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Characterizing US Wholesale Electricity Markets

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ABSTRACT

The purpose of this report is to provide analysts seeking to conduct technoeconomic analysis studies (TEA) on energy systems in US Wholesale electricity markets with a starting point. This document provides an overview of the primary markets related to electricity generation, namely capacity markets and ancillary services markets. The report provides a summary of each of these then provides details on these markets in the context of the seven wholesale electricity markets in the US. The document also summarizes key documents, web resources, and textbooks that will provide useful data and economic understanding for the analyst conducting the TEA studies.

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FIGURES

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ACRONYMS

AGC	Automatic generation control	MISO	Midcontinent Independent System Operator
CAISO	California Independent System Operator	MW	Megawatt
CONE	Cost of new entry	MW-hour	Megawatt hour
CPUC	California Public Utility Commission	MW-year	Megawatt year
DAM	Day-ahead market	NERC	North American Electric Reliability Council
EPRI	Electric Power and Research Institute	NYISO	New York Independent System Operator
FERC	Federal Energy Regulatory Commission	PER	Peak energy rent
Hz	Hertz	PJM	Pennsylvania-Jersey-Maryland Power Pool
ICAP	Installed Capacity Market	PRA	Planning Resource Auction
ISO	Independent System Operator	RPM	Reliability pricing model
ISO-NE	Independent System Operator of New England	RTM	Real-time market
kW-year	Kilowatts per year	RTO	Regional Transmission Organization
LCOE	Levelized cost of electricity	SOI	Show of interest form
LMP	Locational marginal prices	SPP	Southwest Power Pool
LOLE	Loss of load expectation	USD	United States dollars
LRA	Local regulatory authority	VRR	Variable resource requirement
LSE	Load serving entity	WEIM	Western Energy Imbalance Market

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Characterizing US Wholesale Electricity Markets

1. Introduction

The purpose of this document is to provide an overview of electricity markets in the United States so that researchers evaluating new technologies like load response and energy storage can ascertain where these new technologies may play a role. The intent is that the guide acts as resource for analysts who conduct technoeconomic studies of these markets. To accomplish that purpose, the document provides background on capacity markets and the ancillary services market. Then the report describes these in the context of the seven, geographically different wholesale energy markets in the US. These summaries provide the analyst with a sense of how each of these different regional markets value the energy services exchanged therein. The summaries also include, where possible, information on parameters and constraints that pertain to participants in each market.

In the US, roughly one-third of the population receives electricity services from what the industry refers to as "traditional" electricity markets. These are markets that are vertically integrated; a single firm (i.e., a utility) owns the assets for electricity generation, transmission, and distribution. Shown in Figure 1, these areas include a large sector of the Northwest, the Southwest, and the Southeast. Two-thirds of the country receives energy services from a regional, competitive electricity market run by what is called an Independent System Operator (ISO) or Regional Transmission Organization (RTO) (Hytowitz, Ela, Kerr, & Bernhoft, 2020). Data summaries provided in this report do not make distinctions between ISOs and RTOs, hence they are ISO/RTOs. Beginning in the left of the figure, these include the California Independent System Operator (CAISO), the Electricity and Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP), the Midcontinent Independent System Operator (MISO), Pennsylvania-Jersey-Maryland Power Pool (PJM), the New York Independent System Operator (NYISO), and the Independent System Operator of New England (ISO-NE).

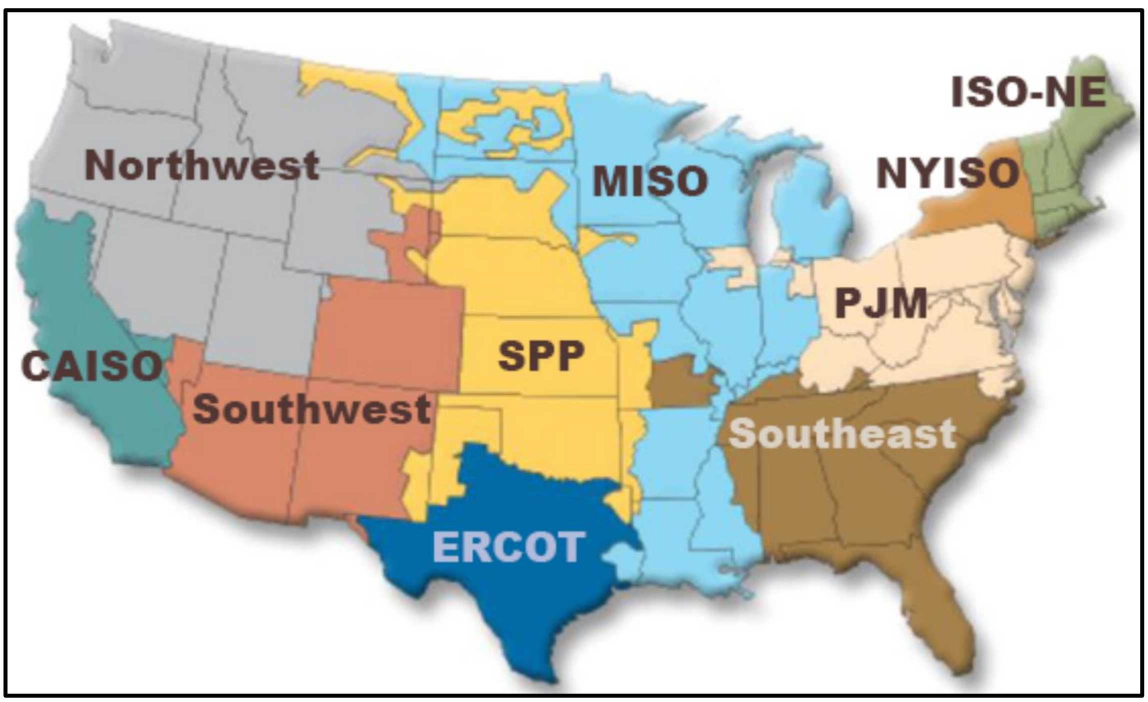


Figure 1 US Electric Power Markets (FERC, 2020a)

In each of these markets electric power is generated and distributed to end-use customers in a fashion like that shown in Figure 2. The major components of the system are generation (power plants that generate electricity), transmission (infrastructure that delivers power across the system), and distribution (infrastructure that delivers power from the transmission grid to retail customers). In vertically integrated systems, a single firm owns and operates these three infrastructure types while in an ISO/RTO that is not the case. Instead, in ISO/RTOs generating capacity can be owned by the Load Serving Entities (LSE) within the system or by merchant generators who own the generation capacity. An LSE can be thought of as the utility who is responsible to receive power from the transmission grid and then distribute it to end-use customers in sectors such as residential, commercial, industrial, and institutional. Load is another term for electricity demand. A merchant generator is an investor-owned generating asset whose primary (in most cases only) purpose is to generate electricity. The ISO/RTO, strictly, does not own generating capacity. The ISO/RTO is responsible for balancing electricity supply with demand. It can also be the case that a generation owner could own multiple generating technologies.

The focus of this report is on information pertinent to technoeconomic studies related to load response and energy storage, so this directs attention to the capacity and ancillary services in each ISO/RTO. However, before leaving them altogether, vertically integrated systems warrant a few words. At one time, the predominant market structure for a system like that in Figure 2 was that of monopoly where a single firm owned and operated a vertically integrated system. That is, the single firm owned and operated all the assets used to generate electricity, transmit it, and distribute it to the final customers. In this arrangement prices resulted not from competitive market forces but instead resulted from what economists call "natural monopoly pricing" which requires rate-of-return regulation on the part of a state regulator (Viscusi, Harrington Jr, & Vernon, 2005) to represent end-use consumer interests. A public utility commission in the states wherein the utilities operate regulate these systems. The firm negotiates with the regulator an allowable percentage mark-up on the prices charged to final customers and must present a "rate case" for any changes to authorized prices.

The single ownership nature of a vertically integrated system means that within a utility, the utility itself can balance demand from retail customers by managing its generation capacity. The utility can "ramp up" or "ramp down" (increase or decrease) electricity generation from the assets it owns. It also means that if the utility needs additional generation then it can engage in bilateral contracts with other utilities to procure generation. That is, vertically integrated utilities can exchange electricity with each other outside of a formal market. Utilities often purchase electric power from federally owned electricity generation such as the Bonneville Power Administration, the Tennessee Valley Authority, and the Western Area Power Administration (FERC, 2020b).

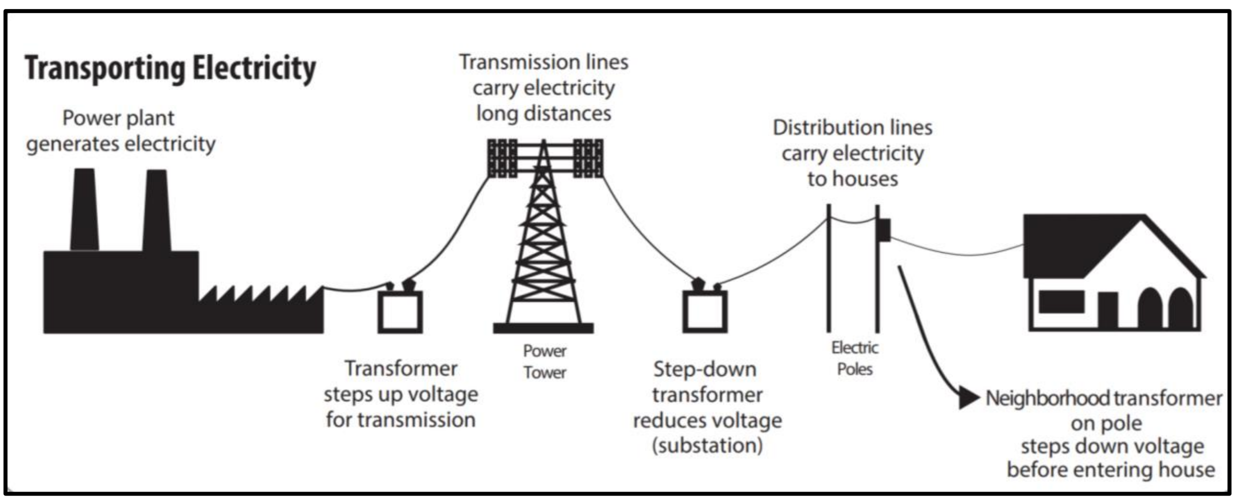


Figure 2 Electricity System Schematic (NEED, 2020)

Because utilities in these systems can balance energy needs with assets owned by the utility, vertically integrated utilities do not need a market for energy, a market for capacity or for ancillary services. Until the market-oriented reforms of the late 20^{th} century, this was the case for most electric power systems in the country. But the market-oriented approach of de-regulation such as selling off generation capacity to merchant generators changed the incentives and rules of the game (Zweifel, Praktiknjo, & Erdmann, 2017). The business decision-making criteria of the profit motive changed the incentives under competition.

In the late 20^{th} Century this market structure evolved to distributed generation. With this development, a single firm no longer owned all assets from generation to distribution. Instead, independent firms took ownership of the generation assets, municipalities and other entities took ownership of distribution services, and a single operator retained ownership and management of the transmission infrastructure. The literature has many studies that describe this market evolution, the details of which are beyond the scope of this report. But this evolution directly impacts how electricity markets function today.

Now, in de-regulated systems where market forces of supply, demand, and price signals allocate electric resources, ISO/RTOs operate markets for energy, capacity, and ancillary services that a system operator needs to balance and maintain grid reliability. In Figure 2 this means that ISO/RTOs manages the transmission infrastructure while ownership of the generating capacity is by a variety of ownership structures competing to offer services to the system operator. Thus, the focus of the report is on the market characteristics where system operators run the markets and generators compete.

Turning now from vertically integrated electricity markets to de-regulated, competitive markets calls for a brief note on terminology. US de-regulated markets operate in what is called a two-settlement system. The first part of the settlement occurs in the Day-Ahead Market (DAM) and the second settlement occurs in the Real-Time Market (RTM). The settlement is to settle the purchase and sales of electricity. The DAM operates 24 hours before the operating hour and the RTM operates one hour before the operating hour, but there are also RTMs that operate 15 minutes and 5 minutes before the operating hour.

The DAM can be thought of as a scheduling mechanism. The ISO/RTO runs a uniform price auction. This means that the generators submit offers to generate electricity at their marginal cost of production. The marginal cost varies across generating technology types. The market operator orders the offers that generators submit from least to greatest. The result is what is called the "bid stack." In economic terms this is the electricity supply curve. Then, based on the ISO/RTO forecast for electricity demand (load), the ISO/RTO market operator notifies the generators of the outcomes of their supply offers. The generators are then scheduled to operate at specified times during the following day. So then why is a RTM needed? The forecast for demand for one hour out is more accurate than the demand forecast 24 hours out. The RTM is used to make adjustments to the schedule that results from the DAM. The RTM is used to "adjust" so that the supply-demand balance can be maintained.

In the DAM and the RTM the prices that result are called locational marginal prices (LMPs). The LMPs are location dependent because in each ISO/RTO there are many nodes that represent where generators are located. Electricity must travel across a grid, and the grid represents a constraint that separates the ISO/RTO into many different load zones. So DAM and RTM results occur for each load zone in the ISO/RTO. If there were not transmission constraints then a single, LMP electricity price would result. As electricity moves around the ISO/RTO, across transmission constraints, variation in LMPs gives rise to what is called "congestion costs." This aspect of electricity markets is outside the scope of this report.

To summarize, DAMs schedule generators to supply electricity 24 hours out. RTMs provide for adjustments to the schedule from the DAM on an hourly basis, a 15-minute basis, or a 5-minute basis. So then how does the grid operator account for supply-demand imbalances on less than the interval accounted for in the RTM? The grid operator uses ancillary services.

At a high-level, one can think of ancillary services as those services the grid operator can call upon to maintain grid reliability. These services include “black start” services which represent the capability of a generator to start up generation capacity independent of electricity from the grid. Compensation for black start services are typically arranged in a direct exchange between the owners of generation capacity and the grid operator. But there are ancillary services that are exchanged in markets. These are called regulation reserves, spinning reserves, and non-spinning reserves. Regulation reserves have to do with control of the frequency on the grid, and the grid operator can call upon these (instantaneously) from generators. Spinning reserves, also called synchronous reserves in some ISO/RTOs, refer to excess capacity the generator has to increase or decrease the amount of electricity provided to the grid. The spinning or synchronous aspect of the term means that the turbines in the generating capacity are “spinning” or “synchronized” with the grid at 60 Hertz (Hz). Non-spinning reserves mean that the generator can generate additional electricity within a specified time frame, but the turbines are not spinning in synch with the grid at the time the grid operator calls upon the generator.

The ISO/RTO grid operator maintains the supply-demand balance to ensure grid reliability today and into the future. But DAM and RTMs result in prices and allocations of electricity in the very near term. So what incentivizes construction of new generating capacity to meet demand in future years? Four of the seven ISO/RTOs run what is called a “capacity market” to procure generating capacity in as far out as three years. The ISO/RTOs that do not operate a capacity market use other means for ensuring generating capacity in future years.

Recently, researchers at the Electric Power and Research Institute (EPRI) completed a study wherein they reviewed these three categories of markets on an economic basis. Table 1 shows data from their study. Although the data are from 2018, the table reflects a relative comparison of the value of electricity services across the ISO/RTOs. The authors note that due to factors such as weather, fuel price fluctuations and policy changes these values change yearly. But relative comparison shows how the markets compare across the country. PJM is the largest market because of its large market for energy and capacity. MISO has the smallest capacity market of those regions that have such a market, but it has a relatively large energy market because of the large geographic region that it covers. All ISO/RTOs have a market for ancillary services but by comparison, this market is smaller than the energy market.

Table 1 Data (2018) on total financial settlements (Hytowitz et al., 2020)

ISO/RTO	Energy ($B)	Capacity ($M)	Ancillary Services ($M)
CAISO	10.6	N/A	189
ERCOT	13.4	N/A	603.5
ISO-NE	6.0	3,600	130.9
MISO	21	431	70.5
NYISO	6.38	1,800	491
PJM	29.61	11,000	654
SPP	7.5	N/A	76

In the sections that follow, the report will provide background information and the approach adopted to generate the report. Then the report discusses the market for capacity markets and for ancillary services. Each of these market sections provides a brief background then a characterization of that market in each ISO/RTO follows. Then the report summarizes and concludes. The following two tables provide a preview to the data summaries contained in each section.

Table 2 Capacity Market Summary

ISO/RTO	**Length of contracting period**	**Average Capacity Prices and CONE[1/]**
CAISO	1-year forward contract	Average Capacity Price: \$100/MW-hour CONE: \$208/MW-day
ISO-NE	3-year forward contract	Average Capacity Price: \$9.63/MW-hour CONE: \$309.59/MW-day
MISO	3-year forward contract	Average Capacity Price: \$1.27/MW-hour CONE: \$257.53/MW-day
NYISO	30-day delivery contract	Average Capacity Price: \$5.04/MW-hour Net CONE: \$366.94/MW-day
PJM	3-year forward contract	Average Capacity Price: \$7.17/MW-hour Net CONE: \$285.5/MW-day
SPP	Incrementally as needed	Average Scarcity Price: \$439/MW-hour[2/] Average Make-whole Payment: \$0.22/MW-hour (DAM), \$18.94/MW-hour (RTM) [2/] CONE: \$234.55/MW-day

Source: author summary of Section 3

1/ Cost of New Entrant; 2/pricing used to incentivize capacity that does not result from a capacity market.

Table 3 Ancillary Services Summary (Average $/MW-hour, Requirement)

ISO/RTO	Spinning	Non-Spinning	Regulation
CAISO	3.61 10-minute response Min run time 2 hours	1.02	7.57 Immediate Response
ERCO	12.12 Response within minutes Min run time 4 hours 2 MW/min, up 3 MW/min, down	4.50 Response within 30 minutes Min run time 1 hour	8.5 Immediate Response 3 MW/min, up 4 MW/min down
ISO-NE	4.66 10-mintue response 1 MW/min up/down	26.63 10 to 30 minute response	18.38 Immediate Response
MISO	1.74 10-minute response	0.23 10-minute response	8.81 Immediate response, full response within 5 minutes
NYISO	3.61 10-minute response	3.08 10 to 30-minute response	6.07 Immediate response, full response within 5 minutes
PJM	3.17 10-minute response	8.11 10-minute response	13.47 Immediate response, 0.1 MW min response
SPP	5.36 10-minute response	0.73 10-minute response	7.28 Immediate

Source: author summary of Section 4

2. Background and Approach

Economic theory asserts that a market is the total of buyers and sellers in a defined geography. Buyers, who want things, demand goods and services and make choices to maximize their value from the goods and services in the market. Sellers, who have things to sell, offer their goods and services to the market because they are profit motivated. When buyers and sellers exchange goods and services then the trade creates value for each, so the theory goes. These basic concepts apply to wholesale electricity markets, like they do for any other market. And, like other markets, electricity markets are dynamic with adjustments to structure over time that impact the incentives and motives of market participants.

In market terminology, the generators are the suppliers of energy, capacity and ancillary services and the buyers are the grid operators who operate the transmission infrastructure. LSEs are also buyers in these markets because in a few cases LSEs are the entity required to secure reserve capacity. But there is an addition to standard economic terminology. Those who operate the distribution side of the system can also provide services to the grid operator. For example LSEs have *demand side resources* that grid operators can use to balance load. The grid operator balances the supply-demand dynamics. The operator can call upon generators to increase or decrease the production of electricity, but they can also call upon operators of the distribution side of the system to increase or decrease demand.

Grid operators at the ISO/RTOs value flexibility to balance load and to ensure reliability (Hytowitz et al., 2020). Flexibility is the ability to adjust supply and demand to adapt to the expected and unexpected changes in the system at different points of time. Value in flexibility also means the ability to provide other services the system needs for reliability, such as operating reserves, regulation reserves and capacity. In the electricity markets those who can offer flexibility respond to incentives from price signals received from various market mechanisms such as auctions and exchange markets, or those who have flexibility services can be mandated by grid operators (Hytowitz et al., 2020).

In the ISO/RTOs, operators ensure non-discriminatory access to the grid as well as procuring services for energy, capacity, and ancillary services to balance supply-demand dynamics. All US ISO/RTOs operate a two-settlement system composed of day-ahead-markets (DAM) and real-time-markets (RTM) (Hytowitz et al., 2020). Within these markets ISO/RTOs operate exchange for ancillary services used to ensure system reliability. Some of the ISO/RTOs use forward markets to procure system capacity.

The data summaries that follow are composed of information from two primary sources. In each ISO/RTO a market monitor conducts an annual report and evaluation of the markets operating therein. These reports constitute a valuable source of current information for each market operated within the ISO/RTO. Additionally, each ISO/RTO provide data on the capacity and ancillary services markets operated therein. Because the primary purpose of this report is to provide the analyst with a reliable starting point for technoeconomic studies, it provides links to these important resources.

The annual reports summarize the performance of each of the markets in each ISO/RTO. They provide information on the volume and value of each market. The links to the data repository take the analyst to the place where each ISO/RTO provides public access to the data generated. The analyst can find data on energy markets, capacity markets and ancillary services markets at each location, among other available data.

Table 4 Links to annual report and data repository by ISO/RTO

ISO/RTO	Annual State of the Market Report	Data Repository
CAISO	http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf	http://oasis.caiso.com/
ERCOT	https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-State-of-the-Market-Report.pdf	http://www.ercot.com/mktinfo
ISO-NE	https://www.potomaceconomics.com/wp-content/uploads/2020/06/ISO-NE-EMM-2019-Report_Final.pdf	https://www.iso-ne.com/markets-operations/iso-express
MISO	https://cdn.misoenergy.org/2019%20State%20of%20the%20Market%20Report453426.pdf	https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#t=10&p=0&s=MarketReportPublished&sd=desc
NYISO	https://www.nyiso.com/documents/20142/2223763/NYISO-2019-SOM-Report-Full-Report-5-19-2020-final.pdf/bbe0a779-a2a8-4bf6-37bc-6a748b2d148e	https://www.nyiso.com/energy-market-operational-data
PJM	https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume1.pdf https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume2.pdf	https://www.pjm.com/markets-and-operations
SPP	https://spp.org/documents/62150/2019%20annual%20state%20of%20the%20market%20report.pdf	https://marketplace.spp.org/

Source: author compilation of web data sources

In addition to these documents and data repositories, there are a few key textbooks on energy economics and energy markets that will serve the analyst well. Although there is much in these texts that the analyst will find useful, the list here shows the relevant sections and chapters noted.

- Biggar, D. R., & Hesamzadeh, M. R. (2014). The economics of electricity markets: John Wiley & Sons.
    - Part IV Efficient Investment in Generation and Consumption Assets
    - Part V Handling Contingencies: Efficient Dispatch in the Very Short Run
- Brewer, J., Lin, S., Prica, M., Wallace, R., Shirley, P., & Logan, C. E. (2019). Power Market Primers. Retrieved from https://www.netl.doe.gov/projects/files/Power%20Market%20Primers%20Rev%2001.pdf
    - Chapter 4 Capacity Market
    - Chapter 6 Ancillary Services
- FERC. (2020). Energy Primer: A handbook for energy market basics: Federal Energy Regulatory Commission.
    - Chapter 3 Wholesale Electricity Markets
    - Chapter 5 Financial Markets and Trading
- Stoft, S. (2002). Power System Economics: Designing Markets for Electricity, Wiley-IEEE Press http://dx. doi. org/10.1109/9780470545584.
    - Part 1 Power Market Fundamentals
    - Part 3 Market Architecture

3. Capacity Market

Among commodity markets in general, the notion of a capacity market is unique. Standard economic theory suggests that that the price of the commodity reflects the cost of its production. That is not the case for energy products. Due to restructuring of electricity markets, and the introduction of market competitiveness as opposed to rate-of-return regulation, energy prices typically reflect the variable cost of production, not the fixed cost. That means that resource owners who collect revenue to cover only variable costs are left short of collecting sufficient revenue to cover fixed costs. This is known as the "mission money" problem in the industry and later in this section a brief example illustrates this. But capacity markets have another function in the set of energy markets, they are often used to correct for market distortions that occur from well-intentioned (albeit distorting) policies in energy markets (Blumsack, 2020).

Because of market distortions in energy markets, capacity markets serve the important function of signaling to industry when the ISO/RTO needs new capacity investment. They also serve as a key mechanism to maintain system reliability and resource adequacy (Brewer et al., 2019). The North American Electric Reliability Council (NERC) sets standards that grid operators, generators and utilities must agree to regarding reliability. These requirements, and NERC specifically, came about due to the large blackouts in the country during the 1960s (Blumsack, 2020). NERC requirements call for "resource adequacy" or sometimes called "installed capacity margin" to shore up system reliability.

Except for ERCOT, all ISO/RTOs have a resource adequacy requirement (Hytowitz et al., 2020), although they are not all set in the same way. For example, in CAISO a state regulatory authority imposes the reliability requirement on LSEs in the state while in other markets such as ISO-NE the ISO/RTO grid operator sets the installed capacity margin.

Notwithstanding a regulatory requirement, owners and operators of generating capacity yet need a financial incentive for providing capacity to the market or else economics will drive them out. This is especially the case because revenue from energy and ancillary services is not always sufficient to keep generation capacity economically viable. The volatility in locational marginal prices (LMP) prices greatly enhances this problem. The second factor stemming from the energy market is that, due to the power crisis in California, price caps in the energy market preclude generators from taking advantage of scarcity pricing as a source of revenue. Although some ISO/RTOs are considering increasing price caps in the energy markets, the standard has been for some time $1,000/MW-hour. Blumsack (2020) describes the important financial role that capacity markets carry out for generating capacity because once capacity is committed (cleared a market) the generator receives compensation regardless of whether the generator actually produces electricity or not.

Blumsack (2020) provides a simple example to illustrate the missing money problem. Suppose an ISO/RTO needs an additional 100 MW of capacity and that it will operate with a 1 percent capacity factor (e.g., gas-peaker plant). The levelized cost of electricity (LCOE) of the plant is $1,005/MW-hour. The energy price cap is $1,000/MW-hour. Economically, plant owners would never build such a plant when its costs exceed expected revenue. Capacity markets are designed to solve this problem by providing an additional revenue source to generator owners.

For ISO/RTOs operating a capacity market, there is variation in how these markets are set up. But the variation can be confined to three basic parameters. ISO/RTOs differ in their approach to modeling capacity demand. Brewer et al. (2019) summarize these. Some use a perfectly inelastic demand curve (vertical) while others use a downward sloping demand curve. There are differences in how ISO/RTOs run the capacity auction. Auction mechanisms include descending clock, sealed-bid and second-price auctions (Hytowitz et al., 2020). Most use optimization while one (ISO-NE) uses a descending clock auction. There is also variation in the length of contractual period. Some auctions are for capacity a few months out while in other ISO/RTOs the commitment period is out a few years (Brewer et al., 2019).

Price auctions in the capacity market work much the same way as the auctions in energy markets. Those resource owners with capacity submit bids to the ISO/RTO who then puts the bids into merit order, from smallest to largest, to form the capacity supply bid stack (Blumsack, 2020). The ISO/RTO then compares the bid stack with the demand for capacity. The intersection of the two curves finds the market clearing price. All capacity owners who submitted bids below the market clearing price are said to have "cleared the market" and they are those who obtain the capacity commitments for some future period; it can be as little as 3 months up to as long as three years (Brewer et al., 2019). When the capacity market clears then the capacity equal to the pre-determined capacity requirement is secured.

Like the energy market where a price cap exists, the ISO/RTO determines the price cap for the capacity market. It sets the cap equal to the CONE, i.e., the cost of new entry. The CONE reflects the cost for the marginal unit of generating capacity. In other words, the CONE is the cost for the highest price capacity to clear the market. Typically, the generating technology associated with the CONE for a capacity market is a gas-fired power plant. Net CONE, which varies by generating technology, is the quantitative measurement of how much the generator needs to be paid for capacity for the generator to remain economically viable. Mathematically, the Net CONE = CONE – revenue from energy products. A helpful example from Blumsack (2020) illustrates these different levels of cost.

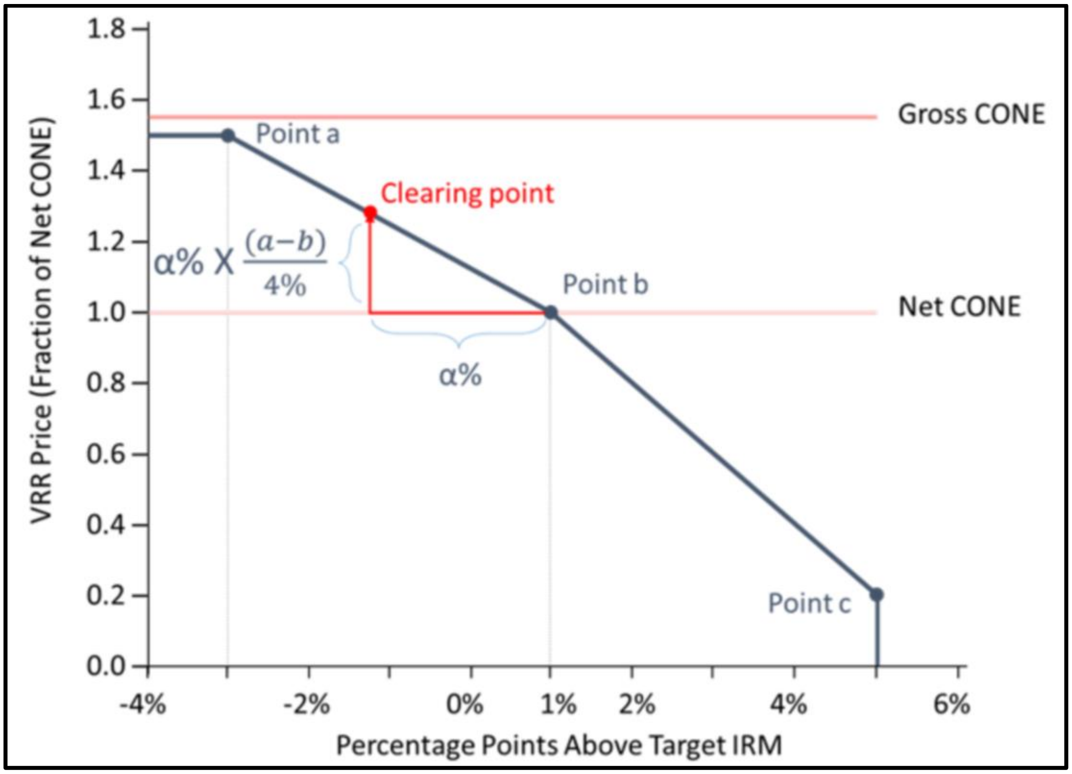


Figure 3 Capacity demand curve in the PJM market (Blumsack, 2020)

The red line indicating Gross CONE is the price cap for the capacity market. It reflects the cost, typically in USD/MW-year, that new generation capacity using a gas-fired power plant would need to receive to be economically viable. Recall the earlier example used to describe the missing money problem. A plant that is used about 1 percent of the time will not receive much revenue from the energy market or the ancillary services market. So, for that generator to be economically viable, it would need compensation equal to its cost of providing an additional increment of capacity.

The horizontal axis indicates percentage levels above and below the installed capacity requirement. The level indicating 0% is the level equal to the requirement. The Net CONE listed shows that 1% above the installed capacity requirement is attained. This value represents the highest bid in the merit order bid stack for capacity. It is the price that clears the capacity market. The generator with the Net CONE is made economically whole because the Net CONE covers the fixed costs of providing capacity that the generator's energy revenue does not cover.

In this example the demand curve for capacity slopes downward. Not all capacity markets have downward sloping demand. Some ISO/RTOs use a vertical demand curve. The argument in favor of using a downward sloping demand is one of reliability. Demand like this allows the ISO/RTO to secure generation capacity according to the marginal value it provides to the system. In the example, capacity above 5% of the requirement provides no additional value to the system and the prices reflect this, thus sending a signal to generators that no additional capacity is needed. Such a demand curve is consistent with a variable capacity resource requirement (Brewer et al., 2019). Another way to think about this is that when the demand price is above Net CONE then installed capacity is less than the requirement. Conversely, when the demand price is less than Net CONE then installed capacity exceeds the requirement.

Brewer et al. (2019) indicate that the advantage of the vertical demand curve is that it is simple to implement. Trade this off against the fact that with a vertical demand curve the system procures only the requirement, no capacity beyond that level is attained. Thus, although a vertical demand is easier to implement it does not yield the system reliability that does a downward sloping demand curve.

The following subsections provide an overview of each of the ISO/RTOs, except for ERCOT which does not have a resource adequacy program.

3.1 Resource Adequacy in CAISO

The Resource Adequacy Program, the program that deals with capacity requirements in CAISO, has as its point of beginning an assignment from a state regulator, the California Public Utility Commission (CPUC) or a local regulatory authority (LRA), for a requirement assigned to a LSE in the ISO. The purpose of the Program is to ensure the system has sufficient resources to operate the grid safely and reliably while at the same time providing incentives for siting and construction of new resources (CAISO, 2020a). LSEs are made up of investor owned utilities (66%), community choice aggregators (18%), municipal entities (9%), and direct access providers (7%) (CAISO, 2020a).

The regulator imposes on the LSE a requirement based on forecasted peak load undergirded by one to two years of historical data (Brewer et al., 2019; CAISO, 2020a). Then added to this forecast is 15% of peak load. Once the LSE has the requirement, it is up to the LSE to procure the required capacity reserves. On an annual basis, the LSE is required to have procured 90% of peak demand during the 5 months of heaviest load. On a monthly basis, the LSE must have procured 100% of the requirement. The sum of LSE capacity requirements is what is referred to as the Resource Adequacy Capacity. This process, of LSEs finding capacity based on regulator-imposed requirements, occurs on a year ahead timeframe.

The LSE has options from where to procure capacity. The LSE can self-schedule capacity reserves, it can procure reserves from the ISO, or it can procure reserves outside of the ISO. For capacity reserves other than self-scheduled, these can be purchased in either the DAM or the RTM. In these markets the buyers and sellers are LSEs and generators, respectively. There are three types of capacity resources exchanged in these markets: system reserves, local reserves, and flexible resources. In 2019, there was more capacity available, 116% in the DAM and 101% in the RTM, than what was required creating a tight capacity market (CAISO, 2020a). For capacity resources outside of the ISO, prices averaged $100/MW-hour.

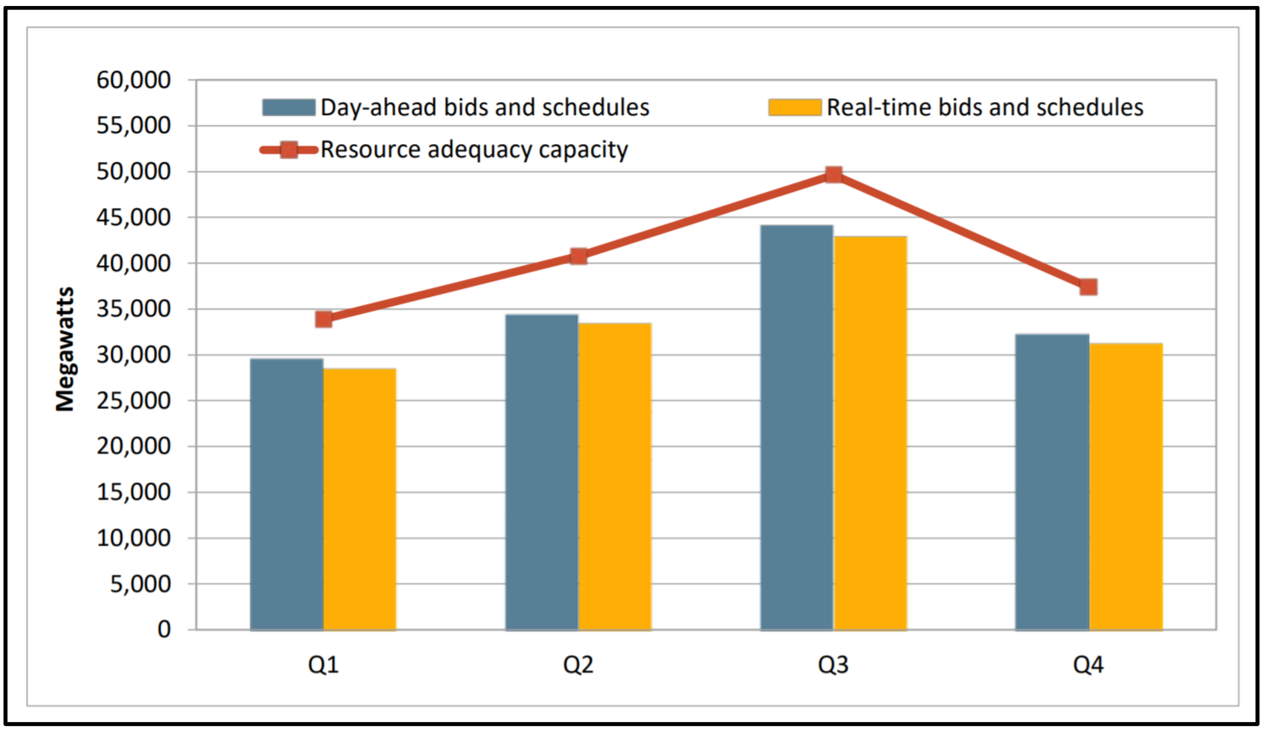


Figure 4 Quarterly resource adequacy capacity scheduled and bid into ISO markets 2019 (CAISO, 2020a)

Figure 4 and Figure 5 show a sense of the volume and value of the Resource Adequacy Program in CAISO. Figure 4 shows that in 2019, on average, capacity requirements were less than what was available. The red line indicates the capacity level that the regulators set as requirements on the LSEs. The columns indicate what was procured, i.e., what the system needed, in the DAM and the RTM. The third quarter of 2019 showed the highest capacity requirement as well as what was exchanged. The figure also shows that a slightly smaller amount of capacity was exchanged in the RTM than in the DAM.

Figure 5 shows the trend of volume and value from 2017 through 2019. The bars in the figure show the volume of imports that the LSEs either self-scheduled or for which an economic bid was placed. These are data from the DAM. The data show that the volume of bids increased in 2019 over 2018 but prices declined. In the first quarter of 2019 prices were at $200/MW-hour and then declined over the rest of the year, to levels not seen since 2016.

CAISO reports the cost of new entry differently than other ISO/RTOs. It uses a backstop capacity soft offer cap, which is analogous to the Gross CONE in Figure 3. In the 2019 report, that estimate is $76/kW-year, which translates to $208.23/MW-day. (CAISO, 2020a).

To access data on the economic bids for different reserves, the analyst can access http://oasis.caiso.com/ then select 'Energy'. There the user can find data on the Resource Adequacy Program, including ramp rates selected for participation.

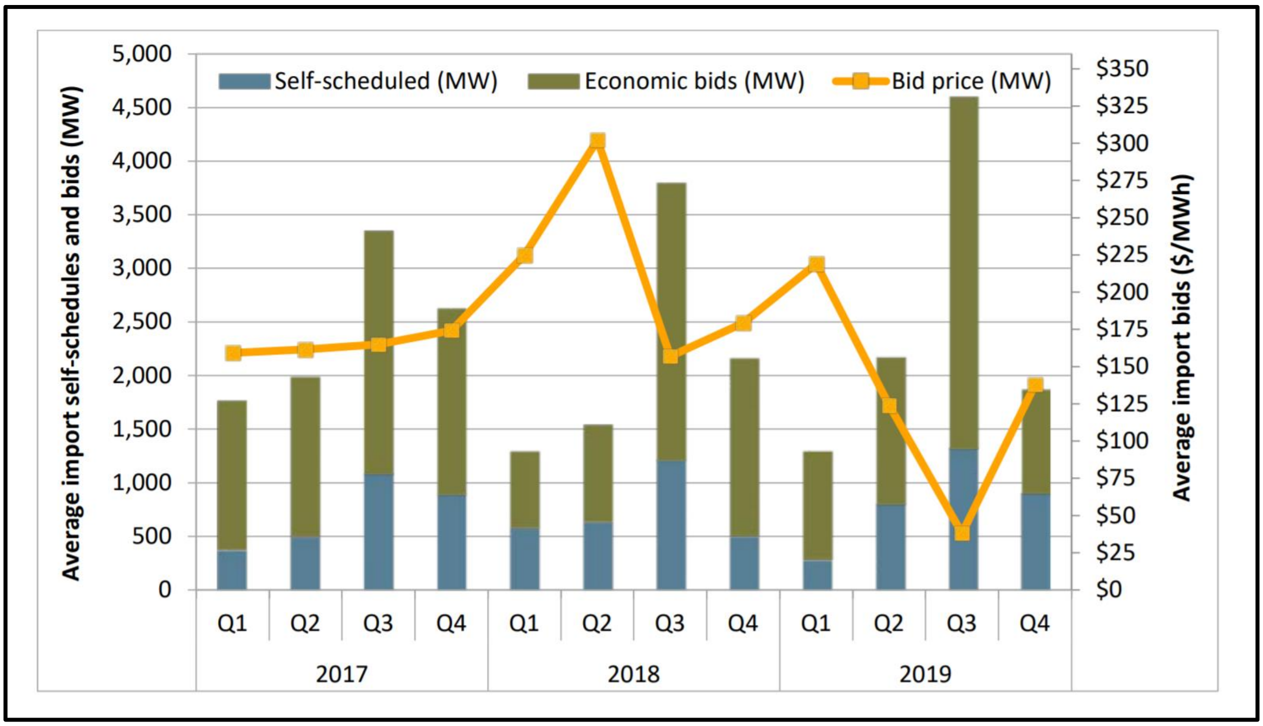


Figure 5 Resource adequacy import self-schedules and bids (CAISO, 2020a)

3.2 Forward Capacity Market in ISO-NE

ISO-NE runs a three year forward capacity market (FCM) annually (Brewer et al., 2019). The ISO computes an installed capacity requirement at the level of the system and for zones within the system then uses the FCM to commit resources to meet the requirement. The forward market includes a two-stage capacity auction where in the bidders are supply-side and demand-side resources. The requirements to participate in the auction vary based on existing resources versus new entrant. ISO-NE uses a descending clock auction to clear the market. In it the ISO reconciles an offer-based supply curve with a vertical demand curve (Brewer et al., 2019).

The first stage of the forward capacity market is a form of a uniform price called the clock-descending auction, and it is composed of several rounds. At the beginning of each round the auctioneer announces a range of prices bracketed by "start-of-round" prices and "end-of-round" prices. Then, while a clock countdowns allowable time to submit bids, resources submit bids within that range. After each round, an amount of capacity is listed so that as rounds progress there is a descending level of capacity that corresponds to a descending level of prices. The target level of capacity is based on system level requirement. Table 1 shows hypothetical results from one of these auctions. Once the auction reaches a point where results by round no longer yield surplus capacity (round 6 in this example) then the auction moves to the second stage of the Forward Capacity Market.

Table 5 Sample Results from a Descending-Clock Forward Capacity Auction (ISO-NE, 2014)

Round	Start-of-Round Price ($/kW-mo)	End-of-Round Price ($/kW-mo)	End-of-Round Resource (MW)	Excess Capacity (MW)
1	$15.00	$9.50	38,000	8,000
2	$9.49	$9.00	32,500	2,500
3	$8.99	$8.00	32,000	2,000
4	$7.99	$7.50	31,000	1.000
5	$7.49	$7.00	30,750	750
6	$6.99	$6.00	29,800	−200

All the resources that bid into the market successfully for Round 6 move to the second phase. In the second stage software is used to minimize the cost to the system for bids remaining in Round 6. The software computes the number of reserves required from each of the remaining market participants and the associated capacity price.

The supply curve results from sequentially aggregating capacity offers from generators and demand side resources. Resource types used in the market include existing generators, planned generators, imports from outside the ISO, and demand resources such as load management, energy efficiency and distributed generation.

Resources eligible to participate in the auction example listed above includes supply resources and demand resources. Capacity payments are paid according to auction clearing price of each round. But there is a provision to the capacity price that has to do with shortage events called *Peak Energy Rent* (PER). If it turns out to the case that when the committed capacity is called upon the energy price exceeds the capacity price then the PER reduces the capacity price because the resource becomes eligible for the higher energy price. The PER is typically used when energy demand is high relative to predicted demand. The PER also discourages market manipulation because generators who hold out on capacity in order to take advantage of higher energy prices are not allowed to do so. The PER is also used to assess penalties to resources if the resource is unavailable during a period of committed performance (ISO-NE, 2014).

Participation requirements differ for new versus existing resources. Requirements also differ for supply-side resources versus demand-side resources. For existing supply resources, the ISO relies on five years of historical data on winter and summer capacity. For existing demand-resources the ISO relies upon the data from the previous year's capacity auction. The ISO assigns requirements to existing resources but existing resources can choose to opt-out of the capacity market by submitting an application to the Independent Market Monitor who then evaluates the application based on the resource's opportunity cost and going-forward costs (ISO-NE, 2014).

New resources wishing to participate in the Forward Capacity Market must apply to the ISO. The ISO intentionally sets financial barriers low to facilitate new entrants, but it rigorously reviews the application package. The new entrant must submit a show of interest form (SOI). The SOI requires supply side resources to show the interconnection point, equipment configuration and capacity in MW. The application must be submitted eight months in advance of the Forward Capacity Market. The ISO requires evaluation tests of supply-side resources, including verification of no impact to safety and reliability of the grid, and verification of no adverse impacts to other generators. The ISO requires of demand side resources a feasibility review that ensures plans and methods for reducing electricity demand and consistent with industry standards (ISO-NE, 2014).

Once the application package is accepted, the new entrant is given a stated price known as the offer-review-trigger price (ORTP). This is the price up to which the new entrant can remain in the forward capacity auction. If the auction price falls below the ORTP assigned to the new entrant then the entrant must leave the market. However, there is a provision by which the new entrant can petition the market monitor for an exception. The criteria is that the new entrant's price is consistent with the long-term average for the relevant technology.

Figure 6 shows the net revenues for a combustion turbine (CT – 7HA) and wind technologies in ISO-NE compared to other markets. The black line illustrates the cost of new entrant (CONE). The CONE has the same interpretation as the ORTP. For ISO-NE, the 2018/2019 average capacity price was $9.55 per kW-month and then fell to $7.03 per kW-month for 2019/2020 (Patton, VanSchaick, Chen, & Naga, 2020a). The Net CONE is $8/kW-month.

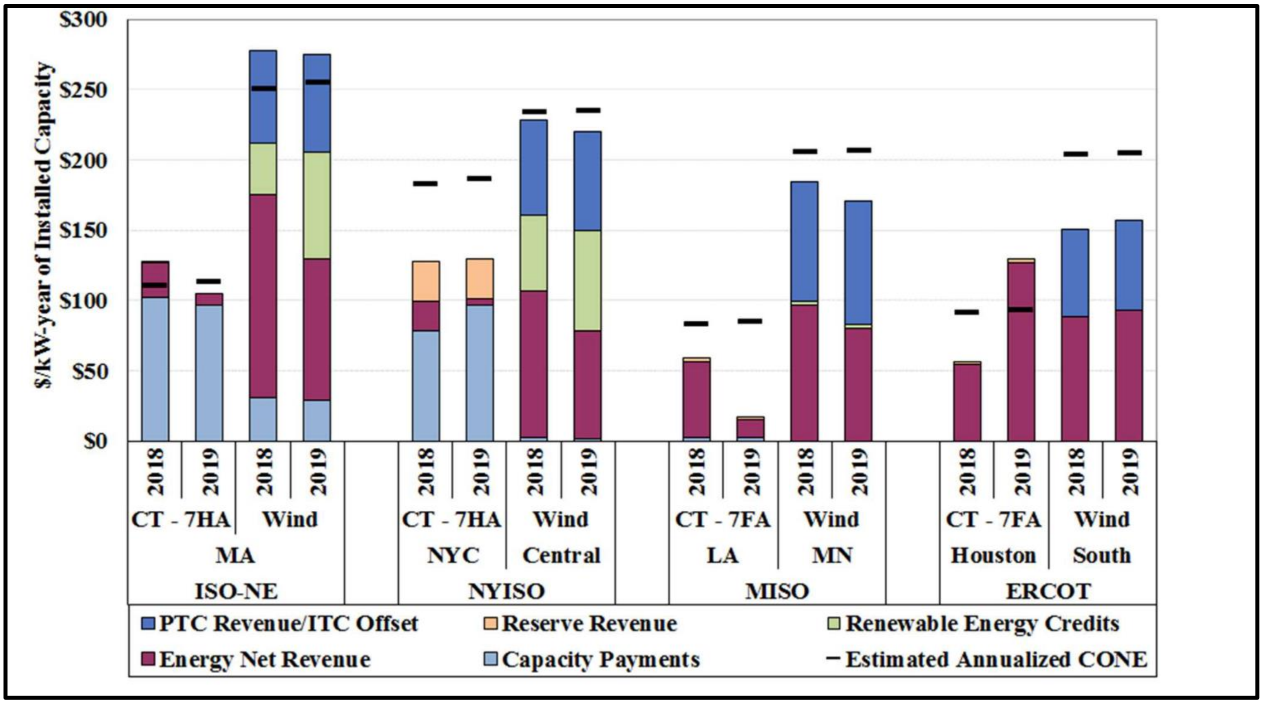


Figure 6 Net Revenues Produced in ISO-NE and Other RTO Markets (2018-2019) (Patton et al., 2020a)

The interested reader can find the most recent results of the FCM in ISO-NE by accessing: https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/auction-results-fr.

3.3 Planning Resource Auction (PRA) MISO

Like other ISO/RTOs, a primary role of the capacity market in MISO is to signal long-term capacity requirements to meet system reliability needs (POTOMAC, 2020). The installed capacity requirement in MISO is set based on an annual study referred to as LOLE, or loss of load expectation study report (Bushnell, Flagg, & Mansur, 2017; MISO, 2019b). The reserve requirement is assessed on both a system-wide basis as well as a zonal basis. But once the requirement is set, the burden of procurement rests upon the LSEs in MISO (Brewer et al., 2019; Bushnell et al., 2017; POTOMAC, 2020). The LSEs are responsible to acquire sufficient capacity to meet what they individually forecast for demand, plus a reserve margin above expected demand. In 2015 the reserve margin was set at about 15 percent above the requirement (Bushnell et al., 2017). That is, the LSEs must contract for planning resources according to their 'Module E' requirements (MISO, 2020b; POTOMAC, 2020). The LSE can contract with either generation resources or with demand response. The mechanisms the LSE can use are either bilateral contracts directly with the resource supplier, the Planning Resource Auction (PRA) run by the MISO, or the LSE can self-schedule capacity resources, if available. The PRA auction is for three year forward capacity commitments (Bushnell et al., 2017). If the LSE does not meet the requirement, it is subject to a fine called a deficiency charge (Brewer et al., 2019). The MISO evaluates the LSE's resource requirement performance through monthly statistical analysis.

In the PRA, the MISO uses a vertical demand curve set equal to the resource requirement. This is a feature that many have suggested leads to system reliability less than what is economically possible. Brewer et al. (2019) points out that this leads to no value assigned to incremental capacity above the requirement, but instead leads to poor pricing stability and the less-than-optimal capacity investment that accompanies unstable pricing signals. The ISO's market monitor POTOMAC (2020) outlines how the ISO's vertical demand approach poorly reflects the true value of capacity reliability. To rectify this, POTOMAC has recommend that the ISO adopt the approach of downward sloping demand for capacity. Doing so would increase system reliability, in an economically efficient way, beyond the requirement. As long as demand is represented vertically, then the last MW of capacity needed to satisfy the minimum requirement is valued at what POTOMAC calls a deficiency price and the first increment of capacity essentially has no value. This reality leads POTOMAC to list the ISO's approach to modeling demand as one of its major concerns for the ISO. When the capacity market clears at the deficiency price then there is a strong incentive for generators to withhold resources to raise prices, a form of market manipulation.

There are seven zones in MISO and each clear the capacity market at a different price. The most recent results of the PRA, for the 2020/2021 planning year, show the following prices (Bermudez, 2020; MISO, 2020a).

- Zone 1-6: $5/MW-day
- Zone 8 and 10: $4.75/MW-day
- Zone 9: $6.99/MW-day
- Zone 7: $257.53/MW-day (this is the market price cap, the CONE for the ISO).

Further data about the PRA, including reports on the maintenance margin and on registered demand response participating in the PRA can be found at the following website: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AResource%20Adequacy&t=10&p=0&s=MarketReportPublished&sd=desc.

3.4 Installed Capacity Market (ICAP) in NYISO

The capacity market in the NYISO is called the Installed Capacity Market (ICAP). Like other capacity markets, one of the primary purposes of ICAP is to send price signals to attract investment in new generation, transmission, and demand side resources (Brewer et al., 2019). These resources allow the ISO to maintain system reliability. It is one based on voluntary participation for monthly auctions but mandatory participation in spot auctions. The ICAP is used to commit resources out for a few months at a time. In the spot capacity auction, capacity owners submit bids that the ISO then uses to construct the merit order bid stack which forms the capacity supply curve. Then the downward sloping demand curve intersects supply to determine which capacity offers clear the market. Those who submit capacity offers in NYISO are based on new and existing generator resources as well as demand side resources (Brewer et al., 2019).

Like other ISO/RTOs, the LSE in NYISO are those with the requirement for procuring capacity. They are required to meet their capacity plus a reserve margin. LSEs are allowed to issue bilateral contracts for capacity, self-schedule their own resources, or procure resources from the ICAP. The ICAP offers two versions of their capacity market. In the monthly auction commitments are attained for 30-day delivery and in the spot market, the commitment period is for two to four days out for delivery (Brewer et al., 2019).

Capacity markets in NYISO are interesting because the ISO designs four different demand curves for capacity which correspond to four different localities in the ISO. These are the New York City area (NYC), Southeast New York State (G-J Locality), the entire state (NYCA), and Long Island (LI) (Patton, VanSchaick, Chen, & Naga, 2020b). The purpose of segmenting different portions of the demand curve is so that adequate capacity resources are procured in each of these localities (Brewer et al., 2019).

The ICAP has measures in place to prevent market manipulation and promote market competitiveness (Patton et al., 2020b). On supply-side resources, the ISO imposes penalties for withholding capacity and sets price caps on specific suppliers. On buyers in the capacity market, the ISO imposes a price offer floor to prevent buyers from depressing market prices. However, a capacity buyer can be exempted from the price floor restriction if the buyer can verify that it does not accept subsidies from state agencies, that the buyers is forecasted to be economically viable withing three years of operation, or if the LSE self-supplies most of its capacity needs. Intermittent renewable resources can also seek an exemption if low capacity factors are demonstrated – essentially these are subverting the price offer floor.

Table 6 from analysis in Patton et al. (2020b) provides a summary of the value and volume of capacity in NYISO. The first row of the table is UCAP. This is the amount of capacity that resources suppliers are qualified to offer. It relates the UCAP margin as a fraction of the reserve requirement then shows the change over the previous year. The Average Spot Prices indicates the value of capacity, except for the locality of New York City, all spot market prices are down over the previous year. The table shows the reduction in demand for capacity for all localities, except NYC. The IRM is the installed reserve margin and the LCR is the locational reserve margin. Then results are further delineated by the seasonal results of the market. These changes were driven by a combination of factors, including changes in the IRM, variations in peak load, reductions in load forecast, and changes in supply. The drivers for the increases in NYC included an increase in the LCR, an increase in the forecasted load. Within the localities there are 15 further disaggregated zones. For the planning year of 2020/2021, eight zones had a Net CONE of $105/kW-year, five were $157/kW-year, and two were $192/kW-year.

The interested reader can find further details about the ICAP, such as current demand parameters and data summaries from the spot auction, by visiting https://www.nyiso.com/installed-capacity-market.

Table 6 Capacity Spot Prices and Key Drivers by Capacity Zone (2019/2020) (Patton et al., 2020b)

	NYCA	G-J Locality	NYC	LI
UCAP Margin (Summer)				
2019 Margin (% of Requirement)	10.5%	10.9%	7.5%	11.9%
Net Change from Previous Yr	2.0%	4.0%	-3.7%	1.8%
Average Spot Price				
2019/20 Price ($/kW-month)	$0.68	$2.49	$8.64	$2.90
Percent Change Yr-Yr	-65%	-57%	50%	-24%
Change in Demand				
Load Forecast (MW)	-519	-72	68	-136
IRM/LCR	-1.2%	-2.2%	2.3%	0.6%
ICAP Requirement (MW)	-1,002	-417	322	-109
Change in UCAP Supply (Summer)				
Generation & UDR (MW)	-73	210	76	-19
SCR (MW)	-47	-26	-33	-3
Import Capacity (MW)	-178			
Change in Demand Curves (Summer)				
ICAP Reference Price Change Yr-Yr	-2%	1%	5%	32%

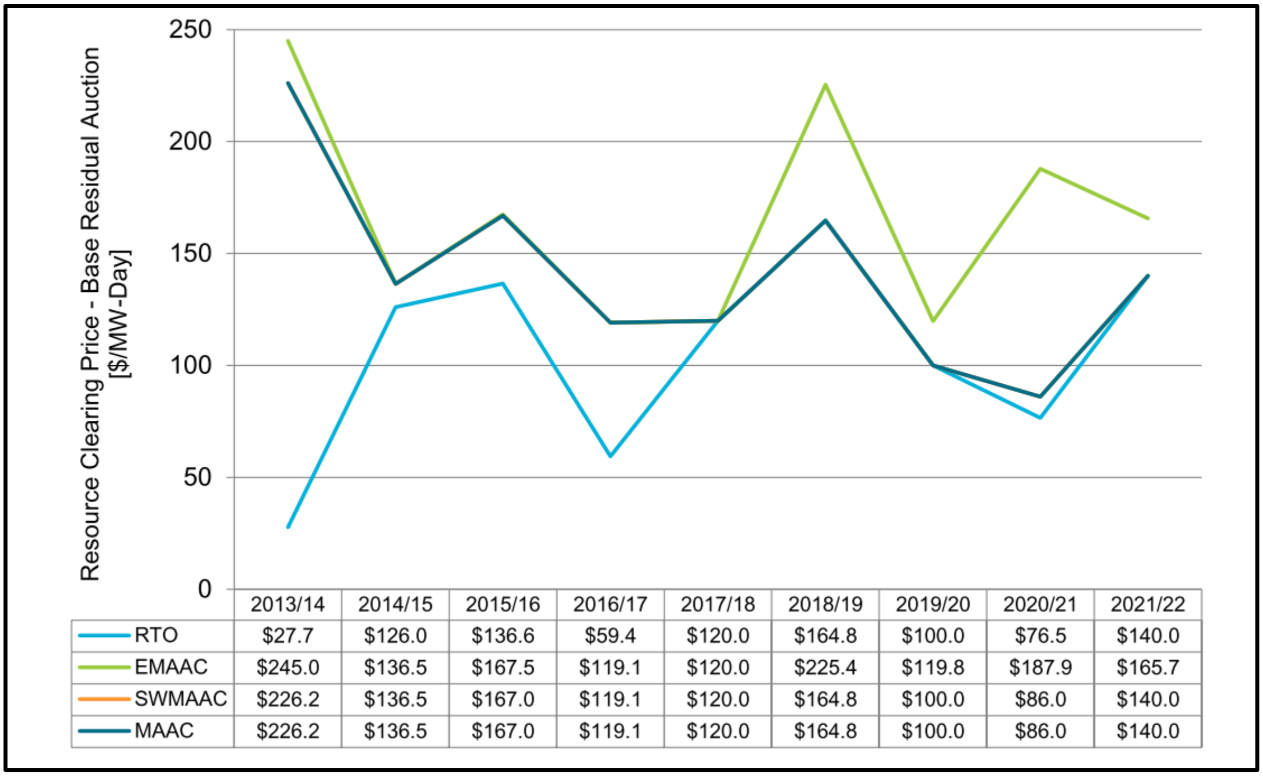
3.5 Reliability Pricing Model (RPM) in PJM

The Reliability Pricing Model is the name of the capacity market in PJM, and like capacity markets in other ISO/RTOs, it is designed to provide long-term investment signals and grid reliability. It is a three year, forward auction with incremental adjustments annually (Brewer et al., 2019). An interesting thing about this market is that once capacity clears the market for a forward commitment, the commitment period is for a whole year. So, the generator must be ready to run during any period within the year. Further, the RPM is run on a locational basis across four zones. LSEs in the RTO are required to procure capacity sufficient to meet forecasted demand. The LSEs have the option to provide capacity based on assets owned by the LSE, or they can procure capacity through bilateral contracting or through the RPM. The RPM has two stages. The first, known as the residual auction, is for commitment periods three years out. The second part of the auction is called the incremental auctions (Monitoring Analytics, 2020). The RPM requires both generators and LSEs to participate. Eligible types of capacity include new and existing generators, demand resources, and efficiency resources although the requirements on efficiency resources may be changing because forecasts now include assumptions of efficiency (Newell et al., 2018).

Price formation in the RPM is similar to the approach of other capacity markets. Capacity owners submit bid offers which are then merit ordered into the bid stack supply curve (Brewer et al., 2019). Then the RPM intersects supply with a downward sloping demand curve constructed from LSE's forecasted load. Of note, the PJM market monitor conducts an evaluation of market competitiveness across PJM markets. Based on their analysis of prices, demand and supply, concentration ratios and key suppliers, they find that the RPM is not a competitive market (Monitoring Analytics, 2020).

Introduced earlier in the example for this section, Figure 3 illustrates demand for capacity in PJM. The vertical axis (VRR) reflects the variable resource requirement and the horizontal axis reflects levels of capacity above and below the installed capacity requirement. Intuitively, when the VRR prices exceeds the Net CONE for the RPM (discussion forthcoming) then the amount of committed capacity is less than the installed capacity requirement. The logic of implementing a variable resource requirement is that it more accurately reflects the value of reliable capacity (Monitoring Analytics, 2020). Alternatively, when the VRR price is less than the Net CONE then reserves exceed the requirement.

Figure 7 shows the results of the Residual Auction (3-year forward) across the four zones within PJM. Drivers of the variation in these data include changes in transmission limits, changes in Net CONE, and changes in exports and imports (Brewer et al., 2019). The market monitor reports that the weighted average of capacity prices across the RTO were $172.09/MW-day for the planning year 2018/2019 (Monitoring Analytics, 2020). Combustion turbines represent the technology currently used to compute the Net CONE. Estimates for the planning year 2022/2023 for the four regions (EMAAC, SWMAAC, Rest of RTO, WMAAC) include ($292, 297, 269, $284) per MW-day (Newell et al., 2018).



	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
RTO	$27.7	$126.0	$136.6	$59.4	$120.0	$164.8	$100.0	$76.5	$140.0
EMAAC	$245.0	$136.5	$167.5	$119.1	$120.0	$225.4	$119.8	$187.9	$165.7
SWMAAC	$226.2	$136.5	$167.0	$119.1	$120.0	$164.8	$100.0	$86.0	$140.0
MAAC	$226.2	$136.5	$167.0	$119.1	$120.0	$164.8	$100.0	$86.0	$140.0

Figure 7 Resource clearing price – base residual auction (2013/2014-2021/2022) (Brewer et al., 2019)

The interested reader can find historical data on the results of the RPM by accessing https://www.pjm.com/markets-and-operations/rpm.aspx.

3.6 Resource Adequacy Program in SPP

The SPP does not operate a capacity market like the other ISO/RTOs, instead it operates a Resource Adequacy Program that incentives reliability through a combination of scarcity pricing, reliability unit commitment, and make-whole payments. This means that to ascertain value for reliability and capacity, and capacity market prices are not available, then it must be ascertained another way.

The SPP tracks the number of scarcity events that occur in the system. This is when some resource (either energy or ancillary services) is in short supply relative to demand. Then SPP issues a scarcity payment to incentive generators to fill in the gap (SPP, 2020). The market monitor reports that the typical case to secure additional capacity is outside of commitments secured through the day-ahead and real-time markets. These additional capacity procurements are called reliability unit commitments (RUC) (SPP, 2020). There are several ways to procure RUCs, these include manual multi-day commitments, day-ahead commitments, short-term intra-day commitments, and manual commitments based on RTO instructions. For multi-day commitments, generators must comply with RTO instructions and are made three days out from the committed operating period.

The scarcity price reflects the value of a product when there is not enough of the product to meet demand. In SPP markets, a marginal cost is used as the basis of price formation, which represents the cost to the producer of providing the next increment of service. Scarcity prices are a factor above the marginal cost that signals to producers the need for additional capacity of the that which is in short supply. It also signals to producers the need for additional provision of the product or service where scarcity prices are applied.

Figure 8 shows the average of scarcity events running from 2017 to 2019. And it shows the scarcity price by different types of services where scarcity values were needed. The average scarcity price in 2019 was $439/MW-hour across events and product types (SPP, 2020)

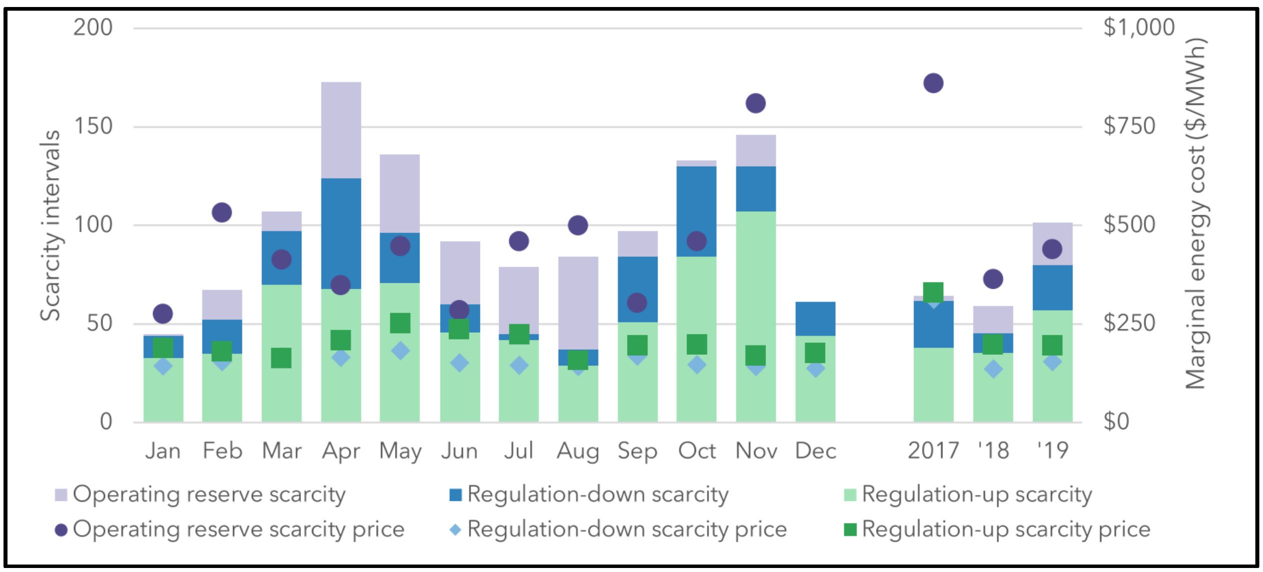


Figure 8 Scarcity Intervals and marginal energy cost (SPP, 2020)

In the day-ahead and real-time markets, generating assets that serve load requirements have must-run requirements imposed by the SPP. The SPP deals with the missing money problem by offering what it calls make-whole payments. Because generators must run to follow dispatch instructions, regardless of what prices may attain, like negative prices, the SPP issues make-whole payments to keep generators economically viable. In 2019, the make whole payments averaged $0.38/MW-hour (SPP, 2020). This translates to $9.12/MW-day. Table 7 shows how these payments have varied across the day-ahead and real-time markets from 2017 to 2019.

Table 7 Make-whole payments for eligible megawatts (SPP, 2020)

	2017	2018	2019
Day-ahead market make-whole payments / eligible MWh	$0.28	$0.22	$0.21
Real-time market make-whole payments / eligible MWh	$14.73	$18.94	$19.64

Another parameter used in SPP to guide capacity expansion is the CONE. At its last update in 2018, it was set at $85.61/kW-year (SPP, 2018). The SPP's guiding documents indicate that this value must be reviewed annually for use in the following planning year.

Additional details and data about the resource adequacy program in SPP can be found at https://spp.org/engineering/resource-adequacy/.

4. Ancillary Services Market

Ancillary services, also called essential reliability services, are a solution to a problem the grid operator faces, which really became a problem when electricity markets moved to distributed generation and competitive wholesale markets. If the real time market is the adjustment market for settlements in the day-ahead market, then ancillary services are the tools of adjustment for the real time market. They allow the grid operator to balance supply and demand in intervals less than the 5-minute clearing of the real time market. These support grid reliability in the short-term and long-term (Hytowitz et al., 2020). Two regulatory authorities define them as, "Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice" (NERC, 2020). The challenge and responsibility the grid operator faces is that of balancing supply and demand at all points in time and maintaining frequency throughout the grid (Zhou, Levin, & Conzelmann, 2016). Achieving the continual balance of supply and demand to ensure reliability is risk management (Biggar & Hesamzadeh, 2014). Resting solely with the grid operator, generators provide ancillary services which solve these challenges (Eash-Gates et al., 2020). If forecasts for demand and supply were perfect, without error, then the grid operator's problem would be less. But since the grid operator must balance supply and demand always, error in the forecast – such as unforeseen weather events disrupting supply while simultaneously increasing demand – means the operator must make continual adjustments. Electricity generators are typically the suppliers of ancillary services where these are co-products to electricity generation (Pollitt & Anaya, 2020). However, wholesale customers can also act as suppliers of ancillary services through demand response programs.

Pollitt and Anaya (2020) describe the set of ancillary services upon which the grid operator can call from generators include operating reserves to balance dis-equilibriums, distinguished by spinning and non-spinning reserves. Regulation reserves to balance frequency. Demand-side management reserves which large wholesale customers provide to balance dynamics. Black start capabilities that generators provide in the event of a system-wide shut down.

Operating, which include spinning and non-spinning reserves, also called synchronous and non-synchronous reserves, are those which the grid operator purchases from generators to adjust for changes in supply and demand dynamics. Online generators provide spinning reserves; they are already "spinning." The grid operator can call upon these generators to adjust the amount of electricity supply to meet grid needs such as forced outages or unplanned contingencies. That is, the generators ramp up or down. The time allowed to the generator to meet these ramp requirements varies across electricity markets from response within the first few minutes up to 10 minutes. Non-spinning reserves are those provided by generators that are not online at the time of the call but who can ramp up to meet grid needs within a specified timeframe, typically a 30-minute window. However, online generators can also provide non-spinning reserves as long as the quantity provided is apart from that provided under spinning reserves (Zhou et al., 2016). Generators bid operating reserves into the market apart from their committed electricity capacity; ancillary services and capacity bid into the electricity market cannot overlap.

Prior to electricity market deregulation, at the time when electricity markets were vertically integrated, the grid operator's problem was not the same as it is today. Under vertical integration, ownership of the generation assets was with the same entity that owned and operated the transmission and distribution infrastructure. This meant that the grid operator could balance supply-demand dynamics using assets held under the same ownership structure. Distributed generation and de-regulation led to the need for ancillary services as they exist today because of the development of wholesale electricity markets that followed de-regulation (Pollitt & Anaya, 2020). Prior to de-regulation, grid operators could provide these functions with in-house capabilities. But when generation assets were sold off to create competitive markets, the supplier of these functions changed. This is the case for the seven wholesale electricity markets in this report. For electricity markets where ownership remains vertically integrated, such as much of the Western and Southeastern US that are not part of ISOs/RTOs, grid operators continue to balance supply-demand dynamics under the same ownership structure through power purchase agreements and bilateral contracts (Zhou et al., 2016).

In addition to balancing supply-demand dynamics, the grid operator must maintain a specified electrical frequency in the grid. In the United States the frequency is 60 Hz (hertz) (Biggar & Hesamzadeh, 2014). Not all electricity is created equal; the quality of the frequency varies by generator type. Frequency control, typically called regulation reserves, is another ancillary service that the grid operator needs to maintain grid stability. These injections of frequency-quality electrons allow the grid operator to maintain a frequency within a very narrow range throughout the grid (Biggar & Hesamzadeh, 2014). Generators supply regulation reserves on very short intervals, typically a single second up to intervals of several seconds. Because of the very short timeframe required to provide these reserves, generators must have the capability to automatically ramp up or down as called for based on signals received from Automatic Generation Control (AGC), which is provided by the grid operator (Zhou et al., 2016). Regulation reserves usually command the highest price of the ancillary service types (Zhou et al., 2016).

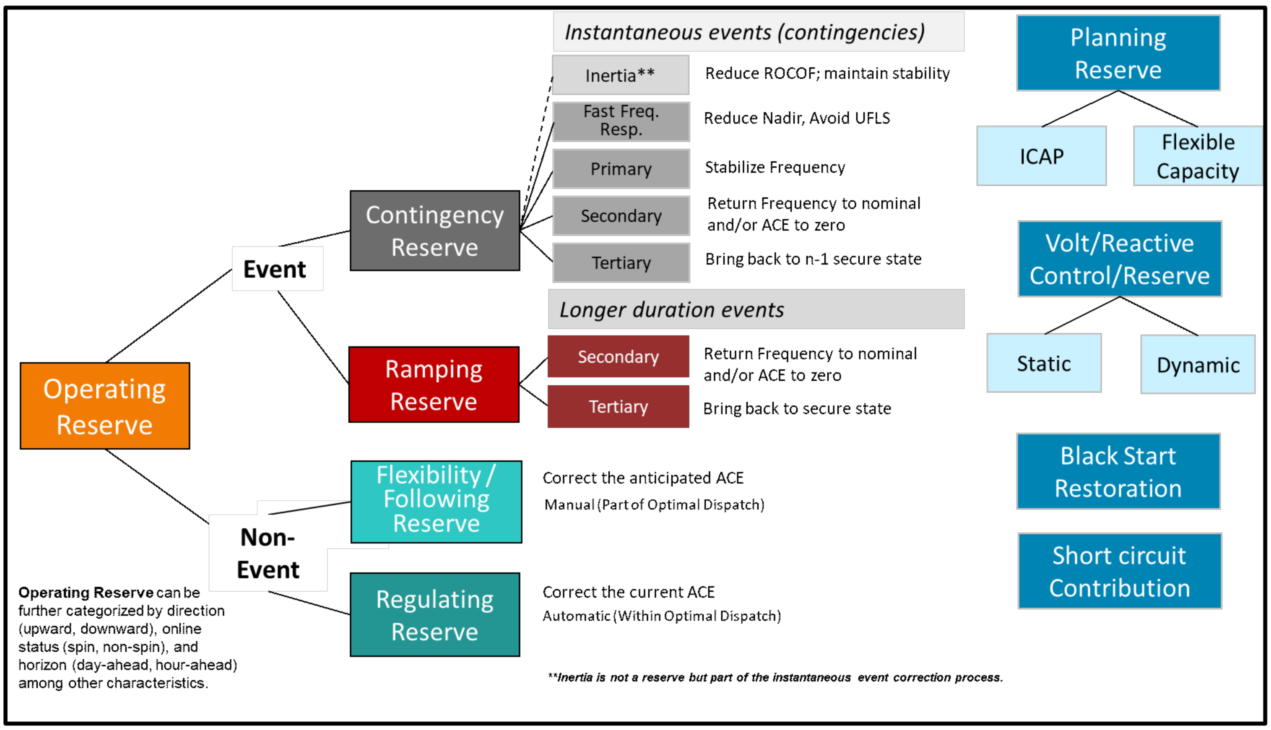


Figure 9 Ancillary services or essential reliability services in US ISOs and RTOs (Hytowitz et al., 2020)

***Note*: ROCOF is rate of change of frequency, UFLS is under frequency load shedding, ACE is area control error**

This section provides a description of how the ancillary services markets operate by ISO. A description of ancillary services is provided then each section includes a data summary of services in that market. The data used to generate these summaries are from the data repositories of each ISO. The reader can find weblinks to these data sources in the summary tables in each sub-section. The data available is these repositories is available at hourly intervals for ancillary services where ancillary services trade in the DAM and in 5-minute intervals where the exchange is in the RTM. For each ISO, data represent two days per month, beginning in December 2019 through November 2020. The analyst-chosen days are the second Saturday and fourth Wednesday of each month, chosen to be representative of 'typical' days within the month. Each ISO records data slightly differently, but data generally represent several regions within the system. Consequently, the data reflect two days per month for one year over hourly intervals across multiple regions within each ISO.

Hytowitz et al. (2020) provide an organizational summary of ancillary services offered across the ISO/RTOs in the US. Figure 9 shows operating reserves dis-aggregated by event types that trigger their need. It also shows the different types of ancillary services offered. They note that each service is characterized by a specific requirement and level within the system or within specific zones within the system. Requirements vary with markets and products. Of the array of services listed in the figure, only a subset generate compensation from the ISO/RTO. Services such as voltage support, reactive power and black start capability are paid through cost recovery, not market mechanisms (Hytowitz et al., 2020).

For ancillary services exchanged in competitive markets, they are typically co-optimized with energy. This means that conditions that impact the energy price also impact the price for ancillary services. One can think of the price for ancillary services as the opportunity cost a generator incurs for holding back energy production for the event of a contingency. If the generator is called upon to activate their committed ancillary service then compensation is that of the energy price instead of the ancillary service price. If the generator is not called upon for their ancillary service then they receive the price resulting from the ancillary services market (Hytowitz et al., 2020).

The sub-sections that follow describe the features of the ancillary services and requirements to participate in each market. Data summaries illustrate the data in two ways, by ancillary service type across all observations and graphical summary by hours of the day.

4.1 CAISO: Spinning, Non-Spinning, Regulation Up/Down

CAISO offers four types of ancillary services: regulation up, regulation down, spinning and non-spinning reserves. The requirements for participating in the ancillary services market at CAISO are consistent with those of the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) (Zhou et al., 2016). The CAISO estimates system needs for ancillary services based on internally forecasted demand, then the load serving entities (LSE) in CAISO can self-provide ancillary services or can procure services from other market participants.

Bids for ancillary services may accompany bids for electricity in the day-ahead-market (DAM) but they must accompany electricity bids into the real-time market (RTM). Ancillary service bids in the DAM must be made no later than seven days prior to the trading day (CAISO, 2020b). Primarily, procurement for ancillary services occur in the DAM but if enough capacity is not met there then additional contingency reserves are procured from the RTM, but exchange in the RTM can only occur after the results of the DAM are published. In the Integrated Forward Market CAISO co-optimizes bids for energy and ancillary services (Zhou et al., 2016). Requirements for operating reserves (spinning and non-spinning) are such that generators must be able to provide the reserve capacity for two hours of generating time. Spinning reserves, which must be synchronized to the grid, must respond to the market operators call within 10 minutes. Non-spinning reserves must respond within 10 minutes but these reserves are not required to be synchronized to the grid.

Table 8 Summary Ancillary Services in CAISO

Products/Attributes	Characteristics	Location of Data or Further Details
Spinning Reserves	Synchronized to grid, Respond within 10 minutes, Run for at least 2 hours	http://oasis.caiso.com/mrioasis/logon.do
Non-Spinning Reserves	Not synchronized to the grid, Respond within 10 minutes, Run for at least 2 hours	Then select: 'Ancillary Services' 'Prices' 'AS Clearing Prices'
Regulation (up/down)	Immediate response (increase/decrease) to automated AGC signals, Control full range without manual intervention and sustain its ramp	
Demand Response	Bids into market for spinning and non-spinning reserves as supply, must bid minimum of 0.5 MW	http://www.caiso.com/Documents/PDR_RDRRParticipationOverviewPresentation.pdf
Ramp Rate	Capacity commitment allowed to ramp in up to three increments to reach committed capacity, full ramp within 30 minutes	https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments/ https://www.caiso.com/Documents/5330.pdf
Flexible Ramping Product	New product as of 2016 for real-time markets, under study for application into day-ahead markets Allows for capacity bids on the margin of production	http://www.caiso.com/Documents/DecisiononFlexibleRampingProductRefinementsProposal-Memo-Sept2020.pdf#search=Flexible%20Ramping%20Product

Source: author summary of referenced data

Suppliers of spinning and non-spinning reserves capacity must be able to ramp according to system needs based on capacity delivery within three increments. Suppliers can provide capacity within two increments but not more than three where the capacity (max capacity – minimum capacity) is distributed over the increments (CAISO, 2020b).

The system requires regulation reserves immediately in response to the automatic generation control (AGC). The CAISO operator maintains a very tight frequency range around 60 Hz, which varies as generators adjust power output to the grid. The AGC sends a signal to online generators for immediate adjustments in response to grid needs. The payment calculation for regulation reserves depends on another ancillary product, regulation mileage. To compute regulation mileage, CAISO sums the AGC signals from generators over a series of set points in four second intervals aggregated to 15-minute intervals. Then the calculation finds the fraction of absolute deviation relative to the control and applies it to the mileage interval requirement to compensate generators for frequency control. Prices for regulation reserves reflect this calculation in the data recorded for regulation up and regulation down services.

CAISO requires LSE to provide their own self-service for ancillary services. If the LSE produces a surplus, these are sold in the ancillary services market. If the LSE is short of ancillary services, the entity can procure additional services.

Demand response is another avenue that can provide for operating reserves. Those entities capable of demand response offer bids into the DAM or the RTM as suppliers of reserves. Then, capacity requirements imposed on demand response assets are the same as supply assets, with an additional requirement. Demand response must be a minimum of 0.5 MW to be eligible.

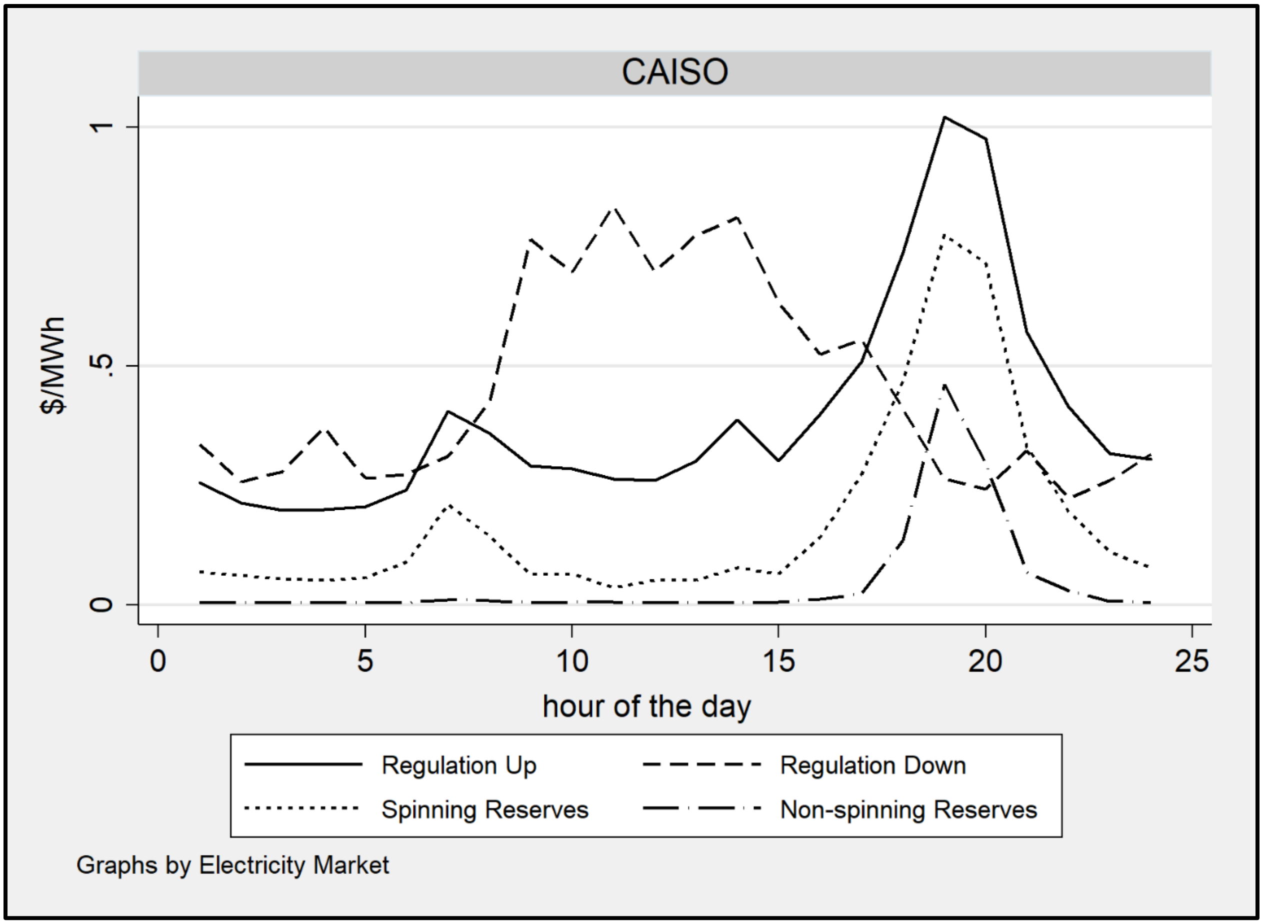
The newly introduced Flexible Ramping Product is exchanged in the 5-minute and 15-minute real-time markets. This product enables generators to bid flexibility into the market according to the uncertainty bands of the demand forecast (Ingersoll, Gogan, Herter, & Foss, 2020). The CAISO is working to extend this product to the DAM.

Table 8 provides a summary of the requirement for each of the ancillary services in CAISO. Table 9 provides a data summary consistent with the data analysis described in the previous section. On average, regulation up is the highest priced of the ancillary services, however that data show that spinning reserves achieved the same maximum in the dataset. Figure 10 plots the hourly average using the dataset.

Table 9 Summary Ancillary Services Prices in CAISO

USD/MW-hour	Mean	Std. Dev.	Min	Max
Spinning Reserves	3.61	8.58	0.01	163.08
Non-spinning Reserves	1.02	8.13	0.01	161.15
Regulation Down	8.91	10.32	0.01	96.05
Regulation Up	6.23	8.43	0.01	163.08

Source: author calculations from data at http://oasis.caiso.com



Source: author calculations from data at http://oasis.caiso.com

Figure 10 Summary of average hourly prices for ancillary services in CAISO

4.2 ERCOT: Responsive, Non-Spinning, Regulation Up/Down

Like CAISO, ERCOT offers four ancillary services: regulation up, regulation down, responsive reserves, and non-spinning reserves. ERCOT maintains system reliability according to standards set by NERC.

In ERCOT, the grid operator balances ancillary services across a single region that encompasses the system service area. The grid operator assigns to LSEs within the system a responsibility for ancillary services that is computed based on load ratio. The load ratio and LSE responsibility is computed based on historical responsibility of the LSE relative to volume of total need in the system. Like LSEs in CAISO, ERCOT LSEs can either choose to self-provide their responsibility of ancillary services or purchase them in the DAM. If a greater supply of ancillary services are needed than what the DAM settles, then additional services can be procured in the RTM.

The value for ancillary services is based on the notion of opportunity cost (Zhou et al., 2016). ERCOT operators have a system of price adders that are added to electricity prices to arrive at the price for ancillary services. The price adder is based on the cost to the system if the energy source fails, and the probability of failure. Generators bid into the DAM based on their cost to supply and then winning bidders receive compensation that includes the price-adder approach.

Responsive reserves (spinning reserves) are quick-response reserves that are allocated in 4-hour blocks of time. The need for these reserves is based on forecasted demand relative to realized demand, net of wind generation. The uncertainty that arises between these two demand quantities generates the need for ancillary services. Conversely, non-spinning reserves must be able to ramp within 30 minutes and operate for 1 hour. Similarly, the need for non-spinning reserves is based on the difference between realized and forecasted demand with the added uncertainty that stems from wind patterns.

ERCOT outlines the demand for ancillary services each day in an ancillary services plan presented in the DAM. There load serving entities receive information on their portion of ancillary services. They have the choice to self-service those needs, purchase ancillary service commitments from generating resources in bilateral contracts, or purchased services through the ancillary services market in ERCOT.

Regulation reserves are triggered by AGC signals sent to generators that require ramp up or down consistent with the signal. Operators tightly control the frequency in a very narrow band around 60 Hz (ERCOT, 2016).

Table 10 provides a summary of the requirement for the ancillary services in ERCOT. Table 11 provides a data summary consistent with the data analysis described in the previous section. On average, responsive reserves is the highest priced of the ancillary services, however that data show that regulation up achieved the highest price in the dataset. Figure 11 plots the hourly average using the dataset.

Table 10 Summary Ancillary Services in ERCOT

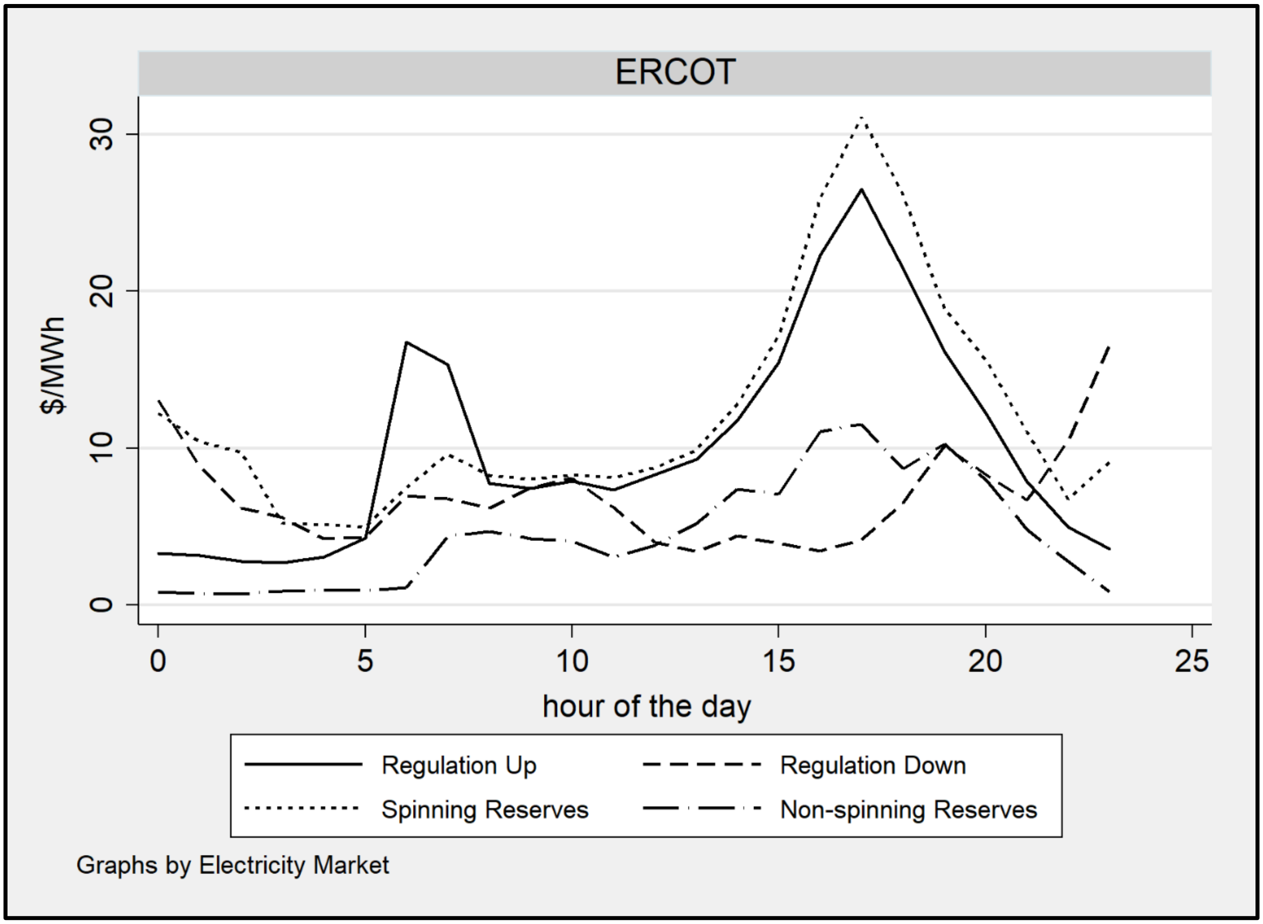
Products/Attributes	Characteristics	Location of Data and Further Details
Responsive Reserves	Response within “first few minutes of an event that causes a significant deviation from standard frequency” Must be able to provide reserves for 4 hour block of time	http://www.ercot.com/mktinfo Then select: ‘Market Prices’ ‘DAM Clearing Prices for Capacity’
Regulation (up/down)	Immediate response (increase/decrease) to automated AGC signals, receive and respond to reg up or reg down and switch control to constant frequency operation	
Non-spinning Reserves	Respond within 30 minutes Run for at least 1 hour	
Ramp rate	Regulation Up, 3 MW/min Regulation Down, 4 MW/min Reserves up 2 MW/min Reserves down 3MW/min	http://www.ercot.com/content/wcm/training_courses/123737/Resource301_-_5_RT.pdf p.14, 29

Source: author summary of referenced data

Table 11 Summary Ancillary Services Prices in ERCOT

USD/MW-hour	Mean	Std. Dev.	Min	Max
Responsive Reserves	12.12	17.70	1.00	166.81
Non-spinning Reserves	4.50	9.96	0.46	94.44
Regulation Down	6.92	5.41	0.01	65.00
Regulation Up	10.08	15.88	0.01	200.00

Source: author calculations from data at http://www.ercot.com



Source: author calculations from data at http://www.ercot.com

Figure 11 Summary of average hourly prices for ancillary services in ERCOT

4.3 ISO-NE: Spinning/Non-spinning and Regulation Service/Capacity

Unlike the previous two summaries, in ISO-NE uses five ancillary services, summarized in Table 12. These include ten-minute non-spinning, ten-minute spinning, thirty-minute operating reserves, regulation service and regulation capacity. ISO-NE is divided up into four service areas. These ancillary services are exchanged in the Forward Market and the Real-Time Market. The system maintains reliability according to the standards of NERC.

The Forward Reserve Market is operated two times per year and the exchanges therein become the operating reserves (ten-minute synchronized and non-synchronized) in the following period. The two periods of this market are June through September and October through May. If the case is realized where operating reserves purchased in the Forward Market are not sufficient to adjust for day-to-day operations, then additional reserves can be purchased in the Real-Time Market. Based on the outcome of the Forward Reserve Market, suppliers of reserve capacity receive assigned operating schedules. Further, the design of this market is such that threshold price points exist at approximately two to three percent of the marginal cost peaking plant (ISO-NE, 2014).

Table 12 Summary Ancillary Services in ISO-NE

Products/Attributes	Characteristics	Location of Data
Ten-minute Non-Spinning Reserves	Respond within 10 minutes	https://www.iso-ne.com/markets-operations/iso-express/ Then select: 'Ancillary Services'
Thirty-minute Operating	Respond within 30 minutes	
Ten-minute Spinning	Synchronized to the grid, Respond within 10 minutes	
Regulation Service	Immediate response to automated AGC signals	https://www.iso-ne.com/markets-operations/markets/regulation-market/
Regulation Capacity	Receive and follow AGC set points at 4 sec intervals	
Ramp rate	Regulation, 1 MW/min minimum, Spinning/Non-spinning, meet full bid level within allotted time frame	https://www.iso-ne.com/static-assets/documents/2017/01/mr1_sec_14.pdf https://www.iso-ne.com/static-assets/documents/2015/04/price_information_technical_session10.pdf
Pay-for-Performance	New product in 2018, additional venue to provide very quick operating reserves during scarcity	https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-fcm-pay-for-performance-pfp-rules

Source: author summary of referenced data

It is in the Forward Reserve Market that ten-minute and thirty-minute, non-synchronized operating reserves exchange. These are reserves that are not online at the time to receive the notification from the market operator but must ramp committed capacity to online electricity within the specified time, 10 or 30 minutes. Because of the need for continual adjustments and supply-demand balancing, the Real-Time Market provides exchange for ten-minute synchronized reserves. Additionally, 10- and 30-minute non-synchronized reserves exchange in the Real-Time Market, but these reserves must be capacity that is not already committed from the Forward Reserve Market. Because of co-optimization in the Real-Time Market between reserve capacity and electricity generation, market adjustments can lead to changes in the LMPs of the electricity market (Zhou et al., 2016).

Analogous to other markets, ISO-NE uses regulation reserves to control the frequency on the grid. Those who supply these reserves must respond to the AGC triggered by the system in the event of frequency moving out of the narrow range around 60 Hz. Generators of these reserves must respond immediately to the AGC signal and be able to ramp at a minimum of 1 MW/min. In ISO-NE, payments for regulation reserves are separated into two components: capacity and service. Capacity captures the frequency control that a generator provides and service accounts for the mileage over which the service runs. Spinning and non-spinning reserves can be used across the system, but operating reserves are used within a single zone.

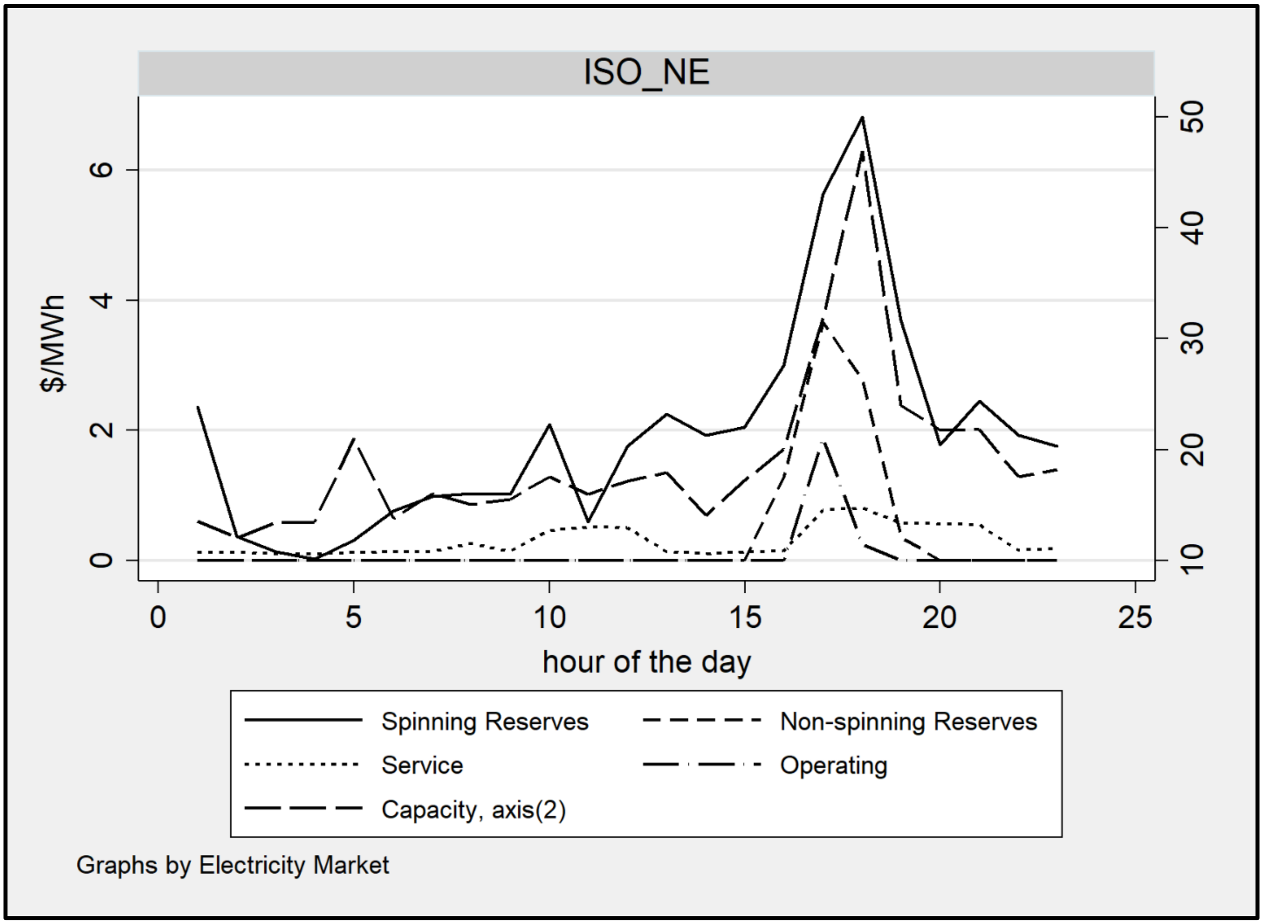
ISO-NE offers a newly introduced product that creates a financial incentive for very fast response operating reserves called Pay-for-performance. These are reserves designed to cover periods of capacity and generation scarcity (Ingersoll et al., 2020). These reserves provide very quick grid capacity, either ramping up or down to meet grid needs. Ingersoll et al. (2020) report that ISO-NE payments for services in this new product are $2,000/MW-hour over the time from 2018 to 2021, $3,500 from 2021 to 2024, and $5,455 from 2024 to 2025.

Table 13 provides a summary of ancillary services in New England. On average, ten-minute non-spinning reserves is the highest priced of the ancillary services, however that data show that regulation capacity achieved the highest price in the dataset. Figure 12 plots the hourly average using the dataset, however notice in the figure that it has a second y-axis. This plots reserve capacity because it is priced out of the range of the spinning and operating reserves.

Table 13 Summary Ancillary Services Prices in ISO-NE

USD per MW-hour	Mean	Std. Dev.	Min	Max
Ten-minute non-spinning reserves	29.72	25.80	2.68	80.5
Ten-minute operating reserves	23.53	19.10	5.66	41.39
Ten-minute spinning reserves	4.66	8.89	0.01	81.09
Regulation Service	0.39	1.46	0.01	10.00
Regulation Capacity	18.38	27.49	0.79	404.67

Source: author calculations from data at http://www.iso-ne.com



Source: author calculations from data at http://www.iso-ne.com

Figure 12 Summary of average hourly prices for ancillary services in ISO-NE

4.4 MISO: Regulation, Spinning, Supplemental

Started in 2009, the ancillary services in MISO include regulation reserves and contingency reserves composed of spinning and non-spinning reserves. The geographic region for these services covers 7 zones in MISO. There are two markets where the exchange for these take place, the Day-Ahead Energy Operating Reserve Market and the Real-Time Energy and Operating Reserves Market (POTOMAC, 2020; Zhou et al., 2016). The first round of the market occurs in the DAM then trades in the RTM adjust for imbalances. Resource owners provide offers for the DAM by 11 a.m. EST on the day before operating the resources. If the RTM ends up short of ancillary services then MISO has a pre-determined demand curve it uses to value purchase. It is based on the value of lost load (VOLL) and the threshold limit is set at $3,500/MW-hour (MISO, 2019a). The value of ancillary services has trended downward in recent years. This is due to the decreasing opportunity cost set by falling natural gas prices, reduction in transmission and congestion, and improvements in the MISO commitment process (MISO, 2017; POTOMAC, 2020).

Regulation reserves operate under the criteria set by NERC (MISO, 2017, 2019a). Resource suppliers of regulation reserves must have their capacity commitment online within 5 minutes of receiving the AGC signal. MISO establishes that those resource types which can provide regulation reserves include generation resources and battery, stored energy resources (MISO, 2019a). Suppliers of spinning reserves must have their committed capacity fully online within ten minutes of receiving the instruction from the market operator. The same is true for suppliers of non-spinning reserves (POTOMAC, 2020; Zhou et al., 2016). Spinning and non-spinning (supplemental) reserves can be supplied by generation resources, demand side resources and resources external to the market (MISO, 2019a).

MISO introduced a new product, ramp capability product, in 2016. This is designed to incentive quicker up-ramps and down-ramps by rewarding resource capacity that can ramp faster than their slower counterparts (Ingersoll et al., 2020; Navid & Rosenwald, 2013). This capability is designed to better respond to uncertainties in forecasted demand and supply contingencies.

Table 14 Summary Ancillary Services in MISO

Products/Attributes	Characteristics	Location of Data
Regulation	Full response within 5 minutes, Online, synchronized to grid, Respond to automated AGC signals, automatically respond to frequency deviations, receive and respond to 4 sec AGC telemetered every 2 sec	https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt= Then select: 'Historical MCP'
Spinning Reserve	Synchronized to grid, Respond within 10 minutes	
Supplemental Reserve	Not necessarily synchronized to grid Respond within 10 minutes	
Ramp Capability Product	Co-optimized with energy market, allows resources capable of faster ramping to displace slower ramping resources	(Navid & Rosenwald, 2013), (Ingersoll et al., 2020)

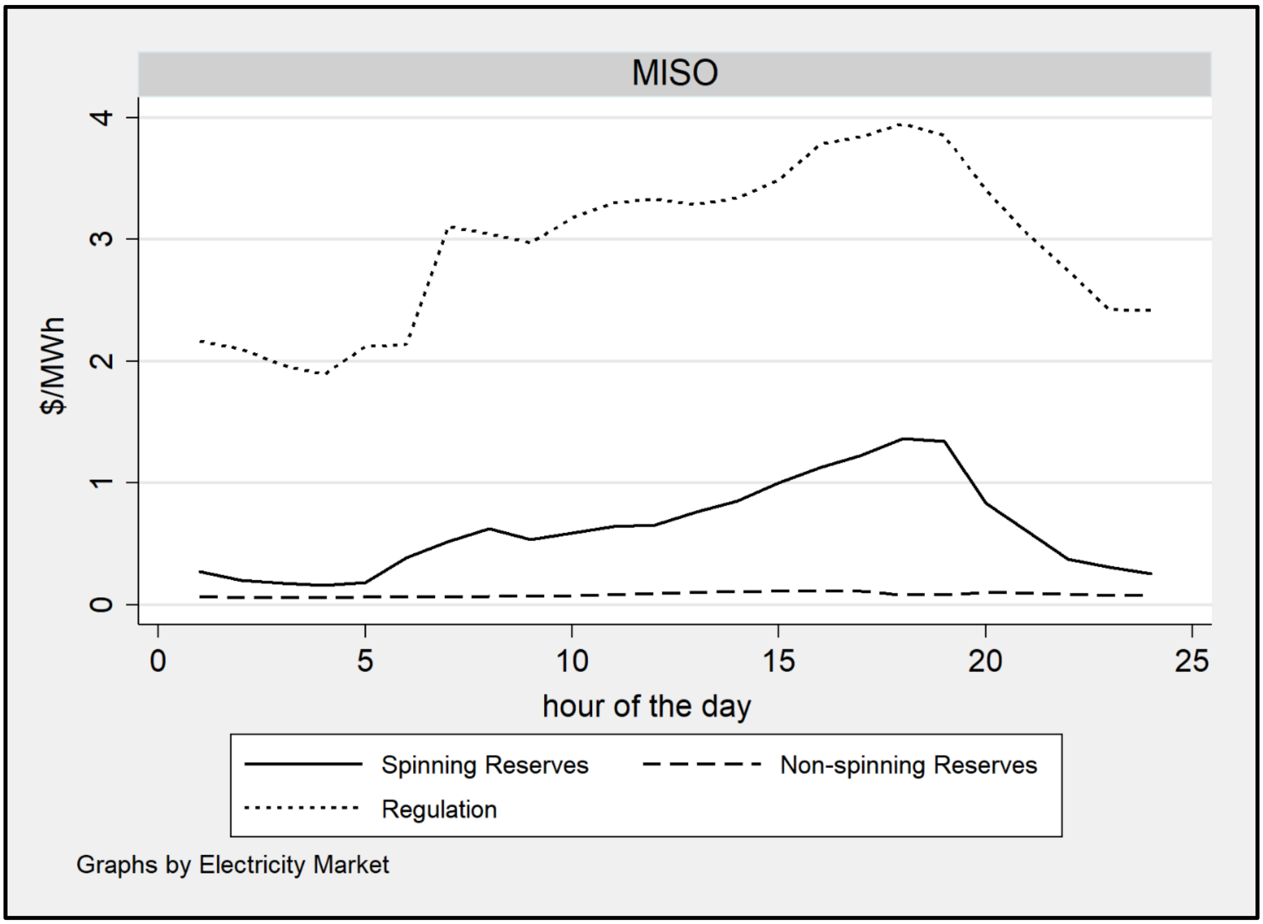
Source: author summary of referenced data

Table 15 provides a summary of ancillary services in the MISO. On average, regulation reserves are the highest priced of the ancillary service. Figure 13 plots the hourly average using the dataset.

Table 15 Summary Ancillary Services Prices in MISO

USD per MW-hour	Mean	Std. Dev.	Min	Max
Regulation	8.81	3.20	2.01	26.49
Spinning Reserve	1.74	2.09	0.18	19.04
Supplemental Reserve	0.23	0.10	0.18	0.99

Source: author calculations from data at https://www.misoenergy.org/markets-and-operations/#t=10&p=0&s=&sd=



Source: author calculations from data at https://www.misoenergy.org/markets-and-operations/#t=10&p=0&s=&sd=

Figure 13 Summary of average hourly prices for ancillary services in MISO

4.5 NYISO: Regulation, Ten-minute spinning and non-spinning

Ancillary services in the NYISO are similar to those in the previous markets listed. The NYISO conducts a two-settlement system using DAM and a RTM. There are four operating reserve products: ten-minute spinning, ten minute non-spinning, thirty minute spinning and thirty minute non-spinning. Regulation reserves are also in this ancillary services market.

The NYISO operates per reliability guidelines of the NERC, maintaining system frequency at 60 Hz using the regulation reserves. Generators must respond immediately to the AGC signal, ramping either up or down as required. Generators that wish to participate in this market must submit bids no later than 75 minutes prior to the operating hour and must include with their bids an array of possible ramp rates they can attain. Entities that can offer regulation reserves include generators and demand-side resources (Zhou et al., 2016).

Table 16 Summary Ancillary Services in NYISO

Products/Attributes	Characteristics	Location of Data
Regulation	Immediate response (increase/decrease) to automated AGC signals every 6 sec, continuous ramp up and down, regulation capacity response rate * 5 min, or max capacity	https://www.nyiso.com/ancillary-services Then select: 'Pricing Data' 'Ancillary Services'
Ten-minute Spinning Reserve	Synchronized to the grid, Respond within 10 minutes	
Ten-minute non-synchronized reserves	Respond within 10 minutes	
Thirty-minute spinning reserves	Synchronized to the grid, Respond within 30 minutes	
Thirty-minute non-synchronized	Respond within 30 minutes	
Flexible Ramping Product	Considering a flexible ramping product, ramp rate becomes an attribute on which to bid, higher value for faster ramp rate, expected completion 2023	https://www.nyiso.com/documents/20142/2545489/Flexible%20Ramping%20Product%20April%2026%20MIWG%20FINAL.pdf/0489ed61-472b-a320-9727-d51f32d8832c https://www.nyiso.com/documents/20142/4347040/2018-Master-Plan.pdf/88225d15-082b-c07a-b8ef-ccac3619a1ce

Source: author summary of referenced data

Bids for operating reserves must be submitted one day prior to the day they will be committed. Resource suppliers of ten-minute reserves must convert the bid capacity to fully online within the ten minute window. This pertains for ten-minute reserves that are spinning as well as non-spinning reserves. The same criteria pertains for 30 minute reserves that are spinning and non-spinning, fully online within 30 minutes. Reserves in the DAM are co-optimized with bids in the energy market (Patton et al., 2020b). If capacity is not met in the DAM then in the RTM exchanges take place to make up for the shortfall. In the

2019 year in review, analysis found that the prices for operating reserves in the DAM were consistently higher than those in the RTM (Patton et al., 2020b).

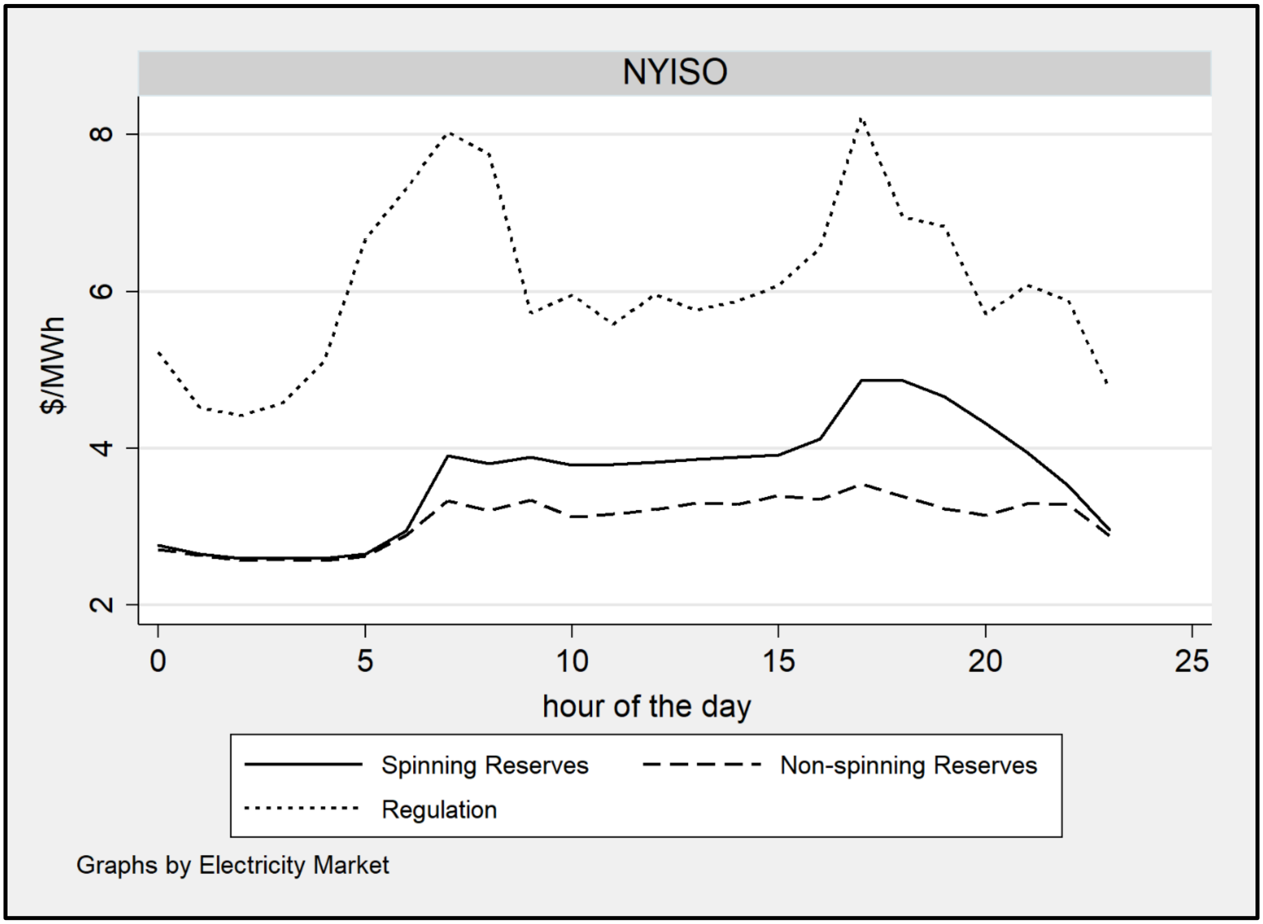
Following the lead of other ISOs, NYISO is considering implementing a Flexible Ramping Product with characteristics similar to those of the other ISOs. The purpose is to enhance system reliability by incentivizing fast ramping generation over slower ramping resources.

Table 16 provides a summary of ancillary services in the NYISO. Table 17 provides a summary of average, ancillary prices. On average, regulation reserves are the highest priced of the ancillary service. Figure 14 plots the hourly average using the dataset.

Table 17 Summary Ancillary Services Prices in NYISO

USD per MW-hour	Mean	Std. Dev.	Min	Max
Regulation	6.07	2.86	3.00	24.57
Ten-minute Spinning Reserve	3.61	1.15	1.74	10.53
Ten-minute non-synchronized reserves	3.08	0.74	1.74	7.15
Thirty-minute spinning reserves	3.06	0.72	1.74	6.48

Source: author calculations from data at https://www.nyiso.com/energy-market-operational-data



Source: author calculations from data at https://www.nyiso.com/energy-market-operational-data

Figure 14 Summary of average hourly prices for ancillary services in NYISO

4.6 PJM: Regulation, Synchronized, and Primary Reserves

PJM market operators run two ancillary services markets, the Forward Regulation Market and the Forward Synchronized Reserve Market. Market participants include owners of demand resources as well as generator resources. LSE in PJM are required to provide ancillary services commensurate with their energy demand, which can be self-provided, purchased in bilateral contracts from other market participants, or purchased in the ancillary services markets. For ancillary services that are exchanged through bilateral contracts, the buyers must report to PJM the details of the exchange followed up by verification from the sellers (PJM, 2020). The three types of ancillary services are regulation reserves, synchronized reserves and primary reserves, which includes the sum of synchronized and non-synchronized reserves (Zhou et al., 2016). The region wherein ancillary services in PJM extends covers two separate regions of the system.

Resource owners submit to PJM offers for services then PJM staff submit these offers to the Ancillary Service Optimizer (ASO) (PJM, 2020). The ASO is an optimizer model that co-optimizes ancillary services with energy generation. The output of this model informs on the allocation of ancillary services to those submitting offers.

Resource owners providing regulation services must have a governor installed at their plant that can respond to AGC signals to increase or decrease load within five minutes of receiving the signal calling for a change (PJM, 2020). PJM operators monitor two types of regulation signals: Signal A and Signal D. Signal D was instituted so that small energy storage facilities can provide regulation reserves. The idea for these facilities is to provide more frequency regulation from energy storage at small facilities. Resources providing ancillary services must be able to respond for a minimum of 40 minutes. For reserves committed in the regulation market, resource owners must be able to provide at a minimum 0.1 MW to the grid.

Synchronized reserves are distinguished between flexible and inflexible reserves (PJM, 2020). Inflexible reserves are those that have to run for at least one hour versus flexible reserves that can run for less time. In either case, a minimum of 0.1 MW is required. For ten-minute reserves, resource capacity has to be converted to fully online within ten minute requirement.

Table 18 provides a summary of ancillary services in the PJM and Table 19 provides a summary of their prices. On average, regulation reserves are the highest priced of the ancillary service. Figure 15 plots the hourly average using the dataset.

Table 18 Summary Ancillary Services in PJM

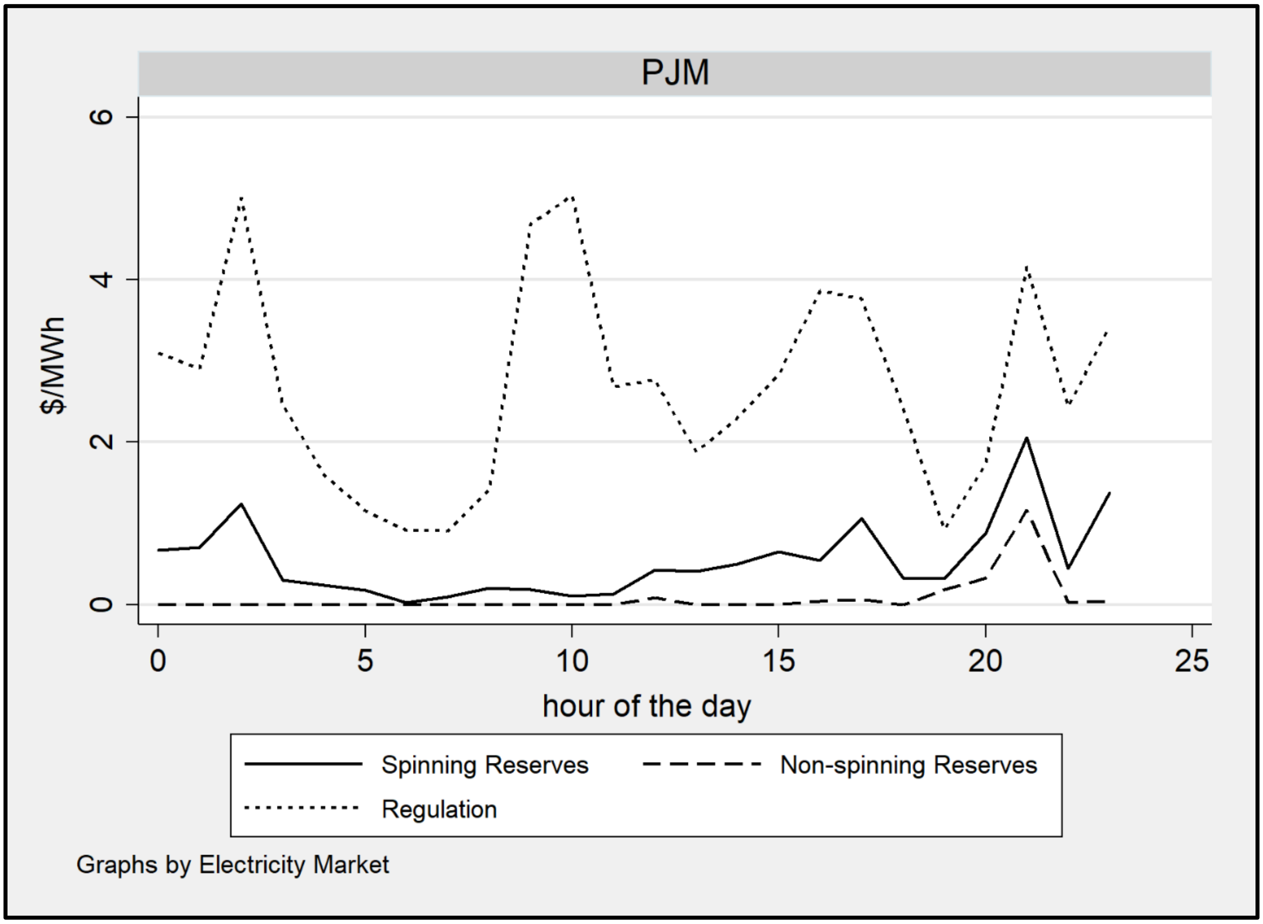
Products/Attributes	Characteristics	Location of Data
Regulation	Immediate response (increase/decrease) to automated AGC signals, operate for 40 minutes, minimum response 0.1 MW	https://dataminer2.pjm.com/feed/reserve_market_results/definition
Synchronized Reserves	Synchronized to grid, Respond within 10 minutes	Then select: 'Ancillary Service Market Results'
Primary Reserves	Includes synchronized reserves, Respond within 10 minutes	

Source: author summary of referenced data

Table 19 Summary Ancillary Services Prices in PJM

USD per MW-hour	Mean	Std. Dev.	Min	Max
Regulation	13.47	26.08	0.01	296.54
Synchronized Reserves	3.17	5.84	0.02	58.53
Primary Reserves	8.11	16.08	0.05	58.53

Source: author calculations from data at https://www.pjm.com/markets-and-operations



Source: author calculations from data at https://www.pjm.com/markets-and-operations

Figure 15 Summary of average hourly prices for ancillary services in PJM

4.7 SPP: Regulation, Spinning and Non-Spinning Reserves

Starting in 2014, SPP operates the Integrated Energy Marketplace where ancillary services are exchanged (SPP, 2020). The ancillary services that are exchanged in this market include regulation reserves (up and down), spinning reserves and non-spinning reserves. In this market, SPP acts as the buyer and the sellers are the generator participants in the market. The Integrated Marketplace has exchange of ancillary services in both DAM and RTM.

Generators providing regulation reserves must be set up with an AGC governor and respond within four seconds of calls for changes. Once deployed, these resources, either up or down, have to operate for at least one hour.

Spinning and non-spinning reserves must be able to convert capacity completely within ten minutes of the grid operator's call do so (Zhou et al., 2016).

Table 20 provides a summary of ancillary services in the PJM and Table 21 provides a summary of their prices. On average, regulation reserves are the highest priced of the ancillary service. Table 20 plots the hourly average using the dataset.

Table 20 Summary Ancillary Services Prices in SPP

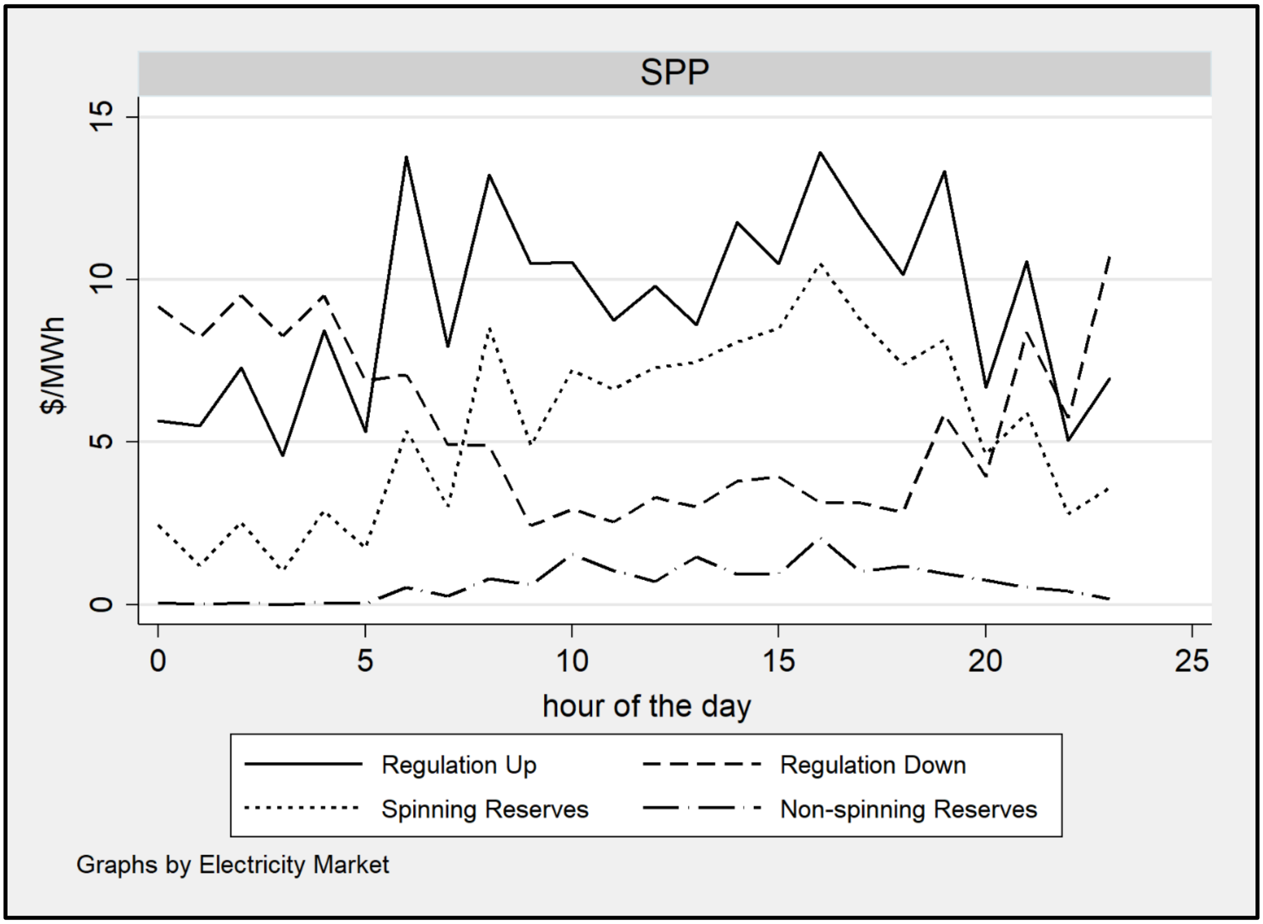
Products/Attributes	Characteristics	Location of Data
Regulation	Immediate response (increase/decrease) to automated AGC signals, follow dispatch signal, test includes max regulation ramp rate	https://marketplace.spp.org/ Then select: 'Public' 'Marketplace Public 'Markets'
Spinning Reserves	Synchronized to grid, Respond within 10 minutes	
Non-spinning Reserves	Not necessarily synchronized to grid, Respond within 10 minutes	

Source: author summary of referenced data

Table 21 Summary Ancillary Services in SPP

USD per MW-hour	Mean	Std. Dev.	Min	Max
Regulation Up	8.99	6.25	2.08	48.25
Regulation Down	5.56	5.65	0.42	36.40
Spinning Reserves	5.36	4.54	0.01	37.81
Non-spinning Reserves	0.73	1.56	0.01	26.37

Source: author calculations from data at https://www.spp.org/markets-operations/



Source: author calculations from data at [*https://www.spp.org/markets-operations/*](https://www.spp.org/markets-operations/)

Figure 16 Summary of average hourly prices for ancillary services in SPP

5. Summary

The purpose of this report is to provide a starting point for analysts who conduct technoeconomic studies on electricity markets where the evaluation is at the level of load response and energy storage. To that end, this document provides data summaries of the energy capacity market and the ancillary services markets in the seven ISO/RTOs that provide service to two-thirds of the US. Each data summary contains key features describing the represented market They also contain links to data repositories and references to key documents outlining the features of the market. There are, however, at least two categories of information the analyst will not find in this report. They are data on non-market energy products and on the energy imbalance market.

The analyst who uses this report will find details on the described markets but will also find the starting point for data acquisition to use in other areas as well. For example, black start is an ancillary service, but it is not listed in the data summaries here because of limited information on how it is valued. However, when the analyst uses the data sources described herein, they will find themselves in documents and websites where technical information can be found for black start capabilities. This is also the case with financial transmission rights and issues of congestion, to name a few.

One-third of the country receives power from systems that are not operated in competitive, auction-style markets, instead they are regulated, vertically integrated utilities. In the western US, a relatively new market arrangement called the Western Energy Imbalance Market (WEIM) was created in 2014. Run by CAISO, this is an arrangement by which utilities in the West can trade electricity in real-time with each other to balance energy supply and demand. The market operates on sub-hourly dispatch at the 5-minute level. Today the WEIM has 11 active member participants made up of utilities that own generation assets and meet load commitments. There as many pending participants as active participants. The WEIM currently operates as a real-time energy market. Consequently, data on ancillary services and capacity are not readily available.

The data contained in this report stem from many websites and data repositories. A logical extension of this work is to create a website where these data sources and key documents can be curated. This would enable the energy systems analyst to easily access the most up-to-date information any time a new technoeconomic study is initiated. A close companion to the website repository is an overview article prepared for a journal submission. This would bring greater exposure to the consolidated data source and facilitate a common starting point for studies in energy systems.

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