Ancillary Services

Ancillary services are "*services that ensure the reliability of and support for the transmission of electricity to serve load.*"[1] The most common ancillary services are regulation and frequency response,[2] operating reserve, reactive supply and voltage control, and black start services. The ancillary services can be market-based or cost-based. Market conditions, such as supply and demand, determine the payments and charges to operate a particular service in the market-based ancillary services. Regulation and operating reserve are the market-based ancillary services. Payments and charges in the cost-based ancillary services are based on the cost to operate ancillary services. Voltage control and black start units are the cost-based ancillary services.

Regulation Market and Frequency Response

Regulation service is used to keep energy in balance by matching generation with demand in a control area and managing a minute-to-minute change in load. A main objective of the regulation market and frequency response is to maintain the scheduled interconnection frequency at 60 Hz. Frequency will be larger than 60 Hz if the total generation is larger than the total demand, and smaller than 60 Hz if the total generation is lower than the total demand.

The regulation service is provided by generation units that can react to an automatic control signal from an Independent System Operator (ISO)/Regional Transmission Organization (RTO) within seconds. This signal is independent of an economic cost signal such as ex-ante location marginal price in a real-time energy market. The regulation signal is sent every 2 seconds in PJM,[3] every 6 seconds in New York ISO,[4] and every 4 seconds in ISO New England.[5] In some markets, such as PJM, units cannot be committed for both regulation and reserve services at the same time.

Regulation requirements are usually equal to 1 percent of the forecasted peak demand during peak periods and 1 percent of the forecasted valley demand during off-peak periods. Load-serving entities are obligated to meet their regulation requirement by self-supply, bilateral contracts, or purchasing from a regulation market.

Generation units will submit availability and bid price to the regulation market. The ISO/RTO will collect the bids and will also take into consideration the lost opportunity costs (LOC) for generating units, if applicable, by adding the LOC to the generators' bids. The LOC is calculated as a difference between the locational marginal price (LMP) and the generation energy bid. The LOC is included to consider potential loss of profit to the generating units, as a result of producing regulation services rather than using the same power amount to provide energy. The ISO/RTO will rank all available units in ascending merit order and will clear the market to meet regulation requirements with minimum regulation production cost. A regulation market-clearing price is a system-wide hourly price.

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[1] ISO New England. (2011). *Glossary & Acronyms*. Retrieved on January 29, 2011, from http://www.iso-ne.com/support/training/glossary/

[2] Many of the technical terms used in this primer are defined in a companion *Glossary for Power Market Primers.*

[3] PJM. (2013). PJM State & Member Training Department – Ancillary Services. Retrieved on January 29, 2011, from http://www.pjm.com/~/media/training/core-curriculum/ip-gen-301/gen-301-ancillary-services.ashx

[4] NYISO. (2013). *Glossary - Base Point Signals*. Retrieved on January 29, 2013, from http://www.nyiso.com/public/markets_operations/services/customer_support/glossary/index.jsp

[5] ISO New England. (2013). *Regulation*. Retrieved on January 29, 2013, from http://www.iso-ne.com/mkts_billing/mkt_descriptions/line_items/regulation.html

Example 1 – Regulation Market Clearing An ISO/RTO receives the regulation bids for a particular hour from two producers (Exhibit 1). A regulation requirement for the particular hour is 25 MW and the locational marginal price is $60/MWh. The ISO/RTO first calculates the LOC and total regulation cost for the specific unit. The LOC is given in the last column of Exhibit 1. The calculated total regulation cost of Gen Company 1 – Unit1 is $52/MWh, Gen Company 1 – Unit2 is $39/MWh, Gen Company 1 – Unit3 is $26/MWh, Gen Company 1 – Unit4 is $6/MWh, Gen Company 2 – Unit1 is $53/MWh, Gen Company 2 – Unit2 is $45/MWh, and Gen Company 2 – Unit3 is $20/MWh.

Exhibit 1 Generating companies' regulation and energy bids

Gen Company	Regulation Capability [MW]	Regulation Bid	Energy Bid	Hourly LMP	Lost Opportunity Cost
Gen Comp 1 – Unit1	10	$2	$10	$60	$50
Gen Comp 1 – Unit2	10	$4	$25	$60	$35
Gen Comp 1 – Unit3	8	$6	$40	$60	$20
Gen Comp 1 – Unit4	5	$6	$60	$60	$0
Gen Comp 2 – Unit1	15	$8	$15	$60	$45
Gen Comp 2 – Unit2	4	$5	$20	$60	$40
Gen Comp 2 – Unit3	3	$10	$50	$60	$10

The ISO/RTO will rank all available units in ascending merit order and will clear the market to meet 25 MW regulation requirements with minimum regulation production cost (Exhibit 2).

Exhibit 2 Ascending merit order of total regulation cost

Gen Company	Regulation Capability [MW]	Total Regulation Cost
Gen Comp 1 – Unit4	5	$6
Gen Comp 2 – Unit3	3	$20
Gen Comp 1 – Unit3	8	$26
Gen Comp 1 – Unit2	10	**$39**
Gen Comp 2 – Unit2	4	$45
Gen Comp 1 – Unit1	10	$52
Gen Comp 2 – Unit1	15	$53

For the particular hour, the market clearing price will be set to $39/MWh and the four first units (Gen Company 1 - Units 2-4 and Gen Company 2 - Unit 3) will be selected to provide the regulation service and will be paid according their regulation capability.

Some ISOs/RTOs, such as California ISO and Electric Reliability Council of Texas (ERCOT), distinguish between two regulation services: regulation up and regulation down. Regulation up means that the generating units will increase their operating levels and regulation down means that the generating units will decrease their operating levels, when an automatic generation control signal is received from the operator. The generating units will be paid according to the service they provide.

Operating Reserve

Reserve capacity is capacity above the forecasted demand in an area that is required for reliability purposes. The system has to have enough reserve capacity to overcome a single contingency such as loss of the largest generation unit or the most critical transmission line. The reserve capacity is provided by generation or load reduction in the event of a system contingency. The operating[6] reserve can be either 10-minute or 30-minute spinning or non-spinning reserve. Exhibit 3 illustrates different types of operating reserve and their providers.

Exhibit 3 Types of operating reserve

Type of operating reserve	Providers
10-minute spinning reserve	Partially loaded on-line generation units that are up and running and are synchronized to the grid. These units can change their output level within 10 minutes
10-minute non-spinning reserves	Off-line generation units that can be started, synchronized to the grid and change their output level within 10 minutes, and load that can be interrupted
30-minute (spinning) reserves	Generation units that are up and running and are synchronized to the grid These units can change their output level within 30 minutes.
30-minute (non-spinning) reserves	Generation units that can be started, synchronized to the grid and change their output level within 30 minutes, and interruptible load

Operating reserve requirements are determined by an ISO/RTO. For example, NYISO's total operating reserve requirement is equal to one and a half times the single largest contingency in the system.[7] NYISO will require 1,800 MW of the operating reserve if the size of the largest contingency is 1,200 MW. ISO NE calculates 10-minute operating reserve requirements as 100 percent of the single largest contingency in the system (50 percent should be provided by 10-minute spinning reserve and 50 percent should be provided with 10-minute non-spinning reserve) and 30-minutes requirements as 50 percent of the second contingency.[8] In winter 2012/2013, ISO NE required 820 MW of 10-minute spinning reserve, 820 MW of 10-minute non-spinning reserve, and 775 MW of 30-minute reserve.

The operating reserve market can be a real-time or a forward market. In a real-time operating reserve market, a market clearing price for the operating reserve is determined simultaneously with the energy market clearing price. Generating units submit availability and price bids to an energy market. The ISO/RTO collects the bids and takes into consideration LOC for generating units, if applicable, by adding LOC to the generators' bids. Similarly as in a regulation market, the LOC is calculated as a difference between the LMP and the generation energy bid. The lost opportunity cost is included to consider potential loss of profit to the generating units as a result of producing reserve rather than using the same power amount to provide energy. The ISO/RTO will use the least-cost method for meeting energy demand while maintaining system reliability to clear the energy and reserve market simultaneously. This approach provides the optimal point for generation revenue. In a forward-operating reserve market, a market clearing price is determined a few times per year. Generating units will submit availability and price bids to the forward reserve market. The ISO/RTO will collect the bids and clear the market based on

[6] The operating reserve should be distinguished from a planning reserve. The planning reserve is used for long-term planning and represents additional capacity that will provide reliable power to the system. Each reliability assessment area may have its own specific margin level based on load, generation, and transmission characteristics. The North American Electric Reliability Corporation (NERC) will assign the planning reserve requirement to a reliability assessment area if the reliability assessment area does not provide the planning reserve requirement to NERC. NERC's planning reserve requirement is 15 percent of the forecasted annual peak demand for thermal systems and 10 percent of the forecasted annual peak demand for hydro systems.

[7] NYISO. (2013). *NYISO Auxiliary Market Operations – Version 3.26*. Retrieved on April 15, 2013, from http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/ancserv.pdf

[8] ISO NE. (2012). *Introduction to Wholesale Electricity Markets (WEM 101) – Reserve Market Overview.* Retrieved on January 15, 2013, from http://www.iso-ne.com/support/training/courses/wem101/18_reserve_market_overview.pdf

reserve requirements using an auction mechanism. A forward capacity market is established for off-line reserve that will be called on in a case of a contingency event or during peak hours. The forward capacity market usually provides revenue to peaking power plants that operate infrequently.

The operating reserve requirement is locational, meaning that each area inside an ISO/RTO has to have the required operating reserve resources available to provide the required level of reliability.

Reactive Supply and Voltage Control

A reactive supply and voltage control service is a cost-based service. It ensures sufficient reactive power to maintain desired voltage level in the system. Reactive power is measured in volt-ampere reactive (VAR) and it is used to maintain voltage in the system. If the system does not provide enough reactive power, it could lead to voltage collapse and blackout events. Lack of reactive power compensation caused the Northeast power system protection to trip, and that brought the system down in August 2003.

Voltage support service is provided by on-line generators, other equipment such as synchronous condensers or capacitors, and non-generation voltage support resources that have the ability to produce or consume reactive power. Generation units that are responsible to provide voltage and reactive power support must have an automatic voltage regulator.

Reactive supply and voltage control suppliers receive monthly payments for the service. In addition, they will receive a loss-of-opportunity cost payment if they are dispatched lower than their economic set-point. Loss-of-opportunity cost is payment to generators that had to decrease real power output to provide more reactive power and voltage support service.

Black Start Service

A black start service is payable to generators capable of starting without an outside electric supply. These units are usually combustion turbines or hydro units that have a strategic location. Generators that provide black start service participate in a system restoration if a partial or a complete system blackout occurs, by providing start-up power to non-black start units.

The black start annual service rate is calculated based on annual capital, operation and maintenance costs to provide the service, and annual restoration plan training cost. Units are paid whether the black start service is utilized or not.