AMERICAN PUBLIC POWER ASSOCIATION
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Wholesale Electricity Markets and Regional Transmission Organizations

Summary

Some utilities generate the power they sell to customers, but a good portion of electricity sold to customers is first purchased at wholesale from a third party. In some regions, wholesale purchases can be made through centralized wholesale electricity markets operated by regional transmission organizations and independent system operators (RTOs and ISOs, respectively, but collectively referred to as RTOs). Public power utilities and many customers have extensive concerns about the high cost and negative effect of mandatory capacity markets operated in some RTOs. The American Public Power Association (APPA) has developed a policy proposal to address these concerns, including proposals to reduce impediments for utilities to self-supply capacity and energy. The association also encourages congressional oversight of Federal Energy Regulatory Commission (FERC or Commission) market policies including, but not limited to, the problems associated with capacity markets and lack of transparency in RTO dealings. Fortunately, FERC in recent months has shown a willingness to revisit some of its harmful policies concerning mandatory capacity markets.

Wholesale Markets Overview

Some utilities generate the power they sell to customers, but most electricity is first purchased at wholesale from a third party. These wholesale purchases can be made bilaterally—although in some instances the third party is simply another company owned by the utility's parent company. Wholesale purchases can also be made through centralized wholesale electricity markets operated by RTOs.

At the wholesale level, electric power generators are paid for providing:

- Energy—the actual electricity consumed by customers;
- Capacity—standing ready to provide a specified amount of electric energy; and
- Ancillary Services—a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves. Ancillary services generally account for a very small portion of market revenue and are largely not the subject of this issue brief.

Within and outside of RTO regions, contracts for wholesale sales of these products can be arranged bilaterally through direct negotiation or through a broker. Energy sales may also be conducted through an electronic brokerage platform, such as the Intercontinental Exchange.

Within RTO footprints, wholesale purchases and sales may also be made through markets operated by RTOs.[1] These RTOs do not own power plants, but they exercise extraordinary control over power generation. RTOs decide which generators will run at what times and how much power they will gener-

1 A more detailed description of all seven RTOs operating in the U.S. can be found at the end of this issue brief.

ate;[2] manage the transmission system;[3] and run the billing systems for payments for power, transmission, and other services.

Energy prices paid in these markets are also determined by the RTO. These prices are generally set through an auction in which the offers to sell power at a given time are stacked in increasing order until there is enough power bid at that price to meet the demand for power. All power is then sold at this highest "market clearing" price paid to generators that bid to provide power at or below this market clearing price.[4] RTOs generally limit the maximum price of a bid, typically $1,000 per MWh, but that cap can go as high as $2,000 if the seller expects their costs of producing power to exceed $1,000. Moreover, RTOs all have some form of shortage pricing where electricity prices can spike above these caps during times of system stress. Within RTO regions, customers can enter bilateral contracts with separate settlements at different prices. However, energy prices set by the RTO strongly influence the price of energy in bilateral contracts.

In some cases, congestion on power transmission lines may prevent generation from being delivered to customers in certain areas, resulting in the use of more expensive generation within these constrained zones to meet demand, producing a higher price for customers in that zone than outside the zone. Financial instruments may be used to hedge against such congestion costs, but some RTO market monitors have expressed concerns in recent years that these financial instruments are providing earnings for financial traders and not providing a sufficient a hedge for load-serving entities.

Capacity Markets Operate in Most RTOs

In addition to energy markets, four of the nation's seven RTOs operate capacity markets.[5] As discussed above, capacity represents a utility's obligation to have enough generation to meet customer demand at all times. Demand can vary widely throughout the year, but the highest demand generally occurs during the hottest and coldest times of the year. For planning purposes, the amount of capacity a utility needs is its estimated peak demand plus a reserve margin. Utilities operating outside an RTO generally make this calculation on their own. Utilities operating inside an RTO generally must meet the capacity requirements calculated for the utility by the RTO. Because there is currently limited capability to store electric energy, the need for capacity is primarily met by electric power plants standing ready to provide power. This means having a power plant in good working order, with staff and fuel on hand regardless of how much power the plant generates. Capacity payments are intended to help cover these costs. Large customers can also provide capacity by agreeing to curtail power usage if needed to help the utility avoid running out of power. This is called demand response.

Capacity can be purchased from days to years in advance, depending upon the nature of the RTO market. As with energy, capacity can be secured through ownership of a generating unit or through a bilateral contract with a third-party provider (collectively referred to as "self-supply"). Capacity can also be purchased through wholesale capacity markets operated by certain RTOs.

2 Generation owners also have the option to self-schedule a plant without it being dispatched by the RTO, but cannot set the price.

3 RTOs have functional control, but not ownership, of the transmission system in their footprint. They ensure non-discriminatory access to transmission lines to sellers and purchasers of electricity and eliminate rate "pancaking" (charging multiple transmission fees for one transaction). RTOs also coordinate regional planning for new transmission lines.

4 ISO-NE uses a reverse auction where the RTO starts at a high price and then sellers pull out in each round as the price is lowered. The price is then set when power from willing sellers equals the demand for power from purchasers.

5 The Southwest Power Pool, California Independent System Operator, and Electric Reliability Council of Texas do not operate capacity markets.

Three RTOs, the New York ISO (NYISO), PJM Interconnection (PJM), and ISO New England (ISO-NE), operate mandatory capacity markets. These markets are considered mandatory because all capacity used to meet required reserve margins must be purchased through a capacity market auction operated by the RTOs—even capacity that is self-supplied.[6]

Like RTO-run wholesale markets for energy, RTO capacity markets rely on an auction, which results in a single clearing price for capacity during the auctioned period determined by the intersection of the supply with a demand curve created by the RTO. Again, capacity bid at or below the clearing price is paid the clearing price. Capacity bid above the clearing price does not “clear” the auction and is not paid.[7] Capacity auctions also allow prices to be set higher within transmission-constrained zones.

Buyer-Side Mitigation Rules Block Resource Choices, Self-Supply

In contrast to energy markets, several RTO capacity markets (ISO-NE, PJM, and NYISO) also include mechanisms to prop up prices for generators, such as minimum offer price rules (MOPR) and other “buyer-side” market power mitigation rules. In general, these rules require electric generating resources to bid into the capacity market auctions at certain minimum prices, even if a generator would be willing to supply capacity at a price lower than the administratively determined minimum price. These rules have become progressively more restrictive because of generation owner backlash against states’ increasing attempts to take control of their energy resource futures, including through contracts with new renewable resources and payments to avoid the retirement of nuclear power plants.

The logical action for state-procured resources is to bid the capacity into the auction at a low or zero price to ensure that the bid price would be less than the clearing price set by the auction. There are two reasons for taking this approach. First, both parties to a bilateral contract for capacity would be indifferent to the final clearing price set by the market. While the purchaser would pay, and the seller would receive, the market clearing price, the seller and purchaser then would make a financial settlement to bring the actual price paid back in line with their bilaterally negotiated price, known as a “contract for differences.” If the unit is owned by a utility, then the owner is also indifferent to the price as it is buying and selling the same amount of capacity in the auction. Second, under the rules of a mandatory capacity construct, capacity that does not clear the auction is not counted toward the utilities’ reserve margin requirement. As a result, the utility’s customers would have to pay for capacity twice: once as part of the long-term contract or other payment to secure that capacity, and then a second time to purchase from the capacity market auction to meet the reserve margin obligation.

Incumbent generators, however, feared the displacement of existing units by state-procured generation and that lower-cost units would now set the market clearing capacity price, thus reducing their profits. In response to generator arguments, FERC has allowed, and even required, the expansion of buyer-side mitigation rules in each of the RTOs with mandatory capacity markets. These expanded buyer side mitigation measures can interfere with state and local resource decisions because a state or public power entity seeking to secure new capacity would like that capacity to be bid at a price that will ensure that it clears the RTO’s auction, but the RTO is instead mandating a higher bid that puts that capacity at risk of not clearing the auction. This does nothing to help build new capacity, but instead simply serves to reward incumbent generators.

While many of these RTO MOPR changes have been proposed and approved by FERC in reaction to states’ efforts to assert control over power generation resource decisions, they affect all entities, including public power utilities seeking similar control. These expanded buyer-side mitigation measures create significant uncertainty for public power’s ability to self-supply in the future.

6 Only some regions of the NYISO capacity market are mandatory.

7 As with energy, ISO-NE uses a reverse auction where the RTO starts at a high price and then sellers pull out in each round as the price is lowered. The price is then set when capacity from willing sellers equals the demand for capacity from purchasers.

Fortunately, FERC in recent months has indicated a willingness to revisit its policies concerning the use of buyer-side market power mitigation measures in mandatory capacity markets. This shift in policy has been driven in large part by the recognition that it is unsustainable for FERC to adhere to policies that severely interfere with state resource choices and decarbonization goals. Both PJM and ISO-NE have indicated that they plan to significantly modify their buyer-side market power mitigation rules, and APPA is hopeful that these rule changes will reduce or even eliminate the obstacles to public power self-supply resources that mandatory capacity markets have long imposed.

Additional RTO Energy Market Concerns

Participating in RTO-operated wholesale energy markets can achieve efficiencies by providing access to a variety of resources, thus reducing energy costs. However, there are still some potential problems, including the ability of some generators to strongly influence market prices (also known as the potential exercise of market power); highly complex rules; and problematic governance processes. These problems have arisen, and remain, because of a lack of sufficient FERC oversight. Although energy prices have declined with the drop in natural gas costs and increased levels of renewable energy, merchant generators operating in these markets still can extract excess revenues—either operating within the existing rules or obtaining FERC's approval for changes to rules to generate excess revenues. In fact, retail electricity prices are, on average, higher in RTO regions, and there is scant evidence that this price differential has produced greater levels of reliability or significant infrastructure development.

Congressional Action

There has been limited activity on wholesale markets in the 117th Congress thus far. In March 2021, House Energy & Commerce Committee Democrats introduced H.R. 1512, the Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act. The bill would amend the Federal Power Act (FPA) to clarify that FERC may approve RTO tariffs that include a carbon pricing regime to set rates. It would also provide that, notwithstanding the fact that FERC's authority in the area of mandatory wheeling does not extend to retail wheeling, no state may "establish or enforce any law or regulation that prohibits or unreasonably burdens the purchase of clean electricity in interstate commerce by an ultimate consumer." Finally, the bill would also require all public utilities to place their transmission facilities under the control of an ISO or RTO within two years of enactment of the bill. While this requirement would not apply to public power utilities directly (because they are not "public utilities" as defined in the FPA), public power utilities may have no choice but to join an RTO or ISO to access wholesale markets if most public utilities in a region are RTO or ISO members.

APPA Position

APPA has long had concerns about RTO-operated markets, particularly related to the costs to electricity customers and potential market manipulation. In recent years, the association has focused intensely on the problematic mandatory capacity markets, but has also closely monitored efforts to change the energy market price formation rules to ensure such changes do not create price increases without benefits to consumers. APPA developed and recently reissued a proposal to replace these mandatory capacity markets with voluntary capacity markets that will create more opportunities for states and public power utilities to procure desired resources at a more reasonable cost. The association continues to urge congressional oversight of FERC market policies including, but not limited to, the problems associated with capacity markets, the lack of transparency for stakeholders in RTO dealings, and the implementation of new price formation rules to ensure fairness.

In relation to the CLEAN Future Act, APPA has serious concerns about the prohibition against states regulating the retail wheeling of "clean electricity" as it would fundamentally alter the FPA jurisdictional divide between wholesale and retail sales of electricity, particularly the ability of states to establish and maintain exclusive retail service territories. APPA does not support this provision. APPA is also opposed to the requirement that all public utilities must join an RTO or ISO within two years of enactment. Again, this would not apply directly to public power utilities, but public power utilities might have no choice but to join an RTO or ISO to access wholesale markets if most public utilities in a region are RTO or ISO members.

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A Description of the RTOs

There are seven RTOs operating in the United States: ISO-NE; NYISO; PJM; the Midcontinent Independent System Operator (MISO); the California Independent System Operator (CAISO); Southwest Power Pool (SPP); and the Electric Reliability Council of Texas (ERCOT). Of the seven, only ERCOT, which operates entirely within the state of Texas, is not subject to FERC jurisdiction. Below are descriptions of the remaining six:

California ISO (CAISO)

CAISO operates only in California, but it is under FERC's jurisdiction because the state's transmission grid is interconnected with the rest of the West. Some public power utilities in the state have chosen not to turn over operational control of their transmission facilities to CAISO, but all public power utilities are impacted by CAISO's energy market prices and provision of transmission service due to the web of business relationships among market participants in the state. In October 2014, the ISO began operating a voluntary energy imbalance market (EIM) with PacifiCorp, which has since been joined by many investor-owned and public power utilities. The EIM is generally viewed as providing many of the benefits from centralized energy dispatch over a large geographic area, but without the risks of a full RTO. CAISO has initiated a stakeholder process to examine whether to extend the day-ahead market to the EIM, which would result in a more RTO-like market structure.

CAISO does not operate a capacity market, and in 2018, FERC rejected a complaint requesting the creation of a capacity market in CAISO. APPA and multiple other parties supported FERC's rejection of the complaint.

ISO-New England (ISO-NE)

ISO-NE operates in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. The region is facing numerous challenges from growing reliance on natural gas without a corresponding increase in natural gas pipeline capacity, retirements of nuclear and coal plants, and rising energy and capacity prices. ISO-NE operates a mandatory capacity market, called the forward capacity market, which procures capacity three years in advance.

Midcontinent ISO (MISO)

MISO operates in all or parts of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, Wisconsin, and Manitoba, Canada. MISO has seen both defections by transmission-owning utilities—FirstEnergy and Duke left

MISO to join PJM in 2011 and 2012 respectively—and a significant expansion of its territory at the end of 2013 to include what is known as MISO South. Many industry observers believe the former MISO utilities that joined PJM did so to receive lucrative capacity market payments not available from MISO, while MISO's revisions to its capacity market were an incentive for the southern expansion. In 2012, FERC approved a voluntary locational capacity market for MISO, but ruled against mandatory participation or a MOPR in that market.

New York ISO (NYISO)

NYISO operates only in New York, but is FERC-jurisdictional because the state's transmission grid is interconnected with the rest of the region. New York City is a very transmission-constrained area within NYISO, requiring substantial mitigation of the power sales into that area. The ISO operates a shorter-term capacity market than in PJM and ISO-NE, but it is only mandatory within the New York City and Lower Hudson Valley zones.

PJM Interconnection (PJM)

PJM operates in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM operates a three-year forward mandatory capacity market, called the reliability pricing model. In December 2019, FERC decided to dramatically expand PJM's capacity market's MOPR, greatly restricting public power's self-supply ability and state efforts to procure renewable resources or prevent nuclear plants from retiring. APPA and numerous other parties are currently challenging this MOPR expansion in federal appeals court, although, as explained above, PJM is currently considering significant changes to its MOPR rules, and FERC has indicated it is receptive to relaxation of PJM's buyer-side market power mitigation measures.

Southwest Power Pool (SPP)

SPP operates in all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. SPP has approached RTO formation and market development on a slower and more conservative track than many other RTOs. SPP transitioned to a full RTO with both a day-ahead and real-time market in March 2014, but has not implemented a capacity market. In June 2019, SPP issued an initial proposal for a Western Energy Imbalance Services market (WEIS), which is similar to, and would operate alongside, the CAISO-operated western EIM. Thus far, six investor-owned, cooperative, and public power utilities have agreed to join the WEIS. FERC approved the WEIS market rules in December 2020 and operations began in February 2021.