Grid Services and Provision from Wind

Course No: R03-013
Credit: 3 PDH

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This course was adapted from the National Renewable Energy Laboratory, Publication No. NREL/TP-6A20-72578, "An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind", which is in the public domain.

Acknowledgments

The authors would like to thank the following individuals for their contributions. Editing and graphics support were provided by Al Hicks, Devonie McCamey, and Katie Wensuc. Helpful review and comments were provided by Sam Baldwin, Philipp Beiter, Dan Bilello, Aaron Bloom, Alex Breckel, Paul Donohoo-Vallett, Vahan Gevorgian, Patrick Gilman, Debbie Lew, Brian Palmintier, and Rich Tusing.

Finally, we gratefully acknowledge funding for this work from the Wind Energy Technologies Office (WETO) of the U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy. We especially thank Patrick Gilman of DOE for his support. This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy under Contract No. DE-AC36-08GO28308. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

List of Acronyms

AC	alternating current
BA	balancing area
CAISO	California Independent System Operator
CC	combined cycle
CT	combustion turbine
DC	direct current
ERCOT	Electric Reliability Council of Texas
ERS	essential reliability service
FERC	Federal Energy Regulatory Commission
FFR	fast frequency response
FRCC	Florida Reliability Coordinating Council
FRO	frequency response obligation
GW	gigawatt
IFRO	interconnection frequency response obligation
ISO	independent system operator
ISO-NE	ISO New England
kW	kilowatt
LCOE	levelized cost of electricity
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
OATT	open access transmission tariff
O&M	operation and maintenance
NREL	National Renewable Energy Laboratory
PFR	primary frequency response
PV	photovoltaics
ROCOF	rate of change of frequency
RTO	regional transmission organization
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
TW	terawatt

Executive Summary

As the role of wind energy grows in the U.S. power grid, there is increased interest and requirement for it to provide "essential reliability" services or ERSs (historically often referred to as "ancillary" services). These services are critical to maintaining the reliability and stability of the grid, and historically were provided by large "synchronous"[1] generators, mainly fossil-fueled and hydroelectric generators. To help evaluate the potential role of wind in providing these services, this report provides an overview of services provided to the grid, including their technical requirements, quantities currently procured, and some estimates of costs. The report also summarizes the technical and regulatory issues around wind providing these services.

Numerous grid services are required in the U.S. electric power system to support reliable grid operations and respond to the inherent variability and uncertainty of electricity supply and demand. Although specific definitions and terms vary by market and region, these services can be categorized as illustrated in Figure ES-1. The first category includes energy and capacity services, which represent the vast majority of costs to the system. The ERS category encompasses the remaining set of grid services discussed in this report. We further subdivide ERSs into two categories: operating reserves and other essential reliability services. One purpose of this report is to provide a structured explanation of the conceptual and technical differences between these widely varying grid services, with a particular focus on ERSs.

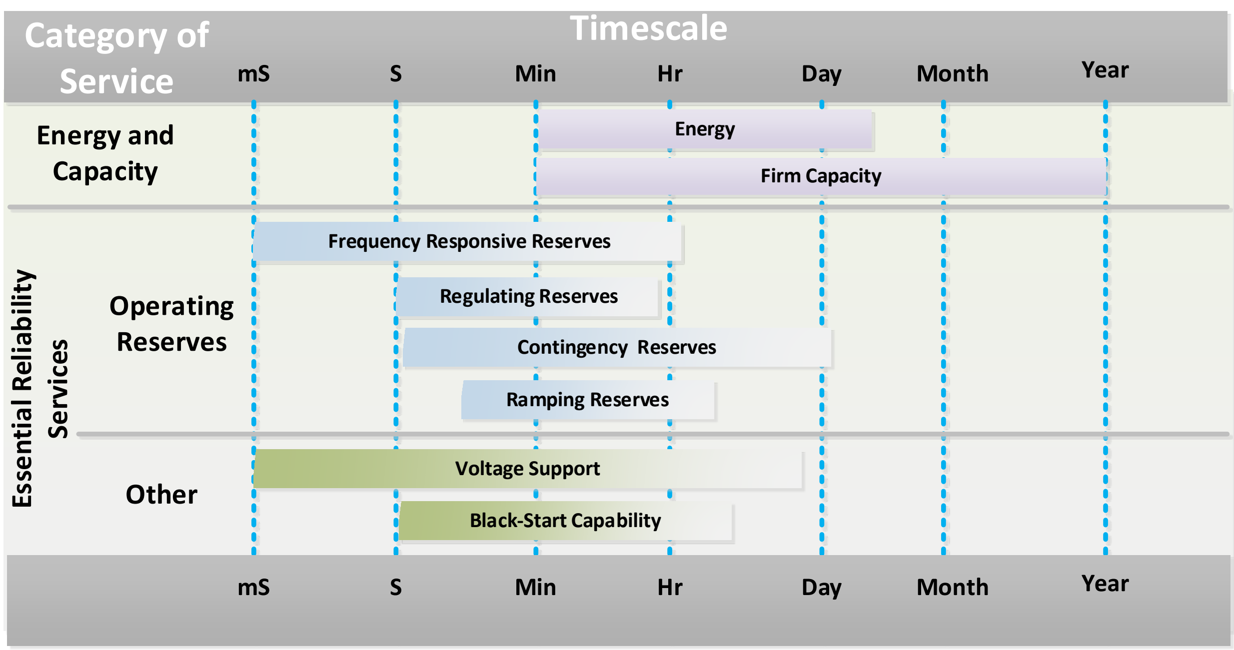

Figure ES-1. Main services procured in the U.S. power system.

[1] A synchronous generator is electrically synchronized to the grid, meaning it rotates in lock-step to all other generators and is therefore able to respond to grid conditions.

Table ES-1 provides a brief description of the ERSs discussed in the report. The first group of services described in the table are operating reserves, which are used to maintain system frequency. Operating reserves are provided by a set of resources with different technical characteristics that are deployed at different times; typically, the resources are deployed in order of response speed, from very fast to slow (and with corresponding costs that range from more to less expensive). Each type of resource in Table ES-1 is described in order of deployment. This cascade of resources is designed to minimize costs while maintaining reliability. In some cases, not all types of reserves are needed to return the grid to its normal state, depending on the severity and length of an event. In the main body of the report we provide additional details, including the technical requirements a generator must possess to provide the service.

Other ERSs—namely black-start and voltage support—are qualitatively different from operating reserves and so are considered in their own category.

Table ES-1: Essential Reliability Services Discussed in This Report

Operating Reserves	
Frequency-Responsive Reserves	Services that act to slow and arrest the change in frequency via rapid and automatic responses that increase or decrease output from generators providing these services. Traditionally provided by synchronous generators, these services include inertial response and primary frequency response (PFR). An emerging product is “fast frequency response,” which can be provided by multiple generator types and demand response and may replace some fraction of traditional inertia/PFR.
Regulating Reserves	Rapid response by generators used to help restore system frequency. These reserves may be deployed after an event and are also used to address normal random short-term fluctuations in load that can create imbalances in supply and demand.
Contingency Reserves	Reserves used to address power plant or transmission line failures by increasing output from generators. These include spinning reserves, which respond quickly and are then supplemented or replaced with slower-responding (and less costly) non-spinning/replacement reserves.
Ramping Reserves	An emerging and evolving reserve product (also known as load-following or flexibility reserves) that is used to address “slower” variations in net load and is increasingly considered to manage variability in net load from wind and solar energy.
Other ERSs	
Black-Start	Capacity that can be started without either external power or a reference grid frequency, and then provide power to start other generators.
Voltage Support	Used to maintain voltage within tolerance levels and provided by local resources.

In addition to describing the types of grid services, we also report the amount of each service procured in recent years for all regions of the conterminous United States, including the seven market and three non-market regions. The reported data reveals regional variations due to differences in size (i.e., annual and peak demand), generation mix, network topology, and market rules and/or system planning decisions. Figure ES-2 shows the total capacity requirements for operating reserve requirements for the 10 regions examined. For all regions, capacity needed to meet operating reserves comprises only 3%–12% of capacity needed for energy requirements, which are represented by 2017 peak demand for each region in the figure.

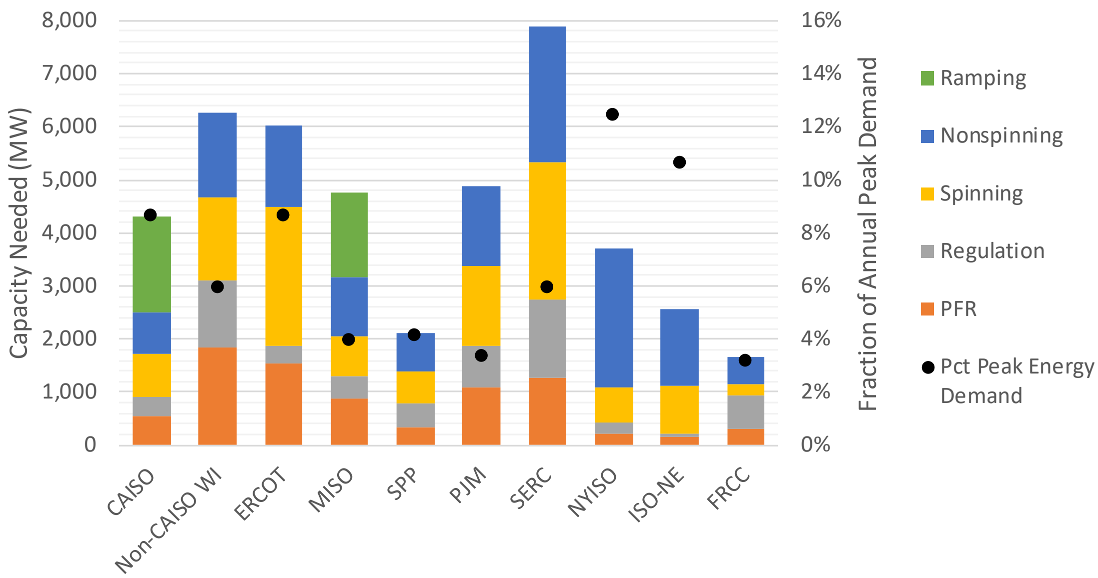

Figure ES-2. Total capacity for reserve requirements.

Along with quantity requirements, we also summarize technical requirements for grid services below and in detail in the main body of the report. Prices for each service depend in part on that service's technical requirements. For example, regulating reserve prices are often higher than those of spinning or non-spinning reserves due to the shorter timescales and more technically stringent eligibility requirements for regulating reserves. In 2017, reserve prices in the market regions averaged up to \$29.23/MW-hr for regulating reserves, \$10.13/MW-hr for spinning reserves, and \$3.18/MW-hr for non-spinning reserves. In addition to the pricing data, we report 2017 market settlement data for ISO-NE and PJM to compare grid services in a way that considers both market depth and prices. In these two markets, operating reserves and essential reliability/ancillary[2] services comprise 2.3% and 3.1% of total settlements, respectively; the remainder of settlements are for energy, capacity, and transmission-related services.

In addition to reporting the service requirement and pricing data, we also discuss the potential ability of wind energy to provide various grid services. Wind's ability to provide energy and capacity is well understood in concept even if industry practices vary by region (e.g., different methods and approximations are applied to estimate wind capacity credit). What is not as broadly understood is the ability of wind technologies to provide ERSs, even as modern wind

[2] We use the term ancillary services here as many market manuals and reports still use this term extensively.

turbines have necessary capabilities built in. While the cost of providing operating reserves is a small fraction of the total cost of grid services, this share could grow under increasing penetration of wind (or solar photovoltaics [PV])—and the provision of operating reserves from wind could grow as well. In fact, in certain regions, wind is required to provide some of the reserve services even today. In this report, we provide a conceptual discussion of how wind can provide various grid services, as well as the technical and economic considerations and limitations for doing so.

The ability of any generator to provide operating reserves is based on three factors: how much, how fast, and how long. “How much” refers to the headroom available for a generator, or the difference between its current output and maximum output. “How fast” represents the response rate, or the amount of time required to increase or decrease the output of a generator. “How long” means the length of time a generator is required to “hold” output at the increased or decreased level. For conventional generators not limited by fuel availability, “how much” and “how fast” are typically the most important factors for determining their ability to provide reserves.

The technical ability of wind (and other variable renewable) generators to provide services varies by service type, and the same three factors can be used to characterize it. A key element particularly related to “how much” reserve service wind can provide is the need for pre-curtailment. Pre-curtailment means reducing the output of the wind turbine below what it could provide at a given wind speed, which enables it to then increase output when needed to provide “upward” reserves. All upward reserve services from wind (except inertia, which can be extracted from the rotating mass of the blades, shaft, and generator) require pre-curtailment, which will incur an opportunity cost of reduced energy sales. It is therefore only economically preferable for wind to provide reserves instead of energy when energy prices fall below reserve prices, given that the variable cost for wind is zero or near zero. In terms of “how fast,” wind can increase output more rapidly than most thermal generators; therefore, this factor is not a limiting constraint for wind to provide operating reserves. This also makes wind a candidate for provision of a fast frequency response product that is being introduced or under consideration as a partial replacement for traditional inertia and PFR. Finally, unlike thermal generators, “how long” the reserve service is needed is a more significant limiting factor for wind, given that wind resource has variable and more unpredictable output, particularly over longer durations. Figure ES-3 conceptually depicts this limitation. For example, the long-duration requirement for non-spinning reserves may limit wind’s ability to provide this service.

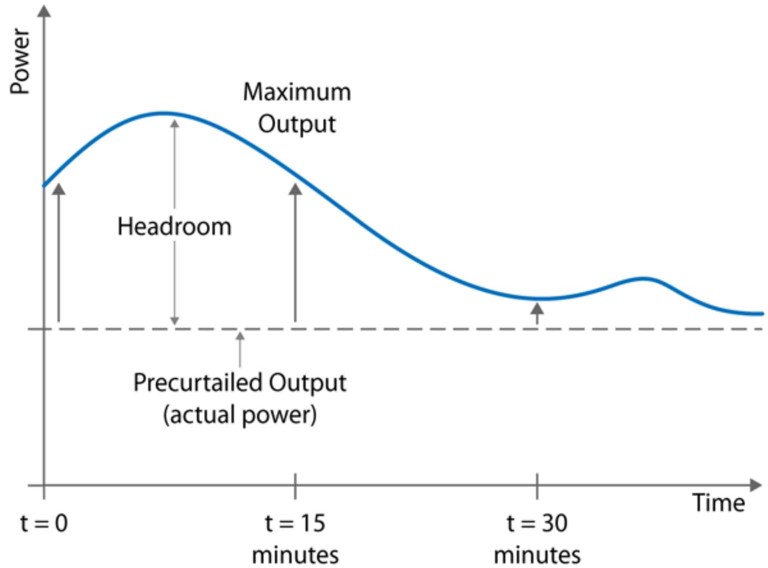

Figure ES-3. The impact of variable output on the ability of wind to provide upward reserve services.

Wind can also provide or potentially provide the two other ERSs discussed in this report: voltage support and black-start. The power electronics built into wind turbines are well suited to provide voltage support (including reactive power). In fact, the Federal Energy Regulatory Commission (FERC) and many utilities and system operators already require wind to provide reactive power. However, voltage support is a localized service, and the dispersed nature of wind resources means that wind generation may not be available where reactive power support is needed. Wind does not yet provide black-start capability in the United States, although the capability has been demonstrated in other countries. Additional research is needed to assess the role of wind in providing black-start capability, including how this capability would be incorporated into system restoration procedures.

In summary, wind power plants can provide many of the services needed by the grid to maintain reliable and stable operation; however, the intrinsic variability and uncertainty of wind, as well as the dispersed nature of wind resources, raise considerations that do not play as significant a role for conventional power plants. For example, longer-duration but slower operating reserve services are among the least technically demanding and lowest cost services for conventional generators to provide, but are less suitable for wind. With power electronics, wind power plants can respond rapidly, but whether the wind resource will be available over the duration the reserves are needed is critically important. Furthermore, as the provision of many reserve products would require pre-curtailment, the opportunity cost to provide reserves becomes a more significant issue for wind compared to thermal generators with more sizable fuel and variable operations and maintenance (O&M) costs. These opportunity costs highlight that the technical considerations need to be weighed with the economic factors for providing grid services, and that—at least under current systems and markets—the need for and value of energy and capacity far exceed those of operating reserves and other ERSs.

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1 Introduction

There is growing interest in wind energy providing a variety of services to maximize its value to the grid. To help evaluate the potential role of wind in providing grid services, this report provides an overview of services provided to the grid, with a focus on essential reliability services. We discuss the technical requirements and quantity of these services procured in various regions and provide some estimates of costs. The report also summarizes the technical and regulatory issues around wind providing these services.

1.1 Geographical Scope and Regions Analyzed

Our analysis is focused on the lower 48 (conterminous) United States. Within the conterminous United States, there are (very loosely) four main geographical levels of the grid: interconnection, North American Electric Reliability Corporation (NERC) regional entity, balancing area (BA), and utility service territory.

The U.S. grid consists of three electrically connected interconnections (the Western Interconnection, Eastern Interconnection, and Electric Reliability Council of Texas [ERCOT]) and eight NERC regional entities (i.e., large regions used for reliability planning). Figure 1 provides a map of NERC regional entities and subregions.

Figure 1. NERC regional entities.

The U.S. grid consists of 66 BAs that are responsible for grid operation. There is significant overlap between NERC planning regions and several large BAs. The U.S. Eastern Interconnection has 31 BAs, while the U.S. Western Interconnection has 34 BAs, and the ERCOT interconnection also serves as a BA (Hoff 2016). Many BAs are operated by the wholesale market operator (an independent system operator [ISO] or regional transmission operator [RTO]). Areas with restructured markets serve about two-thirds of U.S. electricity demand (ISO/RTO Council 2018a). BAs in non-RTO regions are typically run by large utilities. At the finest level there are over 3,200 utilities; most of these are relatively small and are not responsible for providing "bulk" grid services (DOE 2016b).[3] Figure 2 provides a map of regions studied in this analysis. It includes the seven U.S. ISO/RTO market regions, with the remaining BAs in the non-CAISO West and Southeast largely aggregated.

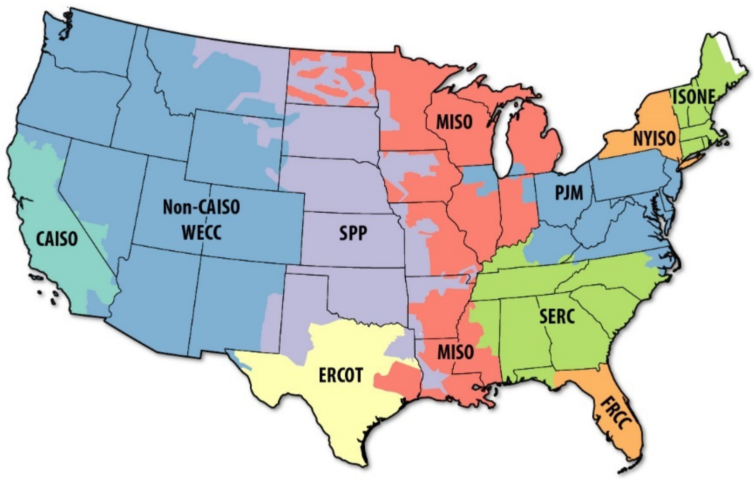


Figure 2. Map of regions analyzed.

Table 1 lists the regions and their approximate size measured in terms of demand and population. Note we use the term "regulated regions" for those areas not served by wholesale markets (FERC 2015).

Table 1. Regions Analyzed

Region	Estimated Electric Demand (TWh / % of U.S.)[a]	Estimated Population (million / % of Total)[b]
Market Regions		
CAISO	228 / 6%	30 / 9%
PJM	759 / 19%	65 / 20%
ERCOT	357 / 9%	23 / 7%
ISO-NE	121 / 3%	14.5 / 4%
NYISO	157 / 4%	19.5 / 6%
MISO	656 / 16%	48 / 15%
SPP	246 / 6%	18 / 6%
Regulated Regions		
Non-CAISO WECC	654 / 16%	52 / 16%
FRCC	231 / 6%	16 / 5%
SERC	673 / 16%	39.4 /12%

[a] Data sources: see Table 2
[b] NERC 2018a; ISO/RTO Council 2018b

[3] Many of these are "distribution" utilities whose primary responsibility is operating and maintaining the distribution networks.

2 Current Grid Services

In this section, we define and describe several general categories of grid services and quantify the amount of each service procured in the U.S. electric power system.

Figure 3 illustrates the set of services currently procured in the grid. We separate energy and capacity services into one category and group the remaining services into a general essential reliability service (ERS) category. ERSs are further subdivided into operating reserves and other ERSs. Each of the following subsections discusses these three groups of services—energy and capacity, operating reserves, and other ERSs—in detail.

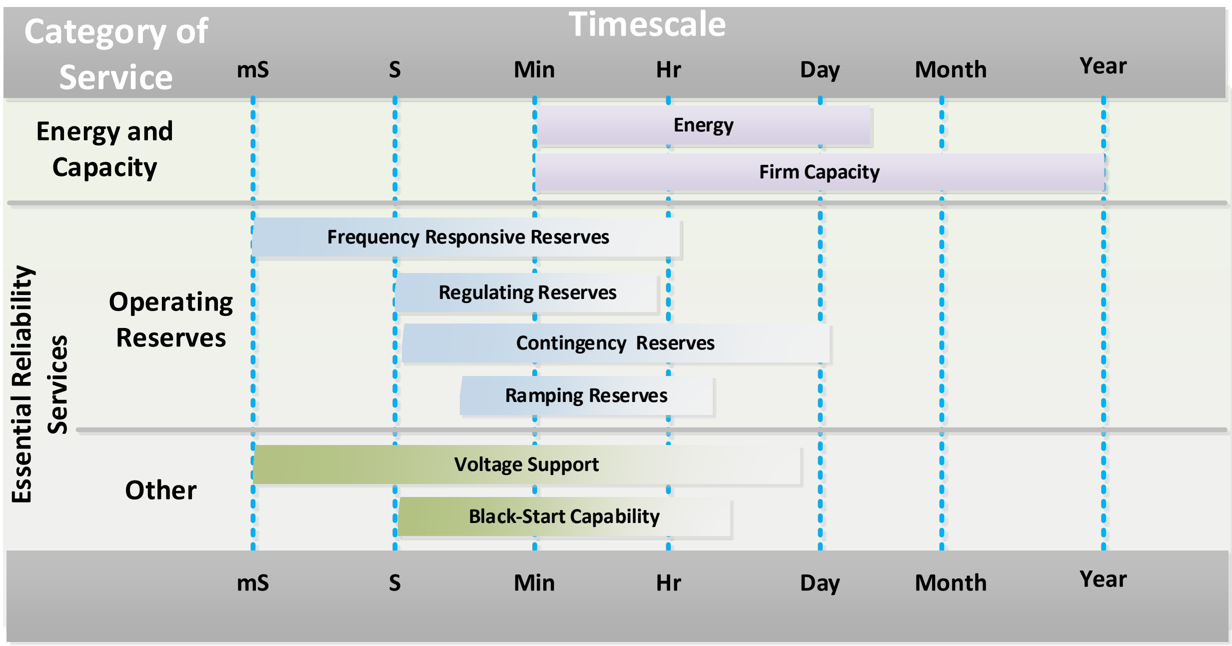


Figure 3. Main services procured in the U.S. power system.

2.1 Energy and Capacity

Energy and capacity are the major services provided by the electric system assets. Capacity is measured in terms of power (e.g., megawatts [MW] or gigawatts [GW]), while energy is measured in terms of the power generated over a period of time (e.g., kilowatt-hours [kWh], megawatt-hours [MWh], or gigawatt-hours [GWh]).

2.1.1 Regional Requirements

Table 2 summarizes the historic peak demand and energy requirement for each region.

Table 2. U.S. Power System Historical Peak and Annual Energy Demand

Region	Peak Demand (GW)		Annual Energy (TWh)	
	2016	**2017**	**2016**	**2017**
Market Regions				
CAISO	46.2[a]	50.1[a]	228.8[b]	228.2[b]
PJM	152.2[c]	145.6[c]	776.1[d]	758.8[d]
ERCOT	71.1[e]	69.5[e]	350.7[f]	357.4[f]
ISO-NE	25.6[g]	24.0[g]	124.1[h]	121.1[h]
NYISO	32.1[i]	29.7[i]	160.3[j]	156.8[j]
MISO	121.0[k]	120.6[k]	664.5[l]	656.3[l]
SPP	50.6[m]	51.2[m]	248.4[n]	246.0[n]
Regulated Regions				
Non-CAISO WECC	110.8[o]	106.0[o]	650.2[p]	653.8[p]
FRCC	47.7[q]	46.6[q]	235.7[r]	230.6[r]
SERC	129.0[s]	132.2[s]	672.7[s]	673.3[s]
Total[t]	786	775	4,111.5	4,082.3

[a] CAISO 2018, 31
[b] CAISO 2018, 32
[c] Monitoring Analytics 2017, 22
[d] Monitoring Analytics 2017, 22; Calculated as the average real-time load multiplied by 8,760 hours
[e] ERCOT 2017a, i
[f] Potomac Economics 2018a, 74
[g] ISO-NE 2018a, 5
[h] ISO-NE 2018a, 5; Calculated as the average real-time load multiplied by 8,760 hours
[i] Potomac Economics 2018b, 6
[j] Potomac Economics 2018c, 8; Calculated as the average real-time load multiplied by 8,760 hours
[k] Potomac Economics 2018b, 6
[l] MISO 2018; Sum of monthly average load
[m] SPP 2017, 18
[n] SPP 2017, 20; System energy usage
[o] WECC 2018
[p] WECC 2018
[q] FRCC 2018, 1
[r] EIA 2018, Table 861
[s] EIA 2017; The year 2016 is actual data; 2017 is estimated data
[t] Simple sum of rows. These values roughly match national totals reported in EIA form 411 and the EIA electricity data browser. Sum of peak demand is non-coincident total.

Each region is required to maintain sufficient capacity to meet the peak demand plus additional capacity to address outages or unanticipated increases in demand. Regions use a variety of methods to determine the additional capacity requirements, but a common metric is the “reserve margin” or percentage of capacity above the anticipated peak demand (NERC 2017b). Table 3 lists the estimated peak demand in 2020, along with the NERC estimated reserve margin. It also lists the total estimated peak capacity requirement and the estimated reserve margin in 2020 based on anticipated retirements and plants under construction (NERC 2017b). It shows that all regions of the United States are expected to have adequate generation capacity to meet peak demand in the near future.

Table 3. U.S. Power System Peak Capacity Requirement Estimates

Region	2020 Estimated Peak Demand (GW)[a]	NERC Estimated Reference Margin Level (%)[b]	2020 Estimated Total Peak Capacity Requirement (GW)	2020 Estimated Reserve Margin (%)
Market Regions				
CAISO[4]	53.6	16.14	62.3	20.6
PJM	147.5	16.60	172.0	28.0
ERCOT	73.7	13.75	83.5	18.0
ISO-NE	26.3	16.90	30.3	23.8
NYISO	32.1	15.00	36.9	25.0
MISO	121.4	15.80	140.6	19.4
SPP	52.5	12.00	58.8	28.9
Regulated Regions				
Non-CAISO WECC	110.0	range of 14.17 to 16.38	136.0	23.7 (range of 22.6 to 27.7)
FRCC	45.8	15.00	52.7	22.5
SERC	131.2	15.00	150.9	23.1

[a] Total demand minus existing demand response resources
[b] NERC 2017b

2.1.2 Energy and Capacity Costs and Prices

The majority of the costs associated with power system generation are the fixed and variable costs associated with providing capacity and energy.

It is very difficult to summarize energy and capacity market prices with a single or limited set of metrics. The energy prices reported by ISO/RTO markets are the locational marginal prices (LMPs) at a specified location on the grid, or the incremental cost of serving an additional unit of energy (FERC 2015). These prices largely represent the variable cost of generation; however, all markets have some degree of scarcity pricing, which allows the price of energy to rise above the variable cost of generation. This allows some of the costs of capacity to be captured in the energy price (FERC 2015). However, price caps and other factors typically require additional costs of capacity (i.e., "missing money") to be captured via other mechanisms, including resource adequacy payments and/or capacity markets (Frew et al. 2016).[5] For non-market regions, individual BAs report system lambdas, which are "system-wide" marginal costs of generation

[4] Actually the CAMX region, which includes nearly all of California plus a small northern portion of the Baja California Peninsula in Mexico. As a result, the load in this region is larger than that of CAISO.
[5] ERCOT is the only "energy only" market in the United States.

(FERC 2018).[6] In addition, most regions in the United States have more capacity than is needed for resource adequacy/planning reserve targets, which tends to suppress capacity market prices (NERC 2017b).

Table 4 summarizes average market energy and capacity prices in the United States.

Table 4. U.S. Power System Energy Requirements

Region	Average Energy Price ($/MWh)		Capacity Market Price ($/kW-month)[a]	
	2016	2017	16/17	17/18
Market Regions				
CAISO	$33.1[b]	$33.3[b]	N/A	
PJM	$29.68[c]	$30.85[c]	$1.81[c]	$3.66[c]
ERCOT	$24.62[d]	$28.25[d]	NA	
ISO-NE	$31.74[e]	$35.23[e]	$3.15[e]	$7.03[e]
NYISO	$31.32[f]	$34.62[f]	Summer: $1.73[g] Winter: $5.77[g]	Summer: $1.25[g] Winter: $6.49[g]
MISO	$26.80[h]	$29.46[h]	NA	
SPP	$22.43[i]	$23.43[i]	NA	

[a] DOE 2016a
[b] Blanke 2018, 19; Simple average of day-ahead prices
[c] Monitoring Analytics 2017, 24; Load-weighted average day-ahead LMP
[d] ERCOT 2017a, Figure 2; ERCOT-wide load-weighted average real-time LMP
[e] ISO-NE 2018a, 5; Load-weighted average day-ahead LMP
[f] Potomac Economics 2018c, A-3; Load-weighted day-ahead price for Zone J – New York City
[g] These are strip prices for 2016 and 2017.
[h] Potomac Economics 2018b; Load-weighted real-time energy price (page i and page 2); day-ahead premium averaged $0.52/MWh (page 26)
[i] SPP 2017, 87; Simple average of day-ahead LMP across years

Figure 4 provides an example of the significant temporal and regional variation in energy prices. It shows the average energy locational marginal pricing (average LMPs) in ERCOT and PJM from July 1–7, 2016. It shows that prices typically peak in the late afternoon and are lowest in the early morning. This has significant implications for the value of wind, as discussed in Section 3.1.

[6] These are typically "true" marginal costs that do not include scarcity pricing.

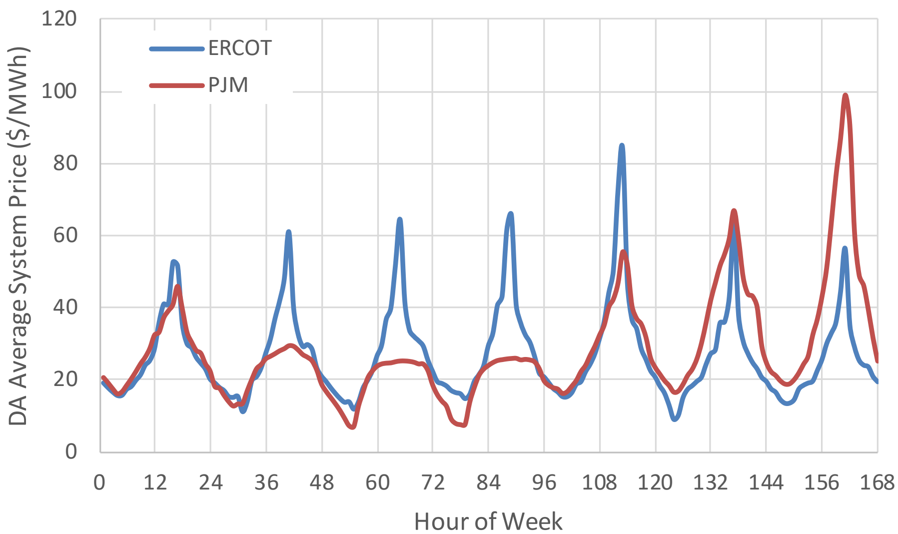


Figure 4. Energy price variation in the ERCOT and PJM day-ahead market during the week of July 1-7, 2016.

2.2 Operating Reserves

Operating reserves are defined as “that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection” (NERC 2018b).

While operating reserves consist of numerous services and market products, they all represent the ability of a generator or aggregated set of generators to increase output (providing “upward” reserves) or decrease output (“downward” reserves). The distinctions between different reserve services can be characterized by three factors: how much, how fast, and how long. This means 1) the difference between the current capacity setpoint and a desired one (or maximum or minimum output) (“how much”); 2) the response rate or how quickly the plant can move from one setpoint to another, which is a combination of the time needed to initiate a response to the reserve event and ramp rate (“how fast”); and 3) the duration for which the plant must hold the new output (“how long”). This is illustrated in Figure 5, which shows the output of a generator operating below maximum output. It can increase output based on its headroom and at a rate limited by response rate. The duration reflects how long it can hold its output at this higher level.

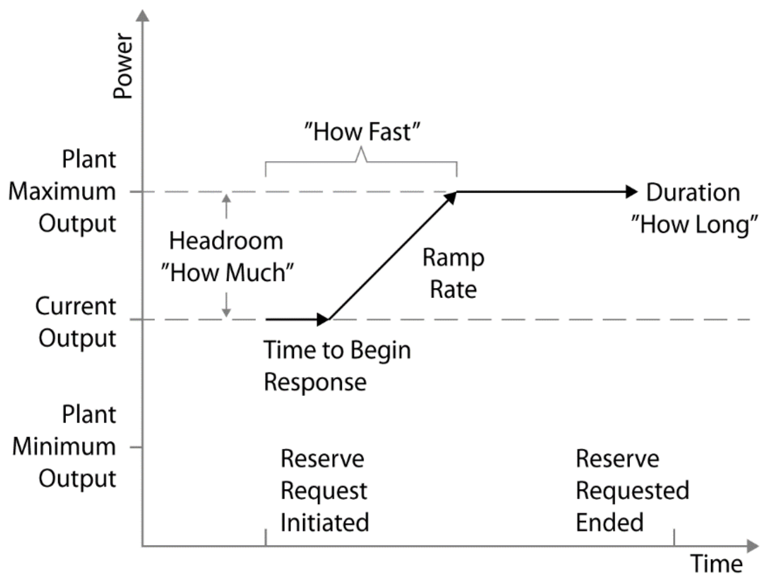


Figure 5. The three characteristics of operating reserves.

It is important to emphasize that there are no uniform definitions for various operating reserve products. U.S. ISOs and utilities use different terms with different product definitions, and there are different terms used in the United States and internationally. Wherever possible, we use terms and definitions used by NERC (2018b). For ease of discussion we consider the four general classes of operating reserve products introduced previously in Figure 3 and further broken down by subcategory illustrated in Figure 6. Figure 6 also includes an approximate measure of two timescale elements. The first is captured by the left side of the bar, which represents the time between the request and the time the reserve must start responding (one element of "how fast"). The second is the duration ("how long") captured by the righthand side, with the fade in color illustrating the significant variation in how long services are actually required based on grid conditions.

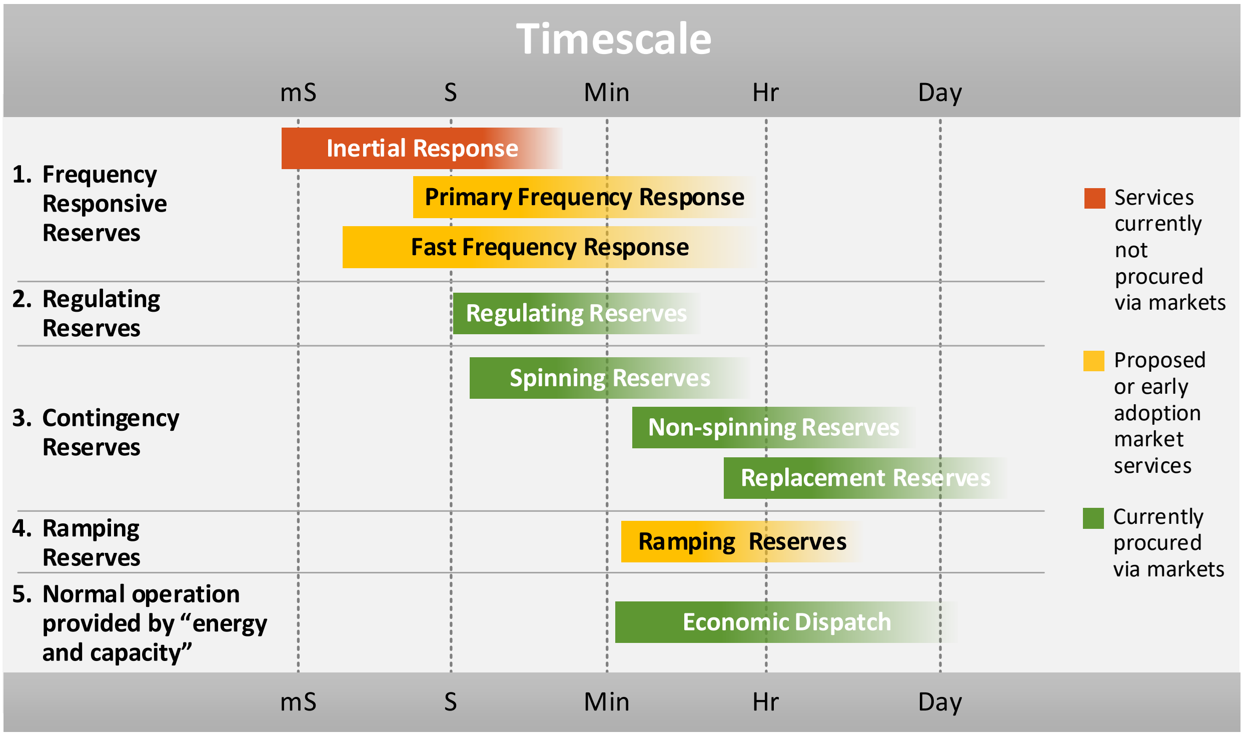


Figure 6. Timescales of operating reserve requirements.

For greater clarity, this sequencing is often shown in response to an "event" (Ela, Milligan, and Kirby 2011). Figure 7 provides an example of this, where a subset of reserve products are deployed in response to a contingency such as a power plant failure that leads to a decline in system frequency and could result in a system blackout unless operating reserves are used to slow, arrest, and restore the frequency.

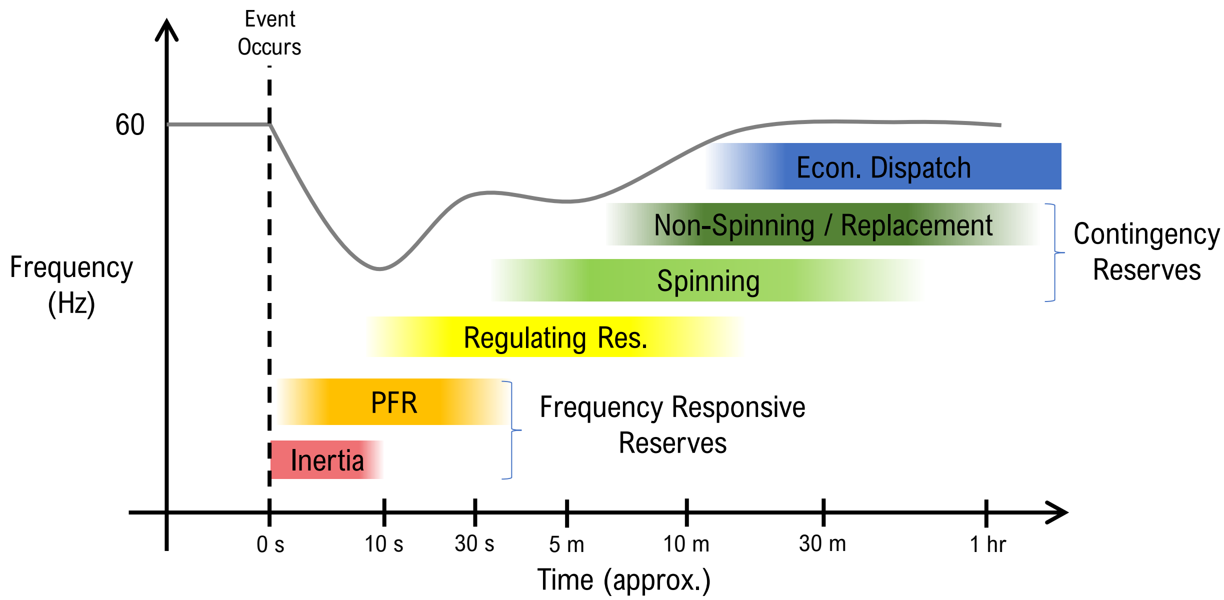


Figure 7. Reserve deployments after a contingency event

Resources with different technical characteristics are deployed at different times; typically, they are deployed in order of response speed, from very fast to slow (and with corresponding costs that range from more to less expensive). This cascade of resources is designed to minimize costs while maintaining reliability. In some cases, not all types of reserves are needed to return the grid to its normal state, depending on the severity and length of an event. Some reserves are typically only used to respond to events such as contingencies, while others are used to as part of normal operation. Each type of resource is described in order of deployment below:

1. **Frequency-Responsive Reserves**

   A. **Inertial Response.** Historically, nearly all grid capacity has been provided by synchronous generators all rotating in lock step. These rotating generators have stored kinetic energy, also known as inertia.[7] When there is mismatch in the supply and demand for electricity, the frequency of the grid will begin to change, but the inertia of the generators on the grid will resist any changes in frequency. If there is too little generation, the frequency declines, but kinetic energy will be extracted from generators, instantaneously and without operator intervention, delaying how quickly the system slows down. The rate at which the frequency changes is determined by the magnitude of the imbalance between load and generation and the total inertia of the system. Inertial response injects stored

[7] More accurately, inertia can be defined as a measure of a generator's resistance to changes to its rotational speed, and the amount of inertia depends on the amount of kinetic energy stored in the rotating generators.

kinetic energy into the system, slowing down the decline in frequency to provide time for other reserve products (including primary frequency response (PFR), which is the next stage of reserve deployment) to detect those changes and respond accordingly.

B. **Primary Frequency Response.** PFR (along with regulating reserves) is one of two parts of the "cruise control" of the electric power system. PFR (sometimes known as governor response)[8] detects changes in frequency and automatically—without action from the system operator—and adjusts operations of online generators to maintain frequency within the desired range.

C. **Fast Frequency Response.** Inertial response and PFR are legacy terms based on systems designed largely on synchronous generators. It has been recognized that these terms may not be suitable when deriving reserves from non-synchronous generators. An example is the provision of frequency-responsive services from battery storage (or wind, as discussed in Section 3). Battery storage injects real energy into the grid through an inverter which converts stored energy into AC power. The power electronics in the inverter can measure system frequency in a manner similar to a generator governor and respond accordingly, rapidly increasing or decreasing output. This response rate can be very fast, faster than PFR from a conventional generator, and can be programmed to respond in a manner similar to the inertial response from a conventional generator.[9] Fast frequency response (FFR) has emerged as the term that describes the general capability of any resource that can detect and rapidly respond to changes in frequency, supplementing or replacing some amount of conventional inertial response and PFR.

2. **Regulating Reserves**

Also commonly referred to as "regulation," regulating reserves[10] provide several services to the grid responding to both event conditions and normal operations. During normal operation, reserves are still required to meet random variations in net load. This is because economic dispatch (as fast as 5 minutes) is too slow to respond to normal variability and uncertainty in load and variable generation supply, and additional capacity may need to be committed to meet intra-hour variability. In general, regulation is used to meet very short-term variability (seconds to a few minutes). This variability can result in either changes in frequency or unscheduled flow of power into or out of the region where local generation is not matching load. Systems measure these imbalances and signal generators in that area to modify their output as needed via a signal from the system operator. Under these conditions, regulating reserves require generators to both increase and decrease output. Regulating reserves are also deployed in a similar manner during events. While inertial response and PFR occur system-wide and work automatically to prevent large frequency deviations, additional actions are needed locally to restore the

[8] Governors measure the rotating speed (frequency) of the generator and automatically adjust the speed if it is greater or less than the target frequency.
[9] The latter service has sometimes been called "synthetic inertia," but the current trend appears to use FFR, as discussed in more detail in Section 3.
[10] While regulating reserves are sometimes referred to as "frequency regulation," the NERC glossary defines frequency regulation to include both governor response (PFR) and the service described in this section.

system to its "pre-event" state—spinning at 60 Hz with all generators operating as scheduled. Regulating reserves are the second part of the "cruise control" of the power system that works to reset the system to "normal" conditions. Regulating reserves are traditionally provided by generators that are synchronized to the grid (spinning) and have spare capacity to either increase or decrease output in response to signals from the system operator and rapidly ramp (i.e., begin changing output within seconds and reach the new desired setpoint within minutes).

3. **Contingency Reserves**

   A power plant or transmission line failure is often referred to as a "contingency." When a contingency occurs, the "cruise control" systems listed above take action to correct and restore frequency and power flows. Systems do not typically have enough PFR capacity and regulating reserves to handle large contingencies. Furthermore, the use of these services depletes their effectiveness for further response to another contingency or other unscheduled variation in supply or demand. System operators address large contingency events using a dedicated class of reserves known as contingency reserves. These reserves are often sized to address the failure of the single largest power plant or transmission line in the system. Contingency reserves are an upward-only reserve product and are often divided into two (or sometimes three) types of reserves deployed sequentially, so that reserves can be restored and be able to respond to another event.

   A. **Spinning Reserves.** Spinning reserves are traditionally provided by generators that are synchronized to the grid (spinning) and have spare capacity (meaning they have headroom or ability to increase output). Spinning reserves have also been provided by demand response. They typically are required to begin responding quickly (within seconds) and with full response in 10 minutes or less. They are required to continue providing energy for up to 60 minutes (30 in most markets).[11]

   B. **Non-Spinning/Supplemental Reserves.** Typically used to replace or supplement spinning reserves, non-spinning reserves are typically fast-starting units that can begin providing energy within about 10 minutes. They may be required to continue providing this service for several hours. In some regions, non-spinning and supplemental reserves are separate categories, where replacement reserves are provided by longer-starting units.

4. **Ramping Reserves**

   Ramping is the least well defined of the reserve products and is not yet a common market product.[12] One definition is a regulation-like product but over longer timescales; for example, regulation is used to meet very short-term variability (seconds to a few minutes), while ramping reserves are used to meet variability in the minutes to tens of minutes timescale. Another definition is a reserve product used to meet normal load-following requirements, particularly in markets that (historically) did not include 5-

[11] See table 3-14 in EPRI (2016).

[12] The NERC glossary does not include a definition for ramping, load-following, or flexibility reserves. However, NERC ERS documents (NERC 2014, NERC 2016a) include ramping as a category of ERS within the general category of frequency support and operating reserves.

minute economic dispatch. Other definitions of this product focus primarily on reserves needed to address normal variability and uncertainty of VG resources. Ramping reserves are not shown on Figure 7 because they are typically used for normal operation as opposed to addressing contingency events. For additional discussion, see Ela, Milligan, and Kirby (2011). From this point, we use "ramping" as an abbreviation for this general category of reserves, while acknowledging the different and evolving nomenclature among various regions.

5. **Economic Dispatch (Normal System Operation)**

   All reserves are eventually replaced by the normal economic dispatch of conventional generators as the system is restored to a pre-contingency state. This is not considered an operating reserve or ERS and is provided by generators delivering energy and capacity services described in Section 2.1.

Each of the following four subsections describes in greater detail the current grid requirements for each major class of reserve product in today's grid ("how much"), and estimates of market prices where available.

2.2.1 Frequency-Responsive Reserve Requirements

Frequency-responsive reserves traditionally consist of two services: inertial response and PFR. To date, there has been little detailed estimation of inertial response requirements in the United States. This is because in a synchronous-generator dominated system, inertia is inherently provided and does not need to be committed or otherwise procured. However, with increasing penetration of non-synchronous generators, there has been growing analysis of the potential need to procure inertial response services. To date, only ERCOT has studied the amount of inertia potentially "required" in their system. This requirement (the "how much" component) of inertia is unlike that of all other operating reserves. For all reserve products other than inertia, the requirement is measured in units of power (MW, GW). This means that a system must have a certain number of MW available of "spare capacity" in an upward or downward direction. For an individual generator, the "how much" is based on the generator's headroom or the difference between its current operating capacity and its maximum (or minimum for downward reserves) output level.

For inertia, the requirement is measured in energy, or how much energy can be injected rapidly into the system. This is often measured in GW-seconds. The inertia provided by an individual generator (measured in MW-seconds) is determined by the amount of stored kinetic energy. This also means there is no "headroom" component of inertial response and that the amount of inertia that can be provided by a generator is independent of instantaneous power output. This is because inertia is the product of the generator's physical mass and rotation speed. Rotation speed is essentially constant regardless of power output, and mass varies in proportion to generator size and by generator technology type.

The inertia of a typical generator is in the range of 2 MW-seconds to 6 MW-seconds per MW of capacity.[13] ERCOT has identified 100 GW-second as a "critical" inertia level for its system (NERC 2017b). This implies that ERCOT would require between 20 GW and 33 GW of online synchronous *capacity* (not generation). The actual minimum amount of generation is based on the system dispatch, including how low the generators can reduce output.[14] The amount of inertia in the ERCOT grid has dropped to as low as 130 GW-seconds during periods of low load when wind has displaced conventional synchronous generation. With wind expected to displace even more synchronous generation in the future, ERCOT is exploring mechanisms to ensure reliability under low-inertia conditions, such as increased procurement of additional frequency-responsive reserves including both PFR and an emerging FFR service mentioned above and discussed later in this section.

While analysis of inertial response requirements is limited, NERC has established minimum recommended standards for PFR for each of the three U.S. grids. Table 5 summarizes PFR obligation by region. Each interconnection has a frequency response obligation (FRO) that is defined as the amount of increase in generation that must occur per unit of frequency decline (MW/Hz). This interconnection FRO (IFRO) is further divided by BA in proportion to demand so that each region "shares" its obligation to the entire interconnection. Also established is the maximum delta frequency (MDF), or the decline in frequency that results in full frequency response. A single MDF is applied to all regions in each interconnection. The product of these two factors is the PFR (in units of MW) obligation by interconnection and BA. This amount represents the "how much" for this class of service, or the aggregated headroom needed across the set of generators providing PFR.

Table 5. Primary Frequency Response Obligation

Interconnection	Region	IFRO (MW/0.1Hz)[a]	MDF (Hz)[b]	Requirement (MW / % of Peak Demand)
ERCOT	**ERCOT**	**381**	**0.405**	**1,543 / 2.2%**
Western	**Western Total**	**858**	**0.28**	**2,402 / 1.5%**
	CAISO	196.5		550 / 1.1%
	Non-CAISO	661.5		1,852 / 1.7%
Eastern	**Eastern Total**	**1015**	**0.42**	**4,263 / 0.8%[c]**
	FRCC	76.2		320 / 0.7%
	SERC	303.6		1,275 / 1.0%
	NYISO	49.9		210 / 0.7%
	PJM	258.3		1,085 / 0.7%
	ISO-NE	38.3		161 / 0.7%
	MISO	210		882 / 0.7%

[13] Inertia scales with generator size because generators with larger capacity have more physical mass in the turbine, generator, and other rotating machinery. Differences in scale factor (referred to as the inertia constant) are based on factors including technology type.

[14] For a discussion of minimum generation levels from conventional generators, see Denholm et al. (2018)

SPP	78.7	331 / 0.6%
Total	**2,254**	**8,208 / 0.6%**

[a] NERC 2016b; 2017 NERC BA-level frequency response obligation in MW/0.1Hz
[b] NERC 2017a; Maximum allowable delta frequency
[c] Requirement divided by noncoincident peak of Eastern Interconnection (the sum of peak demand in Table 2)

Neither inertial response nor PFR is a market product in any ISO/RTO market, so there are no historical prices (EPRI 2016).[15] There have been a number of proposals to introduce an inertial response or PFR market, with the most significant efforts in ERCOT (EPRI 2016, Newell 2016). ERCOT's efforts have included analysis of alternatives to inertial response and PFR, including introduction of an FFR market product. As discussed earlier, inertial response and primary frequency response are legacy products based on systems using synchronous generators. Alternative resources, including inverter-based generators (wind, PV, and storage) or demand response, can provide FFR that could supplement or replace some amount of conventional inertial response and PFR.

2.2.2 Regulating Reserve Requirements and Costs

Regulating reserves are a market product in each ISO/RTO and have the most technically demanding requirements of the various reserve products in terms of response rate and the need for nearly continual ramping of the plant providing this service. Because regulation requires nearly constant up and down changes in output, this produces additional wear-and-tear and less efficient operation, imposing additional costs. As a result, they are typically the most costly of the reserve services.[16]

Table 6 summarizes regulating reserve requirements for the regions evaluated. For the requirement in non-market regions, we multiply the percentage requirement of a large utility in that region by the total peak demand of the larger region in which it is located. This means that we use the requirements of a single utility as the proxy for the larger region as a whole. Average costs are also provided, including the average annual cost for market regions, or the open-access transmission tariff (OATT) for the selected utility. Note that the units for capacity-related services are typically in terms of capacity (e.g., kW or MW) over a certain time period (e.g., hour, month, or year)—so a MW-hr is a MW of capacity for an hour, as opposed to a MWh, which is a unit of energy.

[15] They are also not compensated services, which has led to concerns about system operators having sufficient supplies in competitive markets. For more discussion, see Ela et al. (2011), Ela et al. (2014), and EPRI (2016).
[16] For a discussion of the drivers behind the differing costs of reserve products, see Hummon et al. (2013).

Table 6. Regulating Reserve Requirements

Market Regions	**Average Regulation Requirement (% of Peak Demand / MW)**	**2017 Average Price ($/MW-hr)**
CAISO	Regulation Up: 0.64% / 320 Regulation Down: 0.72% / 360[a]	Regulation Up: $12.13 Regulation Down: $7.69[b]
PJM	Off-peak: 0.36% / 525 On-peak: 0.55% / 800[c]	$16.78[d]
ERCOT	Regulation Up: 0.48% / 318 Regulation Down: 0.42% / 295[e]	Regulation Up: $8.76 Regulation Down: $7.48[f]
ISO-NE	0.25% / 60[g]	$29.23[h]
NYISO	0.73% / 217[i]	$10.28[j]
MISO	0.35% 425[k]	$9.74[l]
SPP	Regulation Up: 0.92% / 470 Regulation Down: 0.63% / 325[m]	Regulation Up: $8.20 Regulation Down: $6.60[n]
Regulated Regions[o]	**(% of Peak Demand / Estimated Region Requirement in MW)**	**Tariff ($/kW-month / $/MW-hr)**
Non-CAISO WECC (proxy utility: Arizona Public Service)	1.17% / 1,240[p]	$7.41/$10.29
FRCC (proxy utility: Florida Power & Light)	1.35% / 629[q]	$4.8/$6.67
SERC (proxy utility: Southern Company)	1.15% / 1,477[r]	$4.2/$5.83
National	**(% of Total)[s] / Estimated Total Requirement**	**Average Price ($/MW-hr)[t]**
	0.90% / 6,000 MW	$11.24

[a] CAISO 2018, 144; 2017 average day-ahead requirement
[b] CAISO 2018, 148; Weighted average day-ahead market clearing price
[c] Monitoring Analytics 2017, 59
[d] Monitoring Analytics 2017, 59; 2017 weighted average clearing price for regulation
[e] Potomac Economics 2018d
[f] Potomac Economics 2018a, 39; Average annual ancillary service price
[g] Tacka 2016; Estimate
[h] ISO-NE 2018a, 180
[i] NYISO 2018a
[j] Potomac Economics 2018c, A-26; Average day-ahead regulation capacity price for 2017
[k] MISO 2018; Summarized
[l] Potomac Economics 2018b, 38; Average real-time regulation price
[m] SPP 2016; 2016 hourly requirements
[n] SPP 2017, 104; Average day-ahead market-clearing price for regulation-up and regulation-down in 2017
[o] For regulated regions, the numbers here show only the requirement and tariff of representative utilities/balancing authorities. Different BAs have different values; the same representative BA is used for spinning and non-spinning reserve tables.

[p] Requirement numbers are a percentage of the transmission customers' contribution to the coincident system peak. The WECC number comes from the regulation requirement of Arizona Public Service Company's OATT files. Data in MW are calculated as an estimate using peak demand in Table 3 multiplied by the percentage requirement of the selected utility.
[q] Florida Power & Light Company 2016
[r] Southern Company 2018
[s] Calculated as the weighted average percentage requirement, weighted by peak demand of each region
[t] Calculated as the simple average of regional price

2.2.3 Contingency Reserve Requirements and Costs

Table 7 summarizes spinning contingency requirements. The actual quantity procured is typically greater than regulation requirements, but the price is typically lower due to the infrequent ramping requirements. Contingency events are relatively rare compared to the nearly continuous ramping required from regulating reserves, resulting in less wear and tear or degraded performance.

Table 7. Spinning Contingency Reserve Requirements

Market Regions	Spinning Requirement (% of Peak Demand / MW)	2017 Average Price ($/MW-hr)
CAISO	1.60% / 800 MW[a]	$10.13[b]
PJM	1.03% / 1,504.8 MW[c]	$3.73[d]
ERCOT	3.76% / 2,616.8 MW[e]	$9.77[f]
ISO-NE	3.75% / 900 MW[g]	$2.96[h]
NYISO	2.20% / 655 MW[i]	$5.00[j]
MISO	0.61% / 740 MW[k]	$2.94[l]
SPP	1.14% / 585 MW[m]	$5.25[n]
Regulated Regions	**(% of Peak Demand) / Estimated Region Requirement**	**Tariff ($/kW-month / $/MW-hr)**
Non-CAISO WECC (Arizona Public Service)	1.50% / 1590	$6.26 / $8.69
FRCC (Florida Power & Light)	0.43% / 200	$5.16 / $7.17
SERC (Southern Company)	2.00% / 2,568	$4.2 / $5.83
National	**(% of Total)[o] / Estimated Total Requirement**	**Average Price ($/MW-hr)[p]**
	1.58% / 12,160	$6.15

[a] Blanke 2018, 146; Estimate
[b] Blanke 2018, 148; Weighted average of day-ahead market-clearing price
[c] Monitoring Analytics 2017, 56; Average hourly required synchronized reserve requirement for RTO zone
[d] Monitoring Analytics 2017, 57; The year 2017 weighted average clearing price for Tier 2 synchronized reserve for all cleared hours in the RTO zone
[e] Potomac Economics 2018d; The year 2017 ERCOT average responsive reserve requirement
[f] Potomac Economics 2018a, 39; Average annual ancillary service price
[g] Brunette 2013, 12; Ten-minute spinning reserve

[h] ISONE 2018, 169; Annual average 10-minute spinning reserve price
[i] Potomac Economics 2018c, A-140
[j] Potomac Economics 2018c, A-16; Day-ahead 10-minute spinning price for the southeast New York zone. Note that the 10-minute spinning price equals the sum of the 10-minute spin component, 10-minute non-spin component, and 30-minute component.
[k] MISO/Manitoba Contingency Reserves, April 13, 2017
[l] Potomac Economics 2018b, 38; Average real-time spinning reserve price
[m] Seel, Mills and Wiser 2018, 45
[n] SPP 2017, 106; Average real-time market-clearing price for spinning reserve in 2017
[o] Calculated as the weighted average percentage requirement weighted by peak demand of each region
[p] Calculated as the simple average of the regional price

The procurement requirement (total MW) for non-spinning reserves is typically similar to that of spinning reserves (because non-spinning typically replace spinning). They have the lowest technical requirements in terms of response rate and are therefore typically the least expensive of the market reserve products. Requirements and prices are summarized in Table 8.

Table 8. Non-Spinning Contingency Reserve Requirements

Market Regions	**Non-Spinning Requirement (% of Peak Demand / MW)**	**2017 Average Price ($/MW-hr)**
CAISO	1.60% / 800 MW[a]	$3.09[b]
PJM	1.03% / 1,053.2 MW[c]	$2.11[d]
ERCOT	2.21% / 1,534.5 MW[e]	$3.18[f]
ISO-NE	10-minute total reserve: 5.98% / 1435 MW 30-minute operating reserve: 3.33% / 800 MW[g]	10-minute non-spinning reserve: $0.89 30-minute operating reserve: $0.82[h]
NYISO	10-minute total reserve: 4.41% / 1310 MW 30-minute reserve: 8.82% / 2620 MW[i]	10-minute non-spinning: $4.18 30-minute component: $4.01[j]
MISO	0.92% / 1,110 MW[k]	$1.14[l]
SPP	1.43% / 730 MW[m]	<$1[n]
Regulated Regions	**(% of Peak Demand)/ Estimated Region Requirement**	**Tariff ($/kW-month / $/MW-hr)**
Non-CAISO WECC (Arizona Public Service)	1.50% / 1,590	$0.97 / $1.35
FRCC (Florida Power & Light)	1.31% / 527	$4.83 / $6.71
SERC (Southern Company)	2.00% / 2,568	$4.20 / $5.83
National	**(% of Total)[o] / Estimated Total Requirement**	**Average Price ($/MW-hr)[p]**
	1.98% / 14,768	$2.92

[a] Blanke 2018, 146; Estimate
[b] Blanke 2018, 148; Weighted average of the day-ahead market-clearing price
[c] Monitoring Analytics 2017, 57; Equals primary reserve requirement minus spinning reserve requirement for RTO zone
[d] Monitoring Analytics 2017, 58; The year 2017 weighted average price of all hours when market-clearing prices were above zero for secondary reserve
[e] Potomac Economics 2018d
[f] Potomac Economics 2018a, 39; Average annual ancillary service price
[g] ISO-NE 2018b, 11; Summer 2017 requirement; 30-minute operating reserve (TMOR) is on top of 10-minute nonspinning reserve (TMNSR)
[h] ISO-NE 2018, 169; Annual average TMNSR and TMOR prices
[i] NYISO 2018c, 43; Potomac Economics 2018c, A-139
[j] Potomac Economics 2018c, A-16; Day-ahead 10-minute non-spinning price for southeast New York zone. Note that the 10-minute non-spinning price equals the sum of the 10-minute non-spinning component and 30-minute component.
[k] MISO 2017b, 3.
[l] Potomac Economics 2018b, 38; Average real-time supplemental reserve price
[m] Seel, Mills and Wiser 2018, 45.
[n] SPP 2017, 106; Average real-time market-clearing price for supplemental reserve in 2017
[o] Calculated as the weighted average percentage requirement weighted by the peak demand of each region
[p] Calculated as the simple average regional price

2.2.4 Ramping Reserve Requirements

These reserves are an emerging product with limited market data for analysis. Table 9 summarizes the ramping reserve requirements for two markets.

Table 9. Ramping (Flexibility) Requirements by Region

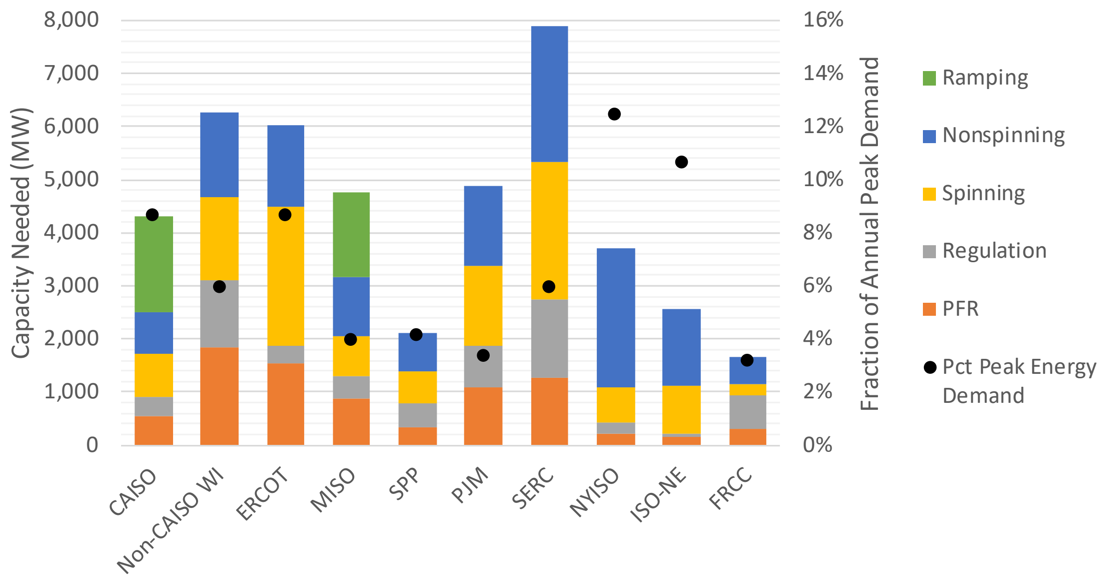
Region	Requirement
CAISO	• Maximum flexible ramp up and down requirements are defined as the 2.5% and the 97.5% percentile of net load change • Uncertainty threshold: o For the system in the 15-minute market: -1,200 MW in the downward direction and 1,800 MW in the upward direction; o For the system in the 5-minute market: -300 MW and 500 MW in the downward and upward direction[a]
MISO	• Depends on the sum of the forecasted change in net load and an additional amount of ramp up/down (575 MW for now) • Highest hourly average real-time ramp-up requirement: 1,554 MW • Highest hourly average real-time ramp-down requirement: 1,614 MW[b]

[a] Westendorf 2018, 5
[b] Summarized from MISO 2018; Monthly Market Assessment Report 'Hourly Average RT Ramp Requirement,' calculated as the simple average across all months in 2017

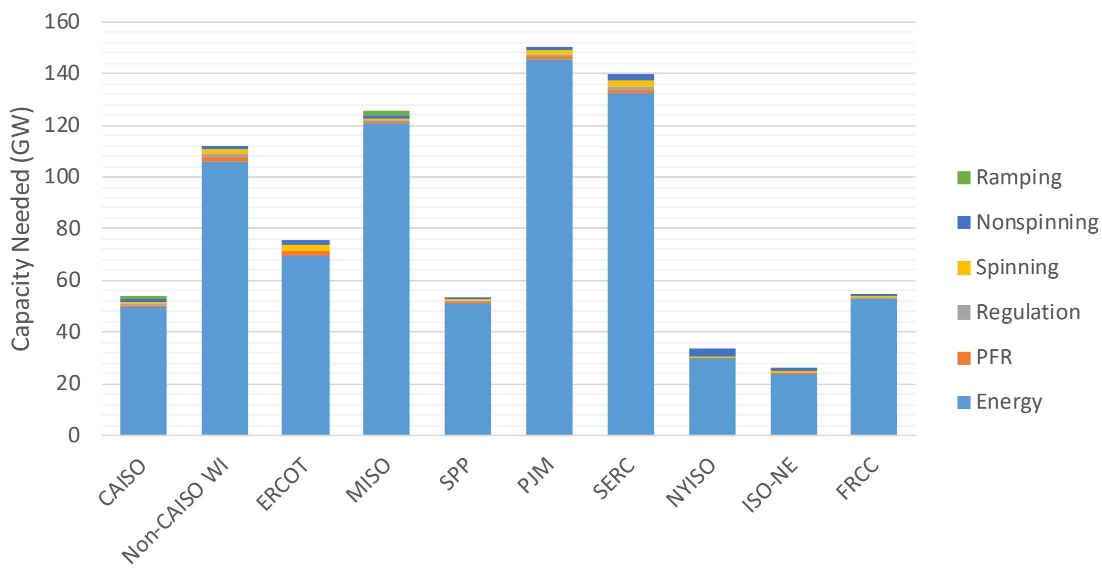
2.2.5 Total Reserve Requirements

Figure 8a shows the total *peak* reserve requirements by region.[17] For context, we also show the reserve requirements compared to the capacity requirements for meeting peak demand in each region (Figure 8b). This demonstrates that while reserves are an important part of reliable system operation, they are a relatively small fraction of total services. It should be noted that for the most part, these services are "mutually" exclusive, meaning that a generator cannot use the same MW of reserve capacity for multiple services. However, this chart assumes that PFR is additive to existing reserve products despite a lack of established market rules for PFR. It is possible that implementation of a PFR market product could reduce the need for other reserve products, or that a unit providing PFR could also be used for spinning reserves, which would reduce the overall quantity of reserve held compared to Figure 8. For additional discussion of this, see Newell et al. (2015).

[17] This chart assumes that PFR is additive to existing market products.



a) Reserve requirements



b) Reserve and energy requirements

Figure 8. Total capacity for energy and reserve requirements.

2.3 Other Essential Reliability Services

There are a number of other ERSs, with two of the most important being black-start and voltage support. These services are different enough from operating reserves that they are not typically categorized as reserve services. A significant difference of these two services relative to most operating reserves is that they are typically acquired on a cost-of-service basis. In wholesale markets, most operating reserves are acquired on a competitive basis, meaning multiple units can bid, and the market operator will acquire the unit that can provide the service at least cost. For black-start and voltage support, specific technical and economic issues limit the effectiveness of operating a market. The best example is when services are required at a specific location. This means that an existing unit at that location would have "market power" or the ability to set a price without competition (i.e., a monopoly), so out-of-market procurement becomes necessary.

2.3.1 Black-Start

Black-start represents capacity that can be started without external power and then subsequently provide power and energy to start other power plants. Black-start units are typically relatively small power plants including certain hydroelectric facilities, diesel generators, or small gas turbines (FERC 2015).[18] Black-start has historically been procured on a cost-of-service basis, even in wholesale market regions (FERC 2017). Each region has specific technical requirements for the type and quantity procured. For reference, the total cost of black-start payments in PJM in 2017 was $72 million or about 0.2% of total costs, while the cost in the New England ISO (ISO-NE) in 2017 was $12 million (0.1% of total) (PJM 2017, 28; ISO-NE 2018c, 21).

2.3.2 Voltage Support

Ensuring electric system reliability requires maintaining both frequency (maintained largely via provision of operating reserves, as discussed in Section 2.2) and voltage. While frequency is constant throughout the grid, voltage varies depending on location. To provide reliable service, power system operators continuously adjust voltage at various points on the grid to keep voltage stable or within a certain tolerance. As with frequency decay, voltage collapse is possible when there is insufficient voltage control to maintain steady voltage after an equipment failure on the grid.[19] Devices that provide voltage control maintain appropriate voltage on the grid during both normal operating conditions and fault conditions.

Voltage is controlled by different methods at different points of the grid. A key element of controlling voltage at each point on the grid is the ability to inject or absorb reactive power. Reactive power is a property of AC electrical current. It is the portion of current that is out of phase with voltage. Because only the portion that is in phase can do work like run motors, heat water, or turn the lights on, the additional current goes back and forth on the line without doing work, introducing added current that still must be generated. Too much or too little reactive power can reduce the flow of power and result in inadequate voltage. Reactive power cannot be transmitted over long distances.[20] Therefore, voltage control is performed at each of the three major parts of the grid, including at the point of generation, at various points in the transmission system, and in the distribution network. Reactive power is provided by "active" devices such as synchronous generators or power electronics devices or by "passive" devices such as capacitor banks.

Because provision of reactive power is very location dependent, it is typically provided on a cost-of-service basis. For an estimate of system costs, in 2017 PJM paid about $309 million for "Reactive services" (or about 0.8% of total billing), while ISO-NE paid about $20 million for "Volt-ampere-reactive capacity cost" (about 0.2% of total billing) (PJM 2017, 28; ISO-NE 2018c, 21).

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[18] The black-start units themselves need a source of energy to start, but the requirements are small enough to use something akin to a "scaled up" car battery. Larger power plants may require many kW or even MW of power to start.

[19] An example of an event caused by voltage collapse was the 2003 Northeast Blackout; see DOE (2004).

[20] For additional discussion of reactive power, see FERC (2005).

2.4 Relative Total System Costs

In total, the vast majority of generation-related costs are associated with the provision of energy and capacity; however, it is difficult to provide an exact breakdown of costs associated with each service. Before the advent of restructured markets, there was little attempt to precisely allocate the costs of individual services. In most cases generators provide multiple services, and allocation of costs among those services was (and still is) challenging. The best example is the challenge of differentiating between the cost of energy and capacity in wholesale markets, where the cost of capacity is partially captured via energy payments (FERC 2015). Likewise, the cost of operating reserves is captured through the variable costs of operating reserve provision, which may not entirely capture the cost of capacity needed to provide reserves.

Despite these challenges, market data, such as that presented in previous sections, can provide some idea of the relative value of the various grid services. Table 10 and Table 11 summarize the market settlements for ISO-NE and PJM for the year 2017. The data shows that the energy, capacity, and transmission costs represent about 97% to 98% of total system costs, with operating reserves and other ancillary services accounting for less than 2%. This follows historical "bottom up" analysis that estimates that the cost of reserves is typically less than 2% of the total cost of grid services (Hummon et al 2013).

Table 10. 2017 ISO-NE Market Settlements Summary[a]

	Billing ($ Million)	Percentage
Energy markets total	4,522	49.50%
Forward capacity market payments	2,244	24.56%
Regional network service	2,163	23.68%
Reserve markets total	70	0.77%
Net commitment-period compensation	52	0.57%
Regulation market	32	0.35%
Financial transmission rights (FTRs)	20	0.22%
Black-start	12	0.13%
Volt-ampere-reactive capacity cost	20	0.22%
Demand-response payments	1	0.01%
Total	**$9,136**	**100.00%**

[a] ISO-NE 2018c

Table 11. 2017 PJM Market Settlements Summary[a]

	Billing ($ Million)	Percentage
Energy market	21,087	52.49%
Capacity	9,103	22.66%
Transmission[b]	8,739	21.75%
Scheduling	366	0.91%
Reactive services	309	0.77%
Regulation market	104	0.26%
Black-start	72	0.18%
Operating reserves	68	0.17%
Synchronized reserve market	49	0.12%
Day-ahead scheduling reserve market	34	0.08%
Other	241	0.60%
Total	**$40,172**	**100.00%**

[a] PJM 2017
[b] This includes the cost of congestion and losses.

3 Provision of Services from Wind

3.1 Energy and Capacity

More than 1,000 MW of wind generation capacity has been deployed in each of the regions analyzed, with the exception of SERC and FRCC. Table 12 summarizes the installed capacity and energy production from wind in 2017, along with estimated fraction of demand met by wind.

Table 12. 2017 Wind Energy Provision

Region	Installed Capacity (MW)	Annual Energy (GWh)	Fraction of Demand (%)
Market Regions			
CAISO	6,296	12,823	6.0
PJM	8,141	20,714	2.7
ERCOT	21,704	62,193	17.4
ISO-NE	1,401	3,444	2.6
NYISO	1,826	4136	2.7
MISO	17,000	50,535	7.7
SPP	17,591	58,874	23.2
Regulated Regions			
Non-CAISO WECC	16,766	43,967	6.7
FRCC	0	0	0
SERC	237	514	0
Total	**87,331**	**225,585**	**5.5**

The value of the energy and capacity provided by wind is impacted by the variable nature of the resource. Wind tends to be somewhat negatively correlated with demand patterns over the diurnal and seasonal cycle. This means that wind may be often less valuable than the average prices seen earlier in Table 4 (DOE 2018). It also has somewhat limited capacity value based on its capacity credit.[21] Capacity credit is the actual fraction of the generator's installed capacity that could reliably be used to meet peak demand (or offset conventional capacity), which is typically measured as a value (e.g., kW) or percentage of nameplate rating.

There is considerable literature on methods to estimate generation capacity credit, and the various approaches to estimating capacity credit differ in complexity (NERC 2011). However, they generally assess the probability of a plant being available during periods of highest net demand, which is typically during hot summer afternoons throughout most of the United States. Most ISO/RTOs and large utilities with substantial wind deployments have performed capacity credit analysis of wind. Table 13 summarizes the capacity credit assigned to wind resource in the regions analyzed. It demonstrates that for nearly all regions of the United States, a capacity credit

[21] Following Mills and Wiser (2012), we use the term "capacity credit" to represent physical capacity, and we use the term "capacity value" to represent the monetary value of this capacity.

of significantly less than 50% is applied to wind, with capacity credits well under 20% applied in many cases.

Table 13. Capacity Credit by Market Region

Region	Capacity Credit	
Market Regions		
CAISO[a]	Summer values of about 27%.	
PJM[b]	Initially applies 13% of nameplate; after three years of operation, historic performance over seasonal peak periods determine unit's capacity credit.	
ERCOT[b]	Based on average historical availability during the highest 20 seasonal peak load hours for each season (2009–2016). Values recalculated after each season with new historical data. Current contribution: 58% coastal and 14% noncoastal (summer); 35% coastal and 20% noncoastal (winter).	
ISO-NE[b]	Summer values average to approximately 13.2% of nameplate rating.	
NYISO[c]	Onshore: summer 10%; winter 30% Offshore: 38%	
MISO[d]	2016	15.6%
	2017	15.6%
	2018	15.2%
SPP	5% assumed for first three years if the load-serving entity (LSE) chooses not to perform the net capability calculation during the first 3 years of operation, after which the net capability calculations are applied by selecting the appropriate monthly MW values corresponding to the LSE's peak load month for each season.	
Regulated Regions		
Non-CAISO WECC	Varies. For example, Xcel Colorado uses 16%.[e] Portland General Electric uses 5%–15% for wind resources located in the Pacific Northwest.[f]	
FRCC	Not applicable.	
SERC	Varies.	

[a] CAISO 2018
[b] NERC 2017b, Table 10
[c] NYISO 2018b, 4–24
[d] MISO 2017a
[e] Xcel Energy 2016
[f] PGE 2016, 126

3.2 Operating Reserves

While wind was once considered a non-dispatchable "must-take" resource without the ability to provide reserves, it is now recognized that the output of a wind turbine can be accurately controlled (up to the amount allowed by instantaneous wind speed) (Milligan et al. 2015). This allows wind to provide multiple reserve services. Of course, wind has important differences that provide both relative advantages and disadvantages compared to more traditional resources.

Table 14 summarizes the three characteristics of conventional thermal/hydro plants and wind when providing operating reserves.

Table 14. Key Parameters for Provision of Operating Reserves for Thermal/Hydro Resources and Wind

Parameter	Thermal/Hydro	Wind
Dispatch Range ("how much")	Min to max, min typically 25% to 50% of max[a]	0 to max, where maximum output is variable (limited by current wind speed)
Ramp Rate ("how fast")	Start time ranges from several minutes to hours. Ramp rate when online ranges from about 1%/min for combined-cycle/coal to 5%/min for combustion turbine[b]	Ramp rate greater than 5%/second[c]
Availability of Output ("how long")	Typically unconstrained with fuel availability	Contingent on wind resource, which has increased unpredictability with duration

[a] Lew et al. 2013
[b] Lew et al. 2013, Table 2, 34
[c] Chen et al. 2017

Because wind performance is different from that of conventional generators, the technical ability of wind to provide reserves varies by service. In general, the ramp rate capability of wind is much higher than that of conventional generators, so the ability of wind to provide reserves is largely related to two issues: the economics of pre-curtailment and the predictability of output over timescales needed for various reserve services. Note that for the most part, our discussions will focus on the provision of upward reserves, as there are few technical constraints on the ability of wind to provide downward reserves.[22]

A key element of providing reserves from wind is the need for pre-curtailment, which incurs the opportunity cost of reduced energy sales. Pre-curtailment requires reducing the output of the wind turbine, performed by changing the blade pitch angle and reducing the amount of energy extracted from the wind. The pre-curtailment requirement reduces the revenue from electricity sales for a wind generator providing this service, at least under current market conditions. The net revenue of a generation resource providing energy or reserves is the price of that service minus the variable cost of providing the service. For wind, the variable cost of providing either energy *or* reserves is about the same (zero). This means that a wind generator will always prefer to provide energy instead of reserves as long as the price of energy is greater than the price of reserves. Under historical grid conditions, the price of energy has almost always been higher than the price of reserves (as indicated by the results in Section 2).

However, as variable generation penetration increases, there may be times when the price of energy falls to zero and wind is curtailed. This may also correspond to times when the price of reserves is greater than zero, because thermal generators must be kept online to provide operating reserves. Under these conditions, it may be economically advantageous—for the wind plant and the system—for curtailed wind to provide reserves, and wind can potentially improve overall system dispatch by allowing decommitment (turning off) of more costly (on an operating basis) generators that are online primarily to provide reserves. Historically, most wind

[22] An exception to this is policy-related issues. For example, CAISO has often asserted limited ability of wind or PV to provide downward reserves because of the need to meet renewable portfolio standards (RPS) obligations. (Providing downward reserves reduces energy production from wind when actually deployed.)

curtailment has been due to transmission constraints, where wind would not be able to provide reserves, as the location where reserves are needed does not correspond to the location of the wind. This has limited the role of wind in providing reserves to date, although there have been locations in the United States where wind has been curtailed due to economic conditions (including minimum generation constraints on conventional plants) and has provided upward reserves (Milligan et al. 2015). Beyond opportunity costs, other costs for wind to provide these services, such as additional maintenance costs for equipment wear-and-tear associated with greater changes in output, are largely unknown.[23]

While the need for pre-curtailment is an economic factor, an important technical factor is ensuring that headroom will remain available for the response time needed. This issue is illustrated in Figure 9, which shows the potential output of a pre-curtailed wind resource. For a wind plant to provide reserve service at t=0 it must be pre-curtailed by the amount of service desired. But the wind availability must not drop below the maximum output at t=0 for the length of the reserve service. In this example, the wind is expected to stay at or above the amount of headroom for about 15 minutes. Beyond this point, the potential (maximum) wind output drops and there is a reduction in headroom, meaning the wind plant can no longer provide the full capacity of the reserve service (without increasing the amount of pre-curtailment). Furthermore, this output must be predictable for the length of the service (meaning the operator must know with high confidence the potential plant output if not curtailed).

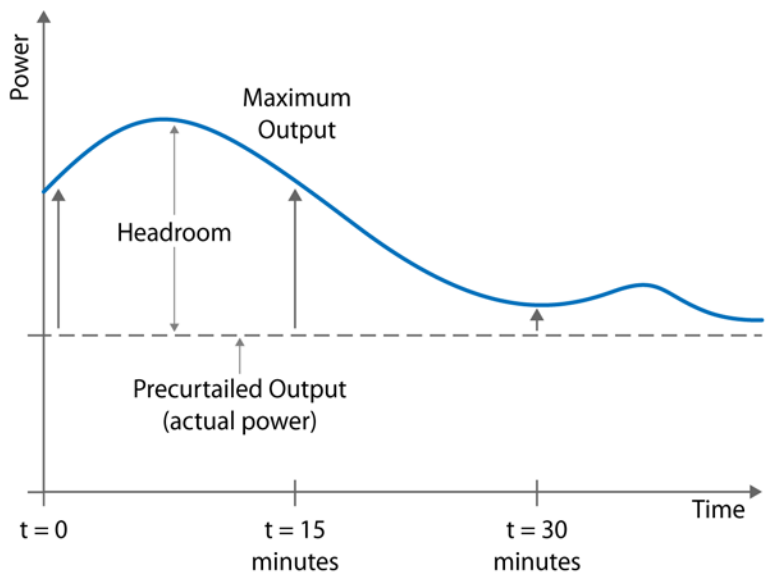

Figure 9. The impact of variable output on the ability of wind to provide upward reserve services.

Following the sequence of reserve deployments in Figure 6 (moving from PFR to non-spinning) increases the length of response, along with decreasing the response speed. For conventional generators, the technical challenges decrease because only the speed matters for resources without fuel supply constraints. For wind, the opposite is true. Wind can increase output very rapidly, but the duration of response becomes problematic. This means the "how long"

[23] For additional discussion of this topic see Ela et al. (2014).

component of reserve service from wind is limited by both the likelihood of wind remaining at or higher than current output *and* the predictability of this output. The uncertainty can become a particular challenge for scheduling the mix of power plants needed to meet energy and reserves. This scheduling often occurs 24 hours or more in advance of when the services are needed, making it more challenging to ensure wind output will be available to provide reserves. As a result, longer-duration (easier) operating reserve services for conventional generators are more difficult services for wind. Improved forecasting, shorter-term scheduling, and taking advantage of spatial diversity can all act to mitigate the impact of forecasting challenges for provision of reserves from wind. While the forecast accuracy of wind is increasing, the ultimate limit to wind headroom is the relatively low capacity credit. A system operator may not be able to plan on the availability of wind to provide upward reserves, and insufficient wind during certain periods may require other sources of capacity to be available to provide reserves. In this sense, similar to provision of energy, wind will act to reduce the variable costs associated with providing reserves, but have somewhat limited availability to reduce the fixed costs.

Each of the following subsections provides a more detailed discussion of the ability of wind to provide the various reserve services established in Section 2.2.

3.2.1 Frequency-Responsive Reserves

As discussed in Section 2.2, frequency-responsive reserves are presently provided by 1) the inherent physical inertia in the rotating mass in synchronous generators and 2) primary frequency response.

Wind generators have demonstrated the ability to provide both an “inertia-like” product and PFR, and FERC requires new wind turbines to provide PFR (FERC 2018c). The growing deployment of wind (and PV) has also led to further examination of alternative frequency response products that are better suited towards a future with a greater presence of inverter-based machines.

Modern wind turbines do not use synchronous generators and therefore do not provide inertia in the traditional sense (defined as automatically resisting changes in frequency). However, wind turbines do have kinetic energy in the rotating mass of the blades, shaft, and generator that can be extracted to rapidly inject real power into the grid. Provision of inertial service in this fashion requires active sensing of grid frequency, so that when a decrease in frequency is sensed, the generator can be programmed to increase output to beyond what can be supported by “steady state” wind speeds (Ela et al. 2014). This action will slow down the turbine and has limited duration.[24] However, it can slow down frequency decay long enough for other mechanisms, including PFR, to arrest and help restore frequency, as illustrated in the sequence shown previously in Figure 6.

The provision of inertia from wind turbines in this manner is unique compared to other reserve service provisions in that it does not require pre-curtailment of wind. (This also represents a substantial difference between wind and other inverter-based technologies such as PV.)

[24] After the wind turbine has slowed, it must reduce output to increase speed. This means that the turbine must temporarily reduce energy output and its generation must be provided by another resource during this recovery period.

Provision of an inertia-like response in this fashion has sometimes been referred to as "synthetic" inertia, although this term does not appear to have a uniform definition. For example, it has been applied to the provision of rapid response from pre-curtailed PV or battery storage. Again, however, actually slowing down wind turbines and extracting kinetic energy is much closer to the definition of "real inertia" than increasing output from a pre-curtailed generator. The latter is more akin to PFR. Providing upward PFR from wind requires pre-curtailment and establishing headroom available for PFR.

Overall, the combination of extracting energy from rotating wind turbines and using pre-curtailed wind energy to provide a rapid increase in output can mimic traditional frequency-responsive reserves. However, it is important to note that because these services do not precisely match those from conventional generators, terminology is still in flux. One of the challenges in defining frequency-responsive reserves from wind (and other non-synchronous generators) is that we are trying to describe somewhat new services using terms established for legacy generators.

Table 15 summarizes some of the terms that have been applied to wind providing frequency-responsive services. In our review of the literature and after discussions with industry experts, it appears that "fast frequency response" (FFR) has emerged as a preferred term that captures the ability of non-synchronous generators to inject real power into a grid upon sensing a change in frequency (Voges 2017).[25] The difference between FFR and PFR is less clear, although generally PFR would reflect a somewhat slower response (but still measured in a few seconds or less). While terminology may not be well established, it is still important to distinguish frequency response that is derived from extraction of turbine kinetic energy as opposed to from pre-curtailment, given the potentially economic implication of these different sources.[26]

Table 15. Terms Applied to Frequency-Responsive Services

Conventional Synchronous Generator	Wind (Previous Terms)	Wind (Current Terms)
Inertia	Synthetic inertia (derived from kinetic energy)	FFR (derived from kinetic energy)[27]
PFR	PFR from pre-curtailment	PFR or FFR (from pre-curtailment)

Regardless of the name, the ability of wind to provide frequency response from both extraction of kinetic energy and increased output from pre-curtailed wind is well established. Major wind turbine manufacturers offer this service, and ERCOT requires all new turbines to have FFR capabilities. However, provision of frequency-responsive services from wind in the United States is largely limited to ERCOT, as most other regions do not yet require wind to provide these reserves; additionally, these services are not a market product, so there is no financial incentive for wind to provide them.

[25] A variety of names have been offered for this service.
[26] Extracting physical inertia from a wind turbine does not require pre-curtailment and thus does not incur lost energy production and lost sales. But pre-curtailment for provision of FFR requires a continual lost opportunity for energy production and sales as long as the wind plant is being held at part load to provide reserves.
[27] Another proposed term is "inertia-based frequency response" (ERCOT 2018).

Along with the evolving terminology is the evolving manner in which wind can provide frequency-responsive services. For example, wind can be “programmed” to provide a response similar to that of legacy synchronous generators. But response of those legacy generators is constrained by their physical characteristics and limits and is not necessarily perfectly aligned with the system’s needs. It is possible that wind response can be optimized to grid requirements and vary based on both the current frequency and the rate of change of frequency (ROCOF). Additional research is needed to understand how to best optimize provision of FFR from wind to maximize its benefits to the grid.

3.2.2 Regulating Reserves

Regulating reserves require a synchronized generator to have the ability to increase or decrease output in response to a signal from the system operator. Provision of regulating reserves is well within the technical capability of wind power plants in terms of speed and duration, but wind requires pre-curtailment to provide upward reserves. Because of this requirement there has been limited use of wind to provide regulating reserves, with one example being Xcel Energy in Colorado (Milligan et al. 2015). This location is fairly unique, as curtailment has been due to a relatively large instantaneous wind penetration as opposed to transmission constraints, which have been the major source of curtailment in other locations such as ERCOT.

Because regulating reserves are typically the highest-cost reserve product, we would expect this to be the “first” market reserve product to be commonly provided by wind. In U.S. ISO/RTO markets, rules for wind providing regulating reserves are unclear, inconsistent, and evolving. Only a few market ancillary service manuals explicitly call out wind in their discussions of service requirements. For example, MISO allows wind to act as a “dispatchable intermittent resource” that can bid into a variety of services based on specific requirements for each type of reserve.

3.2.3 Ramping Reserves

As discussed in Section 2.2.5, flexibility/ramping reserves are an emerging market product without a uniform definition. However, they are similar to regulating reserves in that they require a generator to have the ability to increase or decrease output in response to a dispatch signal. The primary difference is that flexibility reserves are generally slower (i.e., lower ramp rate) and longer (i.e., requiring the generator to hold output for a longer period). The requirement for a plant to be synchronized is inconsistent. Overall, this makes this reserve product easier to meet for a conventional generator, and a lower-cost service from the system perspective. As with all other services, to provide upward flexibility reserves from wind requires pre-curtailment, which makes it more of an economic challenge than a technical one. Whether wind would provide flexibility reserves would depend on the opportunity costs. Given their less stringent requirements, a flexibility reserve product is likely to have lower costs than regulation. Only in likely rare instances when both energy and regulating prices are lower than the price of flexibility reserve would wind provide these services.

3.2.4 Contingency Reserves

Generally, spinning contingency reserves must have the ability to: 1) be synchronized to the grid and begin responding quickly (within a few seconds); 2) reach setpoint within about 10 minutes; and 3) hold output for at least 30 minutes (60 in a few locations). For pre-curtailed wind, criteria

1 and 2 are well within the technical requirements, but the third requirement could be more challenging given the greater variability and lower predictability of wind over longer timescales. Contingency reserve prices are typically lower than those of regulation, so there is little incentive for wind to provide this service, and market rules have limited explicit discussion of wind providing it. For example, PJM considers wind as a resource type that "cannot reliably provide Synchronized Reserve;" however, resources may request an exception (PJM 2018).

Non-spinning reserves are an upward-only reserve product that can be provided by online generators, or units that can start quickly. This results in non-spinning reserves typically being the lowest-cost operating reserve service. Because of this low price, wind has the least incentive to provide this service. Furthermore, the long-duration requirement (multiple hours) may limit the ability of wind to provide this service given the constraints of predictability and limited capacity credit.

3.3 Other Essential Reliability Services

3.3.1 Voltage Support

The power electronics built into wind turbines are well suited to providing voltage control and reactive power. In 2016, FERC issued Order 827 requiring variable generation power plants larger than 20 MW[28] to provide reactive power (FERC 2016), and even before this utilities and system operators were increasingly requiring variable generation units to provide voltage control (Milligan et al. 2015). Modern wind turbines can also provide reactive power even when not generating. However, voltage support is a localized service, and grids often need it in areas where it is not possible to place wind turbines (e.g., large urban areas).

3.3.2 Black-Start Capacity

A black-start generator must be able to start on its own without grid power and create a reference grid frequency. This provides other generators with sufficient power to energize station power requirements, start, and synchronize.

Wind turbines typically start using external grid power. However, these parasitic/operating loads are relatively small and could be provided using a battery or small auxiliary generator. Some modern wind turbines also have "grid-forming" capacity, or the capability to create an AC reference (Göksu et al. 2017).

The primary challenge of black-start capability from wind turbines is their low capacity credit and variability. To date, there has been very little analysis of the ability of wind to provide black-start capability in the United States.[29]

3.4 Summary

Table 16 summarizes the grid services discussed in this report. In general, both existing practices and ongoing research indicate that wind can technically provide nearly all services procured and utilized in the grid, but this ability is constrained by the geographical and temporal availability of the wind resource. Despite its technical capabilities, wind does not provide all services in U.S.

[28] Aggregated capacity of the plant, which typically consist of multiple turbines or solar arrays.
[29] A discussion of the potential role of wind to provide black-start capability is provided in Miller (2018).

regions currently due to market rules, the aforementioned constraints, and economic considerations. Economic considerations include the relative prices or value of the various services, competition from other sources, and opportunity costs caused by the fact that most reserves require pre-curtailment. Until there is significant curtailment of wind energy, wind will likely continue to act primarily as an energy resource.

Table 16. Grid Services and Provision from Wind

Service	Market Procured and Compensated Service?	Wind Can Technically Provide?[a]	Wind Currently Provides in U.S.?	Requires Pre-Curtailment for Wind to Provide?
Capacity	Y	Y	Y	N
Energy	Y	Y	Y	N
Inertial Response	N	Y	N/A	No[b]
Primary Frequency Response	Required but not compensated – proposals only	Y	Limited	Y
Fast Frequency Response	N – proposals only	Y	Limited	Y
Regulating Reserves	Y	Y	Limited	Y
Contingency – Spinning	Y	Y	Limited	Y
Contingency – Non-spinning	Y	Y	No	Y
Contingency – Replacement	Y	Maybe	No	Y
Ramping Reserves	Y (some locations)	Y	Limited	Y
Voltage Support	Y – cost of Service	Y[c] – location dependent	Limited	N
Black-Start	Y – cost of Service	Unclear, location dependent	No	N

[a] Note that all services require actual wind generation potential (the wind must be blowing). The ability of wind to provide all services except where noted is inherently limited by wind's capacity credit.
[b] When providing an inertia-like response using extracted kinetic energy. As noted previously, the terminology around this service is still evolving.
[c] This service does not require the wind to be blowing, so it is the only service not limited by the capacity credit of wind.

4 Conclusions and Research Needs

Historically, the costs of generator-related services have been dominated by energy and capacity, with those comprising more than 95% of total costs. Essential reliability services, while a critical part of system operation, are relatively small in terms of both physical capacity and costs. With increased deployment of variable generation resources including wind, there is potential for growth in and changes to essential reliability service requirements—and potential for wind energy to provide them. In general, wind has already demonstrated the capability to provide multiple reserve services, with response rates that meet or exceed those from conventional synchronous generators. The major limitation of wind in providing operating reserves is the need to pre-curtail and provide upward headroom. This reduces the amount of energy that can be sold, so there is little economic incentive to provide these services in today's grid. As curtailment increases due to greater wind deployment, or as reserve requirements increase, it may become more economic for wind to provide reserves. Some reserve services may be less appropriate for wind, including services (e.g., replacement or supplemental reserves) that require very long (i.e., multiple hour) response time. Wind is far more suited for shorter-term (but more valuable) services that can take advantage of wind's rapid response rate, including fast frequency response, primary frequency response, and regulating reserves.

This work points to several areas of additional analysis needed to better understand the role of wind in providing grid services. Data presented in this work considers historical conditions and does not reflect changes that may occur under increased penetration of variable generation. Further analysis is needed to determine both the types and quantities of reserves needed to address greater variablity and uncertainty of net load under future grid conditions. An important consideration is the evolution of energy markets under these future conditions. A variety of technologies including wind can provide services needed by the grid, but market products may need to be altered to align the technical needs with appropriate economic incentives. This will ensure services are provided by the technologies that can do so in the most cost-effective manner while enabling continued or increased grid reliability.

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