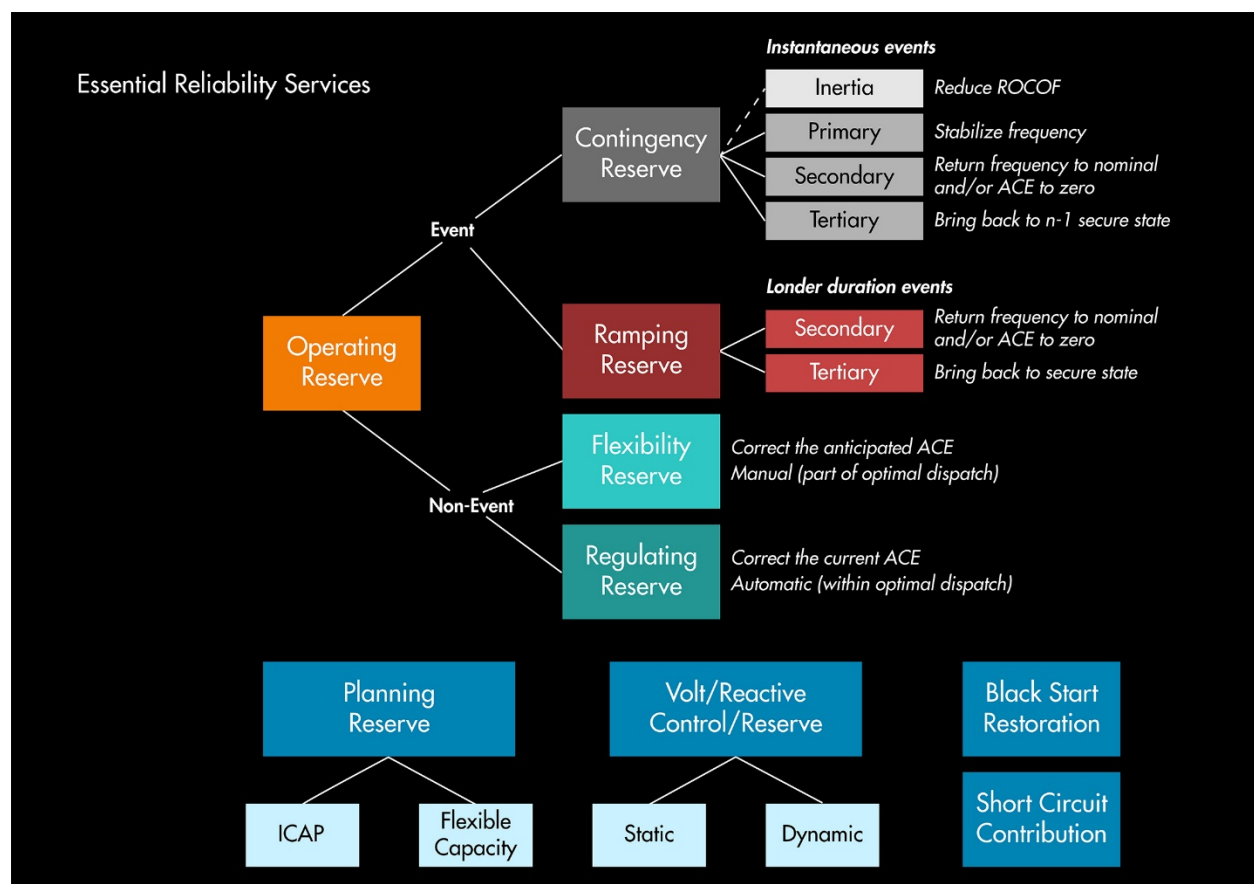


Ancillary Services in the United States

Technical Requirements, Market Designs and Price Trends

3002015670



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Technical Update, June 2019

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ACKNOWLEDGMENTS

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EPRI would like to acknowledge the support of the American Wind Energy Association and input from Sari Fink and John Hensley. EPRI would also like to acknowledge the support of Qingyu Xu for data collection and analysis.

This publication is a corporate document that should be cited in the literature in the following manner:

Ancillary Services in the United States: Technical Requirements, Market Designs and Price Trends. EPRI, Palo Alto, CA: 2019. 3002015670.

ABSTRACT

Ancillary services are services used in electric power systems to ensure the operational reliability of the bulk power system. While a relatively small component of overall electric power costs, the services are a critical need and, in some regions, the types and needs of these services are changing. This report can be used as a guidebook on the topic, summarizing the wide range of services and products that are used to support reliable electricity operations in the United States. The report describes the types of services needed, how the quantity of the service is determined and met, voltage support, and the criteria to be a supplier of the service. Services are then categorized by how they are compensated, either through competitive auctions or cost-based recovery. The last section presents analysis of ancillary service prices over time, analyzing different products and trends of the services market outcomes within the U.S. Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

Keywords

Ancillary services

Reserve

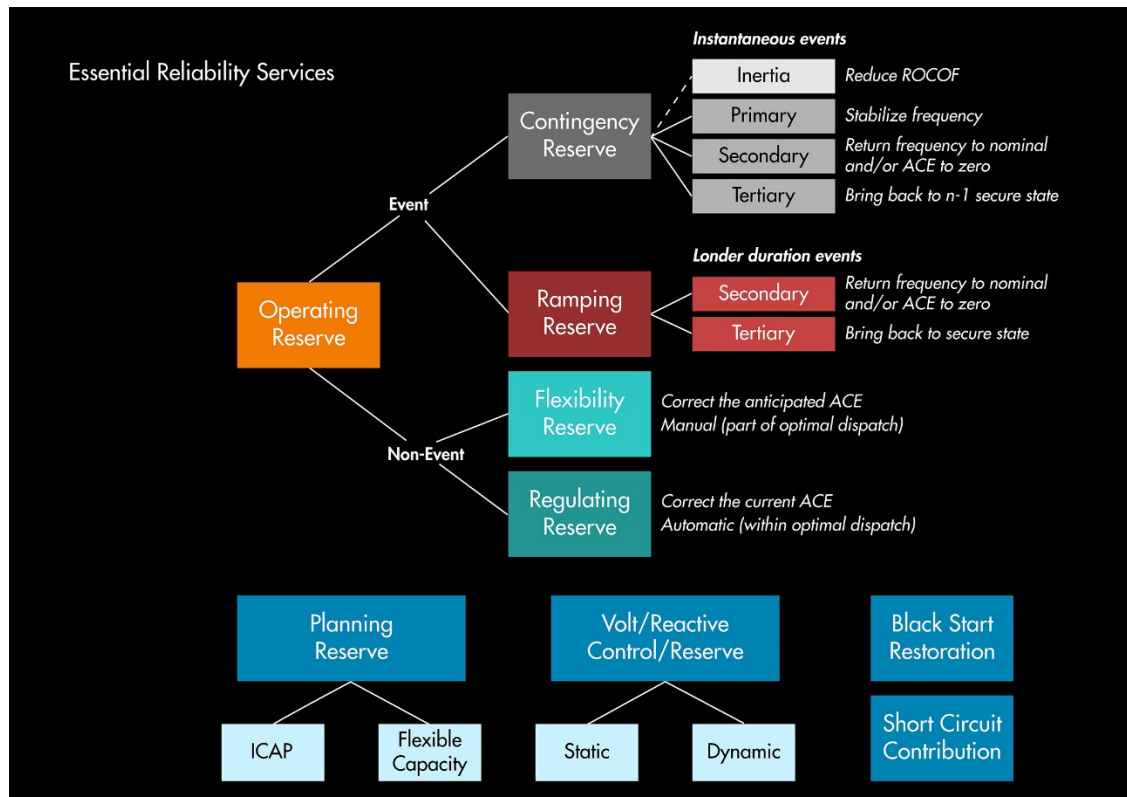
Regulation

Electricity markets

EXECUTIVE SUMMARY

Ancillary services refer to an evolving set of services used in electric power systems that are “ancillary” to the provision of electric energy, necessary to ensure the reliability of the bulk power system. This report can be used as a guidebook on the topic, by defining ancillary service products, requirements, and eligibility both generally and for each U.S. ISO market. Details are also provided about market rules and general compensation structures for difference services, including procurement through bid-based auction markets, tariff fixed or formula-based rates, and competitive solicitations. The report describes the different design features of ancillary service markets, using examples when applicable, and provides regional comparisons of these designs. Finally, the report assesses historical ancillary service market prices across ISOs, examining trends in recent years. This information can be used collectively by the industry at large to understand the challenges and opportunities faced by emerging technologies and how the changing resource supply mix may impact the evolution of the characteristics of these services.

Ancillary services cover a wide range of products and services. Section 2 describes these products in detail, and the figure below provides a high-level view of the relationship between the services. Each service – which may have different names in different regions – has a requirement that varies by region and has a different set of eligibility rules. Within the same category, different products might be compensated through a market mechanism or paid a specific rate to recover the costs incurred from providing the product. These mechanisms are described in Section 3, along with evolving market designs in different regions. The diagram emphasizes the complex relationship between products and the wide range of services that help to ensure reliability in the bulk power system.



Section 4 examines pricing data in recent years, analyzing the different products across all of the U.S. ISOs. Throughout the report, there is a focus on the effect that a changing resource mix has on the various ancillary service products, providing insight on future research needs around ancillary services and ancillary service markets in the final section. The descriptions and analysis throughout the report demonstrate overarching trends in the industry, with common themes and unique differences across regions. Section 5 provides further insight on the findings throughout the report, and several key points are summarized in the table below.

Area	Key Point
Reserve Requirements	<p>Characteristics and methods to determine service needs are based on just a few North American Electric Reliability Corporation (NERC) reliability standards. But, since ISOs and regional reliability organizations can create stricter standards, unique products and requirements can be found around the U.S.</p> <p><i>See Section 1.2.2 and Section 2</i></p>
Eligibility	<p>Eligibility rules to provide the service differs region by region, varying from tests and certification to restrictions on certain technologies.</p> <p><i>See specific products in Section 2</i></p>
Compensation	<p>The way in which ancillary service providers are compensated differs by the type of service. The reasons for how they are compensated are numerous and the compensation structure also changes with priorities and evolving needs. This evolves with ISO priorities and may be changing now.</p> <p><i>See Section 3.1 for market auctions and 3.2 for cost based</i></p>
Market Design	<p>Market designs for ancillary services are complex. They are co-optimized with energy markets and prices are heavily influenced by the lost opportunity cost to provide energy.</p> <p><i>See Section 3.1</i></p>
New Products	<p>New ancillary service products are being created in some markets; drivers can include changing resource mix and evolving system characteristics and needs.</p> <p><i>See Section 3.3</i></p>
New Services	<p>Some services have been provided for a long time but have not been explicitly recognized as a service. Many of these are now beginning to be recognized.</p> <p><i>See Section 3.3</i></p>
Price Trends	<p>In recent years products have not been uniformly increasing or decreasing across all regions. Prices follow the general hierarchy of products (regulation is highest) and are greatly influenced by regional events like storms or cold snaps.</p> <p><i>See Section 4</i></p>
Renewables	<p>Certain characteristics of variable renewable resources may impact ancillary service needs, and they, along with other emerging technologies, have the capability to provide certain ancillary services.</p> <p>Understanding how the markets function for these services will be important for future providers of these services to ensure economic provision.</p>

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1

INTRODUCTION

Ancillary services are services used in electric power systems to ensure the operational reliability of the bulk power system. While a relatively small component of overall electric power costs, the services are a critical need and, in some regions, the types and needs of these services are changing. Within the organized electricity markets – those that are operated and administered by ISOs and RTOs¹ – ancillary services are procured through several mechanisms: bid-based auction markets, tariff fixed or formula-based rates (often based on cost of service), and, less commonly, competitive solicitations. In addition, certain ancillary services are supplied without payment due to a number of reasons.

This report provides a detailed survey of how ancillary services are defined, provided and compensated across the United States. The objective is to provide industry participants a guidebook to ancillary services, including what they are, how they compare across regions, and how they have evolved and continue to evolve. Ancillary service terms and definitions reflect the historical evolution of the U.S. ISO wholesale markets as well as balancing area authorities (BAAs) in areas without organized markets: while there are similarities in the definition of the products, there are differences in terminology, operational methods and market mechanisms. These similarities and differences are important to understand.

The report provides detailed examination of the following topics:

- The regulatory framework that influences ancillary services requirements, and the structure and characteristics of the ISOs who administer ancillary service markets;
- Ancillary service product definitions and eligibility requirements, including more recent additional services, both at a general level and by ISO market;
- Ancillary service market rules and compensation design, both at a general level and by ISO market;
- Statistical assessments of ancillary service market outcomes in several ISO regions.
- Insights and potential topics that require further research

There are several other surveys of ancillary services (e.g., [1]-[5]). The intent here is to provide sufficient detail on the technical and market details, update where necessary, and provide insights on the evolution of these products and services, particularly around the impacts that new technologies and changing resource mixes have on these services. The report also provides ideas for future research, particularly around how evolution of the power system is changing the ways in which different ancillary services are needed for ensuring reliability economically, and how emerging technologies can help provide these ancillary services in innovative ways.

¹ The term ISO is used in this report generically to refer to both ISOs and RTOs as defined by federal and state regulators. The U.S. ISOs are described further in this section below.

These ancillary services have evolved over time, both the services and characteristics that define those services as well as the compensation methods. This report provides a detailed review of several important ancillary services characteristics and their evolution, several competitive ancillary service market designs, and other compensation schemes for select services. The report also reviews historical prices and trends in the ancillary service markets. Throughout the report, there is a focus on the effect that a changing resource mix has on the various ancillary service products and markets, providing insight into future research needs in the final section.

For variable energy resources (VER), primarily wind and photovoltaic solar power, ancillary services are becoming important for at least two reasons:

- First, certain characteristics of VER, notably the increased production variability and forecast uncertainty that they may add to existing variability and uncertainty, may increase the needs of several ancillary services. Assessing how these characteristics impact those needs is important to understand, and whether there are mitigation techniques that can reduce the impacts.
- Second, VER are technically capable of providing several ancillary services. Several studies and pilot projects have demonstrated the technical capability. Doing so during certain time periods can benefit system reliability, reduce operating costs as well as provide an additional revenue opportunity for these technologies when providing ancillary services in competitive ancillary service markets. Understanding how the markets function for these services will be important for future providers of these services to ensure economic provision.

These two trends will interact with each other over time. The potential for providing these services from VER may grow as their penetration increases and they become competitive as a service provider. To provide these services, the benefits in the form of market revenues have to outweigh the costs, which include foregone contracted energy revenues, renewable energy or emissions credits, financial incentives based on energy production, and/or any equipment and administrative costs. While currently the costs of supplying ancillary services from VERs are usually higher than the benefits, this may not always be the case in the future. In some future scenarios, these resources may be expected to provide ancillary services as they displace the existing resources which currently provide most of these services, particularly during certain conditions and time periods. The performance of these technologies, cost-benefit analysis, and the confidence of system operators to rely on the availability of VER to provide services when expected to all will warrant further consideration and study. The supply of ancillary services may also expand from resources other than VER, including energy storage, demand response, distributed energy resources of different types, and others. Thus, there is significant uncertainty about ancillary service needs and value over time and the ways in which these services will evolve along with a changing technology mix.

1.1 What are Ancillary Services?

Ancillary services ensure the operational reliability of the bulk power system. Due to transmission open access in Order 888, the Federal Energy Regulatory Commission (FERC) created a definition of ancillary services 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.” Historically, services that may support distribution system reliability have not been

considered in the lists used if those services do not also support transmission system reliability. In addition, the service of providing capacity, which is a market product in many U.S. ISOs, is often kept separate from the lists of ancillary services (though we discuss the capacity product briefly in Section 2). Finally, several financial products in the markets (notably financial transmission rights and virtual transactions) and development of transmission also are not typically catalogued under the heading of ancillary services and are not discussed here.

When the regulatory reforms of the wholesale markets began, FERC defined six ancillary services in Order 888 (1996) [8], as shown below:

1. **Scheduling, system control and dispatch:** Service provided by the system operator of a control area to schedule the movement of power through, out of, within, or into a control area.
2. **Reactive supply and voltage control from generation service:** Producing or absorbing reactive power to maintain transmission voltages on transmission facilities to within acceptable limits.
3. **Regulation and frequency response service:** Having generation and non-generation resources raise and lower output to maintain power balance, maintaining interconnection frequency at nominal level and interchange schedules intact.
4. **Energy imbalance service:** Providing balance when a difference between actual and scheduled delivery of energy. Note that FERC originally added the definition of the balance error occurring within a single hour.
5. **Operating reserve – synchronized reserve service:** Energy provided immediately after a system contingency by online resources (or non-generator resources providing equivalent service)
6. **Operating reserve – supplemental reserve service:** Energy provided after a system contingency but that is not immediately available, but rather within a short period of time.

Scheduling, system control and dispatch is an ancillary service provided by the system operator, and one in which the industry typically does not categorize with the other services. It is not something that can necessarily be provided by different technologies in the same region. Energy imbalance service in the ISO markets is provided by the real-time energy markets and is typically not classified as a separate ancillary service in those regions. The other ancillary services are familiar to those in the industry as most have been part of bulk power system practice for decades. However, there are a notable number of services that are missing from this list that are being required or procured in several regions. In addition, some in FERC's original list may also need further definition or disaggregation. Figure 1-1 further categorizes the ancillary services that we think about today (adapted from [2], first shown in [7]). A majority of the ancillary services described in this report are based on a higher-level category of operating reserve (including numbers 3-6 of the FERC's list above).

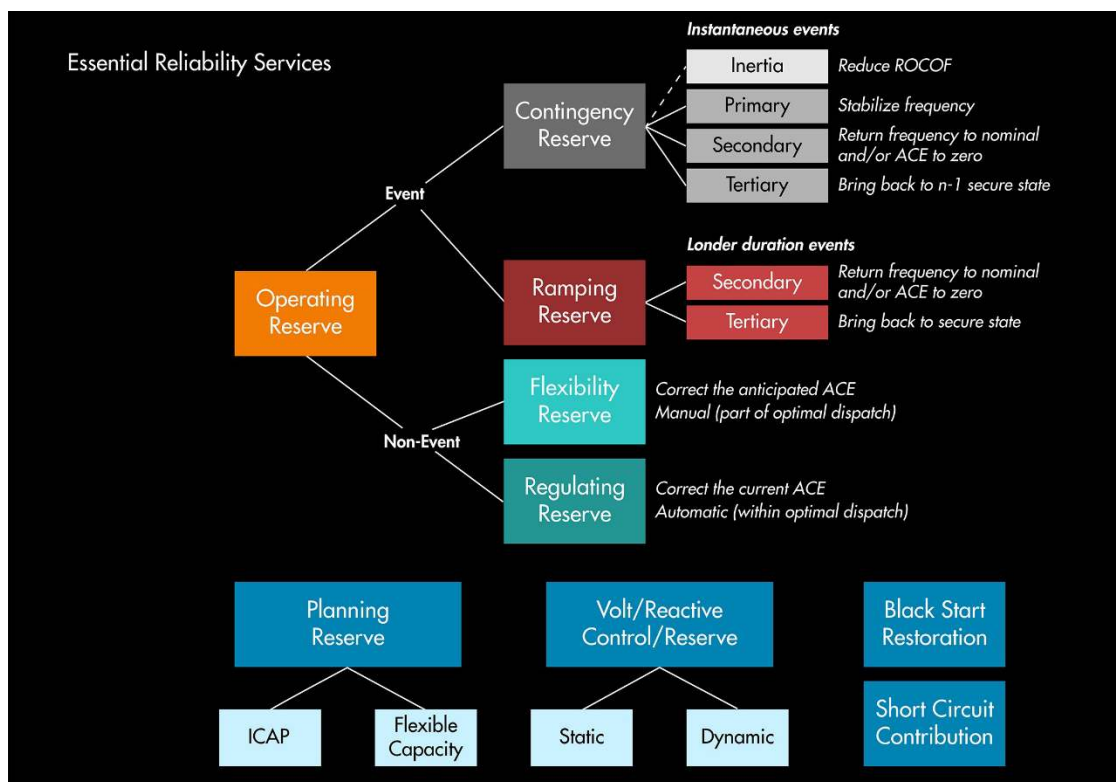


Figure 1-1
Ancillary Services and example categorization.

A number of the products shown in Figure 1-1 are similar to those in FERC’s list. Additional services under operating reserve are either newly introduced based on new needs, or disaggregated components of one of the services on the FERC’s list; e.g., Regulating Reserve and primary contingency reserve (primary frequency response) are shown separately under different categories. The operating reserve services can be categorized in many different ways with Figure 1-1 being one example. The diagram shows services split by event – large in magnitude, rare in occurrence, with magnitude and probability thresholds different by system² – and non-event – needs that are occurring regularly during normal conditions. In Section 2, we will describe each of these products in more detail. In Section 3, we will describe compensation schemes for applicable services. Throughout this report we will refer back to the terminology shown in this chart for clarity given the many different terminologies that are used in practice.

1.2 Regulatory Framework of Ancillary Services

Ancillary services are subject to oversight by federal, regional and state regulators. Requirements of regulatory agencies include aspects of the definition of these services, quantities of the service

² Note that the “flexibility reserve” in Figure 1-1 is most closely related to short-term flexibility products being introduced in many ISOs and described in Section 2.1.4, while “ramping reserve” in this same chart refers to reserve that is saved for large magnitude, rare, long-duration events, like massive multi-hour ramps or substantial forecast errors. It is either also captured in the flexibility products being introduced, met through contingency reserve, or not held at all. They are separated in the figure because there may have been different costs and product definitions associated in the past.

that are required at a minimum, and how market-based and other compensation mechanisms are established and modified. This regulatory and market framework is briefly reviewed here, with more details on market design provided in the subsequent sections.

1.2.1 Federal and State Regulation of Ancillary Service Definitions and Procurement Mechanisms

Under the Federal Power Act, FERC regulates transmission access and wholesale market design across most of the continental United States with the exception of the ERCOT region of Texas, which is regulated by the Public Utilities Commission of Texas (PUCT). Understanding the regulatory framework is important for suppliers of ancillary services as well as “consumers” of the services. Many of the design discussions of these services at the stakeholder meetings within the ISOs must take any regulatory requirements as a constraint when implementing new designs that may be needed for reasons within the region. Commercial revenue estimates and total costs and payments based on provision of ancillary services must also take this into account.

In recent years, FERC has engaged in numerous efforts to revise ancillary service requirements. Note that FERC orders approving NERC reliability standards are discussed in the next section.

- In 2011, Order 755 [9] required all wholesale power markets to ensure proper compensation of performance-based frequency regulation which included that lost opportunity costs be part of the capacity price and that so-called mileage payments be provided to all resources based on the movement that they are asked to provide when regulating.
- In 2012, Order 764 [10] included updated practices on renewable energy resource integration that included forecasting output scheduling transactions and data. One aspect of the rule requires intra-hour scheduling, acknowledging that hourly scheduling might result in significant imbalance charges to VERs (due to forecast error).
- In 2016, Order 827 [11] required that all newly interconnecting technologies including non-synchronous technologies like wind power, must include the capability to provide reactive power and voltage support.
- In 2018, Order 841 [12] required ISOs to adjust market participation rules to, among other directions, allow for energy storage resources to be able to participate in ancillary services that they are capable of providing.
- Also in 2018, Order 842 [13] required all newly interconnecting resources to have frequency response capabilities.

1.2.2 NERC and Regional Reliability Standards for Ancillary Services

The NERC enforces mandatory reliability standards for the United States and voluntary reliability standards for other jurisdictions in North America. The entity responsible for compliance related to most ancillary services is the Balancing Area Authority (BAA).³ The definitions of several ancillary service products are influenced through NERC reliability

³ Balancing areas (BAs) are regions that contain generation, transmission and/or loads that must maintain the balance of generation and load within the metered boundary. In North America, these are managed by the BAA who maintains load/supply balance. ISOs are the BAAs in their regions.

standards [14], a few are listed below.⁴ It is important to recognize these reliability standards, as they are consistent across North America. Regional requirements can only be more stringent. Thus, there is less flexibility in the ancillary service design as related to these requirements.

- BAL-001: This standard refers to balancing during normal conditions. BAL-001 historically defined the NERC Control Performance Standard 1 (CPS1) and Control Performance Standard 2 (CPS2). These define the bandwidth for how a balancing area helps system frequency on a 1-minute timescale for CPS1, and how it limits its total imbalance, or area control error (ACE), on a 10-minute timescale for CPS2. Some recent changes will also replace CPS2 with the Balancing Area ACE Limit (BAAL). The BAAL is a longer-term balancing rule, like CPS2, but will adjust the balancing limit allowed based on the interconnection frequency level. This influences, but does not explicitly set, the requirements for how much regulating reserve BAAs will require.
- BAL-002: This standard is for contingency disturbance conditions. It is also called the Disturbance Control Standard (DCS) and requires that BAAs ensure there is enough contingency reserve to meet the largest contingency in the area, how soon a contingency must be corrected using contingency reserve, how soon that contingency reserve must be replaced, and what constitutes a contingency. This standard sets the requirement for secondary contingency reserve in balancing areas, influences the “ten-minute” requirement for secondary contingency reserve and has some influence on replacement (tertiary) reserve.
- BAL-003: This standard had historically placed a requirement on the frequency bias term in the ACE calculation. However, recently the standard was expanded to include the frequency response obligation (FRO) requirement. The FRO requires a minimum amount of primary frequency response (in MW/0.1Hz) for each BAA to carry. This standard influences the requirement for primary contingency reserve in balancing areas.
- VAR-001: This standard requires that voltage levels are maintained within acceptable limits based on a range or target point as given by the transmission system operator and that the operator schedules sufficient reactive power resources to regulate voltage levels. This standard influences the requirements that a balancing area (or more specifically, transmission operator) hold for voltage control and reactive reserve services.
- EOP-005: This standard requires that balancing area or transmission operators have plans for restoration based on its black start resources. This requirement influences the needs for black start and restoration service and what resources are able to provide that service.

In addition to NERC, Regional Reliability Entities may institute additional reliability standards for balancing areas and transmission operators within their region, as long as the requirements also comply with NERC standards. There are several examples of how regional reliability standards may impact ancillary service products within a region. As an example, a reliability standard in the WECC region called BAL-002-WECC requires that secondary contingency reserve be greater than the maximum of (1) the largest single contingency in the balancing area or (2) the sum of 3% of generation and 3% load within the area. This sets the requirement for that reserve in a way that is different than other regions. The Northeast Power Coordinating

⁴ We avoid the supplemental labeling that is used during the revision process for clarity and because the standards are continuously being updated.

Council (NPCC) sets requirements for 30-minute reserve for BAAs in its region, which leads to a 30-minute reserve product in ISO markets in that region that is often not existing in other regions. There are a few other requirements in other regions that establish the characteristics of ancillary service products.

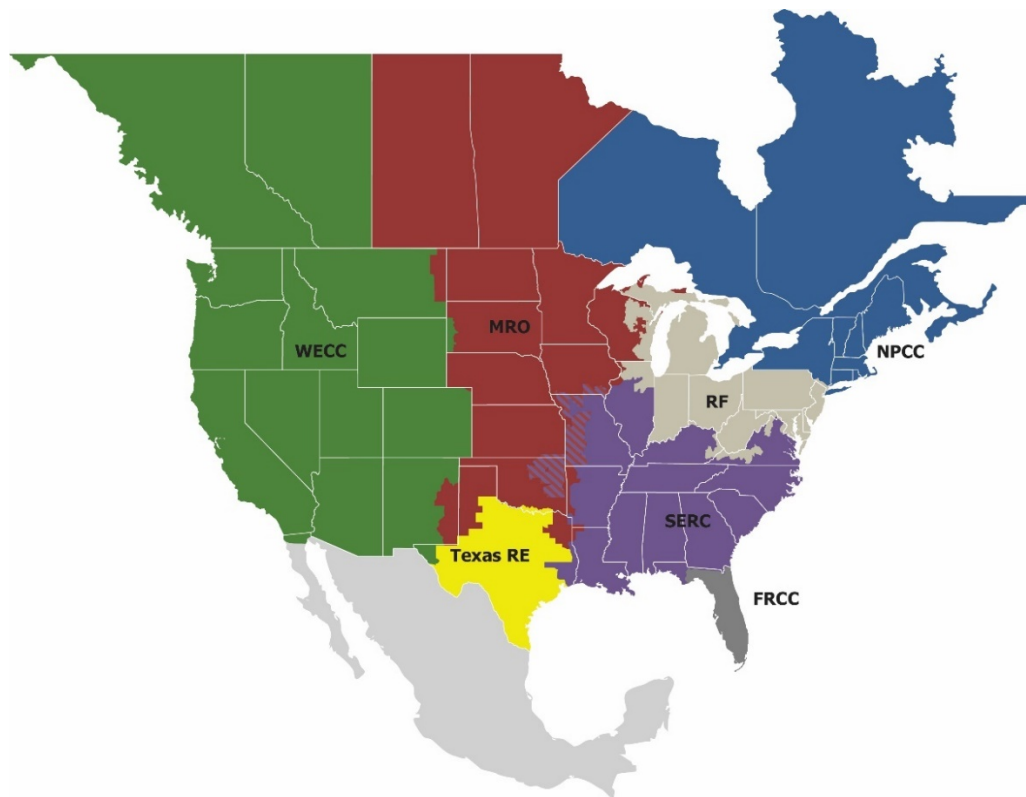


Figure 1-2
NERC Regional reliability organizations in North America; Source: NERC.

1.2.3 State Policies

In addition to federal policies and standards, several types of state policies may have an effect on ancillary service requirements and markets. Notably, state policies introduce new resources which affect these requirements, but also provide new capabilities to meet them. The clearest example of this is the large number of state Renewable Portfolio Standards (RPS), which influence the rate of renewable energy expansion and the types of renewable resources which are procured. As noted, VERs are the primary drivers of changing ancillary service requirements. As states establish higher RPS and decarbonization policies, the impact on ancillary service requirements will need to be considered in detail. At the same time, several states, such as California, allow RPS resources to offer ancillary services to buyers (through stand-alone generation or from integrated storage), which provides another mechanism for more flexible renewable resources to be introduced into the market.

State storage policies also have significant implications for ancillary service market design and the resource mix. To date, these policies are largely introducing lithium-ion batteries and flywheels, which are well suited to supplying a range of ancillary services but have required modifications to ISO software and operating procedures. While the largest quantity of new

energy storage to date has entered the PJM market on a merchant basis to provide frequency regulation, the next significant phase of new storage assets is being deployed in California under state policy requirements and are already participating in the CAISO markets. The states of Massachusetts, New York, and New Jersey have all established storage policies and these resources will also participate in the respective ISO markets.

State policies may also support demand response and distributed energy resources, which are eligible for supplying ancillary services. The ISOs in key states which have such policies, including California and New York, are working on the integration of DER into the wholesale markets.

States may also be engaged in resource planning, either in defining the regulatory requirements for jurisdictional utilities or doing the analysis themselves, which addresses long-term forecasts of operational flexibility requirements. An example is California, which has sponsored such studies and introduced such requirements into its long-term procurement planning processes.

Finally, some states have responsibilities as resource adequacy authorities, which may include program design to address operational flexibility needs. The primary example is the California Public Utilities Commission's (CPUC) flexible capacity requirement, developed jointly with CAISO. While not an ancillary service, the general objective of this design is to ensure that capacity resources have attributes needed for renewable integration.

1.3 Overview of the ISO Markets

The first ISOs began operations in 1998-1999, and steadily expanded until they currently encompass over 60% of the U.S. electricity demand. The wholesale markets which they operate are designed to accommodate a range of different types of utility structures and market participants. In some states with ISOs, the electric power sector was restructured by state regulators, with a separation of the companies which own generation, transmission and distribution, and with both wholesale and retail competition. In others, the sector is still comprised primarily of regulated utilities with different levels of vertical integration, which may be investor-owned, municipal, cooperatives or types of federal or state agencies. As such, the wholesale markets, including for ancillary services, are designed to allow for self-supply (by utilities with both supply and demand) or transactions through an auction market, or a combination of the two. A key feature of the markets is that market prices apply to all resources which are operating, whether self-supplied or cleared through the market independently of their offers.

The ancillary services are needed for the reliability of the bulk power system, and the load-serving entities are allocated a procurement obligation after the fact (typically on a load-ratio share). As such, ancillary services have properties of a public good. The ISO serves as the procurement entity on behalf of the load-serving entities but does not take possession of the services in the process.

In regions that are outside of organized electricity markets, a set of agreed-upon rates between providers and the balancing area, must be approved by the FERC or in some cases state/province regulators. In organized electricity markets, the ISO either has a competitive market with the rules for participation and pricing clearly laid out, a cost-recovery mechanism with a clear description of what costs are eligible for recovery when service is provided, or in other cases no

compensation mechanism. In this report, we primarily focus on organized markets when discussing compensation schemes for ancillary services.

1.3.1 Geographic Scope and Resource Mix

There are many reasons why different products have different compensation schemes. The compensation design of each product is a culmination of history of the ISO, regional reliability rules, FERC directives, the resource mix in that ISO, and its stakeholder process. There are seven U.S. ISOs and two Canadian ISOs, depicted in the map shown in Figure 1-3. Each of the nine ISOs have some form of ancillary service markets for a subset of ancillary services. The design for some of the ancillary service markets like spinning (secondary) contingency reserve and regulating reserve are quite similar across all U.S. ISO markets. Other products may have auction-based markets in some regions and cost-recovery in others. Still other products may have auction-based markets in some regions with no equivalent compensation (or no equivalent product) in others. In Section 3, we will describe the common design of ancillary service markets, unique designs of certain products in certain ISOs, and evolution of ancillary service compensation across competitive and cost-based compensation schemes for all the applicable products shown in Figure 1-1.

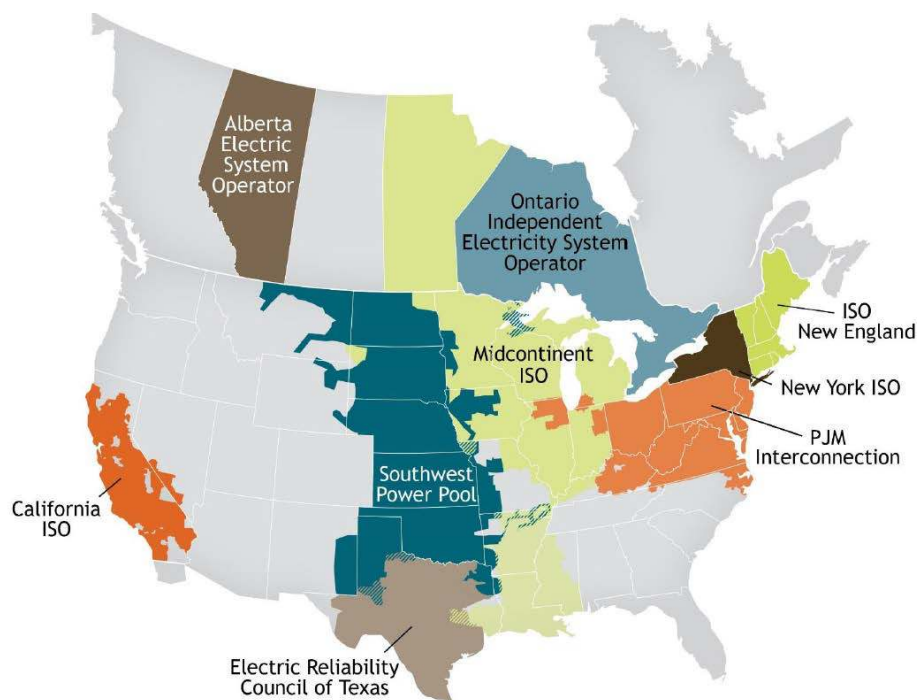


Figure 1-3
Geographic scope of U.S. and Canada ISOs and RTOs, 2018 (source: www.isorto.org)

Figure 1-4 shows the fuel mix for annual energy in the ISOs in 2017 by percentage of annual consumption (we also include the 2016 mix of CENACE, the Mexican ISO for further comparison). The difference in resource mix is relevant because it may drive the different market designs in different regions as well as the potential of resources that will be available to provide ancillary services. Some technologies are adept at providing certain ancillary services and this depends on the attributes of the service.

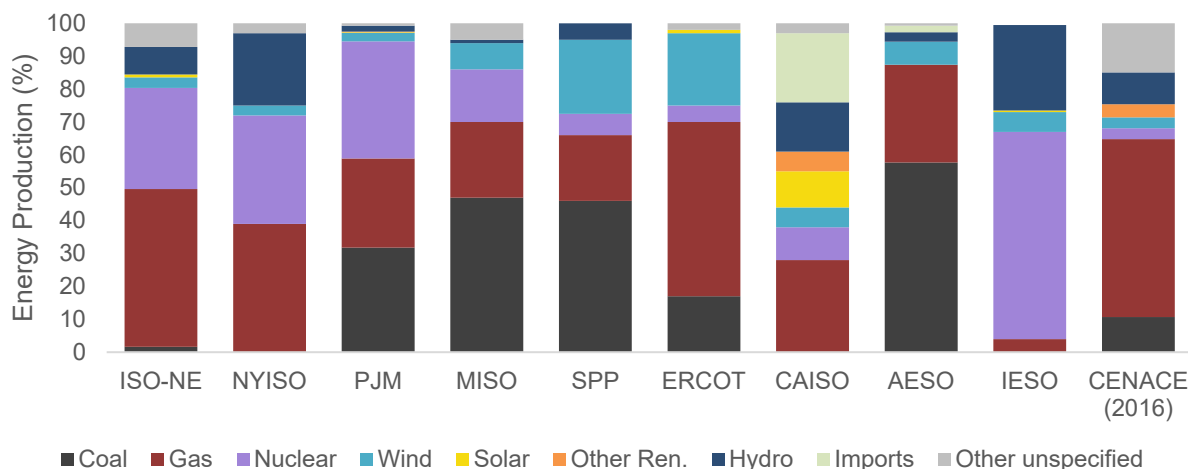


Figure 1-4
Fuel mix of North American ISOs and RTOs, by percentage (%) of total annual energy, 2017 unless otherwise noted.

1.3.2 Market Volume

Table 1-1⁵ provides perspective on ancillary service market volume by placing these expenditures alongside market expenditures for all wholesale services (but excluding administrative costs). Historically, ancillary services have accounted for between 0.5% - 3% of total wholesale payments in organized markets, which can equate to over \$1 billion worth of procurement in the United States organized markets. As can be seen in Table 1-1, the volume of ancillary services varies substantially across the regions. It is not always relative to the size of the region. Other factors include the resources providing the services, the marginal energy costs of resources within the region, the market design of the service, administrative scarcity/shortage pricing levels (described in Section 3.1.5), and many other factors as are discussed in Section 3 and also demonstrated in Section 4.

⁵ There is a wide variety on the information provided by each ISO on specific market volume of different market products, ranging from some ISOs giving the specific number to absolutely no information. For the latter, the research team made estimates based on available data such that large uncertainty in the accuracy may exist. Comparisons should be based on orders of magnitude and not specific values.

Table 1-1**Data on total market financial settlements (2017 unless otherwise indicated)**

	Total Market Volume (\$B)	All-in-Price (\$/MWh)	Energy (\$B)	Ancillary Services Markets⁶ (\$M)	Uplift (\$M)	Financial Transmission Rights (\$M)⁷	Capacity Market (\$M)
AESO (CAD\$)	3	25.5	1.8	81	0.23	N/A	N/A
CAISO	9.3	42	8.7	172	108	80	N/A
ERCOT	14	30.15	10	323	0.5 ⁸	379	N/A
IESO (CAD\$)	17	15.8 ⁹	2.2	57	146 ¹⁰	N/A	N/A
ISO-NE	9.1 ¹¹	76	4.5	128 ¹²	52	30	2,240
MISO	26.9	31.35	24.7	69	104	252	47
NYISO	8.7	40	5.3	110	38	222	3,000
PJM	40.0	54	23.5 ¹³	508.1	129	542	8,800
SPP	16.7	24.08	6.3	80	68	308.8	N/A

The remainder of this report is organized as follows. Section 2 will provide the descriptions of different ancillary service products, focusing on the products that exist today in U.S. ISO regions. The descriptions include more detail on what the ancillary services are, the quantity that is required, and the criteria and eligibility to provide the service. Section 3 then reviews ancillary service compensation including the ancillary service markets where they exist. Several characteristics of ancillary service markets with competitive auctions are described first, followed by comparisons of each service in each of the U.S. ISO markets. This is then followed

⁶ Note that some markets, like PJM, include cost-based ancillary services in this total like blackstart and voltage and reactive power support. Most of the others do not.

⁷ Unless noted, shows net payments made in the FTR auctions, which may be identified as the costs incurred by FTR holders. PJM shows net revenue for the 2017/2018 Annual FTR Auction. MISO shows profits from the Annual, Monthly, and the MPMA. SPP shows payments for load-serving entities, non-load serving and financial entities totaled \$314.3 million. In ERCOT, the total auction revenue is \$379 million; CRR owners received payments totaling \$732 million.

⁸ ERCOT make-whole payments from RUC units totaled \$0.5 million, and costs from all types of uplift totaled \$365 million, which includes, the ERCOT System Administrative Fee, Reliability Unit Commitment Settlement, Operating Reserve Demand Curve Settlement, Emergency Response Service Settlement, in addition to others.

⁹ The weighted average wholesale price of electricity is 15.8 CAD\$/MWh (1.58 ¢/kWh), this is the average Hourly Ontario Energy Price (HOEP). The cost of power for Class A and Class B consumers, including the Global Adjustment, is CAD\$64.9/MWh and CAD\$115.5/MWh respectively. The Global Adjustment Charge is the reason why the Total Market Volume is significantly larger than the sum of other products, relative to other ISOs.

¹⁰ Uplift total includes hourly uplifts, CMSC, IOG, other, and daily and monthly uplift charges.

¹¹ Regional network load accounted for \$2.2 billion in ISO-NE, of the total \$9.1 billion in market volume.

¹² In 2017, about 31% of these total costs were from ISO-NE's forward reserve market.

¹³ This value was paid by demand; generation was paid \$24.6 billion. Total energy costs for 2017 was -\$475.2 million.

by brief descriptions of ancillary services with cost-based compensation and any unique comparisons across the ISOs. Section 4 provides an analysis of outcomes of ancillary service markets in the U.S. focusing on various statistics around ancillary service market prices. In Section 5, a summary is provided including unique aspects that need further research and monitoring, especially around the potential evolution in ancillary service products and ancillary service market designs.

2

ANCILLARY SERVICE PRODUCTS

This section provides ancillary service product definitions and service requirements in the United States. The section begins with an overview and description of the existing ancillary services and some of the products that are being introduced. Many of the modifications to existing services and the specifications of newer ones are due to a changing resource mix, changing operating paradigm, introduced reliability standards, or other technological changes. There are a few aspects that we focus on in this section: the overall definition of the ancillary service and whether that definition has changed in recent time, the attribute requirements of the service including response times and capability needs, the system quantity requirements the system operator sets and how those are determined, and the types of technologies that are capable of providing the service including specific eligibility rules where applicable. We provide a comparison of the different characteristics across the U.S. ISOs for ease of understanding what the differences are in services in different regions, but also provide some explanation where applicable on why these differences exist. Finally, we offer some insight on how these services may be evolving in the future. This section describes the technical description and characteristics of ancillary services in U.S. ISOs whereas Section 3 will describe the characteristics of how the ancillary services are compensated and procured.

In describing and comparing the ancillary service definitions in this section, we will focus on the technical characteristics of the service, what is needed from the system operator perspective, what is delivered from the individual resource perspective, and any linkages across the different services. Depending on the service, characteristics like response times, locational granularity, types of physical equipment used to provide the service, and what condition will trigger the use of the service will all be discussed when applicable. We will primarily use the terminology shown in Figure 1-1, which is a tradeoff between most commonly used terms and desire to disaggregate services to the most detailed level, but provide a list of other terminology examples used across North America and elsewhere in the world in each service subsection.

2.1 Operating Reserve for Active Power Control

Operating reserve defines the active power capacity that is held above or below the energy schedule of the system resources, to be used in case of a defined event or condition that occurs after the schedules are given to correct the active power balance. These reserves encompass the largest set of ancillary services and the services that are primarily selected and compensated through auction-based market mechanisms. Different types of operating reserves are needed for different reasons and terminology differs from region to region. The left-hand side of Figure 1-1 shows examples of operating reserve types with some of the categories based on common existing services while others are new or evolving services, such that operators may not necessarily have seen a need for these until recently. Operating reserves are typically held at a balancing area level or within transmission-constrained zones within a balancing area, although some reserves also can be shared across multiple balancing areas using reserve sharing groups.

The range of responsive capability reserved by the BAA to provide operating reserves is a function of the reason for the reserve. For example, some operating reserve is used for large

events, while others are used for normal, continuous balancing efforts that are not captured by changing energy schedules. The speed of response is also a characteristic in the type of operating reserve, some requiring rapid response, while others may allow slower yet sustained response. Other characteristics include the direction of response to hold: upward, downward, or equal amounts of both, the technology requirements needed: for example, autonomous frequency response capability, automatic generation control, and online status. Table 2-1 describes these characteristics.

Table 2-1
Different characteristics that make up the different operating reserve types

Operating Reserve Characteristic	Description
Condition for Deployment of Reserve	Nonevent, generation contingency event, transmission event, VER ramp event, ACE excursion
Reserve Direction	Upward “raise”, downward “lower”, both “symmetric”
Reserve Speed	Instantaneous response, non-instantaneous response, automatic control, manual control, response speed, delay allowance, sustainment period
Reserve resource status	The state of the resource providing the operating reserve: Spinning (also called synchronized), non-spinning (also called non-synchronized), frequency responsive
Reserve Need (i.e., what does it help accomplish)	Stabilize system frequency, bring frequency to nominal level, replace other reserve, reduce area control error, reduce price spikes, reduce system costs

Operating reserve types discussed here are secondary contingency reserve, tertiary contingency reserve, primary contingency reserve, regulating reserves, and flexibility reserve. Due to its relationship with inertia and fast frequency response, we include primary contingency reserve later in this section when discussing the other two services to emphasize their relationship to system frequency control during the first several seconds following a disturbance.

2.1.1 Secondary Contingency Reserves

Other Common names: Spinning reserve, non-spinning reserve¹⁴, synchronized reserve, ten-minute reserve, ten-minute synchronized reserve, ten-minute non-spinning reserve

Contingency reserves are procured to address unplanned outages of significant generation or transmission facilities. Typically, procurement of these reserves is split between resources that are online or “spinning” and those which are offline or “non-spinning” that can respond within required time frame (e.g., 10 minutes). The minimum requirement for contingency reserve is typically based on the largest contingency within the ISO. The requirement is based on NERC BAL-002 as discussed in Section 1. Table 2-2 summarizes requirements in each ISO, showing that there are differences in how these requirements are established. CAISO determines its contingency reserve requirement based on the regional Western Electricity Coordinating Council

¹⁴ In our definition of secondary contingency reserve, the service is used following a contingency to correct the frequency or ACE. Both online and offline reserve can accomplish that and these two services are not differentiated in the explanation of the product. Since there are requirements for having portions of secondary contingency reserve to be online, they of course are separated when schedules and prices are calculated.

(WECC) contingency reserve rule which requires that the amount be greater than the maximum of either the largest contingency in the area or the sum of 3% of generation in area and 3% of load within area. Other areas require amounts greater than the largest contingency, particularly those in areas that used to include many BAAs (e.g., SPP). Most areas require that at least half of that reserve be spinning. ERCOT currently requires all contingency reserve (up to its largest contingency requirement) to be spinning.¹⁵

Table 2-2
Contingency reserve requirement in U.S. ISOs

ISO/RTO	Requirement Definition ¹⁶
ISO-NE	Ten minute reserve must be greater than or equal to the largest first contingency loss times the contingency reserve adjustment factor (a number between 1 and 2 representing the previous quarter's DCS score with 1 being perfect score) (Generally between 1500 and 1770 MW, half spinning)
NYISO	Total 10-minute operating reserve must be greater than or equal to the largest single contingency. (Currently 1310 MW, half spinning)
PJM	Total contingency reserve must be greater than or equal to 150% the largest single contingency. (ranges from 2000 to over 4000 MW, 2/3 spinning)
MISO	Market-wide contingency reserve requirement set to be greater than or equal to the largest single supply contingency (resource or transmission). (typically around 1100 MW, half spinning)
SPP	The minimum contingency reserve is equal to the generating capacity of the largest unit within the metered boundaries of SPP plus one-half of the capacity of the next largest generating unit within the boundaries of SPP. (around 1500 MW, half spinning)
ERCOT	Requirement is posted for four hour blocks and is a function of anticipated system inertia, primary frequency response, diurnal load and wind patterns, and average temperature. (2300 MW to 3200 MW, 60% demand response)
CAISO	The minimum requirement is equal to the greater of (1) the single largest contingency and (2) the sum of 3% of CAISO hourly integrated load plus 3% of CAISO hourly integrated generation. Up to an addition 25% of solar capacity may be procured in addition. (700 MW to 1100 MW)

On any particular resource, the capability for secondary contingency reserves is typically limited by 10-minutes of ramp rate from the set point of a spinning unit up to its maximum operating level, or in the case of non-spinning reserve, how much it can provide when starting up and synchronizing within 10 minutes. The response time is based on NERC Standard BAL-002, the contingency event recovery period, which requires that Area Control Error (ACE)¹⁷ be returned to its pre-disturbance value within fifteen minutes. All ISOs require the response time to be ten

¹⁵ This requirement may be changing to allow non-spinning to provide ERCOT's new contingency reserve service. In addition, ERCOT currently also allows up to 60% of this reserve to come from loads that trip following large frequency deviations.

¹⁶ Requirements are estimates, and these values are continuously changing.

¹⁷ ACE is a measure of imbalance within a balancing area. It takes the sum of frequency deviation multiplied by the frequency bias and the interchange scheduling error to measure the overall balancing error that is caused by the balancing area.

minutes to allow for five minutes to account for communication time. Often, there are also rules on the minimum duration that contingency reserve suppliers must provide a continuous supply of energy. This is also based on a separate requirement of NERC BAL-002, the contingency reserve restoration period, that allows contingency reserve to be short for at most 105 minutes following a contingency event. Other regional requirements set this value to be less than 30 minutes in some cases. Many areas have historically established between 30 minutes to a one-hour continuous energy duration requirement when contingency reserves are activated.

Locational requirements for contingency reserve can be important in ISOs and other BAs that have substantial transmission constraints within their area. ISOs define regional contingency reserve requirements to ensure that enough reserve capacity is available in import-constrained areas to cover a contingency in the local region when there is not sufficient transmission capacity to allow for activation of reserves outside the region. Both MISO and CAISO have recently implemented post-deployment contingency reserve transmission constraints to explicitly ensure that during certain contingencies the system can remain within emergency limits.

Secondary contingency reserve is typically provided by two separate, but hierarchically substitutable products: spinning (synchronized) and non-spinning (non-synchronized). Spinning reserve can be provided from online generation that can respond immediately. In FERC Order 841, FERC (with agreement from NERC comments) confirmed that the term spinning or synchronized, does not require a resource to be a synchronous generator, but only that it is immediately responsive to provide additional energy. Offline resources that cannot immediately provide energy but can start and provide full response within the time frame (e.g., 10 minutes) can provide non-spinning reserve. While both services are providing the same objective as shown in Figure 1-1 (to correct frequency or ACE), there is greater value in spinning reserve to the system operator due to it providing energy immediately to begin correcting system frequency or ACE.

Secondary contingency reserve is currently mostly provided by on-line thermal and hydro generation. Spinning reserve can technically be provided by any resource that has room to increase energy (i.e., it is below its maximum capacity). Non-spinning reserve is typically provided by off-line gas combustion turbines and hydro turbine generation as these technologies are able to start up in less than 10 minutes. Demand response is also capable of providing these reserves. In ERCOT, demand response that is triggered automatically by under-frequency relays can provide up to 60% of the total contingency reserve. Among the storage technologies, pumped storage has been a major supplier for decades; FERC Order 841 (as discussed in Section 1) may introduce further participation in this service from battery storage technology. Based on the quick response that batteries can provide, available response range on a battery or flywheel would likely count as spinning reserve even when not providing energy prior to the event. Duration requirements and the ESR's state of charge level may impact how much contingency reserve it can provide. VER like wind and solar can each provide a quick response in the time frames necessary for secondary contingency reserve but would need to be curtailed prior to the event and have sufficient forecasted available energy to respond across the full duration required when activated.

Table 2-3
Contingency Reserve Service Characteristics

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Product name – Spinning reserve	Ten-Minute Spinning Reserve (TMSR)	Spinning Reserve	Synchronized Reserve (SR)	Spinning Reserve	Spinning Reserve	Responsive Reserve	Spinning Reserve
Product name – Non-spinning reserves and supplemental reserves	Ten-Minute Non-Spinning Reserve (TMNSR)	Non-spinning reserve	Non-Synchronized Reserve (NSR)	Supplemental reserve	Supplemental Reserves	Non-spin reserve	Non-spinning Reserve
Contingency reserve zones	3 zones	3 zones	3 regions	7 zones	4 zones	One zone (system)	2 fixed zones; up to 8 add'l sub-zones
Minimum continuous energy when dispatched	60 min	60 min	30 min	60 min	60 min	None specified	30 min

Acronyms: TMSR: ten-minute spinning reserve; TMNSR: ten-minute non-spinning reserve; TMOR: Thirty-minute operating reserve; SR: synchronized reserve; NSR: non-synchronized reserve.

Criteria for how resources can become eligible to provide secondary contingency reserve and participate within the secondary contingency reserve market are typically established as part of the ISO tariff and business practice manuals. Table 2-4 provides notable aspects of eligibility for contingency reserve from each of the ISOs. Additional eligibility includes response times, online/offline status, and duration which were described earlier. This table is intended to provide a high-level summary comparison only. Notable aspects are that some ISOs require testing and certification prior to participation (e.g., ISO-NE, CAISO). PJM and MISO have language around technologies that cannot participate (energy storage and VER). Otherwise the eligibility requirements are similar.

Table 2-4
Contingency reserve eligibility

ISO/RTO	Document	Eligibility Requirements
ISO-NE	Market Rule 1, III.9.5.2	Must have electronic dispatch capability. Offline resources can provide up to audited CLAIM10 and CLAIM30 for 10-minute and 30-minute reserve, respectively.
NYISO	Ancillary Service Manual, 6.2	Must offer as flexible (not fixed) and located within New York Control Area. If online, must not be block loaded. Special rules for demand side ancillary services and behind the meter resources.
PJM	Manual 11, 4.4	Located electrically within zone. Specifically mentions that nuclear, wind, solar, storage resources, and hydro have default values of Tier 1 Synchronized Reserve set to 0, unless request extension.
MISO	Business Practices Manual, 4.2.1.2	Spin qualified resources includes all regulation qualified resources except energy storage. Separately mentions dispatchable intermittent resources are not eligible for operating reserve participation.
SPP	Market Protocols, 6.1.11	Resources can self-certify, may require deployment tests.
ERCOT	Nodal Protocols 8.1.1.2.1.2	Governors must be in service. Requires testing over 8-hour period where ERCOT may ask it to provide service at any point.
CAISO	BPM Market Operations, 4.6	Must be able to respond to 5-min dispatch. Includes certification and testing to qualify.

2.1.2 Tertiary Contingency Reserves

Other common terms: Replacement reserve, thirty-minute operating reserve

Tertiary contingency reserve is called “tertiary” because it is used after the primary and secondary reserves are released in the case of a contingency. It is procured to replace reserve imbalance, rather than an energy imbalance, prior to a second contingency event. In other words, it is used to ensure the other contingency reserve are back to the required amount soon after the contingency. In many cases, it may be in place for transmission contingencies as well. Since it is a slower product, resources eligible for replacement reserves can include offline units with the ability to turn on in 30-60 minutes. Table 2-5 summarizes the existing practices for establishing

the requirements for tertiary reserves (the two northeastern ISOs which currently require such reserves do so in compliance with NPCC rules).

Table 2-5
Tertiary Contingency Reserve Requirement Practices by ISO

ISO/RTO	Requirement Definition
ISO-NE	Thirty-minute operating reserve must be greater than or equal to the largest first contingency loss times plus 50% of the second contingency loss. (Generally between 2,300 and 2,600 MW)
NYISO	Total 30-minute operating reserve (including 10-minute operating reserve) must be greater than two times the largest single contingency. (Currently 2,620 MW)
PJM	N/A
MISO	N/A
SPP	N/A
ERCOT	N/A
CAISO	N/A

2.1.3 Regulating Reserves

Other Common names: Regulation, AGC reserve, load frequency control, regulating up and regulating down

Regulating reserve service is used to minimize the BAA's ACE. Regulating reserve capability, also called the regulating range, is procured as capacity reserved above the energy schedule but below the upper operating limit (i.e., head room), and/or below the energy schedule but above the minimum operating limit. The regulating range is controlled through the automatic generation control (AGC) process. The AGC process operates in between the dispatch intervals in the real-time market and ensures any changes from the real-time market are balanced on a time cycle ranging from 2-6 seconds (Table 2-7). Unlike other reserves that are based on significant events, regulating reserve is deployed continuously to adjust to the actual variability of load as well as deviations from VER schedules, resource dispatch instructions, import schedules, and any other variable factors which are not contingencies.

Regulating reserve typically has the highest clearing prices of the market-based ancillary services because not all resources have the automatic capability and providing the service may result in higher O&M costs, which are reflected in resource offers. In addition, all generators have to operate from levels below what their energy market set points would have been if not providing the service. Regulating reserve is procured in both the upward and downward direction to manage under- and over-generation conditions (negative and positive ACE). In some ISO markets the same capacity of upward and downward regulating reserve must come from the same resources while in others they can be separated.

The regulating reserve requirement is set based on meeting NERC's balancing standards: control performance standard 1 (CPS1) and the balancing area ACE limit (BAAL). The regulating reserve requirement is either fairly constant or changes by hour and is typically posted by the ISO prior to the day-ahead market.

Table 2-6 summarizes the methods used in each ISO/RTO to establish the hourly requirement and requirement level ranges.

Table 2-6
Regulating reserve requirement methods by ISO

Region	Requirement Definition ¹⁸
PJM	Constant hourly procurement number “on- ramp” (800 MW), and constant number “off-ramp” (525MW)
NYISO	Hourly requirement based on weekday/weekend, hour of day, and season. Value ranges from 175 MW to 300 MW.
ERCOT	Variable hourly reserve requirement. Based on 95th percentile of regulation reserve utilized and net load changes in previous 30 days as well as in the same month of previous two years. The requirement is then adjusted by a value dependent on increased installed wind penetrations. Value ranges from 100-700 MW.
CAISO	Use a requirement floor of 350 MW regulation up and regulation down where requirement is set based on a percentage of forecasted load.
MISO	Hourly variable requirement established once a day based on conditions and before the day-ahead market closes. Value is consistently about 400 MW
ISO-NE	Variable hourly requirement based on historical control performance. Value ranges from 50 to 200 MW.
SPP	Hourly variable requirement based on calculation that uses magnitude and hourly deviation of load and wind forecast. Value ranges around a few to several hundred MW

Regulating reserve is currently primarily provided by generators with AGC and the ability to automatically adjust output based on a control signal. The capability quantity or range in most markets is limited by the ramp rate over a 5-minute response. ISOs also have duration requirements similar to contingency reserve. These used to be 1-hour based on day-ahead market granularity. The ISOs made changes to reflect the fact that ACE crosses zero in much shorter time periods than one hour (meaning the same direction of response should not be needed for more than that time). Thus, many of the ISOs changed their duration requirements to 15 minutes. This allowed energy storage resources, some of which had limited energy storage capability, to provide regulating reserve service.

¹⁸ Requirements are estimates, and these values are continuously changing.

Table 2-7 summarizes some features of the regulating reserve products and markets.

Table 2-7
Regulating Reserve Market Design General Characteristics

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Product name	Regulation	Regulation	Regulation	Regulation	Regulation Up, Regulation Down	Regulation Service	Regulation Up, Regulation Down
Regulation up / Regulation down product	combined	combined	combined	combined	separate	separate	separate
Frequency of signal (sec.)	4 sec.	6 sec.	2 sec.	4 sec.	4 sec.	4 sec.	4 sec.
Duration requirement	15	15	15	15	60	8	15

Specific eligibility rules and related characteristics are shown in Table 2-8. Specific rules on how a resource can receive and respond to directions at high scan rates and the telemetry required to evaluate the response are all included and somewhat unique from contingency reserve eligibility. MISO has explicit language that excludes intermittent resources (term used for wind and solar) from providing regulating reserve.

Table 2-8
Regulating reserve eligibility

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Documents	Tariff 8.4.1.1, Appendix K, BPM Market Operations 4.6	Nodal Protocols 8.1.1.2.1.1	Market Rule 1 III.14.2, Manual M-REG	BPM 002 4.2.1.1, Tariff 39.2.1B	Manual 2 4.11	BPM 11 3.2.1, BPM 12 4.5.1	Market Protocols 6.1.11
Frequency response and/or control signals	Control full range without manual intervention and sustain its ramp rate	Receive & respond to Reg Up and Down control signals and switch control to constant frequency operation (additional qualifications for Fast Responding Regulation Service)	Receive & follow AGC SetPoints at 4 sec intervals	Automatically respond to frequency deviations; receive & respond to 4 sec. automatic control signal (telemetered every 2 sec.)	Receive & respond to 6 sec. automatic control signal (telemetered every 6 sec.); Continuous response up and down	Receive an AGC signal	Follow a dispatch signal (test includes max Regulation Ramp Rate)
Minimum response	0.5 MW	-	1 MW/min and Generating unit: Min (5 MW, or 2*[AGC SetPoint Deadband + 1] Other: 1 MW	-	During testing Min (Regulation Capacity response rate * 5 minutes, or max capacity)	0.1 MW	-
Instructions or rules for intermittent resources*	-	Post 2010 resources must provide primary frequency response		Dispatchable Intermittent Resources are not eligible for DA or RT operating reserve (BPM 2, 4.2.10.11)			Setpoint instructions if cleared for regulation down (Section 4.4.3.1 waiting FERC approval)
Terminology for renewables	Eligible Intermittent Resource (EIR)	Intermittent Renewable Resource (IRR)	Renewable Technology Resource	Dispatchable Intermittent Resource (DIR)	Intermittent Power Resources		Dispatchable Variable Energy Resource (DVER)

2.1.4 Flexibility Reserves

Other Common names: ramp capability, load following, flexible ramp, following reserve

Other Common names for long-term flexibility: Head room, capacity reserve, scheduling reserve

Flexibility reserve products are a new type of service already implemented in CAISO and MISO and being discussed in other areas. Similar to regulating reserve, the service is used for normal operations rather than for significant events. However, the flexibility reserve capacity is held by the real-time economic dispatch (and possibly also procured in the day-ahead and earlier market processes) based on a ramping requirement forecast, and then deployed by a subsequent RT SCED, rather than the AGC.

Flexibility reserves are being implemented because not enough ramp capability was otherwise being committed and dispatched when meeting the real-time system net load forecasts, given uncertainty about upward and downward ramping requirements within the SCED look-ahead intervals. This would cause price spikes when there was not enough capability to meet those ramps. In MISO, the amount of ramping procured is used to cover a 10-minute ahead forecast error (to provide ramping capability for two five-minute intervals in the future), while for CAISO it is for both 15 minutes (Fifteen Minute Market, FMM) and 5 minutes ahead forecast errors (to provide ramping capability for the next 15 minute and then five-minute intervals). The flexibility reserve requirements are determined to meet the expected ramp (variability) and some confidence level of unexpected ramps. The addition of the flexibility reserve dampens energy price volatility, by adding reserve capacity to the dispatch, but also provides an additional payment for eligible units. The ISOs deploying flexibility reserves also use lower values for its demand curve or scarcity price (discussed in Section 3.1.5) for this product to ensure that ramp capability is only procured when operational benefits exceed costs.

Table 2-9
Flexibility Reserve Service Characteristics

	MISO	CAISO
Product name	Up and down Ramp Capability	Flexible Ramping Constraint (existing) / Flexible Ramping Product (forthcoming) – both are upward and downward reserves
Time Requirement	10 mins	15 mins, 5 mins
Quantity Requirement Method	Expected variability + 2.5 standard deviation of uncertainty	Expected variability + 95th percentile of uncertainty
Quantity Requirement	Large range depending on time of day. From 0 to 1,400 MW for upward ramp capability.	Also varies significantly. Up to about 350 MW for upward ramp capability.
Included market or process	Day-Ahead Market, real-time look ahead commitment, and real-time market	Both Fifteen Minute Market and real-time (5-minute) economic dispatch (product)

Eligibility to provide short-term flexibility reserve products is fairly straightforward. Essentially, if a resource is dispatchable in real-time, it is eligible to provide ramp capability within the range defined by its ramp rate during the operating interval (with the exception of energy storage and

demand response resources type 1 in MISO). No explicit preclusion of particular technologies was found in either MISO or CAISO within the documents reviewed.

Table 2-10
Flexibility reserve eligibility

ISO/RTO	Document	Eligibility Requirements
MISO	Business Practices Manual, 4.2.1.4	Resources qualified for energy offer can provide. Currently demand response resources type 1 and stored energy resources cannot provide.
CAISO	BPM Market Operations, 4.6	No certification required. Resources dispatchable in the real-time dispatch are eligible to provide.

As shown in Table 2-11, ISOs have also used other types of reserve requirements that are similar to flexibility products in that they are held for normal conditions (e.g., load and VER variability and uncertainty) and are there to correct the anticipated imbalance (unlike regulating reserve correcting the current imbalance). However, they have longer horizons, primarily for day-ahead uncertainty and variability. This service has different names in the regions where it is used and different designs and requirements. In some cases, it is a capacity requirement that may or may not have a response time requirement as part of its definition, that is in place to ensure that the ISO commits additional capacity during the unit commitment process. In some regions, the product is not priced, and resources would not be paid for providing the additional head room unless they were providing a separate ancillary service. However, they would be guaranteed to recover operating costs if committed. In other regions there may be a defined ancillary service product to meet these requirements. These services are often held in day-ahead markets but not in real-time markets.

Table 2-11
Flexibility Reserve Market Design Characteristics

ISO/RTO	Requirement Definition
ISO-NE	N/A
NYISO	N/A
PJM	Day-ahead scheduling reserve is a 30-minute reserve only scheduled in the day-ahead time frame. It is currently set to about 5.3% of the load (As high as 8,000 MW)
MISO	Previously had head room requirements but not defined.
SPP	Instantaneous Load Capacity is set based on the difference between the load forecast used in the day-ahead market and the expected real-time instantaneous load within the hour.
ERCOT	Non-spinning reserve in ERCOT is a 30-minute product used for contingencies, load and VER forecast errors, net load ramps, and other conditions. It is set based on the 70th to 95th percentile of hourly net load uncertainty from the same month of the previous three years.
CAISO	N/A

2.1.5 Ramping Reserves

Ramping reserve as shown in Figure 1-1 was included to note that there are some large and rare events, that are not instantaneous, that require reserve to ensure system is balanced. This may include a very large multi-hour net load ramp, or a significant GW-sized forecast error. No ISO

currently includes a specific product for this service, or other products (contingency reserve or flexibility reserve) are used for the condition.

2.2 Inertia Service

Inertia is provided by the rotating mass of synchronous generators that are providing kinetic energy when there is a supply-demand imbalance. The provision of inertia will slow down the rotating machine, which due its synchronism with system frequency, will also slow down (reduce) system frequency. More inertia on the interconnection will lead to a slower rate of change of frequency (ROCOF) during system contingencies, giving more time for primary frequency response to respond and increasing the minimum frequency. Because the provision of inertia is an inherent attribute of synchronous machines, it is not something that can be increased or decreased by these technologies, nor is it something that can be turned on or off. The ability of a synchronous generator to provide inertia is determined only by whether it is synchronized (online) or not (offline).

Inertia is measured through units of the product of apparent power and seconds (MVA*s) and calculated as the inertia constant of a synchronous generator (more rotating mass means greater inertia constant) multiplied by its MVA rating. Table 2-12 shows typical values for different technologies based on ERCOT data [15].

Table 2-12
Inertia constant and response for various technologies, based on ERCOT data [ERCOT inertia report]

Technology	Typical MVA range	Inertia constant	Inertial response range (MVA*s)
Nuclear	1410-1504	3.8-4.34	5344-6530
Coal	194-1120	2.9-4.5	863-3158
Combustion Turbine	7-235	1-12.5	22-1288
Gas steam	14-887	1-5.4	13-2216
Combined cycle	25-1433	1.1-9	97-8765
Hydro	9-36	2-3	19-1133
Reciprocating Engine	10-70	1.1-2.1	13-97

Because of the large number of generators on-line at any one time, most large interconnections have had sufficiently large amounts of synchronous inertia available, such that there was historically no reason to track inertia or request minimum requirements from the resource fleet. Moreover, the available inertial capability is combined with primary frequency response (and fast frequency response based on existing definitions). As such, most ISOs do not have an inertia ancillary service. ERCOT, as an ISO that is the sole balancing area in its interconnection, has calculated example inertia requirements for its system. ERCOT sets their requirement on the level of inertia where load resources may not have enough time to respond and avoid involuntary under-frequency load shedding [15]. This is equal to inertia that would cause the frequency to change 0.4Hz in 0.416 seconds which through calculations has been determined to be a requirement of about 100 GW-seconds (generally equivalent to 100 GVA*s).

With respect to eligibility of other types of resources to provide this service, variable-speed wind (type 3 and type 4), photovoltaic solar and battery storage are non-synchronous, and do not provide instantaneous injections of energy based on spinning mass as the rotational speed is not synchronized with that of electrical frequency. Thus, these resources do not provide any synchronous inertia. Variable-speed wind technologies do have a spinning mass, albeit not synchronous. By use of controls, wind technologies can provide fast, yet not instantaneous, injections of power by extracting the kinetic energy of the spinning wind turbine blades, after controls sense the change in frequency. If wind speeds are at or below the level for full rated electrical output on a wind turbine's power curve, the energy must be "paid back" to prevent the turbine from stalling. If wind speeds are above the level for full rated output on the power curve, and thus the blades have been pitched out of the wind to keep the turbine from exceeding its rated electrical output, the energy may not need to be paid back because the mechanical inertia can be regained by pitching the blades back into the wind. PV has no mechanical inertia but can provide a similar fast frequency response based on rapid injection of power if it is not providing full available power beforehand. Battery storage can similarly provide fast frequency response if it has available charge and was not already discharging at full output. This fast frequency response service is discussed later. Synchronous motors provide inertia similar to synchronous generators.

2.3 Primary Frequency Response

Other common terms: Primary frequency response, frequency responsive reserve, governor response, primary control reserve¹⁹

Primary contingency reserve, which is usually called primary frequency response, is the automatic, autonomous response to system frequency excursions by generators and demand response to stabilize system frequency. This service is provided automatically without direction or external communication from the ISO or other BAA, based on sensing system frequency. The operational features which determine the capability of a particular resource to provide this service include the head room between operating point and maximum power capacity (defining the available range of response), a certain droop setting that determines how much response it gives per frequency deviation, a dead band signifying the minimum frequency deviation before any response, and sufficient capability available for a sustained response until frequency is brought back to its nominal level of 60 Hz.

Due to an observable decline in the system primary frequency response, in 2013, FERC approved the NERC BAL-003-1 standard, which requires each BAA to meet a minimum Frequency Response Obligation. Table 2-13 shows the 2017 Frequency Response Obligation for each ISO. In most power systems, including the organized markets, frequency response is provided currently by committed generation (and demand in ERCOT) without the need to specify a service or provide compensation. ERCOT has only recently set aside an explicit service for primary frequency response.

¹⁹ Note that PJM's "primary reserve" would not be characterized in this category. It is better characterized as secondary contingency reserve, as a 10-minute response time for contingencies to correct the area control error or frequency.

Table 2-13
2017 Frequency Response Obligation by ISOs

ISO	Frequency Response Obligation (MW/0.1Hz)
PJM	258.3
MISO	211.0
SPP	86.9
NYISO	48.8
ISO-NE	38.0
ERCOT	381.0
CAISO	197.6

ERCOT initiated requirements for all generators to have the capability to provide primary frequency response within its area. Subsequently, in Order 842, FERC required all newly interconnecting generators and energy storage resources (with the exception of nuclear units) to have the capability to provide the service. This effectively makes all generators except for nuclear plants eligible to provide the service, with some resources who interconnected prior to the FERC order exempt from doing so. In ERCOT, demand-side resources with automatic under-frequency relays will trip off during certain frequency deviations (59.7 Hz). These resources are currently participating and are paid for providing responsive reserve service. In addition, the system load responds by load reduction to frequency deviations, which is a condition known as load damping, and this equates to primary frequency response. This is typically equal to 0.5-2 percent change in load for a 1% (0.6Hz) change in frequency.

2.4 Fast Frequency Response

The term “fast frequency response” (FFR) originated in the research community and then started to be used in ERCOT as part of its recent ancillary service redesign initiatives (it is also used in the United Kingdom and other European countries). It is not listed in Figure 1-1, because it is still being defined as a product. Fast frequency response combines characteristics of inertia and primary contingency reserve. It is essentially an energy injection that is provided almost immediately following a frequency deviation (but not instantaneously like inertia), that provides support by reducing the rate of change of frequency fractions of seconds after the event, increasing the minimum frequency, and reducing the steady-state frequency deviation due to a more continuous injection. In other words, it can be defined as primary frequency response which has a shorter delay (milliseconds rather than a second or two) than existing response provided by turbine governors. There are generally no explicit requirements or attributes that fit under this category as it is still under development. As discussed in Section 3, ERCOT has recently included it in review of future ancillary services.

Figure 2-1 illustrates an example of three services: decelerating power as provided currently by synchronous machines, primary frequency response, and fast frequency response. It also includes the load damping effect that occurs following a disturbance. In the example, the outage occurs when the time reaches 10 seconds on the x-axis. The synchronous machines instantly provide energy to make up for the energy supply loss by extracting energy from the rotating machines. As soon as the FFR controls can measure the frequency and the frequency surpasses the dead band, the control signals are sent, and a burst of energy is provided. The primary difference between FFR and the disturbance

is the delay in reading the frequency and ensuring the response is needed. The delay has been described as anywhere between 4 cycles (66.7 milliseconds) to 30 cycles (half a second). Thus, the initial ROCOF is only dictated by the synchronous inertia. The primary frequency response provided by gas, steam, or hydro turbines have a longer delay than the FFR due to mechanical and thermal time constants.

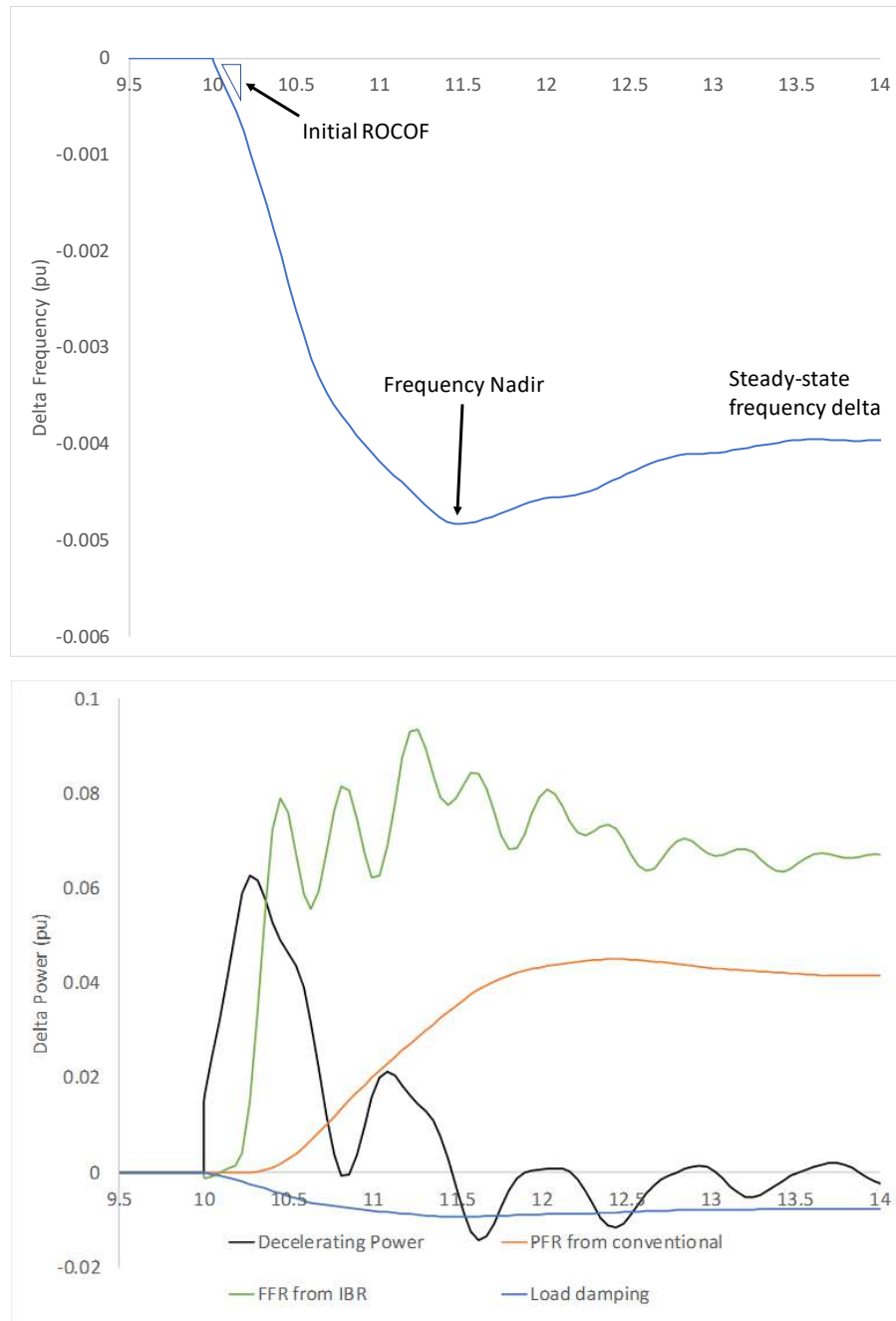


Figure 2-1
Fast Frequency Response compared with synchronous inertia, primary frequency response, and load damping. The response times and timing is the critical illustration while comparison of magnitudes are not meaningful in this example.

The reason why fast frequency response is gaining attention as a new type of ancillary service is that it can be supplied by several emerging technologies like demand response, ESRs, and VERs. Relying on power electronics controls rather than thermal time constants, inverter-based technologies like lithium-ion batteries, wind and photovoltaic solar can provide a response as soon as its controls detect a frequency deviation. This can provide tremendous value as it can support the impact on average ROCOF, frequency nadir as well as steady-state frequency.

2.5 Voltage Support and Reactive Power Provision Including Reactive Power Reserve

Voltage control effectively requires the injection and absorption of reactive power from generating units and transmission assets (e.g., capacitor banks, static VAR compensators, etc.). Voltage must be kept generally within 5 or 10% of their nominal levels. Because of the nature of the transmission system, reactive power cannot be provided through far distances, such that the needs are very localized. Transmission system operators typically require generators to provide reactive power support within specified ranges while in voltage control mode, such that the plant's reactive output is controlled to maintain a specified voltage level at the generator terminals or point of interconnection.

Similar to operating reserve, voltage control can also be further categorized by the speed of response. While there may be a variety of different response times similar to active power control, typically voltage control is separated by static and dynamic control. Static control can come from technologies that are slow moving and supports long-term persistent voltage control. Dynamic voltage control requires fast-responding reactive resources to adjust reactive power based on specific voltage issues that occur. During steady-state operations, voltages must be kept within normal limits such that reactive resources are committed and scheduled to levels where they can provide reactive support in advance. Then, dynamic reactive support requires an immediate control of reactive power to keep voltage levels within emergency limits following a contingency event (e.g., loss of line or generator). The ability to bring the system back to a secure state following the event to ensure stability from a second event is needed through coordinated response as well.

Voltage support can be provided by a variety of different technologies. Static voltage control can be provided by a set of transmission technologies like shunt capacitors, shunt reactors, and tap changing transformers. Dynamic voltage support can be provided by some transmission technologies like synchronous condensers and static VAR Compensators, as well as by most generators. Generators are required to have voltage control capability in the United States. Modern (type 3 and type 4) wind and modern solar generators are also required to have the capability to provide voltage control. These technologies can provide a fast reactive power response during contingency events through power electronics control and control active power and reactive power independently. They can be designed to also provide reactive power support even when not providing active power.

2.6 Black Start and Restoration Service

Black-start service is needed for system restoration following blackout events. Black start resources are defined by NERC as “generating unit(s) and its associated set of equipment which has the ability to be started without support from the system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, meeting the

Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan". These resources must be capable of starting without outside power supply, maintain frequency and voltage under varying load, and maintain rated output for a significant period of time (e.g., 16 hours). Though black start service is seldom needed in practice, having sufficient resources that can be started without external power sources that can maintain voltage and frequency while load is energized is essential. It is critical that these resources can be relied upon to restore power after a complete or partial black out as quickly as possible. Because of the characteristics of this service, black start resources are typically combustion turbines or hydro generation. Additional research is being conducted on how emerging technologies may be able to provide this service as well [27].

2.7 Long-Term Planning Reserve

Although typically not classified as an ancillary service in the usual definitions, long-term services are those that support reliability and are separate from the provision of energy. Therefore, we include here for the service definition aspect. Note that given the length and complexity involved in long-term capacity markets, we do not cover the markets for capacity in Section 3 within this report. Long-term planning reserve can be split into two separate categories: installed/unforced capacity which is generally measured in MW, and flexible capacity which is typically measured in MW/min. Both categories are considered in the planning time frames; i.e., they help planners and market designers on what needs to be built, rather than what needs to be committed and dispatched. Brief descriptions are provided next.

2.7.1 Installed/Unforced Capacity

Long-term capacity is a product that exists in many regions separate from the provision of energy. From a long-term perspective, planners require a certain amount of available capacity within their system or external resources with import capability, such that they can serve load consistently. A reserve margin is used to set the amount of capacity that should be installed above the peak load. In most regions, this requirement is typically set at a 12-18% reserve margin above the expected peak load. The reserve margin is often based on the amount of capacity that will lead to having less than 1 day of involuntary load shedding across 10 years. Table 2-14 provides an overview of the requirements used for each ISO to meet its long-term installed capacity need. Most resources can provide installed capacity, but the level at which they contribute depends on how much they are able to contribute to the peak needs. For conventional resources, the contribution is limited by outage rates. For VER, the contribution is limited by the availability of wind or solar during the peak time periods. Storage may also be limited by its energy limits to provide energy during peak periods.

Table 2-14
Methods for determining resource adequacy requirements

Region/ entity	Reliability Standard	Comments on Reliability Standard
PJM	0.1 LOLE	The LOLE based target reserve margin and various other calculations provide key inputs into the PJM capacity market.
MISO	0.1 LOLE	Performed annually by MISO. Regional reserve margin of 17.0% in 2017/2018.
NYISO	0.1 LOLE	Installed Reserve Margin for 2018 Capability Year is 18.2% IRM calculation includes nameplate of all resources including wind. Results are adapted to derated UCAP for implementation in the NYISO capacity market.
ISO-NE	0.1 LOLE	Annual calculation of Installed Capacity Requirement (ICR) for each Capacity Commitment Period (CCP) based on the 0.1 LOLE.
SPP	2.4 LOLH	Capacity margin criterion of 12%;
CPUC/CAISO	15-17% reserve margin; currently evaluating LOLP-based approaches	LOLE assessment of 2017 determined a 16% reserve margin.

2.7.2 Long-Term Flexible Capacity

Long-term installed capacity is bought and sold in some regions as a product, either through auction-based markets or through bilateral agreements. This provides assurance that the system will have sufficient capacity installed to meet future peak load, considering uncertainties in the load and the supply resource availability. However, this does not assure any other attributes of the suppliers other than MW capacity. With increasing VER output, it may be as important to ensure that the resources installed have enough flexibility characteristics as well, to meet the increasing variability and uncertainty that is anticipated on these future systems when making planning decisions. This flexible capacity paradigm is similar though not identical to the short-term flexibility reserve discussed earlier. While the flexibility reserve product was to ensure that flexibility was being committed and dispatched in a way that enables sufficient flexibility for operational time periods, this flexible capacity service refers to the assurance of flexible capacity being installed on the system in time for planning horizons.

Understanding the need for flexibility is a challenging process. Unlike the need for adequate capacity, flexibility includes more than one attribute. Ramp rates, start-up times, absolute active power range, ability to sustain output, and minimum online and offline times are just a few attributes that differ between technologies that change the ability of the technology to be flexible when certain conditions change and need response over different timescales. Research has been conducted on how to evaluate the amount of flexibility needed on a system and how to assess the amount of flexibility available on a particular system [16]. These assessments are not always easy to translate into the actual need for flexible resources that need to be installed on the power system. Another unanswered question is how to incentivize a resource to build with enhanced flexibility attributes. Many of these unanswered questions may lead to more significant evolution of the need for this long-term service in the future, as utilities and ISOs begin to determine what their needs are on their respective system. Few regions have explicitly labeled long-term

flexibility as a service or made any significant changes to either require that long-term flexibility needs are met or ensure that compensation is provided for providing long-term flexibility. The CAISO is one of the few regions that has made some substantial changes to identify this as a service over the last few years. CAISO's flexible resource adequacy criteria and must offer obligation (FRAC MOO) process provides a method to determine the flexible capacity need over a 3-hour time frame, how much flexibility each resource is eligible to provide, and obligations in the energy market for those resources that do provide flexible capacity [17].

2.8 Short Circuit Contribution

Power system faults cause short circuit currents to flow from synchronous machines into the faults. Various synchronous machines contribute to a given fault current in proportion to their electrical distance (impedance) from the fault and their MVA rating. While higher fault currents increase the potential for damage to system equipment if not interrupted quickly by isolating the faulted element, the availability of higher short circuit currents means lower impedance from voltage sources, indicating high system strength. Generally, system strength is measured in terms of short circuit strength with stronger systems (higher short circuit) being less susceptible to voltage fluctuations due to varying load levels. Higher short circuit strength also makes it easier for protective relays to detect faults and distinguish them from loads. Higher short circuit strength also is important for conventional line-commutated HVDC converter stations. Although some methods exist for improving line-commutated HVDC performance in lower short-circuit strength systems, a high short circuit strength is preferable. It should be noted that increasing short circuit contribution in some areas of the grid may cause fault currents to exceed interrupting ratings of circuit breakers, requiring breaker replacements or other system augmentation.

3

ANCILLARY SERVICE PROCUREMENT AND COMPENSATION MECHANISMS

This section examines how ancillary services are procured and compensated through both market and non-market mechanisms. For market-based ancillary services, the primary procurement mechanism is a competitive auction with uniform market clearing prices paid to selected sellers by the ISO. In the U.S., these auctions are conducted during various time frames and are highly linked with the scheduling and pricing of energy markets. The structure of these markets, including the ways in which schedules and prices are determined, are reviewed along with other key features of the market designs. In addition, a subset of ancillary services, are procured through cost-recovery and long-term contracts using unit revenue requirements. These are discussed briefly as well.

3.1 Ancillary Service Auction Market Design

Secondary contingency reserve and regulating reserve are two ancillary service products that have competitive auction-based ancillary service markets in all U.S. ISOs. These services are highly linked with the energy markets and have well-established needs based on NERC criteria and historical uses. The markets for these services generally follow a similar design. Other new operating reserve products are utilizing similar auctions and market design as they are being introduced as products. Here, we will discuss these ancillary service markets including some key differences across regions.

In the competitive ancillary service auction-based markets, the ISO collects all eligible supply offers and the auction selects the ones needed to meet the ISO's requirement for the ancillary service product in the periods and locations studied. Similar to energy markets, a single uniform price per location and time are paid to all providers of the service for that time period who are in the corresponding location. In fact, operating reserve products such as secondary contingency reserve and regulating reserve are typically co-optimized with the energy market. The following additional aspects of competitive ancillary service markets are listed below. A description is provided with examples when applicable of each of the different ancillary service market design components.

- Offer parameters
- Two-settlement system
- Co-optimization of energy and ancillary services
- Lost opportunity costs
- Pricing hierarchy and product substitution
- Scarcity/shortage pricing
- Location-based reserve scheduling and pricing
- Market power mitigation

3.1.1 Ancillary Service Offer Parameters

Market participants that are participating in the ancillary services markets can submit an offer into the ISO markets (denominated in \$/MWh for energy services, \$/MW-h for reserve capacity, and \$/MW for regulation mileage). These offers are used by the ISO, along with capability parameters, to establish which resources to select to provide the service by minimizing the cost to do so. The cost offers that a resource would provide can be dependent on a number of factors. For regulating reserve, resources provide offers that can be based on wear-and-tear costs from providing the service as well as any efficiency losses that can happen due to rapid response movements. However, some ISOs do not allow non-zero offers for certain products in certain markets. Table 3-1 shows whether nonzero offers are allowed for different products in each ISO. The justification is that for certain products in certain time frames, the costs involved would already be captured inherently within the market clearing model. One example of that is the newly formed ramp products. In both MISO and CAISO, there currently are not options to offer costs, as each ISO and its stakeholders have decided since the product is purely to allocate ramp capacity such that the resource can provide energy at a later time period, the only cost would be lost opportunity costs, which are reflected in the price through a co-optimized model.

Table 3-1
Allowance of non-zero offers in ancillary service products

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Secondary Contingency Reserve	No for TMSR, TMNSR, TMOR	Yes in day-ahead, No in real-time	SR – Yes NSR - No	Yes	Yes	Yes	Yes
Regulating Reserve	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Ramp Product				No			No

Acronyms: TMSR: ten-minute spinning reserve; TMNSR: ten-minute non-spinning reserve; TMOR: Thirty-minute operating reserve; SR: synchronized reserve; NSR: non-synchronized reserve.

In addition to offer costs, the ancillary service providers supply information on the capability to provide the service. In some cases (e.g., ramp products), there is no additional need for parameters beyond what is provided to the energy market. This is because the capacity available to the energy market and the ramp rate limit provided to communicate the amount of power that can be modified from one interval to another in the energy market are all that is needed to determine the amount of ramp capability. For other products, explicit parameters for that service may be required. For example, typically a different ramp rate may be provided for secondary contingency reserve and regulating reserve than the ramp rate used for the energy market.

3.1.2 Two-Settlement Systems and the Market Sequence

Electric power markets in the United States have converged on a two-settlement system for market operations: day-ahead and real-time (and in one ISO, CAISO, a three-settlement system). Settlement refers here to *financial* settlement; actual market scheduling procedures take place more than twice per market interval. In the first settlement, which reflects the results of the day-ahead market, energy and ancillary services are transacted based on the clearing prices which

result from bids and offers. Then as conditions change in real-time, the deviations from the day-ahead conditions are transacted at real-time prices for a second settlement.

In the energy markets, the two-settlement system has a fairly straightforward logic. The day-ahead market results in non-binding energy schedules but binding financial settlements. If the unit deviates from their day-ahead energy schedule, the deviation is re-settled at the real-time price. This creates an incentive for generation to be responsive to changes from day-ahead to real-time.

The sequence of settlements in the ancillary service markets are not as consistent. It is important to note first that ancillary service payments are provided for the capacity reservation of the supplier of the ancillary service. When deployed and additional energy is provided, the additional energy is paid through the energy market prices. This means that the revenue earned from deployment of operating reserve is independent of payments made in the ancillary service markets. The exception is regulation, which has performance payments as discussed later. Ancillary services are procured by the ISO on behalf of load at day-ahead ancillary service prices, and the deviations from the day-ahead amount are then settled at real-time prices. This provides a bit of certainty in the day-ahead time frame such that the set of resources committed a day ahead can meet the ancillary service obligations, given that some resources require substantial lead time to commit. It also makes sure that after conditions present themselves in real-time, the most efficient selection of resources can still meet those ancillary service obligations. Finally, in some unique situations, the ISOs have a forward (advance of day-ahead) procurement of ancillary services. This is analogous to capacity markets and provides revenue to resources who are then obligated to provide those ancillary services when they are available and selected to provide them.

Table 3-2 shows which ISOs have ancillary service markets in long-term forward procurements, day-ahead markets, and real-time markets. All ISOs but ISO-NE have some form of a day-ahead ancillary service market. It should be noted that ISO-NE does ensure their reserve requirements can be met in the day-ahead time frame through their reliability unit commitment process. However, the services are not paid in the day-ahead market. In PJM, the ancillary service products that are procured in the day-ahead market are different from those that are purchased in the real-time market. In the day-ahead, a reserve called day-ahead scheduling reserve (which can generally be considered an aggregate version of all operating reserve as viewed from Figure 1-1 based on how it is being used) is purchased in the day-ahead. Then in real-time, the service is disaggregated with the purchase of synchronized reserve, non-synchronized reserve (both secondary contingency reserve in Figure 1-1) and regulating reserve. The requirements for PJM's services in the day-ahead and real-time are different. Providers of the real-time services are paid the full amount of reserve in real-time, rather than those providers in real-time getting only paid the deviation from their day-ahead schedules.

Every U.S. ISO but ERCOT has a real-time ancillary service market. In ERCOT, the ancillary service obligations are kept constant from their day-ahead solution. However, if for some reason ERCOT sees an issue with the ancillary service obligation due to a resource not being able to meet its obligation, congestion, or if ERCOT believes it needs a greater quantity of ancillary service than it needed in the day-ahead, ERCOT will issue a supplemental ancillary service market (SASM) that must occur at least an hour before the operating hour. This occurs via an ad-hoc process rather than regular intervals. Alternatively, in CAISO, the reserves are settled now

through its fifteen-minute market (which is often labeled within its real-time market) and not resettled in the five-minute real-time market (with the exception of the flexible ramp product which is settled in both).

Finally, only ISO-NE has a true forward reserve procurement for reserve. The forward procurement was meant to incentivize the building of quick start generation and is linked with ISO-NE's capacity market. While CAISO does not have an explicit forward procurement for the reserve products that it uses in real-time, it has a flexible capacity procurement backstop. This process ensures that a certain amount of ramp capability is available to the ISO for the next delivery year, and if insufficient cumulative amounts are present, the ISO will issue a backstop procurement for that flexible capacity and allocate the costs of the flexible capacity to local regions that were deficient.

Table 3-2
Forward, day-ahead, and real-time ancillary service markets

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Forward (Pre-Day-Ahead) procurement	Yes						Yes, but different (flex capacity)
Day-ahead procurement	No	Yes	Yes, with exception	Yes	Yes	Yes	Yes
Real-time procurement	Yes	Yes	Yes	Yes	Yes	No	Yes, with exception

3.1.3 Co-Optimization of Energy and Ancillary Services

Ancillary services that are procured and compensated through competitive markets are typically co-optimized with energy and with each other. When ancillary service markets were first introduced during the early stages of electricity markets, they were typically designed as “sequential” markets. Sequential ancillary service markets meant that the energy market was first solved such that the ISO selected the least cost resources to provide energy, and then selected the least cost set of ancillary service providers from the residual set of resource's capacities. Over time, the substitution properties between these uses of system resources became more apparent, and software evolved. As a result, ISOs all moved towards some variant of co-optimization of energy and ancillary services, which means that the ISO jointly selects the least cost set of energy and ancillary services. Compared to sequential procurement, this leads to a lower total cost of bid-in and scheduled resources. Almost every U.S. ISO currently undertakes simultaneous co-optimized procurement of day-ahead or real-time energy and ancillary services. For historical reasons, PJM's co-optimization process is iterative and not simultaneous. A simple example of the benefits of co-optimization is shown below in Example 3-1.

Example 3-1: Sequential vs. Simultaneous Co-Optimization of Energy and Reserves

A simple example can illustrate the differences between sequential and simultaneous co-optimization of the energy and ancillary service markets. Table 3-3 shows the generator characteristics in the example and Table 3-4 the load demand and reserve requirements. We can evaluate the total cost (energy plus reserve cost of all resources selected for energy and reserve, respectively) for the sequential design and the co-optimized design.

Table 3-3**Characteristics of generators for co-optimization example.**

	Energy Cost or Bid	Capacity	Reserve Cost
Gen1	10 \$/MWh	100 MW	1 \$/MWh
Gen2	20 \$/MWh	100 MW	5 \$/MWh
Gen3	25 \$/MWh	150 MW	15 \$/MWh

Table 3-4**System characteristics for co-optimization example.**

	Load	Reserve
Data for Example	250 MW	50 MW

Table 3-5 shows the solution for a sequential ancillary service market. The ISO selects the least cost way to meet energy by using the two cheapest generators at full capacity and the residual needed from the most expensive resource. It then meets the reserve requirement with the remaining capacity left from the third generator, which happened to have the most expensive reserve cost. Table 3-6 shows the results from the co-optimized solution. In this case the overall costs are minimized simultaneously. Even though generator 2 has a cheaper energy cost, it is scheduled at lower energy because it can then provide reserve at a much lower cost than generator 3. Thus, even though the energy costs are more expensive in the co-optimized case, the total combined costs are less. These benefits have led to all ISOs implementing co-optimization when ancillary service markets are in place.

Table 3-5**Results for sequential ancillary service market solution.**

	Energy Schedule	Energy Cost or Bid	Reserve Schedule	Reserve Cost	Combined Cost
Gen1	100 MW	\$1,000	0 MW	\$0	\$1,000
Gen2	100 MW	\$2,000	0 MW	\$0	\$2,000
Gen3	50 MW	\$1,250	50 MW	\$750	\$2,000
Total	250 MW	\$4,250	50 MW	\$750	\$5,000

Table 3-6**Results for co-optimized ancillary service market solution.**

	Energy Schedule	Energy Cost or Bid	Reserve Schedule	Reserve Cost	Combined Cost
Gen1	100 MW	\$1,000	0 MW	\$0	\$1,000
Gen2	50 MW	\$1,000	50 MW	\$250	\$1,250
Gen3	100 MW	\$2,500	0 MW	\$0	\$2,500
Total	250 MW	\$4,500	50 MW	\$250	\$4,750

Example 3-2: Calculation of Lost Opportunity Costs

An example of lost opportunity costs and how they are calculated is demonstrated next. Table 3-7 shows the characteristics of generators for the example, and Table 3-8 shows the load demand and reserve requirement example. Load and reserve are the same as the co-optimization example, except that we also require a 5-minute response time.

Table 3-7

Characteristics of generators for lost opportunity cost example.

	Energy Cost or Bid	Capacity	Ramp Rate
Gen1	10 \$/MWh	100 MW	1 MW/min
Gen2	20 \$/MWh	100 MW	5 MW/min
Gen3	25 \$/MWh	150 MW	8 MW/min

Table 3-8

System characteristics for lost opportunity cost example.

	Load	Reserve
Data for Example	250 MW	50 MW, 5-min response time required

Without considering the ramp rate requirement, the following solution would be optimal to meet load and reserves: Gen1: 100 MW, Gen2: 100 MW, Gen3: 50 MW and Gen3 provides the 50 MW of reserve. However, given Gen3's ramp rate, it cannot provide the desired reserve requirement in the five minute response time required. Table 3-9 shows the actual feasible results that meet the requirements. The formation of the prices for both energy and reserve is based on their marginal bids or cost to provide each service. If the load demand was 251 MW (that is, if it was increased by an incremental 1 MW) and the reserve requirement remained the same, that next MW of demand would have to be met by Gen3 (if Gen2 provided an additional MW of energy then it could only provide 9 MW of reserve causing the system to be short). The energy price would then be set at Gen3's marginal bid or cost of \$25/MWh. Without opportunity cost pricing, Gen2 would then not want to provide the 10 MW of reserve, because it could make more profit if it provided its full amount of energy ($100 \times \$25 - 100 \times 20 = \500) than in its current schedule ($90 \times \$25 - 90 \times 20 = \450). That is, Gen2 has a lost opportunity cost equal to \$50, because it is losing out on the opportunity to get additional profit out of those last 10 MW. The lost opportunity cost is therefore calculated by the optimization to set the reserve price at \$5/MWh. This makes Gen2 (or any potential supplier) indifferent between providing that 10 MW as energy or reserve. Note that \$5/MWh is also the marginal cost of meeting one more increment of reserve demand. At 51 MW of reserve, Gen2 would back its energy schedule to 89 MW to provide 11 MW of reserve and Gen3 would increase its energy schedule to 61 MW keeping its 40 MW of reserve. That would cost the system \$5 more ($\$25 \times 1 - \20×1).

Table 3-9

Results for solution with lost opportunity cost example.

	Energy Schedule	Reserve
Gen1	100 MW	0 MW
Gen2	90 MW	10 MW
Gen3	60 MW	40 MW
Total	250 MW	50 MW

3.1.4 Lost Opportunity Costs

The market clearing price for ancillary services that have competitive markets is based on the marginal bid cost to provide the next increment of the service. When co-optimized with energy, the ancillary service price can also be set by the lost opportunity cost from backing down a unit that would otherwise profitably provide energy or another ancillary service; when not co-optimized with energy, the ISO may still calculate an expected opportunity cost when stacking offers (e.g., the PJM regulation market). A simple example is shown below in Example 3-2.

With the current market clearing engines that utilize linear programming, the lost opportunity costs are typically calculated automatically in the solution. Historically, some ISOs paid lost opportunity costs only to the resource that incurred the lost opportunity cost, while in others the ancillary service clearing price reflected the opportunity cost of the marginal resource. FERC Order 755 (2011) required all FERC-jurisdictional ISOs to include lost opportunity costs as a pricing mechanism for regulating reserve, such that any resource providing that ancillary service would get paid the lost opportunity cost of the marginal resource, assuming that was the marginal cost of the provision of that ancillary service. In general, it is agreed that this design results in the most appropriate incentives to make sure resources will provide the service that is most necessary to the ISO in a reliable and cost-efficient manner.

3.1.5 Pricing Hierarchy and Product Substitution

Electric power system operators observed over time that not all reserves have equal “quality”. Reserves from on-line, synchronized resources are more valuable in the short time-frames required than reserves from off-line units. More recently, some ISOs have allowed faster responding units to represent their speed in resource selection for regulating reserves, differentiating them from slower responding units.

To reflect this differentiation and ensure incentives are intact for resources to provide the highest quality service possible, the ISO enforces a hierarchy among the reserves, which allows higher quality reserves to substitute for lower quality reserves (but not vice-versa), if the total procurement cost is lower. By nesting the constraints for these services in the market optimization, a pricing hierarchy is also enforced which ensures that the prices for a higher quality service are always greater than or equal to the price of the lower quality service. For example, if the price of non-spinning reserve were higher than the price for regulation, all regulating resources would prefer to provide it, and this could result in less reliable units remaining for regulation and a lower quality or less efficient response.

This hierarchy ensures that suppliers have the right incentives to provide the service that is most important to the ISO and reliability. Most of the ISOs have a similar hierarchy as shown below, but there are a few differences. For example, regulating reserve is not always on the top of the hierarchy and is often separated out of the hierarchy. This may be due to at least two reasons. One, when the service is combined in upward and downward direction, it is not directly substitutable with other upward-only products. Second, regulation may have providers that have limited energy duration (e.g., limited energy storage) that cannot fully substitute for other reserve products that may require longer duration. As new products, such as ramping reserves, are being introduced, questions remain on how to rank the quality of those services in this hierarchy, and hence how prices are set across different products. Sometimes it is not always straightforward.

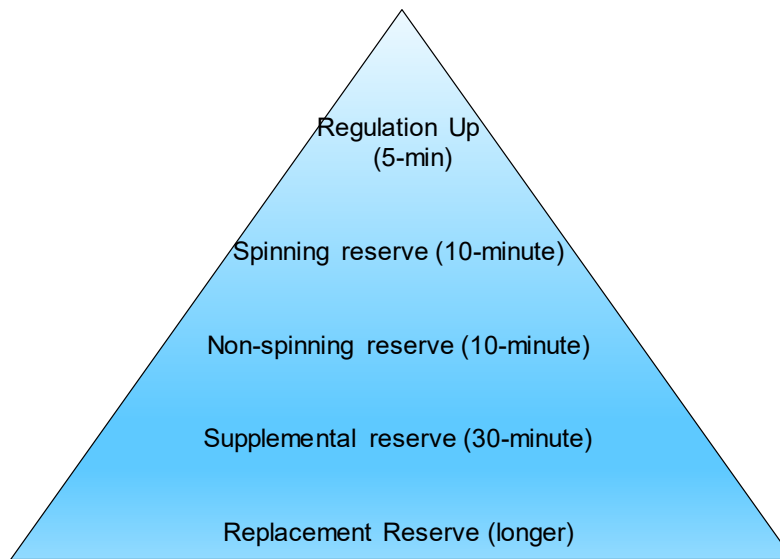


Figure 3-1
Example of hierarchy for ancillary services.

3.1.6 Scarcity Pricing

When wholesale markets run low on available capacity, typically during annual peak load periods, energy prices should increase to signal that additional supply capacity or demand response is needed. To allow for high prices to be set during periods of shortages, but without requiring suppliers to guess at what their high bids should be, in all U.S. ISOs there are now administratively set scarcity prices (also called shortage prices) for ancillary services. These are the prices established for energy and ancillary services when the market is not able to meet the ancillary service requirement. While triggered by ancillary service shortages, scarcity pricing affects the energy price if the reserve is co-optimized with energy; that is, when the scarcity price is set, but resources are still providing energy, they would incur lost opportunity costs since they would otherwise be able to profit more by providing ancillary services. In the presence of bid caps, scarcity pricing is intended to improve short-term incentives for supply and demand response during shortage conditions, and to improve the role of energy market prices in supporting capital investment decisions.

Each market has different scarcity pricing levels, in part reflecting whether the market is “energy-only” (ERCOT) or has a centralized capacity market or bilateral trading mechanisms for ensuring recovery of annual fixed revenue requirements (all other U.S. ISOs). Scarcity pricing methods include single-price settings, stepped, or non-linear (ERCOT) curves. The prices differ based on the product, reflecting the rank order of how reserves are short, with higher prices for the reserves which are typically scarce later in the emergency procedures. Table 3-10 shows the system-wide scarcity prices by ISO; some markets include additional locational (or zonal) scarcity prices that apply to shortages in specific areas. As shown, scarcity prices vary from as low as \$5 for MISO’s ramp capability product to up to \$9,000 when ERCOT is short of its contingency reserve.

Table 3-10
Scarcity pricing

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Regulation	\$100 plus \$10 additional per MW shortfall	Three steps: \$25, \$400, and \$775	None specified	Max of \$100 or Monthly peaker proxy price	varies with six steps up to \$600	None specified	Reg Up - \$200 Reg Down: \$700 if scarcity greater than 84 MW \$600 if between 32 and 84 MW \$500 if scarcity less than or equal to 32 MW
10-minute spin	\$50	\$775	Two steps: \$300 and \$850	\$98 if scarcity greater than 10% of requirement \$65 if scarcity is less than 10% of requirement	\$200	ORDC: Non-linear curve from 0 to \$9,000 Based on On-line reserve price adder	\$100
10-minute non-spin	\$1500	\$750	\$550	System-wide operating reserve: Minimum of \$200 if less than 4% violation Maximum of value of lost load minus regulation demand curve (\$1,100 - \$3,400)	3 steps, \$275, \$550 and \$1100	ORDC: Non-linear curve from 0 to \$9,000 Based on off-line reserve price adder	\$700 if scarcity greater than 210 MW \$600 if scarcity between 70 and 210 MW \$500 if scarcity less than 70 MW
Longer-term reserve	30-minute operating reserve: \$1000 Replacement reserve: \$250	30-minute reserve: Four steps: \$25, \$100, \$200, and \$750	N/A	N/A	N/A	N/A	N/A
Ramp Product	N/A	N/A	N/A	Up and down ramp capability: \$5	N/A	N/A	Several steps up to \$247 for both up and down products

3.1.7 Locational Pricing

Ancillary service procurement may be affected by locational constraints. That is, the ISO may want to position some ancillary services at different locations on the grid to reflect how transmission limits may affect the deliverability of reserves. This is similar to the scheduling of energy although typically at a less granular level (zonal rather than nodal).

As such, many reserve products have a type of locational procurement and pricing at a zonal level. The zonal ancillary service price is based on the shadow price of the zonal ancillary service requirement. For import-constrained zones, this price also has to be greater than or equal to the more aggregate (or system-wide) reserve price, similar to the cascading nature of higher-quality products to lower-quality products. This is because the resource within the import-constrained zone can provide the service to meet both the zonal constraint and the system-wide constraint.

The requirement to procure locational reserves depends on the service as well as the transmission constraints within a region. Often regulating reserve does not have locational requirements or pricing. Because of the short nature of response of regulating reserve and the fact that upward and downward response happens regularly, any impact on transmission constraints for such short durations typically does not require any reliability issue. However, contingency reserve, which when deployed may need to last for up to and sometimes more than an hour, must take into consideration that reserve that is behind transmission constraints may overload lines and interfaces when the contingency happens on the other side of those constraints. Calculating the reserve location and price at a nodal level (like energy) would theoretically be the way to completely ensure deliverability of reserve. However, treating reserve at a nodal level has intractable computational challenges from the solution of the market clearing models.

3.1.8 Market Power Mitigation

In the conventional definition of a perfectly competitive market, individual buyers and sellers cannot influence market prices through their behavior. Electric power markets are not perfectly competitive, but rather typically have some measure of selling or buying power, which may vary by location, product and time of day. Market power by market suppliers refers to the ability to affect market prices by changing either the quantities or offer prices of a market service; usually this results in higher prices. When buyers have market power, they typically try to lower market prices. To better approximate competitive behavior and achieve more economically efficient outcomes, regulators have established a range of market power monitoring and mitigation rules, affecting most market products and modes of market participation.

Ancillary service markets transact in small quantities and often, but not always, have enough potential suppliers. However, most ISOs include offer mitigation rules in the ancillary service markets in addition to the offer caps and floors shown in the tables above. Table 3-11 summarizes these rules based on a similar table in FERC's 2014 "Staff Analysis of Energy Offer Mitigation in RTO and ISO Markets." While mitigation procedures do exist for ancillary service markets, they typically are not as strict as they are in most energy markets. This is primarily due to the fact that reserves are not as localized as energy. Because energy markets use nodal pricing, there may be only one or two resources that can meet load in certain load pockets and this can give them market power and ability to set the price to whatever they want. Because ancillary

service prices are prices at less granular levels (either large zones or ISO-wide) there is more competition to provide the service and less ability to have market power for those services.

Table 3-11
ISO market power mitigation rules in the ancillary service markets

	Ancillary service market mitigation procedures
ISO-NE	Offers are subject to the general mitigation or referral provisions.
NYISO	Conduct and impact tests, for both physical and economic withholding
PJM	Three Pivotal Supplier test in regulation market.
MISO	Conduct and impact tests, for both physical and economic withholding
SPP	Conduct thresholds and impact tests, for both physical and economic withholding
ERCOT	No rules
CAISO	Must offer requirement for total Resource Adequacy capacity equaling 115% of 1 in 2 peak load each month to prevent physical withholding.

3.1.9 Pay for Performance

Pay for performance is a general design concept in which the market design will reward resources which provide greater or higher quality response. For the ancillary services, this concept was first applied to regulation.

For regulation, the issue was that newer types of regulating resources with faster regulating ramp rates, notably batteries and flywheels, were competing with existing, slower resources and being paid the same price. FERC Order 755 thus requires that all ISOs pay all regulating resources both a capacity payment, which includes the marginal regulation provider's lost opportunity cost, and a performance payment (also called movement or mileage payment). Performance is measured as the actual upward or downward movement of a regulating resource as directed by the AGC. For example, if a resource moves from 50 to 60 MW within the interval, that is 10 MW of movement. If it is asked to move from 50 to 60 and back to 50 within the interval, that is 20 MW of movement. ISOs have different rules for selecting the resources to provide regulation with consideration of the mileage costs, how they determine the mileage price, and how they incorporate accuracy incentives into the payment and selection process.

Some markets also allow for different types of AGC signals to be sent to different regulating resources. For example, PJM has a RegA signal sent to traditional conventional resources and a RegD signal, which is a higher frequency component of the ACE, available to any fast resource. This has primarily included batteries and other emerging technologies but has also included gas turbines and pumped storage. In other ISOs, the AGC signal is consistent for all regulating resources, but may be differentiated by resource reflecting ramp rate or other characteristics. The order also required that resources are provided incentives for the accuracy in following the regulation signal. Table 3-12 shows characteristics of regulation performance in each of the ISOs. ERCOT did not have to comply with the Order 755 but has a fast responding regulation service that is similar to the other ISOs, just without a mileage payment.

Table 3-12
Regulation performance market characteristics and metrics

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Mileage price	Highest accepted mileage offer	Mileage offer of marginal capability provider	Highest accepted mileage offer	Highest accepted mileage offer	Highest accepted mileage offer	N/A	Mileage offer of marginal capability provider
Offer selection process	Meet both capability and mileage requirements	Meet capability requirement	Minimize expected costs based on capacity and mileage offers and opportunity costs	Meet capability requirement	Meet capability requirement	N/A	Meet both capability and mileage requirements
Benefits factor used in market offer selection			✓			✓	
Number of regulation signals	Up to 3	1	2	1	1	2	1
Accuracy impacts	Performance monitoring based on percentage of response rate outside 80-95%, and capacity between 5-15%.	Performance index must be within tolerance	Accuracy, Delay, and Precision scoring	Actual mileage measured against desired mileage	Ancillary services tested for performance of 75% or better.		Minimum performance threshold of 25 % accuracy to control signal during a calendar month

3.2 Cost-Based Ancillary Services

As discussed earlier, many ancillary services do not have competitive auction-based markets such as those in place for the various operating reserve products. There are a multitude of reasons for this as shown in Table 3-13 (note that these are hypothetical examples and not necessarily always the true reason why a market does not exist for the example shown).

First, some ancillary service markets may be complex to design. Even the ancillary service markets that do exist are highly complex and can often have significant impacts on the computational time of the market clearing software. To enable an ancillary service market similar to operating reserve for voltage control and reactive power, one would require a more detailed network model, most likely with a full AC power flow as part of the market clearing. To do this accurately may require a non-linear optimization compared to the existing models that have linearized sensitivity factors that only evaluate active power. Adding a non-linear optimization may not be feasible given the existing day-ahead and real-time market solution completion targets currently in place.

Second, it could be that the service may only be provided by a small set of resources or by specific resources and that a market would not have enough competition to provide the benefit that a competitive market provides. Reactive power does not travel very far on transmission systems and therefore when a voltage issue must be resolved in a certain location, there often may only be one resource that can provide it. That resource would have market power in a market, allowing it to bid whatever it wants and setting the price. Similarly, some services may be easier to require on a resource-by-resource basis based on the need. A market may not provide any additional benefit if the need is not needed from a subset of resources and required for every resource.

Next, it could be that the system has sufficient amounts of the attribute or service compared to what it needed. As ISOs have finite budget to implement new software procedures and market design changes, adding markets to promote competition on something that it already has more than sufficient amounts may not provide substantial system-wide benefits assuming other changes require higher priority.

Lastly, it is important to note that implementing and maintaining a market product is not cheap. Typically, there are substantial design, software implementation, and testing requirements to get it started. Maintaining the market may have additional costs. Stakeholder time to design the product market can also be substantial. It may sometimes be the case that the benefits of implementing a competitive market for a product are less than the costs of implementing the market, which would defeat the purposes of that design.

Table 3-13
Examples of why some ancillary services do not have competitive markets

Example	Reasons Why A Market Product May Not Be Implemented
Volt/VAR support	Too complex to design
Volt/VAR support	Too specific to certain local areas (little to no competition)
Low Voltage Ride Through	A specific resource requirement rather than a system-wide need
Synchronous Inertia	System inherently has more than sufficient amounts of the service
Black start (restoration) service	Costs for the service may be small, so cost of administering market product may outweigh benefits

Illustrative examples only.

These are all potential reasons for why certain ancillary services may not have competitive markets in place. Note that each of these reasons may not always apply over time. For example, a service that has sufficient quantities to meet needs today, or that the costs of implementing outweigh the benefits, may not be true in the future. This is why ISOs, stakeholders, and regulatory authorities are proposing, prioritizing, and implementing changes to the ancillary service markets continuously. When ancillary services do not have competitive markets, and there are non-negligible costs associated with providing that service, then it is also important that resources providing the service have an opportunity to recover that cost. This can either be through additional revenue in other product's markets (e.g., energy or capacity markets), or directly through cost-based recovery rules for the particular service, or through both. The remainder of this section describes a few such services with cost-based recovery rules and the particular rules of some ISOs.

3.2.1 Voltage Control and Reactive Power Provision and Reactive Reserve

Reactive power market design options are reviewed in [19], with rules for competitive long-term solicitation issued by FERC over several orders. There are at least two issues for the implementation of bid-based spot markets. First, because of network characteristics, reactive power supply must be very close to the reactive power need and thus subject to local market power (i.e., few suppliers at the location). Second, reactive power prices also require the solution of full ac power flow for the market pricing, as compared to the simplified linear dc power flow model used in most current markets. This can be complex and computationally intensive, and market results may not be solved and published in a timely manner for spot market operations. Therefore, no ISO in the United States has not yet implemented a reactive power market that solves for competitive prices.

ISOs compensate resources for provision of reactive power through tariff-based rates and formulas, which in most cases include compensation for both capability and provision. Several ISOs use the FERC-approved "AEP methodology" for determining capability payments, while others use payments based on settlements. The AEP methodology lists the types of costs that are required to provide reactive power and voltage control and how that can be reimbursed. It primarily exists for conventional generators. Table 3-14 compares current rules for reactive power compensation in the ISOs (information primarily obtained from [19]).

Table 3-14
Reactive power compensation

Entity	Compensation Methodology
ISO-NE	Both capability and provision payments. Capability payment based on settlement using AEP methodology. Provision includes cost of energy consumed and produced and lost opportunity costs in the energy markets.
NYISO	Both capability and provision payments. Capability payment based on settlement. Provision payments includes cost of energy consumed and produced and lost opportunity costs in the energy markets. Compensation may differ by resource type.
PJM	Both capability and provision payments. Fixed costs calculated using the “AEP methodology” and filed with FERC. Provision payments include cost of energy consumed and produced and lost opportunity costs in the energy markets. Compensation may differ by resource type.
MISO	Capability payment based on “AEP methodology”. Qualified resources seeking compensation for reactive service must file with the Commission to justify its cost-based revenue requirements.
SPP	Provision payments. SPP charges a reactive compensation rate which is multiplied by the monthly amount of reactive power provided by a qualifying generator outside of the standard range to calculate monthly payments.
ERCOT	Provision payments of lost opportunity costs in the energy markets.
CAISO	Provision payments based on LMP or RMR contract.

Provision payments for reactive power are based on energy market prices and opportunity costs. Most generators have what is called a “D” curve. The D curve shows the capabilities of how reactive power provision may limit the amount of active power (energy) that a resource can provide (see Figure 3-2). If a resource provides reactive power in a way such that it must reduce energy below its most optimal operating point, the ISOs will provide a lost opportunity cost, similar to the lost opportunity costs provided for operating reserve. However, unlike lost opportunity costs for reserve, the opportunity cost is only provided back to the generator that incurs the opportunity cost, and not to all reactive power providers.

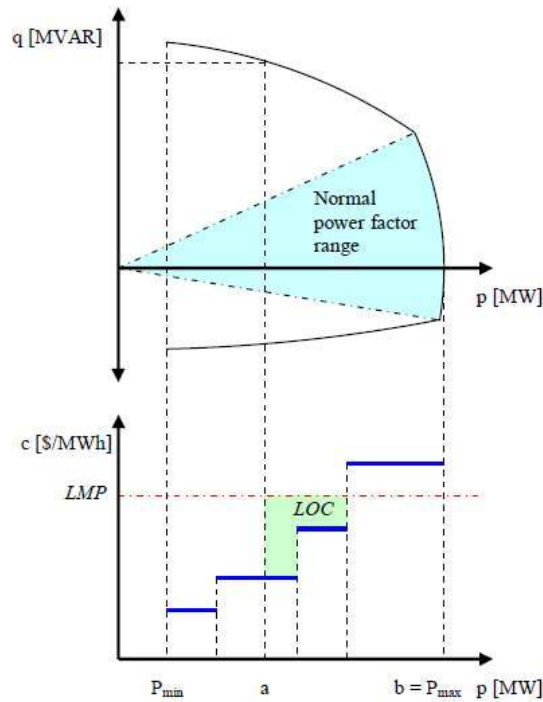


Figure 3-2
D Curve and lost opportunity cost example [20].

3.2.2 Black Start and Restoration Service

Black-start service proposals are solicited for monthly contracts with cost-based recovery mechanisms. Black-start resources usually must include all costs related to capability to provide support during system restoration. The ISO will ensure costs are valid and provide those costs back to the resources in exchange for it being a dedicated black-start service provider. Table 3-15 describes the compensation and cost allocation methods in each of the ISOs (the terminology used by different ISOs – black-start, blackstart, and restoration service – have essentially the same meaning). Important to note is that to date, only ERCOT has used a competitive auction for its black start resources. Eligible black start resources are selected by ERCOT based on resource cost offers and ERCOT meeting its requirements at least cost.

Table 3-15
Black start service compensation.

ISO/RTO	Black start service description
ISO-NE	Designated blackstart resources must be eligible to provide black start service and selected by the ISO to provide the service. Designated Blackstart Resources are paid the Blackstart standard rate or a blackstart station-specific rate. Costs include operations and maintenance, capital costs, Critical Infrastructure Protection (CIP) capital and CIP operations and maintenance costs, and annual adjustment based on Handy-Whitman indexes. Costs for black start payments are allocated to transmission customers based on pro-rata monthly regional load share.
NYISO	Qualified Restoration Services resources are paid cost-based rates which factor in capital and fixed operation and maintenance costs associated with equipment needed for restoration services, annual training costs, and annual costs associated with black start capability tests. Costs for black start are allocated to customers based on their share of the New York Control Area load that is not used to supply station power.
PJM	Black start generators annual revenue requirement is equal to 110% of the sum of its fixed black start service cost, its variable black start service costs, training costs, and fuel storage cost. Ratio share of charges allocated first to point-to-point customers with remaining charges to network customers serving load in transmission zone.
MISO	Blackstart owners initially commit to provide blackstart service for a minimum three-year period. Revenue requirements for blackstart services include those that would not be incurred but for providing the capabilities, including: fixed blackstart costs, variable blackstart costs, training costs, and compliance costs. Charges for the service are allocated to customers based on MISO's Attachment O formula.
SPP	Black start service is not procured through SPP.
ERCOT	Black start service is procured bi-annually through a competitive price-based bid process, where ERCOT selects the resources that meet its reliability criteria at minimum cost. These resources are paid an hourly Black Start "standby fee" determined through the process, which is derated when the resource availability is below some threshold (currently at 85%). Qualified Scheduling Entities representing loads are allocated the black start capacity total cost based on its load ratio share.
CAISO	Contracted annually with agreement negotiated by owner and applicable transmission owner for recovery of cost of service rate.

3.3 Further Evolution of Ancillary Service Compensation and Procurement

Section 3.1 and 3.2 describe the existing characteristics of ISO ancillary service markets and ancillary service compensation schemes. While some specific characteristics have changed over the years, the general services and their compensation designs are fairly consistent and relatively unchanged since ancillary services were first introduced into the ISO markets. In this section, we provide some brief reviews of larger changes and proposals to the ISO ancillary service markets worth noting. These will be revisited in Section 5 on future outlook.

3.3.1 Primary Frequency Response

Primary frequency response (primary contingency reserve) currently does not have an explicit ancillary service market in any of the U.S. ISOs. It is often combined with other services such that there is an incentive for a resource providing a service to be frequency responsive, but not to incentivize primary frequency response by itself. For example, WECC rules require spinning

reserve to have frequency response capabilities while FERC has combined frequency response with regulation as a combined ancillary service schedule. Some of the challenges around frequency response in the U.S. and incentives for the service are discussed in [21]. Due to settlement penalties for deviating from schedules and without frequency being used as an input into the settlement systems, there may be disincentives for providing frequency response. With the recent change from FERC Order 842 to require newly interconnecting resources to have the capability to provide frequency response whenever there is room to provide it, along with the fact that many balancing areas are still able to meet the frequency response obligation (Section 2.3), there is still some debate on whether a separate primary frequency response market, disaggregated from other ancillary service products, is needed.

In early 2019, ERCOT approved a change to its ancillary service markets (Nodal Protocol Revision Request 863) to split out its secondary contingency reserve (called ERCOT contingency reserve service, ECRS) and primary contingency reserve (primary frequency response service, PFRS). Historically, ERCOT's responsive reserve service was an aggregation of both services. This was deemed not to be conducive to new technologies that may have been able to provide one of the services well but not the other, and thus not providing any of the services. Alternatively, due to requirements of having the capability to provide primary frequency response, resources may have been providing the service with risks of compliance penalties and wear-and-tear costs without any compensation. The change also allows ERCOT to allow for off-line quick start generation to provide the ECRS. Thus, with the new change, ERCOT will be the first and only U.S. ISO to have a primary frequency response ancillary service market with resources that provide that response paid explicitly for the service. If they also provide secondary contingency reserve, they may receive a different payment for that service. The design of the new market generally follows the design of other reserve products including many of the characteristics of 3.1. The auction will take place in the day-ahead market only like ERCOT's other ancillary service, prices will include lost opportunity costs if applicable, offers will be allowed, and co-optimized with energy and other ancillary services. The change also includes fast frequency response (FFR) component, described again in Section 3.3.3.

3.3.2 Inertia

As discussed in Section 2.2, synchronous inertia is inherent in the resources that have it (synchronous machines). A resource cannot turn it off, nor can they increase or decrease what they have to provide without a complete change to the installation of the technology. However, if looking at the objective of inertia to reduce minimum frequency, there may be more flexibility to meet those objectives. In addition, there may be benefits to incentivize the service that may help inform decisions on the technology being built. As an example, being short on the service may cause high enough prices that are provided just to those resources that have inertia to incentivize incoming resources to ensure they have the characteristics that they can take advantage of the same high prices.

ERCOT introduced a synchronous inertial response service (SIRS) ancillary service market proposal in 2015 that has been in discussion in some stakeholder meetings ever since. In the proposal, resources could offer costs of inertial service (in \$/MW-second), and the market solution would select sufficient inertia to meet the requirement (see Section 2.2, ERCOT currently using 100GW*s). The shadow price of the inertia constraint, which generally would be

equal to the marginal cost of inertia, would set the ancillary service clearing price for inertia. While not possible in practice, ERCOT would potentially select partial inertia from the marginal inertia provider to ensure a price can be set. Other ISOs have not introduced such an ancillary service product, and it is unclear the interest from ERCOT stakeholders to pursue such a market design.

3.3.3 Fast Frequency Response

As discussed in Section 2.4, FFR is a service without a universal definition, but generally fits between inertia and primary frequency response. It is a response that happens extremely rapidly, but not instantaneously, that supports the reduction in the average rate of change of frequency (ROCOF), the reduction in the frequency nadir deviation, and the steady-state frequency deviation (PFR generally only supports the steady-state frequency deviation, while synchronous inertia supports the instant ROCOF after an event which FFR does not). Unlike inertia, it typically requires reserve capacity to provide (variable speed wind turbines may not need reserve capacity because they must reduce energy soon after when not pre-curtailed, this may not be as desirable) and the amount provided can be changed and optimized. Given these characteristics, it may be an attractive service to providing overall system frequency support, with potential benefits for creating market designs that lead to incentives for more of the service.

In ERCOT's recent change to disaggregate primary frequency response from secondary contingency reserve, it also included an FFR component. FFR can be used to meet the PFRS requirement, as long as it does not exceed a maximum amount that is determined by ERCOT. These resources would be paid the price of the PFRS market.

3.3.4 Voltage and Local Reliability Reserve Market

As discussed in Section 3.2.1, voltage control service is typically paid as a cost-based service, with ISOs reimbursing the costs (including lost opportunity costs) that a resource incurs when providing. In many cases, when the ISO commits resources specifically for voltage or other local requirements that are not priced by the market, the prices for energy and other operating reserves may be reduced (due to oversupply from the commitments). When this occurs, significant uplift is charged to loads to ensure those committed resources are made whole for their commitment and energy costs. This uplift lacks transparency, in that new entrants are not aware of the needs for these services, and incentives to provide the service in a more cost-effective manner are absent. Thus, having transparent prices for these services when possible may have some advantages.

MISO has been evaluating different ways of meeting voltage and local reliability needs [22]. It has recently proposed a short-term capacity reserve to allow for prices to incentivize resources that can start-up quick or that are committed to provide voltage and local reliability. The new reserve market would be designed in a similar manner to other reserve products. However, the requirement would be based on local needs for services like voltage control, rather than power capacity. MISO has seen significant uplift costs in some regions due to commitments for voltage and local reliability and have proposed this new design to make the costs and incentives more transparent.

4

ANCILLARY SERVICE MARKET PRICES AND VALUATIONS

A fundamental question for new participants in the ancillary service markets is whether the forecast market revenues (along with any other quantifiable economic benefits which can be credited to the plant) are less than the costs of provision. As noted above, the ancillary service markets have been in operation for about 20 years in some ISOs, and hence there is a history of market pricing. Historical ancillary service prices might not always be the best indicator of future ancillary service market revenue. Many factors influence future prices, including the changing resource mix and fuel costs to provide energy. In addition to analyzing historical prices, resources can look to forecasts of ancillary service prices, typically provided by commercial vendors through a variety of different methods.

To provide some perspective on these issues, this section reviews the historical pricing outcomes of ancillary service products in the different ISOs over the past five years and discusses challenges in forecasting these prices. Prices may be at the full system level, or on a zonal basis, depending on the ISO and market product. The market price data shows annual averages as well as by time of day and season.

The data used for the statistics shown here are all available publicly from the ISO OASIS websites and similar statistics are shown in ISO state of the market reports.²⁰ Pricing data is also re-packaged by various commercial vendors.²¹ The designs of some products have changed over the last five years, and there are notes on the individual figures when that occurs.

4.1 Regulating Reserve Market Prices

As described in Section 3, the market design and pricing mechanisms for regulating reserve can be complicated, with payment comprised of both capacity and performance (mileage) payments. There can also be major differences in the numbers of qualified resources in particular markets, which may be a function of the depth of the market. In some markets, such as PJM, there is a large excess supply of regulation-certified resources, which limits the ability of participants to significantly alter prices from competitive levels and is now resulting in lower prices. Other markets have experienced conditions where fewer suppliers overall, or during certain system conditions, has resulted in more volatile pricing. Unlike regulating reserve capacity prices, mileage prices should not necessarily be compared across ISOs. There can be different multipliers in each ISO that impact how revenue is calculated, and therefore direct comparison is difficult.

²⁰ The yearly averages published in State of the Market Reports might vary from those shown here if prices have been adjusted after publication.

²¹ The data used here were obtained from a commercial vendor, ABB Velocity Suites.

4.1.1 Trends in Average Regulating Reserve Prices

Figure 4-1 shows the average price over the full year for real-time regulating reserve across the U.S. ISOs, and Figure 4-2 shows day-ahead regulating reserve. Many ISOs show no distinct increasing or decreasing trend across the last five years; MISO, NYISO, and SPP have fluctuated year-by-year, largely in correlation with the energy market prices, with higher average prices in 2014 and slightly higher prices in 2017. CAISO and ISO-NE have experienced increasing prices over the last five years in real-time, with CAISO increasing by almost \$10/MWh and ISO-NE by almost \$15/MWh over the five years. All but these two ISOs also saw the highest average in 2014 over the span, due to the winter weather which affected the eastern markets due to supply limitations. ERCOT²² has also shown no consistent trend, with declining prices since 2014. PJM has been the most volatile, due to the combination of fuel driven pricing and structural changes to the regulating resource mix, with 2014 prices over double the 2016 and 2017 prices. Of the eastern markets, PJM shows the most significant impact of the January 2014 weather events on average prices in that year. In that month, the average cost of regulating reserve was \$161.20/MWh, or about 4 times the average for the full year. This period in 2014 had substantially higher energy prices due to the January 2014 cold weather event which also had an impact on average regulating reserve prices due to increased opportunity costs.

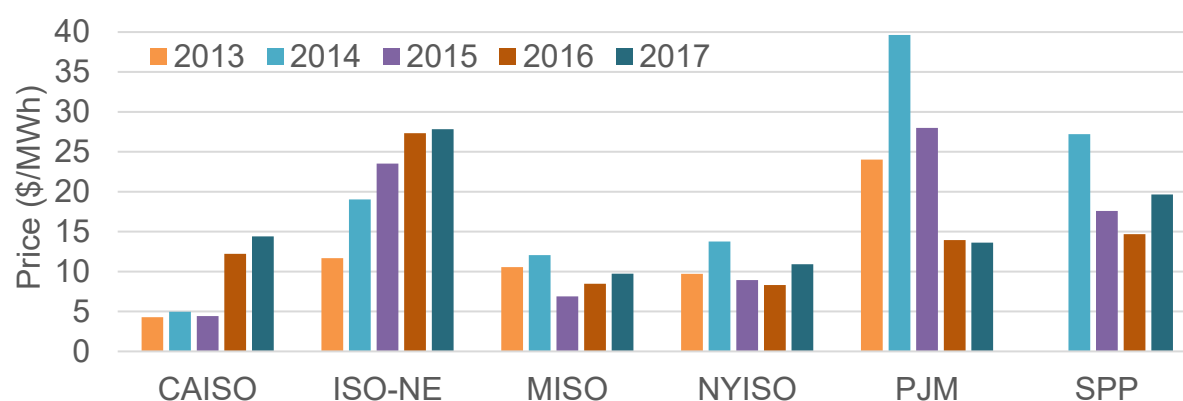


Figure 4-1
Real-time regulating reserve for 2013-2017 by ISO; if not a combined product, figure shows the sum of regulation up and down.

²² ERCOT averages prices are shown from the State of the Market Reports due to the lack of a complete dataset for earlier years.

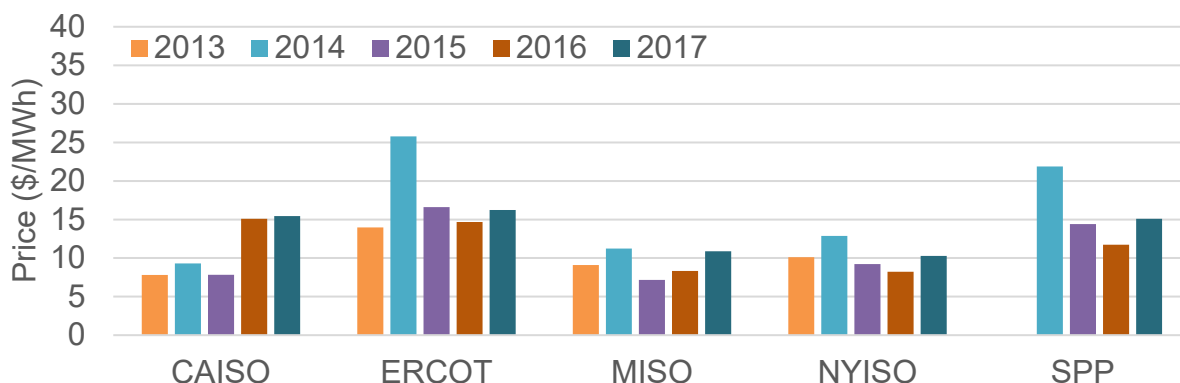


Figure 4-2
Day-ahead regulating reserve for 2013-2017 by ISOs with a day-ahead product; if not a combined product, figure shows the sum of regulation up and down.

Figure 4-3 to Figure 4-10 disaggregate the annual average prices by ISO into the separate up and down products (if they exist) and including the separate prices or payments for capacity and performance (or mileage), and both the day-ahead and real-time prices. Typically, regulation up is a higher price product than regulation down, since there is usually a greater opportunity cost to providing regulation up, and also a higher cost for creating more upwards capability through re-dispatch. However, in some markets, as more conventional generators are pushed down to minimum on-line operating limits in more hours due to increased renewable resource production, there may be less downwards capability than upwards and prices for the downward service may increase (notably CAISO).

In the ISO markets with separate up and down products (CAISO, ERCOT and SPP), market participants with different technology characteristics can potentially more readily evaluate the economic benefits of different configurations – e.g., stand-alone renewable generator or a renewable generator with integrated storage.

CAISO procures all of its regulation up and down requirements in the day-ahead market, with residual procurements in the real-time markets. Figure 4-3 shows CAISO's up and down regulation prices in both the day-ahead and Fifteen Minute Market (FMM) and prices for the mileage up and down payments in the day-ahead and FMM. As shown earlier, prices for regulation capacity have been increasing across the last five years, and procurement has also increased at times, due to several factors including increasing renewable penetration. Mileage prices, on the other hand, have remained low, never averaging above \$0.12/MWh.

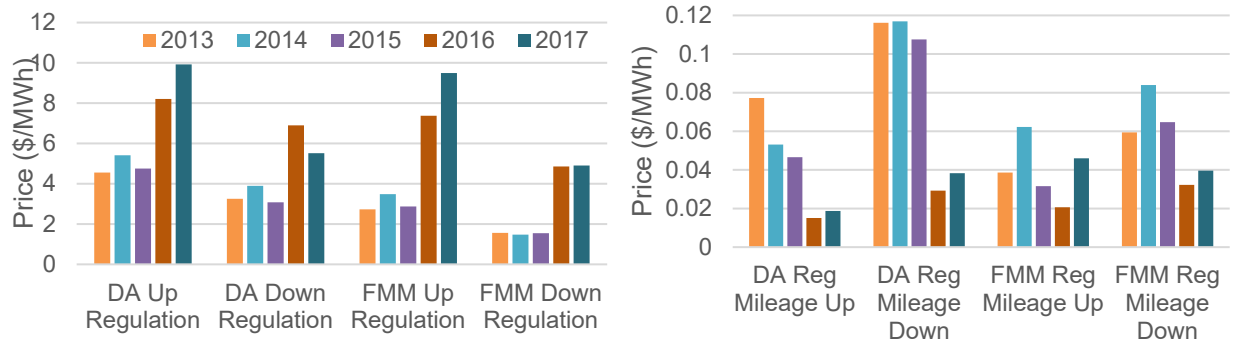


Figure 4-3
CAISO day-ahead and Fifteen Minute Market (FMM) regulating reserve products averaged by year.
Note the change in scale between the two sets of products.

ERCOT also has both regulating reserve up and down products, shown in Figure 4-4. The day-ahead results do not show significant trends over the last five years, but both products had the highest average price in 2014. In SPP, the regulating reserve market only began operations in March 2014, seen in Figure 4-5. While regulation up is slightly higher than regulation down, neither shows an increasing or decreasing trend. Both 2014 and 2017 were higher than the two years in between. The average mileage prices are higher than other ISOs due to the regulation mileage factor in SPP, which may be as low as 10% and that gets multiplied to the price for every resource. The higher prices should not necessary be interpreted as higher overall revenues; other ISOs may have that equivalent multiplier incorporated before the prices are published.

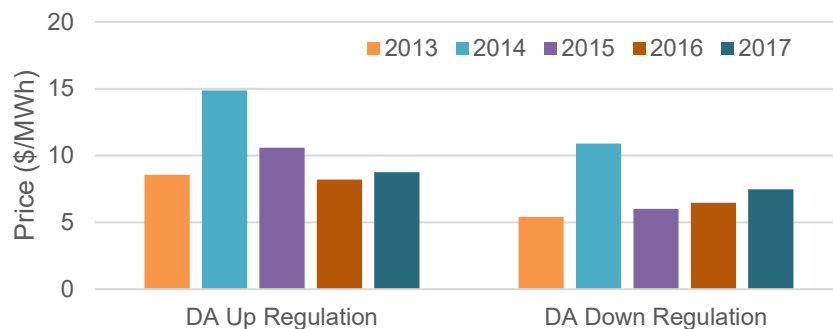


Figure 4-4
ERCOT day-ahead regulating reserve products averaged by year.

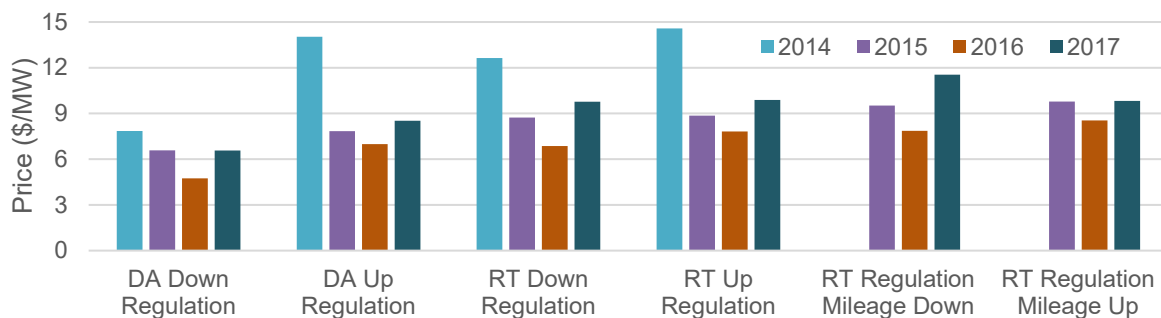


Figure 4-5
SPP day-ahead and real-time regulating reserve and mileage products averaged by year.

For the markets with combined products, there are also several design differences which must be considered, like whether they have a separate fast product (e.g., PJM). ISO-NE has two components of real-time products for regulating reserve, shown in Figure 4-6. Until April 2015, there was a single product, real-time regulation. After April 2015, real-time regulation capacity and real-time regulation service (i.e., mileage price) were introduced. Since introduction, the price of regulation capacity has increased steadily from averaging \$25/MW-h to nearly \$30/MW-h, while regulation (mileage) service has had relatively low prices.

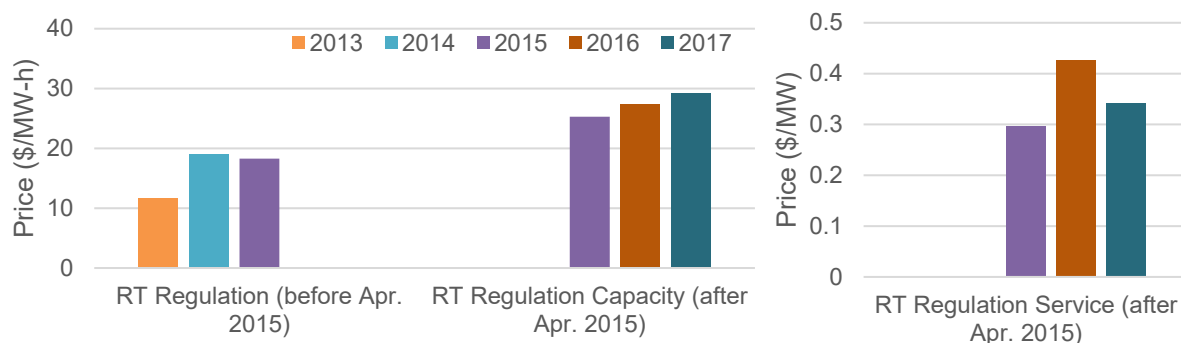


Figure 4-6
ISO-NE real-time regulation products averaged by year; products changed before and after 2015.

MISO and NYISO have the lowest regulating reserve prices among the U.S. ISOs, although there is not a clear trend over this period. In Figure 4-7, MISO day-ahead prices in 2013 and 2014 were slightly lower than real-time, while the reverse became true in 2015-2017. In 2017, day-ahead regulation was about \$1/MWh higher than the real-time price of regulation. Similarly to the other markets, regulation mileage in MISO has relatively low average prices. Figure 4-8 shows NYISO day-ahead and real-time regulation, where 2014 and 2017 were higher than surrounding years. Regulation movement (i.e., mileage), where data was limited to 2015-2017, has shown no significant average increase or decrease in the three-year span.

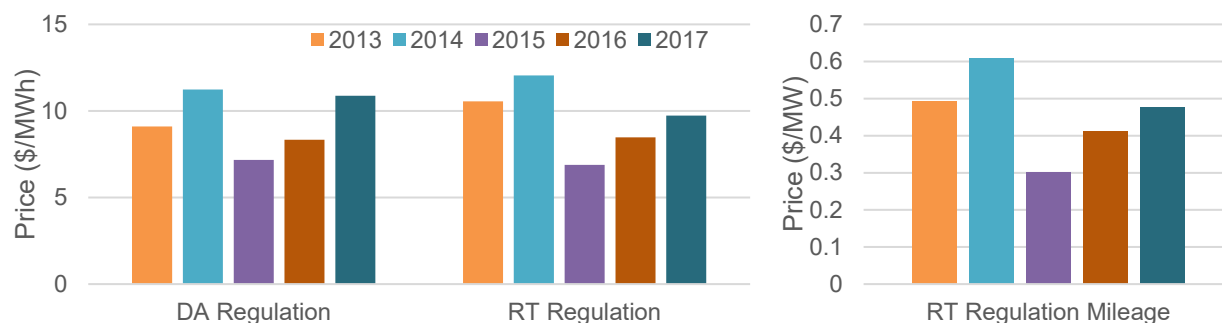


Figure 4-7
MISO day-ahead and real-time regulation product averaged by year.

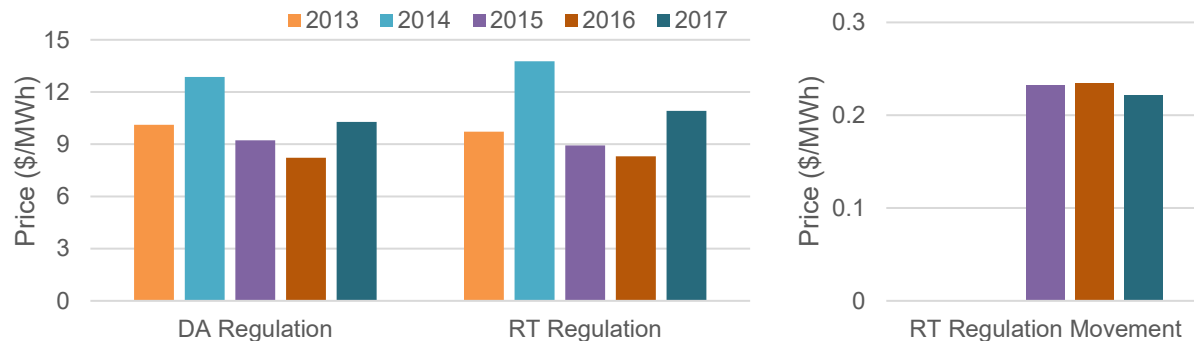


Figure 4-8
NYISO day-ahead and real-time regulation products averaged by year.

PJM has a single regulating reserve price but shows the contribution of the two components shown in Figure 4-9, regulation capability and regulation performance (i.e., mileage). As noted above, the annual averages show the effect of the winter high prices in 2014 and to a less extent in 2015, but then falling due to continued entry of batteries participating in the service and decline in energy prices over that period. The analysis of the prices and set of resources in this market requires attention to several changes in market design over this period. Although regulation mileage or movement has lower average prices in most regions, the revenue from the product can still be significant.

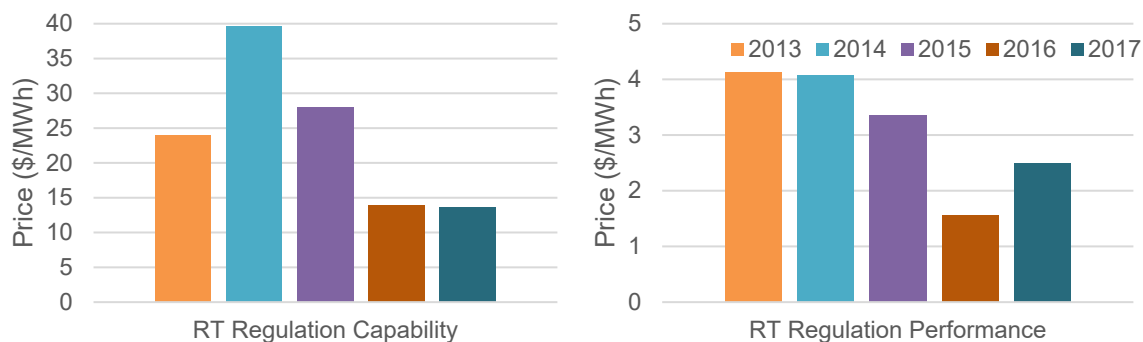


Figure 4-9
PJM real-time regulation capability and performance products averaged by year.

Lastly, regulation prices for the Mexican ISO, CENACE, are shown in Figure 4-10. Average prices are shown for the day-ahead market in 2016 and 2017 and real-time prices are only shown for 2017. The prices are an average of zones 1-4 and shown in U.S. dollars using a conversion rate of 19.769 Mexican pesos to dollars. The annual average for day-ahead regulation increased from 2016 to 2017, with highest monthly prices in June 2017 across all zones.

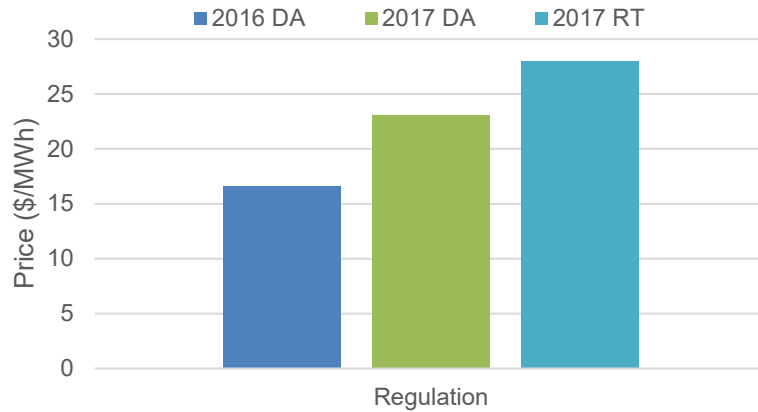


Figure 4-10
CENACE day-ahead and real-time regulation products averaged by year.

4.1.2 Hourly and Seasonal Prices

Of relevance to resources that have seasonal trends in production which will affect ancillary service market participation, prices for regulating reserve do have distinct hourly and seasonal characteristics. Figure 4-11 combines both these factors, showing the hourly average real-time regulating reserve price by month for 2017 in six of the U.S. ISOs (the full regulating reserve price for combined products, or the regulation up price otherwise). The months are along the top/horizontal of the figure, and hours along the side/vertical. The heat map colors are orange for higher-priced hours and white for lower-priced hours; the colors are scaled for individual ISOs rather than across all six.

For CAISO, shown in the upper left of the figure, the regulation up market prices are highly positively correlated with the energy market price “duck curve” all year, with depressed regulation prices during the periods of lowest energy prices, and higher prices during the solar ramp intervals. The highest regulation up prices are from 7 PM to 9 PM in August through October. The early evening hours are generally higher throughout the year, following the evening peak when solar is declining and the evening load is ramping up. The prices are also higher in spring and fall during the morning ramp up hours, following the morning load ramp.

SPP, in the upper middle of the figure, shows a trend in the summer for higher late afternoon prices, while fall and winter months show higher morning and evening ramp peak prices. The highest prices throughout the year, are in winter months at 8 or 9 AM and 7 or 8 PM.

ISO-NE, shown in the upper right of the figure, has small procurement but some of the highest average regulating reserve prices in 2017, with the hourly trend being towards higher prices in the early evening in the fall. The highest prices are in October, between 8 to 9 PM. Prices are higher on average between midnight and the morning peak at 9 AM in winter months, and May and June.

For MISO, in the lower left of the figure, average prices are highest in summer months, from noon to 6 PM, with the highest average price in July at 2 PM. In the lower middle, NYISO's highest average prices are in the morning, between 6 AM and 10 AM. November and December also show higher prices in the morning and evening periods, with the highest price in November at 8 AM.

PJM, in the lower right of the figure, shows the fewest hourly or seasonal trends among the ISOs. With the exception of summer months, morning and evening periods show higher prices. The highest prices are in midafternoon in September, and most periods in December of 2017.

Between the six ISOs, there is no one distinct trend. Many show tendencies toward higher prices in the morning and evening periods, with slightly higher average prices in the evening period. Year-by-year, these trends may also vary depending on the severity of the winter cold periods and summer heat. In addition, periods of regulation shortage in just one of the hours in the month can skew prices on the high side. A report on energy price spikes, which also would provide insight on reserve scarcity periods can be found in [23] to understand more about when these periods may be occurring.

Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2	4	9	14	10	9	6	4	3	5	5	6	1	5	4	5	5	3	3	2	5	6	5	3	2	1	37	50	71	20	48	41	22	16	12	19	20	38
2	2	3	7	11	7	6	4	3	2	5	4	4	2	5	4	7	5	5	3	2	6	9	6	4	1	56	35	52	20	57	61	22	14	11	16	17	35	
3	1	2	5	8	5	3	2	2	2	3	3	4	3	5	4	6	5	6	3	2	7	9	5	3	3	35	30	37	19	63	72	26	15	10	15	18	35	
4	1	2	4	7	5	4	3	2	2	3	3	4	4	5	5	6	5	6	5	2	6	10	6	3	4	34	33	35	19	65	57	18	13	9	14	15	36	
5	1	2	4	8	5	4	2	1	1	3	3	4	5	6	5	6	4	7	4	2	2	7	6	3	5	31	35	35	20	56	59	17	12	13	14	15	35	
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7	3	5	9	17	11	7	3	2	2	5	6	5	7	11	8	9	7	6	4	2	2	6	12	10	8	7	37	55	41	21	56	56	20	17	15	14	19	49
8	6	10	15	24	16	8	4	3	5	12	11	11	8	18	18	21	14	10	5	3	3	13	16	14	11	8	38	43	42	18	52	48	18	16	19	16	24	49
9	8	9	18	20	13	9	3	3	5	14	11	11	9	17	14	14	12	10	8	5	4	9	13	13	11	9	47	36	48	20	37	50	16	16	25	28	31	54
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Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
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21	14	12	16	17	15	11	12	11	13	14	12	12	21	8	8	12	13	13	7	5	5	6	6	14	21	21	13	10	26	19	16	14	15	10	20	23	10	21	
22	13	11	13	15	15	10	11	10	12	11	11	11	22	5	6	10																							

4.1.3 Example of Regulating Reserve Market Participation and Trends

Of all the ancillary service markets, the regulating reserve market has recently attracted the most diverse set of suppliers, in part because of the higher potential revenues in the market. PJM has a wide variety of technologies already providing regulating reserve, including natural gas generation, coal generation, hydroelectric plants (including pumped storage), lithium-ion batteries, flywheels, biomass, and demand response. Notable over the past few years has been the entry of batteries in the regulation market, which accelerated from 2012-2017 before reversing somewhat in 2018 due to market rule changes and market price declines. The batteries have largely displaced coal generation for this service, which provided about 30% of the market in 2012, and is now around 8%. Table 4-1 shows the percentage share of the regulation market taken by batteries, along with the average battery revenue. The example illustrates the potential for market-driven entry for an ancillary service. The large market response of battery entry also contributed to the eventual price decline.

Table 4-1
Battery revenues and market shares in the PJM Regulation market, 2014-2018 (Jan. – Sept.)

Year	Avg. Battery revenue (\$/MW of regulation provided)	Battery share of settled regulation revenues (%)
2014	36.78	16.0
2015	27.07	27.6
2016	15.39	41.0
2017	13.70	46.5
2018, Jan.-Sep. avg.	20.69	32.1

Source: Derived from PJM annual and quarterly State of the Market reports

4.2 Contingency Reserve Products

Contingency reserve markets procure more capacity, and generally have lower prices than the regulating reserve markets. In addition, they have less complicated market designs than for frequency regulation as there exists only a reserve capacity price and no mileage payment. This section shows the prices for the contingency reserve products for each ISO, including spinning and non-spinning reserve, and a few other contingency reserve products specific to each ISO.

4.2.1 Average Prices of Contingency Reserve Market Products

Figure 4-12 shows the average annual spinning reserve prices in either the day-ahead or real-time market for each U.S. ISO and IESO in Canada (which has a similar spinning reserve ancillary service market design to the U.S. markets). Since there is not a day-ahead spinning reserve product, ISO-NE and PJM show real-time reserve. With the exception of CAISO's broad increasing trend, the ISOs do not show a strong trend upward or downward over the five-year period. Between all ISOs, prices show some volatility year-by-year for spinning reserve.

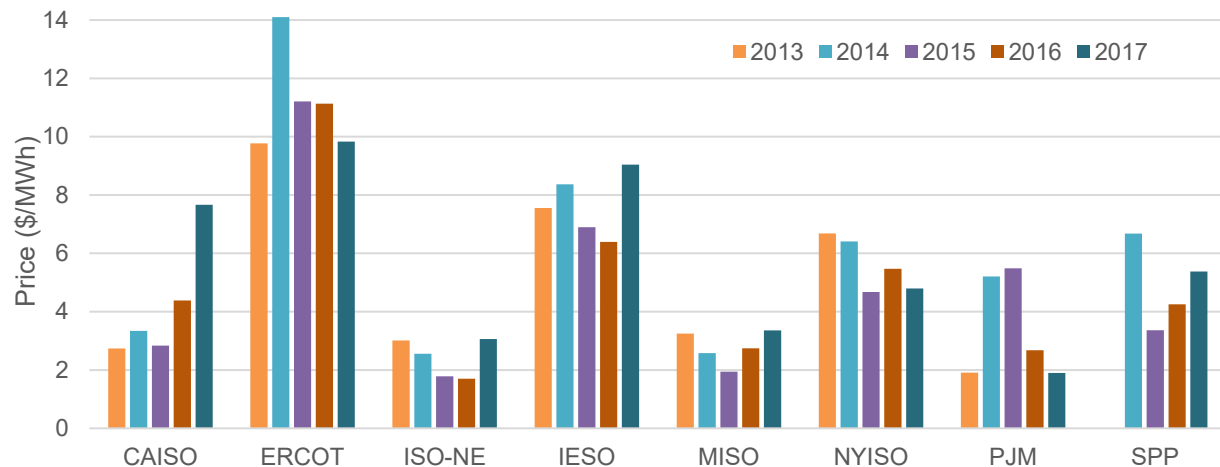


Figure 4-12

Average annual prices for day-ahead spinning reserve from 2013 – 2017; ISO-NE, PJM, and IESO show real-time spinning reserve.

Figure 4-13 to Figure 4-20 show contingency reserve products averaged annually for each of the ISOs. CAISO average prices for day-ahead and FMM 10-minute spinning and non-spinning reserve products are shown in Figure 4-13. Similar to regulation reserve, CAISO shows an upward trend with all products. In 2017, prices increased significantly, reaching over twice the prior levels for non-spinning and spinning reserve. ERCOT prices show a generally declining trend in Figure 4-14. Day-ahead responsive (spinning) reserve and non-spinning reserve have declined over the last 3-4 years, ending 2017 with the lowest prices across the five-year period.

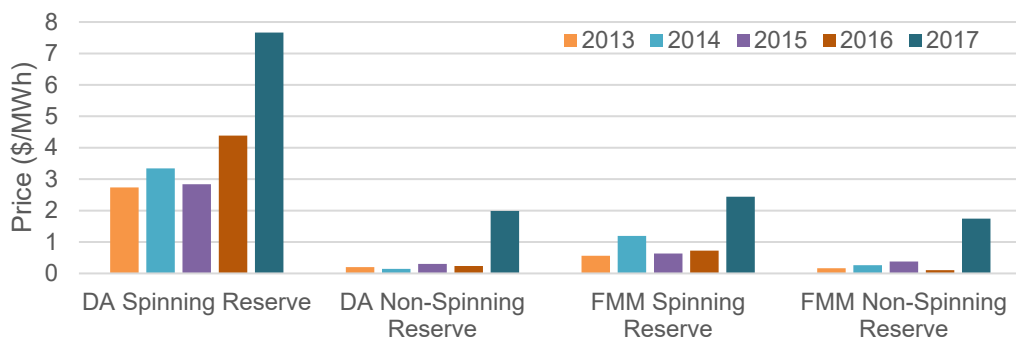


Figure 4-13

CAISO day-ahead and real-time contingency reserve products averaged by year.

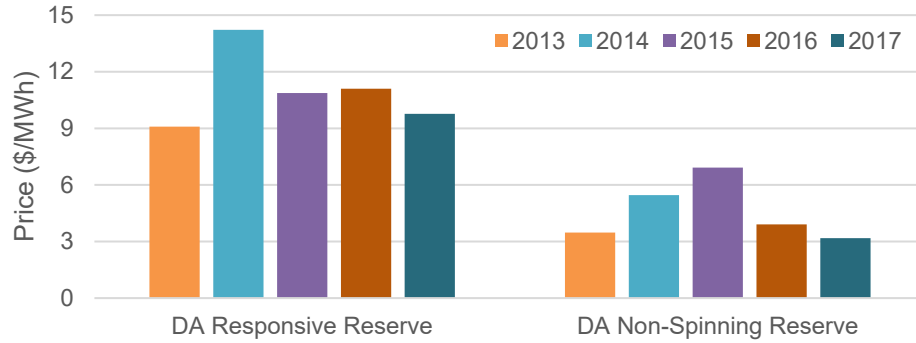


Figure 4-14
ERCOT day-ahead contingency reserve products averaged by year.

ISO-NE's three real-time products are shown in Figure 4-15. While spinning reserve does not show a distinct trend, 10-minute non-synchronous reserve and 30-minute operating reserve show clear declining trends from 2013-2017. Prices in 2016 and 2017 for both products averaged around \$1/MWh, down from \$2.50/MWh and \$2.30/MWh in 2013 for non-synchronous and operating reserve respectively. MISO has both day-ahead and real-time spinning and supplemental reserve products, shown in Figure 4-16. Spinning reserve in both day-ahead and real-time has increased from 2015-2017, while supplemental reserve in both markets declined slightly over the five years.

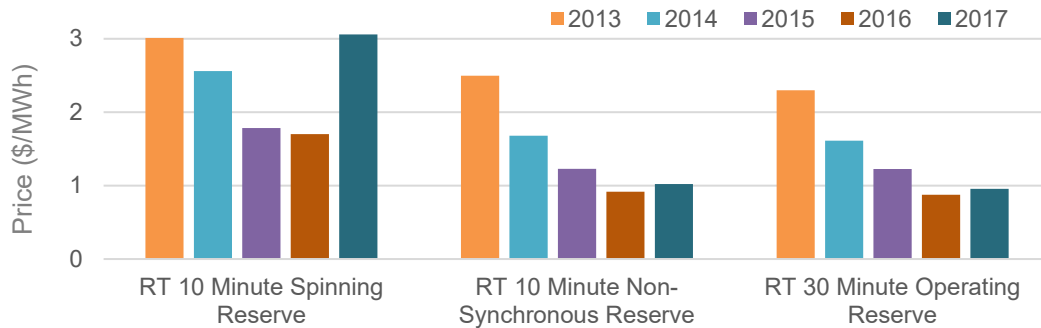


Figure 4-15
ISO-NE real-time contingency reserve products averaged by year.

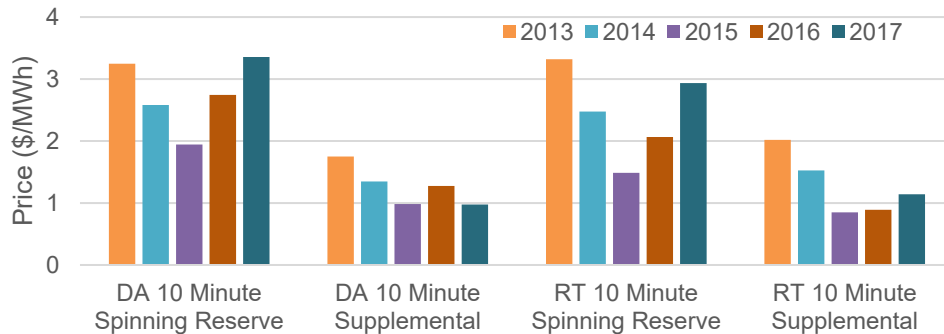


Figure 4-16
MISO day-ahead and real-time contingency reserve products averaged by year.

IESO has shown no distinct trend for the three products shown in Figure 4-17. As would be expected with a higher quality product, spinning reserve has higher average prices compared to synchronous reserve and 30-minute operating reserve. Similar to IESO, NYISO has 10-minute spinning, 10-minute non-synchronous, and 30-minute operating reserve. Both the day-ahead and real-time prices for each product are shown in Figure 4-18. The day-ahead products have higher average prices compared to the real-time, with no discrete trends between the five-year period.

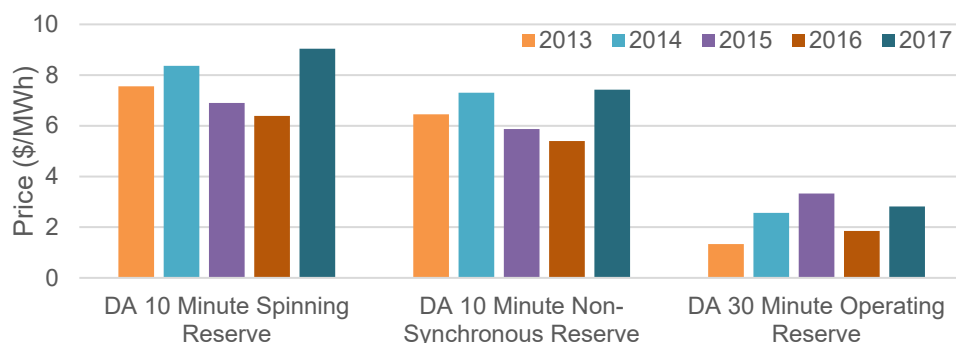


Figure 4-17
IESO real-time contingency reserve products averaged by year.

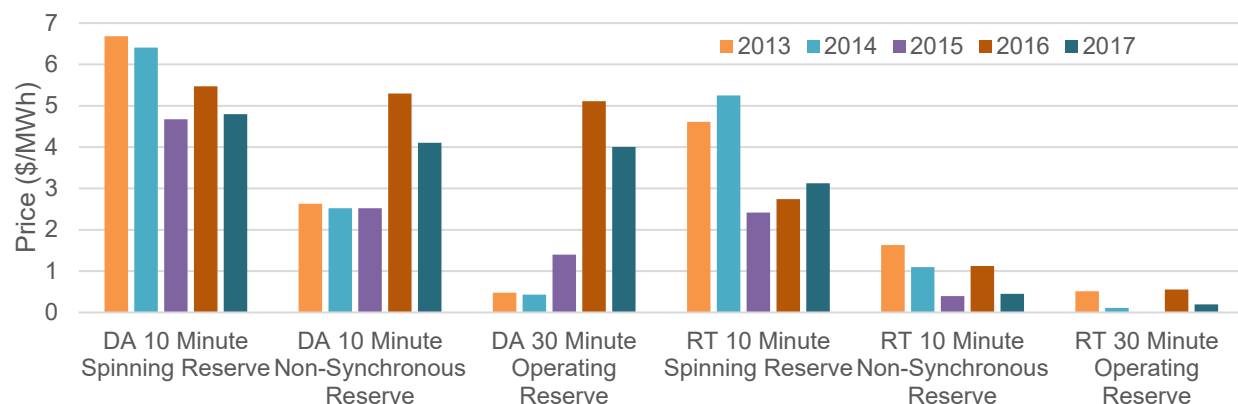


Figure 4-18
NYISO day-ahead and real-time contingency reserve products averaged by year.

PJM real-time spinning and non-synchronous reserve is shown in Figure 4-19. Similar to ISO-NE, prices were highest in 2015, and have declined the following two years, ending under \$2/MWh for spinning reserve. SPP day-ahead and real-time spinning and supplemental reserve are shown in Figure 4-20. While spinning reserve increased in both day-ahead and real-time between 2015 to 2017, supplemental reserve has declined slightly since beginning in 2014. Day-ahead and real-time reserve products are similar in average value across the five years.

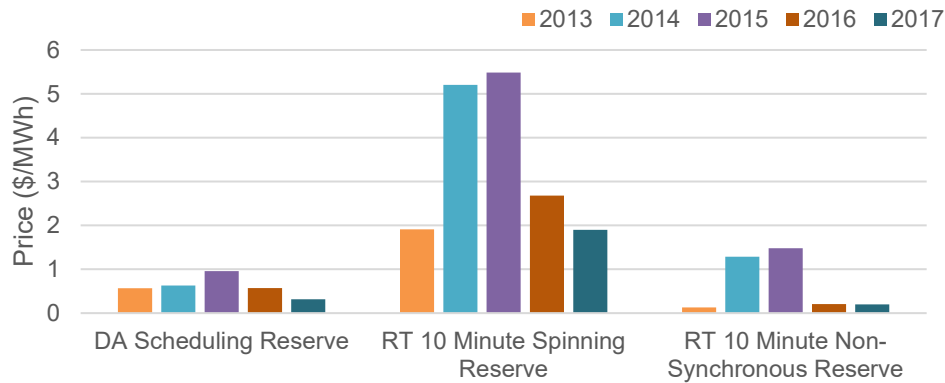


Figure 4-19
PJM day-ahead and real-time contingency reserve products averaged by year.

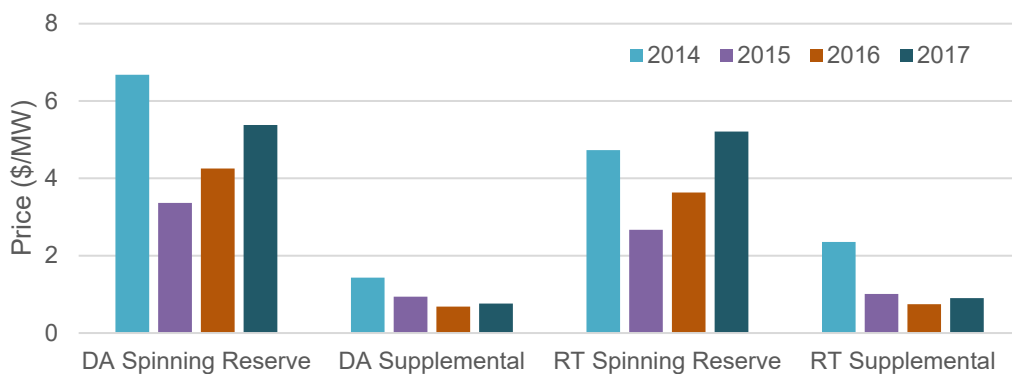


Figure 4-20
SPP day-ahead and real-time contingency reserve products averaged by year.

Finally, CENACE is shown in Figure 4-21. Ten-minute and supplemental spinning and non-synchronous reserves are shown for day-ahead in 2016 and 2017, and real-time in 2017. The 10-minute spinning reserve product (reserva rodante de 10 minutos) has the highest value, followed by the 10-minute non-spinning product. The supplemental product has nearly the same average value for both spinning and non-spinning, which is lower than both 10-minute products.

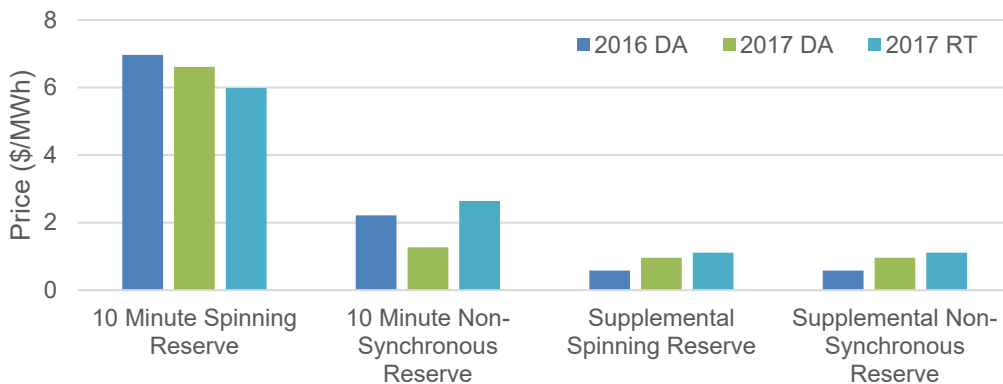


Figure 4-21
CENACE day-ahead and real-time contingency reserve products averaged by year.

4.2.2 Price Distributions of Contingency Reserve Market Products

Similar to the regulating reserve market, Contingency Reserve market prices show hourly and seasonal trends, typically positively correlated with the energy price for spinning reserve (reflecting opportunity costs) and reflecting how much surplus capacity is available for non-spinning reserves.

Another view on how prices are distributed are through variants on price duration curves, that is, measure of the number of intervals at each price levels. Figure 4-22 shows histograms of 2017 real-time spinning reserve prices for each ISO. The total number of periods shown is 8760 (the number of hours in a year), except IESO where daily values are shown (totaling 365). Where there exists a bin labeled " ≤ 0 ", the number shows the number of periods with zero prices. This is evident for PJM and ISO-NE, where there are many hours with zero prices throughout the year. The next largest bin for the two ISOs is the \$0/MWh – \$4/MWh range, with significantly fewer hours of prices above \$8/MWh. CAISO, MISO, and SPP have a majority of hours priced in the \$0/MWh – \$4/MWh range. CAISO and SPP step down in value gradually, while MISO drops off sharply, with few hours of high prices. ERCOT and NYISO have a majority of hours in the \$4/MWh – \$8/MWh range; NYISO has fewer hours with even higher prices whereas ERCOT has several hundred above \$30/MWh. IESO also has a majority of days priced between \$4/MWh – \$8/MWh range, with 7 days of prices above \$30/MWh. Overall, these figures show the spinning reserve price clears a majority of the time below \$8/MWh. In 2017, the price exceeded \$10/MWh as low as 2% of the time in NYISO and 4% of the time in MISO and PJM, up to 20% of the time in CAISO and 33% of the time ERCOT.

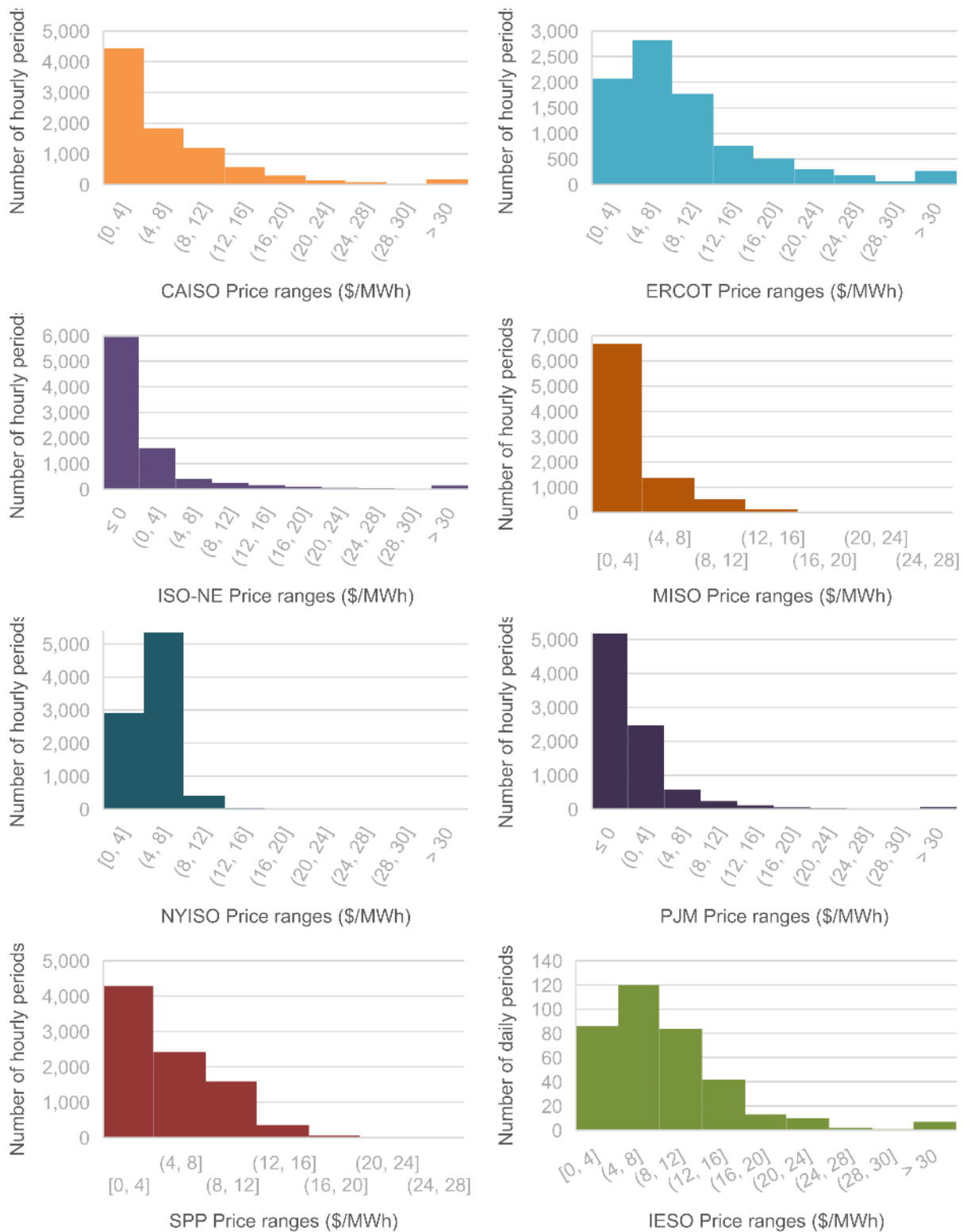


Figure 4-22
Real-time spinning reserve histograms for 2017. From left to right and top to bottom: CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, SPP, and IESO.

Total number of hourly periods is 8760, except IESO which has 365 daily periods. The figures that begin with “≤ 0” indicate the number of zero priced periods for the year.

4.3 Flexibility Reserve Products

As discussed in Section 2.1.4, there are two short-term flexibility reserve products that have been implemented. MISO launched a Ramping Capability Product (RCP) in May 2016 in both upward and downward directions. CAISO implemented a flexible ramping constraint in 2011, followed by the Flexible Ramp Product (FRP) in November 2016, also with both an upward and downward product.

4.3.1 Trends in the MISO Ramp Capability Market

A price duration curve for MISO's upward RCP is shown in Figure 4-23, with data from May 2016 to July 2018. The down ramping product is not shown since the constraints have not been binding (non-zero) since inception, and hence prices have remained at zero. It is first important to note that there are many more periods of zero-priced RCP compared to other reserve products. The curves show that the real-time product has fewer periods of nonzero prices compared to the day-ahead product; periods of nonzero prices range between 4.6%-7% annually in real-time compared to 20%-25% annually in day-ahead. Of the binding periods, real-time RCP frequently hits the fixed \$5/MWh demand (i.e. shortage price) curve. While overall day-ahead prices hit the \$5/MWh cap more frequently (as a percentage of total intervals), there are also a range of other positive prices.

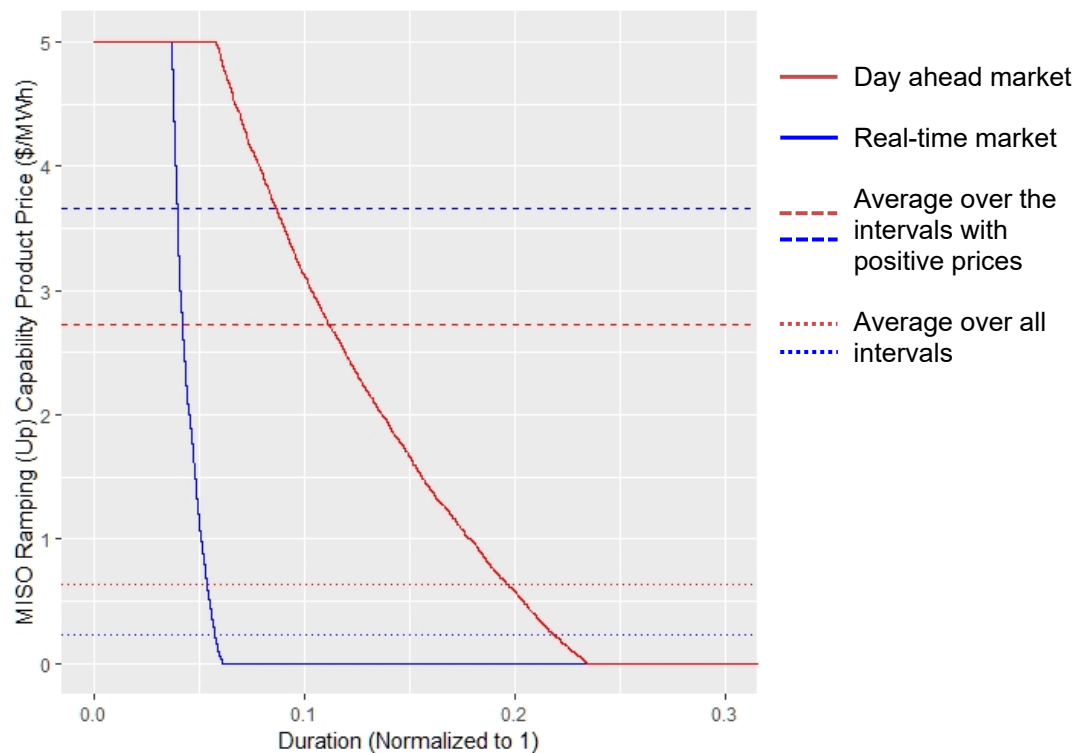


Figure 4-23
Price duration curve of MISO's Ramping Capability Product

Additional statistical information on these prices is shown in Table 4-2. The average price has increased between 2016 and 2018, while the percent of positive priced periods has remained roughly the same between 2017 and 2018. The total number of binding intervals has decreased between 2017 and 2018 while the average price slightly increased in both day-ahead and real-

time. Figure 4-24 shows the percent of hours by hour and month with positive prices for the upward day-ahead RCP. The early mornings and evenings show almost no periods with positive prices throughout the years, as do winter months in the middle of the day. The highest percentage of periods with binding prices is in the late summer months in the middle of the day, between noon and 5 PM, and in winter months in the early evening, between 6 and 8 PM. Both of these periods have stressed system conditions due to load, resulting in the need for additional ramp.

Table 4-2
Annual statistics for MISO's ramping capability product

	2016		2017		2018	
	DA	RT	DA	RT	DA	RT
Number of non-zero (binding) intervals	1183	3274	2163	7357	1217	3722
Average price of binding intervals (\$/MWh)	2.66	3.49	2.67	3.67	2.91	3.81
Standard deviation of prices in binding intervals (\$/MWh)	1.81	1.94	1.75	1.86	1.80	1.77
Number of total intervals	5880	70559	8760	105120	4872	58752
Number of periods at cap of \$5/MWh (percentage of total periods)	297 (5.1%)	1869 (2.6%)	484 (5.5%)	4458 (4.2%)	356 (7.3%)	2361 (4.0%)

Endhour	2016 May	2016 Jun	2016 Jul	2016 Aug	2016 Sep	2016 Oct	2016 Nov	2016 Dec	2017 Jan	2017 Feb	2017 Mar	2017 Apr	2017 May	2017 Jun	2017 Jul	2017 Aug	2017 Sep	2017 Oct	2017 Nov	2017 Dec	2018 Jan	2018 Feb	2018 Mar	2018 Apr	2018 May	2018 Jun	2018 Jul
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.33%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.23%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.23%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.45%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	16.13%	0.00%	3.33%	16.67%	0.00%	0.00%
6	3.23%	0.00%	0.00%	0.00%	0.00%	38.71%	3.33%	6.45%	9.68%	0.00%	48.39%	46.67%	12.90%	0.00%	0.00%	0.00%	0.00%	25.81%	23.33%	0.00%	38.71%	3.57%	46.67%	50.00%	0.00%	0.00%	0.00%
7	3.23%	0.00%	0.00%	0.00%	0.00%	41.94%	50.00%	48.39%	45.16%	21.43%	67.74%	60.00%	32.26%	0.00%	0.00%	0.00%	0.00%	41.94%	53.33%	32.26%	70.97%	46.43%	70.00%	66.67%	3.23%	0.00%	0.00%
8	3.23%	0.00%	0.00%	0.00%	0.00%	32.26%	50.00%	61.29%	67.74%	46.43%	70.97%	60.00%	32.26%	3.33%	0.00%	0.00%	0.00%	38.71%	66.67%	48.39%	77.42%	46.43%	66.67%	70.00%	12.90%	0.00%	0.00%
9	0.00%	0.00%	16.13%	0.00%	3.33%	35.48%	13.33%	32.26%	38.71%	3.57%	61.29%	66.67%	32.26%	10.00%	3.23%	6.45%	10.00%	29.03%	30.00%	25.81%	41.94%	14.29%	53.33%	63.33%	22.58%	3.45%	8.33%
10	6.45%	16.67%	35.48%	29.03%	33.33%	48.39%	23.33%	25.81%	25.81%	3.57%	54.84%	73.33%	48.39%	26.67%	22.58%	22.58%	40.00%	38.71%	36.67%	19.35%	41.94%	10.71%	40.00%	70.00%	67.74%	17.24%	29.17%
11	16.13%	40.00%	61.29%	58.06%	46.67%	51.61%	20.00%	9.68%	22.58%	3.57%	38.71%	63.33%	58.06%	40.00%	54.84%	61.29%	60.00%	48.39%	36.67%	16.13%	29.03%	10.71%	26.67%	50.00%	77.42%	41.38%	70.83%
12	22.58%	56.67%	77.42%	64.52%	56.67%	54.84%	13.33%	3.23%	9.68%	0.00%	25.81%	66.67%	64.52%	50.00%	67.74%	77.42%	76.67%	45.16%	23.33%	3.23%	9.68%	0.00%	16.67%	33.33%	87.10%	72.41%	79.17%
13	25.81%	70.00%	77.42%	83.87%	66.67%	51.61%	16.67%	3.23%	0.00%	0.00%	25.81%	66.67%	67.74%	70.00%	77.42%	93.55%	90.00%	48.39%	20.00%	0.00%	0.00%	3.57%	13.33%	30.00%	90.32%	89.66%	83.33%
14	16.13%	76.67%	87.10%	87.10%	80.00%	51.61%	10.00%	0.00%	0.00%	0.00%	16.13%	66.67%	67.74%	80.00%	87.10%	93.55%	93.33%	45.16%	16.67%	0.00%	0.00%	3.57%	6.67%	23.33%	87.10%	96.55%	91.67%
15	16.13%	66.67%	96.77%	93.55%	80.00%	45.16%	10.00%	0.00%	0.00%	0.00%	6.45%	63.33%	74.19%	80.00%	100.00%	93.55%	93.33%	41.94%	13.33%	0.00%	0.00%	3.57%	0.00%	16.67%	87.10%	96.55%	100.00%
16	19.35%	73.33%	96.77%	93.55%	63.33%	54.84%	6.67%	0.00%	0.00%	0.00%	3.23%	66.67%	67.74%	70.00%	96.77%	93.55%	93.33%	45.16%	10.00%	0.00%	0.00%	0.00%	0.00%	20.00%	87.10%	96.55%	95.83%
17	19.35%	33.33%	74.19%	67.74%	23.33%	70.97%	13.33%	6.45%	16.13%	0.00%	6.45%	73.33%	74.19%	56.67%	87.10%	80.65%	66.67%	41.94%	36.67%	3.23%	3.23%	3.57%	0.00%	26.67%	80.65%	68.97%	83.33%
18	0.00%	0.00%	19.35%	19.35%	20.00%	83.87%	83.33%	87.10%	74.19%	14.29%	25.81%	70.00%	51.61%	26.67%	35.48%	35.48%	26.67%	80.65%	83.33%	61.29%	64.52%	17.86%	10.00%	43.33%	54.84%	27.59%	16.67%
19	3.23%	0.00%	0.00%	3.23%	30.00%	80.65%	66.67%	74.19%	87.10%	53.57%	74.19%	76.67%	29.03%	6.67%	0.00%	12.90%	53.33%	80.65%	80.00%	61.29%	83.87%	78.57%	83.33%	56.67%	29.03%	0.00%	0.00%
20	12.90%	0.00%	0.00%	0.00%	0.00%	0.00%	3.33%	22.58%	29.03%	21.43%	77.42%	100.00%	61.29%	0.00%	0.00%	3.23%	3.33%	6.45%	36.67%	12.90%	32.26%	28.57%	76.67%	93.33%	38.71%	0.00%	0.00%
21	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.45%	12.90%	3.57%	6.45%	13.33%	3.23%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.33%	3.23%	16.13%	0.00%	3.33%	9.68%	0.00%
22	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 4-24

Occurrence of positive (binding) ramp-up prices in the MISO day-ahead market, values represent percentage of positive prices over all hours associated with hour and month shown.

4.3.2 Trends in the CAISO Market

Price duration curves for the CAISO FRP up and down are shown in Figure 4-25 with prices from November 2016 to July 2018. Similar to the MISO product, there are few periods with non-zero prices, less in real-time (5-minutes) and more in the Fifteen Minute Market. Both markets still have significantly fewer periods of non-zero prices compared to MISO. Unlike MISO, the FRP-down product does have a limited number of periods of non-zero prices, though less than 3.5% of all intervals.

Statistical information for each product and balancing area is shown in Table 4-3 for the Fifteen Minute Market and Table 4-4 for the five-minute market. The prices are averaged over the number of positive (binding) prices in the top half of the table and over all periods in the bottom half. Since many periods have \$0/MWh prices (non-binding), the two sets of prices show the average value from the market over the year, and the average price that resources could receive when prices are non-zero. The standard deviations are often the same in magnitude as the average prices, highlighting the sparse range of prices for FRP. Among the different balancing areas, Arizona Public Service is one of the few to have consistently higher and more frequent FRP down prices. Most areas saw a steady increase in average price over the three years, while PacifiCorp West and Portland General Electric had higher prices in 2017 than 2018. Also note data for 2016 and 2018 show partial year averages.

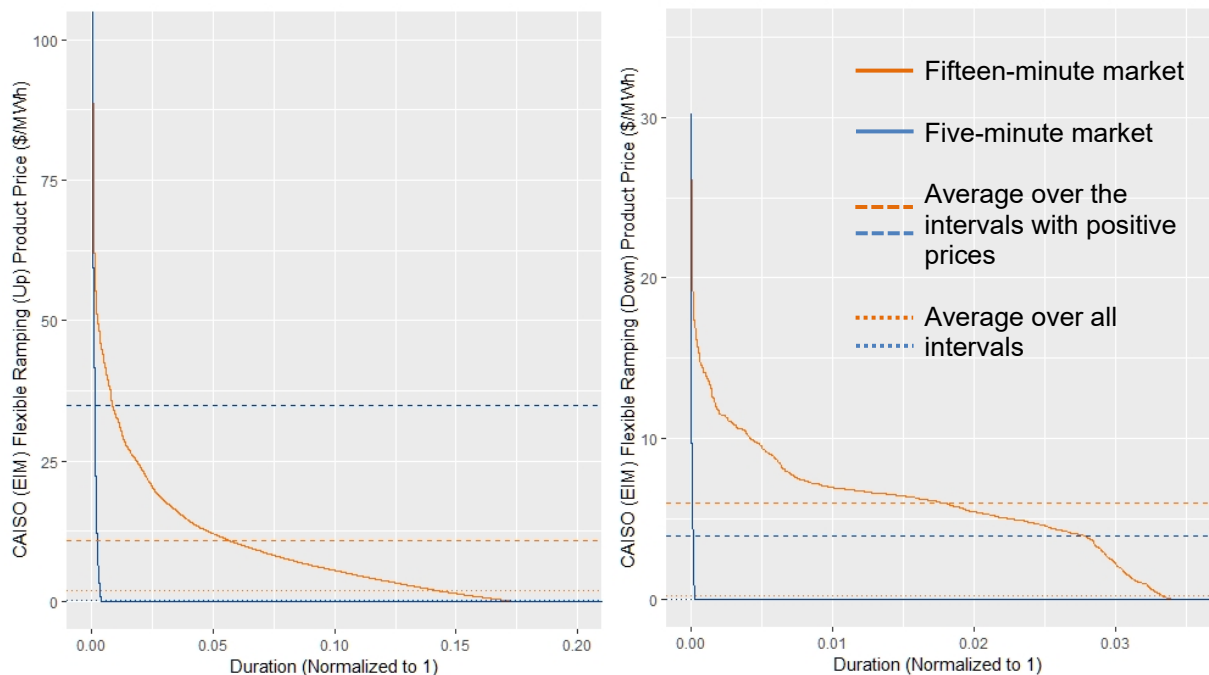


Figure 4-25
Price duration curves for CAISO's Flexible Ramp Product (note differences in x- and y-axis scales)

Table 4-3**Annual average prices and standard deviation (in parentheses) for CAISO's FRP in the Fifteen Minute Market**

	Ramp-up Price in Fifteen Minute Market (\$/MWh, over positive intervals)			Ramp-down Price in Fifteen Minute Market (\$/MWh, over positive intervals)		
Year	2016	2017	2018	2016	2017	2018
Arizona Public Service	49.57 (77.65)	96.65 (92.77)	119.79 (116.49)	20 (23.18)	37.82 (36.31)	55.03 (61.13)
BC Hydro			72.95 (103.88)			20.06 (22.80)
CAISO	0 (0)	8.85 (10.46)	14.51 (0.00)	0 (0)	8.9 (4.74)	11.53 (6.92)
EIM Area	8.54 (8.54)	11.28 (15.48)	11.62 (17.43)	3.97 (2.48)	6.31 (3.16)	5.63 (4.62)
Idaho Power			23.02 (33.13)			33.88 (17.65)
Nevada Power	73.55 (70.34)	122.35 (106.42)	153.27 (100.96)	4.27 (3.08)	32.16 (32.52)	33.6 (39.53)
PacifiCorp East	48.37 (65.73)	50.98 (65.12)	78.45 (82.03)	3.13 (3.63)	7.73 (9.57)	11.07 (15.38)
PacifiCorp West	46.34 (70.45)	65.41 (78.30)	28.95 (68.33)	5.84 (5.76)	24.43 (33.08)	17.16 (16.07)
Portland General Electric		42.68 (84.55)	34.78 (53.99)		6.71 (5.19)	19.95 (21.31)
Puget Sound Energy	65.74 (81.52)	47.30 (65.25)	92.54 (99.40)	8.86 (0)	25.71 (31.33)	45.1 (56.22)
	Ramp-up Price in Fifteen Minute Market (\$/MWh, over all intervals)			Ramp-down Price in Fifteen Minute Market (\$/MWh, over all intervals)		
Year	2016	2017	2018	2016	2017	2018
Arizona Public Service	0.87 (12.10)	1.84 (19.54)	2.26 (22.86)	1.6 (8.51)	1.88 (11.54)	1.01 (11.11)
BC Hydro			-0.25 (5.85)			-0.06 (1.74)
CAISO	0 (0)	-0.18 (4.72)	-0.02 (1.47)	0 (0)	0.01 (0.43)	0.03 (0.75)
EIM Area	2.37 (5.90)	2.48 (8.64)	0.75	0.11 (0.78)	0.29 (1.49)	0.09 (0.94)
Idaho Power			0.55 (6.21)			0.06 (1.69)
Nevada Power	0.26 (6.03)	2.57 (24.29)	3.81 (28.83)	0 (0.11)	0.39 (5.03)	0.5 (6.37)
PacifiCorp East	0.70 (9.73)	0.67 (11.20)	0.35 (7.85)	0.04 (0.58)	0.14 (1.66)	0 (0.29)
PacifiCorp West	1.29 (14.0)	0.46 (10.60)	0.03 (3.97)	0 (0.29)	0.09 (2.52)	0.01 (0.71)
Portland General Electric		-0.06 (3.67)	0.17 (5.26)		0.01 (0.33)	0.18 (2.78)
Puget Sound Energy	0.53 (9.32)	0.40 (9.81)	0.58 (11.17)	0 (0.11)	0.68 (6.55)	0.41 (6.9)

Note: Resources receive two payments. One from EIM level and one from BAA-level.

Table 4-4**Annual average prices and standard deviation (in parentheses) for CAISO's FRP in the Five-Minute Market**

	Ramp-up Price in Five Minute Market (\$/MWh, over positive intervals)			Ramp-down Price in Five Minute Market (\$/MWh, over positive intervals)		
Year	2016	2017	2018	2016	2017	2018
Arizona Public Service	129.09 (108.88)	182.26 (97.28)	192 (93.04)	42.13 (46.2)	50.37 (49.14)	51.4 (35.55)
BC Hydro			247 (0)			63.57 (13.74)
CAISO	0 (0)	9.54 (7.55)	0 (0)	0 (0)	7.24 (6.1)	6.42 (5.1)
EIM Area	38.9 (52.53)	32.78 (47.5)	40.52 (52.31)	0 (0)	4.41 (3.43)	16.04 (20.09)
Idaho Power			28.16 (38.38)			38.1 (30.23)
Nevada Power	19.85 (42.38)	135.41 (108.82)	173.15 (96.28)	1.49 (0)	63.18 (47.56)	44.98 (39.86)
PacifiCorp East	115.29 (109.41)	139.73 (110.22)	100.45 (102.14)	0 (0)	39.56 (37.27)	0 (0)
PacifiCorp West	37.54 (74.53)	93.23 (122.06)	109.4 (113.29)	0 (0)	64.18 (57.79)	18 (16.55)
Portland General Electric		186.05 (105.27)	30.92 (58.87)		52.86 (34.93)	19.55 (28.91)
Puget Sound Energy	121.31 (118.95)	140.23 (111.89)	176.92 (101.65)	95.71 (72.49)	76.62 (54.52)	39.45 (27.15)
	Ramp-up Price in Five Minute Market (\$/MWh, over all intervals)			Ramp-down Price in Five Minute Market (\$/MWh, over all intervals)		
Year	2016	2017	2018	2016	2017	2018
Arizona Public Service	0.43 (9.67)	1.31 (17.62)	1.69 (19.96)	0.85 (8.85)	0.92 (9.46)	0.5 (6.17)
BC Hydro			0.06 (4.71)			0.03 (1.54)
CAISO	0 (0)	-0.02 (1.59)	-0.01 (0.95)	0 (0)	0 (0.22)	0.01 (0.34)
EIM Area	0.3 (5.67)	0.14 (3.8)	0.09 (3.24)	0 (0)	0 (0.11)	0 (0.12)
Idaho Power			0.31 (4.98)			0.02 (1.17)
Nevada Power	0.02 (1.59)	0.99 (15.04)	2.57 (24.07)	0 (0.01)	0.38 (6.11)	0.44 (5.9)
PacifiCorp East	0.21 (6.74)	0.19 (6.96)	0.13 (5.36)	0 (0)	0.02 (1.12)	0 (0)
PacifiCorp West	0.24 (6.61)	0.23 (7.96)	0.14 (5.86)	0 (0)	0.03 (2.34)	0 (0.12)
Portland General Electric		0.16 (7.15)	0.16 (5.02)		0.03 (1.49)	0.03 (1.43)
Puget Sound Energy	0.22 (7.2)	0.26 (8.01)	0.37 (9.58)	0.02 (1.47)	0.53 (7.83)	0.25 (3.81)

Note: Resources receive two payments. One from EIM level and one from BAA-level.

The percent of positive prices for FRP up in the Fifteen-Minute Market by hour and month is shown in Figure 4-26. There are a large number of nonzero prices at 8 AM throughout the year, following the morning ramp period for load. For a year after the product launched, there were also many periods of nonzero prices in the late evening hours, from 6 PM until 1 AM. In February of 2018, the CAISO Department of Market Monitoring found errors in the implementation of the FRP, which likely impacted prices. The price trends shown in the figure are likely to change over the coming years to reflect implemented changes starting in March 2018.

	2016 Nov	2016 Dec	2017 Jan	2017 Feb	2017 Mar	2017 Apr	2017 May	2017 Jun	2017 Jul	2017 Aug	2017 Sep	2017 Oct	2017 Nov	2017 Dec	2018 Jan	2018 Feb	2018 Mar	2018 Apr	2018 May	2018 Jun
1	12.71%	4.03%	16.94%	14.41%	23.97%	22.88%	18.55%	20.83%	26.61%	17.74%	18.33%	0.00%	1.67%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	5.08%	0.00%	0.00%	0.00%	3.23%	8.40%	2.42%	1.67%	2.42%	0.00%	0.83%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	5.08%	3.23%	0.00%	6.45%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.00%	0.00%	1.61%	0.00%	5.65%	2.52%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.89%	2.42%	0.83%	0.00%	0.00%
6	0.00%	0.00%	0.81%	2.68%	1.61%	0.00%	2.42%	0.00%	1.61%	0.00%	0.83%	0.00%	0.00%	0.00%	0.00%	6.25%	28.23%	30.00%	18.55%	0.00%
7	4.17%	3.23%	8.06%	0.89%	8.06%	8.33%	26.61%	17.50%	16.94%	14.52%	15.83%	0.00%	0.00%	0.00%	0.00%	0.00%	20.97%	29.17%	4.03%	1.67%
8	77.50%	83.87%	89.52%	95.50%	87.90%	88.33%	67.74%	30.83%	38.71%	27.42%	55.00%	43.55%	22.50%	40.32%	57.26%	33.04%	19.35%	22.50%	6.45%	1.67%
9	59.17%	68.55%	74.19%	75.89%	81.45%	79.17%	67.74%	9.17%	2.42%	0.00%	5.00%	7.26%	10.00%	8.87%	9.68%	20.54%	42.74%	39.17%	4.03%	0.00%
10	23.33%	44.35%	41.94%	55.36%	31.45%	29.17%	12.90%	0.00%	0.00%	0.00%	0.83%	0.00%	1.67%	0.00%	0.81%	11.61%	33.06%	25.00%	7.26%	0.00%
11	4.20%	17.74%	25.00%	41.07%	12.90%	5.83%	6.45%	2.50%	1.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.45%	5.83%	4.84%	0.00%
12	1.69%	13.71%	16.13%	35.71%	1.61%	5.00%	3.23%	2.50%	0.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.81%	0.83%	0.00%	0.00%	0.00%
13	2.52%	15.32%	5.65%	6.25%	12.10%	8.40%	4.03%	4.17%	3.23%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
14	5.93%	8.87%	4.03%	17.86%	29.03%	9.17%	12.10%	15.00%	12.10%	0.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.33%	0.81%	1.67%
15	14.17%	11.29%	11.38%	14.29%	22.58%	14.17%	16.13%	11.67%	8.06%	9.68%	5.00%	0.00%	0.00%	0.00%	0.00%	0.00%	5.65%	3.33%	0.00%	1.67%
16	18.42%	9.84%	3.28%	9.91%	13.11%	21.05%	20.97%	19.17%	16.94%	23.39%	22.50%	0.00%	2.50%	0.00%	0.00%	0.00%	18.55%	12.50%	1.61%	0.83%
17	26.89%	16.26%	0.83%	5.41%	6.50%	10.00%	20.97%	25.83%	10.48%	24.19%	17.50%	2.42%	2.50%	0.00%	0.00%	8.04%	12.10%	16.67%	10.48%	2.50%
18	45.83%	50.81%	48.39%	44.55%	19.35%	13.45%	25.81%	13.33%	12.90%	40.32%	28.33%	21.77%	12.50%	1.61%	4.84%	2.68%	25.00%	24.17%	16.13%	6.67%
19	27.73%	57.26%	66.94%	75.68%	55.65%	9.17%	19.35%	15.00%	15.32%	38.71%	50.00%	45.97%	6.67%	2.42%	9.68%	8.04%	33.06%	30.83%	23.39%	13.33%
20	46.67%	55.65%	54.03%	51.79%	85.37%	48.33%	17.74%	28.33%	72.58%	91.13%	66.67%	20.16%	6.67%	2.42%	3.23%	2.68%	16.94%	48.33%	34.68%	9.17%
21	63.03%	66.94%	58.06%	62.50%	85.37%	81.67%	66.94%	50.00%	66.94%	69.35%	77.50%	44.35%	12.50%	12.90%	12.10%	7.14%	7.26%	26.67%	17.74%	3.33%
22	67.50%	61.29%	64.52%	73.21%	82.11%	74.17%	84.68%	85.83%	81.45%	89.52%	84.17%	50.00%	29.17%	19.35%	19.35%	9.82%	7.26%	3.33%	1.61%	0.00%
23	76.67%	66.94%	67.74%	56.25%	62.90%	84.17%	73.39%	85.83%	91.13%	83.87%	80.00%	47.58%	27.50%	16.13%	11.29%	3.57%	0.00%	0.83%	0.81%	0.00%
24	58.33%	33.06%	42.74%	36.61%	34.17%	50.00%	60.48%	70.00%	71.77%	60.48%	61.67%	14.52%	9.17%	0.00%	1.61%	2.68%	0.00%	0.00%	0.00%	0.00%

Figure 4-26
Occurrence of positive (binding) ramp-up prices in the CAISO Fifteen-Minute market, percentages represent frequency of positive prices

4.4 Forecasting Reserve Prices

Due to the many complex features of ancillary service markets, forecasting prices can be very difficult. For most reserve types, the most common type of forecast method uses statistical models which use an energy forward price curve derived from another model to estimate associated reserve prices using historical correlations between the two prices. There are many variants on these types of models. A key limitation of this type of forecast is that it does not capture structural changes in the market which can affect prices, such as the entry of energy storage resources.

In contrast, production cost models can evaluate structural changes to the markets as resources enter and exit, but the “shadow prices” calculated in the model are typically more indicative of trends and less reliable as true price forecasts. With any type of market price forecast, the analyst will need to consider the many factors that impact prices, including market design changes, fuel prices, significant resource mix changes, opportunity costs, and the contribution from side-payments (e.g., regulation performance payments).

4.5 Summary of Market Trends

Average prices over the last five years in ancillary service markets reveal few distinct trends. Some ISOs have seen a net increase in average prices in the last three years, but few have shown a steady year-over-year upward trend. Regulation up prices in CAISO and ISO-NE have been increasing, but only CAISO showed an increasing trend for spinning reserve. Most ISOs have seen volatile average prices in recent years. The average prices do reveal that extreme events can have a significant impact. This is evident by the high energy and ancillary service prices in the eastern ISOs in 2014, which are due to the month-long period of extremely high natural gas prices during the Polar Vortex weather event.

Prices for regulation products vary across the ISOs. Across the five-year period, real-time regulation up prices in CAISO were the lowest, averaging just above \$5/MWh. ERCOT, MISO, NYISO, and SPP averaged around \$10/MWh, and PJM and ISO-NE average above \$20/MWh. While ISO-NE has trended up from 2013 to 2017, PJM has trended down after an overall peak around \$40/MWh in 2014. For all ISOs with a mileage product, the mileage prices are much lower than regulation capacity prices, usually by an order of magnitude. However, SPP's mileage prices are notably larger relative to the other ISOs.

Contingency reserve prices are lower than regulation reserve prices, which is expected given it is typically a lower quality product that has lower wear-and-tear costs given the relatively infrequent deployments. Day-ahead spinning reserve prices (or real-time if the ISO has no day-ahead product) across the ISOs average between \$2/MWh and \$5/MWh, with the exception of IESO at \$7.65/MWh and ERCOT at over \$11/MWh. Non-spinning or supplemental reserve averages up to half as much, which is also expected due to its lower quality. There are few annual trends that can be observed across different contingency products over the five years. For instance, while non-spinning and 30-minute operating reserve in ISO-NE declined, spinning reserve grew to a peak in 2017. While not significant in magnitude for most, for those ISOs with both a day-ahead and real-time spinning reserve product, the day-ahead price trended higher than the real time price.

Although most ISOs began their ancillary service markets many years ago, the products and offerings are still changing. Flexibility products have been implemented in two ISOs and are under consideration in others. Prices for the products have remained at zero for a majority of time periods, but the average positive price has slightly increased in CAISO and remained consistent in MISO since 2016. While these products are still developing, new price trends might emerge.

5

SUMMARY AND FUTURE RESEARCH

5.1 Key Findings

The preceding sections provided a review of ancillary service products that are currently a part of the operations and planning of the United States bulk power system, how those services are compensated through auction-based competitive markets or otherwise, and insights into the results of those ancillary service markets. The key points are summarized below:

- In general, product characteristics and requirement methods for regulating reserve and contingency reserves in the U.S. are based on just a few NERC reliability standards. However, specific stricter requirements made through regional reliability organizations or the ISOs themselves may lead to some unique products and requirements.
- Some ancillary services are newly recognized; however, these services have been around for a long time, they are just being recognized explicitly as a new service. These services typically do not have reliability standards that dictate their definition or system requirements or have only recently had standards introduced.
- System-wide requirements, while often based on the same reliability standard, differ across ISOs. They are not always proportional to the size of the ISO.
- The eligibility of who can provide ancillary services differs in the explicit tariff or business practices manual language across the ISOs. In some regions, tests and certification are required. In others, specific technologies are currently not eligible (though may be able to ask for exception).
- Several complex characteristics of ancillary service market designs were discussed. It is important for industry participants (both buyers and sellers of services) to understand these features as they have significant impact on prices for those services. The market designs of ancillary services often differ more across ISOs than the product definitions.
- While competitive auction-based markets for ancillary services have advantages, there are some distinct reasons that they do not exist for all ancillary services. One reason may involve the priority of changes the ISO must go through each year. However, many of the reasons that services did not have competitive markets may be changing.
- Some new ancillary service markets or large changes to existing markets may be seen. ERCOT has been evaluating and proposing (and recently approved) the most changes of all the ISOs. It is unclear whether the reasoning is due to its large amounts of wind power on the system, its being a single area in an interconnected system, or its stakeholder and regulatory situations. Many areas are considering the benefits of new flexibility products, in addition to MISO and CAISO who already have implemented the product.
- No clear across-the-board increasing or decreasing trend in ancillary service prices has been observed in recent years. Some consistent trends are seen like regulating reserve being the highest ancillary service price, high prices being observed during stressed periods, ramp products often being set at \$0/MWh, to name a few.

- Prices differ across products and regions, sometimes substantially. Prices are not necessarily proportional to ancillary service requirements, but may be impacted by resource mix, fuel costs, and the characteristics of the market design in that area.

5.2 Future Research

There are many aspects of the ancillary service product definitions and market designs that are evolving. Recent revisions have been due to regulatory requirements (both FERC and NERC), stakeholder priorities, software enhancements and improved knowledge and experience, and the changing resource mix. Of these, the changing resource mix, notably the integration of VER but also the participation of other new technologies, such as battery energy storage, can have a large impact on future design and software changes. The Electric Power Research Institute (EPRI) continues to evaluate and prioritize the research needs in all areas that affect the affordable, reliable, and environmentally responsible delivery of electricity. A few of the topics that EPRI believes are crucial research topics around ancillary service evolution, particularly with potential resource mix changes but also other changes. Some are listed below.

5.2.1 Ancillary Service Requirement Determination with a Changing Resource Mix

Most of the ancillary services have existed with clear definitions for decades and, with a few exceptions, the system-wide requirements for those services have remained relatively unchanged over the years. Contingency reserve requirements are set based on the size and probability of a large instantaneous contingency. Regulating reserve requirements are generally based on a combination of operational estimates based on historical need. Newer products like flexibility reserve are based on historical experience with net load forecast error and variability statistics. The use of dynamic reserve requirements – requirements that change through time based on existing conditions, historical conditions and anticipated conditions – can lead to potentially significant improvements in reliability as well as cost savings. As the simplest example, the ISO does not need to carry reserve at night specifically for a drop in solar power. In studies that EPRI has conducted, the move to a dynamic reserve requirement method can lead to millions of dollars of savings while simultaneously improving reliability compared to the status quo requirement methods. This win-win result for reliability and economics is not common in electric power systems, as usually either improvements to reliability cost money, or reductions in expenditures on reserves may cause greater risk and reliability degradation. With these new methods, the ISO or other BAA can “forecast” the reserve requirement based on information available, just like forecasting load, wind, or solar power. Advancing this technique and understanding exactly how VER, load, interchange, and other factors impact reserve needs and putting it into practice can provide ways to enable changing power systems reliably and cost-effectively.

5.2.2 Advanced Scheduling Techniques and Market Designs

In some cases, improvements to the software programs that schedule resources on a regular basis, including the security-constrained unit commitment (SCUC) and economic dispatch (SCED) models, can provide similar or greater benefits to improving the methods in which ancillary services are held and utilized. Advanced scheduling methods include stochastic unit commitment, robust unit commitment, multi-period economic dispatch, and formulation refinement. These methods essentially schedule reserve implicitly within the scheduling tools, such that exogenous reserve requirements become less important. They do so in a way such that the costs of holding and deploying ancillary services are all optimized. This can lead to the same

win-win as improved dynamic reserve requirement methods, with potential for even greater cost savings or reliability improvements. Some challenges like solution time, data requirements, and market design integration, are still needed for many of these advanced techniques. But additional research can remove these hurdles to provide additional ways of enabling changing power systems in a reliable and cost-effective manner.

5.2.3 Advanced Renewable Forecasting Techniques

As the procurement of some ancillary services is based on the impact of VERs, such as flexibility reserves and regulating reserve, improvements in renewable forecasting will affect the quantities transacted. The ISOs all now use at least some type of commercial vendor renewable forecasting in their operations. With a few exceptions, these involve deterministic point forecasts that represent the expected value of output for each plant or set of plants. Probabilistic forecasting is a technique that most of the forecast vendors are capable of providing. Probabilistic forecasts can include several different variations including scenario forecasts, confidence intervals, and probability distributions, to name a few. These forecasts can provide more information. With additional research on improving these forecasts, developing metrics of forecast performance for these forecasts, and methods for how operators can use these forecasts for scheduling resources can all lead to improvements to economics and reliability.

5.2.4 Provision of Ancillary Services from Wind and Solar

With systems that are seeing larger penetrations of wind and solar on their system, the ability for these plants to provide ancillary services and participate in ancillary service markets will become more important. The technical capability of wind and solar to provide the majority of ancillary services, including regulating reserve, contingency reserve, fast frequency response, voltage control, and even black start has been demonstrated by a number of studies [24]-[26]. However, it is still rare in the United States for wind and solar to be participating in ancillary service markets. The following research should provide additional understanding for the provision of ancillary services by wind and solar.

- *Understanding the economics of provision of ancillary services by wind and solar.* If energy sales must be foregone to provide ancillary services, when/where/how might it be economic from a societal perspective for wind and solar to provide the service, and when will it be economic from the owner perspective in terms of profit making. Additional investigations in how subsidies may be allowed and the emissions reduction of wind and solar providing ancillary services can also be studied. Studies using advanced market simulation evaluating different future scenarios and different market designs can provide insights into these questions.
- *Understanding the impact of uncertainty on the provision of ancillary services.* Although the technical capability of wind and solar plants given existing technology to provide ancillary services has generally been proven for a large amount of ancillary service types, there is still the challenge of a system operator relying on wind and solar providing a service in advance of real-time, and the energy that is needed to provide the service is no longer available due to unforeseen weather conditions. In this scenario, the service must be replaced by other resources to ensure reliability. If other resources are not available to provide it, the system may be at risk. Additional strategies including using probabilistic forecasts, relying on “closer to real-time” markets for ancillary services, and understanding the actual probabilities

and risks that are present when energy is not available during times when wind and solar were initially committed to providing the service can all be investigated. Simulation studies can evaluate these challenges and provide meaningful results back to the industry on the practical issues that are present and potential mitigation strategies.

- *Evaluation of different services including directional services.* Because wind and solar resources earn revenues from production-based mechanisms in parallel to wholesale market revenues, it may appear that downward reserve service is more economical for these resources to provide. This may be true but may not be as beneficial a service compared to upward reserves or combined, symmetric service as some may think. This is due to hidden lost opportunity costs that may not be triggered or observed during the market scheduling process. When a wind or solar plant provides downward reserve, the ISO software may see that it is a free cost, because there is no opportunity cost to provide downward reserve as seen by the software. However, for ancillary services that require deployments that happen on a regular basis (e.g., regulation and flexibility reserve, which is typically the only reserve products that have downward services), the opportunity cost actually occurs after the market solution and the deployed downward reserve results in the lost opportunity to sell as much energy as the plant could have provided. Investigations into the true tradeoffs of directional services and any mitigation strategies to ensure that costs are correctly captured and incentives are provided to lead to the most reliable and cost-effective service for the system and the owners should be carried out.

5.2.5 Provision of Ancillary Services from other Emerging Technologies

In addition to wind and solar, other emerging technologies can provide many of the ancillary services with high quality and at low costs. Energy storage, demand response, and distributed energy resources are all technologies that are newly participating in ISO markets. These resources can provide the majority of the services with high quality and can be used by the ISO to increase competition and reduce overall costs. However, certain limitations, like energy limits for energy storage, call limits for demand response, and telemetry and distribution system limits for distributed energy resources need to be evaluated further by the system operator. Additional studies can be conducted to understand how to capture these and understand the potential benefit of ancillary service provision from all of these technologies.

5.2.6 Investigation into Converting Cost-Based Ancillary Services to Competitive Ancillary Services

As shown in Section 3.2, there are a number of ancillary services that do not have competitive markets in the U.S. ISOs. The reasons for this were also described in detail. It will be important to evaluate whether future changes may lead to greater advantages to converting these services to competitive markets and what the overall benefits vs costs may be of doing so. Research can help understand the potential benefits as well as the actual design structure. Converting services to competitive markets can be complex in terms of the software and structural designs such that research that proposes alternative designs and tests these for flaws can be advantageous to all parties in the ISO markets.

5.2.7 Ancillary Services During Extreme Events

A number of events over the past decade have impacted the power system in ways that planners may not have fully planned for or prepared for in planning studies. These include recent

hurricane events, wildfires, and extreme cold temperatures that have different impacts on the system. Electric power system resilience is the term that has been used to describe infrastructure and operational methods for ensuring the system is intact and can be recovered rapidly during and following these events. In many ways, modifications made to ancillary services procurement can be part of system resilience. For example, changing current practices by increasing reserve requirements during anticipated cold weather events, or locating reserve requirements in areas that are least affected by transmission outages during hurricane or wild fire events, can lead to improved reliability. Further, analyzing and addressing limitations on how ancillary services can be provided during these events (e.g., the ability of gas plants to provide these services when the natural gas pipeline system is vulnerable) can also lead to improvements. Studies and simulations should be undertaken to provide insights into efficient methods to modify operations and electricity market designs.

There are many more opportunities for advancing the way in which ancillary services are formulated, procured, and utilized in a manner that is both reliable and economic. The services are a small part of the overall costs of investment and operating the power system, but they are crucial towards getting electricity to consumers. As the system evolves, it will be ever more important to make the improvements, foster innovation, and ensure the objectives of reliability and economic efficiency can continue to be achieved.

6

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