AMERICAN PUBLIC POWER ASSOCIATION
Powering Strong Communities

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# Wholesale Electricity Markets and Regional Transmission Organizations


## Summary

In the U.S., roughly five billion megawatt (MWh) hours of electricity are sold at the wholesale level, i.e., sold to a utility or other entity reselling that energy to residential, business, or industrial customers. There is no single national market for these wholesale electricity sales. In some regions, these sales are conducted bilaterally, through direct contact and negotiation, through a voice broker, or through an electronic brokerage platform, such as the Intercontinental Exchange (ICE). In many parts of the country, specifically in the Northeast, Mid-Atlantic, California, and the middle section of the country from Texas to North Dakota, there are wholesale electricity markets operated by large entities known as regional transmission organizations (RTOs) and independent system operators (ISOs)—collectively referred to as RTOs. Bilateral transactions can also occur in RTO regions, but through separate settlements and in compliance with complex RTO rules. These RTO markets provide for the wholesale sale of electric energy (both day-ahead and real-time purchases), as well as ancillary services. Some RTOs also operate capacity markets.[1]

Public power utilities, state utility commissions, consumer- and low-income advocates, and industrial electric power customers have raised concerns about RTO-run wholesale electricity markets, which are not markets in the traditional sense. Such concerns initially revolved around high and volatile prices. More recently, the leading concerns have been the cost and effects of mandatory markets for capacity run by some RTOs. The American Public Power Association (APPA or Association) has developed a policy proposal to address public power's concerns with capacity markets. In addition, the Association strongly supports congressional oversight of Federal Energy Regulatory Commission (FERC) market policies including, but not limited to, the problems associated with capacity markets and lack of transparency in RTO dealings. Congress also needs to delve into the intricacies of FERC policies to ensure fairness.


1 See APPA Issue Brief, "RTO Capacity Markets and Their Impacts on Consumers and Public Power," for more information.

## Wholesale Markets Overview

In regions without markets operated by an RTO, wholesale sales are conducted bilaterally, through direct contact and negotiation, through a voice broker, or through an electronic brokerage platform, such as the ICE. They also have forums that serve to create robust bilateral markets in these non-RTO regions. For example, the Western Systems Power Pool provides a standardized power sales agreement that provides for a liquid wholesale power market with transparent price information reported through multiple indices. Generally, these regions are where traditional vertically integrated utilities (i.e., utilities owning generation, transmission, and distribution facilities) continue to operate. (Some RTOs are also predominantly categorized by vertically integrated utilities as discussed below.)

RTOs were formed as some state regulators changed retail electricity markets rules to encourage or require traditional vertically integrated utilities to sell their generation facilities and give retail utility customers the ability to purchase power from other generators. As a result, private utilities were forced to purchase their power on the wholesale market. (Most states exempted not-for-profit, locally governed public power utilities from these requirements, though for unrelated reasons, these utilities generally must make wholesale purchases of power). Intended to spur competition, this "deregulation" allowed for the sale of electricity and related products, such as energy management, beyond traditional utilities. However, many utilities simply sold their generation facilities to a parent holding company that continued to sell a significant portion of the electricity purchased by the utility's customers.

Meanwhile, at the federal level, RTOs were authorized by FERC in 1996 to "remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce." (FERC Order No. 888, April 24, 1996.) RTOs have functional control, but not ownership, of the transmission system in their footprint. They provide 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.

RTOs were also authorized to administer wholesale markets for the sale of electric energy (both day-ahead and real-time purchases), electric power capacity, and ancillary services. RTOs do not own the power plants that generate the power bought and sold in the market, but do exercise extraordinary control over power generation. They decide which generators will run and at what levels, grant (or deny) the transmission services needed for transactions to occur, and run the billing systems for payments for power.

Prices paid in these markets are not set through bilateral exchanges—they are centrally determined by the RTO. Customers can, however, engage in bilateral contracts with separate settlements at different prices. All RTOs have centralized markets for the day-ahead and real-time purchase of wholesale electric power. The prices are set every five minutes based on the bids that sellers submit to the RTO. The RTO takes all bids in ascending order and stops with the last incremental bid needed to supply power to buyers in that time interval. The price all sellers in that time interval receive, however, is based on the last bid the RTO accepted—this is known as a single clearing price market. Bids need not reflect the sellers' actual costs of generating power, as FERC formerly required. As a result, low-cost generation can reap substantial financial windfalls. 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 (prices paid in these markets also strongly influence the price of electricity charged by generators outside these markets in bilateral or standard offer contracts).

In some cases, congestion on power transmission lines may prevent all available generation from being delivered to customers in a constrained zone. As a result, the RTO may allow more expensive generation located within the zone to meet that demand, and customers in the zone must pay the higher price. The difference between the lower price in the RTO generally and the higher price being charged in the congested zone is called the congestion charge. This congestion pricing system is known as locational marginal pricing (LMP), and in theory LMP was designed to incentivize construction of new generation or additional transmission facilities or reduce power usage through conservation or a constrained zone. In reality, generation and transmission development has not been greater in higher LMP regions.

There are financial instruments available to hedge this congestion, such as financial transmission rights (FTR) or congestion revenue rights, but some RTO market monitors, notably in the PJM Interconnection (PJM) and California Independent System Operator (CAISO), have expressed concern in recent years that the hedges are being used to generate earnings for financial traders rather than provide a hedge for load-serving entities. FERC approved several rule changes in 2018 that were proposed by CAISO, and supported by APPA, to improve the value of congestion revenue rights as a hedge for load-serving entities. In PJM, a financial entity defaulted on its payments owed for its FTRs in 2018, costing PJM market participants over $100 million. An investigation into this event by PJM's Board found that PJM management had failed to recognize or take action to prevent or minimize the default, and also made a number of recommendations for improvements.

In addition to the energy markets, most RTOs (other than the Southwest Power Pool (SPP) and CAISO) operate markets for capacity. One way a utility can ensure it can meet its peak load is to pay a generator to stand ready to provide power, i.e., to have the capacity necessary to meet peak load. Capacity can also be met by securing an obligation from customers that they will curtail power at times of peak load. The cost of capacity is in addition to the price paid for the actual delivery of power and other ancillary services. Like RTO-run wholesale markets for energy, RTO capacity markets rely on a centrally determined single clearing price (again allowing windfall profits for low-cost units), are subject to locational pricing, and impose dollar caps on bids. Capacity prices are established in periodic auctions—typically on an annual basis. In contrast to energy markets, several RTO capacity markets (ISO New England (ISO-NE), PJM, and New York ISO (NYISO)) also include mechanisms to prop up prices for generators, such as minimum offer price rules or buyer-side mitigation rules.

## Market Concerns

While participating in RTO-operated wholesale energy markets can produce benefits for public power in terms of cost savings and additional opportunities to sell power, there are still some potential problems with the markets that require vigilant oversight. Concerns with RTO-operated markets include the ability of some generators to strongly influence market prices (also known as exercising market power), highly complex rules, and problematic governance processes. These problems have arisen, and remain, because of a lack of sufficient FERC oversight. Although electricity prices have declined with the drop in natural gas costs and increased levels of renewable energy, merchant generators[2] operating in these markets still can extract excess revenues—either operating within the existing rules or obtaining FERC's approval for changes to existing rules to generate

2 A merchant generator is a generating plant that does not receive revenue from utility customers or energy sales contracts and earns revenue only from sales into the RTO-operated markets.

excess revenues. For its part, FERC continues to impose a strict reliability standard on these RTOs, while taking a hands-off approach as to whether resulting rates to customers are still "just and reasonable."

Ironically, when RTOs first established wholesale markets, proponents said switching from a cost-based rate to a market-based rate would increase price competition, and consumers would benefit both from lower prices and greater investment in new infrastructure necessary for the future reliable operation of the grid. But retail electricity prices are, on average, higher in those RTO regions where the states are no longer vertically integrated, and there is scant evidence that this price differential has produced greater levels of reliability or significant infrastructure development. Within the RTO regions, several states have established additional revenue streams to ensure the continued operation of nuclear power plants that would otherwise retire.[3]

In response to generation owner recommendations, FERC initiated an effort in late 2014 to examine price formation in the energy and ancillary services markets. This docket resulted in two final rules that could significantly increase prices. In June 2016, FERC approved its first rule under the price formation effort. One problematic component of the rule is it requires all RTOs to trigger price spikes, known as shortage prices, during any time period when a shortage of energy or operating reserves occurs, rather than requiring a shortage to have a minimum duration before such shortage pricing occurs. APPA and the National Rural Electric Cooperative Association filed comments, as did many other parties, questioning the benefits of shortage pricing for such transient shortages relative to the costs. A second rule, issued in November 2016, would allow energy market offers to exceed the current cap of $1,000 per MWh if the seller of energy believes its costs are likely to exceed that amount. APPA and American Municipal Power requested a rehearing of the rule because the removal of the offer cap represents the elimination of a key protection against market power abuses; FERC rejected that request.

Two additional and highly complex proposed price formation rules were issued in 2017. The first one is on the setting of prices by fast-start resources. The second one is on "uplift" payments to generators whose costs are not recovered through LMPs that proposes to continue to allow the allocation of such costs to load in some RTOs, even when load was not the cause of such uplift. FERC in late 2017 terminated the proposed fast-start resource pricing rule in response to requests to allow for individual RTO flexibility, and instead opened three investigations into whether PJM, NYISO, and SPP should amend their tariffs to allow fast-start resources to set the price with greater frequency and expand the range of costs included in their offers. In 2018, FERC issued a final rule on uplift that did not address the allocations and instead only required additional data on uplift to be provided by the RTOs, which APPA supports. Meanwhile, PJM in late March proposed a series of price formation rule changes that were opposed by many stakeholders and the market monitor because these rule changes are projected to increase energy prices without sufficient justification.

3 Seven nuclear power plants have retired since 2013, amounting to 6 gigawatts of capacity. Owners of nuclear power plants claim that reduced electricity prices in RTO-operated markets are a primary factor in lowering needed nuclear plant revenue and spurring retirements. Such price drops have resulted from decreases in the price of natural gas and growth of wind power. Because of these lower earnings, nuclear plant owners have sought to increase their revenue through state programs that have been created to direct additional revenue to nuclear plants in Illinois, New York, New Jersey, and Connecticut, and advocated for overall changes in wholesale markets that would boost electricity rates.

## Congressional Action

The direction Congress may take on wholesale electricity markets issues in the 116th Congress remains unclear. In the 115th Congress, the House Energy & Commerce Committee held a series of hearing on these markets, but the Senate Energy & Natural Resources Committee never began a comparable effort. The leadership of the House Energy & Commerce Committee will continue its examination of the Federal Power Act this year, which could touch on wholesale markets issues, and held a hearing on oversight of FERC in June 2019 that examined how the Commission's decisions impact the nation's energy and environmental future. Topics covered included transmission policy, energy storage in wholesale markets, and wholesale capacity markets.

## American Public Power Association Position

APPA has long had concerns about RTO markets, particularly related to the costs to electricity customers and market manipulation. In recent years, the Association has focused intensely on the problematic mandatory capacity markets operated by the Eastern RTOs. As discussed above, many questions have been raised about whether these markets can provide reasonably priced and reliable long-term service to electricity customers, and whether the rules will interfere with public power's ability to procure resources needed to serve its customers. In response, APPA developed 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 needed resources at a more reasonable cost.

Finally, the Association continues to support congressional oversight of FERC market policies including, but not limited to, the problems associated with capacity markets, the lack of transparency in RTO dealings, and the implementation of new price formation rules. Congress needs to delve into the intricacies of FERC policies to ensure fairness. APPA staff have met with members of Congress and their staff regarding these issues and will continue to conduct such outreach to increase their understanding of RTO-related problems.

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## A Description of the RTOs

There are seven RTOs operating in the United States: ISO-NE; NYISO; PJM; MISO; CAISO; 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 several 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 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 protested 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—First Energy 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 minimum offer price rule in that market. MISO filed a proposal in 2016 to create a mandatory capacity auction in those regions where there is retail choice and the utilities are not responsible for supplying power to their customers, which was later rejected by FERC.

### 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, which requires 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 2018, FERC found that the capacity market rules in PJM are not just and reasonable because they do not prevent reductions from capacity prices due to state efforts to procure renewable resources or prevent nuclear plants from retiring. An investigation was opened by FERC into PJM's capacity market rules.

### 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 a proposal for a Western Energy Imbalance Services market, which is similar to and would operate alongside the CAISO-operated western EIM.

The American Public Power Association is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 93,000 people they employ. Our association advocates and advises on electricity policy, technology, trends, training, and operations. Our members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power.