

ENERGY

# Electricity Markets: A Primer for State Legislators



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# Introduction

Policymakers in the United States have demonstrated a renewed interest in electricity markets in recent years. The promise of competitive electricity generation is that economic efficiencies in the transmission and dispatch of generating resources will lead to lower prices than are possible under the traditional cost-of-service regulatory model. The intent is that the improved efficiencies and wholesale prices, in turn, will lead to lower retail prices and customer savings.

The move toward competitive wholesale electricity and the restructuring of the power sector began in the 1990s. However, following a series of failures in the early 2000s, several states reconsidered or scaled back these ambitious shifts in regulatory approach. While close to two-thirds of the electricity demand in the U.S. is served through entities that operate wholesale electricity markets, only around one-third of states have fully restructured their electric sector in a manner designed for competition.

Today, the grid itself is changing—from the way it's managed, to its structure and the services required of it. The promise of markets has returned as a potential option to economically unlock emerging technologies to build a cleaner, more efficient grid. In response, policymakers and utilities have proposed methods of expanding market access to new regions of the country.

State legislators play a large role in making these decisions. They decide how to regulate and structure electric utilities. They influence utility participation in markets and regional grid operations. Their policies and programs interact with and influence market operations—in some cases coming into conflict with market rules set by federal regulators.

This primer aims to offer state policymakers an unbiased, brief and straightforward review of electricity markets in the U.S. It explores the traditional regulatory models that prevented competition, the movement to drive down prices through competitive markets and an overview of the organizations and structures that emerged from the upheaval. In addition, the primer seeks to provide context around the way state policies and markets interact so that lawmakers have a clearer understanding of why these decisions were made in the past and how they might play out in the future.

## The Basics & the Background

It's impossible to discuss electricity markets in the U.S. without discussing utility regulation—and regulatory reform—in the power sector. The two concepts went hand-in-hand in the 1990s, when states began to explore restructuring the electric sector. While there were many reasons states debated these options, [the primary drivers included](#):

- A precipitous rise in electricity prices throughout the 1980s due to the development of significant new generating capacity, along with a corresponding desire to reduce the cost to consumers.
- Recent changes to the structure of telecommunications and natural gas industries that favored competition, along with the development of advanced technologies to enable responsive market operations.
- A shift in thinking about the regulation of electric utilities as “natural monopolies.”

In order to affect market competition in the electric sector, states considered restructuring the electric sector and how it had been developed and regulated since the early 1900s.

### Utility Models

There are more than 3,300 electric utilities in the U.S., but three [primary utility models](#):

- Investor-Owned Utilities (IOUs):** Private, for-profit companies subject to state regulation and financed by shareholder equity and bondholder debt. Around three-quarters of the U.S. population is served by IOUs.
- Public Power and Municipal Utilities:** Publicly owned utilities, subject to the oversight of a governing board. These utilities are often owned and operated as semi-autonomous government agencies tasked with providing public services.
- Electric Cooperatives:** Situated primarily in rural areas, electric co-ops are private nonprofit entities. Co-ops are customer owned and governed by a board.



## The Utility Business Model & State Regulation

Like other industries that provide essential services considered vital to the health, safety and economic productivity of society, the electric sector has been subject to government oversight to protect the public interest. The infrastructure necessary to provide service also led to the determination that electric utilities are “[natural monopolies](#)”—industries in which a single entity can serve a market at a lower cost than any combination of two or more entities, often due to high start-up costs and economies of scale.

The electric industry has been regulated by federal, state and local entities [under these principles](#). Often referred to as the “regulatory compact,” a utility waives market competition and subjects itself to government oversight in exchange for revenue guaranteed by a cost-of-service model. In practice, this allows regulated utilities the opportunity to recover prudently incurred costs and an authorized rate of return on investments through electricity rates paid by customers.

Under this construct, state utility regulatory commissions—often referred to as public utility commissions (PUCs) or public service commissions (PSCs)—provide oversight of utility rates and service. PUCs approve retail electricity rates in order to create the opportunity for the utility to recover its operating and capital costs, including a small return on investment. Investments in infrastructure, such as new power plants or substations, require PUC approval.

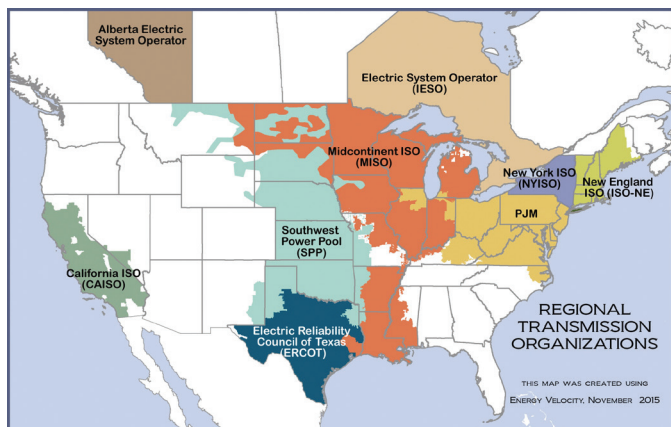
For much of their history, many investor-owned utilities operated in this capacity as vertically integrated monopolies within a service territory: they owned and operated everything from the power plants to the meter on a customer’s home and received guaranteed, though limited, revenue in exchange for reliable and safe service.

However, in the 1990s a shift emerged. Most policymakers still believed that electricity delivery—comprised of nearly 160,000 miles of high-voltage transmission lines and millions of miles of low-voltage distribution systems—fell under the functional definition of a natural monopoly. But electricity generation was another story, and that’s where some states focused their efforts to deliver lower power bills.

# Competition & Restructuring

The idea behind the shift toward shared infrastructure and the economic dispatch of the lowest-cost generation dates back to before the Great Depression. In 1927, three utilities in the Pennsylvania, New Jersey and Maryland region formed the PJM power pool. These utilities relinquished some control over their individual systems and generation resources, allowing a common grid operator to manage transmission and generation to optimize economic dispatch. Over the ensuing decades, four additional power pools formed across the country.

**Fig. 1 — Map of ISO/RTOs**



Source: FERC

However, the traditional utility regulatory structure wasn't truly altered until the [Public Utility Regulatory Policies Act of 1978 \(PURPA\)](#), which opened the door to independent power producers (IPPs)—non-utility owners and operators of power generating units. Prior to PURPA, these IPPs operated at a competitive disadvantage; utilities didn't have to consider IPPs in electricity procurement and IPPs weren't guaranteed access to transmission networks that moved electricity from generators. PURPA required utilities to [provide IPPs with an opportunity to participate and compete](#) to supply electricity, but transmission access was still not guaranteed.

The appetite for greater competition in the electric sector grew through the 1980s as advancements in generation technologies made it easier for IPPs to effectively and economically compete with larger,

utility-owned power plants. These shifts led Congress to pass the [Energy Policy Act of 1992](#), which [aimed to promote wholesale competition in power generation](#) by enabling industry restructuring and removing remaining barriers to competition, including access to transmission. The new law expanded the Federal Energy Regulatory Commission's (FERC) authority to address these barriers.

Building on this authority, [FERC issued a series of orders](#) designed to open transmission access and allow for wholesale market competition among power generators. FERC mandated open transmission access for IPPs, established a system to facilitate electricity procurement and encouraged utilities to join independent system operators (ISOs) and regional transmission organizations (RTOs). These ISO/RTOs serve as grid and market operators, designed to manage a region's transmission system and dispatch electricity using a least-cost methodology that doesn't sacrifice reliability.

States took the next step toward competition in the form of electric restructuring—also referred to as “de-regulation.” Restructured states relied on retail market reforms to introduce competition into additional utility functions, thereby eliminating vertically integrated utilities. In most cases, these reforms forced electric utilities to divest their generating assets. In those states, generating resources became competitive generators, which were dispatched by the ISO/RTO to reliably meet demand at the lowest cost. Meanwhile, the utilities became largely “wires companies;” they continued to own and operate transmission and distribution systems as regulated utilities, with state and federal oversight and set fees for grid services.

During the first wave of restructuring legislation at least 23 states and Washington, D.C., enacted electric restructuring legislation, while another seven states conducted studies but decided not to pursue restructuring. However, early problems with implementation —particularly in California and Montana—caused a handful of states to freeze or reconsider these policies.

Ultimately, 16 states and Washington, D.C., implemented some form of restructuring, with the flavor and details varying significantly between regions and ISO/RTOs.

However, it's important to note that electric restructuring is not necessary for wholesale market participation. Utilities may—and many do—voluntarily participate in ISO/RTO markets.

Around two-thirds of electricity in the United States is now served through ISO/RTOs; the Southeast and Western U.S. are the exceptions. In recent years, state legislation and policymakers in those regions unserved by an ISO/RTO have raised the prospect of developing new markets.

## Elements of Restructuring

The two most fundamental changes brought about by electric restructuring concern power sales. The first is at the wholesale level, where distribution utilities and IPPs buy and sell bulk power. The second is at the retail customer level, with some states seeking to provide customers with a choice over who supplies their service.



### Wholesale Power

This is the most common element of restructuring—so common, in fact, that even states with traditionally regulated utilities participate in wholesale markets. These markets vary in many ways, but there are common elements. First, they are operated by an ISO/RTO, which acts as an independent platform where generators sell electricity and load-serving entities purchase electricity before selling it to end-users. In states with restructured power systems, resource planning is conducted by the RTO/ISO through competitive solicitation and price signals.



### Retail Choice

Retail choice allows customers to choose who provides their power, whether that's their local distribution utility or an alternative retail electric supplier (ARES). While retail choice is popular among large consumers, such as industrial and large commercial, only a handful of states have robust retail choice at the residential level. The local distribution utility is often the default service provider, but customers can choose to sign with alternative suppliers, which offer competitive and sometimes complex pricing structures.

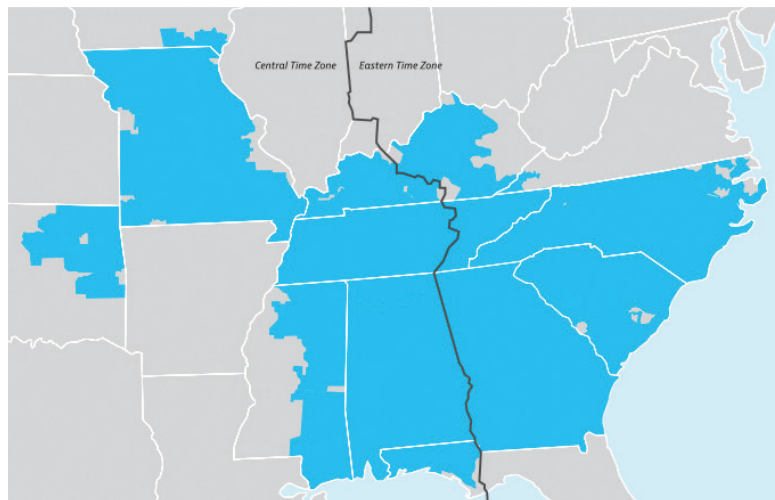
## Show Me the Markets

There are currently seven ISO/RTOs (see Figure 1) operating organized wholesale electricity markets in the United States and serving as grid operator for around two-thirds of the nation's electric load. The largest in terms of peak load is [PJM Interconnection](#)—the successor to the first power pool—which serves 65 million people across 13 states and Washington, D.C. The smallest, with a peak load nearly one-sixth that of PJM's, is [ISO-New England](#) (ISO-NE), which serves six states in New England.

Each ISO/RTO is unique due in large part to its makeup. For instance, three ISO/RTOs—[California ISO](#) (CAISO), [New York ISO](#) (NYISO) and the [Electric Reliability Council of Texas](#) (ERCOT)—operate almost exclusively within a single state, which simplifies the incorporation of state policies into market operations.

It's also noteworthy that ERCOT is an isolated grid—it maintains only a few interconnections with the two U.S. grids and Mexico's grid. This isolation so severely limits ERCOT's ability to import or export power that it exempts ERCOT from federal oversight on the basis that interstate commerce is negligible. It can be stated without any controversy that ERCOT is the purest example of market-based restructuring in the U.S. At the wholesale market level, ERCOT relies on day-ahead and real-time markets, with no "capacity" payments to ensure resource adequacy. At the retail market level, the state forced utilities to divest of generation and enacted mandatory retail choice for electric customers.

## Fig. 2 — Proposed Southeast Energy Exchange Market (SEEM) Footprint



Source: SEEM

On the other hand, PJM, ISO-NE, the Southwest Power Pool (SPP) and the Mid-continent ISO (MISO) operate across regions with many different states and many different state policies. In some cases, these ISO/RTOs consist predominantly of restructured states, such as ISO-NE and PJM. In others, many of the states maintain a traditional utility regulatory structure. While this doesn't afford customers access to retail choice, it does provide significant opportunities for greater efficiencies through wholesale electricity markets, the benefits of which trickle down to ratepayers.

Meanwhile, proceedings are underway regarding new and expanded wholesale markets in regions that are currently operating under traditional, vertically integrated regulatory structures.

In the Southeastern U.S., 15 of the largest utilities in the region have proposed the creation of a [Southeast Energy Exchange Market \(SEEM\)](#). The new market proposes to be a sub-hourly bilateral trading platform to allow utilities to trade excess electricity through spare transmission capacity. SEEM will not function as an ISO/RTO; it will not operate transmission or optimize savings through least-cost, market-based dispatch of generation. Opponents have argued the SEEM proposal falls short of providing a true, open market, given that it is largely reserved as a more efficient trading platform between utilities in the region (see Figure 2). While its backers have claimed the new platform could save customers up to \$150 million annually, other independent studies have [claimed those savings could be significantly higher](#) with open access and least-cost dispatch.

FERC reviewed the SEEM proposal throughout much of 2021. In October, the market became effective after [FERC commissioners deadlocked](#) on the proposal. SEEM could begin operations as early as mid-2022.

Like the Southeast, there is no ISO/RTO coordinating electric transmission and wholesale market operations throughout most of the Western U.S. However, there are significant differences. First, the Southeast is part of the Eastern Interconnect—one of the two major power grids operating in North America. Five ISO/RTOs operate on the Eastern Interconnect, which generally consists of everything east of the Rocky Mountains. The Western Interconnect—the other major power grid, consisting of everything west of the Rockies—currently has only CAISO. (ERCOT, considered a minor interconnection operating solely in Texas, completes the [power grid puzzle](#) for the contiguous U.S.)

CAISO, which operated largely within the borders of California since 2000, began operating a [Western Energy Imbalance Market \(EIM\)](#) in 2014. The Western EIM is a voluntary, real-time market platform that allows for the sale and purchase of electricity among participating utilities and IPPs. The market currently has 15 participants; another seven are expected to join by 2024, at which point Western EIM participants will represent [more than 80% of the load](#) in the Western Interconnection (see Figure 3).

However, SPP has moved to provide an alternative to the Western EIM, with [plans to expand](#) its footprint into the Western Interconnection by March 2024. SPP has announced prospective participants across at least six Western states, potentially expanding its services, such as market access, transmission planning and balancing operations.

In 2021, state legislators in Colorado ([S.B. 72](#)) and Nevada ([S.B. 448](#)) required utilities in those states to join an ISO/RTO by 2030, while additional states are formally exploring the topic.

With a growing number of states and utilities considering joining either CAISO or SPP, studies have sought



to characterize the potential benefits. A [recent study](#) funded by the U.S. Department of Energy proposed that a single Western ISO/RTO could result in up to \$2 billion in annual benefits by 2030. [Another study](#) by the Colorado Public Utilities Commission concluded the state’s utilities could save up to \$230 million annually and effectively meet the state’s clean energy goals through participation in an ISO/RTO.

(For a detailed description of existing ISO/RTOs and other regional markets, see [FERC’s Primer on Energy Markets](#), pages 72-98.)

## Types of Markets

The North American electric grid is sometimes referred to as the “[world’s largest machine](#)”—an interconnected system serving nearly 400 million consumers. It’s a machine that must operate within clearly defined parameters, delivering a product that must be consumed the instant it’s generated. The entire system is predicated upon maintaining perfect balance: supply and demand must always be equal.

So how exactly do electricity and grid services markets meet the demands of this complex machine? This section will explore the various “markets within the marketplace” that enable grid operators to maintain reliable electric service at the lowest possible cost.

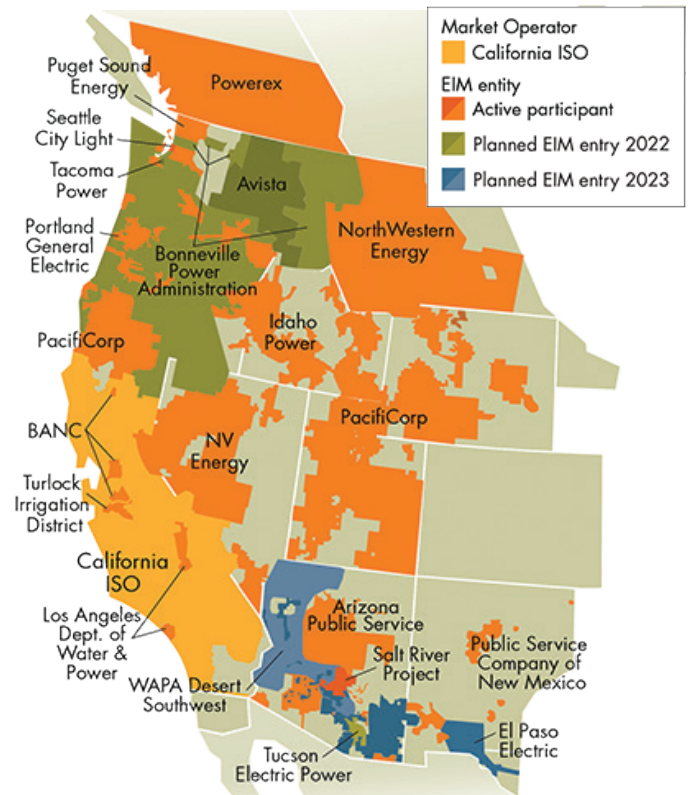
### ENERGY MARKETS

These are the primary markets used to meet daily power demand in ISO/RTOs, determining which resources will be dispatched to supply electricity and which resources are surplus to requirements at any given moment.

While markets are intended to operate on a technology-neutral basis, the reality is that markets are still adapting to the changing resource mix. They have their own policies and structures that require refinement as new technologies change the dynamics and states seek to realize policy goals. In recent years, FERC has stepped in to remove barriers to market access for various new resources, including demand response, energy storage and distributed energy resources.

On the one side, there are load-serving entities—primarily distribution utilities—which submit bids to purchase a certain amount of electricity to serve their customers’ electricity demands. On the other side, power resources—including power plants that supply electricity and demand-side resources that reduce load—submit offers to satisfy that electric load at a certain price. In the middle, the ISO/RTO “clears” the market when the amount of power resources meets the demand for electricity. Every resource that clears the market is then compensated at the highest clearing price, and the power they bid into the market is dispatched into the system and consumed. The resources that didn’t clear—the ones that bid above the clearing price—remain unused and unpaid through that period.

**Fig. 3 — Planned Expansion of Western Energy Imbalance Market**



Source: Western EIM. Images in this section were used with permission from SEEM and CAISO. This authorization does not reflect the endorsement of either organization.

### Two Types of Energy Markets:

1. To satisfy the **bulk of demand** based on load projections for the next day
2. Operated in near real-time to make up for the **differences between projections and reality**.

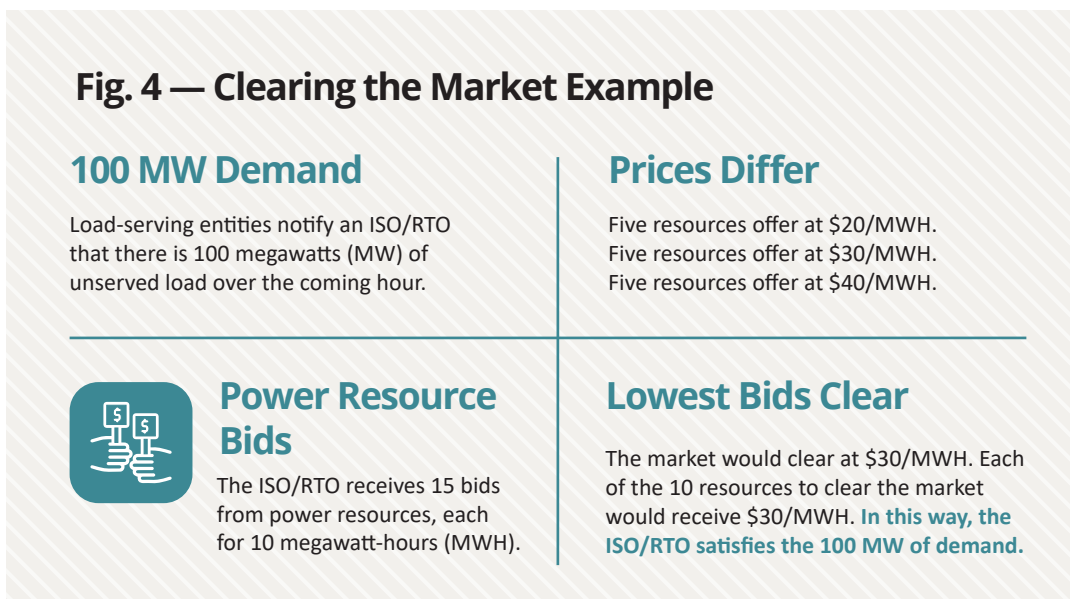
In this way, ISO/RTOs dispatch based on the lowest cost mix of resources needed to reliably meet demand. The greater the demand, the higher the cost of electricity as more expensive resources are dispatched to satisfy demand. When the system is truly strained and nearing its limits, with even reserve capacity running low, ISO/RTOs may implement “scarcity” or “shortage” pricing to substantially increase energy and ancillary service market prices. In doing so, the ISO/RTO signals the need for all quick-start and fast-ramping resources in order to stabilize the system. These price signals—which can reach as high as \$2,700/MWh in PJM or \$9,000/MWh in ERCOT—are often sufficient to incent the development of “peaker” resources, designed to run only during scarcity events.

ISO/RTOs operate two distinct energy markets: one to satisfy the bulk of demand based on load projections for the next day, and the other operated in near real-time to make up for the differences between projections and reality.

### Day-Ahead Energy Markets

Day-ahead markets are exactly what they sound like: they’re markets based on the forecast load for the following day. These forecasts are based on incredibly detailed modeling algorithms that use artificial intelligence and incorporate inputs like weather forecasts and historical usage data to anticipate hourly system demands over the next 24 hours. This information is used to run a day-ahead market for every hour of the coming day, allowing the ISO/RTO to line up ahead of time—or “commit”—the resources necessary to satisfy that anticipated demand.

These forecasts are extremely accurate. A recent analysis based on data from the U.S. Energy Information Administration revealed that ISO/RTO day-ahead hourly projections on average missed real demand by less than 3%, with CAISO and ERCOT off by an average of 2.3% over a six-month timeframe.



### Real-Time Energy Markets

As accurate as these load forecasts are, they’re still forecasts and demand for electricity fluctuates in real-time based on factors that aren’t entirely predictable. For that, ISO/RTOs rely on real-time markets to make up the balance between the day-ahead market’s projections and real-world demand.

Real-time markets operate at five-minute intervals in most ISO/RTOs. Using the same methodologies, markets dispatch additional resources throughout the day to balance the grid and make up for however much the forecasts were off.

## CAPACITY MARKETS

By design, energy markets are competitive. That's normally a good thing. More expensive resources become increasingly uneconomic if they can't reduce costs or survive through scarcity pricing alone. Less expensive resources thrive, leading to lower power costs for load-serving entities and, ideally, lower power bills for consumers.

However, as the nation has witnessed during recent events, it [can be dangerous](#) to focus primarily on lowering system costs without an adequate eye for reliability or resilience. As an essential service that is vital to health, safety and economic activity, government oversight of the power sector has always been designed to ensure reliable service at just and reasonable rates. Unfortunately, reliability and low rates are not complimentary. In fact, they're often at odds with one another. And without the right structures, market operators may unintentionally emphasize low-cost power over system reliability.

This is the idea behind capacity markets, which aim to secure forecast capacity and adequate generating reserves several years down the line. In essence, this is a market to help ISO/RTOs plan for bulk power system requirements, ensuring that longer-term demand projections are reliably met with adequate generating capacity. Depending on the ISO/RTO, the capacity market may be several months or several years ahead. Capacity markets are also intended to incent new resource development by signaling additional system capacity requirements and providing more certainty for those investments through a pathway to recover fixed costs over time.

Capacity markets—or a lack thereof—are where ISO/RTO differences are most starkly apparent. PJM and ISO-NE run capacity auctions to secure capacity three years down the line. Both markets are regional and primarily composed of states that restructured their electricity markets. Meanwhile, MISO and SPP are primarily composed of states with traditional utility regulatory systems. Utilities in these states own generation and primarily use the state-regulated integrated resource planning process to satisfy resource adequacy requirements. MISO operates a voluntary capacity market for utilities to secure the balance of projected demand. SPP does not offer a capacity market; it requires market participants to maintain enough capacity to cover their obligations.

CAISO and ERCOT also don't operate capacity markets. CAISO has established mandatory resource adequacy rules, which require distribution utilities to procure 115% of their aggregate system load every month and obligates those resources to be available. ERCOT, on the other hand, relies on energy market signals to fully compensate existing resources and incent development of new resources. This method relies on the use of scarcity pricing as an incentive to develop resources that will meet peak demand.

## ANCILLARY SERVICES MARKETS

Ancillary services refer to a number of services that are used to maintain reliability in the short-run and support the electric transmission system. These services are supplied and consumed in real time and include the following:

**Regulation:** If the real-time market makes up for the shortcomings of the day-ahead market, regulation services make up for the shortcomings of the real-time market. This service is provided to resources that can respond to the imbalances between load and supply that occur between the five-minute real-time energy market signals in order to maintain a more exacting system balance.

**Reactive Power:** This provides compensation for resources that help the grid operator maintain system current and voltage, either by providing incremental voltage or absorbing voltage necessary to move electricity on the transmission system.

**Operating Reserves:** The purpose of this market is to make up for sudden losses that could cause sudden system imbalances. These are provided to highly responsive generating units or demand-side resources that can either increase output or reduce demand quickly. There are three primary types of reserves:

- *Spinning reserves* are already operating and synchronized with the grid, often with some capacity to spare that can be quickly converted to energy, as needed.

- *Non-spinning reserves* are from resources that are not in operation but can start up quickly (often within 10 minutes) to provide the needed energy within a short amount of time.
- *Supplemental reserves* are resources that may take longer to start up (perhaps requiring up to 30 minutes) and would only be required if spinning and non-spinning reserves were insufficient to respond to the grid's needs.

**Black Start:** These units can restart the power grid in response to catastrophic failures. They can start themselves and deliver electricity without external assistance. Hydroelectric facilities and diesel generators are some of the primary suppliers of this service.

## ENERGY IMBALANCE MARKETS

Imagine a real-time market operator with no authority over transmission. This, essentially, is an energy imbalance market and it's the type of market that's been deployed throughout much of the West. Within these markets, individual utilities do not relinquish autonomy. They still operate their own resources and transmission system, are still responsible for planning for both of those systems.

In practice, these are voluntary platforms through which utilities can buy and sell electricity among the participants, based on their system's needs. For participating utilities, this establishes a more efficient platform for buying or selling excess generation. Depending on how the market is set up, it may also allow IPPs to sell electricity, which some advocates have argued will lead to increased development of lower-cost resources by independent entities.

## How State Policies and Markets Interact

Under the Federal Power Act, states maintain significant authority to regulate companies and rates within their jurisdiction, including authority over retail sales, generation and electric distribution facilities. This offers states several avenues by which they can impose policy requirements on companies that make up the electric sector in pursuit of certain outcomes.

One of the most influential decisions states make is how to regulate the electric sector, whether that's through traditional regulatory constructs or a restructured regulatory approach. While state PUCs and other state agencies implement these policies, the foundational constructs are enacted through state legislation. Lawmakers in at least 23 states and Washington, D.C., enacted legislation to explore or implement electric sector restructuring during the late 1990s and early 2000s. In more recent years, a number of additional states have either commissioned studies to explore the benefits of wholesale energy markets and ISO/RTO participation or directed state-regulated utilities to pursue these options. In 2021, Colorado and Nevada moved to require utilities in those states to join an ISO/RTO by 2030, while Arizona and Oregon are formally exploring the topic.

It's important to note, however, that with regional wholesale markets come certain limitations to state authority—whether by law or practice. Except for ERCOT, FERC has jurisdiction over wholesale electricity markets and transmission in interstate commerce. In some cases, FERC's efforts to promote competition in organized markets has led to conflicts with state policies supporting specific types of resources. The point at which one jurisdiction begins to impede on the other is a matter of considerable debate.

In recent years, much of the debate has centered around state policies aimed at promoting renewable or clean energy resources. Opponents have argued that those resources are distorting wholesale market prices because state-supported resources receive out-of-market compensation—compensation that isn't available to all resources. On the other hand, proponents point out that states retain authority over generation facilities, including authority to promote specific resources.

Ultimately, federal courts have ruled that these policies are not preempted under the Federal Power Act, while also upholding FERC's authority to address whether they distort competitive wholesale market outcomes. Pol-

icies that have withstood legal challenge include state-run programs for renewable energy credits (RECs) and zero emissions credits (ZECs), which were designed to support renewable and nuclear resources, respectively.

However, in *Hughes v. Talen Energy Marketing*, the U.S. Supreme Court ruled that a Maryland program designed to encourage construction of new electric capacity did infringe on PJM wholesale power prices by soliciting proposals and guaranteeing the new resource would earn a certain amount on power sales over a period of 20 years and requiring the plants be bid into PJM’s capacity market.

Most recently, this state-federal conflict came to a head when [FERC ordered PJM in late 2019](#) to expand an existing capacity market program called the “Minimum Offer Price Rule” (MOPR). If implemented, the MOPR order would have required resources that receive state support, such as RECs or ZECs, to bid into PJM’s capacity market at higher, predetermined prices.

The order drew immediate rebuke from a variety of stakeholders, including many states, which argued that the order not only targeted state energy policies but would lead to artificially inflated capacity prices that natural gas and coal units would benefit from. [PJM filed comments](#) with FERC arguing the order was overly prescriptive, needlessly interfered with state policies and “may have paradoxically unintended consequences over time and may result in less economic efficiency.” Some states within the PJM footprint considered legislative and regulatory approaches to limit their exposure to the MOPR by withdrawing from the capacity market. Ultimately, the rule fizzled in 2021, following the change in presidential administration and the appointment of a new FERC chair.

## Conclusion

The electric grid is experiencing a moment of profound change and organized wholesale electricity markets are viewed by some as a means of facilitating this transition through competition. As state policymakers consider new and expanded markets, along with regional approaches to meeting future energy needs more efficiently, it is important to consider how state regulatory structures and programs might play out under these new constructs.

As states in the Southeast and West take a fresh look at organized regional wholesale markets, policymakers will need to consider how existing and future state policies will work within these structures—not only to realize the economic benefits that markets offer, but also to ensure markets enable and enhance state policy goals.

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