TOO MUCH OF THE WRONG THING:

THE NEED FOR CAPACITY MARKET REPLACEMENT OR REFORM

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EXECUTIVE SUMMARY

A large and increasing component of certain wholesale electric markets is the capacity market construct, a mandatory program of procuring resources to be available at peak times. Capacity market performance has fallen short in a number of respects. "Capacity" does not distinguish between resources that can provide flexibility and other increasingly needed reliability services versus those that cannot. In addition, many current and proposed capacity market rules do not accurately account for the contributions of renewable resources and energy-limited resources like battery storage. As the resource mix evolves, this raises fundamental questions about the need to significantly reform or replace capacity markets altogether.

The shape of the demand curve for reserves and the crude product definition are the principal problems with capacity markets. Flaws in these areas can be addressed to improve performance in the near term.

Broader reforms include giving states more authority over RTO resource adequacy decisions, as is the model in the SPP region. This model stands in stark contrast to the PJM region on the other extreme where state regulators have essentially no power to guide the policy.

This paper summarizes capacity market performance, outlines key design flaws that regulators have approved, and provides some ideas for future directions that state and federal policy makers could take to improve the reliability and efficiency of markets for customers. We begin with a short background on what capacity markets are and why they exist.

INTRODUCTION

No issue in electric power markets has been more controversial than capacity markets—how they should be designed and whether they should even exist. "Capacity" is treated as a separate product from "energy" and "ancillary services" in certain regional electric power markets. PJM, New York ISO, and ISO-New England run mandatory capacity markets, while the Midcontinent ISO operates a voluntary capacity market. Key policy makers across the political spectrum have recently questioned the need for capacity markets in the US and elsewhere. Capacity markets were ruled to be illegal generator subsidies in the UK.[1] Recent FERC Chairman Norman Bay challenged capacity markets and suggested that energy-only markets would be better.[2] FERC Commissioner Richard Glick recently stated: "One lesson I would take out of [my first year] is probably not to have a mandatory capacity market or at least find a way to get to resource adequacy without going through a mandatory capacity market."[3] Travis Kavulla, former Montana Commissioner and President of the National Association of Regulatory Utilities Commissioners testified recently to the US Senate: "An appropriate end result to such work would be an electricity market that fully supplants today's mandatory capacity markets."[4]

CAPACITY MARKET BACKGROUND: WHO, WHAT, WHERE, WHEN, AND WHY?

Electricity is different from most other commodities because if a shortage of power exists, an entire grid operating area can experience rolling blackouts. Since all types of generators experience unexpected forced outages, power system planners have always maintained a reserve margin of capacity above the expected peak demand. Prior to the existence of organized power markets, utilities and state regulators worked within the vertically integrated industry structure to determine and plan to meet these reserve margins.

Federal involvement in reserve margins increased as bulk power trading expanded in the late 1990s. At that time, reliability authorities observed "several control areas were found to be "leaning on the Interconnection" by failing to own or contract sufficient resources to cover their own peak demand needs, and noted "when a Control Area relies on unscheduled energy from the Interconnection rather than its own resources and scheduled purchases, it …reduces the frequency throughout the entire Interconnection."[5] That threat to reliability from "leaning on the system," or what economists call "free-riding," led to wholesale power pools, the predecessors to today's regional system operators, which imposed reserve margin requirements on utilities. As the industry restructured, separating generation from transmission and load-serving functions, the obligation was placed on load-serving entities (LSEs) to either own or procure enough supply to meet the requirement. As markets developed, RTOs and ISOs offered LSEs means of trading capacity resources to meet their obligations, and created an auction-style exchange for efficiency and transparency; thus began central capacity markets in some RTO/ISOs. Originally the markets were voluntary; as will be discussed later, they later became mandatory for all load and generation in some regions.

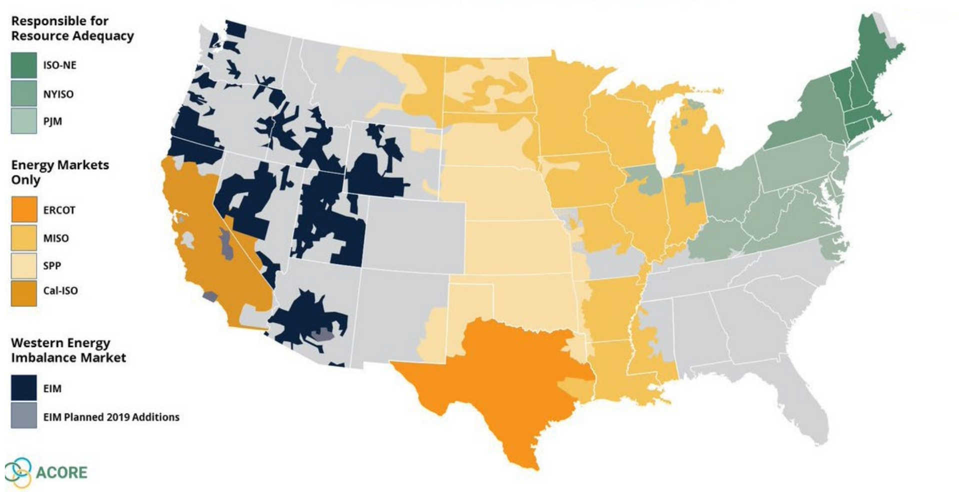
"Capacity" is a separate product from "energy" and the "ancillary services," such as operating reserves and reactive power service, which are also bought and sold in wholesale power markets. The D.C. Circuit Court of Appeals definition of "capacity" reflects the common understanding: "a commitment to produce

1 Vaughn (2018).
2 FERC (2017).
3 Bade (2019).
4 Testimony of Kavulla (2019).
5 Cook (2000).

electricity or forgo the consumption of electricity when required."[6] Because capacity is not actual electricity, but rather the ability to produce energy when necessary, capacity markets essentially function to create "options contract[s]" where "[g]eneration resource owners sell capacity to utilities, which need sufficient capacity to provide electricity to their customers reliably."[7]

Grid operators in the Mid-Atlantic, New York, and New England have mandatory capacity markets, while those in other regions leave resource adequacy largely to states, as shown in the map below.[8] MISO, SPP, ERCOT, and CAISO all have some role in resource adequacy but much less than the mandatory enforceable rules in PJM, ISO-NE, and NYISO.

U.S. CENTRALIZED POWER MARKETS



LARGE AND GROWING ROLE OF CAPACITY MARKETS

Capacity markets are large and growing in economic importance. The annual value of capacity markets for the year 2017 was $2.2 billion in New England[9] and $8.55 billion in PJM.[10] The GAO study noted that four US regions charged consumers a total of $51 billion from 2013 through 2016,[11] so the cost has been consistently above $10 billion per year across the regions that have them.

Capacity market revenues are growing relative to revenue from energy and ancillary services markets. Figure 1 below shows the increasing value in capacity markets relative to energy and ancillary services markets in PJM:[12]

6 *Advanced Energy Management Alliance v. Federal Energy Regulatory Commission (2017).*

7 *Advanced Energy Management Alliance v. Federal Energy Regulatory Commission (2017).*

8 Map by the American Council on Renewable Energy, (https://www.google.com/search?q=acore+grid+map+image&source=lnms&tbm=isch&sa=X&ved=0ahUKEwjC8dyA2M_fAhVlUd8KHa0fCnEQ_AUIDigB&biw=1680&bih=786&dpr=1.13#imgrc=DyEoVRXTRGt3zM:)

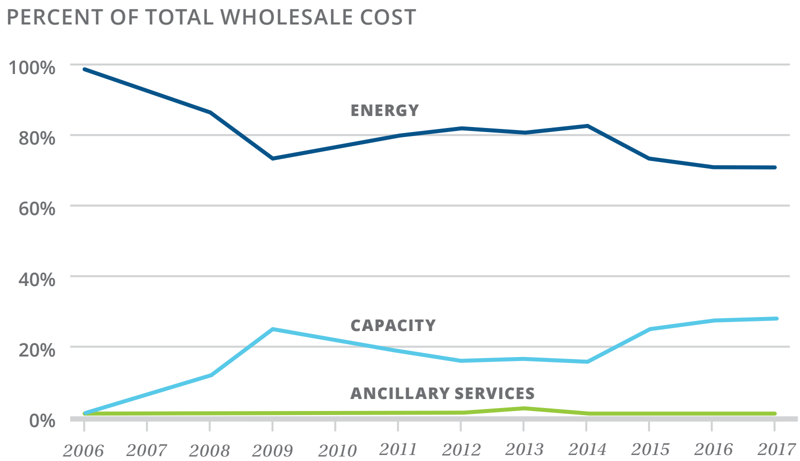
9 ISO-NE IMM (2018).

10 Monitoring Analytics (2019).

11 GAO (2017).

12 PJM (2017a).

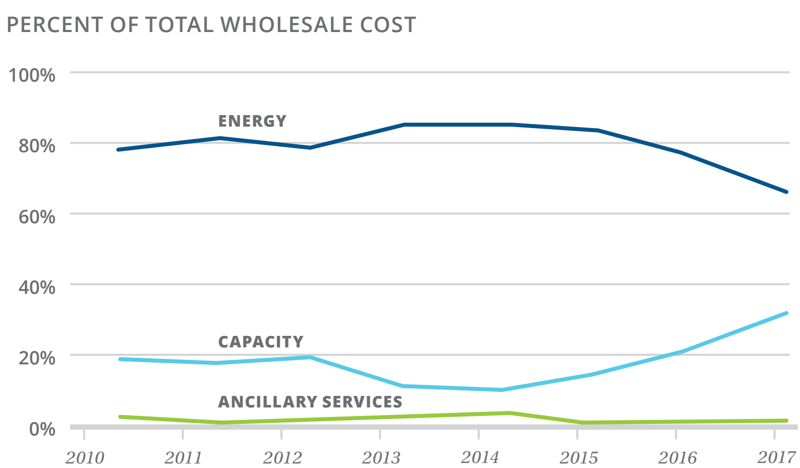
FIGURE 1. *Shift from Energy Market and Ancillary Services Market to Capacity Market in PJM*



The same pattern is unfolding in New England. In figure 2 below, the dark blue line shows capacity payments as a percent of total market payments rising over the last decade.[13]

The increase in capacity market revenues relative to energy market revenues can at least partially be attributed to the falling cost of energy due to decreasing natural gas costs and larger penetrations of zero marginal cost renewable resources. A higher ratio of capacity to energy is itself not evidence of a problem, but rather evidence that capacity markets warrant extra scrutiny to ensure the extra money consumers are paying is buying them something valuable.

FIGURE 2. *Energy, Ancillary Services, and Capacity as Shares of ISO-NE Wholesale Costs*



13 Calculated from ISO-NE IMM Annual Markets Reports 2011-2017. See, e.g., ISO-NE IMM (2018), pp. 3-4.

PERFORMANCE OF CAPACITY MARKETS HAS BEEN POOR

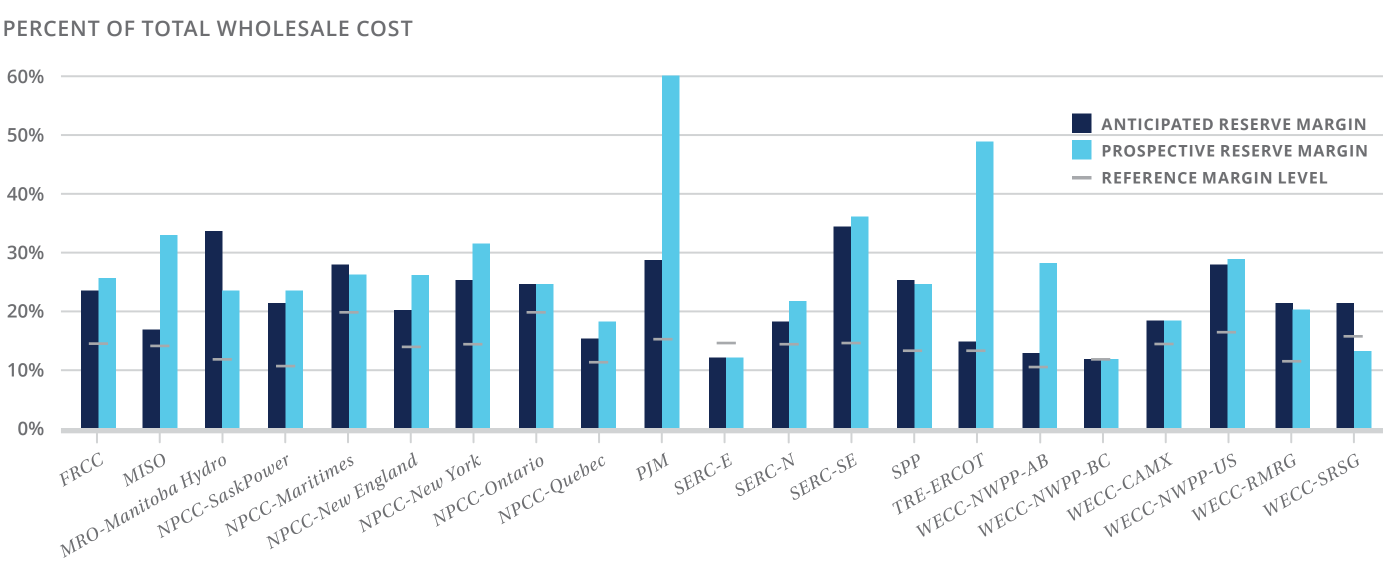
A number of indicators suggest that mandatory capacity markets have failed to provide consumers with reliability at least cost. This section reviews problems with excess capacity retention, capacity market prices that are above competitive levels, market power exertion, and reliability concerns.

An efficient market would retain an efficient quantity of resources at a price that is competitive over the long run. In equilibrium, the quantity of generation would equal load plus an optimal reserve margin that reflects the value of lost load. The price in equilibrium would equal long run marginal cost, where suppliers receive a normal return on their investment. When there is an excess of supply over demand, prices should be near zero. It is not possible to precisely demonstrate what this reference price and quantity are, without having access to confidential supply curves or having an objectively drawn demand curve. However one can draw strong indications of excess capacity and excessive consumer payments from the evidence below.

THERE IS EVIDENCE THAT CAPACITY MARKETS DRIVE EXCESS CAPACITY

The regions with centralized mandatory capacity markets have attracted and retained much more generating capacity than typical reserve margins. Figure 3 below shows that PJM, ISO-NE, and NYISO have large excess reserve margins over the target "reference margin level" shown as the black hash mark. Reserve margins in PJM expanded from under 20 percent in 2008-9 to over 35 percent in 2019-20, a period over which capacity markets transformed from voluntary residual trading platforms to mandatory markets.[14] For reference, the Brattle Group estimated the economically optimal reserve margin in the ERCOT market to be around 10 percent,[15] and PJM's own analysis shows that reserve margins in excess of 20 percent provide rapidly diminishing marginal returns.[16]

FIGURE 3. *2023 Anticipated and Prospective[17] Reserve Margins by Region[18]*



14 Chen (2018).

15 Newell et al. (2018a).

16 PJM (2017b).

17 "Prospective" includes additional potential capacity resource additions and subtractions beyond the more certain additions and retirements included in "anticipated" resources. NERC (2018).

18 NERC (2018), p. 10.

A rough estimate of the cost of this excess capacity is around $1.4 billion per year across the three markets based on a calculation of the excess in each region times the cost of capacity. This analysis is described in Appendix A. It is not possible to accurately say how much excess cost is absorbed by consumers versus producers without access to the market's supply curve which is not public, or an objectively drawn demand curve.

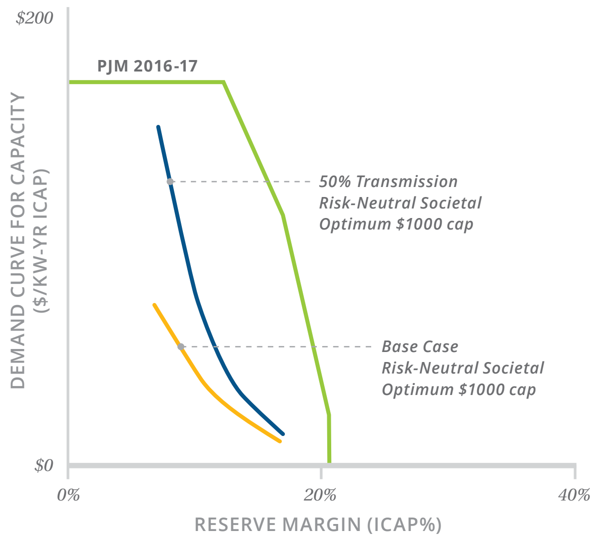
Another way to assess the cost of excess capacity retention is to consider how much existing generation above the reserve margin target level is not earning sufficient revenues from energy markets to justify remaining in service, but is able to remain online because of capacity market revenue. If one compares energy market prices to the ongoing fixed and variable costs for coal generators in PJM, one can see that approximately 18 GW of coal generation is not economic but for capacity market payments. This analysis is described in Appendix B. If capacity markets were replaced with a market that relied more on scarcity pricing in the spot energy and reserves markets, this uneconomic generation would face economically efficient price signals to exit the market.

Despite reserve margins that greatly exceed their targets, generation market entry is still occurring.[19] A primary factor appears to be low-cost gas supplies driving the construction of new gas combined cycle generation, particularly in PJM markets with access to Marcellus shale gas. Despite stagnant electricity demand, the market exit of resources that are no longer economic sources of energy and capacity is not keeping pace with that market entry, indicating a failure of market signals.

Over-procurement of capacity is driven by many factors. In designing capacity markets, RTOs and ISOs must make a variety of assumptions. The most important is the shape and placement of the demand curve for capacity. A demand curve is normally a downward sloping line reflecting consumers' willingness to pay for a good. In mandatory capacity markets an administratively determined level of demand replaces consumer preferences. The figure below shows the "wide and fat" demand curve that is used in capacity markets, compared to what a economics-based value of lost load curve would look like. While it is generally accepted in economics that demand curves should be based on consumer value, a report for FERC noted "U.S. RTOs with capacity markets and their regulators have not yet demonstrated substantial interest in considering such a value-based approach to estimating demand curves."[20] The Value of Lost Load implied by the reserve requirement in capacity markets has been calculated to be $1 million/MWh in New York, $200,000/MWh for ISO-NE[21], and $250,000/MWh for typical systems[22], well over ten times conventional estimates of the value of lost load.

19 ISO-NE IMM (2018), p. 152.
20 Pfeifenberger, Spees, Carden, and Wintermantel (2013).
21 New York and New England data from personal communication with the MMU, August 8, 2019.
22 Bushnell, Flagg, and Mansur (2017); Cramton and Stoft (2006).

FIGURE 4. *Administrative PJM Capacity Demand Curve Compared to Consumer Value-Based Curve*[23]



With a "wide and fat" demand curve, the quantities and prices procured will almost necessarily exceed economically efficient levels, a point that has been made repeatedly by states and consumer interests.[24]

Administratively determined demand curves have many design features, which can be thought of as dials, that RTO management and stakeholders can turn. Some of the design features and their settings include:

- *Consistent over-forecasting of peak load*. A high forecast leads to higher demand and tends to result in higher prices and excess quantities of capacity. PJM has over-forecast load consistently by about 10,000 MW or 7 percent.[25] ISO-NE has similarly consistently over-forecast load.[26] While the ISO-NE forecast has improved incrementally in recent years, it continues to over-forecast load, in part due to under-forecasting of energy efficiency and behind-the-meter solar PV, which results from discounting assumptions hardwired into the forecast methodology.[27] Given load forecasts that show persistent upward bias, there is a critical need to benchmark and recalibrate ISO/RTO forecast models and scrutinize key assumptions, including econometric models and assumptions about distributed and demand-side resources, that may contribute to these errors.

- *Over-stated generation reference cost*. The demand curve is based in part on the cost of competitive new generation (despite the lack of a basis for setting demand based on supply factors in economics). Estimates of competitive new generation costs vary widely and change over time. PJM's external consultant noted, "The current curve is based on our 2014 analysis, where we assumed entry occurs at a price approximately 2.5 times higher than our current estimate of CC Net CONE."[28] Use of the wrong generator type for reference costs can over-state capacity demand. PJM's external consultant recommended the use of combined cycle generation, yet PJM decided to use combustion turbines, a technology that has very little role in new entry in the PJM market.[29] The issue of reference generator type is being debated in New England and New York, and was the source of extensive analysis and debate in Alberta when they were considering adopting a capacity market until recently. Reference costs have sometimes used outdated and more expensive generation reference costs.[30] Use of backward-looking rather than forward-looking Energy and Ancillary Services Cost payments also raises the competitive reference cost. Net CONE is intended to be a prospective estimate of the cost of new entry net of expected revenues from energy and ancillary services. Even when known changes are occurring in energy and ancillary services payments, such as price formation-related market design changes, those are not taken into account in net CONE determinations. A forward-looking approach would also allow

23 Comments of Robert Borlick (2018), redrawn from Pfeifenberger, Spees, Carden, and Wintermantel (2013).
24 See NYPSC/NYSERDA (2016) protest of NYISO capacity demand curves; Wilson Affidavit (2018); PJM IMM (2018).
25 Wilson Affidavit (2018), p. 11.
26 Synapse Energy Economics (2017).
27 Synapse Energy Economics (2017).
28 Newell et al. (2018b).
29 Wilson Affidavit (2018), p. 4.
30 Wilson Affidavit (2018), p. 4.

for gas forward curves to be used.[31] Use of administrative rather than observed market indicators of net CONE raises cost. Clearing prices have tended to be around 1/3 of administrative estimates of net CONE, yet that has not been taken into account.[32] Infrequent updating of gross CONE costs has been a problem as gas prices have consistently come in below expectations, so only updating the costs every four years tends to over-state reference costs. Escalation factors are also problems for some cost elements, such as those affected by expected tax policy that may not actually occur.[33]

- Incorporation of expected *regulatory changes* that may or may not occur.[34]
- Arbitrary reductions in a reference technology's *expected revenue from other markets* increases the amount of capacity revenue the technology must receive to enter the market. Estimated Energy and Ancillary Services ("EAS") payments are deducted, or offset, from gross capacity cost estimates to determine the net Cost of New Entry ("net CONE") that determine generation reference costs. PJM applies an arbitrary 10 percent adder to the energy market offers of the reference unit, which leads to that unit being dispatched less frequently in PJM's models, and therefore actually lowers the EAS offset by nearly 30%.[35]
- Inaccurate assumptions of *how units are dispatched* in the calculation of Energy and Ancillary Services payments. For example, RTOs sometimes include maintenance costs in energy offers for these assessments, even though that is not allowed in PJM market rules.[36] This tends to over-state costs and under-state net revenue from energy and ancillary services markets, leading in turn to higher net CONE estimates. Fixed blocks of output are used rather than dispatching flexibly according to prices, which is particularly salient for the gas CT units used for setting reference prices.[37]
- *Gas interconnection cost assumptions* for the reference unit,[38] which the PJM IMM says is over-stated by almost 100 percent.[39]
- Inclusion of the cost of dual fuel capability costs in cost calculations, even though this capability is not required in many capacity markets or market zones. This raises costs in some zones by 8 percent.[40]
- Choice of gas hub for determination of variable cost, which has been estimated to raise the reference price by 37 percent as compared to a choice that would more appropriately reflect the cost of fuel.[41]
- Under-statement of market imports by ignoring the diversity of external resources. When one region experiences scarcity, it is often the case that supplies and transmission capacity are available to deliver needed capacity from other regions. PJM represents its diverse neighbors as a single external zone, called the "rest of the world" in its modeling, and limits imports to 3,500 MW.[42] The resources that can, in fact, come to the region's assistance are as far away and diverse as Mississippi and New Hampshire.
- Arbitrary shifts rightward of the demand curve based on *subjective risk assessments*.[43] This shift has

31 Newell et al. (2018b); PJM IMM (2018), p. 16.

32 PJM prices ranged from $51.40/MW-d to $128.26/MW-d in delivery years 2013 through 2021 while prices ranged from $292.95/MW-d to $351.39/MW-d over the same period.

33 PJM IMM (2018), p. 8.

34 NYPSC/NYSERDA (2016), p. 4.

35 PJM IMM (2018), p. 10.

36 PJM IMM (2018), p. 3

37 PJM IMM (2018), p. 9

38 NYPSC/NYSERDA (2016), p. 13.

39 PJM IMM (2018), p.4

40 NYPSC/NYSERDA (2016), pp. 6-9.

41 NYPSC/NYSERDA (2016), pp. 37-39.

42 PJM (2015).

43 Wilson Affidavit (2018), p. 4.

been justified on the basis of uncertain environmental regulation, which is not an issue on which grid operators are expert. This item alone was estimated to raise prices and total market revenues by over 7 percent in PJM.[44]

- Modified shape of the demand curve. The shape was changed from concave to convex in PJM after the Polar Vortex. "The August 2015 auction for delivery in 2018/2019 (which reflected these VRR demand curve changes) saw a 35% increase in capacity prices (compared to the prior year) to $165/MW-day (or $60/kW-year) for most of the RTO even though the supply cleared with a 19.8% RM, 4.1% in excess of the target RM and similar to the RM in 2014."[45]

CAPACITY MARKETS APPLYING A MINIMUM OFFER PRICE RULE TO LEGITIMATE PUBLIC POLICIES CAUSE CONSUMERS TO PAY FOR REDUNDANT CAPACITY

The New York, New England, and PJM ISO/RTOs all hold the view that if a resource receives a state incentive, their bids in capacity markets should be administratively raised through a Minimum Offer Price Rule (MOPR). The argument is that there is "buyer-side market power" and "price suppression" that would cause prices to deviate from a just and reasonable rate without this price mitigation. In fact, many states are remedying a market failure themselves by putting value on emissions-free resources, and it is not an RTO's role to second guess state policy.[46] Broadly applying MOPR deliberately charges customers for more capacity than is needed to meet each region's desired level of reserves.

FERC policy for decades has been clear regarding what is a just and reasonable rate in a market: where demand and supply intersect, as long as market power is absent or mitigated. This has been the general framework established by FERC and the courts since electricity competition began in the early 1990s.[47,48,49]

MOPR causes a significant departure from what should be the just and reasonable rates. MOPR proposals do not identify or mitigate any actor's market power, focusing instead on raising suppliers' bids. It is generally accepted that by raising suppliers' bids, MOPR tends to raise prices and causes consumers to pay for redundant capacity—customers first pay for the construction of resources through state policy, but when that is unable to clear the capacity market due to the MOPR, customers are forced to buy an equivalent amount of capacity that does clear in the capacity market. This is despite the widely agreed-upon fact that this extra capacity is unnecessary because the state-supported resources continue to provide physical capacity, despite being subject to the MOPR. FERC has recognized that consumers pay for such redundant capacity and found it beneficial to "avoid requiring customers to pay twice for capacity as a result of state policy decisions."[50] A diverse coalition of interests who hold different views on state policies petitioned FERC to not charge customers for redundant capacity.[51] Consumer advocates stated "any changes should be 'surgical' so consumers do not pay for resources twice. However, there are potentially enormous consequences of federal responses to state policy actions if those responses result in additional costs through wholesale market mechanisms."[52] Former FERC Chairman Norman C. Bay stated "[T]he MOPR not only frustrates state policy initiatives, but also likely requires load to pay twice –

44 See Scenario 4, Monitoring Analytics (2018).

45 Jenkin, Beiter, and Margolis (2016).

46 None of the ISO Principles in FERC Order No. 888 nor the RTO Characteristics and Functions in FERC Order No. 2000 include any mention of mitigating state policy.

47 Elizabeth Gas Co. v. FERC (1993).

48 "[I]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment." Tejas Power Corp. v. FERC (1990).

49 Gramlich (2006).

50 FERC (2018).

51 Letter from ACORE, APPA, AWEA, ELCON, LPPC, NASUCA, NRECA, NRDC, SEIA, and TAPS to FERC (2018).

52 Poulos (2017).

once through the cost of enacting the state policy itself and then through the capacity market . . . . The Commission should only apply the MOPR in the uncommon situation when state action is not permitted under federal law."[53] Industrial customers stated, "The MOPR is best characterized as a blunt instrument that is capable of inflicting harm on consumers that had no responsibility whatsoever for the state public policy initiative... Consumers are acutely aware that, without some level of wholesale accommodation in regards to state actions, they face the potential of being charged twice for capacity."[54] If fully imposed on resources receiving state incentives, MOPR could add up to $45 billion in costs to consumers across PJM, NY, and New England over the next decade (See Appendix C).

"CAPACITY" IS NOT THE SERVICE NEEDED TO SUPPORT RELIABILITY

"Capacity" means the capability to provide something, and does not mean actual provision of a service. For most of the twenty-year history of capacity constructs, measuring and incentivizing actual performance has been a challenge. Unlike actual markets that have buyers of real products, performance is not enforced in contracts. Capacity constructs spell out performance terms in ISO and RTO tariffs. For many years they had little obligation or enforcement for actual performance. Resources that sell capacity are still typically only obligated to offer into energy markets if they are on-line. They get a pass for outages or if the resource was not committed in the day-ahead unit commitment process by the grid operator.

There have been several instances when the power system was under stress and units that received capacity payments did not perform. ISO-New England and PJM have observed that their markets are not attracting resources needed during extended periods of cold weather. Gas generators who commit to provide capacity do not necessarily have firm pipeline supply contracts, and dual fuel units with onsite oil storage may not have sufficient fuel to last for more than a week, especially when there are competing uses of that fuel and weather-related forced outages that can disrupt supply from multiple generation sources.[55] PJM reports high coal plant failure rates in 2014 and 2018 cold weather episodes.[56]

Capacity is vague as to what energy or reliability service is being provided, and where and when it is to be provided. The North American Electric Reliability Corporation (NERC) has defined Essential Reliability Services as "frequency support," "ramping and balancing," and "voltage support."[57] Notably, "capacity" is not identified as an Essential Reliability Service. As noted by the current head of the national industrial customer association, "The conventional concept of resource adequacy refers to having sufficient generation output to meet maximum demand. However, a more refined suite of generation services is necessary for grid reliability."[58] Similarly, Bethany Frew from the National Renewable Energy Laboratory observed, "With an evolving grid and a dynamic market landscape, the questions and tools we use also need to change. Our questions should shift from 'how many MWs do we need?' to 'what resources do we need to provide the full set of required system services under a wide range of possible futures?'"[59]

What the grid increasingly needs is flexibility—resources that can ramp up and down in response to increasingly variable generation and load. This need is widely expected to grow in the future, and a variety of existing and new sources are able to provide flexibility if they are signaled to enter the market and provide it where and when it is needed. [60] However, the crude definition of capacity does not

53 FERC (2017), pp. 5-6.
54 PJM Industrial Customer Coalition (2017).
55 Van Welie (2018).
56 PJM (2018c).
57 NERC (2016).
58 Hartman (2017).
59 Frew (2018).
60 See, e.g., Orvis and Aggarwal (2017). Also, Milligan, Frew, Zhou, and Arent (2016).

distinguish between flexible and inflexible resources, and many fossil and nuclear resources that receive large capacity payments provide little to no flexibility.

CAPACITY MARKETS DULL PRICE SIGNALS

RTOs have attempted to solve the performance problem by instituting "capacity performance" rules. These rules provide penalties for non-performance and have improved performance for many generator types by incentivizing maintenance investments and fuel arrangements so they can perform when called upon. However, by retaining excess capacity and diverting generator revenue away from the energy market, the capacity market suppresses the energy market's price signal to perform. As Dr. William Hogan has stated in response to capacity performance providing correct price signals, "Not if prices facing the demand-side do not reflect the true scarcity conditions. Forward contracting could hedge the prices on average, but need not hedge prices on the margin. This choice is not available to participants in PJM or ISONE."[61] Similarly, Harvey, Hogan, and Pope stated in their review of the New York capacity market: "The use of a capacity market to make up the 'missing money' needed to support the capacity required to meet capacity requirements has the unintended consequence of creating a series of missing incentives relative to an energy-only market as that maintained in ERCOT."[62] Further, they state that "attempting to use capacity market rules to elicit capacity resources with the optimal mix of characteristics to meet load over the operating day has the potential to become more and more difficult as the diversity of the resource mix increases and has the potential to end badly, resulting in both lower reliability and higher consumer cost."[63] In other words, the price signals for performance at particular hours and locations are removed and put into a single abstract product.

CAPACITY MARKETS HAVE BEEN DEFINED INAPPROPRIATELY AS ANNUAL, RATHER THAN SEASONAL PRODUCTS

Capacity markets in ISO-NE and PJM are annual, meaning all capacity resources must perform all year, despite the fact that peak demand needs and resource capabilities vary by season. Wind energy capacity value is much higher in winter. Demand, or peak load, is higher in the summer in most systems, and may switch to winter with the increasing frequency of polar vortex-related weather patterns. Forced outages vary by season. Imports and exports tend to vary by season. Thermal units can produce more in winter than in summer. If all of these resources are penalized for not performing in the seasons when they are not as strong, they will be reluctant to participate in the market and consumers will pay more than is needed to procure sufficient resources. Forcing such resources to coordinate and bid in as aggregations with complementary resource types abdicates the market coordination function that a grid operator is best suited to fulfill, raises transaction costs for such resources and reduces the potential for each resource's value to be fully leveraged. The long annual commitment duration penalizes seasonal resources, as observed by Bialek and Unel: "Shorter commitment duration is also favorable to generators characterized by seasonal generation capabilities because capacity products with long durations, e.g. annual capacity products, limit what those generators can offer."[64] An NREL report on capacity market design found that "given the seasonality of both load and generation, shorter obligation periods will likely improve the efficiency of capacity markets… When bidding into a market, resources are often allowed to offer only their lowest effective capacity value for the obligation period. For example, in PJM, where only an annual capacity product is traded, combustion turbines get assigned their summer capacity

61 Hogan (2015).

62 Harvey, Hogan, and Pope (2013).

63 Harvey, Hogan, and Pope (2013), pp. 32-33.

64 Bialek and Unel (2019).

factor even though their effective capacity in the winter is much higher."[65] The Brattle Group found that separating summer and winter capacity markets in PJM would save consumers $100 to $600 million per year on a continuing basis.[66]

Fundamentally, capacity markets are designed as a single product for what are really different products. Seasonality would add an important level of detail to move towards the ideal of time-, location-, and service-differentiated markets.

Seasonal resources are increasing in importance. The Brattle Group report about PJM states: "Over the past decade, the supply mix has shifted toward a different composition of resources with more variation in seasonal availability."[67] Given the evolving resource mix, Brattle has advised that, "over the long term, an efficient seasonal construct is likely to become increasingly important as the resource mix continues to shift toward non-traditional resources with differentiated seasonal capability such as wind, solar, distributed resources, and imports, and as load patterns change with the potential electrification of transportation and heating."[68]

New York's capacity market is seasonal, demonstrating that it is a feasible and workable alternative to annual capacity markets. The New York capacity market is defined for summer and winter periods separately, with performance obligations tied to those periods.[69]

CAPACITY MARKETS ARE PLANNING FOR PAST LOAD SHAPES AND OUTAGE PATTERNS, NOT THE FUTURE

Capacity markets use historical load patterns to set future requirements. A Loss of Load Probability model is run with load shapes based on historical patterns. The market rules then procure what is deemed by the model to be needed, forcing customers to procure resources that may not be the ones actually needed as the system changes. Net load shapes (load minus renewable energy output) are changing with the evolving resource mix, and the growth of gas generation and increasing instances of climate-driven extreme weather appear to be causing more instances of correlated forced outages among conventional generators. Capacity value accounting rules have not kept up with these changes, causing overstatements of the capacity value of conventional resources and understatements of the contributions of renewable resources.

The resource mix and weather patterns are changing such that shortage conditions are happening at very different times of year. Winter cold snap conditions now drive much of the reliability concern for ISO-NE and PJM. PJM recently stated, "Though PJM consistently sees its highest customer demand during the summer, the greatest strain on fuel supply and delivery occurs in the winter. This is primarily because during the winter, the needs of commercial and residential heating are competing with natural-gas-fired and dual-fuel generators (which generate more than 30 percent of the energy produced in PJM) for natural gas, oil, pipeline transportation and oil deliveries."[70] Yet PJM's capacity market design, including reserve margins, capacity value, and other components, is focused on summer conditions. MISO has noted that shortage conditions are happening in the spring, fall, and winter now.[71]

65 Jenkin, Beiter, and Margolis (2016), pp. 23 & 26.
66 Newell, Spees, Yang, Metzler, and Pedtke (2018).
67 Newell, Spees, Yang, Metzler, and Pedtke (2018), p. 3.
68 Newell, Spees, Yang, Metzler, and Pedtke (2018), p. 2.
69 Hibbard, P., Schatzki, T., and Bolthrunis, S. (2017), pp. 6-7.
70 PJM (2018a).
71 MISO (2019).

CAPACITY MARKETS CONTAIN BIASES AGAINST RENEWABLE ENERGY AND STORAGE

Capacity markets were designed around the characteristics of conventional resources such as nuclear, coal, and gas plants. The expectation when they were designed, which proved to be correct, was that the resource that would be attracted would be natural gas plants, and a number of design features are specifically built around gas plants.[72] Likely as a result of this history, capacity markets have built-in biases against renewable energy. Capacity market prices are highly volatile as they are sensitive to supply and demand and regulatory changes. This causes investors in capital-intensive generation resources, like renewable and storage resources, to discount the value of capacity market revenues. This disproportionately harms capital-intensive renewable sources relative to fossil resources with lower capital costs but higher operating costs. As a recent paper co-authored by a senior FERC economist concluded, "the introduction of a capacity market will tilt the technology mix arising in equilibrium toward resources with higher operating costs, even if the capacity contribution of all resources has been correctly assessed" and "capacity markets as currently structured may work against efforts to decarbonize."[73] Similarly, Dr. William Hogan stated that the alternative to capacity markets—energy-only markets with scarcity pricing—would be better for renewables: "Better scarcity pricing would reduce the size and importance of capacity payments and improve incentives for renewable energy."[74] Battery storage resources are similarly capital-intensive, and thus are also disadvantaged in capacity markets relative to fossil resources with lower up-front costs but higher operating costs. Capacity markets tend to reduce prices in the wholesale energy markets on which renewable sources depend. Sellers of capacity can earn less in energy markets because their revenue is made up in capacity markets; that is not the case for resources that sell little capacity or are excluded from fully participating in capacity markets. In regions without capacity markets, those costs are typically recovered from the energy market when, during a small number of hours per year when energy supply is scarce, energy market prices increase to very high levels.

The penalty structure of the capacity construct is also biased against renewable energy because there is more certain downside risk to under-performing relative to the less certain upside (from the capacity payment plus energy scarcity pricing) to over-performing. An asymmetric performance incentive can make sense for dispatchable generators that tend to have a binary output level (either near-full output if available, or zero output if experiencing an outage) and can take steps to increase their availability rate. However, for variable resources, this structure needs to be more symmetric for them to be willing to participate and accurately offer the expected value for their level of output. This issue was raised at PJM and FERC in the post-Polar Vortex reforms and with the court, but FERC and the court deferred to PJM on all such design details. That is unsurprising given the time period immediately following a reliability event, but after five years the unintended impacts of this rule remain unaddressed.[75]

Capacity planning has also failed to account for storage capacity value. Energy-limited resources like battery energy storage provide significant capacity value, but many traditional measures or requirements of capacity value, such as arbitrary duration rules requiring a resource to be able to provide power for 4 or 10 hours, fail to accurately account for that contribution. CAISO's "duck curve" has occurred as afternoon peaks are met by solar energy, so the period of peak net load is made shorter and shifted later into the early evening. Figure 5 below shows the period of peak net load becoming thinner and shifting later as solar penetration grows. This late afternoon solar output reduces the duration of the peak net load period, which tends to increase the capacity value of short-duration resources like battery storage.[76]

72 For example the demand curve is based on the cost of new entry ("net CONE") of natural gas-fired plants.

73 Mays, Morton, and O'Neill (2019).

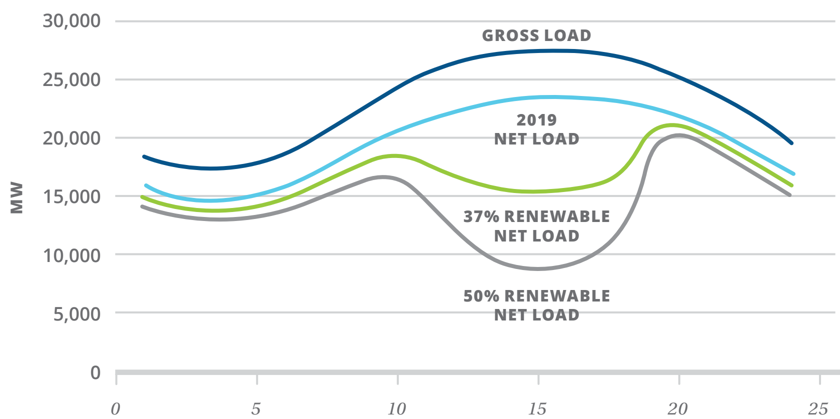
74 Hogan (2015), slide 9

75 Wind-Solar Alliance (2018).

76 Denholm, Nunemaker, Gagnon, and Cole (2019).

This same dynamic will happen in all regions as solar PV expands. Solar's capacity contribution during afternoon periods is dependable because of correlations between air conditioning load and the sun's intensity; when it is cloudy, buildings use less air conditioning so there is less load. Recent studies show that the capacity value of four-hour duration resources remains at 100 percent of nameplate capacity through penetrations of 4000 MW in the PJM region.[77]

FIGURE 5. *Changing Net Load Shape*[78]



CAPACITY MARKETS OVER-STATE THE CAPACITY VALUE OF CONVENTIONAL RESOURCES

Capacity value (the contribution of a given resource to system reliability) calculation methods often overstate the capacity contributions of conventional resources. Typical capacity valuation methods are usually based on the erroneous assumption that generator-forced outages are random uncorrelated events. This assumption has been disproved by data demonstrating the frequent occurrence of correlated common mode failures across conventional generators, particularly due to weather-induced equipment failures.[79] Coal piles freezing or flooding also tend to happen at the same time, fossil and nuclear plants tend to simultaneously experience cooling water interruptions due to drought or high temperatures, and gas plant outages are correlated due to susceptibility to the same pipeline or compressor outage. Common mode failures are rigorously accounted for in renewable energy capacity value determination through Effective Load Carrying Capability analysis, but that is not often the case for conventional sources.

CAPACITY MARKETS HAVE NOT SERVED THEIR PURPOSE OF PROVIDING A STABLE INVESTMENT SIGNAL

One of the main justifications for capacity markets has been that they provide a more stable investment signal than energy-only markets. Yet capacity market rules change so frequently that they do not provide such stability. Over twenty lawsuits have been filed in federal courts to appeal FERC capacity market decisions so far. The Government Accountability Office noted "there have been 190 proposals to change capacity markets from 2012 through July 2017, of which 125 were approved and resulted in a change to the markets."[80] Capacity market prices have been highly volatile, having fluctuated by a factor of 10 from year to year over the last decade.[81]

77 Carden, Wintermantel, and Krasny (2019a).

78 Carden, Wintermantel, and Krasny (2019b).

79 Murphy, Apt, Moura, and Sowell (2018).

80 GAO (2017), p.22.

81 See Monitoring Analytics (2019), pp. 287-288; for the results of each ICAP auction see NYISO, "Installed Capacity Market (ICAP)", (https://www.nyiso.com/installed-capacity-market); for ISO-NE forward capacity auction results by year see ISO-NE, "Markets", (https://www.iso-ne.com/about/key-stats/markets#fcaresults).

CAPACITY MARKETS HAVE BEEN NON-COMPETITIVE

There has been evidence of significant exercise of market power in capacity markets. Generation market power is when prices exceed competitive levels due to physical withholding or elevated bidding. The Independent Market Monitor for PJM declared both the structure and behavior in the capacity market to be non-competitive: "The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS)[82], which is conducted at the time of the auction. Structural market power is endemic to the capacity market… Participant behavior was evaluated as not competitive."[83] From 2010 through 2016, FERC conducted 25 investigations of the exercise of market power in US capacity markets.[84] According to one economist, "Market power is endemic because the capacity construct seeks commitments from nearly all available capacity and ownership is highly concentrated."[85] Electricity capacity markets, unlike energy markets, display the capacity constraints and "quantity strategies" that have long been known to increase market power in what economists call Cournot-Nash equilibria.[86] Capacity markets rigidly establish these quantities and make others' capacities known to bidders, who can bid an inflated price when they know there is some amount of residual demand that only they can serve after all other suppliers offer their full capacity. Local zones of capacity markets are particularly vulnerable to bidders exercising market power to drive clearing prices up in that zone, as generation ownership tends to be even less diverse in individual zones. Energy markets are less susceptible to market power because the amount of supply and demand is less easy for a potential pivotal supplier to know, as it changes all the time.

CAPACITY MARKETS ARE ONLY ATTRACTING ONE KIND OF CAPACITY

Diversity of generation sources is generally viewed as beneficial from a reliability and efficiency standpoint, since all generation types have their vulnerabilities. Capacity markets have not attracted diverse sources. In a review of entry, Sam Newell of the Brattle Group observed, "Nearly all new generating units entering the BRAs are natural-gas-fired."[87] As Jay Morrison with the National Rural Electric Cooperative Association observed, "An organized capacity construct that operates only three years ahead and that clears based solely on levelized fixed costs will drive the construction of gas generation, because that is the dispatchable generation resource with the lowest levelized fixed costs that can be built in that time frame."[88] In New England, there were 10,075 MW of new generation in the 2018/2019 auction, with 10,050 MW coming from natural gas.[89] PJM's CEO told the US Senate: "As natural gas becomes a more dominant fuel in the PJM footprint, our dependence on the natural gas pipeline infrastructure has grown significantly."[90] ISO-NE's CEO similarly testified, "New England was becoming more reliant on natural gas for power generation without making a subsequent investment in natural gas supply infrastructure."[91] Figure 6 below shows the new generation capacity dominance of natural gas in New England and Figure 7 shows the increase in gas and lack of growth in any other source in PJM.

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82 A pivotal supplier is one that must be chosen given the residual demand after all other suppliers have been selected. That position gives them the ability to raise prices, which is market power. PJM uses a test where three entities together are in this position.

83 Monitoring Analytics (2019), p. 251.

84 GAO (2017), p. 39.

85 Wilson (2016).

86 Bornstein, Bushnell, and Knittel (1999).

87 Newell et al. (2018c).

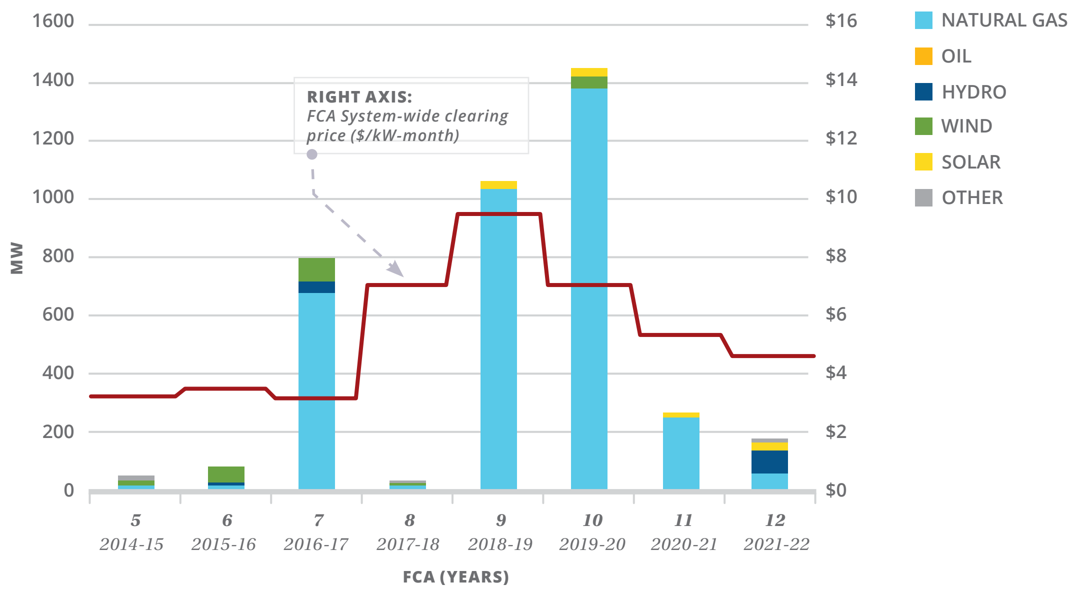
88 Glazer, Morrison, Breakman, Clements, and Mork (2017).

89 ISO-NE IMM (2018), p. 152.

90 Testimony of Ott (2018).

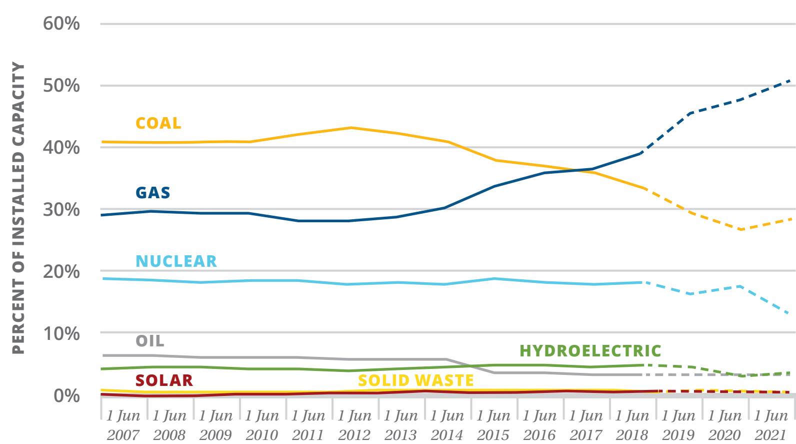
91 Testimony of Van Welie (2018), p. 1.

FIGURE 6. *New Generation Capacity in ISO-NE by Fuel Type from FCA 2 to FCA 11*[92]



NOTE: *"Other" category includes landfill gas, methane, refuse, solar, steam, and wood.*

FIGURE 7. *Percent of Installed Capacity in PJM by Fuel Source*[93]



92 ISO-NE IMM (2018), p. 152.
93 Monitoring Analytics (2019), p. 263.

CAPACITY MARKET GOVERNANCE IS INADEQUATE

Capacity markets' poor economic and reliability performance, the tendency of market design changes to increase reserve margins and raise prices, and the lack of initiative to explore capacity market alternatives suggests a deeper problem. There may be a systematic bias at RTOs.

FERC generally views RTOs as self-regulating organizations, and tends to defer to what is proposed by RTOs and ISOs. The problem in this case is that RTO/ISOs are not disinterested. A risk-averse grid operator benefits from excess reserve margins but does not suffer the consequences because it is not the one paying the cost. The US Government Accountability Office reviewed capacity markets and found they were very costly and lacked appropriate review by FERC.[94]

With expansion of MOPR, RTO/ISOs are expanding their mission into energy policy and price management. Neither of these were the roles outlined for ISOs or RTOs when they were created. Nothing in FERC's Order No. 888 ISO Principles or Order No. 2000's RTO Characteristics and Functions says anything about mitigating state policy or managing prices to adjust for their impact. RTOs are not well-suited to making public policy decisions because they respond primarily to industry stakeholders and are not accountable to voters. Yet RTO/ISO mission creep is advancing apace.

RTOS ARE INFLUENCED BY STAKEHOLDERS WHO GENERALLY WANT HIGHER RESERVE MARGINS AND PRICES

Capacity markets are particularly vulnerable to stakeholder influence because the parameters tend to be subjective and unmoored from technical engineering parameters. They depend inherently on RTO decision-making over product definition, the level of demand, eligibility rules and other market features, unlike markets for energy and other well-defined products such as frequency regulation, which are driven by customer demand and well understood system needs. Charles River Associates notes an underlying problem with capacity markets: "...from a political and regulatory perspective, capacity markets have proven controversial and difficult to administer."[95]

RTOs and ISOs are influenced by their stakeholders because they are voluntary organizations; their role diminishes if utilities leave. Incumbent stakeholders tend to favor higher capacity market prices and larger reserve margins, and in many cases want to minimize capacity revenues for new resources like renewables, battery storage, and demand response that compete with their incumbent assets. Consumers and new entrants face systemic barriers to participation in RTO/ISO decision-making processes and, with little or no assets in an RTO, lack the leverage of large incumbent utilities. FERC noted this conflict of interest in its Standard Market Design proposal, but that proposal was never implemented: "We are concerned that the existing stakeholder process may not provide adequate representation for all market participants and interested parties. The lack of adequate representation may hinder development of alternative energy resources, such as distributed generation, renewable energy, or demand response programs, since these programs may be contrary to the business interests of certain market participants."[96] Stakeholder committees have even been compared to cartels where competitors get together to restrict trade.[97]

94 GAO (2017).
95 Rivard, Kwok, and Sterns (2017).
96 FERC (2002).
97 O'Malley (2019).

RTO GOVERNANCE IS AN INADEQUATE CHECK

In some cases stakeholder support is not even needed to proceed with a capacity market rule change. In PJM, capacity market rules do not require stakeholder input; RTO management and board can proceed on their own to file rule changes.

Capacity market rules are complex and constantly changing. In addition to imposing cost and uncertainty on market participants, that complexity also puts smaller developers of new resources at a disadvantage to larger incumbent generation owners, as smaller developers lack the resources to dedicate employees to attending countless RTO stakeholder meetings.

NEW DIRECTIONS

In light of ineffective RTO/ISO oversight of capacity markets and these markets' demonstrated and systemic tendency to overcharge customers for reliability, other options are needed. The original intent of capacity markets was that they would be temporary, and fade away as demand response was developed. FERC supported capacity markets early in the ISO/RTO market design development because the demand side of the market had not yet been developed at that time.[98] The Commission noted the lack of demand response and the inability to curtail demand from free-riding load-serving entities created a market failure as long as that structural condition existed. The economists on whom FERC relied at market startup stated it might take a decade to develop the demand side: "The market, without administrative guidance, cannot determine what level of installed capacity is needed to provide adequate reliability. This...will not be remedied for perhaps another decade or more."[99] It has of course been well over a decade now, and grid operators are now able to engage the demand-side and could pursue methods to curtail free-riding load serving entities, yet capacity markets continue with no end in sight. Unless actions are taken to either reform or replace capacity markets, they will likely remain and continue to grow in economic importance.

FIX THE FLAWS

The simplest approach is of course to fix the flaws with capacity market design. There are many "dials" that market designers turn as described in this paper. FERC could end its practice of providing excessive deference to RTOs and ISOs and review proposals more carefully by exercising its FPA Section 206 authority to find rules are unjust and unreasonable. FERC was urged by the US GAO to take a much more active role in regulating capacity markets and there are plenty of opportunities for it to do so.

The biggest flaw is the broad application of MOPR, which is not in place yet but could be soon. If implemented, that may require a court challenge to overturn. Congress should consider clarifications of FERC authority regarding whether mitigating state policy is a function the Federal Power Act intended the agency to pursue.

RTOs and ISOs for their part can develop a better economic reference framework based on principles of value of lost load, loss of load probability, and more precise analysis of what is and is not market power market power (choosing to buy renewable energy either voluntarily or as directed by a state is not an exercise of market power).

Another improvement to current capacity markets is to make them operate more consistently with spot markets by considering the capacity market a forward "call option" on energy and operating reserves. The product being sold is energy and operating reserves, just well ahead of time. If sellers fail to produce, they would pay the real time price at that time. That would align incentives to attract good performance when it matters to the system. This directly synchronizes capacity and energy markets, such that consumers are getting the benefit of a well-defined product for consumers. Economists have long argued for capacity markets as call options.[100] This change to the penalty structure still leaves unresolved many other design features and the governance challenges, but improves performance of the existing market.

98 FERC (2002), Par 461: "as long as regional resources are made available to all regional load-serving entities and their customers during a shortage, such entities have the incentive to lower their supply costs by depending on the resource development investments of others, a strategy that leads to systematic under-investment in infrastructure by all load-serving entities in the region." Citing Stoft (2002).

99 Cramton and Stoft (2006), p. 4.

100 See, e.g., various papers by Dr. Peter Cramton.

EXPAND OPT-OUT OPPORTUNITIES

Another approach to restore some discipline over capacity markets is to allow end-use customers and wholesale customers to take care of their own resource adequacy. The “fixed resource requirement” (FRR) that FERC has approved in PJM, and which FERC proposed to expand to apply to state-supported resources through the resource carve-out option, is the type of approach that could be developed. Eastern RTOs could operate more like MISO, which does not have a mandatory capacity market. Vertically integrated utilities could utilize the “fixed resource requirement” (FRR), and it could be made less restrictive in its rules and its eligibility. FERC introduced the idea that this could be expanded to address state-supported resources without applying the MOPR.[101] Customers, utilities, and load-serving entities could be allowed to bypass the mandated centralized capacity market and undertake their own contracting. As Morrison and Breakman suggested, “the solution is fairly simple on its face. To eliminate the conflict, the Eastern RTOs should go back six years and restore the mandatory capacity markets to their status as residual markets that supplement, rather than substitute for, the judgments made by utilities, their regulators and their consumers.”[102] Load-serving entities, whether they are end-use customers, vertically integrated utilities, or competitive retail suppliers, could be given more flexibility to make their own decisions.

End-use customer opt-out options are currently nearly non-existent. Many end-use customers have their own on-site reliability and resilience options, through backup generation and increasingly through micro-grid options. When a customer provides its own backup in this manner, it should not be required to pay for system backup, otherwise it is paying for a redundant product. Little has been done to provide this option to opt out.

LOCATIONAL CAPACITY NEEDS COULD BE ADDRESSED THROUGH TRANSMISSION

Another modest improvement is to rely more on transmission planning. One of the more controversial aspects of capacity markets has been their locational requirements. Resources may be needed in particular locations due to transmission constraints. Capacity market zones can experience higher prices due to both higher costs and market power, which is increased when smaller geographic areas are defined. One solution to locational requirements would be economic transmission planning to improve the competitiveness of energy and capacity markets. Most transmission planning is focused on reliability needs alone, yet competitiveness of power markets is a benefit that could be incorporated into ISO/RTO transmission planning.[103] More could be done to alleviate this aspect of capacity markets, yet little is being done to pursue it.

GREATER STATE ROLE

A broader reform would be to give states greater roles in determining resource adequacy policies for a region. Resource adequacy has traditionally been a function overseen by states. FERC has in some cases pro-actively worked to keep resource adequacy under state control even with RTO formation. The Commission stated in the SPP RTO approval order in 2004 about the role of the Regional State Committee (RSC): “The RSC should … determine the approach for resource adequacy across the entire region.”[104] Providing this role to regional state committees is one change that could restore some discipline to capacity markets. For single state ISOs, the state would assume the roles FERC outlined for multiple states in the SPP order.

101 FERC (2018).
102 Glazer, Morrison, Breakman, Clements, and Mork (2017), p. 28.
103 Chang (2016).
104 FERC (2004).

Any change in resource adequacy governance would necessarily entail a FERC proceeding and FERC's approval of RTO/ISO tariff changes. The threshold for such a FERC finding is much higher for a Section 206 filing where the proceeding initiates from a complaint, than under Section 205 in which the proceeding begins with a filing from the regulated ISO/RTOs. The change requires not only a state to agree to take on the resource adequacy responsibilities and functions, but for FERC to agree.

States could assume a variety of functions in resource adequacy, as indicate by the range of state roles currently in place across the country. Appendix D categorizes the key resource adequacy functions and identifies which entities are responsible in each region. Two recent papers outline options for greater state involvement in RTO resource adequacy decisions.[105]

RELY MORE ON SPOT MARKETS AND BUYERS

FERC and RTOs could turn their focus towards getting wholesale spot prices right, and state regulators could focus on making sure load-serving entities do their job of procuring supply to serve the load they commit to serve. When states restructured, too little attention was paid to making sure some entity is in charge of resource procurement. Federally regulated capacity markets became a crutch to fill this flaw in state structures. In Texas, where there is a full retail market, Retail Electric Providers are responsible for procuring power on behalf of any retail customers they commit to serve. The PUC of Texas requires these REPs to have sufficient financial wherewithal to be able to sign the PPAs and other arrangements to serve those customers. Sometimes the Texas model is misleadingly referred to as an "energy-only" market because it does not have capacity requirements. However this label fails to recognize the key role that long term bilateral contracts play in Texas to lock-in prices for consumers and support the financing of new generation. To address concerns about the lack of transparency in bilateral contracting, regulators can require contract terms to be posted, as FERC has done with Electronic Quarterly Reports.[106] If states can fix this flaw in their markets, then the crutch of capacity markets can be relied on less, and perhaps fade away over time.

A key component of the Texas model is accurate spot market pricing. Spot markets include scarcity pricing and an operating reserves demand curve, such that the actual value of service at a time and place is reflected in its price. These features have long been recognized as beneficial components of market design, but they have only been implemented relatively recently. These prices attract supply and demand resources to perform when needed, and to enter if they suggest a long-term opportunity. Dr. Peter Cramton explains: "An important advantage of scarcity pricing is that it motivates load to contract for the energy it needs in advance of real time. Forward contracting provides a hedge against volatile real-time prices. Forward contracting thus reduces price risk."[107]

This combination of wholesale market design with state-level development of credit-worthy buyers puts more decision-making power into de-centralized hands, so market participants can re-engage in markets to provide the natural discipline that comes with markets. RTOs and ISOs have recognized the superior performance of spot energy and reserves markets with accurate pricing in stimulating market response. New York ISO stated in its Grid in Transition paper, "Real-time shortage pricing enhancements are preferable to capacity market enhancements because real-time prices can reflect varied and dynamic operational needs better than any products that might be procured as "capacity.""[108]

New technologies that allow greater demand-side participation can help enable de-centralized decision-making. As Dr. James Bushnell stated in a recent review of capacity markets, "These developments imply

105 Chen and Murnan (2019); McCabe, Svanda, and Kane (2019).
106 See FERC (https://www.ferc.gov/docs-filing/eqr.asp).
107 Cramton (2017).
108 NYISO (2019a).

that it may be possible to retreat from the axiomatic belief that reliability is a public good. Certainly within short operational time frames, shared responsibility for operating reserves will be necessary for the foreseeable future. However, over longer planning horizons it may be possible to identify control areas or individual Load-Serving Entities who have failed to provide adequate resources and to isolate involuntary load curtailments to only the customers of the responsible LSEs."[109] Modern monitoring, communications, and control technologies will assist with this "privatization" of the public good.[110] Similarly, A paper from the Oxford Institute for Energy Studies looking at experiences around the world finds "The concept of reliability as a public good, however, can be increasingly challenged as it relates to a balancing of supply and demand."[111] If there is not a "public good" or other market failure, then economic policy dictates that there is no basis for intervention in the form of imposing capacity requirements.

Relying more on spot markets and bilateral contracts compared to centralized capacity constructs is not all-or-nothing, and can be phased in over time. Capacity market designs can continue to move towards performance requirements where the non-performance penalty reflects the real-time value of energy. State regulators can improve long-term bilateral contracting. RTOs and FERC can improve accurate spot pricing for the voluntary residual RTO/ISO-administered spot markets. A challenge for consumers is when capacity markets have locked in supply and commitments for multiple years and there are proposals to introduce scarcity pricing and ORDCs, without a corresponding reduction in payments for that capacity. The transition requires careful planning and balancing of interests.

Relying on markets rather than central capacity constructs allows a wider variety of demand side arrangements to be worked out. All customers value reliability differently and have different constraints on when and how much they can respond. The Texas market allows customers to reveal their preferences and be compensated for the reliability service they provide if they can agree on terms with Retail Electric Providers, who have an incentive to pay for them. This approach would provide many more options than the single "vanilla" flavor of demand response that is typically provided in ISO/RTO capacity markets. The approach has been discussed in other countries, such as Australia: "A compensation mechanism in the event of involuntary load shedding, paid for by retailers, may better allocate the risk of load shedding to those well placed to manage it. In turn, this may be expected to improve reliability outcomes (or reduce costs for a given reliability outcome), and reduce the [grid operator's] reliance on out-of-market intervention measures."[112] There has been little if any consideration of the approach in the US.

INSURER OF LAST RESORT

Another approach is an insurer-of-last resort model, which is being considered elsewhere. It is intended to avoid some of the problems with capacity markets: "Under a market transition where generation is increasingly stochastic and decentralized, two key issues emerge...First, centralized mechanisms put increased focus on the efficiency of central authority decision making and the alignment between performance outcomes for reliability and agency incentives. Second, existing capacity mechanisms require the central agency to infer consumer preferences for reliability, something that is very challenging in practice. This is especially relevant in markets where the value of lost load is increasingly differentiated among different consumers."[113] An insurer-of-last-resort approach is an overlay on an energy-only market that adds a requirement for customer-specific insurance to cover needs at times of shortage conditions.[114]

109 Bushnell, Flagg, and Mansur (2017), p. 53.

110 Public goods are those that are "non-excludable" and "non-rival" and as a result lead to inefficiency and a market failure. Technology can make them excludable and/or rival.

111 Billimoria and Poudineh (2018).

112 Walker, Falvi, and Nelson (2019).

113 Billimoria and Poudineh (2018), p. ii.

114 Billimoria and Poudineh (2018), p. 10.

CONCLUSION

Capacity market performance has been poor, and there is no current mechanism in RTO/ISO governance to bring them under control due to systematic bias in capacity market design and oversight.

FERC, states, and stakeholders should begin by fixing flaws in the market design. They can evolve capacity markets towards operating more as if they are forward markets for energy. They can avoid trying to mitigate legitimate state policy. They can improve the design settings on all of the dials of capacity market design.

A more ambitious option is to allow greater opt-out opportunities for entities that take care of their own resource adequacy. Certainly any entity whose load can be curtailed can demonstrate that it is not causing a free-rider problem for which it needs to be “taxed” to avoid imposing costs on others. Opt-outs could apply to whole utilities, or individual customers, or various levels in between.

Increasing the magnitude of change a step further, states could be given more say in resource adequacy design. Presumably they will not want to have their retail customers paying excessively for little benefit. A model of state power over a federally regulated entity’s resource adequacy program has been approved by FERC in the SPP region, which can serve as a model.

Longer term, there may need to be a shift towards greater reliance on de-centralized contracting with efficient spot market design. Over time this could fully replace centralized capacity constructs.

APPENDIX A

COST OF CAPACITY MARKET EXCESS IN ISO-NE, NYISO, AND PJM

METHODOLOGY

A cost estimate of the excess reserve margins in ISO-NE, NYISO, and PJM service territories in the year 2021 can be developed through the following method:

- For each region, collect values for the net internal demand (MW), anticipated reserve margin (%), and reference reserve margin (%) using the North American Electric Reliability Corporation's (NERC) 2018 Long-Term Reliability Assessment.[115]
- Determine capacity excess (MW) for each RTO/ISO using the following equation:

  Capacity Excess = (Net Internal Demand x Anticipated Reserve Margin) - (Net Internal Demand x Reference Reserve Margin)

- Assume the cost of capacity is $40,000/MW-year based on the average of the most recent capacity market clearing price in PJM (~$50,000/MW-year[116]) and coal plant fixed O&M (~$30,000/MW-year[117]). This is a low-end, or conservative, estimate of the cost of developing new capacity.
- Multiply capacity excess (MW) by assumed cost of capacity ($/MW-year) to calculateexcess cost ($).

DATA

ISO-NE

Net Internal Demand (MW)	24,511
Anticipated Reserve Margin (%)	0.3228
Reference Reserve Margin (%)	0.1636
Excess (MW)	3902.15
Waste ($)	$156,086,048

NYISO

Net Internal Demand (MW)	31,581
Anticipated Reserve Margin (%)	0.2164
Reference Reserve Margin (%)	0.15
Excess (MW)	2096.9784
Waste ($)	$83,879,136

PJM

Net Internal Demand (MW)	144,672
Anticipated Reserve Margin (%)	0.3566
Reference Reserve Margin (%)	0.158
Excess (MW)	28731.8592
Waste ($)	$1,149,274,368

The total across the three regions is approximately $1.4 billion per year.

115 NERC(2018), pp. 80, 87, & 102,

116 The resource clearing price for PJM's 2021/2022 RPM Base Residual Auction was $140.00/MW-day, or $51,100/MW-year. PJM (n.d.).

117 NREL data projects new coal fixed O&M in 2021 to be $33/kw-year, and data from FERC Form 1 indicates that average fixed O&M costs for the PJM coal fleet is $27/kw-year. We base the calculations above on the average of these two values: $30/kw-year, or $30,000/MW-year. NREL, , (2018), (https://atb.nrel.gov/electricity/data.html); FERC, , (2017), (https://www.ferc.gov/docs-filing/forms/form-1/data.asp).

APPENDIX B
QUANTITATIVE ASSESSMENT OF EXCESS CAPACITY RETAINED BY CAPACITY MARKETS

This analysis attempts to provide another indicator of the amount of capacity that is being uneconomically retained by capacity markets.

METHODOLOGY

Unit-level generation, fuel consumption, and fuel price data were obtained from Energy Information Administration's Form 923 2017 database for all coal plants in PJM.[118] For plants for which fuel price data was not available, average fuel prices for the state or region were used instead.[119] The unit-specific heat rate was calculated by dividing the fuel consumption data by the generation, and then multiplying by the plant's fuel price to calculate the unit's fuel-related marginal production costs. Estimates of unit-specific fixed and variable O&M costs, derived from FERC Form 1 data, were added to the fuel-related marginal production cost to calculate the total annual operating cost of each coal unit. That total operating cost was divided by the total generation to calculate an ongoing operating cost in $/MWh.

The $/MWh ongoing operating cost was then compared to the average energy market price in PJM for the last four years, $33.66/MWh.[120] The economic viability of all coal units was then analyzed with and without capacity market revenues.

Capacity market payments were calculated based on the plant's nameplate capacity derated by the PJM coal fleet average forced outage rate of 12.123%.[121] It was assumed that coal plants clear the capacity market and receive capacity market revenue at the PJM-wide clearing price of $140/MW-day. This estimate could be low if many uneconomic coal plants are located in PJM zones that cleared at higher capacity market prices, or high if many of those coal plants are not clearing the capacity market and receiving capacity market revenues. However, the analysis was tested with capacity market prices higher than $140/MW-day, and it yielded the same results.

RESULTS

The analysis indicates that 17,792 MW of coal PJM capacity is uneconomic but for capacity market payments. Said another way, these units' ongoing costs are higher than their energy market revenues, but their combined energy and capacity market revenues are sufficient to cover their ongoing costs.

One 610 MW unit was uneconomic with both capacity and energy market payments. An additional 32,392 MW of coal plants are economic from energy market payments alone, so capacity market payments to those plants could also be viewed as wasted spending, as it is a windfall profit for the plant owner.

118 EIA, (2017), (https://www.eia.gov/electricity/data/eia923/).
119 EIA, , (February 2019), (https://www.eia.gov/electricity/monthly/).
120 Monitoring Analytics (2019), p. 18.
121 PJM (2018b).

CAVEATS AND OTHER NOTES ON ANALYSIS ASSUMPTIONS AND LIMITATIONS

There would likely be a rebound in energy market prices if capacity market payments were removed and coal plants started to retire. If that feedback were accounted for, the estimated amount of capacity that is uneconomic but for capacity market payments would be smaller. However, the impact of that rebound effect is likely to be relatively small, given that most gas combined cycle and coal generators in PJM currently operate at roughly the same marginal production cost, so energy market prices should not significantly increase.

Similarly, if capacity markets were replaced with a market design that included more scarcity pricing in the spot energy and operating reserves markets, some of the capacity identified here would remain economic. However, given the supply excess currently present in PJM, scarcity pricing is unlikely to take place for some number of years. Moreover, the coal plants identified here tend to be inflexible and incapable of responding to spot price signals so they may not receive that revenue.

Gas and nuclear generators were not evaluated in this analysis, reflecting that many PJM states have subsidized nuclear plants at risk of retirement, while many new gas combined cycle generators are being added primarily as energy resources in PJM, indicating that existing plants are unlikely to retire. Gas combustion turbines are typically built primarily to provide capacity and ancillary services and only provide energy during peak demand hours, so it did not make sense to evaluate their energy market economics in this analysis.

The analysis assumed that coal plants receive the average price in the energy market. Relative to more flexible gas generators, coal plants have limited opportunity to time their production to when energy market prices are high on a diurnal basis (e.g. they must remain online during overnight low price periods), so for that reason coal plants are likely to receive lower energy market prices than the gas fleet. However, unlike nuclear generators, coal plants can time their production on a seasonal basis (i.e. primarily operating during the summer months or winter periods of high demand). On net those two factors should roughly cancel out, putting coal generators in the middle of the pack of PJM's generating fleet when it comes to resource flexibility, and making average energy market prices a reasonable estimate of coal plant revenue.

Revenue from providing ancillary services was not accounted for in this analysis, as coal plants lack the flexibility to effectively provide many ancillary services, and regardless ancillary services account for only 1.6% of total generator revenue in the PJM market.[122]

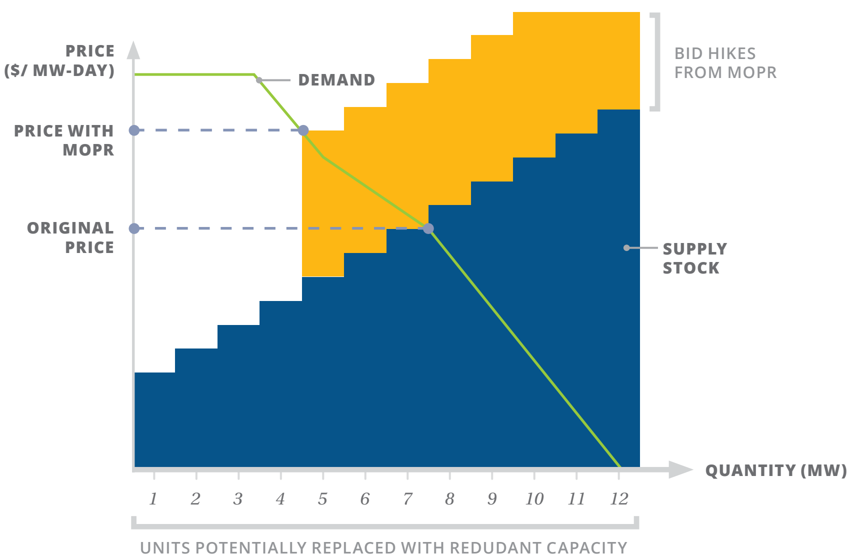
122 Monitoring Analytics (2019), p. 18.

APPENDIX C
COST OF THE MINIMUM OFFER PRICE RULE (MOPR)

If fully imposed on resources that receive state incentives, the MOPR could add up to $45 billion in costs to consumers across PJM, NY, and New England over the next decade.

The MOPR works by raising the bids of state-supported resources. This is shown in the capacity supply and demand curves below. The yellow MOPR bid adders raise certain resources' bids, which makes it harder for those resources to clear the capacity market. In turn, customers must pay for redundant capacity to replace those resources that did not clear the market, even though the state-supported resources are providing capacity value to the power system.

FIGURE 8. *MOPR Impact on Supply and Demand for Capacity*



NEW ENGLAND:

If all state Renewable Portfolio Standard and nuclear policies were mitigated, consumers in New England could pay around $3 billion.[123]

PJM:

PJM's MOPR-Ex proposal would result in the procurement of roughly between $14 billion and $24.6 billion of redundant capacity over roughly the next 10 years. These costs would ultimately be borne by PJM customers, translating to a cost of between $216 and $379 for each of the 65 million people in the PJM footprint.[124] The estimate here is over the longer term after market participants have had time to build new generating capacity. The amount may be well above that in the near term when supply is inelastic (unable to increase in response to higher prices). We have previously estimated the near-term impact of imposing broad MOPR to be $5.7 billion per year in PJM.[125]

NEW YORK:

In the table below, the cost of procuring redundant capacity in New York is calculated by summing the actual capacity value contributions of nuclear and renewable resources that would not be counted due to the MOPR, multiplied by each resource's respective capacity value (%) and current regional clearing price in NYISO's capacity market.[126] This analysis is conservative because the MOPR would cause capacity demand to exceed supply, increasing capacity market prices in addition to requiring ratepayers to

123 Gramlich (2018).
124 Goggin (2018).
125 Goggin and Gramlich (2019).
126 NYISO (2018a).

purchase a large quantity of redundant capacity. The MOPR cost is estimated for the years 2021, 2025, and 2030, with the increasing costs reflecting increasing state-mandated renewable procurements over that time period. A linear interpolation between the 2021, 2025, and 2030 results indicates $17.6 billion in total costs over 10 years.

TABLE 1. *Cost of Procuring Redundant Capacity*

ANNUAL COST IN MILLIONS OF $	2021	2025	2030
MOPR cost	$948	$1,589	$2,697

I. METHODOLOGY

A. NAMEPLATE CAPACITY

To estimate MOPR costs for 2021, 2025, and 2030, we begin by calculating the nameplate capacity (MW) of nuclear and renewable resources in the New York ISO. We base the majority of renewable resource nameplate capacity calculations on New York Clean Energy Standard (CES) goals, in which the New York State Public Service Commission (PSC) requires 50% of the energy consumed in the ISO to be generated by renewable resources by the year 2030. The PSC has determined that approximately 17,000 MW of new renewable capacity would be need to be added onto the grid by 2030 as a result, as well as approximately 70,500 GWh of total renewable energy generation, "including approximately 29,200 GWh of new renewable energy production in addition to existing levels of production at the time the order was adopted."[127] As part of the CES, Governor Cuomo also calls for the development of 2,400 MW of offshore wind by 2030.[128] We keep these benchmarks in mind as we carry out our analysis.

We estimate nuclear nameplate capacity to be 3,353.5 MW for years 2021, 2025, and 2030 by summing the capacity for the James A. Fitzpatrick, R.E. Ginna, and Nine Mile Point (units 1 & 2) nuclear plants.[129] To meet the CES goal of 2,400 MW of offshore wind by 2030, we assume 800 MW are included by 2021, and 1,600 MW by 2025, and to account for the Governor's 9 GW of offshore wind by 2035 goal, we multiply 9 GW by 2/3 to estimate 6,000 MW by 2030.[130] Since the CES goal looks to add 29,200 GWh of renewable energy production *in addition* to existing levels of energy production as of 2016,[131] the year the New York PSC adopted the CES, we include 1,754 MW of existing wind and 32 MW of existing PV for years 2021, 2025, and 2030. For the years 2025 and 2030, we also estimate the nameplate capacity for battery storage using the Governor's target of 3 GW of deployment by 2030. Nameplate capacity for battery storage is assumed to reach the 1,500 MW halfway mark in 2015, and the 3,000 MW target in 2030.

To calculate nameplate capacity for new wind and PV, we assume that a total of 8,043 MW will be developed by 2030, with 4,188 MW coming from new wind and 3,855 MW coming from new PV, 373 MW of which would be located in Long Island.[132,133] We use the 29,000 GWh figure above, as well as annual LSE requirements in table 2 below to calculate the nameplate capacity of new wind and PV.

127 NYISO (2018b).

128 NYISO(2018b).

129 EIA, , (https://www.eia.gov/nuclear/state/newyork).

130 Gheorghiu (2019).

131 NYISO (2018b), p. 42-44.

132 State of New York Public Service Commission (2016).

133 We assume that all new wind and PV, with the exception of the 373 MW of PV in Long Island, to be located in upstate NY. This becomes a critical assumption later when we multiply nameplate capacity by the capacity value and market price, as market prices differ by region.

TABLE 2. *Annual LSE Requirements Under the CES*[134]

YEAR	% OF LSE TOTAL LOAD	RENEWABLE RESOURCE MWHS	% RENEWABLE RESOURCE
2016 (Baseline)	-	41,296,000	25.71%
2017	0.60%	42,270,000	26.32%
2018	1.10%	43,037,270	26.81%
2019	2.00%	44,420,100	27.69%
2020	3.40%	46,598,371	29.08%
2021	4.80%	48,826,642	30.54%

To calculate new upstate wind, upstate PV, and Long Island PV nameplate capacity in 2021, we begin by using table 2 above to calculate the renewable MW needed by 2021 according to the CES. First, subtract the 2016 renewable resource MWh, 48,826,642 MWh, from the 2021 renewable resource MWh, 41,296,000 MWh to get 7,530,642 MWh. From there we divide this by 8,760, the total number of hours in a year, and divide again by a calculated implied capacity factor of .27.[135] From this calculation, we estimate the renewable MW needed by 2021 to be 3,203.35 MW. We then divide each upstate wind, upstate PV, and Long Island PV MW value (4,188 MW, 3,482 MW, and 373 MW respectively) by the total wind and PV in 2030 value, 8,043 MW, and multiply each by 3,203.35 MW, the renewable MW needed by 2021. The shares of upstate wind, upstate PV, and Long Island PV are as follows: 1667.99 MW, 1386.80 MW, and 148.56 MW.

To calculate new wind and PV nameplate capacities in 2025, we again divide each upstate wind, upstate PV, and Long Island PV MW value (4,188 MW, 3,482 MW, and 373 MW respectively) by the total wind and PV in 2030 value, 8,043 MW. This time, however, we multiply this value by the renewable MW needed by 2025 according to the CES, which we estimate to be 7,300.07 MW. We estimate this value by starting with the renewable resource MWh difference from 2025 and 2016, 171,161,468 MWh. This value is found by the additional renewable energy MWh/year needed to reach 50% CES, 292,00,000 MWh, less the MWh difference from 2016 and 2021 we calculated above, 7,530,642 MWh. This is then multiplied by 4/9 to linearly interpolate 2025 deployment between the 2021 and 2030 levels, plus the MWh difference from 2016 and 2021, 7,530,642 MWh. Finally, this value is divided by 8,760 and divided again by our calculated implied capacity factor of .27. The shares of upstate wind, upstate PV, and Long Island PV are as follows: 3,801.15 MW, 3,160.37 MW, and 338.55 MW.

Finally, we estimate new wind and PV nameplate capacities in 2030. We begin these estimates by obtaining the new renewable energy MWhs needed to reach 70% of the CES goal by 2030, which is 98,700,000 MWh. We take this value and subtract the 2016 baseline for renewable resource MWh found in table 2 above, 41,296,000 MWh. This value is then subtracted by the amount of offshore wind generation in 2030, 23,652,000 MWh,[136] to leave us with 33,752,000 — the additional MWhs needed in 2030, beyond those provided by existing resources and offshore wind. We find the renewable energy MW needed in 2030 by taking 33,727,000 MWh and dividing this by our implied capacity factor, .27, and dividing it again by 8,760. This leaves us with 14,357.27 MW. The new wind and PV capacities are found by dividing 14,357.27 by the sum of new wind and PV capacity we

134 DSIRE (2019).

135 Our implied capacity factor is calculated by dividing the sum of total wind and solar generation in 2030, 18,908,000 MWh, by the sum of total wind and solar capacity, 8,043 MW, times 8,760.

136 This can be calculated by taking the 6000 MW offshore wind in 2030 figure*0.45*8760.

previously found in 2025, 7300.07 MW, and multiplying that value by respective capacity shares of upstate wind, upstate PV, and Long Island PV in 2025. New upstate wind, upstate PV, and Long Island PV shares are as follows: 7,475.85 MW, 6,215.6 MW, and 665.83 MW.

B. CAPACITY VALUE

The second component of our MOPR cost estimates is the capacity value (%) of each resource as a share of its nameplate capacity. The New York ISO determines its nuclear resource's five-year weighted EFORd value to be 3.1%.[137] We therefore estimate nuclear capacity value to be 96.9%. For both new and existing upstate and Long Island PV, we use a capacity value of 46.3%, which is the summer, statewide average capacity value for NYISO's 1 axis tracking installation configuration.[138] The capacity values for new and existing land-based and offshore wind are taken from the PJM renewable integration study, as the reported wind capacity values in the NYISO renewable integration study do not disaggregate the capacity value of offshore versus land-based wind generators.[139] The PJM values are 27% for offshore wind, and 17% for land-based wind.[140] We determine the capacity value for battery storage to be 90%, using the Astrapé analysis.[141]

C. MARKET PRICE

We determine the market-clearing price ($/kw-year) for each resource based on the resource's location in the state of New York. We assume all nuclear, new upstate wind, new upstate PV, and existing wind to be located in the NYCA capacity locality, which has an ICAP clearing price of $193.85/kw-year.[142] Offshore wind, new Long Island PV, and existing PV, on the other hand, are all assumed to be located in the Long Island Capacity locality, which has an ICAP clearing price of $298.07/kw-year.[143] For years 2025 and 2030, we assume an equal distribution of battery storage both in both upstate NY and Long Island, and therefore average the NYCA and Long Island market prices to assign battery storage a price of $245.96/kw-year. Existing wind resources received the NYCA price as all are located upstate, while the existing utility-scale solar resources are located in Long Island and therefore received the Long Island clearing price.

D. COST PER YEAR

To estimate the total MOPR cost for years 2021, 2025, and 2030, we multiply each resource's nameplate capacity value (MW) that would not be counted due to the MOPR, by their respective capacity value (%) and current regional clearing price ($) to get annual costs ($).

137 NYISO (2018c).
138 Dong (2011).
139 NYISO (2010).
140 GE Energy Consulting (2014).
141 Carden, Wintermantel, and Krasny (2019).
142 NYISO (2018a).
143 NYISO (2018a).

II. RESULTS

The MOPR calculations for 2021, 2025, and 2030 are as follows:

YEAR 2021	NAMEPLATE MW	CAPACITY VALUE %	MARKET PRICE ($/KW-YEAR)	COST PER YEAR
Nuclear	3353.3	96.9%	$193.85	$629,886,051.65
Offshore wind	800	27%	$298.07	$64,383,120.00
New upstate wind	1668	17%	$193.85	$54,967,730.75
New upstate PV	1387	43.6%	$193.85	$117,210,756.75
New PV Long Island	149	43.6%	$298.07	$19,306,342.09
Existing wind end of 2016	1754	17%	$193.85	$57,802,193.00
Existing PV end of 2016	32	43.6%	$298.07	$4,158,672.64
			TOTAL	**$947,714,866.87**

YEAR 2025	NAMEPLATE MW	CAPACITY VALUE %	MARKET PRICE ($/KW-YEAR)	COST PER YEAR
Nuclear	3353	96.9%	$193.85	$629,886,051.65
Offshore wind	1600	27%	$298.07	$128,766,240.00
New upstate wind	3801	17%	$193.85	$125,265,142.08
New upstate PV	3160	43.6%	$193.85	$267,109,846.03
New PV Long Island	339	43.6%	$298.07	$43,996,935.14
Battery storage	1500	90%	$245.96	$332,046,000.00
Existing wind end of 2016	1754	17%	$193.85	$57,802,193.00
Existing PV end of 2016	32	43.6%	$298.07	$4,158,672.64
			TOTAL	**$1,589,031,080.53**

YEAR 2030	NAMEPLATE MW	CAPACITY VALUE %	MARKET PRICE ($/KW-YEAR)	COST PER YEAR
Nuclear	3353	96.9%	$193.85	$629,886,051.65
Offshore wind	6000	27%	$298.07	$482,873,400.00
New upstate wind	7476	17%	$193.85	$246,362,906.15
New upstate PV	6216	43.6%	$193.85	$525,333,359.58
New PV Long Island	666	43.6%	$298.07	$86,530,160.13
Battery storage	3000	90%	$245.96	$664,092,000.00
Existing wind end of 2016	1754	17%	$193.85	$57,802,193.00
Existing PV end of 2016	32	43.6%	$298.07	$4,158,672.64
			TOTAL	**$2,697,038,743.14**

APPENDIX D
RESOURCE ADEQUACY MODELS IN OTHER REGIONS

GENERAL OVERVIEW

The allocation of resource adequacy functions varies widely across the country. Generally the function is performed by ISOs in PJM, NY, and New England, under FERC jurisdiction, and by the states elsewhere. But there are variations. FERC has approved a wide range of structures and has resisted requests from some stakeholders to standardize and impose approaches from one region onto another. There is no NERC standard requiring enforceable resource adequacy levels or a reserve margin, only to *assess* resource adequacy.[144] The key functions include:

1. *Determination of requirements.* Typically this is an Installed Reserve Margin (IRM) that is set region-wide based on a Loss of Load Expectation (LOLE) analysis. The IRM tends to be in the range of 12-18 percent of generation capacity (MW) above peak load. Regions with more renewables are beginning to add flexibility (MW per minute change in output) requirements as well.

2. *Enforcement of requirements on load.* Load-Serving Entities (LSEs) are typically assigned a share of the regional IRM, subject to oversight and penalty.

3. *Enforcement of requirements on generation*. Generators or demand side resources that are counted towards an entity's capacity obligation are typically required to offer the capacity and deliver when needed ("must-offer" requirements), subject to penalties.

4. *Operating a market*. Supply and demand are stacked into central auctions, which some regions have and some do not. Some are voluntary residual auctions, some are mandatory for all load.

5. *Determination of resource credit towards meeting requirement.* Generators and load sources that are used to meet obligations are given credit typically based on their historical performance, such that forced outage rates, for example, reduce the capacity value a unit is able to sell. Capacity credit for storage and variable renewables is subject to debate currently, as well as capacity value for conventional generation that may be subject to "common mode failures." "Capacity value" (contribution to serving peak load) is not the same as "capacity factor" (annual average output as a percentage of maximum potential output).

The table below lists the roles for each of the seven US ISO/RTOs. In many cases, there are overlapping roles for both states and the ISO/RTO. Local authorities oversee municipal and cooperative utilities. While there are often overlapping roles, ultimately one entity is the final decision-maker. The table lists the final decision-maker between government entities or the system operator (SO).

144 NERC is required to conduct "periodic assessments of the reliability and adequacy of the bulk-power system in North America," FERC (2006).

TABLE 3. *Ultimate Decision-Maker for Resource Adequacy Functions*

(System Operator (SO) under FERC jurisdiction vs state and local entities)

	MISO	CAISO	SPP	ERCOT	PJM	NYISO	ISO-NE
Set reqmt	State&local[145]	SO and local[146]	State&local	n/a[147]	SO	State[148]	SO[149]
Enforce on load	State&local	State&local [150]	State&local	n/a	SO	SO	SO
Enforce on gens	State and SO	SO[151]	State&local	n/a	SO	SO	SO
Central auction	Yes	none[152]	none[153]	none	Yes[154]	Yes[155]	Yes
Resource credit	State&local	State&local [156]	State&local	n/a	SO	SO	SO
Backstop procurement	n/a	SO	n/a	n/a	n/a	n/a	n/a

145 While MISO sets an Installed Reserve Margin based on LOLE, it can be over-ridden by a state and MISO will adopt it. MISO (2018).

146 For non-CPUC regulated entities, CAISO accepts the IRM of local regulatory authorities. CAISO (2018a).

147 Not applicable because ERCOT does not have a reserve margin requirement. ERCOT does set a target PRM of 13.75%, but it is not a requirement. ERCOT (2018).

148 NYISO (2019b); NYPSC (2018).

149 NESCOE votes on the ISO-developed reserve margin. It is not clear what happens in the case of a conflict.

150 CPUC (2019).

151 Florio (2018).

152 Load Serving Entities (LSEs) can meet capacity requirements through self-supply or resources procured through bilateral contracts. Bushnell, Flagg, and Mansur (2017), p.25.

153 Load Serving Entities (LSEs) can meet capacity requirements through self-supply or resources procured through bilateral contracts. Bushnell, Flagg, and Mansur (2017), p.25.

154 Limited exemption from PJM auction under Fixed Resource Requirement.

155 Bilateral transactions are allowed. NYISO (2019b), p. 157.

156 “The ISO defers to the CPUC and other LRAs to determine Qualifying Capacity (QC) values for all resources interconnected to the ISO system.” CAISO (2018b).

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