed in units of installed capacity (ICAP) (PJM, 2021b). Percentages are based on how much PJM reserve exceeds or falls below the 1-day-in-10-years LOLE criterion (Garrido, 2021).
ISO-NE	ISO-NE has a system-wide downward sloping demand curve and zonal demand curves to procure zonal capacity. ISO-NE uses a Marginal Reliability Impact (MRI)-based demand curve that was first implemented in delivery year 2021/2022. The MRI is the decrease in Expected Energy Not Served from an additional MW of capacity added to the system. NE-ISO calculates the MRI for a range of capacity values for the system and zonal levels and uses a scaling factor (based on the net ICAP requirement, NICR, to meet a 1-day-in-10 years LOLE) to translate the slope of the MRI curve to a demand curve (Byers et al., 2018). The purpose of the MRI curve is to increase or decrease capacity payments in direct proportion to incremental marginal capacity contributions to improve system reliability (Spees et al., 2019).	The MRI demand curve has a price cap that is based on the greater of the CONE or 1.6 times net CONE and a quantity cap at 110% of the NICR. Price cap = max (CONE, 1.6 * Net CONE) Where CONE = Cost of New Entry And Net CONE = is equal to the net present value of the levelized costs of each resource, net of expected revenues from energy, ancillary services, and pay-for-performance. The CONE and Net CONE values are parameters that are intended to reflect the revenue a new entrant would need from the capacity market (net of expected revenues) to recover its capital and fixed expenses under long-term equilibrium conditions, given reasonable expectations about future cost recovery and market conditions (Mott, 2020). And NICR is the total amount of capacity required to achieve the corresponding reliability target determined by ISO-NE. Similar to the ORDC approach, the price at each marginal reliability impact point on the MRI curve is the product of the possibility of unserved load and the implied cost of that unserved load (Kaslow, 2016).[12]

[12] See Zhao (2022) for further reading.

RTO/ISO	Demand Curve Design	Demand Curve Parameters
NYISO	NYISO has a system-wide downward sloping demand curve and separate demand curves for locality or capacity zones. The first segment of the NYISO demand curve is the price cap, which is based on 1.5*CONE. The second segment is a downward sloping line that passes through the minimum installed capacity requirement (MICR) and the installed capacity (ICAP) reference point price; the line also passes through the zero-crossing point, which is the point where additional surplus capacity has $0 value (Smith, 2019b).The third segment is a horizontal line at the price of 0 for ICAP values greater than the Zero Crossing Point. Demand curves are constructed using ICAP values and translated to UCAP values by a scaling factor (1 – weighted average derate factor) (Byers et al., 2018).	Price cap: $\frac{1.5*CONE}{1-WADF}$ ICAP reference point price: $\frac{Net\ CONE}{1-WADF}$ Where CONE: cost of new entry Net CONE: net cost of new entry WADF: Weighted Average Derated Factor. Derating factors are computed using actual outages over an 18-month rolling average when the resource is programed to dispatch (Smith, 2019a). MICR: It is equal to New York Control Area (control area under the NYISO) Forecasted Peak Load times (1 + IRM) where the IRM is used to derive the amount of capacity that must be available to ensure resource adequacy and reliability (Byers et al., 2018).
MISO[13]	MISO's demand curve is based on a fixed capacity target to meet its planning reserve margin, based on LOLE and UCAP, resulting in a vertical demand curve (Byers et al., 2018; MISO, 2021). MISO is currently considering moving to seasonal capacity markets, which would potentially change its current demand curve design.	The CONE is used primarily in MISO as the maximum offer and maximum clearing price in Planning Resource Auctions. MISO determines CONE values for each of its 10 load zones but does not calculate a system-wide value. In calculating the CONE, MISO considers factors such as physical factors (type of generation resource), financial factors (debt/equity ratio, cost of capital, etc.), and other expenses (permit costs, environmental costs, maintenance, etc.). But MISO does not use net CONE (i.e., does not subtract expected net revenue from energy, ancillary services markets) (MISO, 2019a).

Some limitations to current capacity market design are that conventional generators are only able to provide their UCAP rating to the capacity market. UCAP derates a generator's installed or nameplate capacity according to their forced outage rate based on the probability that the unit will not be available during the system peak. From the system perspective, this ensures that sufficient supply will be available given the expected amount of unavailable generation capacity. This design assumes that forced outages are independent and occur randomly. However, outages due to common modes of failure, such as extreme weather, have the potential to reduce the amount of capacity available during critical periods. Generators may still receive capacity payments even if they happen to be on forced outage during system peak, which has resulted in calls for reforms to improve incentives in capacity markets.

[13] MISO has a voluntary centralized capacity market.

Forecasted peak demand can also be reduced and emergency situations addressed with flexible demand resources, but representation of demand-side flexibility in wholesale capacity markets remains an open question. Dupuy and Linville (2019) document several barriers to participation for demand-side resources in capacity markets, including complex market rules, limited geographical and high minimum aggregation requirements, as well as 365-days/year availability requirements. Demand response participation decreased nationally by 4 percent from 2019 to 2020 (although demand response as a percent of peak demand increased from 6 percent to 6.6 percent during that same period due to lower peak demand) (FERC, 2020a; FERC, 2021). How Federal Energy Regulatory Commission (FERC) Order 2222 will affect participation of demand-side resources in capacity markets and resource planning over the longer term (and under non-pandemic conditions) remains to be seen. Barriers to participation for demand-side resources will be discussed in more detail at the end of this section.

3.1.1 Generator Availability

To make sure resources produce power or reduce demand when needed, several markets have added various "pay-for-performance" capacity market mechanisms. For example, some markets (PJM, ISO-NE, NYISO) either pay resources a bonus or charge resources a penalty for each hour they do not meet their compliance obligation during certain compliance hours (for example, when the system is under shortage) (PJM, 2022b).[14] Other markets, such as MISO, do not have a pay-for-performance mechanism.[15] Table 2 outlines pay-for-performance requirements, rewards, and penalties by ISO/RTO.

Table 2. Pay-for-Performance Mechanisms by ISO/RTO

RTO/ISO	Performance Requirement	Reward if Resource Overperforms	Penalty if Resource Underperforms
PJM	**100% Capacity Performance Resources**: Resources must be available for the entire delivery year whenever PJM declares an emergency. **PJM's Non-Performance Assessment**: Measure of performance shortfall calculated by subtracting actual performance from expected performance. Expected performance of a resource is its capacity performance commitment. Actual performance is the output of a resource during an event (performance	Overperforming resources receive a **Bonus Performance Credit**, a share of the revenues collected from underperforming resources. When a resource overperforms it is considered to have provided bonus performance (in MW). PJM divides a resource's bonus performance quantity by the total bonus performance (of all other resources) to obtain the bonus performance credit for that resource.	Underperforming resources are subject to a **Non-Performance Penalty**, a fine paid by underperforming resources. The non-performance charge is obtained by multiplying the performance shortfall by the non-performance charge rate. The non-performance charge rate is calculated as the net cost of new entry (Net CONE, in $/MW-day in ICAP terms) for the local delivery zone where the resource is located, multiplied by the number of days in the delivery year, and divided by 30 hours and divided by 12 intervals. Thirty

[14] For more details see ISO-NE's forward capacity market participation homepage: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-fcm-pay-for-performance-pfp-rules (accessed 9/27/2022).
[15] For more details see MISO's resource adequacy homepage: https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (accessed 9/27/2022).

RTO/ISO	Performance Requirement	Reward if Resource Overperforms	Penalty if Resource Underperforms
	assessment interval) (PJM, 2020c).	Note that bonus MW are capped at the schedule and dispatch instructions for a resource to incentivize resources to follow dispatch.	represents the foreseen number of hours per year PJM anticipates emergency actions to be effective, 12 intervals divide the hour into 5-minute performance assessment intervals.
ISO-NE[16]	ISO-NE's **Pay-for-Performance** mechanism is a two-settlement system where resources that overperform receive bonuses from the funds collected on penalties incurred by underperforming resources. In the first settlement stage, capacity suppliers receive their monthly capacity payment (**capacity base payment**). The second settlement stage is based on suppliers' performance during capacity scarcity conditions, when at least one of ISO-NE's three reserve requirements is not met,[17] and the reserve-constraint penalty factor is determining the reserve price. In the second settlement stage, a **capacity performance payment** is determined for each resource based on its performance against its forward position (its share of the system requirements during the capacity scarcity event). Resources that underperform are fined and the revenue is distributed to overperformers.	The **capacity performance payment** is based on an administratively determined rate specified in ISO-NE's tariff. Capacity performance payment rates are currently \$3,500/MWh and will increase to \$5,455/MWh in 2024.	The **capacity performance payment** is based on an administratively determined rate specified in ISO-NE's tariff. Capacity performance payment rates are currently \$3,500/MWh and will increase to \$5,455/MWh in 2024. ISO-NE has stop loss provisions that limit the losses a resource could incur on a monthly or annual basis but also limits the compensation for generators that perform well.

[16] For more details see 147 FERC ¶ 61,172; Potomac Economics (2021); ISO-NE's Forward Capacity Market Performance Incentives Project Overview homepage: https://www.iso-ne.com/committees/key-projects/implemented/fcm-performance-incentives (accessed 8/23/2022); ISO-NE's forward capacity market participation homepage: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-fcm-pay-for-performance-pfp-rules (accessed 9/27/2022).
[17] (1) the system minimum 30-minute reserve requirement, (2) the system 10-minute reserve requirement, (3) the zonal 30-minute reserve requirements. For more details see ISO-NE's Forward Reserve Market and Real-Time Reserve Pricing homepage: https://www.iso-ne.com/markets-operations/markets/reserves#reserve-requirements-in-new-england (accessed 8/23/2022).

RTO/ISO	Performance Requirement	Reward if Resource Overperforms	Penalty if Resource Underperforms
	The capacity performance payment rate is based on the net cost of new entry, as the capacity base payment and capacity performance payment should be at least as large at the net cost of new entry for a new resource needed to satisfy the ICAP, and the negative capacity performance payment that would fully offset the capacity base payments of a resource that had expected performance of zero during the capacity commitment period.		
NYISO	ICAP suppliers in NYISO that sell more UCAP than they are qualified to sell (either for a specific month in the capability period or in monthly auctions) will be deemed to have a shortfall for that month. To cover the shortfall, the ICAP supplier must purchase sufficient unforced capacity through relevant monthly auctions or through bilateral transactions. The NYISO will purchase unforced capacity on behalf of the ICAP supplier to cover the shortfall if the supplier does not do so. Penalties also apply for ICAP suppliers found to supply less UCAP during the capability period than they were committed to supply (NYISO, 2022a).	NYISO does not have rewards for overperformance.	The NYISO will purchase unforced capacity on behalf of the ICAP supplier to cover the shortfall if the supplier does not do so. The price paid by the installed capacity supplier is the market clearing price of UCAP in the ICAP Spot Market Auction multiplied by the number of MW the installed capacity supplier needs to meet its shortfall. Further, if the ICAP supplier is found to supply less UCAP during the capability period than it was committed to supply, it will pay a deficiency charge equal to 1.5 times the market clearing price of UCAP, as determined in the ICAP Spot Market Auction, multiplied by the number of MW the installed capacity supplier is deficient.
MISO	MISO tracks market participants to determine if they have met their must-offer requirements in the day-ahead reserve and energy markets (Byers et al., 2018).	There is no payment for overperformance.	Participants that fail to meet their must-offer requirements are informed, but there is no formal penalty.

Dupuy and Linvill (2019) highlight that some performance requirements, such as requiring demand response resources be available 365 days per year, can be problematic, as not all resources—for example air conditioning loads—will be available year-round. Nevertheless, pay-for-performance incentives can improve capacity performance. As an example, due to high levels of forced outages during the January 2014 polar vortex, a pay-for-performance mechanism was implemented in PJM's capacity market starting with the 2016–2017 capacity auction. Forced outage rates went from 22 percent during the 2014 polar vortex down to 8.6 percent and 10.6 percent during a similar cold weather event on January 30 and 31, 2019 (Chen et al., 2020).

3.1.2 Capacity Zones

Most markets employ capacity zones to reflect regional or more granular capacity requirements. Some of these capacity zones or requirements predate electricity restructuring, as they were based on decisions made by vertically integrated utilities evaluating the inherent trade-off in investing in more generation or more transmission, leading to an electricity system with varying transmission capacity, local generation resources, and electricity demand. Although electricity restructuring changed the nature of how utilities procure sufficient generation to meet resource adequacy needs, capacity zones still largely reflect the capacity needs based on preexisting regulatory or service area boundaries, although more granular areas—such as transmission constrained or load pocket areas—have been added over time. All ISOs with centralized capacity markets procure capacity for local delivery areas or subzones, with separate zonal clearing prices. Although the California ISO does not have a centralized capacity market, it has a process for addressing local capacity requirements with its local resource adequacy construct, which will be discussed next.

3.1.2.1 California's Local Resource Adequacy Construct

The California Public Utilities Commission (CPUC) adopted local resource adequacy requirements in 2015 with the purpose of ensuring adequate capacity is procured in local areas to mitigate potential reliability issues. Each load-serving entity (LSE) is assigned its local resource adequacy requirement based on an annual California ISO (CAISO) study, the "Local Capacity Technical Analysis" that determines the minimum energy (in MW) that must be available within local capacity areas using a 1-in-10 weather year and N-1-1 contingencies, based on mandatory reliability standards. Local capacity areas are transmission constrained "load pockets" (i.e., specific areas that have limited import capability and need local generation capacity to mitigate local reliability problems in those specific areas within the ISO controlled grid) (CAISO, 2018). LSEs must show on an annual basis that they have fulfilled their local resource adequacy obligations for a three-year forward-looking period (fulfilling 100 percent of local resource adequacy obligations for each month in years one and two, and 50 percent in year three) (CPUC, 2022).[18]

To show fulfillment of obligations, the local resource adequacy program requires LSEs enter into forward commitment capacity contracts that carry a must-offer obligation with generation resources. The must-offer obligation requires that these resources are bid into CAISO's day-ahead and real-time markets and be available for dispatch. A resource's net qualifying capacity is the maximum capacity that can be counted toward meeting an LSE's local resource adequacy requirement and varies by resource type, as shown in Table 3.

[18] For more details see CPUC's Resource Adequacy Homepage: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage (accessed 8/3/2022).

Table 3. Resource Net Qualifying Capacity

Resource Type	Qualifying Capacity Methodology
Dispatchable resources	Most recent maximum capability (Pmax) test
Non-dispatchable hydro/geothermal	Based on historical production
Combined heat and power/biomass (not fully dispatchable)	Based on MW amount bid or self-scheduled in the day-ahead market
Wind and solar	Effective load carrying capability modeling

Demand response can also count toward resource adequacy obligations. Capacity procured from third-party providers through auction, as well as event-based demand response resources, can count toward resource adequacy. Resource adequacy credits are based on the capacity estimated using expected load impact compared to actual load impacts from the previous year (based on CPUC's Load Impact Protocols).

Performance and penalties are subject to the resource adequacy availability incentive mechanism (RAAIM), which provides incentives for resources to meet their obligations. Resources are either charged or paid each month, depending on average capacity availability during assessment hours (CAISO, 2022a). For 2022 system and flexible capacity obligations, penalties are based on a points system where, for each non-summer month, one point is incurred for each instance of resource adequacy deficiency, and two points are incurred in the summer months. Penalties depend on accrued points, as shown in Table 4 (CPUC Rulemaking (R.) 19-11-009).

Table 4. Resource Adequacy Availability Incentive Mechanism

Tier	Points	Penalty Price
1	0–5	Applicable system penalty price
2	6–10	2x penalty price
3	11+	3x penalty price

In 2021, CAISO highlighted several challenges to resource adequacy and local resource adequacy, including that current counting rules do not adequately reflect resource availability, and that there was a growing reliance on availability-limited resources that may not be able to reliably meet energy needs in local capacity areas (CAISO, 2021). Because of the changing nature of resource adequacy due to variable and energy-limited resources, CAISO noted that resource counting rules need to reflect a resources' ability to meet operational and reliability requirements all hours of the year, and that more reliable resources should be rewarded. CAISO also found that relying on an installed-capacity-based planning reserve margin as required by CPUC was not sustainable and, instead, recommended a new resource adequacy framework, including resource adequacy assessments based on both the UCAP of resources and the resource adequacy portfolio's ability to meet CAISO's operational and reliability requirements. To address these and other resource adequacy concerns, CPUC adopted a new resource adequacy framework, the "24-hour slice," (CPUC R.21-10-002 Appendix A) based on proceedings with stakeholders in June of 2022 (CPUC R.19-11-009). The changes are applicable to the 2023–2025 local capacity obligations.

The 24-hour slice framework requires each LSE to demonstrate sufficient capacity (load plus planning reserve margin) in all 24 hours of the day for CAISO's "worst day" (day that contains the hour with the highest coincident peak load forecast) of the month. In terms of net qualifying capacity, resources will still have a monthly value representing their deliverability-adjusted peak hour contribution, but wind and solar will have a peak hour deliverable capacity based on their monthly 24-hour profile for that hour. Penalties will be assessed based on the hour with the largest deficiency that an LSE fails to meet its requirement in any of the 24-hours.

Because capacity needs can vary both geographically as well as over time, it is important to incentivize investment in generating capacity where it can be used most effectively. However, current zonal definitions for capacity markets create a rough approximation for the local value of capacity and do not reflect differences in resource variability. Additionally, it is difficult to know in advance how much transmission capacity will be available. Current geographic limitations can limit the participation of demand-side and DERs if capacity zones do not align how those resource are best aggregated to reduce load. CAISO's local resource adequacy construct provides an insight into challenges and opportunities for valuing local capacity that can be leveraged to improve future ISO- or DSO-level capacity market design.

3.1.3 Renewable Generation

Like conventional generators, renewable generator capacities are also derated for participation in capacity markets. Based on the expected availability during system peak, wind is usually credited about 20 percent and solar about 60 percent of their nameplate capacity. However, many ISOs have implemented enhanced mechanisms for renewable capacity market participation because, unlike conventional generators, UCAP calculations do not accurately capture the amount of system capacity provided by resources with correlated output. That is, UCAP will overestimate the capacity provided by renewable power generation since all solar or wind generation will have low output at the same time, and in addition, the typical change in renewable power output throughout the day can shift the timing of critical periods when the system is short on capacity.

Most markets have implemented or are considering an approach called ELCC to quantify the incremental contribution of renewables to capacity and resource adequacy needs. ELCC methods broadly consist of performing Monte Carlo simulations to estimate the marginal contribution of additional capacity given typical weather patterns and the market's existing resource portfolio. ELCC calculations are typically performed for each individual resource and, therefore, will vary by location. The effects of implementing ELCC over previous heuristic methods can have a huge impact on investment decisions; for example, in a study examining the implications of 50 percent renewable energy penetration in the PJM footprint, PJM found an additional 78 percent of nameplate capacity was required on top of the forecasted peak load to satisfy resource adequacy needs (PJM, 2021a). Additional methods for calculating renewable generation capacity credits are reviewed in Dent et al. (2010). Current ISO/RTO methods for renewable generation participation in capacity markets are summarized in Table 5.

Table 5. ISO/RTO Methods for Renewable Energy Capacity Valuation

RTO/ISO	Wind Credit	Wind Method	Solar Credit	Solar Method
CAISO[19]	13.9–36.4%	ELCC (regional)	6.6–7.8%	ELCC (system average)

[19] See Carden et al. (2021). Note that these ELCC values are to meet CPUC's Mid-Term Reliability Procurement Decision, Decision (D.) 21-06-035 for procurement of net-qualifying capacity, or the value

RTO/ISO	Wind Credit	Wind Method	Solar Credit	Solar Method
ERCOT[20]	11–31%	ELCC (resource)	71–75%	ELCC (resource)
ISO-NE[21]	~25%	Historical Performance	~21%	Historical Performance
MISO[22]	0.3–31.1%[23]	ELCC (nodal)	50%[24]	Historical Performance
NYISO[25]	~32.6% (winter), ~17.7% (summer)	Historical Performance	~0.56% (winter), ~35.9% (summer)	Historical Performance
PJM[26]	16% (onshore), 37% (offshore)	ELCC (resource)	36% (fixed panel), 54% (tracking panel)	ELCC (resource)
SPP[27]	16.8% (summer), 17.1% (winter)	ELCC (resource)	85.1% (summer), 32.3% (winter)	ELCC (resource)

One question is whether capacity markets are well-suited for incentivizing investments in renewable or carbon-free resources such as hydroelectric or nuclear. Various generation technologies depend on capacity revenues to varying degrees based on their competitiveness in the energy market. For example, some generators may require a large capital investment cost in order to produce electricity more efficiently and at a lower marginal cost. These resources can rely on the energy market to recover most of their investment costs. Conversely, other resources may have very low investment costs but are accordingly less efficient and have more expensive marginal operating costs. These resources would not be very profitable in the energy market due to their high costs, but their low capital investment costs may make them attractive for meeting resource adequacy needs. Mays et al. (2019) carries this argument to conclude that capacity markets, although nominally technology neutral, will in effect favor investment in resources with high marginal costs and low capital costs due to differences in the risks associated with energy and capacity market revenues. Capacity market incentives may, therefore, work against investment in resources with low marginal costs and high capital costs, such as renewable wind and solar resources.

Capacity market reforms have the potential to correct the issues discussed above and to better align investment incentives in renewable resources with system capacity needs. The locational contribution of renewable capacity is a major area for potential reforms. Because renewable power generation is correlated with geography and can affect the timing of peak net load, additional capacity investments can have a greater improvement to resource adequacy if they

that resources are expected to contribute to peak load for 2023–2026. 2023 ELCC values for resource adequacy follow a different methodology (monthly average rather than incremental annual ELCC) and are currently being revised, see CPUC R.21-10-002.

[20] Note that the numbers provided are for year 2020 from Tables A2-7 and A2-8 for the modeled reliability contribution of the renewable resources. The reported numbers are more conservative than ERCOT's capacity, demand, and reserves (CDR) accounting methodology, used for reserve margin reporting. See Carden and Dombrowsky (2021) for further detail.

[21] Reported numbers are from Figure 17, based on median output during the top five annual net load hours (Potomac Economics, 2021a).

[22] See MISO (2022).

[23] System-wide average was 15.5%.

[24] In first year, followed by historical summer performance.

[25] Reported numbers based on ICAP, slides 13 and 31 (NYISO, 2020).

[26] See PJM (2021c).

[27] Reported numbers are based on a preliminary study, SPP to implement ELCC in 2023 (SPP, 2021).

are less correlated or negatively correlated with the existing renewable capacity mix. Bothwell and Hobbs (2017) show how capacity markets can support more efficient investment incentives by using the location and type of renewable resources to calculate each capacity resource's marginal contribution to system resource adequacy. Today's capacity markets include zonal definitions that reduce capacity price signals to a rough approximation. However, the zonal definitions often follow preexisting regulatory or service area boundaries that do not reflect differences in resource variability. More efficient participation from seasonal demand-response programs like air conditioning load control might better supported by monthly or seasonal, rather than annual, capacity markets.

Such reforms to capacity markets could be effective in improving the incentives for efficient investment in renewable capacity, especially if incentives from energy markets become inadequate as the grid relies on an increasingly large proportion of renewable resources. Because capacity market revenues are less volatile than energy markets, it may be easier for renewable developers to plan and finance potential projects. The viability of this approach, however, will depend on designing capacity markets to provide accurate price signals for the locational and temporal availability of resources, as well as mechanisms to support flexible resources that complement the inherent variability of renewables. Other reforms, such as the ORDC approach to improve the value of capacity scarcity in energy and ancillary service market prices, are also important for valuing reserves in times of system stress and for the zero marginal cost future.

3.1.4 Demand-side Resources and Third-Party Aggregators

In many markets, participation of demand-side resources in wholesale energy, ancillary service, or capacity markets is through a third-party aggregator. For example, in CAISO, demand response capacity utilized for monthly resource adequacy supply plans is scheduled by third-party non-utility demand response providers who contract with and sell capacity to load-serving entities. Most capacity is procured through CPUC's Demand Response Auction Mechanism (DRAM). In PJM, qualified Curtailment Service Providers, such as electric utilities, energy service companies, or companies that focus solely on customer demand response, facilitate participation in PJM's demand response markets. Current rules for participation of demand-side resources in capacity markets or as contributors to resource adequacy are provided in Table 6. This table illuminates the complexity of requirements facing responsive-demand assets, a key barrier to demand-side participation. With the ongoing implementation of FERC Order 2222, broader participation from third-party aggregators can be expected to impact how demand-side resources participate in wholesale markets. See Eldridge and Somani (2022) for further reading on these impacts.

Table 6. Rules for Demand-Side Participation in Resource Adequacy Constructs

RTO/ISO	Program(s)	Demand Resource Requirements	Participation
CAISO[28]	Demand response can be either **proxy demand response (PDR)** or **reliability demand response resources (RDRRs)**. PDR bid economically into day-ahead and real-time markets as	**PDR** must have a minimum load curtailment of 100 kW for day-ahead and real-time energy markets and 500 kW for day-ahead and real-time non-spinning reserve and spinning reserve. Smaller loads may be aggregated to reach minimums.	Demand response was 3 to 4% of total system resource adequacy capacity (1,760 MW) in 2021 Summer peak months. Of this

[28] See CAISO (2020), CAISO (2022b) and CAISO (2022c).

RTO/ISO	Program(s)	Demand Resource Requirements	Participation
	supply. RDRR can participate in the day-ahead market. **Utility demand response programs** are operated by load-serving entities with capacity credited toward meeting resource adequacy requirements. Most of these resources are RDRRs composed of Base Interruptible Program customers and agricultural and pumping loads. RDRRs are only called upon in emergency conditions. This capacity is not shown on monthly resource adequacy supply plans and is not subject to ISO must-offer-obligations or RAAIM. **Supply plan (third-party) demand response** is shown on monthly resource adequacy supply plans. This capacity is scheduled by third-party non-utility demand response providers who contract with and sell capacity to load-serving entities. Most capacity is procured through CPUC's Demand Response Auction Mechanism (DRAM), although some is through bilateral contracts. Most of these resources are proxy demand resources. Resources greater than 1 MW are subject to the RAAIM.	**RDRR** participates in the day-ahead market, responds to reliability events, but may not provide ancillary services. **RDRR** must have minimum load curtailment of 500 kW and deliver reliability energy within 40 minutes, minimum run times cannot exceed 1 hour, and maximum run times must be at least 4 hours. Resources must be available for up to 15 events/and or 48 hours per each Summer or Winter term. All resource aggregations are required to be within a single sub-load aggregation point and are only allowed for a single LSE. PDR aggregations > 10 MW require telemetry.	capacity, ~260 MW were supply plan demand response resources. RDRR participation is limited to CPUC jurisdictional programs. Resource adequacy credits for demand response are based on their expected load impact compared to actual load impacts from the previous year (estimations follow the CPUC Load Impact Protocols).
ERCOT[29]	Load resources can participate in the **responsive reserves market**, in ERCOT dispatched **reliability programs**, or as **self-dispatched demand response**. Because ERCOT is an energy only market,	**Responsive reserve market:** There are two (2) types of LRs. Non-Controllable Load Resources (NCLRs), which use high-set under-frequency relays.[30] and do not follow base points.[31] CLRs that use software control and follow base points.	**Responsive reserve market:** CLRs are primarily data mining loads (8 data mining loads with ~ 750 MW of controllable load as of Q4 2021).

[29] See 16 Tex. Admin. Code § 25.507 (TAC), Potomac Economics (2022a), ERCOT (2021a), ERCOT (2021b), ERCOT (2022), and the ERCOT Emergency Response Service Homepage: https://www.ercot.com/services/programs/load/eils (accessed 7/29/2022).
[30] Used to automatically shed a certain portion of load under low system frequency levels (below 59.7Hz).
[31] ERCOT uses Security Constrained Economic Dispatch base points (SCED base point), which can be seen as dispatch instructions on how much to consume; see ERCOT (2014b).

RTO/ISO	Program(s)	Demand Resource Requirements	Participation
	there are no revenue contributions from an ICAP market; as such, energy and reserve prices provide the only funding for revenue sufficiency. **Responsive reserve market** participants are qualified Load Resources (LRs) that offer Responsive Reserve Services. There are two (2) types of LRs. NCLRs and Controllable Load Resources (CLRs). There are two reliability programs: **Emergency Responsive Service** (**ERS**), which offers four service types (non-weather and weather sensitive, each procured for 10- or 30-minute response times) and is supervised by ERCOT. **Load management programs** supervised by transmission and distribution utilities (TDUs). Load management programs are only implemented during weekdays starting from June 1 to Sept. 30, between 1 p.m. and 7 p.m., and vary in demand response requirements. There are two forms of **self-dispatch demand response** programs: Demand response administered by Retail Electric Providers (REPs) active in the ERCOT area and third parties referred to as Non-Opt-In Entities (NOIEs), and the second program is the Four Coincident Peak or 4CP. Participants in 4CP can avoid or reduce their share of transmission costs by reducing demand during four peak summer demand periods.	NCLRs are typically large industrial or commercial loads that simply turn off or reduce consumption in blocks. CLRs have more sophisticated control systems and are capable of controllably reducing or increasing consumption under ERCOT dispatch control. **Emergency Responsive Service:** Participant in ERS must have an interval data recorder meter or smart meter that records demand and consumption levels every 15 minutes and be capable of reducing at least 100 kW during an event, which can be aggregated at several places and across multiple loads to reach minimum offer. Each ERS participant must be available for up to 8 cumulative hours of load reduction during each contract period (Dec–Mar, April–May, June–Sept, Oct–Nov). **Load Management Programs:** End-use customers enter into a program by accepting to receive a payment from a Transmission and Distribution Service Provider (TDSP) in return for decreasing peak demand an amount of time determined by the TDSP. Participants must commit to the program for one summer period and can drop out without penalty. These loads may be deployed by ERCOT instruction during Energy Emergency Alert Level 2 events (reserves are low and there is a risk of mandated controlled outages). **Self-dispatch demand response:** Price-responsive demand products are offered to their customers by REPs and some NOIEs in ERCOT. 4CP billing can incentivize customers to reduce load during 4CP intervals (four 15-minute intervals corresponding with the highest ERCOT load in June, July, August, and September).	NCLRs are large industrial/commercial loads, 600+ NCLRs have maximum interruptible load of 7600+ MW in Q4 2021. **Emergency Responsive Service:** Typically, smaller industrial/commercial loads and residential aggregations. In 2021, more than 24,000 sites provided ~1,000 MW to ERCOT reliability programs. **Load Management Programs:** In 2021, there were 325 MW of load participating across four TDU service territories. **Self-dispatch demand response:** In Summer 2021, load reduction amounts exceeded 1,250 MW for 19 days examined by ERCOT, and ~4,000 MW of load was reduced during 4CP intervals.

RTO/ISO	Program(s)	Demand Resource Requirements	Participation
ISO-NE[32]	ISO-NE has a centralized capacity market called the Forward Capacity Market. Annual ICAP requirements are determined once a year, and resources are procured three years in advance for the FCM. The FCM uses downward sloping demand curves for system and zonal resource procurement. System curve determines regional capacity price. Zonal curves reflect additional congestion price. Buyer- and supplier-side mitigation rules to address market power. Buyer side is the minimum offer price rule (MOPR). Annual and monthly reconfiguration auctions are held prior to the final delivery month. Both **Active Demand Capacity Resources** and **Passive Demand Capacity Resources** can participate in the FCM. Note that active demand resources can also participate in ISO-NE's Price-Responsive Demand (PRD) program, which provides demand response to real-time and day-ahead energy markets.	**Demand capacity resources** must demonstrate the resource can operate at a specific MW value for the relevant capacity commitment period. Qualification criteria vary by resource type and service provided.[33] **Active demand resources** (demand response) are dispatched by the ISO. To participate in the FCM, resources have obligations and compensation similar to other power resources. Demand response resources are mapped to active demand capacity resources to fulfill capacity supply obligations. These resources are required to offer demand reductions into the energy market to fulfill the capacity supply obligations. Resources must be in the same zone to be mapped. **Passive demand resources** cannot be dispatched but save energy across many hours. They include energy efficiency and passive behind-the-meter generation. Passive demand resources (which include on-peak and seasonal peak demand resources) capacity supply obligation is based on the expected impact of the measures on reducing peak load.	In 2020, Demand Response Resources had capacity supply obligations of approximately 438 MW. Under the PRD program, more than 600 MWs of demand response resources participate in the real-time and energy markets.

[32] See ISO-NE (2018), Potomac Economics (2021b), ISO-NE (2021), ISO-NE's Forward Capacity Market Participation Guide Homepage: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-the-fcm-and-its-auctions (accessed 3/9/2022), and ISO-NE's About Demand Resources Homepage: https://www.iso-ne.com/markets-operations/markets/demand-resources/about (accessed 3/18/2022).

[33] For further details see: ISO-NE's Qualified Capacity for CSO Bilateral Periods and Reconfiguration Auctions Homepage: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/qualified-capacity-post-fca (accessed 8/1/2022); and ISO-NE's Qualification Process for Existing Generators Homepage: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/qualification-process-for-existing-generators (accessed 8/1/2022).

RTO/ISO	Program(s)	Demand Resource Requirements	Participation
MISO[34]	In MISO, demand response (DR) resources can participate in the DR market as one or more of these three categories: **Load-Modifying Resources** (LMRs), **Demand Response Resources** (DRRs), and **Emergency Demand Response Resources** (EDRs). **LMRs** are capacity resources required to curtail in emergencies and to meet Planning and Reserve Margin Requirement (PRMR). LMRs can also participate in the Planning Resource Auction (PRA), MISO's voluntary capacity market. **DRRs** economically adjust to prices in the ancillary services and energy markets. **EDR**s are requested in emergencies but do not have the obligation to offer nor to satisfy PRMR. There are two types of **DRRs**: Type I and Type II. Type I **DRRs,** sometimes considered Fast-Start Resources, can procure a predetermined amount of energy via a physical load interruption and fix prices in Extend Locational Marginal Pricing (ELMP). And Type II **DRRs** procure diverse levels of operating reserve or energy on a five-minute basis.	**LMRs** must be able to: curtail a minimum of 100 kW, five times per year, for at least four uninterrupted hours. LMRS can only be accessed in the event of an emergency. They must curtail during the summer months (June to August). **LMRs** are paid even in the absence of event, and they can receive up to 12 hours' notice ahead of an event. **DRR** Type **I** resources must participate in the Energy and Operating Reserve Markets, they must be able to supply a predetermined amount of energy, Contingency Reserve through controllable Load and/or Behind the Meter Generation, they must have the proper metering equipment installed and comply with Transmission Provider's Setpoint Instructions. **DDR** Type II also participates in the Energy and Operating Reserve Markets, they must be capable of procuring varying levels of energy, Up/Down Ramp Capabilities, and Operating Reserve through a controllable Load and/or the Behind the meter generation. They must be able to meet Provider's Setpoint Instructions and have the appropriate metering material installed. **EDR**s submit information detailing their costs incurred to decrease load during an emergency event and their availability in the day-ahead time frame. They can also set prices along with offers during an emergency and have the possibility of changing their availability and offers daily. **DDRs** can meet **LMR** qualification, while **LMR** can choose to dual register as **EDRs.**	In 2021, MISO had 12 GW of DRRs, most in the form of interruptible load under regulated utility programs. In MISO, nearly all (90%) DRRs are **LMRs**. **LMRs** were deployed three times in February 2021 in response to winter storm Uri and once more in June 2021 when MISO announced a Maximum Generation Event. 711 MW of **DRR Type I** and 115 MW of **DRR Type II** were registered in MISO in 2021. In 2021, 785 MW of **EDRs** were registered in MISO with 158 MW cross-registered as LMRs.

[34] See Potomac Economics (2022b), MISO (2019b).

NYISO[35]	NYISO has seasonal, monthly, and spot ICAP Auctions. Capacity requirements are determined by a downward sloping demand curve and zonal resource targets. In NYISO, Demand Response (DR) resources can participate under two main categories: Reliability-Based Programs and Economic-Based Programs. In Reliability-Based Programs demand response is activated by NYISO. Reliability-based programs include **Emergency Demand Response Program (EDRP)**, **ICAP Special Case Resources (SCR)**, and **Targeted Demand Response Program (TDRP). SCRs** participate in installed capacity auctions. In Economic-Based Programs, resources decide when they participate through supply offer. Historically, Economic-Based programs included: **Day-Ahead Demand Response Program** (**DADRP**) and **DSASP**, which allowed qualified economic demand resources to participate in the ancillary service markets and in the day-ahead market. Because there have been no resources engaged in DADRP since 2010, NYISO is transitioning the five active DSASP resources to a new model, the DER model.	Reliability-Based Programs: **EDRP**: Participants must provide a minimum of 100 kW reduction. Must be able to reduce load through interruptible loads or a qualified behind the meter local generator.[36] Must be registered by a Curtailment Service Provider (CSP)[37] and able to reduce load during a reliability event voluntarily. **SCR**: Participants must be registered by Responsible Interface Party (RIP),[38] must be able to offer a 100-kW reduction in aggregate by Load Zone. They must be capable of reducing load through interruptible loads or loads with a qualified behind the-meter local generator. Participants are obliged to respond during reliability events for at least 4 hours, and they must sell capacity in bilateral contracts or offer into Installed Capacity auctions (ICAP). **TDRP**: Participants are either SCR or EDRP resources in particular sites in Load Zone J (NYC). Participation is voluntary for both SCR and EDRP. They cannot determine real-time market price, and they receive payment based on the type of program they are enrolled in. **Economic-Based Programs:** **DADRP**: Participants must offer to reduce load in the Day-Ahead Market, be able to reduce load through interruptible loads or qualified behind-the meter local generator and respond to NYISO instruction when scheduled. They must be able to procure a minimum reduction of 1 MW (in aggregate by LSEs and Load Zone), must be enrolled in NYISO as a DADRP provider, and meet the Monthly Net Benefit Offer Floor (the price in $/MWh set by the ISO below which demand response offers will not be considered). **DSASP**: Participation is compulsory when scheduled. Must participate in Ancillary Service Market to supply	In Summer of 2021, 1170 MW of demand response resources participated in NYISO with 1007.8 MW coming from **SCR** program, and 3.7 MW from the **EDRP** program. The 5 remaining **Demand-Side Ancillary Services Program (DSASP)** resources provide 175 MW of reserve resources in upstate New York.

RTO/ISO	Program(s)	Demand Resource Requirements	Participation
		Regulation Service and Frequency Response and/or Operating Reserves. Must offer a minimum reduction of 1 MW in aggregate by Load. The minimum energy offer is the Monthly Net Benefit Offer Floor and DSASP must be register with NYISO by DSASP provider.	
PJM[39]	PJM has an annual centralized capacity market, the Reliability Pricing Model (RPM). Capacity is procured based on a downward sloping demand curve and zonal resource requirements. Incremental auctions are held every 20, 10, and 3 months prior to delivery. Demand response in PJM is classified into **emergency and pre-emergency demand response** (**demand resources**), and **economic demand response** (**economic resources)**. Synchronized regulation and reserves are provided by **demand response resources**. **Demand resources** (emergency and non-emergency) participate in the energy and capacity markets. **Economic resources** participate in the energy	**Emergency and Pre-Emergency Demand Response Programs:** Pre-Emergency and Emergency demand response have a mandatory commitment to reduce load or only consume a certain amount of electricity during supply shortages or emergency operating conditions. Participants enroll (through a qualified Curtailment Service Provider, such as an electric utility, energy service company, or company that focuses solely on customer demand response) to respond within 30, 60, or 120 minutes of a PJM dispatched event. All participants must enroll as pre-emergency (unless the resource has environmental restrictions reducing its operational capability or the resource relies on behind-the-meter generation). As of the 2021/2022 capacity market delivery year, all emergency and pre-emergency demand resources must be enrolled as capacity resources. Capacity resources must deliver electricity when needed for system	**Emergency and Pre-Emergency Demand Response Programs:** During the RPM FY 2020/2021 delivery year, pre-emergency demand response participation had the following committed MW: 30-min: 4,097.02 60-min: 326.9 120-min: 3,043.0 Emergency demand response had the following committed MW: 30-min: 240.6 60-min: 28.8 12-min: 150.0 In January through March 2021, the economic demand response program

35 See Potomac Economics (2022c), NYISO (2022b), NYISO (2022c), NYISO (2022d), NYISO Demand Response Homepage: https://www.nyiso.com/demand-response (accessed 8/1/2022).

36 A local generator is a resource operated by or on behalf of a load that is (i) either synchronized to a local distribution system solely to support a load that is in excess or equal to the resource capacity; or (ii) not synchronized to a local distribution system. See NYISO (2011).

37 A CSP is a LSE, or an individual customer taking service from an LSE and enrolled to take service directly from NYISO, or a curtailment customer aggregator (a NYISO limited customer that helps demand resources to easily participate in NYISO), or a curtailment program end use customer (a NYISO limited customer that is a retail end user capable of reducing load up to 100 kW). See NYISO (2022e).

38 A Responsible Interface Party (RIP) is a customer authorized by the ISO to be the installed capacity supplier for one or more Special Case Resources that agree to certain requirements. See FERC News Statement E-6: Commissioner Clements Concurrence in Part and Dissent in Part Regarding NYISO, available at: https://www.ferc.gov/news-events/news/e-6-commissioner-clements-concurrence-part-and-dissent-part-regarding-new-york (accessed 8/1/2022).

39 See PJM (2017), PJM (2022c), and Monitoring Analytics (2022).

RTO/ISO	Program(s)	Demand Resource Requirements	Participation
	markets. Demand response resources can also participate in both synchronized reserve and regulation markets.	emergencies and comply with PJM's capacity performance requirements. Summer only resources are allowed to aggregate with winter resources to fulfill their requirements.[40] Resources are compensated based on load reduction commitment and the RPM price. Penalties are incurred for non-performance. **Economic Demand Response Program**: Participants are demand response customers that offer into the day-ahead or real-time energy market. Estimated load reductions are paid the zonal LMP. Qualified PJM market participants (Curtailment Service Providers) act as agents for retail customers who wish to participate in demand response. Customers must meet certain requirements in order to qualify for payment, including reducing demand from their baseline normal usage. Economic demand response resources may also provide ancillary services if they have appropriate infrastructure and are qualified by PJM.	had total load reductions of 2,572 MWh and 5,494 MWh, respectively.
SPP[41]	In 2019, Southwest Power Pool (SPP) was a demand response capability in its market for the first time since 2015 and announced tariffs changes to allow for behind-the-meter generation and demand response resources to meet resource adequacy. SPP demand response programs are **dispatched load curtailment** or **controlled load curtailment** programs.	Demand response resources register as either **block demand response resources** or **dispatchable demand response resources** with SPP. **Block demand response resources** are eligible for energy and operating reserve products but are not eligible for ramp capability projects. They have hourly blocks for commitment and dispatch and must have a corresponding demand response load. **Dispatchable demand response resources** are eligible for energy, operating reserve, and ramp	In March 2014, SPP launched its Integrated Marketplace, initially registering six demand response resources (48 MW). In January 2015, the resources withdrew, and SPP remained without demand response resources until December 1, 2019. Demand response resource additions in

[40] See PJM (2015).
[41] See FERC (2020b), SPP (2022a), SPP (2022b), and the SPP Integrated Marketplace Homepage: https://www.spp.org/markets-operations/integrated-marketplace/#:~:text=Specifically%2C%20the%20Integrated%20Marketplace%20includes,Imbalance%20Service%20(EIS)%20Market (accessed 8/2/2022).

RTO/ISO	Program(s)	Demand Resource Requirements	Participation
	In 2019, SPP reported demand response capability in its market for the first time since 2015 and announced tariffs changes to allow for behind-the-meter generation and demand response resources to meet resource adequacy. For resource adequacy in SPP, dispatchable and controllable demand response programs are treated as a decrease to the reported peak demand of a Load Responsible Entity. Behind the meter generation is viewed as a resource capable of supplying capacity to meet resource adequacy.	capability products. They have 5-minute increments for commitment and dispatch and must have a corresponding demand response load.	2019, 2020, and 2021 resulted in 102 demand response resources consisting of 176.2 MW of nameplate capacity in December 2021. However, total generation from dispatchable demand response resources remains low, at 17 MW for 2021.

Holmberg and Omar (2018) also provide examples of DERs participating in ancillary service markets. Despite a lack of retail markets or residential tariffs for ancillary services, several programs nationwide provide for the participation of residential devices in ancillary service markets. Because residential devices cannot participate directly in wholesale markets, the most common avenue for participation is through an aggregator or utility, such as a curtailment service provider, who facilitates participation in demand response programs or direct participation in wholesale markets. Examples of DERS participating in ancillary service markets include electric vehicles providing regulation in CAISO, as well as water heaters performing regulation in PJM. As an example, Mosaic Power's Water Heater Efficiency Network (WHEN) provides regulation services in PJM's frequency regulation market. With its network of water heaters, Mosaic can load shift, as well as provide reduction to frequency regulation. The program encompasses over 14,000 water heaters across seven states.[42]

However, the combination of energy, ancillary services, and capacity market incentives have not resulted in a significant amount of demand response participation in electricity markets to date. Nolan and O'Malley (2015) discuss a number of potential causes for this. For example, participation in the energy and ancillary services markets requires consistent and reliable load reductions that may be at odds with typical consumer expectations for on-demand power. Capacity mechanisms would require participation and reliable performance in these markets, which may dissuade participation from consumers who are satisfied with paying a fixed rate for their power. Further, although capacity markets provide more stable investment signals in principle, ongoing debates about the design and effectiveness of capacity markets may increase the uncertainty and risk associated with designing and implementing new demand response programs. Dupuy and Linvill (2019) add that capacity markets are too blunt in their ability to signal locational and temporal needs. For example, demand response may be effective for alleviating transmission congestion or as a substitute for generator ramping flexibility, but these

[42] See Mosaic Power's About Frequency Regulation Homepage: https://mosaicpower.com/the-frequency-regulation-market (accessed 8/4/2022).

services are difficult to value in a capacity market construct. Energy, ancillary services, and capacity markets may also generally undervalue demand response due to the inclusion of price caps, given that price caps primarily affect resources that are infrequently dispatched, such as demand response.

4.0 Discussion on the Transactive Approach to Capacity Markets

Distribution systems may also benefit from capacity markets. Increasing levels of customer-owned distributed renewable energy are also driving changes in load shapes and volatility at more granular levels. Properly valued and coordinated demand response and DERs can address a range of challenges on the distribution system, including local peak reduction, voltage regulation, and other ancillary services (Dupuy and Linvill, 2019; Holmberg and Omar, 2018). However, fully realizing the benefits of DERs and demand response requires addressing barriers that limit participation in wholesale markets, clarifying the role of the DSO in addressing resource adequacy, and identifying possible participation models to capture the value of these resources. One potential model that can address these issues is the transactive energy approach.

Recognizing that capacity markets continue to be refined and adapted based on the transmission system's resource portfolio and resource adequacy needs, capacity market designs for a DSO-level system may also take many forms based on the needs and circumstances of a particular DSO. The missing money problem found in the transmission system mainly relates to incentives to meet resource adequacy goals of the bulk grid (e.g., a desired reserve margin). Because the bulk grid would always be responsible for supplying power to the DSO, resource adequacy is unlikely to be a root cause for missing money problems in DSOs. However, other possible DSO objectives (e.g., reactive power/voltage control, environmental policies, resilience, equity, etc.) may lead to other, distinct missing money problems for transactive energy systems to resolve. DSOs could also include a capacity-based market products to ensure that the distribution system is not operated too close to its feasibility limits (Heinrich et al., 2020), while still passing through the value or price of the wholesale capacity and energy markets.

In the wholesale market, the estimated economic value of unresponsive demand implies a missing incentive to supply the economically efficient level of reliability, typically expressed as a capacity reserve margin and a LOLE. Transactive energy systems can avoid this problem by relying on flexible, PRD in the market clearing framework. When the amount of supply is insufficient to serve all demand, the market clearing price can be explicitly set by bids from unserved demand. Price signals for the economically efficient capacity levels, therefore, can be endogenized by the market, instead, and there is less need for regulatory pricing schemes and unpriced load curtailment, as well as complex participation rules for demand-side resources.

A side-benefit of the transactive approach is that less capacity is needed to maintain reliability. Because the demand-side bids into the market, energy consumption can automatically be shifted out of the periods that are short of capacity and into periods with excess capacity (see Heinrich et al., 2020). Therefore, in addition to avoiding the missing money problem through better price signals, transactive systems also reduce resource adequacy needs by rescheduling flexible, PRD. On the other hand, there is also some evidence that transactive systems could exacerbate network feasibility issues, especially if complex network power flows are not considered in market clearing (Dynge et al., 2021).

Nonetheless, a DSO with transactive elements may have other considerations aside from reliability that warrant the creation of a capacity-like market at the DSO level. For example, DSOs may pursue resilience goals associated with supply disruptions during hurricanes, earthquakes, winter storms, or other natural disasters due to local geography. The product supplied by such a market could either be capacity-like (i.e., obligation to serve MW during a weather emergency), or it could be entirely different. Other non-capacity products might include contracts to harden or weatherize energy supply resources. Similar schemes could also be created to achieve environmental or equity goals, such as an obligation to supply renewable energy or a transfer scheme to levelize the energy prices paid by consumers at different locations in the distribution system.[43] The reliability needs of distribution systems can differ substantially from the transmission grid, since they may be related to the failure modes of distributed generation, islanded or grid-connected operating modes, how the underlying resources are dispatched, resource energy limitations, or power quality (see Escalera et al., 2018; Sperstad et al., 2020). Such DSO-level markets may differ substantially from RTO- and ISO-level capacity markets and would likely need to be specifically designed for DSOs.

Although a DSO market could avoid having its own capacity market, it may yet still need to identify how participation in the ISO-level capacity market should be passed down to end users. A DSO that primarily serves consumers would presumably need to purchase capacity from its RTO or ISO, and this cost could be passed to end users in the form of annual membership fees, peak day surcharges, or any manner of other rate design. One option is a transactive rate design that allows customers' electric bills to reduce in proportion to the actual value the DSO derives from their demand response (Widergren et al., 2022). Likewise, some DSOs may just as well receive capacity credit for the flexible demand-side resources that they provide, and the DSO would again need to decide how the capacity revenue should be allocated.

[43] In addition to inequities related to socioeconomic factors, the potential application of marginal pricing to distribution feeders could create very large price differences due to distribution system location among otherwise similar consumers (e.g., high value of marginal line losses to homes on the end of a distribution feeder). End users who stand to see large increases in their energy bill may object to the formation of a DSO unless their individual cost increases can be spread out equitably.

5.0 Conclusion

Capacity markets are likely to remain an important part of maintaining incentives for resource adequacy in electricity markets as the electric grid continues to decarbonize. Capacity markets may be especially appealing when considering the changes to prevailing energy market prices as more zero marginal cost resources are added to the grid. State policy makers may also look to capacity markets as a convenient way to implement policies requiring a specific proportion of capacity coming from clean, renewable, or carbon-free resources. In a 100-percent decarbonized grid, capacity markets may be able to provide the necessary price signals and market transparency to support efficient levels of generation capacity. However, as appealing as this may sound, there are numerous other aspects of capacity markets that may limit the benefits they provide in the future grids.

Today's electricity markets are characterized by active supply-side participation from conventional thermal generators and, increasingly, from renewables like wind and solar. In the United States, most ISOs conduct capacity markets in order to ensure there is enough supply to maintain system reliability and to support efficient investment incentives with less reliance on price spikes in the energy market. Capacity market designs were initially based on operational characteristics of conventional generators, and recent reforms are aiming to provide more efficient incentives for increasing levels of renewable generation. However, current market designs (energy and capacity) limit DERs and demand-side resources from playing a more active role. Further reforms may be necessary once DERs, and demand-side participation play a more active role in wholesale markets.

DER and demand-side participation in electricity markets is still in its early stages, often participating in wholesale markets through small reliability programs. More participation from these resources may soon develop due to policy reforms such as FERC Order 2222. However, rather than participating individually, these resources are most likely to participate in wholesale markets through various aggregation schemes.

Distribution systems may benefit from capacity markets as increasing levels of customer-owned distributed renewable energy drive changes in load shapes and volatility at more granular levels. However, capacity market designs for a DSO-level system could take many forms based on the needs and circumstances of a particular DSO. Because the missing money problem in wholesale electricity markets mainly relates to incentives to meet resource adequacy goals of the bulk grid, and the bulk grid will always be responsible for supplying power to the DSO, resource adequacy is unlikely to be a root cause for missing money problems in DSOs. Further transactive energy systems can ameliorate many current reliability problems by incorporating flexible, PRD into the market clearing framework, allowing shifting of demand from high price (and short of capacity) periods to low price (and excess capacity) periods. However other DSO objectives, including resilience, reactive power, voltage control, environmental policies, energy equity, and more, could lead to other, distinct missing money problems for transactive energy to resolve. In future research, we aim to develop analytical models of potential DSO-level capacity market designs to address these potential objectives and examine their implications for DSOs and consumers.

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