THE Brattle GROUP

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cc: Senator Lisa Murkowski
Senator Maria Cantwell

Re: Response to U.S. Senators' Capacity Market Questions

Dear Dr. Rusco:

On November 19, Senators Lisa Murkowski and Maria Cantwell from the U.S. Senate's Committee on Energy and Natural Resources issued a letter to the U.S. Government Accountability Office (GAO) requesting that the GAO examine the efficacy of U.S. electricity capacity markets.[1] The letter asked how capacity markets affect reliability, costs, and the generation mix compared to traditionally-regulated systems. We offer below our responses to each of Senators' questions as an input to your assessment. Our responses are informed by many years of consulting experience analyzing the very issues raised by the Senators, conducted on behalf of clients from all sectors of the electricity industry.[2] We provide references to additional information and industry studies where possible.

The following responses to the Senators' questions use the same numbering convention, with the original questions repeated for reference.

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1 Murkowski and Cantwell (2015).

2 This letter is not sponsored by any client company. It reflects the views of the letter's authors and not necessarily the views of other members of The Brattle Group or any of its clients.

1. **We are concerned about the relationship of the increments of new capacity cleared in an auction and the increments of new capacity actually installed. Two recent surveys suggest that only a small fraction of new capacity has been built in organized markets except under bilateral power purchase agreements or direct ownership by LSEs [Load Serving Entities].[3] Additionally, it is our understanding that except for one sub-region within PJM, capacity has never cleared above the "cost of new entry" in PJM or MISO. These observations prompt us to ask a central overarching question:**

   1a. **Since their establishment, how effectively have capacity markets influenced the construction, maintenance, or retirement of generation in order to ensure resource adequacy and reliability in a cost-effective manner?**

After more than a decade of experience, the U.S. capacity markets have demonstrated that they generally fulfill the design objective of meeting "resource adequacy" requirements cost effectively.[4] They do so by establishing the quantity of capacity needed, and procuring that capacity through a competitive auction that is open to all types of resources. This auction-based, competitive format has proven effective at leveraging competitive forces to attract the lowest-cost combination of available resources, including demand response resources and the refurbishment and upgrades of existing resources. Capacity markets have created a level playing field that enables competition among new and existing generators, incumbents and new entrants, internal supply and imports, traditional and new types of technology, generation and demand-side resources, and centralized and distributed resources. These competitive forces have consistently achieved required reserve margins at prices below the system operators' estimates of the long-run costs of new generating plants.[5]

The success of capacity markets to date does not mean that they cannot be improved. In fact, each of the markets has encountered challenges that needed to be addressed over time, and has areas for improvement.[6] We anticipate the future will continue to pose new challenges as market forces evolve. As long as these solutions comport with fundamental economic principles and rely on sound analyses, we anticipate that capacity markets will continue to perform well.

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3 American Public Power Association (2012); American Public Power Association (2014).

4 The purpose of capacity markets is to procure sufficient capacity to meet resource adequacy requirements, and to do so cost effectively by allowing all qualified MW competing to meet the need. These markets were never intended to directly address other policy objectives, such as fuel diversity or environmental quality. Such other objectives have to be addressed through other means, which can be implemented to complement capacity markets.

5 For a review of the experience with the first decade of capacity market operations, see Spees, Newell, and Pfeifenberger (2013).

6 For examples of recommendations to improve the existing capacity market designs, see Pfeifenberger, *et al.* (2014); Spees, Newell, and Lueken (2015); and Pfeifenberger, Spees, and Newell (2012).

The PJM experience provides a good example of capacity market performance in achieving reliability objectives cost-effectively. That capacity market was instituted in 2007 at a time when PJM anticipated impending shortfalls in capacity, especially in import-constrained areas.[7] By implementing the capacity market, PJM was able to procure enough capacity to meet and exceed the requirement by attracting a substantial influx of new, low-cost resources. These resources included increases in net imports, uprates to existing generation, and demand response resources. Few analysts had anticipated so many low-cost resources. Their entry is a testament to the creativity of competitive markets.

Securing a large quantity of low-cost resources postponed the need for new generation investments for almost a decade. More recently, new generating capacity has been needed due to load growth, retirements, and limited additional capacity available from existing resources. Capacity prices have risen sufficiently to attract those investments. Even so, capacity prices remain substantially below the system operator's estimates of the long-run cost for new generating plants. For example, PJM's recent auction for the 2017/18 delivery year attracted nearly 6,000 MW of new generation commitments at prices that were 35–41% of PJM's estimated net cost of new entry (Net CONE).[8] This further demonstrates the competitive market's success in maintaining resource adequacy in a cost-effective manner.

We now address the specific concerns noted in the Senators' question:

- **Increments of New Generation Cleared versus Built.** The Senators state that they are concerned that less generating capacity will actually get built than has cleared in PJM and ISO New England's forward capacity markets. It is true that that some of the capacity commitment cleared in the forward auctions will likely be bought out in incremental auctions and thus not get built; some of it may also come online with a one or two year delay.[9] While one of the APPA reports referenced by the Senators suggests that a lower quantity of realized capacity additions would demonstrate that FERC and the system operators have to revisit the resource adequacy procurement mechanisms, we are less concerned.[10]

  First, we note that there generally will be a difference between the quantities cleared and built. The magnitude of that difference is likely to be modest or consistent with a decline in load forecasts for the delivery year. The APPA reports do not attempt to quantify this magnitude or explain the reason for any difference, perhaps because the timing of the reports would have made such a comparison impossible. The latest APPA report was issued in 2014, but it was not until the 2015 delivery year that significant new generation was committed to come online (a point

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7 See a more detailed discussion of this history in Pfeifenberger, *et al.* (2011) and PJM Base Residual Auction Results.

8 See Newell, Oates, and Pfeifenberger (2015).

9 New York ISO will not have any similar cases given its near-term capacity market design.

10 American Public Power Association (2014), p. 5.

acknowledged in the report).[11,12] It is still too early for a complete comparison of the quantities cleared in forward capacity markets versus the generation actually built. But as a partial comparison, approximately 18,000 MW of new (not refurbished or life-extended) traditional thermal capacity has cleared PJM's capacity auctions starting with the delivery year 2015/16.[13] That compares to 13,500 MW that have either come online or are currently under construction.[14] In other words, the majority of the plants committed in prior capacity auctions are online or are being built; and others have additional time before they will need to begin construction to fulfill their future commitments.

Second, if there is some discrepancy between original commitments and actual construction, it is most likely related to the fact that PJM's three-year load forecasts have been overstated compared to the subsequently-revised forecasts for the delivery year. As a result, PJM has procured more capacity in the three-year forward auction than what was actually needed.[15,16] As

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[11] Neither of the two pieces of evidence cited in the APPA report demonstrates any difference between the quantity cleared and the quantity built. The first APPA point was that a non-public internal projection from a third-party consulting firm (ICF) assumed that not all of the cleared capacity would get built. This assumption may prove accurate or inaccurate in retrospect. Even if accurate, this does not indicate whether this would be a problematic outcome. The second APPA point was that more generation projects were cancelled than built between 2008 and 2012. This does not acknowledge that it is common in all regions that many more projects will be proposed than completed. As in other industries, only the most competitive projects will tend to move forward. The report fails to note that no new generation was actually needed over that period as discussed above.

[12] As noted in the second report "the 7,700 MW of planned merchant generation that cleared the last two auctions in PJM appears to mark a dramatic change in the pattern reported in this study." American Public Power Association (2014), pp. 4–5.

[13] See PJM Base Residual Auction Results.

[14] These resources are primarily natural gas-fired combined-cycles in the range of 300 to 900 MW in size, as well as 120 MW of combustion turbines. We identified units as being non-merchant if they were owned by a public power entity, were listed as "regulated," or were owned by the traditionally-regulated Dominion utility. We believe that this has screened out resources that are supported by regulated cost recovery, but we have not undertaken a more thorough review of each project. Data source: ABB, Inc., Energy Velocity Suite.

[15] As an illustration of the magnitude of over-forecasting, see Newell, Oates, and Pfeifenberger (2015), p. 9. Drivers of the downward revisions in load forecasts include recognition of the long-term effects of the economic recession, policy-driven energy efficiency investments, and lower energy intensity associated with new economic growth.

[16] A much more problematic situation would be if a substantial quantity of new generating capacity were committed and actually needed for the delivery year but failed to come online without procuring replacement capacity. We have not yet observed such outcomes, except under an ISO-NE provision that explicitly allows for a delayed online date in certain circumstances. PJM and ISO-NE have included measures in their market designs to protect against such outcomes, through qualification requirements, credit requirements, milestone

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load forecasts for the delivery year have been revised downward, some of the new generating units that cleared in the auction can buy out of their commitments or postpone their online dates. This is a more cost-effective outcome than requiring the originally-committed plant to proceed with construction if the plant is no longer needed based on the updated load forecast. However, persistently over-forecasting loads imposes additional costs and is therefore undesirable. Recognizing this concern, PJM has been working to address the issue through enhancements to its load forecasting methodology.

- **Prices Below the Net Cost of New Entry (Net CONE).** As the Senators noted, prices have been below the administrative estimates of Net CONE in most of the capacity markets for most auction years in ISO New England, New York, and PJM.[17] We do not see this as a concern for these three markets. Rather, we view this as evidence of beneficial competitive market performance. It may be disappointing to generation owners hoping for more financial support from these markets; but, from a customer's point of view, quality of service has been high and less expensive than if prices were clearing at the administrative estimate of Net CONE. Each of these markets has maintained low prices while meeting or exceeding reliability requirements, thus over-performing in both dimensions. We anticipate that in future years, average prices will rise to levels that are sustainable in the long run, but market forces will determine whether that long-run average price is above, below, or exactly at the administrative Net CONE estimate.[18]

  In the Midcontinent ISO (MISO), however, we take a different view. Prices in MISO's capacity auction have been consistently near zero and are not likely to rise sufficiently to attract new generation investments when needed. In most of MISO, capacity needs are satisfied through state resource planning efforts by regulated, vertically-integrated utilities such that there is no

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tracking during construction, and penalties for non-delivery. If such undesirable outcomes were to arise, these market design elements would need to be refined.

[17] The statement that prices have exceeded Net CONE only once is not correct. ISO-NE prices exceeded Net CONE in the 2016/17 auction for new and existing resources in NEMA and in the 2017/18 auction for new resources in the whole ISO and existing resources in NEMA. PJM prices have exceeded Net CONE in the ATSI Zone in the 2015/2016 auction and above zonal Net CONE for numerous MAAC regions in the 2013/14 auction.

[18] It is somewhat unclear why prices in these markets have remained consistently below administratively estimated Net CONE, despite new capacity being built, and the reasons likely differ by market. Capacity offers reflect how much the entrant needs to be paid in the capacity market to be willing to enter, given its costs and its anticipated net revenues from energy and ancillary services markets as well as future capacity prices. Offers may differ from administrative estimates of Net CONE for a variety of reasons. The relatively low offers could reflect lower capital costs, lower financing costs, higher anticipated net energy revenues, technological innovation, different technology types, or greater optimism about future capacity prices than assumed by the system operator in these estimates. It may be that the relatively lower net costs could be a transitional effect as low-cost opportunities are developed first.

need for additional capacity to be attracted through MISO's capacity auction. That is, the capacity market in MISO is not really the prime driver of entry or expansion decisions. Rather, it is more of a balancing market for temporary variance in the timing or performance of assets being developed for other reasons, under state requirements. However, a modest portion of MISO LSEs do need to rely on market-based capacity, and so may fall short of their requirements if prices cannot rise sufficiently to attract entry once the current capacity surplus is depleted. MISO has identified this concern, and we recommended a series of reforms to address the issues.[19] MISO has recently issued its own proposal to stakeholders.[20]

- **Generation Being Built Under Contract with Load Serving Entities (LSEs).** It is not correct that new generating capacity has been built only under bilateral agreements with LSEs or under direct ownership by LSEs, although this was likely the case up until the 2011 and 2013 periods examined by the APPA studies. Until those years, competition from lower-cost resources had postponed the need for new generation, which meant that no private entity would make an investment without a long-term contract. Thus, in those years with excess supply, only regulated entities with cost recovery were building generation or signing contracts to build new generating plants.

  More recently, we have seen substantial investments in new merchant generation resources. Of the 13,500 MW of traditional thermal capacity recently built and now under construction, approximately 11,000 MW are new merchant generation.[21] In ISO-NE, 4,050 MW of new generation has cleared in the last five auctions.[22] As mentioned previously, most of these resources have now begun construction.

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[19] The concerns are driven by a combination of a vertical demand curve, a non-forward market, and a low price cap. These issues do not affect the ability to meet capacity needs in most of the MISO footprint where regulated utilities build new generation under traditional resource planning processes. These are likely to raise resource adequacy concerns for the approximately 9% of the loads in MISO that will rely on market-based investments to meet capacity needs. We have recommended reforms to address these concerns in a recent report see Spees, Newell, and Lueken (2015).

[20] See MISO (2016).

[21] We identified units as being non-merchant if they were owned by a public-power entity, were listed as "regulated," or were owned by the traditionally-regulated Dominion utility. We believe that this screened out resources that are supported by regulated cost recovery but have not undertaken a more thorough review of each project. Data source: ABB, Inc., Energy Velocity Suite. As another comparison point, for the past three PJM auctions spanning delivery years 2016/17 to 2018/19, PJM's capacity auctions cleared 13,600 MW of new generation and uprates in total, of which 11,230 MW was merchant and 2,370 MW was LSE built or contracted. Prior to those years, a substantial quantity of new generation did clear in prior PJM auctions, but the large majority of those resources were likely LSE self-supply (although PJM did not report precise statistics on the portion designated as merchant until the 2016/17 auction). See PJM Base Residual Auction Results.

[22] ISO-NE Forward Capacity Auction Results, see ISO-NE (2016).

2. Maintaining resource adequacy and reliability are essential requirements of any electric power system. As described above, RTOs/ISOs have developed various approaches to maintaining reliability through capacity markets. In regions without organized markets, reliability criteria such as planning reserve margins are typically established by states or balancing authorities. In those regions, the costs of new capacity to meet reliability criteria must be approved through traditional cost-of-service rate regulation, usually through a state utility commission or a consumer-owned utility board.

2a. How do capacity costs borne by wholesale customers (including costs passed-through to end-use customers) compare among consumers subject to mandatory capacity markets, voluntary capacity markets, and traditional rate regulation?

Before responding to the question, we clarify that we do not distinguish between mandatory and voluntary capacity markets in this response. MISO's capacity auction is labeled as "voluntary," but it is voluntary in name only. LSEs would face substantial penalties if they failed to procure enough capacity to meet their requirements. A truly voluntary capacity market that did not impose any penalty for falling short would not be a workable construct. In that case, an individual LSE could choose to procure less than the requirement without financial consequence, and the market as a whole would not meet the resource adequacy requirement.[23,24] We therefore reinterpret this question and all following questions as referring to the differences between restructured markets that rely on capacity markets and traditional rate regulation.[25]

We first address the question of whether restructured capacity markets or traditional rate regulation have produced lower capacity costs. As a theoretical question, the answer is that a traditionally-regulated system and an efficient market-based system should expect to produce similar total customer costs under idealized conditions.[26] However, the two constructs differ in who bears the risk of

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[23] Resource adequacy is a classic example of a "public good" that is subject to a free ridership problem. Without mandatory enforcement, no individual entity would privately benefit from unilaterally meeting the requirement. See additional discussion in Spees, Newell, and Lueken (2015).

[24] Some might distinguish between capacity markets where LSEs must secure all of their load and owned or contracted supplies through the auction, as in PJM, vs. "voluntary" ones where only uncovered load must participate in the auction, as in NYISO. This is a trivial distinction, however, since covered load is unexposed to auction prices in either case.

[25] The MISO region relies primarily on traditional rate regulation to meet resource adequacy needs, but uses the short-term mandatory capacity auction to account for any imbalances and ensure locational needs are met. A subset of MISO loads do rely on the MISO capacity construct to meet resource adequacy requirements, which has posed substantial challenges that have yet to be resolved. See MISO's initial assessment of the challenge and our proposed reforms in Spees, Newell, and Lueken (2015).

[26] Both systems will produce the same lowest-customer-cost outcomes as long as: (a) the regulated planner and competitive market participants all have perfect information about future conditions and the same resource choices available, (b) the restructured electricity markets (including capacity markets) are efficiently designed

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investments becoming uneconomic due to unforeseen events and trends. In a traditional rate-regulation construct, investment costs are passed to ratepayers so that customers pay for the costs of uneconomic investment decisions. In contrast, restructured markets require supply-side entities to absorb those risks, with uneconomic investments translating to financial losses to the investors. This shifts investment risks from consumers to suppliers.

Conditions are never "ideal" because regulators and market participants face imperfect information, disparate incentives, multi-dimensional objectives, and sometimes imperfect markets. The two frameworks could therefore produce different outcomes apart from their different risk characteristics.

As an empirical question, we caution that it would be very difficult to develop a valid comparison of capacity costs between traditionally-regulated and restructured market systems. "Capacity costs" are not transparently tracked in traditionally-regulated regions. While the capital costs of a regulated utility may be substantial, those costs are not unbundled from the rest of the utility's costs and consequently are not available to the public in simple terms of price and quantity. Instead, capacity-related costs are embedded in average regulated rates and combined with many other costs, including the utility's fuel costs, return on investment, rate riders, and many other costs.

Even comparing prices between two regions with transparent capacity prices is more complicated than it looks. One cannot conclude that a market with lower capacity prices is working better for customers because capacity payments come with offsetting benefits to customers. Building more capacity reduces energy prices and increases reliability. Indeed, the constructs used to set pricing parameters in RTO markets are themselves adjusted so that capacity prices fall if energy prices increase.

Further, differences in underlying market fundamentals such as the level of excess capacity, fuel prices, environmental regulations, renewable portfolio standards, and the region's resource endowment all have a major influence on capacity costs and other components of electricity costs. A valid comparison of customer costs between two capacity markets would need to account for these complexities.[27]

Despite these strong caveats, we suspect that a valid comparison would show lower costs in capacity markets compared to traditionally-regulated regions in many (but not all) cases. We take this view

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and operating competitively, (c) the regulated planner minimizes costs as the only objective, and (d) long-run equilibrium conditions are assumed. We have demonstrated this result in a theoretical modeling exercise conducted for the Federal Energy Regulatory Commission (FERC), see Pfeifenberger, *et al.* (2013).

[27] We have developed cost comparisons for the state of Texas that account for these offsetting effects, including the customer costs of moving from an energy-only market to a capacity market at 4% greater capacity levels. We estimated the capacity payments needed to support the higher reserve margin at approximately 5% of total customer costs, while reflecting only a 1% increase in customer costs compared to the energy-only design because the capacity costs would be largely offset by reductions in energy prices. See Newell, *et al.* (2014).

primarily based on the observation that capacity markets have attracted a large quantity of low-cost resources that regulated planning likely would not have identified as supply options.[28,29]

2b. Are there differences with respect to resource adequacy or reliability (historical, current, or projected) among regions covered by mandatory capacity markets, voluntary capacity markets, and traditional rate regulation?

In principle, yes, if any system failed to meet its objectives. In practice observed to date, no. Restructured markets and traditionally-regulated systems are both designed to meet a specific resource adequacy standard, most commonly the 1-event-in-10-year "loss of load event" (LOLE) standard.[30] Both regulated and market-based systems have consistently met or exceeded the applicable resource adequacy standards, although the method for meeting those standards is quite different.[31]

At various points in capacity markets' history, regulators and market participants have expressed concerns about reliability.[32] These concerns needed to be seriously considered, but any that posed a substantive reliability risk has been or is being addressed through market reforms. Specifically, the most prominent past concerns included:

- Relying on Demand Response rather than "Steel in the Ground." Generators regularly express the concern that the substantial influx of demand response capacity poses a reliability risk. They argue that demand response resources are untested, unreliable, and less available compared to conventional generation plants. These arguments have sometimes been overstated but have reflected a real underlying (if only modest) reliability concern. The RTOs have responded to such concerns by imposing more stringent testing, measurement, verification, collateral, penalty, and performance requirements on demand response resources.[33] We agree with imposing

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28 For example, the PJM market has seen a significant increase in demand response (see Figure 1 below).

29 There are other aspects of centralized markets that would likely reduce aggregate costs, but we expect these would be smaller in magnitude. Among these are the benefits of having a liquid centralized market as opposed to less liquid bilateral markets with higher transactions costs, and the ability for small surplus and excess quantities to net out across utilities, thus enabling a smaller surplus overall.

30 The more substantial driver of reliability differences between regions is the actual meaning of 1-in-10 and the modeling that underpins that calculation. See Pfeifenberger *et al.* (2013).

31 NERC has consistently found that both types of regions are meeting their resource adequacy needs. For example, see NERC (2015).

32 We note that resource adequacy (*i.e.*, having sufficient supply to meet peak demands) is only one aspect of reliability, and is not the largest driver of outages experienced by customers. Distribution system outages lead to 100 times higher outage durations and frequency. Even at the bulk power system level, reliability concerns are more often driven by operational issues, such as contingency events or day-ahead load and wind forecast uncertainties, than by resource adequacy shortages. See Newell, *et al.* (2012).

33 We recommended a series of such reforms in Pfeifenberger, *et al.* (2008)

requirements to ensure that demand response resources provide the same marginal reliability value as generation (when being rewarded as such), but we caution against imposing excessive requirements that may exclude valuable resources. Capacity markets provide the most value when they maximize competition among resources.

- **Ability to Address the Surge in Coal Plant Retirements**. Many market participants and regulators expressed concern that PJM would not be able to absorb the large quantity of coal retirements that were driven by environmental regulations and low gas prices. The Mercury and Air Toxics Standard (MATS), in combination with market forces, have led to approximately 18,500 MW of recent or announced coal plant retirements in PJM alone.[34] This sudden wave of retirements raised legitimate concerns regarding how well the capacity market would perform when facing such unprecedented pressures.

  So far, the PJM capacity market passed this stress test with surprising robustness and no evident threat to reliability. PJM capacity prices did rise when a large fraction of the fleet faced a retire-or-reinvest decision, commensurate with the costs of maintaining or replacing those resources. Some of the to-be-retired plants were not replaced given PJM's projected capacity surplus at the time. Other to-be-retired plants were replaced by increases in commitments from demand response, imports, uprates, and new generation. PJM addressed localized reliability concerns by creating additional capacity zones and enhancing transmission plans to address local reliability concerns related to the retirements.

- **Ability to Attract New Generation Investments.** For many years, the capacity markets had not attracted new merchant generation investments. To some regulators and market participants, this raised the concern that the capacity markets were simply unable to attract merchant investments.

  These concerns were misplaced. The primary reason that merchant investment was not happening was that new generation was not needed, given how much capacity could be attracted more cheaply and quickly from other resources that might not have been expected to exist prior to the introduction of capacity market incentives. The resulting capacity market prices were appropriately low and discouraged investments in unneeded new generation. As market conditions changed and new generation investments became necessary, merchant generation investments did commit to meet that need (as discussed above).[35]

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[34] This includes only the 18,500 MW of coal capacity that has either retired or notified PJM of their planned retirement. Other coal plants may retire but have not yet submitted notification to PJM. See PJM (2015a).

[35] This has been the experience of the northeastern U.S. capacity markets, and we expect it would be the case in any capacity market designed according to sound economic principles and in a context without excessive regulatory risks. We have observed other capacity markets with design flaws that would prevent them from attracting new generation when needed. We view this as being the case in MISO's current capacity market, as well as with California's short-term resource adequacy construct (a bilateral capacity market). See

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- **Gas Pipeline Constraints.** A more recent concern has been expressed about the resource adequacy implications of limited gas pipeline capacity. Substantial coal retirements and the addition of new gas-fired generation are combining to increase reliance on natural gas pipeline infrastructure. Ensuring adequate winter fuel supplies had not previously been a focus in most capacity markets; instead, they were mostly focused on meeting summer peak demands. These winter-peak and pipeline-related reliability concerns were highlighted by the shortage events during the winter 2014 "Polar Vortex" when gas pipeline shortages led to extreme high gas and wholesale electricity prices for several days.

  The RTOs have responded to these natural-gas-related concerns with a series of reforms intended to ensure that reliability can be maintained should similar events occur in the future. ISO New England developed its Winter Reliability Program to incentivize generators to maintain access to backup oil and liquefied natural gas. For longer-term solutions, the three Northeastern capacity markets (ISO New England, NYISO, and PJM) have all proposed or implemented higher penalties and/or stronger price signals to incentivize better performance during shortage events. Ontario and MISO propose to impose separate winter resource adequacy standards that are designed to meet these requirements. Note that these reforms have yet to be tested during another extreme winter weather event.

Capacity markets and traditionally-regulated systems will continue to face different types of reliability challenges in the future. We expect that both systems will continue to address these challenges with appropriate reforms to maintain their resource adequacy standards.

2c. Are there differences in the generation mix (including with respect to characteristics such as fuel diversity and firm versus intermittent service) among regions covered by mandatory capacity markets, voluntary capacity markets, and traditional rate regulation as a result of different market structures?

There are many significant differences in fuel mix and generation technology across the various power market regions of the U.S. The majority of these differences are due to historical and geographic circumstances, such as proximity to coal mines, large rivers and dams, or natural gas production and pipelines. Capacity markets have very little influence on these intrinsic differences that tend to persist for long periods of time. Thus, it is very difficult to draw conclusions about the benefits or disadvantages of capacity markets (or regulatory processes).

However, there can be some differences in the resource mix of the two types of capacity management systems that arise more from the presence or lack of market mechanisms and the associated regulatory rules that are applied:

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Pfeifenberger, Spees, and Newell (2012) and Spees, Newell, and Lueken (2015). See also Pfeifenberger and Newell (2011).

- **Regulated Planning May More Flexibly Consider Priorities Other than Cost Minimization.** Regulated planning may be focused on lowest costs only as one of several objectives. Other objectives may focus on achieving specific environmental goals, fuel diversity, local jobs, technology development, or utility asset ownership.[36] These considerations can result in resource choices that are not lowest cost and that deviate from capacity market outcomes. In contrast, capacity markets minimize only the bid-based cost of meeting resource adequacy objectives. Other objectives are considered to the extent that they are expressed through programs or regulations outside of the capacity market itself. Renewable portfolio standards, energy efficiency programs, and environmental regulations, for example, affect market participants' investment decisions and the prices at which they offer their capacity. Even fuel diversity is considered, since market participants recognize that alternative fuels have a chance to be very profitable in the event that the dominant fuel becomes expensive.

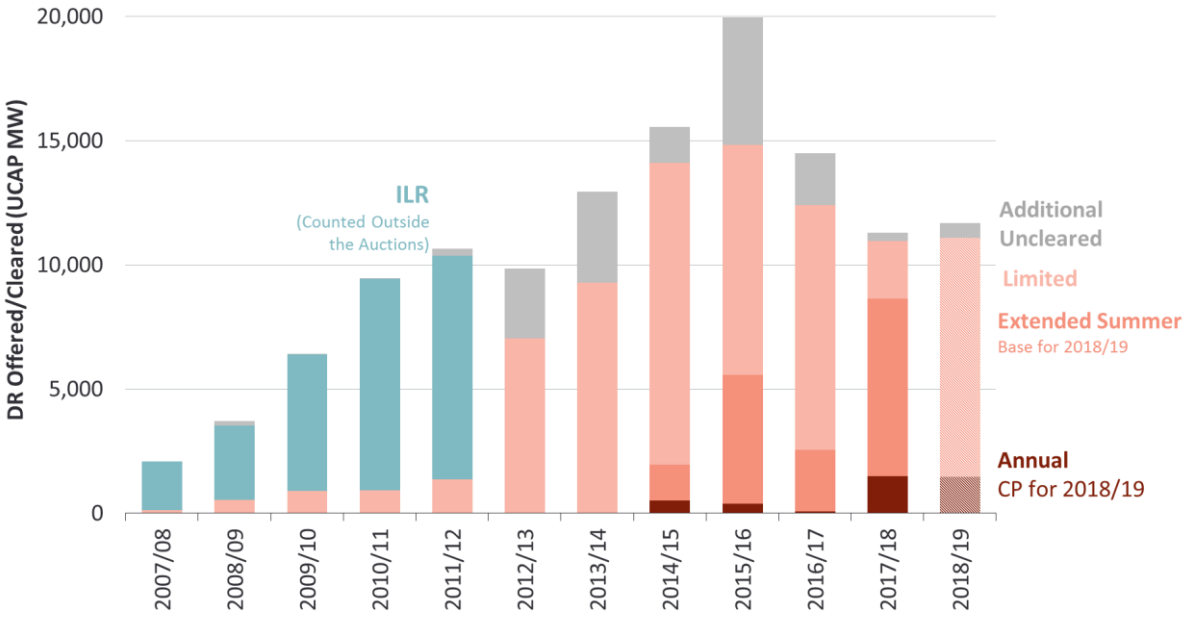
- **Regulated Systems May Apply a Longer Horizon for Expansion Decision Making.** One of the typical goals of regulation is to create stability for customers and investors, and to that end the planning horizons, financial structures of firms, and discount rates used to evaluate long-term development alternatives are different for regulated utility and merchant generation developers. In some cases, this can allow the planning entity to incorporate considerations that may arise beyond the horizon of market expectations, such as greenhouse gas mitigation. In other cases, the greater uncertainties associated with that longer planning horizon may lead to resource investments that do not fit the changing needs. The longer horizon and range of priorities considered by regulated systems are likely reasons why regulated utilities have pursued some new nuclear generating projects, although no such projects are underway based on capacity market incentives.

- **Expectations of Utility Planners May not Match the Expectations of the Market.** Which resources are expected to be lowest cost depends in part on projected future market conditions. If one forecasts strict environmental regulations, sizeable CO_2 emissions costs, and low natural gas prices, then gas-fired and renewable generation resources may appear to minimize costs. Based on recent market-based investment trends, this seems to be the dominant view of private investors as well as many utilities. If one expects the opposite, then reinvesting in an existing coal plant may be lower cost, which seems to be the view of some regulated utilities and their regulators. This apparent difference in projected future conditions seems to be contributing to a greater shift from coal to natural gas-fired generation in regions with capacity markets than in traditionally-regulated regions.

[36] Regulators of utilities in regions with capacity markets can pursue such policy goals, but will need to do so outside the capacity market construct. For example, renewable portfolio standards and distribution utility efficiency mandates are common in both capacity markets and traditionally-regulated systems.

- **Capacity Markets Enable a Wider Range of Resource Options, Including Innovative Technologies.** When making planning decisions, regulated utilities are often only able to consider a modest number of potential resource alternatives. In contrast, capacity markets invite any and all potential resources and technologies to be employed, as long as they meet the technical requirements. Thus, a capacity market can attract a wider range of market participants and spur innovation in a wider range of low-cost supplies than a traditionally-regulated utility would be able to consider. This competitive format opens opportunities for non-traditional technologies such as demand response. As illustrated in Figure 1, PJM has attracted large quantities of demand response, starting with 2,100 MW in 2007/08 to clearing more than 11,000 MW in its most recent auction.[37] Traditionally-regulated regions tend to have a much smaller share of demand response.

Figure 1
DR Participation in PJM Base Residual Auctions



Sources and Notes:
PJM BRA Auction Results. Newell, Oates, and Pfeifenberger (2015).

2d. Are capacity market rules contributing materially to broad scale premature retirements of in-service baseload units?

Regions with capacity markets have experienced a greater quantity of baseload generation retirements than traditionally-regulated regions. However, rather than considering these retirements "premature,"

[37] See PJM (2015b).

we view them to be consistent with the underlying economics of baseload plants in today's regulatory and market environment.[38] Reinvesting in coal plants can be more costly than developing new natural gas plants. Uneconomic coal plants are retiring more quickly in capacity market regions because their owners and investors cannot shoulder persistent financial losses to keep them online.

Coal plants are retiring in traditionally-regulated regions, but to a lesser extent. This difference may be driven partly by regional differences in market fundamentals and partly by differences in regulatory structures. Some regulated utilities may perceive that the full recovery of an existing plant's remaining book value through regulated rates is less certain if the plant is retired prematurely, and therefore they may prefer not to retire a plant prior to the end of its useful life. This may be the case even if retiring the plant would be the lowest-cost option going forward. It is also the case that vertically-integrated utilities have an obligation to serve and so often cannot retire an asset until a replacement is arranged, which may take some time to develop. In contrast, a merchant plant owner can close its operations whenever the going forward economics no longer look attractive.

Some utilities and market participants have raised the concern that baseload generation may provide "special benefits" that are not captured by the current capacity and wholesale-energy market designs. Such benefits may include fuel diversity, local jobs, or avoidable transmission costs.[39] We are skeptical of these arguments in the context of baseload coal plants for several reasons. For instance, these claims sometimes point to benefits that are remunerated through existing market structures; reflect temporary transfer payments from suppliers to consumers associated with market price suppression; involve only wealth transfers from one region to another or one type of provider to another; or ignore pollution-related and other societal costs that are not internalized in market prices.

We take a different view for baseload nuclear units, which face similar economic pressures, particularly in restructured regions that do not ensure cost-recovery through regulated rates. The fact that nuclear plants do not emit CO_2 and certain other pollutants offers significant societal value that is not yet remunerated in most wholesale power markets. Even in California and the Northeastern states that participate in the Regional Greenhouse Gas Initiative, CO_2 prices are lower than the societal costs of the

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[38] Coal plants' financial performance has declined in recent years due to: (a) low natural gas and electricity prices, reducing revenues to coal plants; (b) tightening environmental restrictions, especially from the Mercury and Air Toxics Standard (MATS) that required many coal plants to make major investments in air pollution controls if they were to continue operating; (c) the expectation that the Clean Power Plan or another CO_2 emissions restriction will limit coal plants' operations; and (d) standard reinvestment costs that arise for aging power plants.

[39] For example, AEP argued that these benefits justified their proposed purchased power agreements (PPAs). See Ohio Power Company's Electric Security Plan. Filed before the Public Utilities Commission of Ohio, December 20, 2013. Case No. 13-2385-EL-SSO. Posted at http://dis.puc.state.oh.us/TiffToPDf/A1001001A13L23B40635F07212.pdf

emissions as estimated by the Environmental Protection Agency.[40] More importantly, in some cases, avoiding the retirement of a nuclear plant can be the lowest-cost option from a societal perspective that values the reduction of CO_2 and other emissions. A nuclear plant in a capacity market region may therefore be more likely to retire than a nuclear plant in a regulated region that considers the value of reduced CO_2 emissions in the planning process.

3. The capacity markets in three RTOs/ISOs with mandatory markets have design differences. These differences range from treatment of non-generation resources such as demand response and energy efficiency to varying opportunities for LSEs to self-supply capacity.

3a Please identify any inherent market design considerations that explain limitations on the ability of LSEs to self-supply in mandatory capacity markets in PJM, ISO-NE, and NYISO.

Capacity markets generally accommodate self-supply by LSEs. LSEs are able to procure, build, or otherwise self-supply the capacity needed to meet their customers' capacity requirements. If an LSE has fully self-supplied its capacity requirements, then it will incur no capacity costs that depend on the market price. Any deficit will be procured by the RTO in the capacity auction, and any surplus will be compensated at the auction price. Such self-supply is generally supported in capacity markets with few restrictions.

The existing restrictions include the following:

- Self-Supply Must be Arranged Prior to the Capacity Auctions. LSEs' self-supply procurements must take place prior to the capacity auction, as any deficit will be procured within the auction. In PJM and ISO-NE, this means that self-supply must be procured three years ahead of delivery. In MISO and NYISO's non-forward markets, self-supply can be completed right up until the start of the delivery period.

- LSEs Face Some Uncertainty in the Quantity Required by the RTOs. PJM, NYISO, and ISO-NE utilize "downward-sloping demand curves" in their capacity auctions. This means that LSEs do not know the exact quantity of capacity that the RTOs will require them to have prior to the auction. LSEs that rely on self-supply may thus have a few percentage points of their load as surplus to sell or deficit to procure at the market price.

- A Subset of New Generation Builds is Subject to Minimum Offer Price Rules. PJM, ISO-NE, and NYISO impose so-called "Minimum Offer Price Rules" (MOPR) on some types of new generation investments. The details differ among the markets, but the purpose of these rules is to prevent large LSEs or state agencies from building uneconomic generation in an attempt to artificially suppress capacity prices for the remainder of their capacity needs. When MOPR limits are

[40] See EPA (2016).

imposed, an LSE will be required to offer the new generator into the capacity auction at a price that is no lower than the costs of the plant. This means the LSE will be able to use the plant for self-supply only if the plant is found to be lower-cost than market alternatives. Each of the capacity markets incorporates a number of exemptions to these rules to avoid imposing this restriction on LSEs that are not attempting to artificially suppress market prices.

3b. To what extent is the status of industry restructuring (with respect to generation ownership and rate regulation) a factor in limiting the ability of LSEs to self-supply within the states subject to mandatory capacity markets?

As described above, self-supply is generally accommodated within capacity markets, and the same rules are applied to all LSEs regardless of the state's retail restructuring status. However, the state's restructuring status does have a substantial impact in determining the extent to which self-supply is pursued:

- Regulated Utilities and Public Power Companies Engaging in Self-Supply. Regulated utilities and public power companies engaged in traditional resource planning are generally free to do so as long as the resulting supply plans are in place prior to the capacity auctions. In PJM, MOPR restrictions do not apply to such entities, and NYISO has proposed a similar exemption. In ISO-NE (and currently in NYISO), MOPR rules do apply, which imposes the unique risk that new self-supply resources that were deemed to be cost effective by an LSE in the planning process may face a minimum offer pricing restriction that does not allow the resource to clear in the capacity market. This could result in substantial additional costs to the affected LSE, which could be burdened with both the cost of the self-supplied resource and capacity market charges for the load that was supposed to be covered by that resource. LSEs are able to manage some of these risks (as discussed above), but not without some restrictions.

- LSEs Acting Directly on Behalf of Retail Choice Customers (*e.g.*, Large Industrial or Commercial Customers). LSEs that act directly on behalf of retail choice customers can similarly engage in self-supply, and they often do so through direct capacity ownership or bilateral contractual purchases. However, these retail customers are typically not willing to engage in contract terms for more than a few years; LSEs would not want or need to contract for power beyond the term over which their customers are committed to them.

- LSEs Supplying Customers via "Standard Offer Service" or "Default Service" Auctions. Another class of LSEs serve load in restructured states by offering a regulated standard offer service (also referred to as default service). In this case, the utility or a state agency seeks suppliers to take on the capacity and energy supply obligations in a competitive auction over a one- to three-year period. In these cases, the supplier that wins the auction becomes the LSE for a tranche of retail customers' needs and fulfills that obligation through a combination of contracts and its own assets.

3c. Based on capacity market outcomes in the various RTOs and ISOs (both voluntary and mandatory markets), what appear to be best practices and market designs in terms of auction frequency, forward time periods (*e.g.*, 1-year versus 3-year versus other periods), market power mitigation, and LSE self-supply options?

There is no single best capacity market design. RTOs have demonstrated a range of workable designs to account for the unique conditions within each RTO, such as regulatory structure, existing supply, and transmission constraints. Over time, RTOs and stakeholders are improving those designs to meet new challenges. However, experience over the past decade has revealed several effective capacity market design practices:[41]

- **Level the Playing Field to Enhance Competition among All Types of Resource.** Market rules should be structured so that all types of capacity can compete on even footing. New resources should be able to compete with existing resources and *vice versa*. Non-traditional sources of capacity, such as demand response and energy efficiency resources, should be able to compete with generation.

- **Downward-Sloping Demand Curves.** Downward-sloping demand curves have advantages over vertical demand curves in that they mitigate price volatility and the ability to exercise market power.

- **Auction Timing.** Forward auctions held three to four years prior to delivery help to set market expectations, reduce price volatility, increase forward pricing transparency, and help investors time their entry. This forward period provides sufficient time to enable a wide range of existing and potential new supply types to compete on a level playing field while avoiding longer commitment periods that would impose additional risks. Non-forward capacity markets such as in NYISO may need to compensate for the shorter forward period through other means such as a flatter demand curve to support more price stability. NYISO bolsters its reliability assurance through a planning backstop provision.

- **Avoid Regulatory Uncertainties and Mixing Regulated with Market-Based Capacity Development.** We have identified economic inefficiencies and regulatory uncertainties in systems that have attempted to combine regulated planning for new units with market-based capacity incentives for existing plants. This combination can lead to over-compensation and over-investment in new plants while resulting in under-compensation and the premature retirement of lower-cost existing plants.[42]

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41 See Spees, Newell, and Pfeifenberger (2013).

42 For example, we have identified such concerns with the California resource adequacy construct. See Pfeifenberger, *et al.* (2012).

There are many other components to an effective capacity market design, but we view these as some of the most essential components.[43]

3d. Are there any mechanisms within the RTO/ISOs to account for the degree to which capacity market revenues overlap with revenues from other market features also designed to ensure resource adequacy and reliability such as shortage pricing?

Yes. The markets are designed such that there is no overlap, and the marginal resource earns enough revenue across all revenue streams to enter and remain in the market as needed. Suppliers may earn net revenues from three types of wholesale electricity markets: capacity markets, energy markets, and ancillary services (AS) markets. Capacity revenues reward resource adequacy value. Net energy revenues reward low-variable-cost generation and performance during periods of energy scarcity/shortage pricing. And ancillary services revenues reward flexibility (with higher prices during scarcity). These three revenues sources are complementary and not-overlapping because the more net revenues a resource earns in the energy and ancillary services markets, the less it needs to earn in the capacity market to recover its fixed costs. This means suppliers' expectations of higher scarcity prices in the energy and AS markets lead them to offer their capacity at lower prices, resulting in lower capacity clearing prices. The same logic is applied to the administrative pricing parameters in the capacity demand curves. Higher energy and shortage prices will result in a lower administrative estimate of the long-run marginal cost of new capacity.

The complementarity of the three wholesale markets means that more efficient or flexible resources with higher net energy and ancillary services revenues will be more competitive than others, all else equal. In this way, the three markets work together to result in the most economically efficient solution to serving load and maintaining reliability. (However, the markets do not solve externalities, such as carbon emissions, to the extent that they are not included in generators' costs.)

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[43] See Pfeifenberger and Spees (2013).

Thank you very much for taking the time to review this letter as an input to your study. We would be pleased to speak with you if that would be useful as you conduct your study.

Sincerely,

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