ISSUE BRIEF July 2017

# RTO Capacity Markets and Their Impacts On Consumers and Public Power

## What is a capacity market?

To serve their customers, electric power utilities provide not only electric power on a continuous basis, but related services, including "capacity." Capacity is the maximum amount of electricity that a power plant can produce, usually stated in megawatts (MW). Customers who agree to curtail their use of electric power when called upon (known as demand response) also provide capacity.

In the context of wholesale electric markets, a capacity market is a mechanism to provide revenue to a power plant owner to stand ready to supply power when needed. An electric power utility or other load-serving entity (LSE[1]) purchases or owns capacity to ensure a reliable supply of power during peaks in demand (generally the hottest and coldest times of the year). The LSE needs to have in place sufficient capacity to meet the projected peak demand plus a reserve margin, as determined by regional reliability entities, which help ensure that the regional grid can "keep the lights on."

In several regions of the country, large bureaucratic, quasi-governmental entities, known as regional transmission organizations (RTOs), operate and oversee the bulk power grid and operate wholesale markets for energy, capacity, and other "ancillary services" that help provide reliability to the bulk power grid. Three of the nation's seven RTOs operate mandatory capacity markets. In these mandatory markets, capacity must be bought and sold through the RTO market. Capacity that is owned or contracted for bilaterally by an LSE still must be offered into (and meet the market clearing price set by) the capacity auctions. The price paid for capacity purchased through the auction is set by the RTO. The three RTOs with mandatory capacity markets are ISO New England (ISO-NE), PJM Interconnection (PJM) (covering the mid-Atlantic states, Ohio, and Northern Illinois), and New York ISO (NYISO). PJM and ISO-NE both operate a "forward" market where capacity is procured three years in advance for a one-year period. The capacity auctions in NYISO are shorter term and are procured close to the period when the capacity will be needed.

The Midcontinent ISO's (MISO) capacity market is voluntary and LSEs can choose whether to participate. MISO proposed in November 2016 to develop a capacity market that would be mandatory just for the utilities that have been restructured (which means they no longer own generation to serve their customer's load). Public power and consumer representatives opposed the proposal out of concern that it will lead to a mandatory capacity market in the remainder of MISO. FERC rejected MISO's proposal out of concern that such a bifurcated market would result in inefficient and volatile pricing. Neither the California ISO nor the Southwest Power Pool operates a capacity market. The Electric Reliability Council of Texas (ERCOT), which functions as an RTO, but is not under FERC's jurisdiction because of the intrastate nature of its grid, does not operate a capacity market.

While RTO markets for capacity are described as "competitive," they are highly mechanized, centrally administered constructs governed by thousands of pages of complex rules. Transactions in these markets are opaque, with little meaningful data available to the public. RTO-operated wholesale electricity markets are regulated by the Federal Energy Regulatory Commission (FERC).[2]

## What is wrong with the mandatory capacity markets?

Capacity prices in mandatory capacity markets have increased the cost of electricity and account for a significant share of the total electricity costs paid by consumers and businesses. In theory, capacity payments cover a power plant's fixed capital costs and other costs not recovered through electricity sales in energy and other markets. But these markets have not demonstrated that they incent investment in either the generation necessary to achieve a reliable and diverse supply of power or generation where it is most needed. Moreover, they do not ex-

[1] A Load Serving Entity (LSE) is an entity that provides electricity to end-users, including a utility or alternative supplier serving the utility's customers.

[2] See the APPA's Issue Brief, "Wholesale Electricity Markets and Regional Transmission Organizations" for more information.

hibit any of the features of competitive markets, and are instead administrative constructs requiring elaborate rules and processes. The RTOs have continually tweaked the rules in an attempt to address increasing reliability concerns in light of: pending coal and nuclear retirements; an increased reliance on natural gas; poor performance of generators during the 2014 winter; and new environmental regulations. Often these rule changes have not improved the markets, but instead simply increased the revenue paid to owners of existing generation resources, who have a strong interest in a regime that limits competition from new entrants and props up capacity prices, as described below.

To illustrate the high costs of these markets, in the PJM capacity market (known as the Reliability Pricing Model or RPM) approximately $102 billion has been paid or pledged to capacity suppliers through the middle of 2021. This works out to approximately $1,700 per man, woman, and child living in PJM's 13-state area. In 2016, the RPM added $120 per year to the average electric bill of a homeowner, $915 for a retail establishment, and $19,000 for an industrial facility. But only a small portion of the $100 billion spent or committed is financing new generation capacity. More than 90 percent of the capacity procured since the creation of the capacity market is existing power plants and only two percent is new and "reactivated" generation resources. While PJM touts demand response as a successful outcome of its capacity market, this resource, combined with energy efficiency, on an annual average has accounted for only five percent of the capacity.

### What are the most problematic changes to the capacity markets?

Among the more problematic changes to capacity market rules have been "buyer side mitigation" or "minimum offer price rules (MOPR)." The impetus for these changes began about five years ago, when several states located within RTOs became frustrated with the lack of new power generation being developed despite billions of dollars spent on capacity payments. These states sought to take control of their energy resource future and protect their residents from high electricity prices. New Jersey, Maryland, and Connecticut all took steps to establish competitive bidding processes for the procurement of capacity for long-term bilateral contracts. In January 2011, New Jersey Governor Chris Christie signed legislation to create a competitive bidding process for long-term fixed-price contracts for new power plants and, at about the same time, the Maryland Public Service Commission issued an order to procure long-term contracts for new capacity.

Fearful of the lower prices that would result from the entry of new generation constructed under these state efforts, owners of existing power plants sought to block this competition. PJM responded with a similar proposal, and in 2011, FERC approved changes to PJM's MOPR. This more stringent rule requires PJM to replace low- or zero-price offers from new natural gas plants with higher price offers, making it more difficult for these new plants to "clear" the capacity auctions.

ISO-NE, in accordance with an order from FERC, modified its rules to create a similar MOPR to PJM in December 2012, despite the absence of support from stakeholders in the region, and received approval from FERC in February 2013. The ISO-NE minimum offer price applies to all resources, including renewable energy (other than a small exemption). In both PJM and ISO-NE, FERC actually reversed carefully negotiated provisions agreed to when the markets were created that guaranteed that self-supply resources could clear the auctions. The PJM and ISO-NE orders were appealed to the U.S. Court of Appeals for the Third Circuit. Unfortunately, the court ruled that the self-supply appeal was mooted by FERC's approval of a compromise for a self-supply exemption (described later), and also rejected the states' appeals of the MOPR rule. In separate cases, federal district courts in Maryland and New Jersey invalidated the Maryland order and New Jersey law, respectively, because, the courts stated FERC has jurisdiction over wholesale power rates and states cannot take actions that impact wholesale power markets. These decisions were appealed and upheld by the U.S. Courts of Appeals for the Third and Fourth Circuits. Both New Jersey and Maryland state commissions and two independent power producers filed petitions for certiorari to the U.S. Supreme Court asking it to review the Circuit Court decisions, which were granted for the Maryland and independent power producer cases, and consolidated into a single case. In a narrowly written decision on April 19, 2016, the U.S. Supreme Court affirmed the Fourth Circuit and invalidated the Maryland long-term contract because the contract would guarantee the owner of the new power plant a wholesale interstate rate, and therefore "disregards an interstate wholesale rate required by FERC," and is preempted by the Federal Power Act. The U.S. Supreme Court also let stand the Third Circuit's decision with regard to the preemption of the New Jersey contracts.

A second set of problematic changes to the capacity markets, referred to as "capacity performance" in PJM or "performance incentives" in ISO-NE, will also significantly increase capacity costs and further constrain supply. In New England, generators that are not operating or not providing reserves during scarcity conditions are subject to stringent penalties, encouraging resources not meeting this requirement to face significantly higher costs and submit higher price offers for capacity. PJM has placed new capacity performance requirements on all resources that wish to participate in the capacity auction similarly requiring resources to be available during emergency periods. These rules carried significant capacity price increases in both RTOs, but especially in PJM where the offer cap was lifted, thus allowing capacity resources to bid in much greater prices than needed to meet the capacity performance obligations. Moreover, these rules will greatly disadvantage hydropower and other forms of renewable energy, demand response, and energy efficiency programs, further constraining supply. PJM's Capacity Performance rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit by APPA and eight other parties, including public power utilities, trade associations, and environmental groups, but the court upheld the rule in a decision issued in June 2017.

### How will these changes impact public power?

In a mandatory capacity market, a public power utility or other LSE that constructs generation for its own customers still must offer such "self-supply" capacity into the RTO's capacity auction. If that capacity is required to be offered at a higher price under buyer-side mitigation rules, that capacity might not clear the auction while the utility would be required to purchase capacity that had cleared the auction. Thus, the buyer-side mitigation rules could force an LSE to pay for capacity twice—first in paying for the construction of its own power plant and then again as a capacity payment to a generator that did clear the auction. The original rules of the capacity markets in PJM and ISO-NE contained provisions to ensure that self-supplies capacity would clear capacity auctions. This blanket exemption for self-supply was undone by FERC, and revised capacity market rules now threaten a cornerstone of the business model for public power and cooperative utilities—their ability to self-supply energy services to their own customers. Moreover, the capacity performance and performance incentive rules will further increase the cost of the portion of capacity that is purchased by public power and place additional constraints on their ability to self-supply, especially when using resources, such as hydropower, that may not meet the overly stringent performance criteria.

There have been recent positive developments that may minimize the negative impacts on public power of the buyer-side mitigation rules. Negotiations among merchant generators, industrial customers, and public power and cooperative utilities in 2012 resulted in an agreement providing for a MOPR exemption for both competitive entry and self-supply resources that meet certain criteria. This agreement was approved by FERC in May 2013. The competitive entry exemption applies to resources without any support from a utility customer charge or payments from a governmental entity. Exempt self-supply resources are those owned or procured by LSEs who have long standing business models (i.e., public power, cooperative, and vertically-integrated utilities) and who can meet certain "net-short" or "net-long" thresholds. Net-short, net long means that the exempt resource would not result in the LSE buying substantially more capacity in the capacity markets than they sell (net-short) or selling substantially more capacity than they buy (net-long). Such thresholds are intended to demonstrate that the LSE would not have any financial incentive to exercise "buyer-side market power." But these exemptions were challenged in the U.S. Court of Appeals for the District of Columbia Circuit by a group of merchant generators.[3] In July 2017, the court vacated portions of FERC's orders dealing with the exemptions and remanded the matter back to FERC. This means that the competitive entry exemption and self-supply exemption will no longer be in effect in PJM, until and unless FERC acts on remand to reinstate the exemptions.

State-sponsored resources are still not subject to any exemption in PJM unless they can demonstrate that the resource was procured through a process that was open to all generation types, an unrealistic scenario given the need for states to be able to determine what resources best meet regulatory and policy needs. In NYISO, self-supply exemptions were granted by FERC in two separate 2015 dockets. First, FERC approved a competitive entry exemption for resources that are offered into the auction, but receive no payments from bilateral contracts or other "subsidies." Second, FERC later approved exemptions for self-supplied resources and a limited amount of renewable energy. Resources eligible for the self-supply exemption would be required to meet net-short and net-long thresholds as in the PJM MOPR self-supply exemption. But the NYISO's proposed rule changes to implement FERC's order have been challenged by the New York Power Authority, New York Public Service Commission, and New York State Energy Research and Development Authority, as well as the New York Association of Public Power because these rules would make it very difficult for self-supply resources to qualify for the exemption. Thus far, no exemption has been approved by FERC for the NYISO.

These self-supply exemptions represent a significant improvement to the buyer-side mitigation rules, but still are not a return to the complete exemption for self-supply agreed to in the original design of the capacity markets in PJM and ISO-NE (which still does not have a self-supply exemption) and later overturned by FERC. Self-supply is one of the few viable alternatives that public power has to RTO-operated capacity markets, and therefore greater certainty of this right is critical for public power.

### What is the alternative to a mandatory capacity market?

LSEs in regions without mandatory capacity markets meet their reliability requirements through ownership and bilateral contracts—and generators recoup the costs of providing capacity through these mechanisms. In contrast to the RTO-operated mandatory capacity markets, such long-term contracts are procured and negotiated through truly competitive processes. Procuring capacity through long-term bilateral contracts and ownership is important for maintaining adequate capacity, and

[3] A merchant generator is a generating plant built with no energy sales contract in place.

necessary to obtain financing for new power plants, including nuclear and renewable energy projects.

## State Actions

In recent years, many of the states within these RTOs have taken or are considering steps, either legislatively or through state commission actions, to procure greater levels of renewable power and/or to establish sources of revenue to prevent existing nuclear plants from retiring. In response to the nuclear payments, some merchant generators have argued for an expansion of the MOPR to apply to existing generation, which public power has strongly opposed, along with cooperative and investor-owned utilities and consumer representatives. ISO-NE, PJM, and NYISO have all implemented stakeholder processes with the goal of determining how to better accommodate state actions, especially renewable energy procurements, within the capacity markets. PJM and NYISO are also looking at changes to the energy markets, such as carbon pricing, that could in theory achieve the goals of these state actions.

In recognition of this growing state interest in having greater autonomy over resource choices, the Eastern RTOs and FERC have created forums to discuss how the capacity markets can accommodate such state policies. FERC held a two-day technical conference in early May 2017 to address state policies and the wholesale markets, particularly the capacity markets in the Eastern RTOs. The technical conference focused on strategies to accommodate state policies, while keeping the capacity markets intact, and as well as mechanisms that may achieve state policy goals through changes to the wholesale market pricing rules. These RTO and FERC processes will provide an opportunity for public power to advocate for more fundamental reforms that not only accommodate state resource decisions, but also reduce the impediments to self-supply.

## Congressional Action

The House and Senate approved competing versions of comprehensive energy legislation in the 114th Congress: H.R. 8, the North American Energy Security and Infrastructure Act of 2015, and S. 2012, the Energy Policy Modernization Act of 2016. House and Senate conferees were unable to resolve differences between the bills, though, and the measures died upon adjournment of the 114th Congress.

One point of contention during the energy bill conference was the issue of wholesale capacity markets. H.R. 8 proposed requiring RTOs with capacity markets to report on whether their markets ensure a sufficient supply of capacity meeting certain reliability attributes. Generally, these criteria matched the performance requirements established in PJM and, generally, would have excluded renewables, including hydropower. These reports would have had to have been filed with FERC every time an RTO sought a change to market rules. While this language was better than language in an early draft of the bill that would have required all RTO capacity markets to meet PJM-like performance requirements, APPA had concerns that even a simple report, particularly when filed with every proposed change to RTO capacity market rules, would have increased pressure on all RTOs to adopt these performance requirements. The Senate bill would have required a one-time report from RTOs on electric capacity resources available; the current and projected state of reliability; and the extent to which RTO market rules meet a series of criteria related to: wholesale electric prices; diversity of generation; and availability of self-supply of electric capacity resources by public power entities. This report provision has reappeared in S. 1460, the "Energy and Natural Resources Act of 2017," introduced in June by Senate Energy & Natural Resources Committee Chairman Lisa Murkowski (R-AK) and Ranking Member Maria Cantwell (D-WA).

## American Public Power Association Position

The Association has long advocated for fundamental reforms that would transition from mandatory capacity markets to voluntary residual markets, with the primary procurement of capacity conducted by states and local public power and cooperative utilities through bilateral contracts. In the near term, however, APPA has sought to fully restore public power rights to self-supply. In close cooperation with its members, in the spring of 2015, the Association drafted legislative language for this immediate fix for the RTO capacity markets. Specifically, APPA proposed that: 1) RTOs that have not yet implemented a mandatory capacity market should not move to do so without unanimous support by the states in the region; and 2) RTOs that have already adopted a mandatory capacity market should not impair (through rates, rules, regulations, or practices affecting rates) the ability of a load-serving entity to meet its capacity obligations through a resource it owns, builds, controls, or for which it has a contract for capacity.

## American Public Power Association Contacts

John Godfrey, Senior Government Relations Director,
202-467-2929 / jgodfrey@publicpower.org

Elise Caplan, Senior Manager, Electric Market Analysis,
202-467-2974 / ecaplan@publicpower.org