NATIONAL ENERGY TECHNOLOGY LABORATORY

# Power Market Primers

April 23, 2013

**DOE/NETL-2013/1617**

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# Disclaimer

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# Table of Contents

# Exhibits

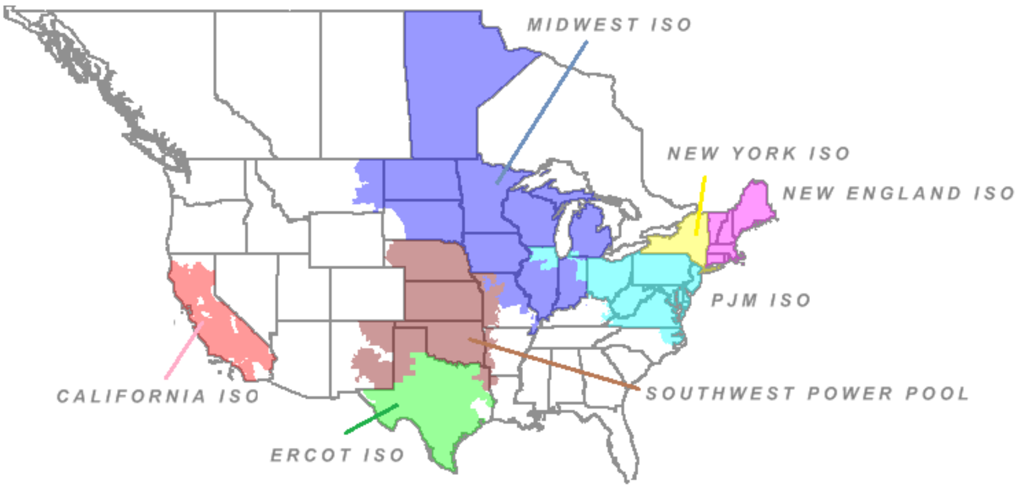
# Acronyms and Abbreviations

| | |
|---|---|
| AVR | Automatic voltage regulator |
| CAISO | California independent system operator |
| CONE | Cost of a new entry |
| CP | Capacity price |
| CQ | Capacity quantity |
| CRR | Congestion revenue right |
| DAM | Day-ahead market |
| EIS | Energy imbalance service |
| ERCOT | Electric reliability council of Texas |
| FCM | Forward capacity market |
| FERC | Federal Energy Regulatory Commission |
| FTR | Financial transmission rights |
| GWh | Gigawatt-hour |
| Hz | Hertz |
| ICAP | Installed capacity |
| ICR | Installed capacity requirement |
| ICT | Independent coordinator of transmission |
| IE | Imbalance energy |
| IPP | Independent power producer |
| ISO | Independent system operator |
| ISO-NE | Independent system operator of New England |
| kV | Kilovolt |
| kW | Kilowatt |
| kWh | Kilowatt-hour |
| LBMP | Locational based marginal pricing |
| LIP | Locational imbalance price |
| LMP | Locational marginal prices |
| LSE | Load serving entities |
| MCP | Market clearing price |
| MCQ | Market clearing quantity |
| MISO | Midwest independent system operator |
| MVA | Mega-volt-ampere |
| MVAr | Mega-volt-ampere reactive |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NERC | North American Electric Reliability Corporation |
| NETL | National Energy Technology Laboratory |
| NYISO | New York independent system operator |
| OASIS | Open access same-time information system |
| OOMC | Out-of merit commitment |
| OOMC | Out-of-merit capacity |
| PJM | PJM Interconnection, L.L.C. |
| PMA | Power marketing administration |
| PSC | Public service commission |
| PUC | Public utility commission |
| REP | Retail electric provider |
| RPM | Reliability pricing model |
| RPS | Renewable portfolio standards |
| RTO | Regional transmission organization |
| SPP | Southwest Power Pool |
| TCC | Transmission congestion contracts |
| VAr | Volt-ampere reactive |
| VCA | Voluntary capacity auction |
| VRR | Variable resource requirement |
| W | Watt |
| Wh | Watt-hour |

# 1 ISO/RTO Primers Overview

National Energy Technology Laboratory (NETL) has developed a series of primers on Independent System Operators (ISO) and Regional Transmission Organizations (RTO). The primers primarily explore the history, workings, and types of electricity markets comprising the seven regional transmission organizations in the U.S. (Exhibit 1-1).

**Exhibit 1-1 North American regional transmission organizations**




*Map created by NETL. Source: ABB Velocity Suite*[1]

The primer series includes sixteen documents. A general introduction to ISOs/RTOs is given in *Regional Transmission Organizations and Independent System Operators*. Specific details about the seven existing ISOs/RTOs in the U.S. are given in seven additional primers:

- *California Independent System Operator*
- *ERCOT Independent System Operator*
- *ISO New England Regional Transmission Operator*
- *MISO Regional Transmission Operator*
- *New York ISO Regional Transmission Operator*
- *PJM Regional Transmission Organization*
- *Southwest Power Pool, Inc.*

These primers provide a history of the ISOs/RTOs, short explanations of products and services (different types of electricity markets) offered by the ISOs/RTOs, and the ISO's/RTO's generation mix. Readers who are not familiar with the different types of markets and their mechanisms can find basic information in six additional primers titled:

- *Ancillary Services*
- *Capacity Market*

[1] ABB Velocity Suite. (2012). *Intelligent Map – US RTO Regions*. Retrieved on November 29, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx

- *Comparison of Different ISO/RTO Capacity Market Structures*
- *Energy Market*
- *Financial Transmission Rights*
- *Power Markets*

Additionally, the primer *North American Electric Reliability Corporation (NERC)* introduces the electric reliability organization, which is responsible for reliability of the bulk power system.

All the primers are very short and concise documents. They are accompanied by a *Glossary for Power Market Primers* in which many of the technical terms used in these primers are defined.

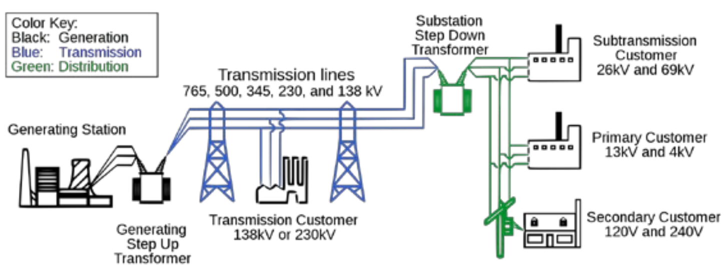
# 2 Power Markets

## 2.1 History of Power Markets

The U.S. power markets are extremely complex, not only in their technical dimensions but in their business structures. Markets operate with both public and private ownership, in both regulated and deregulated environments,[2] and under both federal and state regulatory control. In addition, electricity markets create contracts with a flow of obligations for power delivery that do not match the flow of electrons. The result is a physical infrastructure with varying contractual structures, and complex, occasionally-conflicting incentives.

In an industry that was served by highly-regulated, regional or local monopoly utilities, the electric grid started simply as a delivery device for electric service, owned and operated by vertically-integrated utilities. These utilities managed and invested in their own local generation, transmission, and distribution infrastructure, with the changing needs of their service area and with the blessing of state regulators. Eventually utilities began connecting their local transmission grids to neighboring systems, primarily to improve reliability, but also to reduce redundant generation. While state regulators oversaw the retail rate setting and utility investment decisions, the federal government, through the Federal Energy Regulatory Commission (FERC), regulated transactions across state lines—namely, wholesale power purchases and transmission investments. Typically, a retail electricity rate is composed of three charges: generation, transmission, and distribution.[3] The supply charge accounts for the largest percent of the total rate while the transmission charge accounts for the smallest percent (e.g., a Duquesne Light residential consumer in 2012 paid 7.86 cents/kWh for supply, 1.46 cents/kWh for transmission, and 4.85 cents/kWh for distribution).[4]

**Exhibit 2-1 Generation, transmission, and distribution**




*Source: U.S.-Canada Power System Outage Task Force* [5]

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

[3] United States Government Accountability Office. (2008). *Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance.* Retrieved on September 16, 2011, from http://www.gao.gov/products/GAO-08-987

[4] Duquesne Light Company. (2012). *Electricity bill – rate: RS – Residential Service*. Retrieved on June 14, 2012, from a customer bill.

[5] U.S. – Canada Power System Outage Task Force. (2004). *Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations*, p. 5. Retrieved on September 16, 2011, from http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf

**Exhibit 2-2 Generation, transmission, and distribution regulation and ownership**

| | Generation | Transmission | Distribution |
|---|---|---|---|
| **Regulator** | ▸ State Public Utility Commissions (PUC) | ▸ FERC<br>▸ State PUCs<br>▸ North American Electric Reliability Corporation (NERC) (sets reliability standards) | ▸ State PUCs |
| **Owner** | ▸ Investor-owned utilities<br>▸ Publicly-owned utility<br>▸ Independent power producers<br>▸ Federal power marketing authorities | ▸ Investor-owned utilities<br>▸ Publicly-owned utility<br>▸ Federal power marketing authorities<br>▸ Independent transmission companies | ▸ Investor-owned utilities<br>▸ Publicly-owned utility<br>▸ Federal power marketing authorities |

*Source: U.S.-Canada Power System Outage Task Force* [5]

**Exhibit 2-3 Power market regulators**

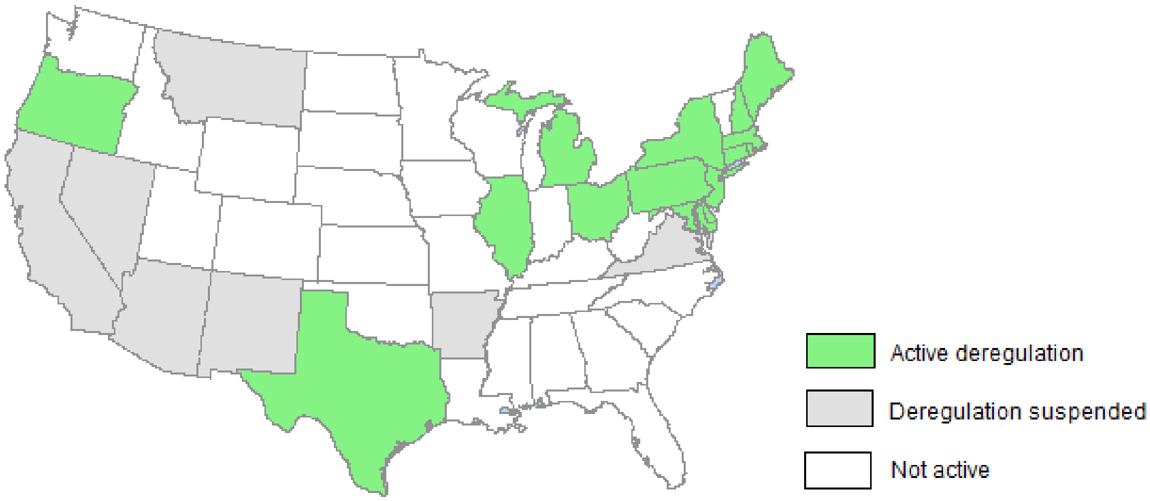
| | |
|---|---|
| **FERC** | ▸ Federal Energy Regulatory Commission (FERC) – an independent commission with regulatory power over issues of interstate commerce of electricity, natural gas, and oil pipelines<br>▸ Monitors and investigates energy markets, establishes transmission tariffs, and maintains the authority to impose civil penalties on energy organizations or individuals who violate FERC rules |
| **NERC** | ▸ North American Electric Reliability Corporation (NERC) – a non-profit organization formed in 1968 to ensure adequate power supply for electric utility systems in North America<br>▸ NERC is designated by FERC as an electric reliability organization<br>▸ NERC primarily works with industry to develop standards for power system operation monitoring and enforcing compliance with those standards, and assessing resource adequacy[6] |
| **State PUC/PSC** | ▸ Public Utility Commissions (PUC)/Public Service Commissions (PSC) – state-by-state regulatory bodies with responsibility for overseeing utility activity within the state<br>▸ Primary activities include reviewing proposed utility investments and establishing allowable rates for utilities to charge ratepayers |

In the early 1990s, the federal government, along with several states, began to take a series of steps aimed at restructuring the electricity industry, particularly targeted at increasing competition in wholesale power markets. In order to facilitate competition, FERC issued a variety of orders, starting in April 1996 with Order 888[7], which required that transmission owners under FERC jurisdiction (mainly large investor-owned utilities) allow other entities to access the transmission owners' transmission lines at the same prices and with the same terms and conditions that they applied to themselves. Deregulation of power markets has been implemented in several states, while other states have suspended deregulation due to a variety of factors.

[6] More details about NERC can be found in *North American Electric Reliability Corporation* primer.

[7] Federal Energy Regulatory Commission. (1996). Order No. 888: Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Retrieved on September 16, 2011, from http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp

**Exhibit 2-4 U.S. deregulation status**




*Map created by NETL. Source: ABB Velocity Suite* [8]

## 2.2 Regulated Markets

Typically in both regulated and deregulated markets the retail rate of electricity is viewed in three components—generation, transmission, and distribution. In regulated states all these rates continue to be monitored and controlled by state PUCs/PSCs. Utilities are allowed to recover the costs of service along with an approved return on investment, which is typically presented as a percentage of the value of assets in a utility's "rate base." The components of a utility's rate base are dominated by the annual cost of property, plant, and equipment, but can also include other expenses at the discretion of each individual state's PUC/PSC. A utility's largest operating expense—fuel—is typically treated as a pass-through to consumers without an additional return on investment to the utility. PUCs/PSCs are tasked with ensuring the utilities operating in their state are able to provide reliable energy services to the state's population at the lowest possible cost. However, the state PUCs/PSCs must also allow utilities to follow legislative requirements, such as meeting Renewable Portfolio Standards, which could cause a utility to procure power at a cost higher than the lowest technically possible cost (i.e., by using different energy sources).

## 2.3 Deregulated Markets

In deregulated states, distribution rates are still regulated by state PUCs/PSCs, and transmission rates are regulated by FERC, but generation rates and ancillary services markets are determined by competitive markets. The wholesale markets continue to be monitored by FERC to ensure that they are competitive markets. Deregulated states typically have markets for wholesale power, ancillary services, and capacity services. In addition, Regional Transmission Organizations (RTO) or Independent System Operators (ISO), which maintain grid operations,

[8] ABB Velocity Suite. (2012). Intelligent Map - US Electric Deregulation. Retrieved on June 14, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx

typically facilitate other markets or provide other services such as transmission congestion hedging, integration studies, and functioning as a contract clearinghouse.

Wholesale power markets consist of transactions of large amounts of power from a generator to a supplier, such as a load serving entity (LSE). The LSE is typically a business, such as a generator, broker, marketer, aggregator or utility that sells electricity to consumers using the transmission or distribution facilities of an electric company, and pays a tariff to the distribution company. Wholesale market prices are set on a local ("node") basis to account for the physical restrictions of transmission capacity and generation asset access. Wholesale markets are typically managed on a day-ahead, hour-ahead, and spot basis such that generators can plan their operations and consumers can count on adequate supply. Additionally, generators, LSEs, or large retail users can enter into bilateral contracts —buying/selling power between two parties—without going through the wholesale market; however, the grid operator (typically an RTO/ISO) must be aware of the contract in order to maintain reliability and order generators dispatch.

Reliability is ensured by the market (and facilitated by grid operators) via forward capacity markets and services markets. Forward capacity markets provide payment to generators for having generating capacity available in sufficient quantity to provide a reserve margin above the anticipated demand for a certain period. Forward capacity markets are typically for medium to long term, with generators providing capacity availability for three months to a year, up to three years in advance. Ancillary services markets are run on a shorter timeframe, with generators bidding capacity to provide availability for regulation support, operating reserve, or reactive power in order to maintain the minute-to-minute reliability of the grid.

***Ancillary services***

- **Frequency regulation support:** Generators that provide a short-term response capability (or demand response) used to balance short-term deviations between system load and generation
- **Operating reserve:** Generators and demand resources that are used to balance shorter-term deviations between system load and generation, correct-load forecasting errors, handle forced outages, and recover from a contingency
- **Reactive power**: Used to compensate for voltage drops, typically provided closer to the load than real power needs

Another key feature of deregulation is the ability for retail consumers to choose their supplier of electric services. Through FERC Order 888, transmission lines are required to be offered to the market at established tariffs; similarly, deregulation typically provides for distribution lines to be available to the market at established tariffs. Each of these elements is key to retail competition in that they allow third parties (i.e., parties other than the direct owner of the transmission or distribution line) to access the lines and provide electric service to consumers. Retail choice in an electric provider means that a consumer can sign a contract with a qualified third party electric service provider who could, in turn, contract with a generator (on a bilateral basis), self-generate, or purchase power in the wholesale market, and pay the necessary tariffs to the transmission and distribution owner. Third party electric service providers make money when they are able to sign contracts with retail consumers at higher prices per kWh than they must pay for transmission, distribution, and wholesale power, and often engage in energy trading or hedging activities.

While the markets have devised methods for writing contracts between generators, LSEs, and transmission owners, these contracts do not necessarily reflect the physical flow of electrons on the grid. Electrons flow along paths of least resistance, not as written in a contract. Contracts will, in part, reflect this reality, as RTOs/ISOs will account for the maximum transmission line capacity when administering contracts and will disallow contracts that exceed the physical limitations of the grid. However, other contracts—such as retail purchases of "green" power—are allowed despite the physical reality that once electrons enter the grid it is impossible to determine which electrons are delivered to a load. Contracts may be written as shown in Exhibit 2-5 depending on a variety of economic factors, including the marginal cost of production for each generator, the marginal price at each node, costs of congestion, and expected line losses. However, depending on the resistive properties of each node (including the distance from each generator to each node), the actual power flow may be different from the contract power flow.

**Exhibit 2-5 Simplified contract flow**

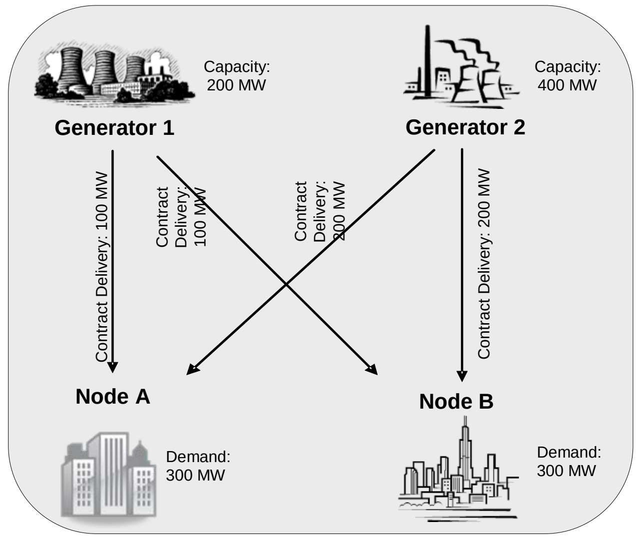



*Image created by NETL.*

RTOs and ISOs have the responsibility for maintaining the physical flow of power, but this is done on a day-to-day (and hour-to-hour) basis by providing dispatch signals to generators in the region. The RTO then administers the market by settling contracts between buyers and sellers of power based on the forward contracts that were previously executed or by the spot prices that existed when the RTO sent the dispatch signal. In the simplistic example above, the RTO would settle payments from the load center based on the contract flow, not on the expected physical flow.

Although the physical power flows and contractual agreements do not match, FERC and other market players have decided that this inconsistency is acceptable, and thus there are no adverse impacts on generators or LSEs for the mismatch. FERC recognized this difference in Order 888, which determined that contract flow was acceptable predominantly because going to a power flow-based contracting system would be too disruptive to the industry and thus would slow the move to more competitive wholesale power markets and hinder open access to transmission.

More details about different markets can be found in the primers *Energy Market*, *Ancillary Services* and *Capacity Market*. More details about different ISO/RTO can be found in the ISO/RTO primers *California Independent System Operator*, *ERCOT Independent System Operator*, *MISO Regional Transmission Organization*, *ISO New England Regional Transmission Organization*, *New York ISO Regional Transmission Organization*, *PJM Regional Transmission Organization* and *Southwest Power Pool, Inc.*

# 3 Energy Market

Electric energy[9] is "*the generation or use of electric power over a specified time, usually expressed in gigawatt-hours (GWh), megawatt-hours (MWh), or kilowatt-hours (kWh).*"[10] An electric energy market is a "*system for purchasing and selling electric energy using supply and demand to set the price*."[10] It is a part of an electricity market and is coordinated by an Independent System Operator (ISO) or a Regional Transmission Organization (RTO). The energy market is used in a restructured electric industry where the electric power generating facilities and services are separated from the power transmission and distribution lines and services to provide more energy-efficient energy production. In the restructured industry, generating companies are competing to sell the energy, allowing a consumer to choose his or her own electricity suppliers.

An energy market is different than any other economic market. First, electrical energy cannot be stored in large quantities. It must be produced in real-time to meet a constantly changing demand. Second, electric energy cannot be labeled or traced out to sources or sinks. Once energy is produced, whether by a coal power plant or a renewable power plant, it cannot be distinguished. Third, power flows cannot be controlled by contracts because power flows follow the laws of physics. These differences make an energy market very challenging to operate.

An energy market can have one of three architectures:

- Poolco model – a spot market where generating companies compete for the right to supply energy and consumers compete for the right to consume energy. In the poolco model, supply and consumption go directly to and from the grid, instead of to a specific consumer and from a specific generating company
- Bilateral contracts – trading contracts between a specific generating company (a seller) and a consumer (a buyer) without going through a spot market
- Hybrid model – a combination of the poolco model and the bilateral contracts

Today's markets are mostly hybrid models where an ISO/RTO is coordinating the spot market and is acting as a clearinghouse for the bilateral contracts.

## 3.1 Market Clearing

The energy market is a two-sided auction model. Generating companies submit bids and consumers submit offers to the ISO/RTO. The generating companies submit bids to supply a certain amount of electrical energy at a certain price, while the consumers submit offers to consume a certain amount of electrical energy at a certain price. The ISO/RTO aggregates the bids in a supply curve and the offers in a demand curve. The intersection of the aggregated demand and supply curves represents the market clearing price (MCP) and the market clearing quantity (MCQ). If the generating company's bid is less than the MCP, it will be accepted.

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

[10] ISO New England. (2012). *Glossary and Acronyms.* Retrieved on January 5, 2012, from http://www.iso-ne.com/support/training/glossary/index-p2.html

Conversely, if a consumer's offer is larger than the MCP, it will be accepted. The generating companies will be informed by the ISO/RTO how much they should generate; consumers will be informed how much they are allowed to draw from the grid. The market clearing mechanism can be illustrated using a simple example with two generating companies and two consumers.

**Example 1 – Market Clearing:** An ISO/RTO receives the bids and offers, for a particular hour, from two producers and two consumers as shown in Exhibit 3-1 and Exhibit 3-2, respectively. Gen Company 1 is willing to sell 200 MWh at $10/MWh, an additional 50 MWh at $25/MWh, an additional 50 MWh at $40/MWh, and an additional 50 MWh at $60/MWh. Gen Company 2 is willing to sell 150 MWh at $15/MWh, an additional 100 MWh at $20/MWh, and an additional 50 MWh at $50/MWh.

**Exhibit 3-1 Generating company bids**

| Gen Company 1 | |
|---|---|
| Price [$/MWh] | Quantity [MWh] |
| 10 | 200 |
| 25 | 50 |
| 40 | 50 |
| 60 | 50 |

| Gen Company 2 | |
|---|---|
| Price [$/MWh] | Quantity [MWh] |
| 15 | 150 |
| 20 | 100 |
| 50 | 50 |

Similarly, Consumer 1 is willing to buy 50 MWh at $60/MWh, an additional 50 MWh at $50/MWh, and an additional 100 MWh at $30/MWh. Consumer 2 is willing to buy 50 MWh at $80/MWh, an additional 75 MWh at $70/MWh, an additional 150 MWh at $40/MWh, and an additional 200 MWh at $20/MWh.

**Exhibit 3-2 Consumer offers**

| Consumer 1 | |
|---|---|
| Price [$/MWh] | Quantity [MWh] |
| 60 | 50 |
| 50 | 50 |
| 30 | 100 |

| Consumer 2 | |
|---|---|
| Price [$/MWh] | Quantity [MWh] |
| 80 | 50 |
| 70 | 75 |
| 40 | 150 |
| 20 | 200 |

In order to clear the market, the ISO/RTO determines the aggregated supply and demand curves by stacking up the bids and offers (Exhibit 3-3).

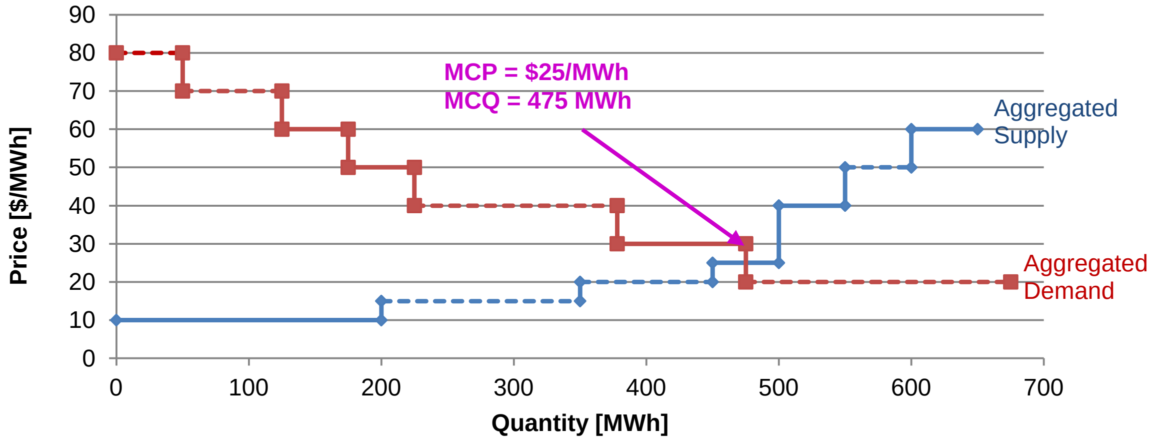
**Exhibit 3-3 Aggregated supply and demand curves**

| Aggregated Supply | | |
|---|---|---|
| Price [$/MWh] | Quantity [MWh] | Gen Company |
| 10 | 0-200 | 1 |
| 15 | 200-350 | 2 |
| 20 | 350-450 | 2 |
| 25 | 450-500 | 1 |
| 40 | 500-550 | 1 |
| 50 | 550-600 | 2 |
| 60 | 600-650 | 1 |

| Aggregated Demand | | |
|---|---|---|
| Price [$/MWh] | Quantity [MWh] | Consumer |
| 80 | 0-50 | 2 |
| 70 | 50-125 | 2 |
| 60 | 125-175 | 1 |
| 50 | 175-225 | 1 |
| 40 | 225-375 | 2 |
| 30 | 375-475 | 1 |
| 20 | 475-675 | 2 |

The supply and demand curves are depicted in Exhibit 3-4. The intersection of these two curves represents the MCP and the MCQ. All bids and offers shown to the left of the MCQ will be accepted.

**Exhibit 3-4 Market clearing price and quantity**




For the particular hour, the MCP will be set to $25/MWh and the total traded energy will be 475 MWh. All participants receive/pay the same MCP because the transmission network was not included in the analysis. Gen Company 1 will sell to the grid 225 MWh, with revenue of $5,625. Gen Company 2 will sell 250 MWh, with revenue of $6,250. Consumer 1 will draw from the grid 200 MWh, with an expense of $5,000. Consumer 2 will draw 275 MWh, with an expense of $6,875. The total revenue is equal to the total expenses, if the transmission network is not included in the analysis, or if there is no network congestion.

An ISO/RTO dispatches generators in a merit order, meaning that it starts from the least expensive units and moves up to more expensive units. However, sometimes this is not possible due to power delivery limitations or power constraints of the transmission system. In this case, more expensive generators that have no transmission system limits may be operated in place of the less expensive units. This is referred to as "out of merit dispatch."

## 3.2 Locational Marginal Price

Locational marginal price (LMP) is a pricing mechanism used by an ISO/RTO to price energy purchases and sales, to price transmission congestion cost, and to price the cost of energy losses. LMP is defined as a cost to serve the next MW of load at a specific location, using the lowest production cost of all available generators and with respect to all transmission limits.[11] LMP is

[11] New York ISO. (2011). *Glossary: Locational Marginal Price*. Retrieved on December 28, 2011, from http://www.nyiso.com/public/markets_operations/services/customer_support/glossary/index.jsp

based on actual (physical) energy flows within an ISO/RTO, not on contract paths. Example 2[12] is used to illustrate the LMP pricing mechanism.

**Example 2 – Locational Marginal Price:** An ISO/RTO receives the bids and offers, for a particular hour, from two producers and two consumers, shown in Exhibit 3-5. Gen Company 1 and Consumer 1 are located in Area 1, and Gen Company 2 and Consumer 2 are located in Area 2. Area 1 and Area 2 are connected with a transmission line with a power limit of 500 MW. Gen Company 1 is willing to sell 500 MWh at $25/MWh and Gen Company 2 is willing to sell 250 MWh at $35/MWh. Consumer 1 is willing to buy 200 MWh and Consumer 2 is willing to buy 275 MW, regardless of the electricity price. Using the same approach illustrated in Example 1, the ISO/RTO set the MCP to $25/MWh and energy traded at 475 MWh.

**Exhibit 3-5 Simple electric energy system without congestion**

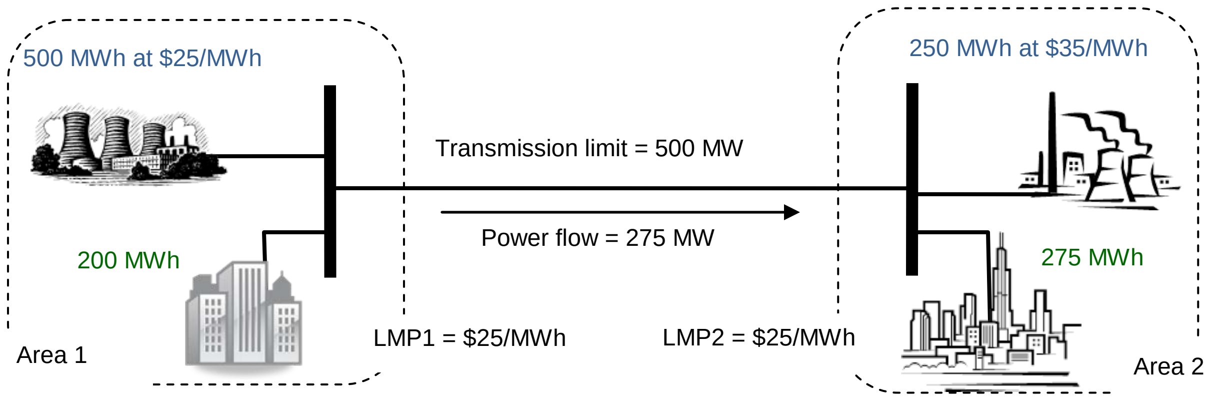



*Image created by NETL.*

Gen Company 1 meets all demand and sells to the grid 475 MWh at $25/MWh. Consumer 1 draws 200 MWh from the grid and pays $25/MWh, while Consumer 2 draws 275 MWh and pays $25/MWh. Power flow over the transmission line is 275 MW from Area 1 to Area 2. The generating companies' total revenues ($11,875) are equal to the total consumers' payments ($11,875) because there is no congestion in the system. The ISO/RTO used the cheapest generation company to provide energy for both demands.

Assuming the transmission line has a power limit of 250 MW (Exhibit 3-6), the ISO/RTO will not be able to schedule the cheapest resources first. The maximum power that can be transferred from Area 1 to Area 2 is constrained to 250 MW. Because of the fully-loaded transmission line, an additional MW of load in Area 1 is provided by Gen Company 1 at $25/MWh and an additional MW of load in Area 2 is provided by Gen Company 2 at $35/MWh. The marginal production cost is therefore different in each area. Because the marginal price depends on the

[12] Example 1 may also be used to illustrate LMP; however, due to the complexity to obtain the optimal solution for a transmission congestion problem, Example 1 is replaced with a simpler example that illustrates LMP more intuitively. Solving a transmission congestion problem in Example 1 requires using an optimization solver and is beyond the scope of this primer.

location where the energy is produced or consumed, it is called “locational marginal price.” LMP for Area 1 is set to \$25/MWh and LMP for Area 2 is set to \$35/MWh.

**Exhibit 3-6 Simple electric energy system with congestion**

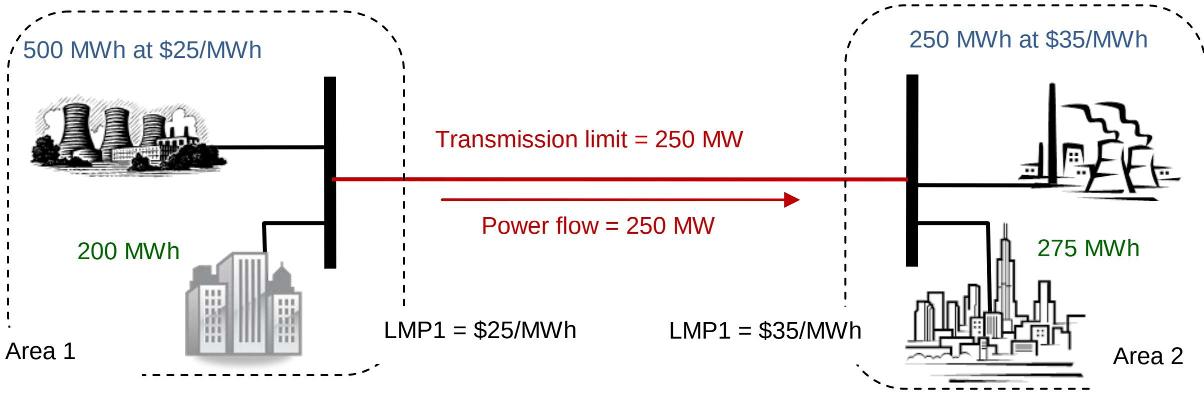



*Image created by NETL.*

Gen Company 1 produces 450 MWh and is paid \$25/MWh. Gen Company 2 produces 25 MW and is paid \$35/MWh. Consumer 1 buys 200 MWh at \$25/MWh. If this was a bilateral market, Consumer 2 would buy 250 MWh at \$25/MWh and 25 MWh at \$35/MWh; however, Consumer 2 buys all 275MWh at \$35/MWh because Consumer 2 is in a pool market. The total generators' revenue (\$12,125) is not equal to the total consumers' payment (\$14,625), because the congested transmission limited the use of cheaper generating resources. In this case the consumers pay more than the generating units receive. The excess is the congestion cost. The congestion costs are collected by the market operator and are given to holders of a financial transmission right (FTR) as a compensation for transmission congestion charges that arise when the transmission grid is congested. More details about FTR can be found in the *Financial Transmission Rights* primer.

## 3.3 Congestion Cost (Congestion Surplus)

The congestion costs are approximately[13] equal to a difference in LMP prices across the transmission line multiplied by the transferred amount. In Example 2, the congestion cost is equal to \$2,500.

## 3.4 Time Frames of Energy Markets

Different ISOs/RTOs in the United States coordinate energy markets over different time frames. Energy markets can be day-ahead, hour-ahead, or real-time, depending on when the operating hours occur. The illustrated procedure for the market clearing and locational price is applicable to each market. However, some markets have additional decisions that should be made and can influence the generation dispatch. As an example, in a day-ahead market, generating units are

[13] Exact calculation of the transmission cost is a more complex problem and it requires usage of optimization tools.

dispatched based on several factors including marginal fuel cost and technical constraints, such as start-up and shut-down costs, how fast the unit can go from zero to maximum power output, and the water level for hydro units.

Exhibit 3-7 summarizes the existing energy markets in the U.S. by ISO/RTO.

**Exhibit 3-7 Energy markets in the U.S.**

| ISO/RTO | Energy market | | |
|---|---|---|---|
| | Day-ahead | Hour-ahead | Real-time |
| California ISO | Yes | Yes | Yes |
| ERCOT | Yes | No | Yes |
| Midwest ISO | Yes | No | Yes |
| ISO New England | Yes | No | Yes |
| New York ISO | Yes | No | Yes |
| PJM | Yes | Yes | Yes |
| Southwest Power Pool | In 2014 | In 2014 | Yes |

More details about the different markets can be found in the ISO/RTO primers *California Independent System Operator*, *ERCOT Independent System Operator*, *MISO Regional Transmission Organization*, *ISO New England Regional Transmission Organization*, *New York ISO Regional Transmission Organization*, *PJM Regional Transmission Organization* and *Southwest Power Pool, Inc*.

# 4 Capacity Market

Capacity is "*the rated and continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA), of generation, transmission, or other electrical equipment*."[14] A capacity market, when it exists, is a part of the electricity market and is coordinated by an Independent System Operator (ISO) or a Regional Transmission Organization (RTO).[15] A capacity market is designed to provide long-term pricing signals to attract needed new investments and to maintain existing resources required to ensure resource adequacy and the reliability of an ISO/RTO region. The capacity market is used to commit capacity resources required to reliably meet forecasted demand and to provide sufficient reserve margins. It can be mandatory or voluntary with a timeframe from a few months to three years in advance (forward market). The capacity market usually has a few additional incremental auctions that are held closer to the capacity commitment period, to adjust the capacity obligation due to a load forecast increase or decrease. The capacity markets developed by different ISOs/RTOs differ with respect to:

- Demand curve (e.g., vertical versus downward-sloping)
- Auction mechanism (e.g., optimization or descending clock auction)
- Length of the forward commitment period (e.g., a few months to a few years)

## 4.1 Market Clearing

The capacity market uses a capacity auction mechanism to clear the market by reconciling an offer-based supply curve with a demand curve. The auction mechanism can be an optimization or descending clock auction. In both cases, the ISO/RTO defines a price cap. The price cap is imposed to avoid unreasonably large capacity prices.

***The supply curve*** is designed by sequentially aggregating offers submitted by capacity resource owners. The capacity owners submit offers to provide a certain amount of capacity at a certain price. An ISO/RTO aggregates the offers in a capacity "offer curve." Depending on the ISO/RTO, the capacity resources may consist of:

- Generator resources (existing and planned)
- Demand resources
- Energy efficiency resources
- Qualifying transmission upgrades
- Interruptible load for reliability resources

***The demand curve can be vertical or downward-sloping.*** The vertical demand curve is the simplest way to specify a capacity requirement (Exhibit 4-1). For example, the vertical demand curve in ISO New England is determined by using an installed capacity requirement (ICR). The ICR is based on a probability that the customers will be disconnected due to resource deficiency

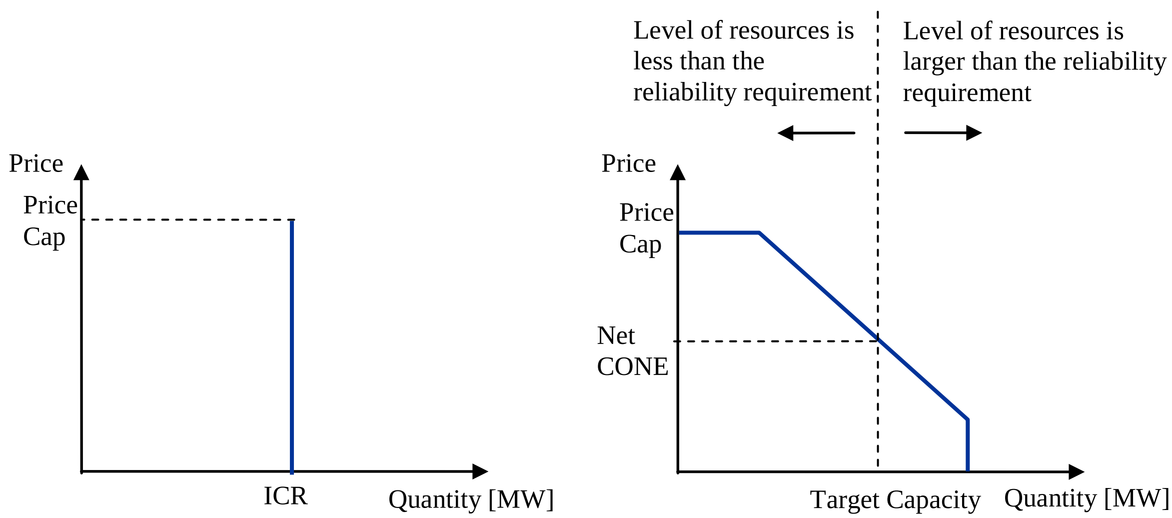
[14] ISO New England. (2011). *Glossary & Acronyms*. Retrieved on January 10, 2011, from http://www.iso-ne.com/support/training/glossary/index-p1.html

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

no more than once in ten years. The ICR is usually calculated as a sum of a forecasted demand and a planning reserve margin, that is developed based on the required reliability level (once in ten years loss of supply).

The downward-sloping demand curve is based on a variable resource requirement concept. The purpose of the resource requirement concept is to prevent overbuilding and to provide revenue to a resource when the reliability level is lower than required. The demand curve is defined by a family of price/quantity points where each level of the resources is correlated with a specified price (Exhibit 4-1). The demand prices are a function of the net cost of a new entry (CONE), and the demand quantities are a function of the reliability requirement. The net CONE is defined as a difference between investment costs and estimated variable profits over the life of the project expressed in $/MW-day or $/kW-month. The demand price is higher than the net CONE if the level of the resources is less than the reliability requirement. The demand price is lower than the net CONE if the level of the resources is larger than the reliability requirement. The reliability requirement is a function of regional and locational target reserve margins.

**Exhibit 4-1 Demand curve**



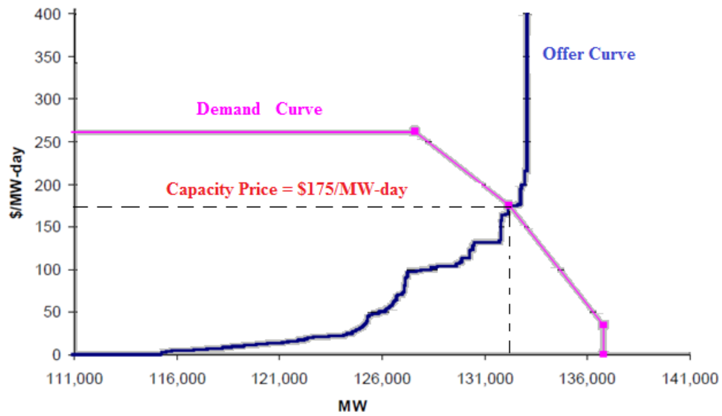

a) Vertical Demand Curve

b) Downward-Sloping Demand Curve

*Images created by NETL.*

***An auction mechanism that is used to clear a capacity market can be an optimization or a descending clock auction.*** The optimization mechanism is based on determining a capacity requirement that provides the required reliability level at the minimum cost. The resource owners submit offers to provide capacity at a certain price while the load-serving entities (LSE) submit forecasted capacity requirements. The ISO/RTO aggregates the capacity offers in a capacity offer curve and uses the LSE's capacity requirements to determine a demand curve. The intersection of the capacity offer curve and the demand curve represents the capacity market price (CP) and the capacity quantity (CQ) (Exhibit 4-2). If the resource owner's offer is smaller than the CP price, it will be accepted and the capacity resource owner will be obligated to provide the submitted level of capacity during the operating year. If the resource owner's offer is higher than the CP price, it will not be accepted and the capacity resource owner will not be obligated to provide the submitted level of capacity during the operating year.

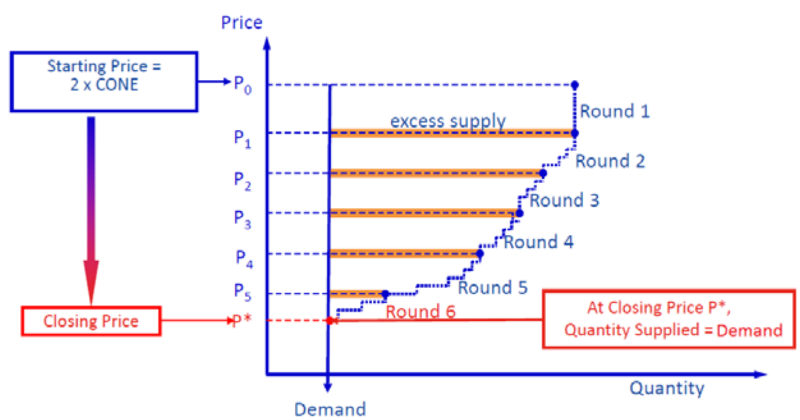
**Exhibit 4-2 Illustration of an ISO/RTO capacity market clearing results**




(*Adapted with permission from PJM.*[16])

The descending clock auction is a multi-round process that is used in ISO New England. The process is based on reducing the capacity market price until the quantity of available capacity resources matches the fixed capacity demand. The basic concept of the descending clock auction is that more than enough capacity resources will submit offers if the market capacity price is high. Some capacity resources will remove themselves from the auction as the capacity market price drops (Exhibit 4-3).

**Exhibit 4-3 Descending clock auction mechanics**




(*Adapted with permission from ISO New England.*[17])

[16] PJM. (2013). *2010/2011 RPM Base Residual Auction Results*. Retrieved on January 15, 2013, from http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/20080201-2010-2011-bra-report.ashx

[17] ISO NE. (2013). *Introduction to Wholesale Electricity Market (WEM 101) – Overview of Forward Capacity Market (FCM)*. Retrieved on January 15, 2013, from http://www.iso-ne.com/support/training/courses/wem101/21_overview_of_fcm.pdf

In each round the auctioneer announces a start of round price, the end of round price, and excess supply at the end of the prior round, and participants submit offers at prices within the announced price range. The descending clock clearing mechanism can be illustrated using a simple example.

**Example 1 – A Descending Clock Auction** An ISO NE auctioneer conducts a descending clock auction to provide enough capacity resources to meet the future demand. The auctioneer forecasts that the installed capacity requirement is 25,000 MW, existing capability is 23,000 MW, participating new capacity is 5,000 MW and CONE = $5/kW-month. The auctioneer announced $10/kW-month as the start of round 1 price and $8/kW-month as the end of the round price. The resource owners offer all available capacity (28,000 MW) and the auctioneer calculates 3,000 MW of excess capacity. The auctioneer then announces $7.99/kW-month as the start price and $6/kW-month as the end price for round 2. Some owners decide to remove their offers from the auction because the new price is not profitable for them. The new capacity offer is 26,000 MW. The auctioneer determines that there is still 1,000 MW of the excess capacity. New start and end of the round 3 prices are $5.99/kW-month and $4.00/kW-month, respectively. The resource offer is 25,500 MW, which leads to -500 MW of excess capacity. The auctioneer stops the auction and determines the closing price as the intersection between the demand curve and offer curve. The closing price will be between 5.99/kW-month and $4.00/kW-month.

## 4.2 Zonal or Locational Capacity Price

The forward-capacity auction begins with a single system-wide price. However, making sure that there is enough capacity in the ISO/RTO area does not mean that capacity is deliverable to specific locations. ISOs/RTOs introduce zonal or locational capacity prices to overcome this obstacle.

An ISO/RTO determines the locational capacity price using a similar approach as described above. The only difference is that it will use zonal/local demand, capacity resources, and CONE. A zonal capacity price will be different than the region capacity price if the location is import-constrained. The difference between these two prices should attract capacity resources in locations where they are needed the most. The New York ISO was the first market to introduce a locational capacity market. It has three different zones: New York City, Long Island, and New York Control Area. For each of the zones, the New York ISO determines different net CONE values that are used to develop a local demand curve and to set the locational capacity price (Exhibit 4-4).

**Exhibit 4-4 CONE – New York ISO (2010/2011 capability period)**

| Zone | New York City | Long Island | New York Control Area |
|---|---|---|---|
| CONE [$/kW-year] | 219 | 194 | 107 |
| Capacity price [$/kW-month] | 9.22 | 1.67 | 1.47 |
| Capacity price [$/kW-year] | 110.64 | 20.04 | 17.64 |

*Data Source: New York ISO - 2010 State of the Market* [18]

[18] Potomac Economics. (2011). *New York ISO - 2010 State of the Market, July 2011*. Retrieved on January 10, 2011, from http://www.potomaceconomics.com/markets_monitored/new_york_iso

Similarly, PJM has defined five zones with different CONE prices. ISO New England was directed by the Federal Energy Regulatory Commission to model eight capacity zones corresponding to its eight load zones.

## 4.3 Types of Capacity Markets in the U.S.

Different ISOs/RTOs in the U.S. coordinate capacity markets over different time frames. Capacity markets can be a few months to a few years in advance. Each capacity market has its own characteristics (these were not explained in this primer because some of the capacity rules in different ISOs/RTOs are still changing). More details about the capacity markets in different ISOs/RTOs can be found in the primer *Comparison of Different ISO/RTO Capacity Market Structures.*

Exhibit 4-5 summarizes the existing U. S. energy markets by ISO/RTO.

**Exhibit 4-5 Simple electric energy market**

| ISO/RTO | Capacity Market | |
|---|---|---|
| | Forward (years) | Forward (months) |
| California ISO | No | No |
| ERCOT | No | No |
| Midwest ISO (voluntary) | No | Yes |
| ISO New England | Yes | No |
| New York ISO | No | Yes |
| PJM | Yes | No |
| Southwest Power Pool | No | No |

More details about the different markets can be found in the primers *Energy Market, Ancillary Services* and *Capacity Market*. More details about the different ISOs/RTOs can be found in the ISO/RTO primers *California Independent System Operator*, *ERCOT Independent System Operator*, *MISO Regional Transmission Organization*, *ISO New England Regional Transmission Organization*, *New York ISO Regional Transmission Organization*, *PJM Regional Transmission Organization* and *Southwest Power Pool, Inc.*

# 5 Comparisons of Different ISO/RTO Capacity Market Structures

Capacity markets[19] are designed to provide long-term pricing signals to attract new investments. Capacity markets also maintain existing resources required to ensure resource adequacy and the reliability of an Independent System Operator (ISO)/Regional Transmission Organization (RTO) region. The capacity market's main tasks are to commit capacity resources required to reliably meet forecasted demand, to provide sufficient reserve margins, and to provide fixed-cost recovery (e.g., capital cost, fixed operation and maintenance costs) for existing and new generators.

## 5.1 Overview of RTO and ISO Capacity Markets

In the U.S., four ISOs/RTOs offer a capacity market:

1. PJM's Interconnection, L.L.C. – Reliability Pricing Model (RPM)
2. New York ISO – Installed Capacity (ICAP) market
3. ISO New England – Forward Capacity Market (FCM)
4. Midwest ISO – Voluntary Capacity Auction (VCA)

## 5.2 Reliability Pricing Model (RPM): PJM

The RPM is a three-year forward capacity market model. The RPM was designed to provide long-term pricing signals to attract necessary investments required to ensure the reliability of the PJM region. The RPM is used to commit capacity resources required to reliably meet forecasted demand on an annual basis, to provide sufficient reserve margins, and to help plan transmission upgrades. The RPM uses an annual capacity auction mechanism to clear the market by reconciling an offer-based supply curve with a downward-sloping demand curve.

The supply curve is designed by sequentially aggregating offers submitted by capacity resource owners. In the RPM, the capacity resources consist of:

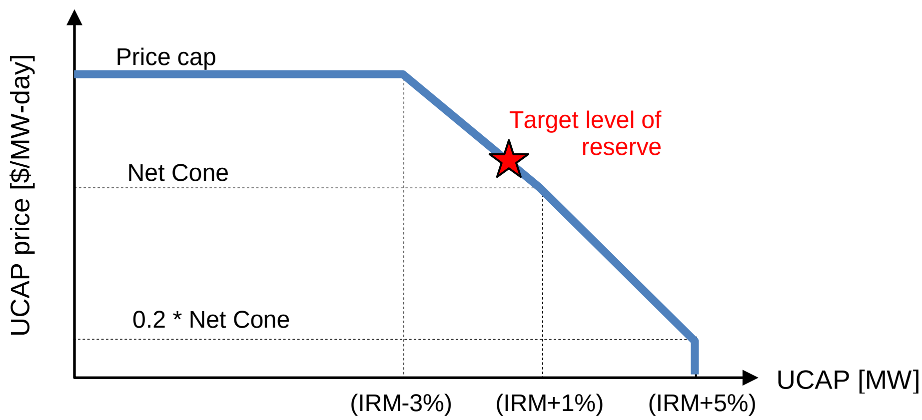
- Generator resources (existing and planned)
- Demand resources
- Energy efficiency resources
- Qualifying transmission upgrades

The demand curve, also known as the variable resource requirement (VRR) curve, is based on the variable resource requirement concept. The purpose of the resource requirement concept is to prevent overbuilding and to provide revenue to a resource when the reliability level is lower than required. The demand curve incorporates the value of the reliability into the price. The demand curve is defined by a family of price/quantity points in which each level of the resources is correlated with a specified price relative to reliability requirements (Exhibit 5-1). The demand

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

prices are a function of the net cost of new entry (CONE)[20] and the demand quantities are a function of the reliability requirement. The unforced capacity (UCAP) requirement is calculated as a product of the forecasted peak load increased by installed reserve margin (IRM) and the probability that the generating unit will be available. The VRR (demand) price is higher than the net CONE if the level of the resources is less than the reliability requirement.[21] The VRR (demand) price is lower than the net CONE if the level of the resources is larger than the reliability requirement. The demand capacity price is capped at 150 percent of the net CONE. The VRR curves are defined by PJM for the PJM region and for each of constrained locational deliverability areas. Locational deliverability areas are areas within the PJM footprint that have been identified as constrained because of their limited import capability in the event of an emergency. The limited import capability is caused by transmission system capacity limitations or voltage limitations.

**Exhibit 5-1 Illustrative example of a variable resource requirement curve**




(*Adapted with permission from PJM.*[22])

The intersection of the supply curve and the VRR curve determines the capacity market clearing price. Exhibit 5-2 illustrates the RPM base residual auction resource clearing price for 2007/2008 – 2015/2016 delivery years.[23]

[20] PJM defines cost of new entry as "levelized annual cost in installed capacity $/MW-Day of a reference combustion turbine to be built in a specific location." PJM. (2013). *Glossary*. Retrieved on January 15, 2013, from http://pjm.com/Home/Glossary.aspx

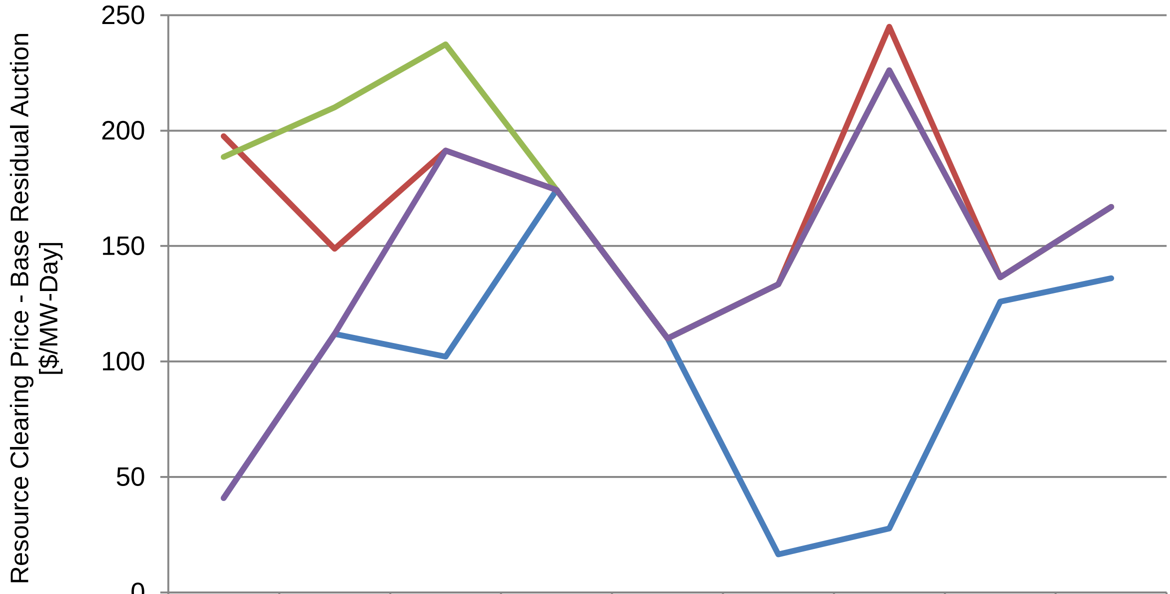
[21] The reliability requirement is a function of regional and locational target reserve margin.

[22] PJM. (2013). *Load Serving Entity 202 – Reliability Pricing Model*. Retrieved on January 15, 2013, from http://pjm.com/training/training-material.aspx

[23] Mid-Atlantic Area Council (MAAC) includes: Pennsylvania Electric, Metropolitan Edison, Jersey Central Power and Light, PPL Electric Utilities Corporation, PECO Energy, Public Service Electric and Gas, Baltimore Gas and Electric, Potomac Electric Power Company, Atlantic City Electric, Delmarva Power and Light, UGI corporation and Rockland Electric.

Southwestern Mid-Atlantic Area Council (SWMAAC) includes: Baltimore Gas and Electric, and Potomac Electric Power Company.

**Exhibit 5-2 Resource clearing price – base residual auction (2007/2008 – 2015/2016)**




| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|---|---|---|---|---|---|
| RTO | $40.8 | $111.9 | $102.0 | $174.3 | $110.0 | $16.5 | $27.7 | $126.0 | $136.0 |
| EMAAC | $197.7 | $148.8 | $191.3 | $174.3 | $110.0 | $133.4 | $245.0 | $136.5 | $167.0 |
| SWMAAC | $188.5 | $210.1 | $237.3 | $174.3 | $110.0 | $133.4 | $226.2 | $136.5 | $167.0 |
| MAAC | $40.8 | $111.9 | $191.3 | $174.3 | $110.0 | $133.4 | $226.2 | $136.5 | $167.0 |
| Date held | May-07 | Jul-07 | Oct-07 | Feb-08 | May-08 | May-09 | May-10 | May-11 | May-12 |

*Data Source: 2015/2016 RPM Base Residual Auction Results*[24]

In the 2008/2009 auction, the increase in RTO's RPM price from $41/MW-day to $112/MW-day was caused by the increase in load growth that was in excess of supply growth. Decreases in EMAAC's RPM price from $198/MW-day to $149/MW-day was caused by the rise in capacity import capability into the EMAAC locational deliverability area (LDA) (multiple transmission upgrades were scheduled to be in service prior to the delivery year). This increase in import capability allowed more capacity to be imported into constrained EMAAC and caused EMAAC's RMP price to be lowered. On the contrary, a decrease in capacity import capability into SWMAAC LDA caused SWMAAC's RMP price to increase.[25]

In the 2009/2010 auction, the RTO's RPM price decrease was result of addition of new capacity and a decrease of export from the PJM system. The growth in supply was in excess of the growth in load and caused a decrease in the RTO's price. Although the RTO's price decreased, a new constrained area MAAC (contains EMAAC, SWMAAC, Pennsylvania Electric, PPL Electric

Eastern Mid-Atlantic Area Council (EMAAC) includes: Jersey Central Power and Light, PECO Energy, Public Service Electric and Gas, Atlantic City Electric, Delmarva Power and Light and Rockland Electric.

[24] PJM. (2012). *2015/2016 RPM Base Residual Auction Results*. Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx

[25] PJM. (2007). *2008/2009 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

Utilities Corporation, Metropolitan Edison and Allegheny Power System zones), was formed due to transmission limitation. EMAAC was not constrained in the 2009/2010 auction due to an increase in capacity import capability and an increase in available supply. However, since it was a part of MAAC, its RPM price was the same as that of MAAC. SWMAAC was more constrained in the 2008/2009 auction than in the 2007/2008 due to an increase in emergency requirements and a net decrease in capacity.[26]

In the 2010/2011 auction, there were no constrained LDAs and the entire PJM system had a uniform RPM price.[27]

The same situation occurred in the 2011/2012 auction, so there were no constrained LDAs and the entire PJM system had a uniform RPM price. The decrease in the RPM price is caused by an increase in new capacity, demand response resources and power imports. In addition, the Duquesne Light Company zone was not included in the auction causing lower load growth in the PJM area and increased import (Duquesne Light Company capacity was offered as an external resource in the auction).[28]

In the 2012/2013 auction, several changes to the RMP design were accepted. Duquesne Light load was included in the demand curve; the CONE was increased; and criteria for LDA modeling were changed. In addition, interruptible load was eliminated; energy efficiency and planned external generators were permitted; and the avoidable cost rate values were increased. The decrease in the RTO's RPM price is caused by new capacity introduced in this auction and decreases in exports from PJM. MAAC was a constrained area in the 2012/2013 auction due to transmission import limitations and new criteria for the LDA selection.[29]

American Transmission Systems, Inc. (ATSI) transmission zone, which joined the PJM in 2011, participated for the first time in the 2013/2014 capacity auction. Load in the ATSI zone was included in the RTO demand curve and supply resources were included in the RTO supply curve. The MAAC, SWMAAC and EMAAC price increases were mostly due to reduced transmission transfer limits into the areas and partially due to increase in the net CONE.[30]

The RTO's price of $126/MW-day in 2014/2015 is due to high bids and the excused capacity from coal units related to the U.S. Environmental Protection Agency regulations.[31] For 2014/2015, a large amount of demand response capacity was cleared, replacing the existing generating units.

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[26] PJM. (2007). *2009/2010 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

[27] PJM. (2008). *2010/2011 RPM Base Residual Auction Results.* Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

[28] PJM. (2008). 2011/2012 RPM Base Residual Auction Results. Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

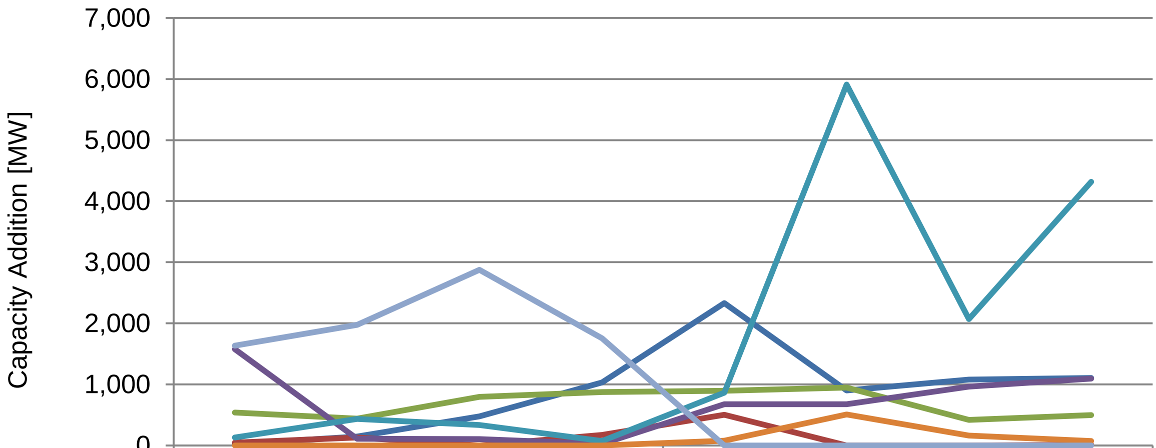
[29] PJM. (2009). 2012/2013 RPM Base Residual Auction Results. Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

[30] PJM. (2010). 2013/2014 RPM Base Residual Auction Results. Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

[31] PJM. (2011). 2014/2015 RPM Base Residual Auction Results. Retrieved on January 15, 2013, from http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01

Since the RPM was established in 2007, about 35,000 MW of the new capacity was added. Since the 2010/2011 auction, the addition of the new generation capacity resources has been decreasing while the DR addition has been increasing (Exhibit 5-3).

**Exhibit 5-3 Capacity additions (2007/2008 – 2015/2016)**




| | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 |
|---|---|---|---|---|---|---|---|---|
| New | 19 | 145 | 476 | 1,031 | 2,332 | 901 | 1,080 | 1,102 |
| Reactivated | 47 | 131 | - | 170 | 501 | - | - | 9 |
| Uprates | 536 | 438 | 793 | 876 | 896 | 946 | 418 | 499 |
| Imports | 1,576 | 107 | 105 | 24 | 672 | 676 | 963 | 1,096 |
| DR | 127 | 432 | 333 | 70 | 864 | 5,908 | 2,068 | 4,316 |
| EE | - | - | - | - | 76 | 509 | 163 | 74 |
| ILR | 1,636 | 1,972 | 2,873 | 1,755 | - | - | - | - |

*Note: New = New Generation Capacity Resource, Reactivated = Reactivated Generation Capacity Resource, Uprates = Uprates to Existing Generation Capacity Resources, Imports= Net Increase in Capacity Imports, DR = Demand Resources, EE =Energy Efficiency, ILR = Interruptible Load for Reliability*

*Data Source: 2011 State of the Market Reports*[32]

The significant increase in demand response in the 2012/2013 auction is caused by capacity market incentives (the existing demand response offer price is equal to $0/MW-day and they are price takers) and the elimination of the ILR alternative. Since the 2012/2013 auction, EE was permitted as a new type of capacity resource.

Exhibit 5-4 illustrates incremental capacity resource additions from 2007/2008 to 2015/2016.[31] There is a significant increase in the amount of new capacity offered in the 2015/2016 auction. The most recent auction attracted mostly natural gas resources. The largest growth remains in gas turbines and combined cycle plants. The 2011/2012 and 2012/2013 were the last auctions when coal power plants had a significant growth in the new capacity units.

[32] PJM. (2012). *2011 State of the Market Reports*. Retrieved on January 15, 2013, from http://pjm.com/documents/reports/state-of-market-reports/2011-state-of-market-reports.aspx

**Exhibit 5-4 Incremental capacity resource additions from 2007/2008 to 2015/2016**

| | Delivery Year | CT/GT | CC | Diesel | Hydro | Steam | Nuclear | Solar | Wind | Fuel Cell | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| New Capacity Units (ICAP MW) | 2007/08 | | | 18.7 | 0.3 | | | | | | **19** |
| | 2008/09 | | | 27.0 | | | | | 66.1 | | **93** |
| | 2009/10 | 399.5 | | 23.8 | | 53.0 | | | | | **476** |
| | 2010/11 | 283.3 | 580.0 | 23.0 | | | | | 141.4 | | **1.028** |
| | 2011/12 | 416.4 | 1,135.0 | | | 704.8 | | 1.1 | 75.2 | | **2,332** |
| | 2012/13 | 403.8 | | 7.8 | | 621.3 | | | 75.1 | | **1,108** |
| | 2013/14 | 329.0 | 705.0 | 6.0 | | 25.0 | | 9.5 | 245.7 | | **1,320** |
| | 2014/15 | 108.0 | 650.0 | 35.1 | 132.9 | | | 28.0 | 146.6 | | **1,101** |
| | 2015/16 | 1,382.5 | 5,914.5 | 19.4 | 148.4 | 45.4 | | 13.8 | 104.9 | 30.0 | **7,659** |
| Reactivated Units (ICAP MW) | 2007/08 | | | | | 47.0 | | | | | **47** |
| | 2008/09 | | | | | 131.0 | | | | | **131** |
| | 2009/10 | | | | | | | | | | **-** |
| | 2010/11 | 160.0 | | 10.7 | | | | | | | **171** |
| | 2011/12 | 80.0 | | | | 101.0 | | | | | **181** |
| | 2012/13 | | | | | | | | | | **-** |
| | 2013/14 | | | | | | | | | | **-** |
| | 2014/15 | | | 9.0 | | | | | | | **9** |
| | 2015/16 | | | | | | | | | | **-** |
| Uprates to Existing Resources (ICAP MW) | 2007/08 | 114.5 | | 13.9 | 80.0 | 235.6 | 92.0 | | | | **536** |
| | 2008/09 | 108.2 | 34.0 | 18.0 | 105.5 | 196.0 | 38.4 | | | | **500** |
| | 2009/10 | 152.2 | 206.0 | | 162.5 | 61.4 | 197.4 | | 16.5 | | **796** |
| | 2010/11 | 117.3 | 163.0 | | 48.0 | 89.2 | 160.3 | | | | **578** |
| | 2011/12 | 369.2 | 148.6 | 57.4 | | 186.8 | 292.1 | | 8.7 | | **1,063** |
| | 2012/13 | 231.2 | 164.3 | 14.2 | | 193.0 | 126.0 | | 56.8 | | **786** |
| | 2013/14 | 56.4 | 59.0 | 0.3 | | 215.0 | 47.0 | | 39.6 | | **417** |
| | 2014/15 | 104.9 | | 0.5 | 41.5 | 138.6 | 107.0 | 7.1 | 73.6 | | **473** |
| | 2015/16 | 216.8 | 72.0 | 4.7 | 15.7 | 63.4 | 149.2 | 2.2 | 24.1 | | **548** |
| **Total** | | **5,033** | **9,831** | **289** | **735** | **3,108** | **1,209** | **62** | **1,0743** | **30** | **21,372** |

*Data Source: 2015/2016 RPM Base Residual Auction Results* [24]

The largest growth in new capacity units remains in gas turbines and combined cycle plants. While the largest growth in uprates to existing resources remains in gas turbines and combined cycle plants, a fair amount of uprate capacity in Steam and Nuclear were offered into the recent auctions.

## 5.3 Installed Capacity (ICAP): NYISO

The ICAP consists of voluntary monthly auctions and mandatory spot auctions. The ICAP market should produce efficient long-term economic signals that give incentives to invest in new generation, transmission, and demand response resources and to maintain existing resources. The NYISO uses the spot capacity auction mechanism to clear the market by reconciling the offer-based supply curve with the downward-sloping demand curve.

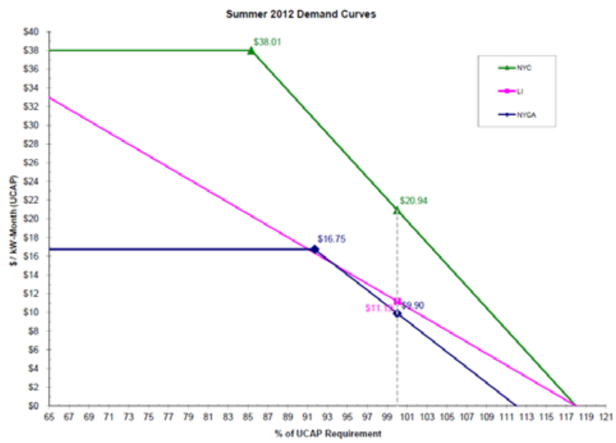
The supply curve is designed by sequentially aggregating unforced capacity offers submitted by capacity resource owners or load serving entities. In the ICAP, the capacity resources consist of:

- Generator resources (existing and planned)

- Special case resources – end-use loads capable of being interrupted upon demand, and distributed generators

The ICAP demand curve is similar to the PJM curve with three different slopes. The NYISO designs three demand curves. The first curve is for the entire NYISO area (NYCA). The second curve is for the New York City area (NYC), and the last curve is for the Long Island area (LI) (Exhibit 5-5).

**Exhibit 5-5 Illustrative example of a NY ISO demand curve**




*(Used with permission from New York ISO.[33])*

The intersection of the supply curve and the demand curve determines the capacity market clearing price. Exhibit 5-6 illustrates ICAP base residual auction resource clearing prices for the last four auctions.

**Exhibit 5-6 ICAP clearing price**


| | Summer 2010 | Summer 2011 | | Winter 2010-2011 | Winter 2011-2012 |
|---|---|---|---|---|---|
| NYC | $13.1 | $8.4 | | $3.7 | $3.7 |
| NYCA | $1.7 | $0.3 | | $0.4 | $0.2 |
| LI | $1.7 | $0.3 | | $0.4 | $0.2 |

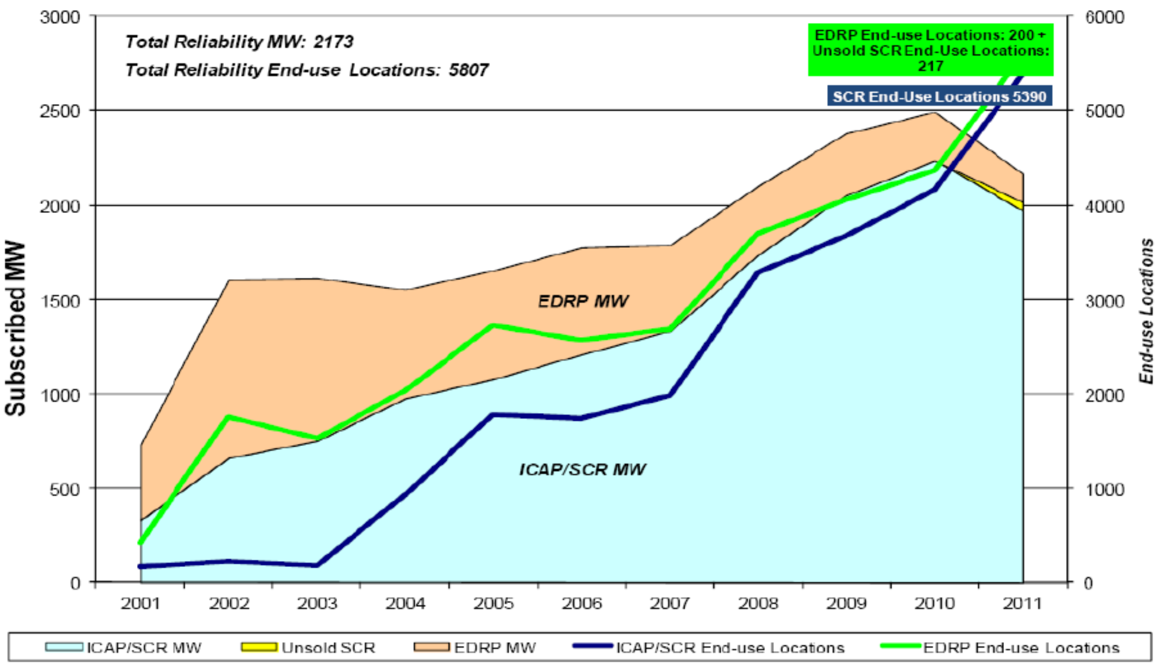
*Data Source: Potomac Economics, 2011 State of the Market Report for the New York ISO Markets[34]*

[33] New York ISO. (2012). ICAP/UCAP Translation of Demand Curve - Summer 2012 Capability Period. Retrieved on February 25, 2013, from *http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP%20Auctions/2012/Summer%202012/Documents/Demand_Curve_Summer_2012_FINAL.pdf* )

The summer capacity market price decrease of 35 percent in New York City and 80 percent in other areas from 2010 is primarily the result of new capacity (~1 GW) and a lower summer peak load forecast. Seasonal variations are the result of additional capability typically available in the winter periods due to lower ambient temperatures, which increase the capability of some resources to produce electricity.

The NYISO offers five different demand response programs. In the Installed Capacity/Special Case Resource Program, the demand resources (Exhibit 5-7) sell capacity in the ICAP and accept an obligation to respond when called upon within a two-hour notice. These resources are paid the higher of their strike price (any dollar value between $0 and $500)[35] or the real-time clearing price.[36]

**Exhibit 5-7 NYISO demand response reliability programs**




*(Used with permission from New York ISO.[37])*

[34] New York ISO. (2012). *2011 State of the Market Report for the New York ISO Markets*. Retrieved on February 25, 2013, from http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp

[35] New York ISO. (2013). *Demand Response Information System Market Participant's Guide.* Retrieved on January 15, 2013, from http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Guides/User_Guides/DRIS_User_Guide.pdf

[36] Potomac Economics. (2011). *2011 State of the Market Report for the New York ISO Markets*. Retrieved on December 15, 2012, from http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp

[37] New York ISO. (2012). 2011 State of the Market Report for the New York ISO Markets - Potomac Economics. Retrieved on February 25, 2013, from *http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp*

## 5.4 Forward Capacity Market (FCM): ISO New England

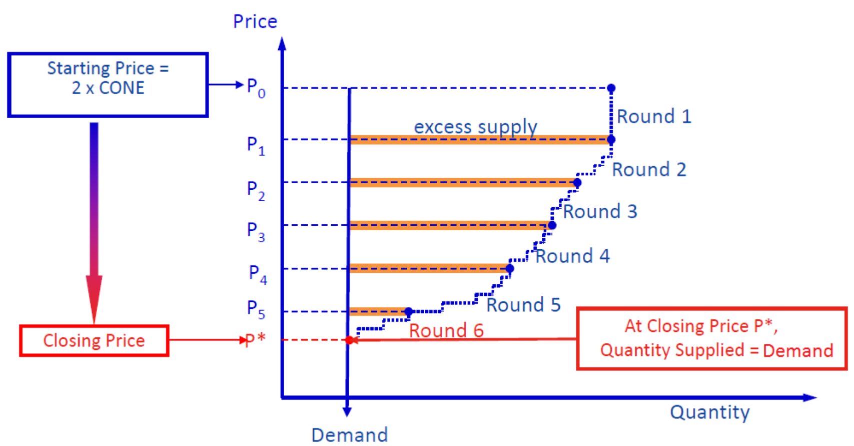
The FCM is a three-year forward capacity market model. The FCM was designed to provide long-term pricing signals to attract needed investments required to ensure the reliability of the ISO New England region. The FCM is used to commit capacity resources required to reliably meet forecasted demand on an annual basis, to provide sufficient reserve margins, and to help plan transmission upgrades. The FCM uses a descending clock auction annual mechanism to clear the market by reconciling an offer-based supply curve with a vertical demand curve and price floor and cap.

The supply curve is designed by sequentially aggregating unforced capacity offers submitted by capacity resource owners or load serving entities. In the FCM, the capacity resources consist of:

- Generator resources (existing and planned)
- Import
- Demand resources (load management, energy efficiency, distributed generation)

The descending clock auction is a multi-round process. The process is based on reducing the capacity market price until the quantity of available capacity resources matches the fixed capacity demand requirements. The basic concept of the descending clock auction is that more than enough capacity resources are offered if the market capacity price is high. Some capacity resources are removed from the auction by the system operator as the capacity market price drops (Exhibit 5-8).

**Exhibit 5-8 Descending clock auction mechanics**



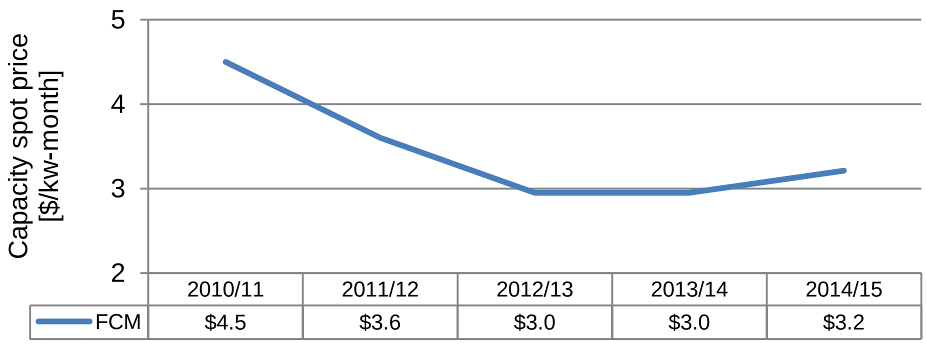

*(Adapted with permission from ISO New England.[38])*

In each round the auctioneer announces the start and end of the round price and the excess supply at the end of the prior round. The participants respond by submitting offers at prices within the announced price range.

[38] ISO NE. (2013). *Introduction to Wholesale Electricity Market (WEM 101) – Overview of Forward Capacity Market (FCM)*. Retrieved on January 15, 2013, from http://www.iso-ne.com/support/training/courses/wem101/21_overview_of_fcm.pdf

Exhibit 5-9 illustrates the FCM base residual auction resource clearing price for the last five auctions.

**Exhibit 5-9 FCM clearing price**

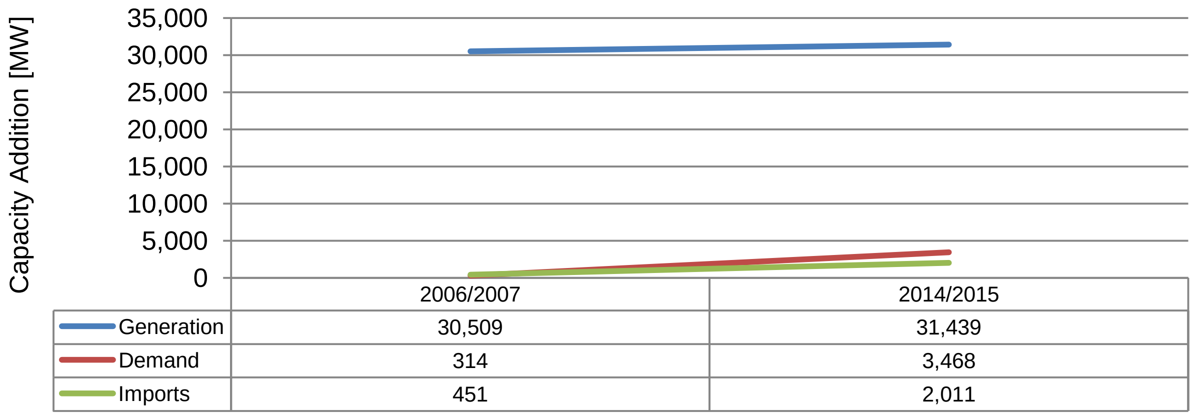



*Data Source: 2011 Assessment of the ISO New England Electricity Markets*[39]

Each auction was cleared at the floor price, illustrating that there is a surplus of capacity.

The FCM, similarly to the RPM, resulted in most of the resources added in the recent years being demand resources or imports (Exhibit 5-10).

**Exhibit 5-10 Cumulative capacity additions**




*Data Source: 2011 Annual Markets Report-Internal Market Monitor* [40]

## 5.5 Voluntary Capacity Auction (VCA): Midwest ISO

The VCA is a voluntary market. This market may be vulnerable to the exercise of strategic withholding due to its voluntary nature. The VCA was designed to provide long-term pricing signals to attract needed investments required to ensure the reliability of the MISO region. The

[39] Potomac Economics. (2012). *2011 Assessment of the ISO New England Electricity Markets*. Retrieved on January, 2013, from http://www.potomaceconomics.com/markets_monitored/iso_new_england

[40] ISO NE. (2012). *2011 Annual Markets Report-Internal Market Monitor*. Retrieved on January 15, 2013, fromhttp://iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html

cleared capacity in the VCA averaged only 1.7 GW in 2010-2011 since most load serving entities' obligations were satisfied through owned capacity or bilateral purchases. The VCA market clearing price was around $0 in 2011.

Recognizing the limitations of the existing capacity market, MISO proposed a model for planning resource auctions that should be used for the annual planning resource auction and zonal auction clearing processes. The proposed model is a linear programming model that minimizes the cost of providing capacity service. The constraints include capacity offer constraints, non-negative cleared capacity constraints, system demand constraints, and minimal and maximal zonal clearing constraints.[41]

## 5.6 Advantages and Disadvantages of Different Markets

An advantage of the market with the vertical demand curve is that it is simple to implement. A disadvantage of the vertical demand curve is that the curve values incremental capacity as zero value.

An advantage of the downward-sloping demand curve is its stabilization of the capacity market price in a case of a very steep demand curve. It also recognizes that incremental capacity above the minimum requirement has a non-zero value (i.e., improves reliability).

A disadvantage of the downward-sloping curve is that it does not represent buyers' bids or actual customer demand. These demand curves are based on the net CONE that may lead to inefficient levels of investment or sustained surpluses. Today, most ISO/RTOs select a peak unit for the net CONE.

## 5.7 Does Today's Capacity Market Favor Natural Gas over Other Fuels?

Capacity markets are designed to ensure that investments which may not be recoverable through the energy and ancillary services markets are recovered. PJM's and NYISO's demand curves are established to allow suppliers to recover the net CONE for the investments over a long term. The levelized RPM net CONE was estimated at $320.63/MW-day in PJM, $360/MW-day in ATSI, and $270/MW-day in MACC zones. The levelized ICAP net CONE for a new peaking unit was estimated at $280 per kW-year (or $767/MW-day) in New York City, $250 per kW-year (or $685/MW-day) on Long Island, and $120 per kW-year (or $330/MW-day) in the New York control area for the 2011/12 capability period. The levelized FCM net CONE was estimated at $6.055/kW-month (or $200/MW-day) in ISONE. Comparing these numbers with an estimated daily cost of the cheapest coal power plant ($470/MW-day), nuclear power plant ($974/MW-day), hydro ($460/MW-day), and natural gas ($120/MW-day to $360/MW-day), it is clear that other technologies cannot compete with natural gas power plants in the capacity markets, except in NYISO, unless they get enough revenue from energy and ancillary service markets.

In the PJM market, a coal power plant is a marginal unit about 5 percent of the time in the day-ahead market and 70 percent in the spot market. It means that the coal power plants will not

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[41] MISO. (2012). *Planning Resource Auction Software Formulation*. Retrieved on December 15, 2012, from https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2012/20121101/20121101%20SAWG%20Item%20XX%20PRA%20Auction%20Formulations.pdf

receive adequate revenue to recover both capital and operating costs, and they will face a problem of “missing money” without capacity payments.

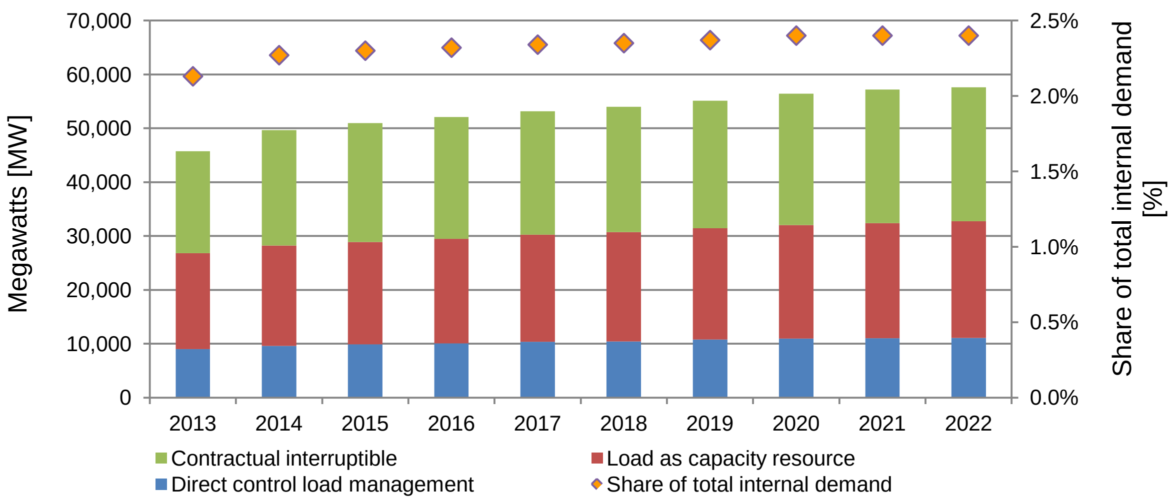
## 5.8 Summary

Today’s capacity markets are designed mostly using a peaking plant as a new entry and corresponding net CONE. This approach was acceptable for coal power plants before natural gas prices dropped and the U.S. Environmental Protection Agency regulations were accepted. Now, natural gas power plants are competitive with coal power plants in the energy market. Coal power plants cannot obtain enough revenue from the capacity market to recover fixed and variable costs.

The capacity markets design does not consider the type of power plant (base, intermediate, and peaking). This will very likely lead to replacing retired coal power plants with demand resources and natural gas power plants.

In the last few years, generation capacity has been replaced with demand resources and that trend will probably continue to exist in the future, but may slow down. According to North American Electric Reliability Corporation total expected demand resource increases steadily over the next ten years.

**Exhibit 5-11 Demand resource (dispatchable and controllable) expected capacity**




*Data Source: North American Electric Reliability Corporation - 2012 Long-Term Reliability Assessment*[42]

More details about the different markets can be found in the primers *Energy Market*, *Ancillary Services* and *Capacity Market*. More details about the different ISOs/RTOs can be found in the ISO/RTO primers *California Independent System Operator*, *ERCOT Independent System Operator*, *MISO Regional Transmission Organization*, *ISO New England Regional Transmission Organization*, *New York ISO Regional Transmission Organization*, *PJM Regional Transmission Organization* and *Southwest Power Pool, Inc.*

[42] North American Electric Reliability Corporation. (2012). *2012 Long-Term Reliability Assessment*. Retrieved on February 15, 2013, from http://www.nerc.com/files/2012_LTRA_FINAL.pdf

# 6 Ancillary Services

Ancillary services are "services that ensure the reliability of and support for the transmission of electricity to serve load."[43] The most common ancillary services are regulation and frequency response,[44] 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.

## 6.1 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 ISO/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,[45] every 6 seconds in New York ISO,[46] and every 4 seconds in ISO New England.[47] 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

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

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

[45] 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

[46] 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

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

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.

**Example 1 – Regulation Market Clearing** An ISO/RTO receives the regulation bids for a particular hour from two producers (Exhibit 6-1). 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 6-1. 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 6-1 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 6-2).

**Exhibit 6-2 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 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.

## 6.2 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[48] reserve can be either 10-minute or 30-minute spinning or non-spinning reserve. Exhibit 6-3 illustrates different types of operating reserve and their providers.

**Exhibit 6-3 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 operating reserve requirement is equal to one and a half times the single largest contingency in the system.[49] 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

[48] 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.

[49] 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

reserve) and 30-minutes requirements as 50 percent of the second contingency.[50] 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 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.

## 6.3 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

[50] 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

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.

## 6.4 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.

# 7 Financial Transmission Rights

Financial transmission rights (FTRs),[51] also known as transmission congestion contracts (TCCs) or congestion revenue rights (CRRs), provide a financial instrument for market participants to hedge against congestion costs in the system.[52]

The main purposes of the FTRs are to allow:[53]

- Market participants to eliminate or greatly reduce the cost uncertainties resulting from congestion transmission charges.
- The Regional Transmission Organization (RTO) and the Independent System Operator (ISO) to redistribute any over collection of money (due to transmission congestion) to market participants.

In the absence of any transmission constraints, all locational marginal pricing (LMP) nodes would price at the lowest-priced generation resource. However, there is not enough physical transmission to deliver electricity from low-cost resources to the place demanding the electricity at all times. Thus, some nodes will, by necessity, use power from higher-cost resources and therefore the LMP at that node will be higher. The difference in day-ahead LMPs congestion components[54] between two nodes that is attributable to the transmission constraints multiplied by the transfer amount is called "congestion cost" or "the cost of congestion." There is an overload of congestion dollars during constrained conditions because the RTO collects more from loads than it pays to generators. Since an RTO is a non-profit organization, the RTO cannot keep the difference. The FTR is used to redistribute this over collection back to market participants.

The FTRs are not associated with physical delivery rights (FTRs do not represent a right for physical delivery of power).[55] The FTRs can be thought of as a "reservation" for access to a specific transmission path (e.g., between LMP nodes) for a specific timeframe, but they do not actually correspond with a physical right to deliver energy. Rather, the FTRs will create a revenue stream (or charges) based on the difference between two congestion components of day-ahead LMP at specific times.

The FTRs are bought and sold in long-term, annual, and monthly auctions. An RTO/ISO cannot grant more FTRs than the transmission system is capable of supporting. Both market and non-market participants can register to acquire the FTRs. Methods and auction processes of the FTR vary by the RTO and ISO.

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

[52] The financial transmission rights (FTR) are a service offered by PJM, Midwest ISO, and ISO New England. Transmission congestion contracts (TCC) are a service offered by New York ISO. The congestion revenue rights (CRR) are a service offered by ERCOT and California ISO.

[53] PJM. (2013). *ARR and FTR 101.* Retrieved on February 16, 2013, from http://pjm.com/Globals/Training/Courses/ol-arr-ftr-101.aspx

[54] Since marginal losses were implemented in the calculation of LMP (LMP = marginal energy price + marginal congestion price + marginal losses price) only the difference in the marginal congestion price component between two nodes has been used to value the congestion costs. In the given examples, it is assumed that the marginal losses price is equal 0.

[55] ISO New England. (2013). *ISO New England Manual for Financial Transmission Rights*. Retrieved on February 16, 2013, from http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

The FTRs are characterized by:[53]

- Quantity – number of MWs desired to buy or offered for sale
- Price – buy bids and sell offers in $/MW
- Class type – peak, off-peak or 24-hour
- Path – a point of injection (source location) and a point of withdrawal (sink locations). The locations can be any pricing node, zone, or hub. The source and sink locations are selected by the FTRs buyers and sellers.
- FRT Hedge (Credit) = (Day-ahead LMP congestion component $_{\text{sink location}}$ –Day-ahead LMP congestion component $_{\text{source location}}$)*FTR quantity award

**Example 1 – FTR as a hedging instrument to provide price certainty** An ISO/RTO receives the bids and offers, for a particular hour, from two producers and one consumer, shown in Exhibit 7-1. Gen Company 1 is located in Area 1, and Gen Company 2 and a consumer are located in Area 2. Area 1 and Area 2 are connected with a transmission line with a power limit of 350 MW. Gen Company 1 is willing to sell 500 MWh at $25/MWh and Gen Company 2 is willing to sell 250 MWh at $35/MWh. The consumer is willing to buy 275 MW, regardless of the electricity price. The ISO/RTO sets the MCP to $25/MWh and energy is traded at 275 MWh.

Gen Company 1 meets all demand and sells to the grid 275 MWh at $25/MWh. The consumer draws 275 MWh and pays $25/MWh. Power flow over the transmission line is 275 MW from Area 1 to Area 2. The generating company's total revenues ($6,875) are equal to the total of the consumer's payments ($6,875) because there is no congestion in the system. The ISO/RTO used the cheapest generation company to provide energy for the consumer's demand.

**Exhibit 7-1 Simple electric energy system**

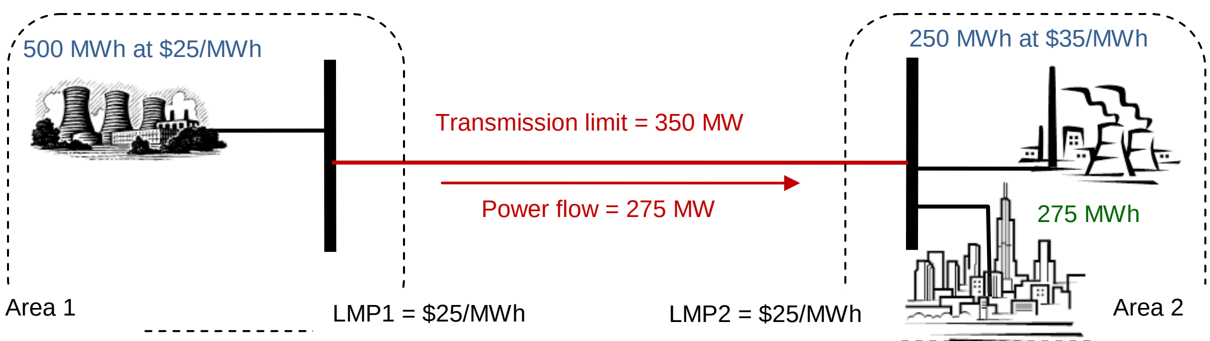



*Image created by NETL.*

Assuming the transmission limit is 250 MW, the situation becomes more complex. Because of the fully loaded transmission line, LMP for Area 1 is set to $25/MWh and LMP for Area 2 is set to $35/MWh.[56]

Gen Company 1 produces 250MWh and is paid $25/MWh. Gen Company 2 produces 25MWh and is paid $35/MWh. The consumer buys all 275MWh at $35/MWh. The total generator's revenue ($7,125) is not equal to the total of the consumer's payment ($9,625), because the transmission congestion limited the use of a cheaper generating resource. In this case the

[56] See *Energy Market Primer* for LMP calculation.

consumer pays more than the generating units receive. The excess is the congestion cost or congestion revenue fund. The congestion costs are collected by the market operator and are given to holders of a FTR as a compensation for transmission congestion charges that arise when the transmission grid is congested.

Assuming that the consumer has a FTR for 250MW[57] with Area 1 as the source and Area 2 as the sink, the congestion rent will be 250MW * ($35/MWh – $25/MWh) = $2,500 for that hour. The consumer will pay to the ISO/RTO $9,625, but it will get back $2,500 as the FTR holder. In total, the consumer will pay $7,125 for its consumption. This value is equal to the total generator's revenue. The FTR allows the holder to have the same energy price at the point of withdrawal as the price at the point of injection.

The congestion charge is calculated as $MWh_{delivered}$*(Day-ahead LMP congestion component $_{sink\ location}$ –Day-ahead LMP congestion component $_{source\ location}$) while the FTR credit is calculated as $MW_{awarded}$*(Day-ahead LMP congestion component $_{sink\ location}$ –Day-ahead LMP congestion component $_{source\ location}$). If the MWh delivered is equal to the FTR MW award and they are over the same path, customers have option to perfectly hedge the congestion charges.

FTR is traded separately from transmission service. The FTR will provide a benefit if the path is in the same direction as congestion (the LMP at sink is higher than the LMP at source). The FTR will provide liability if the path is in the opposite direction from congestion (the LMP at sink is lower than the LMP at source). FTRs are separate from energy delivery and can be on separate paths from the energy delivery.

**Example 2 – FTR as benefit and as liability** Gen Company 1 is located in Area 1, and a consumer is located in Area 2 (Exhibit 7-2). Gen Company 1 is selling 100 MWh to the customer over a transmission line with a power limit of 100 MW. Energy flow is from Area 1 to Area 2.

**Exhibit 7-2 Simple electric energy system with congestions**

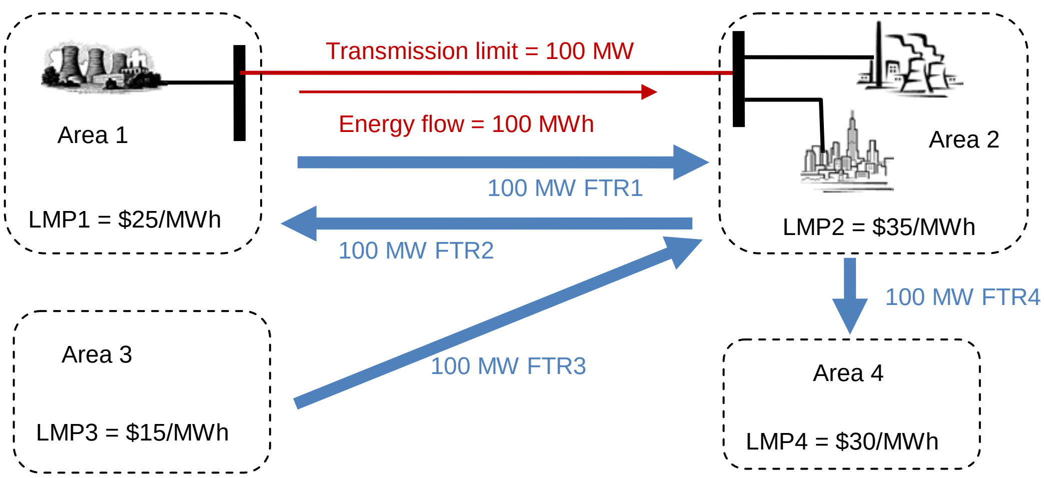



*Image created by NETL.*

57 The ISO/RTO cannot grant more FTRs than the transmission system is capable of supporting.

The customer has multiple options to hedge against the congestion. FTR1 and FTR2 are on the same path as energy flow. FTR1 is in the same direction and FTR2 is in the opposite direction as the energy flow. FTR3 and FTR4 are across different paths than the energy flow. Exhibit 7-3 summarizes the outcomes of these four FTR.

**Exhibit 7-3 FTR outcomes**

| FRT | FTR Path | $LMP_{sink}$ \$/MWh | $LMP_{source}$ \$/MWh | MW | Congestion charge [\$] | FTR credit [\$] | Outcome |
|---|---|---|---|---|---|---|---|
| FTR1 | Area 2-to- Area 1 | 35 | 25 | 100 | 1,000 | 1,000 | Benefit – perfect hedging |
| FTR2 | Area 1-to- Area 2 | 25 | 35 | 100 | 1,000 | -1,000 | Liability |
| FTR3 | Area 2-to- Area 3 | 35 | 15 | 100 | 1,000 | 2,000 | Benefit – over-hedging |
| FTR4 | Area 2-to- Area 4 | 35 | 30 | 100 | 1,000 | 500 | Benefit – under-hedging |

FTRs are requested based on expected power flow and expected LMPs, since the FTRs are granted before the day-ahead market is conducted. This represents a risk to FTR holder because the FTRs with negative price paths create liability to them.

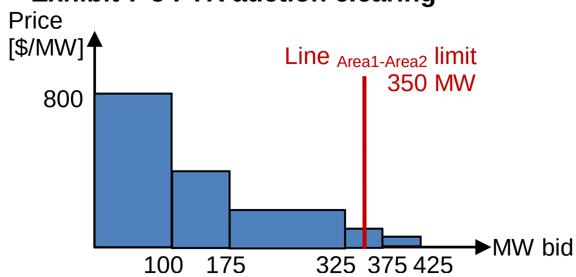
Market participants purchase FTRs by participating in a FTR auction. They submit the quantity (how many FTRs they desired to buy or offered for sale), price (buy bid and sell offer), FTR sink and FTR source to an ISO/RTO. The ISO/RTO stacks the bids up in a descending order and clears the market by maximizing the FTR bid-based value. The objective of a FTR auction is to get the highest bid for the FTR and to generate the most revenue to FTR holders. The ISO/RTO then runs a feasibility test to check simultaneous feasibility of the FTRs. The simultaneous feasibility test ensures that the limits of the transmission system are respected.

**Example 3 – FTR auction and clearing mechanism** An ISO/RTO receives FTR bids and offers from five market participants for 350 MW of transmission capacities between Area 1 and Area 2. The ISO/RTO accepts all bids and stacks them up (Exhibit 7-4) in a descending order (Exhibit 7-5). The ISO/RTO checks the simultaneous feasibility of the FTRs by adding all FTRs and comparing to the line capacity. Total MW bid is equal to 425 MW and it over-exceeds the line capacity. The ISO/RTO will clear the market at 350 MW. The FTR clearing price in Area 1 will be equal \$0/MW and the FTR clearing price in Area 2 will be equal \$100/MW.

**Exhibit 7-4 FTR Bids**

| Market participant | FTR MW requested [MW] | FTR bid [\$/MW] |
|---|---|---|
| MP1 | 100 | 800 |
| MP2 | 75 | 400 |
| MP3 | 150 | 200 |
| MP4 | 50 | 100 |
| MP5 | 50 | 50 |

**Exhibit 7-5 FTR auction clearing**




The ISO/RTO will grant FTRs to four participants with the highest bids: MP1 will be granted 100 MW, MP2 will be granted 75 MW, MP3 will be granted 100 MW, and MP4 will be granted 25 MW (out of 50 MW requested) at \$100/MW clearing price. The total FTR auction revenue is equal \$35,000. MP5 will not be granted any FTR since its bid is lower than the market clearing price. These four market participants will receive a share of the congestion cost collected at the day-ahead market.

The FTR revenue is distributed to auction revenue rights (ARR) holders. The ARR are allocated to network transmission customers and firm point-to-point transmission customers for the duration of one year. Only firm transmission customers can be granted ARR based on historical usage data. Market participants will request ARR and the ISO/RTO will approve them based on the simultaneous feasibility test conducted before the annual FTR auction.

**Example 4 – Auction revenue rights allocation** Three firm transmission customers (FTC) are using the transmission line between Area 1 and Area 2 (Exhibit 7-4). FTC1 load peak is 20 percent of the area peak, FTC2 load peak is 30 percent of the area peak and FTC3 is 50 percent of the area peak. All three FTC are ARR holders. The FTR revenue collected in the FTR auction in Example 3 will be distributed based on the load peak percent. FTC1 receives $7,000, FTC2 receives $10,500 and FTC3 receives $17,500.

Often, the amount collected during the FTR auction is not equal to ARR targeted amounts. If the FTR revenue is insufficient, ARR credits are prorated proportionally to ARR values. If the FTR revenue exceeds ARR targeted amounts, the excess revenue is used to fund any shortfall in FTR target allocations. (ARR allocation is a multi-step process where during each step only percents of the total capacity are allocated. In some steps there will be insufficient revenue and some steps there will be excess revenue.)

Examples in this primer are simplified. The main objective of the primer is to explain the different terminology and processes at a very high level. Real power systems are much more complex and the FTR auction and the ARR allocation process are much more complicated than is presented in the examples. However, detailed explanations and processes are beyond the scope of this primer and can be found in ISOs/RTOs tutorials and manuals.

More details about the different markets can be found in the primers *Energy Market, Ancillary Services, Capacity Market, Comparison of Different ISO/RTO Capacity Market Structures* and *Power Markets*.

# 8 Regional Transmission Organizations and Independent System Operators

## 8.1 Overview of RTOs and ISOs

Regional Transmission Organizations (RTO)[58] and Independent System Operators (ISO) are non-profit organizations established in particular geographic regions to manage the operations of the transmission grid. Broadly, RTOs/ISOs are responsible for ensuring the reliability of the transmission grid by facilitating wholesale power markets, monitoring transmission grid performance, and coordinating the operations of power generators in the region. An RTO performs the same type of business activities as ISO, but has additional requirements and has to be approved by the Federal Energy Regulatory Commission (FERC). FERC defined four characteristics and eight functions that an entity must satisfy in order to become an RTO (Exhibit 8-1).

**Exhibit 8-1 Regional transmission organization characteristics and functions**

| Regional transmission organization characteristics | Regional transmission organization functions |
|---|---|
| ‣ Independence from control by any market participant<br>‣ Sufficient scope to maintain reliability and support nondiscriminatory power markets<br>‣ Operational authority for transmission facilities under their control<br>‣ Exclusive authority for maintaining the short-term reliability of the grid they operate | ‣ Administer tariffs and a pricing system to promote efficient use and expansion of transmission and generation facilities<br>‣ Create market mechanisms to manage transmission congestion<br>‣ Address parallel path flow issues<br>‣ Serve as a supplier of last resort for ancillary services<br>‣ Operate a single Open Access Same-Time Information System (OASIS) site for transmission facilities under their control<br>‣ Monitor markets to identify design flaws and market power<br>‣ Plan and coordinate transmission additions and upgrades<br>‣ Ensure integration of reliability practices within an interconnection and market-interface practices among regions |

Existing voluntary power pools that shared power and system stability were the earliest examples of an ISO. In the early 1990s, the federal government, along with several states, began to take a series of steps aimed at restructuring the electricity industry, particularly targeted at increasing the competition in wholesale power markets. To facilitate competition, FERC issued a variety of orders, starting in April 1996 with Order 888[59], which required that transmission owners under FERC jurisdiction (mainly large investor-owned utilities) allow other entities to access the transmission owner's lines at the same prices and with the same terms and conditions that they applied to themselves. This effectively required vertically integrated utilities to internally create organizational divisions that would split the operation of their transmission lines from their

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

[59] Federal Energy Regulatory Commission. (1996). *Order No. 888: Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*. Retrieved on September 16, 2011, from http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp

generation and distribution operations, although the utility continued to maintain ownership of the transmission assets. This organizational change was required in order for a utility to be able to accurately determine the cost of transmission service, such that this service could be provided to both internal and external customers (i.e., the utility that owned the transmission assets as well as third parties). Additionally, Order 888 encouraged—but did not require—transmission owners to form independent entities called ISOs to manage the transmission network (neither ISOs nor RTOs own transmission lines). FERC did not (and still does not) require vertically integrated utilities to sell their transmission assets, but rather encouraged participation in ISOs as a means of institutionalizing the separation of the operation of transmission assets from the ownership of generation assets. FERC recognized that the initial regulatory efforts outlined in Orders 888 and 889[60] were not sufficient to guide non-discriminatory access to the transmission grid, and in December 1999 issued Order 2000.[61] Order 2000 encouraged transmission owners to form RTOs, and outlined the minimum characteristics an RTO should have, and the minimum functions an RTO should perform.

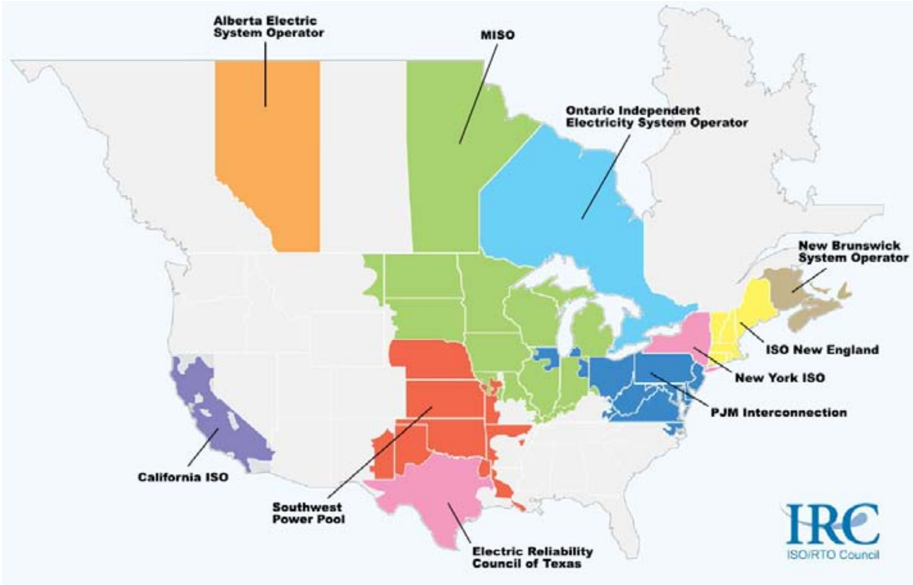
Currently, approximately two-thirds of U.S. electricity consumers are served by seven ISOs/RTOs, predominantly in the Northeast, Midwest, and California. In other areas of the country, particularly in regulated states, the regulated utilities, Publicly Owned Utilities (POU), or federal Power Marketing Authorities (PMA) own and operate transmission assets.

The seven regional grid operators in the U.S. are: California ISO (CAISO), Midwest ISO (MISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), PJM Interconnection (PJM), New York ISO (NYISO), and ISO New England (ISO-NE) (Exhibit 8-2).

[60] Federal Energy Regulatory Commission. (1996). *Order No. 889: Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*. Retrieved on September 16, 2011, from http://www.ferc.gov/legal/maj-ord-reg/land-docs/order889.asp

[61] Federal Energy Regulatory Commission. (1999). *Order No. 2000: Establishment of Regional Transmission Organizations Proposals*. Retrieved on September 16, 2011. from http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.

**Exhibit 8-2 North American transmission organizations**




*Source: ISO/RTO Council* [62] (Copyright © ISO/RTO Council, all rights reserved)

*RTO:* *MISO, ISO-NE, PJM and SPP*

*ISO:* *CAISO, ERCOT, NYISO, Alberta Electric System Operator, Ontario Independent Electricity System Operator, and New Brunswick System Operator*

Of these seven U.S. grid operators, six are regulated by FERC, and four have been approved by FERC to be recognized as RTOs (i.e., they meet the requirements set out in FERC Orders 2000 and 2001[63]). NYISO and CAISO have not gained FERC approval because they do not cover a large geographic area and FERC does not see them as regional in scope. ERCOT is not regulated by FERC because it is not under FERC jurisdiction. ERCOT operates fully within Texas state lines and has chosen to remain regulated by the Public Utility Commission of Texas. The transmission grids that are not covered by these regional grid operators are controlled by the individual utilities for their specific service areas.

All seven transmission organizations in the U.S. are organized as non-profit corporations or limited liability companies, and recoup expenses through regulatory-approved tariffs. These expenses are outlined below in the major categories as identified on FERC Form 1. [64]

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[62] ISO/RTO Council. (2011). *ISO/RTO Operating Regions*. Retrieved on September 16, 2011, from http://www.isorto.org/site/c.jhKQIZPBImE/b.2604471/k.B14E/Map.htm.

[63] Federal Energy Regulatory Commission. (2002). *Order No. 2001: Revised Public Utility Filing Requirements*. Retrieved on September 16, 2011, from http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9512346.

[64] United States Government Accountability Office. (2008). *Electric Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance.* Retrieved on September 16, 2011, from www.gao.gov/new.items/d08987.pdf

**Exhibit 8-3 RTO/ISO expenses and category descriptions**

| Category | Description |
|---|---|
| Transmission service | ‣ Load dispatch scheduling, monitoring, and reliability<br>‣ Reliability planning<br>‣ Interconnection studies |
| Market expenses | ‣ Day-ahead, real-time, transmission rights, and ancillary markets facilitation<br>‣ Market monitoring and compliance services |
| General and administrative expenses | ‣ Administrative salaries, benefits<br>‣ Outside services, insurance, rent |
| Other expenses | ‣ Customer assistance service (e.g., billing / cost / contact inquiries)<br>‣ Informational and instructional services expenses |

*Source: GAO, "Electricity Restructuring," (2008)*[64]

While a small portion of an ISO/RTO's revenue is derived from membership fees or reimbursements for integration studies, the majority of an ISO/RTO's costs for administering the transmission grid are passed on to the market (ultimately paid by the electricity consumer) based on FERC-approved tariff formulas. This cost reimbursement can be thought of as a small surcharge on each transaction in the power market, and is collected by the ISO/RTO as the settlement agent between generators, transmission owners, and load-serving entities. Thus, the cost per MWh for administering transmission services in a given region can vary fairly significantly based on the services provided by the ISO/RTO and the volume of electricity transferred by the region's transmission system.

## 8.2 Products and Services of RTOs and ISOs

Despite differences in nomenclature, RTOs and ISOs largely serve the same market purpose and provide similar market services. RTOs previously have been ISOs and that is why some of the RTOs still have ISO as part of the name (e.g., ISO New England). These organizations are charged with operating the transmission grid, and are responsible for maintaining the reliability of the systems under their control. RTOs/ISOs oversee and direct the high-voltage, bulk power systems, and provide a clearinghouse for wholesale power purchases by matching buyers and sellers of electricity in day-ahead, hour-ahead, and real-time markets. RTOs/ISOs offer different market services depending on the accepted market design (e.g., a market design accepted by ERCOT, SPP, and CAISO does not include a capacity market). The market can evolve over time, and additional services can be added to the market (e.g., SPP will launch day-ahead and ancillary service markets in 2014). Additionally, they have the authority to coordinate the output of generators in their service area, and provide reliability services such as outage coordination, generation scheduling, transmission planning, voltage management, ancillary services provisions, and load forecasting.

In areas of the country not covered by regional grid operators, market offerings are typically performed by vertically integrated utilities, under the oversight of the state Public Utility Commissions/Public Service Commissions. These utilities will forecast daily loads and coordinate generation facilities to meet the expected demand, and will provide regulation services with their own generation assets in real-time. There is no need for day-ahead or real-time energy markets, as the vertically integrated utility owns and controls the full value chain from generation through transmission and distribution.

**Exhibit 8-4 RTO/ISO characteristics and market offerings**

| | Profile | | | Transmission functions | | | | Wholesale energy market functions | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | RTO/ ISO | Approx pop. (Mil) | Line miles (>230 kV) | Service provider | Balancing authority | Reliability coordinator | Planner | Real-time market admin. | Day-ahead market admin. | Ancillary services market admin. | Capacity market admin. |
| **California ISO** | ISO | 30 | 11,730 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | |
| **ISO New England** | RTO | 14 | 2,526 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| **Midwest ISO** | RTO | 40 | 14,678 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| **New York ISO** | ISO | 19 | 4,121 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| **PJM** | RTO | 51 | 19,710 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| **SW Power Pool** | RTO | 5 | 10,257 | ✓ | | ✓ | ✓ | ✓ | (2014 launch) | (2014 launch) | |
| **ERCOT** | ISO | 22 | 8,917 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | |

*Sources: GAO, "Electricity Restructuring" (2008)[64]; ISO/RTO Council, "The Value of Independent Regional Grid Operators" (2005)[65]; and the organizations' respective websites*

**Exhibit 8-5 Description of RTO/ISO market offerings**

| | |
|---|---|
| **Service provider** | Administers the transmission tariff and provides transmission services, receives and processes transmission service requests, and determines available capacity |
| **Balancing authority** | Integrates resource plans regionally and maintains in real time the balance of electricity resources and electricity demand |
| **Reliability coordinator** | Ensures the real-time operating reliability of the transmission system |
| **Planner** | Works with stakeholders to develop overall plans for new transmission needed to meet future projected electricity demand |
| **Real-time market administrator** | Administers a market where electricity is bought and sold at prices determined in real time to satisfy the difference between projected needs and actual demand<br>Many of these markets price electricity differently at various locations across the region in order to reflect the costs associated with congestion. |
| **Day-ahead market administrator** | Administers a forward market where electricity is bought and sold for use the following day based on projected customer needs |
| **Ancillary services market administrator** | Manages services necessary to support the reliable operation of the transmission system and provision of electricity at appropriate frequency and voltage levels |
| **Capacity market administrator** | Administers a system to procure a sufficient portfolio of supply and demand resources to meet future electricity needs and encourage investment |

*Source: GAO, "Electricity Restructuring," (2008)[64]*

[65] ISO/RTO Council. (2005). *The Value of Independent Regional Grid Operators.* Retrieved on September 16, 2011, from http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/Value_of_Independent_Regional_Grid_Operators.pdf

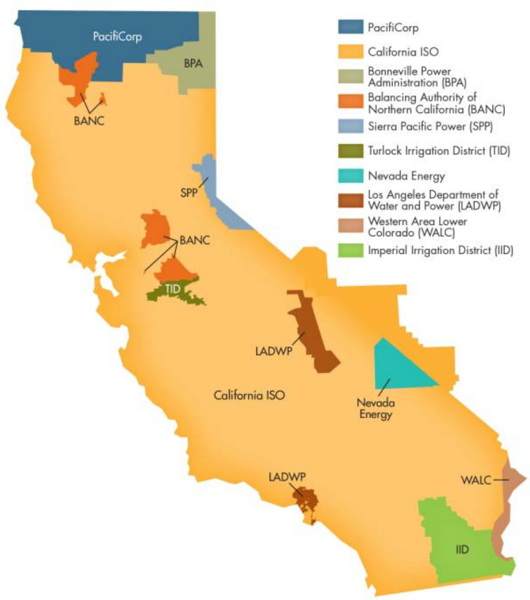
More details about different ISOs/RTOs can be found in the ISOs/RTOs primers: *California Independent System Operator*, *ERCOT Independent System Operator*, *MISO Regional Transmission Organization*, *ISO New England Regional Transmission Organization*, *New York ISO Regional Transmission Organization*, *PJM Regional Transmission Organization*, and *Southwest Power Pool, Inc*.

# 9 California Independent System Operator

## 9.1 History and Geography of California ISO

The California Independent System Operator (CAISO)[66] was established as a non-profit corporation in 1998 to operate the transmission system. CAISO is responsible for maintaining and enhancing reliability, establishing and overseeing competitive wholesale electricity markets, and planning the power system for California's future electrical grid. As of September 2012, CAISO dispatches approximately 58,700 MW of generating capacity over about 25,800 miles of the state's transmission lines, providing electric service to 30 million people or about 80 percent of California (Exhibit 9-1).[67] An all-time peak demand of 50,270 MW was set on July 24, 2006.

**Exhibit 9-1 California ISO market area**






Similar to other ISOs, a primary function of CAISO is to facilitate the energy markets in its service area, maintain minute-to-minute reliable electricity service in a cost-effective manner, manage wholesale markets, and develop bulk power system planning processes. CAISO operates the electricity (energy, capacity, and ancillary services) markets to serve load and meet reserve obligations with the lowest-cost resources possible. It has designed a locational market structure to ensure that transmission capability is used efficiently and that energy prices reflect the

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

[67] California ISO. (2012). *Annual Report: State of the Grid – September 4, 2012*. Retrieved on December 3, 2012, from http://www.caiso.com/Documents/2012StateoftheGrid.pdf

[68] California ISO. (2013). *The ISO Grid*. Retrieved on March 28, 2013, from http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx

marginal cost of providing the service at each location. While the wholesale electric energy cost includes capacity and ancillary services to ensure reliable supply of power, as seen in Exhibit 9-2, the majority of the electricity price in CAISO is dominated by energy cost (i.e., the cost of generating power, which includes fuel costs, operation and maintenance for generators, and reimbursement for the capital cost of generators).

**Exhibit 9-2 CAISO average wholesale electricity price 2009, 2010, and 2011 ($/MWh)**

| Price | 2009 | 2010 | 2011 |
|---|---|---|---|
| **Energy** | $ 37.70 | $ 39.53 | $ 35.78 |
| **Ancillary services** | $ 0.39 | $ 0.37 | $ 0.62 |
| ***Total*** | ***$ 38.09*** | ***$ 39.91*** | ***$ 36.39*** |

*Data Source: 2011 Annual Report on Market Issues and Performance* [69]

## 9.2 CAISO Products and Services

CAISO manages competitive markets that provide energy services and reliability services through a day-ahead energy market, hour-ahead energy market, real-time energy market, congestion revenue rights (CRR), and an ancillary services market. In 2011, these markets aggregated billings of over $8.3 billion (energy market $8.2 billion and ancillary services $139 million).[69]

## 9.3 Energy Market

CAISO's main role as an ISO is to coordinate an energy market throughout the service area, which consists of facilitating the continuous buying, selling, and delivery of wholesale electricity, providing dispatch requests to generators, and acting as a data clearinghouse. In addition to acting as a clearinghouse for bilateral power contracts, CAISO manages a day-ahead market, an hour-ahead market and a real-time market for power delivery. In each market CAISO "clears the market," i.e., coordinates which generators will operate, at what time, and at what price to meet electricity demand. The price of electricity is based on the cost of bringing the next marginal unit of electricity on line at a specific location throughout the California control area. This method of calculating electricity price is called locational marginal pricing (LMP).

The day-ahead market clears both energy and ancillary services markets for each hour of the operating day by matching energy demand bids at each LMP node and by operating reserve requirements throughout the system with the generators' ability to provide power taking into account physical limiting factors such as transmission capacity and the generators' scheduled maintenance. The market opens seven days prior to the operating day and closes the day before the operating day.[69]

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[69] California ISO. (2012). *2011 Annual Report on Market Issues and Performance*. Retrieved on December 3, 2012, from http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx

The hour-ahead market pre-dispatches non-dynamic (fixed) imports or exports about 45 minutes prior to the start of the identified hour of operation (i.e., the hour in which a fixed level of export and import will be provided for the entire hour). The hour-ahead market considers all real-time schedules and bids from resources inside and outside of the CAISO and the forecast of real-time demand during the identified hour of operation.[69]

The real-time market procures energy and ancillary services, and manages congestion in real-time. The real-time market opens at 1:00 p.m. prior to the operating day and closes 75 minutes prior to the identified hour of operation (i.e., the hour in which the generator proposes operating and providing the electricity). It uses the final day-ahead and hour-ahead schedules and re-dispatches the generators every five minutes based on the current demand and the generators' bid prices—with the lowest-cost resources dispatched first.[69]

## 9.4 Ancillary Services Market

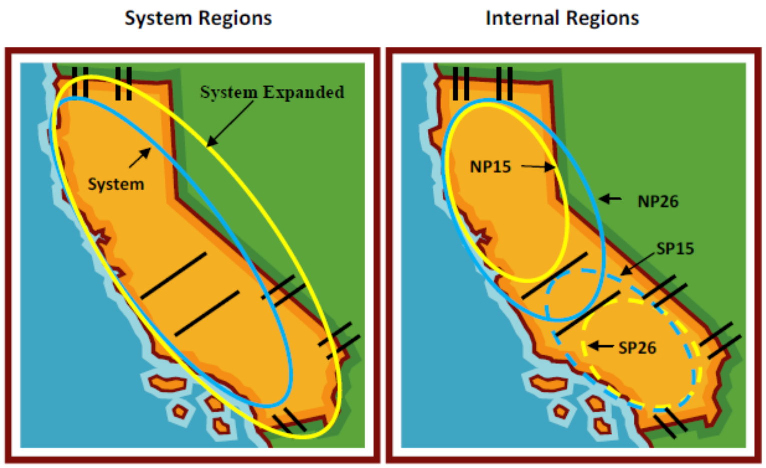
CAISO facilitates an ancillary services market to ensure the reliability of electricity production and transmission. The ancillary services include operating reserve (spinning and non-spinning reserve) and regulation (regulation up and regulation down).

The operating reserve service provides backup generation in the event of a system contingency such as unexpected failure of generators, transmission lines, or other electrical equipment. The spinning reserve must be from units that are on-line and can provide additional output within 10 minutes. The non-spinning reserve must be from resources (generation units or demand response resources) that are able to synchronize with the grid and provide output within 10 minutes. Both spinning and non-spinning capacity can be bid as non-contingent or contingency-only, where the contingency-only can only be used to avoid a system contingency.

The regulation service allows CAISO to manage small changes in the system's electrical load by increasing (up regulation) or decreasing (down regulation) the generators' output by sending a control signal to adjust the power output. The up and down regulation requirements are set and provided independently. The regulation up is provided by generator units that can quickly increase the power output in response to automated signals from CAISO. The regulation down is provided by generator units that can quickly decrease the power output after receiving the automated control signal from CAISO.

An ancillary service market clearing price received by each unit for each service provided is calculated as a sum of regional ancillary services shadow prices. The regional ancillary services shadow prices reflect the cost of providing the next available MW of the service inside of a region. There are ten different regions: NP15, NP15 expanded, NP26, NP26 expanded, SP15, SP15 expanded, SP26, SP26 expanded, system, and system expanded (Exhibit 9-3). For example, the ancillary service market clearing price for a service provided in the SP26 region is equal to a sum of regional ancillary service shadow prices for SP26, SP26 expanded, system, and system expanded regions.

**Exhibit 9-3 Ancillary services market regions**




*Note: the expanded internal regions will include any inter-ties with one end in the unexpanded region.*


## 9.5 Congestion Revenue Right (CRR)

The CRR market provides a financial instrument for market participants to hedge against congestion costs in the system and they are settled in the day-ahead market only. In the absence of any transmission constraints, all LMP nodes would price at the lowest priced generation resource. However, there is not enough physical transmission to deliver electricity from low-cost resources to the place demanding the electricity at all times. Thus, some nodes will, by necessity, use power from higher cost resources and therefore the LMP at that node will be higher. The difference in LMPs between two nodes that is attributable to the transmission constraints multiplied by the transfer amount is called “congestion cost” or “the cost of congestion” because, but for the lack of transmission capacity, a lower-cost resource would be used to meet demand. A CRR can be thought of as a “reservation” for access to a specific transmission path (e.g., between LMP nodes) for a specific timeframe, but does not actually correspond with a physical right to deliver energy. Rather, a CRR will create a revenue stream (or charges) based on the difference between two day-ahead LMP prices at specific times.

## 9.6 Transmission Planning

CAISO is responsible for maintaining the operations and reliability of the grid in its service area and, as such, conducts periodic reviews of grid adequacy. It conducts an annual transmission planning process to identify necessary grid expansions. In addition, it provides support to generation interconnection.

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[70] California ISO. (2011). *2010 Annual Report on Market Issues and Performance*. Retrieved on March 28, 2013, from http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf

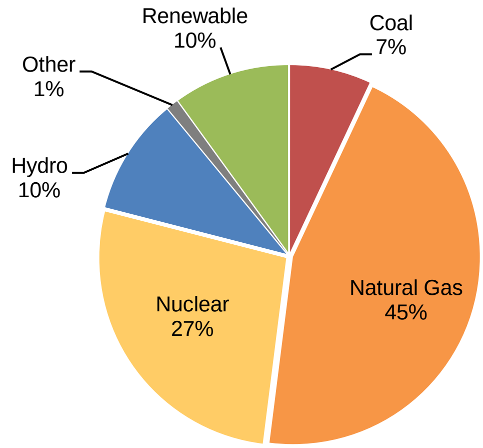
## 9.7 Capacity Market

CAISO does not have a centralized capacity market. It relies on a resource adequacy program established by the California Public Utilities Commission to provide sufficient generation capacity. Load-serving entities are responsible for contracting for capacity services above the anticipated demand (115 percent of the forecasted peak demand) in their service area for each month. This process is conducted on a year-ahead basis.

## 9.8 CAISO Generation Profile

While CAISO does not own or directly operate power generation facilities, it is responsible for managing scheduled outages for maintenance and maintaining reliable electricity service at the lowest cost possible, as provided by the different generators on the system. Thus, to maintain reliability, CAISO continually evaluates the fuel mix of generation assets in the region. As seen in Exhibit 9-4, the majority of the region's power comes from natural gas and nuclear generation facilities.

**Exhibit 9-4 California ISO generation (MWh) by fuel type (2011)**




*Data Source: ABB Velocity Suite*[71]

[71] ABB Velocity Suite. (2012). *Velocity Suite Database: Power/Regional Report Analysis/ISO Region/California ISO*. Retrieved on December 3, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/site/default.aspx

# 10 ERCOT Independent System Operator

## 10.1 History and Geography of ERCOT

The Electric Reliability Council of Texas, Inc., (ERCOT) is an Independent System Operator (ISO)[72] that manages the high-voltage transmission system and the wholesale electricity markets in the majority of the state of Texas (Exhibit 10-1). ERCOT's four main objectives include ensuring reliability and adequacy of the regional electric network, facilitating nondiscriminatory access to transmission/distribution systems, maintaining a competitive retail electric market (ensuring customers have choice in providers), and operating a fair and competitive wholesale electric market. ERCOT is unique in that its electrical transmission system is contained entirely within the state of Texas, and thus is primarily regulated by the Public Utility Commission of Texas (PUCT) and not the Federal Energy Regulatory Commission (FERC). ERCOT dispatches approximately 74,000 MW of capacity over 40,500 miles of transmission lines to more than 23 million Texas consumers. An all-time peak demand of 68,305 MW was set on August 3, 2012.[73]

**Exhibit 10-1 ERCOT geographic area**


*Image created by NETL. ABB Velocity Suite*[74]

Similar to other ISOs, ERCOT is responsible to facilitate the energy markets in its service area and maintain reliable electricity service in a cost-effective manner. ERCOT manages this responsibility by operating the energy markets to serve load and meet reserve obligations with the lowest-cost resources possible, serving as a data clearinghouse for wholesale energy markets, and facilitating the retail electric competition in the state. While the total cost of wholesale electricity includes services to ensure a reliable supply of power, and non-market-based expenses (uplift cost which includes out-of-merit energy dispatch, out-of-merit

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

[73] ERCOT. (2012). *Company Profile: ERCOT Quick Facts (October 2012)*. Retrieved on December 3, 2012, from http://ercot.com/about/profile/

[74] ABB Velocity Suite. (2012). *Intelligent Map – US RTO Regions*. Retrieved on November 29, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx

commitment, replacement reserve services, and reliability must-run contracts),[75] the majority of the wholesale electricity price in ERCOT is dominated by energy services (i.e., the cost of generating power, which includes fuel costs, operation and maintenance for generators, reimbursement for the capital cost of generators, etc.) (Exhibit 10-2).

**Exhibit 10-2 ERCOT average wholesale electricity price 2009, 2010 and 2011 ($/MWh)**

| Price | 2009 | 2010 | 2011 |
|---|---|---|---|
| Energy | $ 34.03 | $ 39.40 | $ 53.23 |
| Ancillary Services | $ 1.15 | $ 1.26 | $ 2.41 |
| Uplift | $ 0.65 | $ 0.40 | --- |
| ***Total*** | ***$ 35.83*** | ***$ 41.06*** | ***$ 55.64*** |

*Data Source: 2011 State of the Market Report for the ERCOT Wholesale Electricity Markets* [76]

## 10.2 ERCOT Retail Competition

Deregulation in the electric utility industry created a landscape open for retail competition for residential, commercial, and industrial electricity customers. The requirement that transmission and distribution line owners allow third parties access to these assets (in exchange for compensation) created an opportunity for a new market to exist. In this new market—retail competition—third-party retail electric providers (REP) are allowed to purchase wholesale power, delivery service, and related power services (i.e., ancillary services), and sell the power to retail customers at retail rates.

ERCOT plays a key role in maintaining and facilitating retail competition in Texas, as all retail electric providers are required to register with the Public Utility Commission in Texas, which adds them to a centralized registration database managed by ERCOT. Additionally, ERCOT tests retail provider's electronic interface systems prior to the retail provider serving customers to ensure adequate, accurate information flow. ERCOT then serves as the transaction clearinghouse for all retail transactions, matching retail provider's wholesale power purchases with the aggregated loads of retail customers, and ensuring payments are processed properly. Additionally, ERCOT is responsible for managing all retail customers' switching choices in order to facilitate customer choice. This means that ERCOT must maintain a record of individual retail customers changing their electric service providers (e.g., new service requests, change of provider, account cancellations, etc.) in order to properly match the usage of customers with the wholesale power purchases of each REP. As of October 2012, 58 percent of residential load and 64 percent of small commercial load had switched electricity providers to a competitive retailer.[73]

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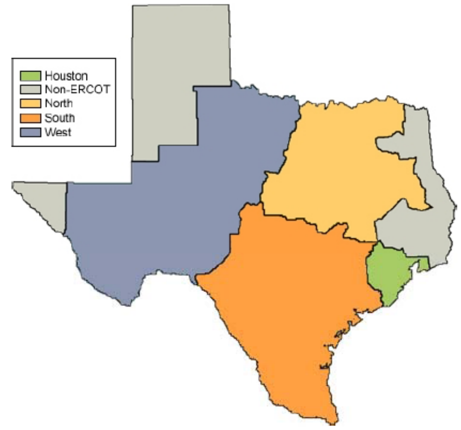
[75] Potomac Economics. (2011). *2010 State of the Market Report for the ERCOT Wholesale Electricity Markets (August 2011)*. Retrieved on October 19, 2011, from http://www.potomaceconomics.com/uploads/ercot_reports/2010_ERCOT_SOM_REPORT.pdf

[76] Potomac Economics. (2012), *2011 State of the Market Report for the ERCOT Wholesale Electricity Markets (July 2012)*. Retrieved on October 19, 2011, from http://www.potomaceconomics.com/uploads/ercot_reports/2010_ERCOT_SOM_REPORT.pdf

## 10.3 ERCOT Zonal vs. Nodal System

**Exhibit 10-3 ERCOT zonal market**

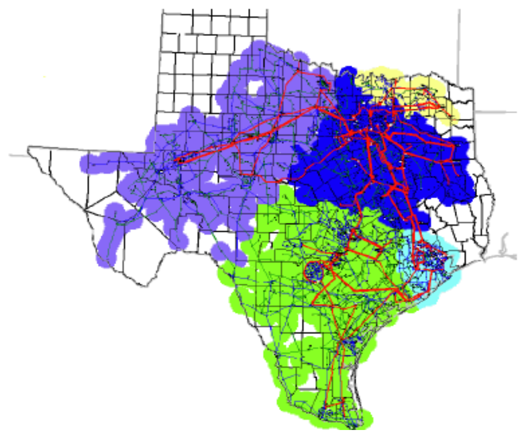



*(Used with permission from ERCOT[77])*

In response to a PUCT order in 2003, ERCOT undertook a significant change to the region's market structure by changing from zonal pricing to a nodal pricing system. Under the zonal pricing system, ERCOT's geographic region was divided into four zones, also known as congestion management zones (Exhibit 10-3).[77] By having only four zones, at any one time there were at most four different prices for electricity, with congestion within a zone essentially averaged out within the zone.

Since inter-zone congestion costs were averaged to apply to the zone as a whole, the market signal for new generation or transmission needs was lost. However, as shown in the map to the right (Exhibit 10-4)[77], several transmission corridors experienced ongoing constraints—these constraints are exactly the cause of congestion costs. As part of "Project 26376," in September 2003 PUCT ordered ERCOT to institute a nodal wholesale market, which would serve to eliminate the averaging of inter-zonal transmission costs, provide better price signals for locating generation and transmission, and develop a day-ahead energy market. On December 1, 2010, the new market design was launched, with locational marginal pricing (LMP) at over 8,000 nodes. Potomac Economics estimated that ERCOT's nodal market design provided approximately $30 million in savings over its first four months of operation.[78]

**Exhibit 10-4 ERCOT zones**



*(Used with permission from ERCOT[77])*

## 10.4 ERCOT Products and Services

ERCOT facilitates markets for energy services and reliability services through a day-ahead market and a real-time market, as well as a congestion revenue rights (CRR) market. In 2011 ERCOT's markets consisted of approximately $34 billion in billings with over 1,100 market participants generating, moving, buying, selling, or using wholesale electricity.[73] The wholesale power markets are managed with a day-ahead market and a real-time market.

[77] Electric Reliability Council of Texas. (2010). *ERCOT Board Members Overview and Orientation.* Retrieved October 18, 2011, from http://www.ercot.com/content/news/presentations/2010/ERCOT%20Board%20Orientation,%20June%202010.pdf

[78] ERCOT. (2011). *ERCOT Quick Facts.* Retrieved on October 3, 2011, from http://www.ercot.com/content/news/presentations/2011/ERCOT+Quick+Facts+-+Aug+2011.pdf

### 10.4.1 Day-Ahead Market

In the day-ahead market, ERCOT clears both energy and operating reserve requirements by accounting for existing bilateral contracts, matching bids for supply with demand projections, determining a clearing price at each node, and providing dispatch orders. This scheduling process takes into account multiple physical limitations of the system, including planned generator outages due to maintenance, as well as physical constraints of existing transmission lines.

### 10.4.2 Real-Time Market

In the real-time market, generators not already contracted to run via bilateral contracts or dispatched in the day-ahead (or other ancillary service market commitment) can provide bids to run for the next hour. ERCOT runs a dispatch model every five minutes that calculates the LMP for each node and issues orders to generators participating in the real-time market to run and at what level. While ERCOT plans sufficient generation capacity to cover anticipated demand in the day-ahead market, unforeseen outages, weather problems, or significant variations from anticipated load can create energy needs in the real-time market.

### 10.4.3 Ancillary Services Market

Generators are required to provide their own ancillary services (i.e., reliability services) in order to participate in the wholesale power market. A generator can achieve this in three ways—by agreeing to provide the services through its own generation fleet; by contracting with another generator to provide the services; or by purchasing ancillary services in the day-ahead market. In this transaction, ERCOT solicits bids to provide ancillary services and matches the needed quantity with the available supply; thus, a specific generator is not buying services from a particular supplier, but rather from a pool of available supply.

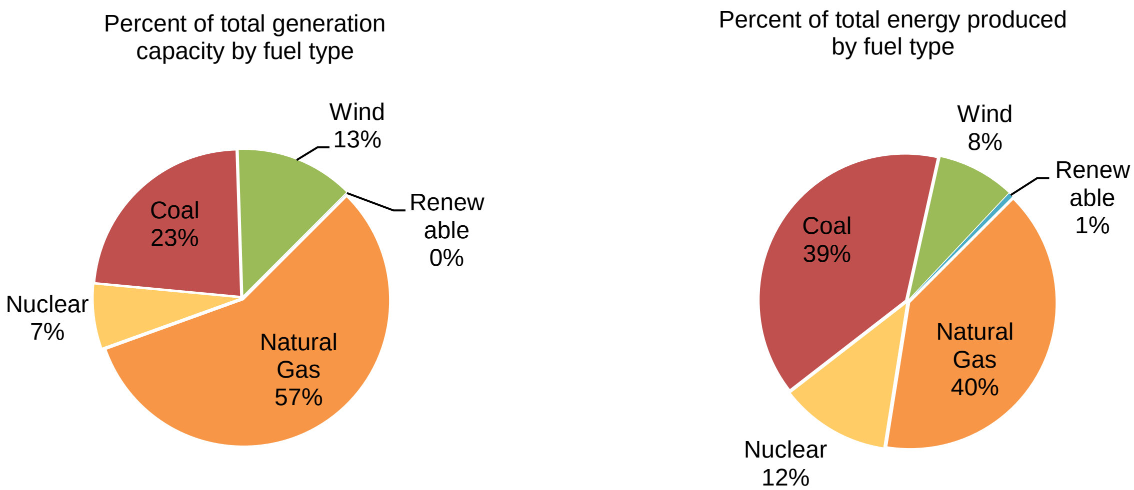
### 10.4.4 Congestion Revenue Rights Market

The congestion revenue rights (CRR) market provides a financial instrument for market participants to hedge congestion costs in the day-ahead market. In the absence of any transmission constraints, prices at all nodes would equal the lowest-priced generation resource. However, transmission constraints exist in that there is not enough physical transmission to deliver electricity from the lowest-cost resources to all the places demanding electricity at all times. The system operator will calculate the least expensive way to service load while respecting transmission limits, but some nodes will be required to draw power from higher-cost resources, and thus the LMP at those nodes will be higher. The difference in LMP between nodes that is attributable to transmission constraints is called "congestion cost" or "the cost of congestion" because, but for the lack of transmission capacity, a lower-cost resource would be used to meet demand. A CRR can be thought of as a "reservation" for access to a specific transmission path (e.g., between LMP nodes) for a specific timeframe, but does not actually correspond to a physical right to deliver energy. Rather, a CRR will create a revenue stream (or charges) based on the difference between the prices of two nodes for a particular hour of delivery in the day-ahead market.

## 10.5 ERCOT Generation Profile

Although ERCOT does not own or directly operate power generation facilities, it is responsible for managing scheduled outages for maintenance, and maintaining reliable electricity service at the lowest cost possible, as provided by the generators on the system. The diversity of fuel sources in ERCOT's system helps it maintain reliability at a low cost by ensuring that individual fuel price spikes do not disproportionately affect system cost. The capacity and energy from different fuel types in the ERCOT region are shown in Exhibit 10-5.

**Exhibit 10-5 ERCOT capacity and energy production by fuel type (2011)**




*Data Source: Company Profile: ERCOT Quick Facts (October 2012)* [73]

# 11 ISO New England Regional Transmission Operator

## 11.1 History and Geography of ISO New England

The Independent System Operator (ISO)[79] New England was established as a non-profit corporation in 1997. It was designated by the Federal Energy Regulatory Commission (FERC) as a Regional Transmission Operator (RTO) in 2005.[80] ISO New England is responsible for ensuring reliability and establishing and overseeing competitive wholesale electricity markets for six U.S. states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont (Exhibit 11-1). As of January 2013, ISO New England dispatches approximately 32,000 MW of generating capacity and 2,000 MW of demand resources over 8,000 miles of transmission lines providing electric service to 14 million people.[81] An all-time peak demand of 28,130 MW was set on August 2, 2006.

**Exhibit 11-1 ISO New England market area**


(*Used with permission from ISO New England.*[81])

Similar to other RTOs and ISOs, a primary function of ISO New England is to facilitate the energy markets in its service area, maintain minute-to-minute reliable electricity service in a cost-effective manner, manage wholesale markets, and develop bulk power system planning processes. ISO New England operates the electricity (energy, capacity, and ancillary services) markets to serve load and meet reserve obligations with the lowest-cost resources possible. It has designed a locational market structure to ensure that transmission capability is used efficiently and that energy prices reflect the marginal cost of providing the service at each location. The electricity price in ISO New England (Exhibit 11-2) is dominated by energy cost (i.e., the cost of generating power, which includes fuel costs, operation and maintenance for generators, and reimbursement for the capital cost of generators).

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

[80] ISO New England. (2011). *Timeline*. Retrieved on November 14, 2011, from http://www.iso-ne.com/aboutiso/co_profile/timeline/index.html

[81] ISO New England. (2013). *Key Facts: New England's Power System and Wholesale Electricity Market*. Retrieved on April 6, 2013 from: http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/ (Also source of map in Exhibit 1)

**Exhibit 11-2 ISO New England average wholesale electricity price 2009, 2010, and 2011 ($/MWh)**

| Price | 2009 | 2010 | 2011 |
|---|---|---|---|
| Energy | $ 42.89 | $ 50.98 | $ 48.00 |
| Capacity | $ 13.90 | $ 12.69 | $10.47 |
| Ancillary Services | $ 2.51 | $ 1.93 | $ 0.88 |
| Total | $59.30 | $ 65.60 | $59.35 |

*Data Source: 2011 Annual Markets Report* [82]

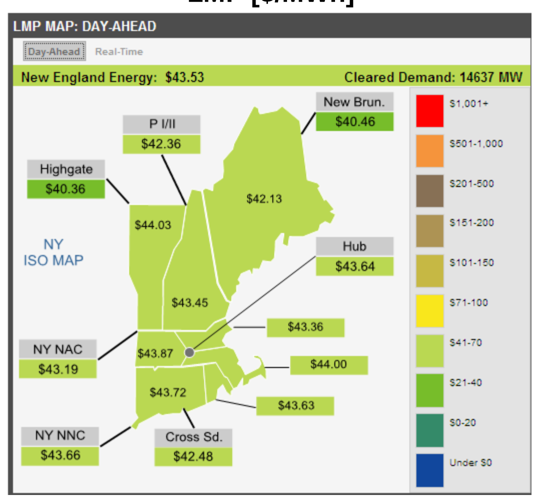
## 11.2 ISO New England Products and Services

ISO New England manages competitive markets that provide energy services and reliability services through a day-ahead energy market, real-time energy market, forward capacity market, financial transmission rights (FTR) market, and an ancillary services market. In 2011, these markets aggregated billings of over $8.2 billion ($6.8 billion were traded in energy markets and $1.4 billion were traded in capacity and ancillary services markets) across ISO New England's 500 market participants.[83]

### 11.2.1 Energy Market

ISO New England's main role as an RTO is to coordinate an energy market throughout the service area, which consists of facilitating the continuous buying, selling, and delivery of wholesale electricity; providing dispatch requests to generators; and acting as a data clearinghouse. In addition to acting as a clearinghouse for bilateral power contracts, ISO New England manages a day-ahead market and a real-time market for power delivery. In each market ISO New England "clears the market," i.e., coordinates which generators will operate at what time, at what price, and at over 900 pricing nodes, to meet electricity demand. The price of electricity is based on the cost of bringing the next marginal unit of electricity on line at specific locations throughout the New England area. This method of calculating electricity price is called locational marginal pricing (LMP). ISO New England features the LMP since 2003 (Exhibit 11-3).[84]

**Exhibit 11-3 Day-ahead market - zonal LMP [$/MWh]**




*(Used with permission from ISO New England.[84])*

[82] ISO New England. (2013). *2011 Annual Markets Report*. Retrieved on January 17, 2013, from http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf

[83] ISO New England. (2012). *2011 Financial Report*. Retrieved on December 3, 2012, from http://www.iso-ne.com/aboutiso/fin/finstmnts/2011_financial_statements.pdf

[84] ISO NE. (2013). *ISO Express*. Retrieved on March 28, 2013, from http://isoexpress.iso-ne.com/guest-hub

The day-ahead market clears both energy and operating reserves for each hour of the next operating day by matching energy demand bids at each LMP node and operating reserve requirements throughout the system with the generators' ability to provide power. Thus, ISO New England ensures scheduling adequate resources to meet the next day's expected demand, taking into account physical limiting factors such as transmission capacity and the generators' scheduled maintenance.

Generators participate in the real-time market by submitting bids to provide electricity at a certain price during a reoffer period. The reoffer period is between 4:00 – 6:00 p.m. the day before operating day. ISO New England produces real-time hourly commitments after 6:00 p.m. the day before operating day and sends the generators' dispatch signals every ten minutes during the operating day based on the current demand and the generators' bid price—with the lowest-cost resources dispatched first.[85]

### 11.2.2 Capacity Market

ISO New England established a forward capacity market (FCM) to provide appropriate price signals to attract new capacity investments and maintain existing resources in order to ensure the reliability of the New England bulk power system.[86] The capacity market includes traditional generation (e.g., oil, coal, natural gas) and non-traditional supply resources (e.g., demand resources [demand-side management, energy efficiency, load management, distributed generation], intermittent generation and imports). ISO New England projects the need of the power system and conducts the forward capacity auction approximately three years in advance (e.g., auction in 2011 for delivered capacity in 2014/2015) for a one-year period (e.g., from June 1, 2014 to May 31, 2015). Capacity obligations are adjusted by annual and monthly reconfiguration auctions.

### 11.2.3 Ancillary Services Market

ISO New England facilitates an ancillary services market to ensure the reliability of electricity production and transmission. The ancillary services include a forward reserve market, real-time reserve market, and regulation market.

The forward reserve market is held two months in advance of the Summer Capability Period (from June 1 to September 30) and the Winter Capability Period (from October 1 to May 31) to acquire off-line operating reserve. The forward reserve market is a locational forward reserve market where the clearing prices are based on the cost of serving the next increment of reserve at specific locations throughout the New England area. Capacity resources that were cleared in the forward reserve market have to offer their capability into the real-time energy market.[86]

The real-time reserve market is cleared simultaneously with the real-time energy market to provide reserve every five minutes during the operating day. The hourly reserve market clearing

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[85] Potomac Economics. (2011). *2010 Assessment*. Retrieved on November 14, 2011, from http://www.potomaceconomics.com/markets_monitored/iso_new_england

[86] ISO New England (2011). *Overview of ISO New England (ISO-NE 101). Module 6 – Introduction to New England's Forward Capacity Market.* Retrieved on November 14, 2011, from http://www.iso-ne.com/support/training/courses/isone_101/index.html

prices are determined using energy offers. Real-time reserve is provided by all units in New England that are capable of providing operating reserve.[87]

Regulation service allows ISO New England to manage small changes in the system's electrical load by increasing or decreasing the generators' output. Generators submit offers by 6:00 p.m. the day before operating day. Hourly real-time regulation clearing price is computed from five-minute samples while the generator receives a control signal to adjust output every four seconds.[88]

The ISO New England offers two specialized ancillary services: voltage support and black start capability. The voltage support is used to maintain transmission voltage while black start capability is used to restart the transmission system following a system-wide blackout.[85]

### 11.2.4 Financial Transmission Rights (FTR)

The FTR market provides a financial instrument for market participants to hedge against congestion costs in the system. In the absence of any transmission constraints, all LMP nodes would price at the lowest-priced generation resource. However, there is not enough physical transmission to deliver electricity from low-cost resources to the place demanding the electricity at all times. Thus, some nodes will, by necessity, use power from higher cost resources and therefore the LMP at that node will be higher. The difference in LMPs between two nodes that is attributable to the transmission constraints multiplied by the transfer amount is called "congestion cost" or "the cost of congestion" because, but for the lack of transmission capacity, a lower-cost resource would be used to meet demand. An FTR can be thought of as a "reservation" for access to a specific transmission path (e.g., between LMP nodes) for a specific timeframe, but does not actually correspond with a physical right to deliver energy. Rather, an FTR will create a revenue stream (or charges) based on the difference between two day-ahead LMP prices at specific times.

### 11.2.5 Transmission Planning and Resource Adequacy

ISO New England is responsible for maintaining the operations and reliability of the grid in its service area and, as such, conducts periodic reviews of grid adequacy. It publishes a regional system plan annually. Transmission expansion is assessed on an annual basis, in conjunction with members' annual planning cycles, to understand the projects being studied or currently underway, as well as to suggest future projects needed to ease congestion or other grid issues. Similarly, ISO New England undertakes a resource adequacy study on an annual basis, modeling expected supply and demand to determine available reserve margins and plan for the integration of additional generation or transmission, in order to maintain reliable service. In addition to assessing the need for new transmission or generation resources, ISO New England is also responsible for administration of the generator interconnection process.

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[87] ISO New England. (2011). *ISO New England Markets and Transmission Services: An Intermediate Overview – Day Two*. Retrieved November 16, 2011, from http://www.iso-ne.com/support/training/courses/mrkts_trans_serv/index.html

[88] ISO New England. (2011). *Overview of ISO New England (ISO-NE 101). Module 5 – Introduction to New England's Wholesale Electricity Market*. Retrieved on November 14, 2011, from http://www.iso-ne.com/support/training/courses/isone_101/index.html

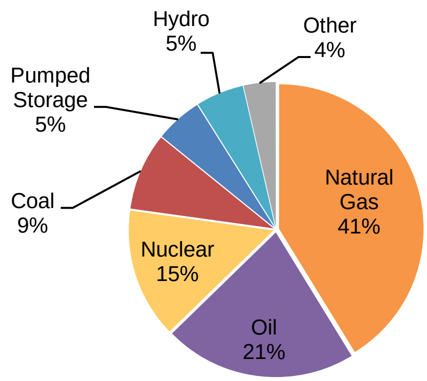
### 11.2.6 Tariff Administration

As an RTO, ISO New England is responsible for administering its "Open Access Transmission Tariff" as a part of ISO New England's "Transmission, Markets and Services Tariff." This tariff is filed with FERC and outlines how ISO New England will determine rates for transmission service, evaluate and approve requests for transmission service, perform transmission impact studies, and coordinate use and administration with other transmission providers in the region, among other activities. With FERC's approval of the tariff, ISO New England is the sole decision-making authority on the provision of transmission service in accordance with the tariff. However, in a case when a dispute cannot be solved internally as a part of good-faith negotiations for a period of not less than sixty (60) calendar days, the dispute may be submitted to arbitration or any other form of alternative dispute resolution.[89] The dispute may be submitted by any party for resolution to FERC, to a court, or to an agency with jurisdiction over the dispute.

## 11.3 ISO New England Generation Profile

While ISO New England does not own or directly operate power generation facilities, it is responsible for managing scheduled outages for maintenance and maintaining reliable electricity service at the lowest cost possible, as provided by the different generators on the system. Thus, to maintain reliability, ISO New England continually evaluates the fuel mix of generation assets in the region. As seen in Exhibit 11-4, the majority of the region's power comes from natural gas generation facilities.

**Exhibit 11-4 New England capacity by fuel type (2010)**



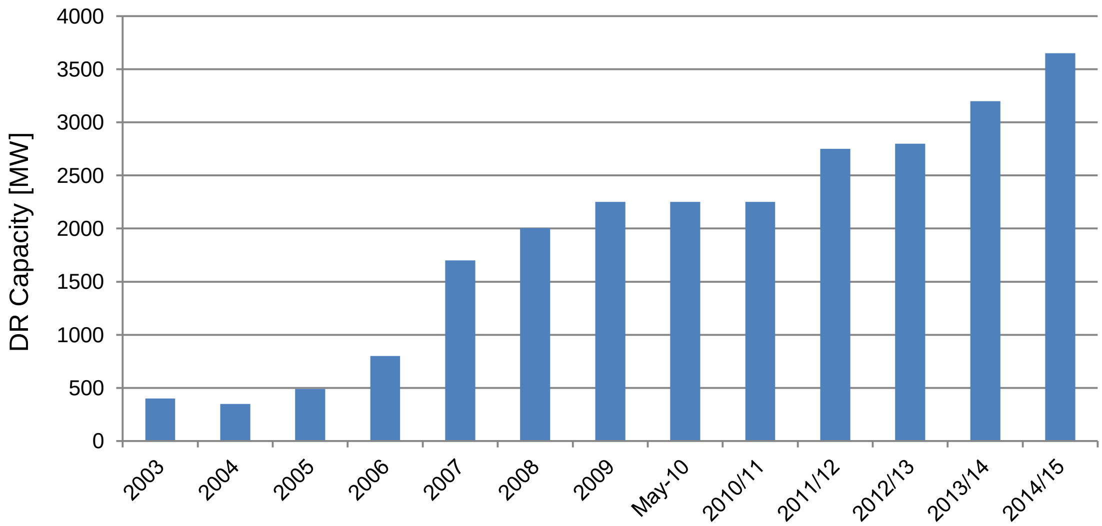

*Data Source: ISO New England Markets and Transmission Services* [90]

[89] ISO New England. (2013). *Transmission, Markets and Services Tariff*. Retrieved on January 17, 2013, from http://www.iso-ne.com/regulatory/tariff/sect_1/sect_i.pdf

[90] ISO New England. (2011). *Overview of ISO New England (ISO-NE 101).* Module 4 - Overview of ISO New England System Planning. Retrieved November 16, 2011, from http://www.iso-ne.com/support/training/courses/isone_101/index.html

Demand resources, such as energy efficiency and demand response, can participate just like traditional generation resources in the forward capacity market. The demand resources accounted for up to 10 percent of the region's annual installed capacity requirements since the forward capacity market started in 2010 (Exhibit 11-5).

**Exhibit 11-5 New England demand resource**



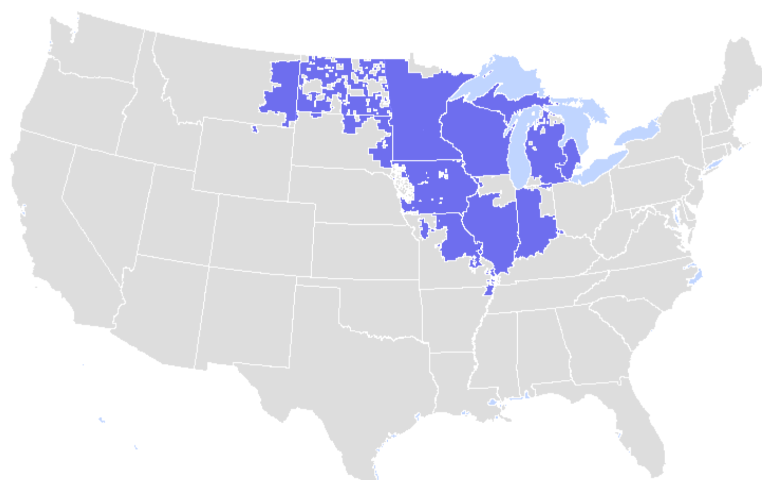

*Data Source: ISO New England Markets and Transmission Services* [87]

# 12 MISO Regional Transmission Operator

## 12.1 History and Geography of MISO

The Midwest Independent System Operator (MISO) is a Regional Transmission Operator (RTO).[91] Established in 1998, MISO was one of the first organizations to be recognized by the Federal Energy Regulatory Commission (FERC) as an RTO (in 2001). MISO is responsible for managing the energy and operating reserves markets for 11 U.S. states in the upper Midwest (Exhibit 12-1).[92] MISO is established as a non-profit corporation, and has over 130 members including 35 owners of transmission line assets, with over $18.1 billion in transmission assets under MISO's functional control. As of November 2012, MISO provided dispatch signals and reliability services to 144,599 MW of capacity over 49,670 miles of transmission lines providing electric service to 38.9 million people.[93] An all-time peak demand of 98,576 MW was set on July 23, 2012.[93] In December 2013 the utility Entergy is expected to join MISO, which will add over 15,000 miles of transmission lines and 30,000 MW of generation capacity and 35,000 MW of load to MISO's footprint. This will expand the RTO's geographic scope through parts of Louisiana, Arkansas, Mississippi, and Texas.[94]

**Exhibit 12-1 MISO market area**



*Map developed by NETL. Source: ABB Velocity Suite* [92]

Similar to other RTOs and ISOs, a primary function of MISO is to facilitate the energy markets in its service area and maintain reliable electricity service in a cost-effective manner. MISO operates the energy markets to serve load and meet reserve obligations with the lowest-cost resources possible, and has designed a locational market structure to ensure that transmission capability is used efficiently and that energy prices reflect the marginal cost of providing the service at each location. While the wholesale cost of electricity includes services to ensure

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

[92] ABB Velocity Suite. (2013). Intelligent Map. Retrieved on January 16, 2013, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx

[93] MISO. (2012). MISO Corporate Information (November 2012). Also source of maps herein. Retrieved on December 3, 2012, from: https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Corporate%20Fact%20Sheet.pdf

[94] MISO. (2011). Entergy Initiative. Retrieved on October 20, 2011, from https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/EntergyInitiative.aspx

reliable supply of power, as seen in Exhibit 12-2, the majority of the electricity price in MISO is dominated by energy services (i.e., the cost of generating power, which includes fuel costs, operation and maintenance for generators, and reimbursement for the capital cost of generators).

**Exhibit 12-2 MISO average wholesale electricity price 2009, 2010, and 2011 ($/MWh)**

| Price | 2009 | 2010 | 2011 |
|---|---|---|---|
| **Energy** | $ 28.99 | $ 34.21 | $ 33.61 |
| **Ancillary Services** | $ 0.15 | $ 0.15 | $ 0.15 |
| **Uplift** | $ 0.29 | $ 0.39 | $ 0.31 |
| **Capacity** | $ 1.85[95] | $ 0.01 | $ 0.01 |
| ***Total*** | ***$ 31.28*** | ***$ 34.76*** | ***$ 34.11*** |

*Data Source: 2011 State of the Market Report for MISO Electricity Markets* [96]

## 12.2 MISO Products and Services

MISO manages competitive markets that provide energy services and reliability services through a day-ahead market, real-time market, financial transmission rights (FTR) market, and, as of January 2009, an ancillary services market (ASM). In 2011 these markets aggregated billings of over $23.6 billion across MISO's 356 market participants.[93]

### 12.2.1 Energy Market

MISO's main role as an RTO is to coordinate an energy market throughout the service area, which consists of facilitating the continuous buying, selling, and delivery of wholesale electricity, providing dispatch requests to generators, and acting as a data clearinghouse. In addition to acting as a clearinghouse for bilateral power contracts, MISO manages a day-ahead market and a real-time market for power delivery. In each market MISO "clears the market," i.e., coordinates which generators will operate, at what time, and at what price, at over 1,900 pricing nodes, or local areas. At each node the price of electricity is based on the cost of bringing the next marginal unit of electricity on line. This method of calculating electricity price is called locational marginal pricing (LMP).

The day-ahead market clears both energy and operating reserves for each hour of the next operating day by matching energy demand bids at each LMP node and operating reserve requirements throughout the system with the generators' ability to provide power. Thus, MISO ensures scheduling adequate resources to meet the next day's expected demand, taking into account physical limiting factors such as transmission capacity and generators' scheduled

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[95] Capacity market began in June 2009; in the first month of operation of the market, a number of capacity bids were entered at non-competitive rates and did not clear. However, since average prices are calculated at spot prices, this capacity price is included in the average cost for the year. Capacity prices going forward are expected to be more in line with 2010 cost, because the region currently has more than sufficient generation resources.

[96] Potomac Economics. (2012). *2011 State of the Market Report for MISO Electricity Markets*. Retrieved on December 3, 2012, from http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf

maintenance. Generators participate in the real-time market by submitting bids to provide electricity at a certain price at least 30 minutes prior to the identified hour of operation (i.e., the hour in which the generator proposes operating and providing the electricity). MISO then sends the generators dispatch signals every five minutes based on the current demand and the generator's bid price—with the lowest-cost resources dispatched first.[97]

### 12.2.2 Capacity Market

To ensure that generators have sufficient incentive to develop and make available sufficient generation resources to meet expected demand plus a reserve margin, load-serving entities (LSE) are responsible for contracting for capacity services above and beyond the anticipated demand in their service area. Thus, LSEs calculate an expected peak demand and then must contract for "Planning Resources"—which can be either generation or load response programs—to account for events such as unplanned outages, weather disruptions, or an unexpected surge in demand. LSEs can meet their requirement for planning resources through their own generation assets, bilateral contracts with other generators, or participation in MISO's monthly Voluntary Capacity Auction. Statistical back testing is performed on a monthly basis to determine if LSEs provided for sufficient planning resources to meet reserve margin requirements. If the requirements were not met, LSEs are subject to a deficiency charge.

### 12.2.3 Ancillary Services Market

MISO facilitates an ancillary services market in a similar manner to the real-time market, with generators providing bids for 15-minute increments. MISO then matches this availability with minute-by-minute grid demand in order to ensure adequate supply of electricity within a variety of technical reliability parameters (e.g., voltage, physical power flows, etc.)

### 12.2.4 Financial Transmission Rights

The FTR market provides a financial instrument for market participants to hedge against congestion costs in the system. In the absence of any transmission constraints, all LMP nodes would price at the lowest-priced generation resource. However, there is not enough physical transmission to deliver electricity from low-cost resources to the place demanding the electricity at all times. Thus, some nodes will, by necessity, use power from higher cost resources and therefore the LMP at that node will be higher. The difference in LMPs between two nodes that is attributable to the transmission constraints is called "congestion cost" or "the cost of congestion" because, but for the lack of transmission capacity, a lower-cost resource would be used to meet demand. An FTR can be thought of as a "reservation" for access to a specific transmission path (e.g., between LMP nodes) for a specific timeframe, but does not actually correspond with a physical right to deliver energy. Rather, an FTR will create a revenue stream (or charges) based on the difference between two LMP prices at specific times.

[97] Potomac Economics. (2012). *2011 State of the Market Report for MISO Electricity Markets*. Retrieved on December 3, 2012, from http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf

### 12.2.5 Reliability Assurance

**Exhibit 12-3 MISO reliability coordination area**



*Map developed by NETL. Source: ABB Velocity Suite* [92]

MISO manages the reliability of the power grid per North American Electric Reliability Corporation (NERC) standards in a geographic region slightly larger than its market area (Exhibit 12-3), with the greatest differences being the inclusion of the remainder of North and South Dakota, and the Canadian Province of Manitoba.[98] Although MISO does not provide energy market services to these additional areas, it is responsible for modeling expected electricity demand and providing dispatch signals to generators to match supply and demand.

MISO employs a variety of system monitors and modeling tools to compare actual and predicted electricity flows against individual lines' voltage limits or other constraints. These data points and the results from modeling calculations are presented to grid operators, on a real-time display, to help visualize the status of the grid and to inform any needed corrective actions.

### 12.2.6 Transmission and Resource Planning

MISO is responsible for maintaining the operations and reliability of the grid in its service area and, as such, conducts periodic reviews of grid adequacy. Transmission expansion is assessed on an annual basis, in conjunction with members' annual planning cycles, to understand the projects being studied or currently underway, as well as to suggest future projects needed to ease congestion or other grid issues. Similarly, MISO undertakes a resource adequacy study on an annual basis, modeling expected supply and demand to determine available reserve margins and plan for the integration of additional generation or transmission, in order to maintain reliable service. Seasonal assessment reviews are also completed prior to each summer and winter, to review predicted demand and resources for the MISO reliability area and to assess potential risks.

In addition to assessing the need for new transmission or generation resources, MISO also performs generator interconnection studies to understand the impact of connecting new generation resources to the grid.

### 12.2.7 Tariff Administration

As an RTO, MISO is responsible for administering its "Open Access Transmission, Energy and Operating Reserve Markets Tariff." This tariff is filed with FERC, and outlines how MISO will determine rates for transmission service, evaluate and approve requests for transmission service,

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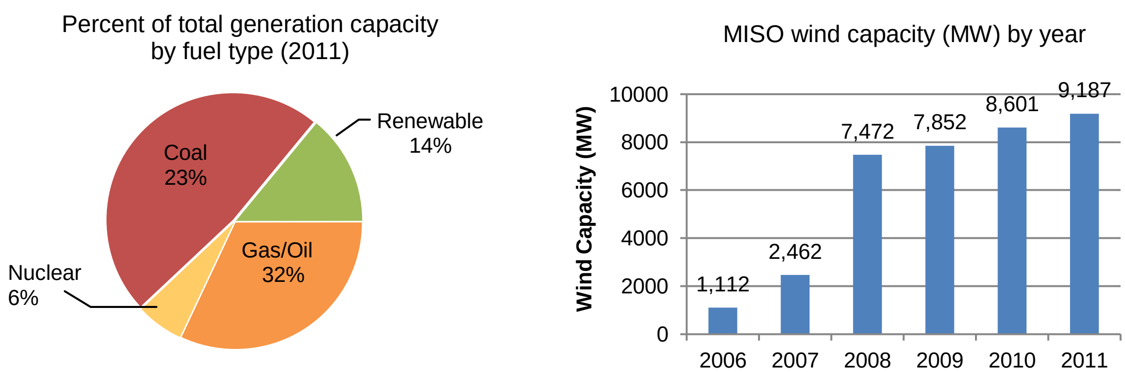
[98] MISO. (2013). *Corporate Information*. Retrieved on January 16, 2013, from https://www.midwestiso.org/Library/Repository/Communication%20Material/Corporate/Corporate%20Fact%20Sheet.pdf

perform transmission impact studies, and coordinate use and administration with other transmission providers in the region, among other activities. With FERC's approval of the tariff, MISO is the sole decision-making authority on the provision of transmission service in accordance with the tariff. However, MISO has established an Alternate Dispute Resolution (ADR) Committee[99], a six-member, board-appointed, closed committee to adjudicate disputes between parties who may have different interpretations of the tariff.

## 12.3 MISO Generation Profile

While MISO does not own or directly operate power generation facilities, it is responsible for managing scheduled outages for maintenance and maintaining reliable electricity service at the lowest cost possible, as provided by the different generators on the system. Thus, to maintain reliability, MISO continually evaluates the fuel mix of generation assets in the region. As seen in Exhibit 12-4, the majority of the region's power comes from coal-fired generation facilities. However, wind capacity has grown over eight fold in the past five years alone. Since wind is an intermittent resource, this creates additional complexity for MISO as a grid operator to ensure that sufficient generation resources are available to provide more or less power should the strength of the wind significantly change hour-by-hour (or even minute-by-minute).

**Exhibit 12-4 MISO fuel mix and wind capacity additions**




Data Source: *2010 Annual Report* [100]

In June 2011, MISO introduced a new resource designation: Dispatchable Intermittent Resource (DIR). Previously, wind resources were "price takers," meaning they were paid for the prevailing energy cost at the time they were in operation, without any supply bids into markets. The DIR designation allows wind resources to fully participate in the real time market and be automatically dispatched (up to a forecasted limit based on an offer price and system conditions).

[99] MISO. (2013). *Alternative Dispute Resolution*. Retrieved on January 17, 2013, from https://www.midwestiso.org/Library/Tariff/Pages/AlternativeDisputeResolution.aspx

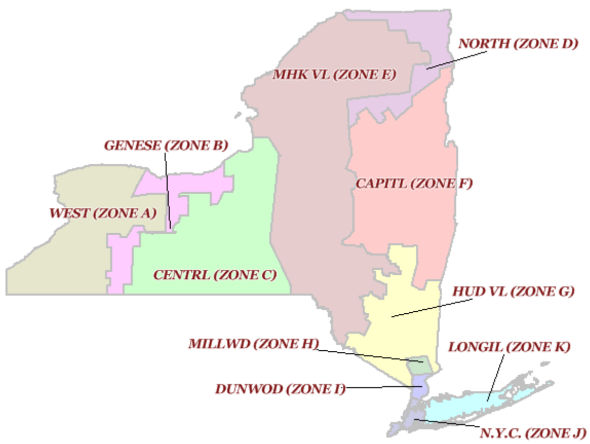
[100] MISO. (2011). *2010 Annual Report*, p. 12. Retrieved on October 11, 2011, from https://www.midwestiso.org/Library/Repository/Communication%20Material/Financial%20Information/2010%20Annual%20Report.pdf

# 13 New York Independent System Operator

## 13.1 History and Geography of New York ISO

The New York Independent System Operator (NYISO)[101] was established as a non-profit corporation in 1999. NYISO is responsible for maintaining and enhancing reliability, establishing and overseeing competitive wholesale electricity markets, and planning the power system for the future for New York State's electrical grid. NYISO has eleven load zones[102] (Exhibit 13-1). As of November 2012, NYISO dispatches approximately 39,570 MW of generating capacity and 2,173 MW of demand resources over 11,016 miles of transmission lines providing electric service to 19 million people[103,104]. An all-time peak demand of 33,939 MW was set on August 2, 2006.

**Exhibit 13-1 NYISO market area – load zones**




*Map developed by NETL. Source: ABB Velocity Suite*[105]

Similar to other ISOs, a primary function of NYISO is to facilitate the energy markets in its service area, maintain minute-to-minute reliable electricity service in a cost-effective manner, manage wholesale markets, and develop bulk power system planning processes. NYISO operates the electricity (energy, capacity, and ancillary services) markets to serve load and meet reserve

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

[102] According to the NYISO glossary, a load zone is a geographical area located within New York. All loads located within the same load zone pay the same price for energy purchased in those markets. New York ISO. (2012). *Glossary*. Retrieved on November 30, 2012, from http://www.nyiso.com/public/markets_operations/services/customer_support/glossary/index.jsp

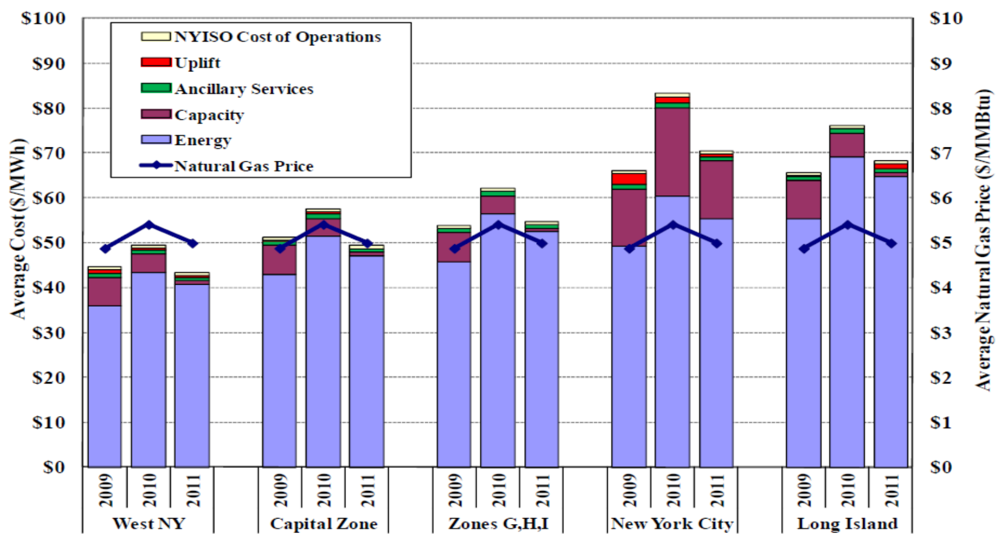
[103] New York ISO. (2012). *NYISO Key Facts*. Retrieved on November 30, 2012, from http://www.nyiso.com/public/media_room/key_facts/index.jsp

[104] IRC ISO/RTO Council. (2012). *New York Independent System Operator*. Retrieved on November 30, 2012, from http://www.isorto.org/site/c.jhKQIZPBImE/b.2604613/k.CC49/NYISO.htm

[105] ABB Velocity Suite. (2012). *Intelligent Map – NYISO Load Zones*. Retrieved on November 29, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx

obligations with the lowest-cost resources possible. It has designed a locational market structure to ensure that transmission capability is used efficiently and that energy prices reflect the marginal cost of providing the service at each location. While the wholesale electric energy includes capacity and ancillary services to ensure reliable supply of power, as seen in Exhibit 13-2, the majority of the electricity price in NYISO is dominated by energy cost (i.e., the cost of generating power, which includes fuel costs, operation and maintenance for generators, and reimbursement for the capital cost of generators).

**Exhibit 13-2 NYISO average wholesale electricity price 2009, 2010, and 2011 ($/MWh)**




*(Used with permisssion from New York ISO.* [106]*)*

## 13.2 NYISO Products and Services

NYISO manages competitive markets that provide energy services and reliability services through a day-ahead energy market, real-time energy market, capacity market, financial transmission rights (FTR) market, and an ancillary services market. In 2011, these markets aggregated billings of over $6.7 billion.[107]

### 13.2.1 Energy Market

NYISO's main role as an ISO is to coordinate an energy market throughout the service area, which consists of facilitating the continuous buying, selling, and delivery of wholesale electricity, providing dispatch requests to generators, and acting as a data clearinghouse. In addition to acting as a clearinghouse for bilateral power contracts, NYISO manages a day-ahead

[106] New York ISO. (2012). *2011 State of the Market Report for the New York ISO Markets – Potomac Economics (Figure1)*. Retrieved on November 29, 2012, from http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2011/SOM_Report-Final_41812.pdf

[107] New York ISO. (2012). *2011 Annual Report – New York Independent System Operator*. Retrieved on November 29, 2012, from http://www.nyiso.com/public/about_nyiso/nyisoataglance/annual/index.jsp

market and a real-time market for power delivery. In each market NYISO “clears the market,” i.e., coordinates which generators will operate, at what time, and at what price, to meet electricity demand. The price of electricity is based on the cost of bringing the next marginal unit of electricity on line at specific locations throughout the New York control area. This method of calculating electricity price is called locational marginal pricing (LMP) or locational based marginal pricing (LBMP).

The day-ahead market clears both energy and operating reserves for each hour of the next operating day by matching energy demand bids at each LBMP node and by operating reserve requirements throughout the system with the generator’s ability to provide power. Thus, NYISO ensures scheduling adequate resources to meet the next day’s expected demand, taking into account physical limiting factors such as transmission capacity and the generators’ scheduled maintenance.

Generators participate in the real-time market by submitting bids to provide electricity at a certain price at least 75 minutes prior to the identified hour of operation (i.e., the hour in which the generator proposes operating and providing the electricity). NYISO then sends the generator’s dispatch signals every five minutes based on the current demand and the generator’s bid price—with the lowest-cost resources dispatched first.[108]

### 13.2.2 Installed Capacity (ICAP) - Capacity Market

NYISO established a forward capacity market, ICAP, to provide appropriate price signals to attract new generation, transmission and demand resource investments, and maintain existing resources in order to ensure the reliability of the New York bulk power system.[109] The capacity market ensures resource adequacy, guarantees market stability, and provides price signal for investments. Load-serving entities (LSE) are responsible for contracting for capacity services above and beyond the anticipated demand in their service area. Thus, LSEs calculate a share of expected-peak demand and add an additional amount for the installed reserve margin. NYISO conducts a capability period auction at least 30 days prior to the start of the capability period, a monthly auction at least 15 days prior to the start of the month, and a spot market auction two to four days prior to the start of the month.

### 13.2.3 Ancillary Services Market

NYISO facilitates an ancillary services market to ensure the reliability of electricity production and transmission. The ancillary services include operating reserve and regulation as well as frequency control.

Operating reserve service provides backup generation in the event of a system contingency, such as unexpected failure of generator, transmission line, or other electrical equipment. The

[108] New York ISO (NYISO). (2012). *Market Participants User’s Guide (June 2012)*. Retrieved on November 29, 2012, from http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp

[109] New York ISO (NYISO). (2011). *Previous Course Materials: Ancillary Services*. Retrieved November 18, 2011, from http://www.nyiso.com/public/markets_operations/services/market_training/library/index.jsp

operating reserve must be from units and demand-side resources within the New York control area or reserve sharing agreements. The operating reserve market is a locational reserve market where the clearing prices are based on the cost of serving the next increment of reserve at specific locations throughout the New York control area.[109]

Regulation service allows NYISO to manage small changes in the system's electrical load by increasing or decreasing the generator's output by sending a control signal to adjust output every six seconds. The regulation service is accomplished by committing online generators, demand-side regulation providers, and limited energy storage resources in day-ahead and real-time markets. The regulation clearing price is computed based on the actual cost to provide the next available MW of regulation.[109]

NYISO offers two specialized ancillary services: voltage support and black start capability. The voltage support is used to maintain transmission voltage in real-time while black start capability is used to restart the transmission system following a system-wide blackout.[109]

### 13.2.4 Transmission Congestion Contracts (TCC)

The TCC market provides a financial instrument for market participants to hedge against congestion costs in the system, and they are settled in the day-ahead market only. In the absence of any transmission constraints, all LBMP nodes would price at the lowest-priced generation resource. However, there is not enough physical transmission to deliver electricity from low-cost resources to the place demanding the electricity at all times. Thus, some nodes will, by necessity, use power from higher-cost resources and therefore the LBMP at that node will be higher. The difference in LBMPs between two nodes that is attributable to the transmission constraints multiplied by the transfer amount is called "congestion cost" or "the cost of congestion," because, but for the lack of transmission capacity, a lower-cost resource would be used to meet demand. A TCC can be thought of as a "reservation" for access to a specific transmission path (e.g., between LBMP nodes) for a specific timeframe, but does not actually correspond with a physical right to deliver energy. Rather, a TCC will create a revenue stream (or charges) based on the difference between two day-ahead LBMP prices at specific times.

### 13.2.5 Transmission Planning and Resource Adequacy

NYISO is responsible for maintaining the operations and reliability of the grid in its service area and, as such, conducts periodic reviews of grid adequacy. NYISO and its stakeholders developed a comprehensive system planning process that includes local transmission owner planning process, NYISO's reliability planning process, congestion assessment, and resource integration study. The output of this process is a comprehensive reliability plan for the 10-year study period that is used for economic planning. The NYISO does not have the authority to license or construct projects, but it monitors progress of the proposed projects and reports its findings annually.

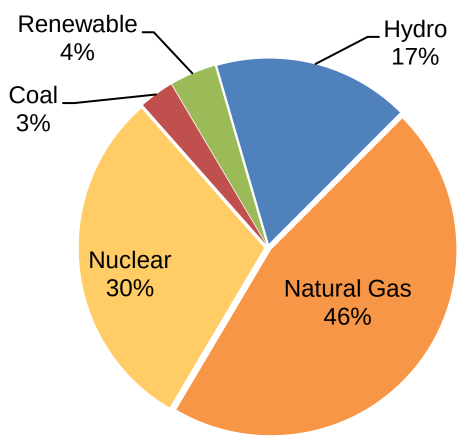
### 13.2.6 Tariff Administration

As an ISO, NYISO is responsible for administering its "Open Access Transmission Tariff." This tariff is filed with the Federal Energy Regulatory Commission (FERC) and outlines how NYISO will determine rates for transmission service, evaluate and approve requests for transmission service, perform transmission impact studies, and coordinate use and administration with other transmission providers in the region, among other activities. With FERC's approval of the tariff, NYISO is the sole decision-making authority on the provision of transmission service in accordance with the tariff. However, in the case of a dispute, when the dispute cannot be solved internally, it may be submitted to non-binding mediation or arbitration, or may commence legal proceedings before FERC or a court of competent jurisdiction.[110]

## 13.3 NYISO Generation Profile

While NYISO does not own or directly operate power generation facilities, it is responsible for managing scheduled outages for maintenance and maintaining reliable electricity service at the lowest cost possible, as provided by the different generators on the system. Thus, to maintain reliability, NYISO continually evaluates the fuel mix of generation assets in the region. As seen in Exhibit 13-3, the majority of the region's power comes from natural gas generation facilities.

**Exhibit 13-3 New York ISO generation by fuel type (as of December 2012)**




*Data Source: Power/Regional Report Analysis/ISO Region/New York ISO* [111]

[110] NYISO. (2013). *MST 11 Dispute Resolution Procedures*. Retrieved on January 17, 2013, from http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/Market_Services/Tariff_Documents/NYISO_MST_11_Dispute_Resolution_Procedures.pdf

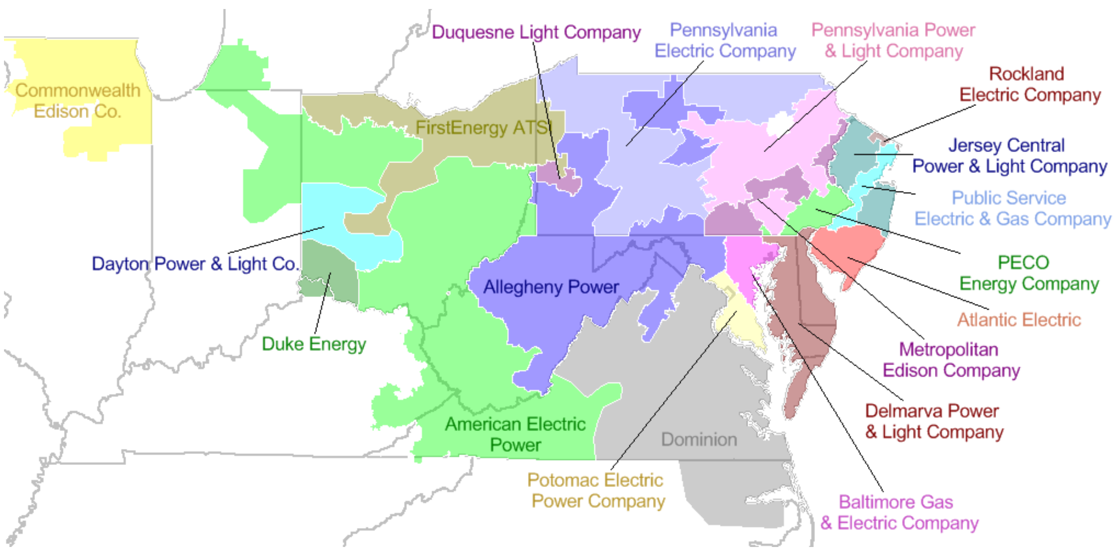
[111] ABB Velocity Suite. (2012). *Power/Regional Report Analysis/ISO Region/New York ISO*. Retrieved December 3, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/site/default.aspx

# 14 PJM Regional Transmission Operator

## 14.1 History and Geography of PJM

PJM Interconnection, LLC (PJM) is a Regional Transmission Organization (RTO)[112] that manages the high voltage transmission system and the wholesale electricity markets in all or parts of 13 states: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia (Exhibit 14-1). PJM's main objectives include the reliable generation and transmission of electrical energy at competitive prices while providing meaningful incentives for future generation and transmission expansion. Currently, PJM is the largest RTO in the world, dispatching about 185,600 MW of capacity over more than 65,000 miles of transmission lines to more than 60 million people and 750 member entities.[113] An all-time peak demand of 158,450 MW was set on July 21, 2011.

**Exhibit 14-1 PJM utility service areas**




*Map developed by NETL. Source: ABB Velocity Suite*[114]

As an RTO, PJM's main responsibility is to operate a regional power grid by acting as a market clearinghouse and ensuring ongoing grid reliability. PJM operates the energy markets to serve load and meet reserve obligations with the lowest-cost resources possible, and has designed a locational market structure to ensure that transmission capability is used efficiently and that

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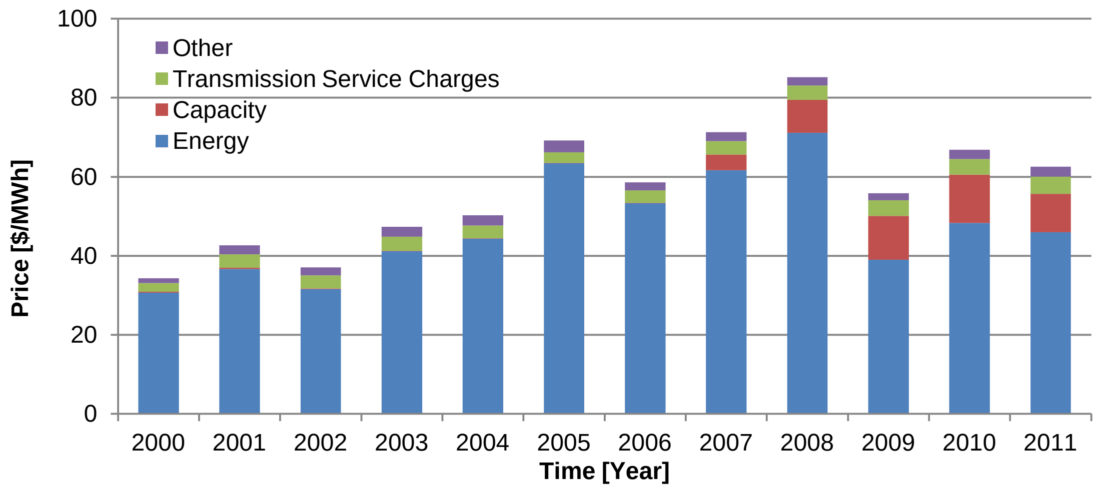
[112] Many of the technical terms used in this primer are defined in a companion *Glossary for Power Market Primers.*
[113] PJM. (2012). *2011 Annual Report* (April 2012). Retrieved on December 3, 2012, from http://www.pjm.com/~/media/about-pjm/newsroom/annual-reports/2011-annual-report.ashx
[114] ABB Velocity Suite. (2012). *Intelligent Map – PJM Transmission Zones*. Retrieved on November 29, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx

energy prices reflect the marginal cost of providing the service at each location. While the wholesale cost of electricity includes services to ensure reliable supply of power, as seen in Exhibit 14-2, the majority of the electricity price in PJM is dominated by energy services (i.e., the cost of generating power, which includes fuel costs, operation and maintenance for generators, reimbursement for the capital cost of generators). In 2011, approximately $0.37/MWh was used to fund PJM administrative functions, as the majority of funds were for energy generation ($45.94/MWh), capacity payments ($9.72/MWh), and transmission services ($4.42/MWh).

**Exhibit 14-2 PJM's historical total price by category 2000-2011**




*Note: Other includes Operating Reserves (Uplift), Reactive, PJM Administrative Fees, Regulation, Transmission Enhancement Cost Recovery, Transmission Owner (Schedule 1A), Synchronized Reserves, NERC/RFC, Black Start, RTO Startup and Expansion, Day-Ahead Scheduling Reserve, Load Response, Transmission Facility Charges.*

*Data Source: 2011 State of the Market Report for PJM* [115]

## 14.2 PJM Products and Services

PJM manages competitive markets that provide energy services and reliability services through an energy market, capacity market, transmission service charges, and an ancillary services market. In 2011, these markets aggregated billings of over $35.9 billion across PJM's 750 market participants[113] or $62.56 per MWh transmitted throughout the PJM service area

### 14.2.1 Energy Market

PJM's main role as an RTO is to coordinate an energy market by facilitating the continuous buying, selling, and delivering of wholesale electricity throughout the service area while acting as a data clearinghouse and dispatch decision maker. The energy market facilitates bilateral contracts between generators and load serving entities (LSE), as well as day-ahead, hour-ahead,

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[115] Marketing Analytics, LLC. (2012). *2011 State of the Market Report for PJM.* Retrieved on November 29, 2012, from http://www.pjm.com/documents/reports/state-of-market-reports/2011-state-of-market-reports.aspx

and spot markets for power demand. In each market, PJM ensures adequate supply to meet projected (and actual) demand, taking into account all physical limitations of the system, including generator-maintenance schedules and transmission-capacity constraints. This is done by managing a locational marginal pricing (LMP) system in which prices are set at over 100 local nodes. The LMP system calculates a local price for the next marginal MWh of demand based on the operating status of generation facilities, including accounting for existing bilateral power delivery contracts as well as the availability of transmission assets to deliver power to specific nodes. In the absence of transmission constraints, all nodes would price at the lowest-priced generation resource. However, with the presence of transmission congestion, energy cannot flow to all points in the service area; hence, different prices occur at different nodes depending on the available generation assets and transmission capacity.

### 14.2.2 Capacity Market

The capacity market is designed to provide a long-term price signal to the market on a location-by-location basis in order to encourage development of generation assets, where current resources (either generation assets or transmission assets) are relatively scarce. Each utility in PJM's geography is required to have the generating capacity to meet the expected demand (plus a reserve) in their service area. Utilities can meet this requirement with their own generation assets, by contracting for the capacity of other companies' generating assets, or by participating in PJM's capacity-market auction. In 2007, PJM instituted a reliability pricing model (RPM) as a means of pricing capacity for the capacity market auction. The RPM is designed to settle on locational prices that will stimulate investment in locations of the highest need (i.e., areas with relatively higher electricity prices) through the development of new sources of capacity—be it expansions of existing facilities, new generation assets, or demand response and energy-efficiency programs. Auctions are performed for capacity three years out (e.g., auction in 2011 for delivered capacity in 2014/15), and contracts are written for a year's worth of capacity availability.

### 14.2.3 Transmission Service Charges

Transmission service charges are payments to transmission asset owners based on the utilization of the owner's transmission lines. Tariffs for transmission are based on Federal Energy Regulatory Commission (FERC)-approved rates for interstate transmission lines, and on a state-by-state basis for intrastate lines (although typically state utility regulatory bodies follow FERC guidance to establish transmission tariffs).

### 14.2.4 Ancillary Services

Ancillary services are a key aspect of ensuring the reliability of the grid, and consist mainly of regulation services and synchronized reserve service. LSEs are required to provide regulation and synchronized reserve to the grid based on their demand, and can provide this service either through their own generation assets, by direct contract with another generation asset, or by participating in PJM's regulation market or synchronized reserve market. In each of these markets, resource owners submit offers to provide the service to PJM. PJM then optimizes the cost of these offers and, in conjunction with the expected supply and demand at each node, determines a clearing price for the service. Run by PJM's proprietary Synchronized Reserve and

Regulation Optimizer, this also provides PJM with the direction to dispatch additional generation assets if/when incidental synchronization or regulation is insufficient to provide the necessary capacity.

### 14.2.5 Other Markets/Services

PJM offers a variety of other services to its members to facilitate markets and to ensure grid reliability, such as financial transmission rights, black start service, demand response, and generation interconnection, among others.

***Financial Transmission Rights*:** Financial transmission rights (FTR) is a financial contract used by market participants to hedge their exposure to transmission congestion. This contract can be thought of as a "reservation" for access to a specific transmission path (i.e., between LPM nodes) for a specific timeframe in the day-ahead market, but it does not actually correspond with a physical right to deliver energy. Rather, an FTR will create a revenue stream (or charges) based on the difference between two LMP prices at specific times. PJM facilitates four ways for market participants to obtain FTRs:

- Bid for FTRs in the long-term auction for FTRs ranging from one to three years
- Bid for FTRs in the annual auction, which includes FTRs for the entire transmission capacity
- Bid for leftover FTRs in the monthly auction, which includes the upcoming three months or any quarter in the remainder of the planning year
- Purchase/sell FTRs on the secondary market

***Black Start Service*:** Black start service is essential to ensuring grid stability and reliability. It is a method of ensuring generation capacity exists to come on-line in the event of a total loss of power across the transmission system. PJM designates certain generators as "black start units" based on an annual series of performance tests, which include the ability to start up and deliver power to the grid without an outside source of power, or to remain in operation at reduced output levels when disconnected from the grid. Once designated a black start unit, generators are compensated based on cost-based payments for providing the service. This cost is paid on a pro-rata basis by all generators in the PJM region.

***Demand Response*:** PJM is one of the first RTOs to incorporate demand response into the wholesale energy and capacity markets, allowing for retail customers to participate in the markets and receive compensation for the demand reductions they make. PJM works with qualified agents—Curtailment Service Providers (CSP)—who aggregate retail customers to participate in demand response and facilitate demand reductions. CSPs can participate in either day-ahead or real-time markets, by monitoring LMPs and providing demand reduction when LMPs are high, which is the equivalent of bidding in generating capacity at those times. Similarly, CSPs can bid their aggregated MW of load into the forward capacity markets. For example, in the 2011 three-year capacity auction, PJM secured 14,940 MW of demand response capacity for the 2014/2015 delivery year—the highest amount of demand response resources of any organized wholesale electricity market in the nation.

***Generation Interconnection*:** To ensure reliability, PJM performs feasibility/reliability studies, coordinates the planning process for connecting new generation, and oversees the construction of the facilities necessary to interconnect new generation to the grid. These activities are part of

PJM's larger Regional Transmission Expansion Planning process, as new generation capacity must be factored in when considering generator retirements or transmission expansion/upgrades. These services are typically paid for by the owner of the new generation, on a cost-reimbursement basis.

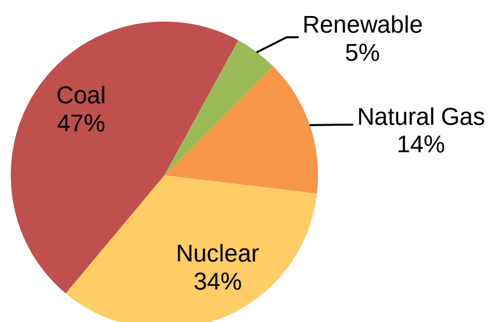
### 14.2.6 Tariff Administration

As an RTO, PJM is responsible for administering its "Open Access Transmission Tariff." This tariff is filed with FERC, and outlines how PJM will determine rates for transmission service, evaluate and approve requests for transmission service, perform transmission impact studies, and coordinate use and administration with other transmission providers in the region, among other activities. With FERC's approval of the tariff, PJM is the sole decision-making authority on the provision of transmission service in accordance with the tariff. However, in a case when a dispute cannot be solved internally by a senior designated representative of the transmission provider and a senior representative of the transmission customer, the dispute may be submitted to arbitration.[116] The arbitrators are selected by the parties or by the American Arbitration Association if the parties cannot agree on the selection. The arbitrators are subject matter experts that do not have any business or financial relationship with the parties.

## 14.3 PJM Generation Profile

While PJM does not own or directly operate power generation facilities, it is responsible for managing scheduled outages for maintenance and maintaining reliable electricity service at the lowest cost possible, as provided by the different generators on the system. Thus, to maintain reliability, PJM continually evaluates the fuel mix of generation assets in the region. As seen in Exhibit 14-3, the majority of the region's power comes from coal and nuclear generation facilities.

**Exhibit 14-3 PJM generation (MWh) by fuel type (2011)**




*Data Source: 2011 State of the Market Report for PJM* [117]

[116] PJM. (2013). Open Access Transmission Tariff. Retrieved on January 17, 2013, from http://pjm.com/~/media/documents/agreements/tariff.ashx

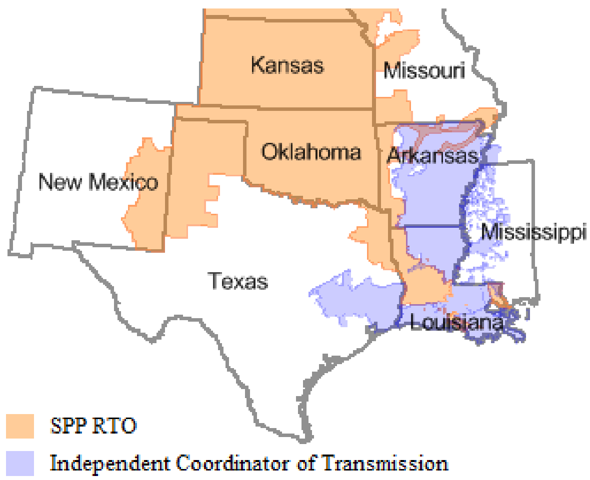
[117] Marketing Analytics, LLC. (2012). *2011 State of the Market Report for PJM (Table 2-2).* Retrieved on November 29, 2012, from http://www.pjm.com/documents/reports/state-of-market-reports/2011-state-of-market-reports.aspx

# 15 Southwest Power Pool, Inc.

## 15.1 History and Geography of the Southwest Power Pool

The Southwest Power Pool (SPP) was designated by the Federal Energy Regulatory Commission (FERC) as a Regional Transmission Operator (RTO)[118] in 2004, and as a Regional Entity (RE) in 2007.[119] SPP is responsible for ensuring reliability and establishing and overseeing competitive wholesale electricity markets for all or parts of nine states in the U.S.: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. As an RE, SPP is responsible for enforcing compliance and overseeing development of the federal and regional reliability standards. In addition, SPP serves as an Independent Coordinator of Transmission (ICT) for Entergy Services[120] (blue areas in Exhibit 15-1[121]). As an ICT, SPP administers Entergy's open access, conducts long-term transmission planning, serves as reliability coordinator, and oversees Entergy's operation. In 2011, SPP dispatched approximately 72,700 MW of generating capacity and 1,500 MW of demand resources over 49,000 miles of transmission lines, providing electric service to 15.5 million people.[122] An all-time peak demand of 54,949 MW was set on August 2, 2011.

**Exhibit 15-1 SPP market area**




*Map developed by NETL. Source: ABB Velocity Suite[121]*

Similar to other RTOs, a primary function of SPP is to facilitate the energy markets in its service area, maintain minute-to-minute reliable electricity service in a cost-effective manner, manage wholesale markets, and manage the bulk power system planning processes. SPP operates the energy imbalance service and transmission service markets to serve load with the lowest-cost resources possible. It has designed a locational market structure to ensure that transmission capability is used efficiently and that energy prices reflect the marginal cost of providing the service at each

[118] Many of the technical terms used in this primer are defined in a companion Glossary for Power Market Primers.
[119] ISO/RTO Council. (2011). About Southwest Power Pool. Retrieved on December 30, 2011, from http://www.isorto.org/site/apps/nlnet/content2.aspx?c=jhKQIZPBImE&b=2613997&ct=8961273&notoc=1
[120] "Entergy Corporation is an integrated energy company engaged primarily in electric power production and retail distribution operations. Entergy owns and operates power plants with approximately 30,000 megawatts of electric generating capacity. Entergy delivers electricity to 2.7 million utility customers in Arkansas, Louisiana, Mississippi and Texas." Retrieved on January 9, 2011, from http://www.entergy.com/about_entergy/ .
[121] ABB Velocity Suite. (2012). *Intelligent Map – SPP Regions and Entergy Service Area*. Retrieved on November 29, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx
[122] ISO/RTO Council. (2012). *Fast Facts: Handout with basic SPP facts*. Retrieved on November 30, 2012, from http://www.spp.org/section.asp?pageID=28

location. The electricity price in SPP (Exhibit 15-2) is determined by energy cost (i.e., the cost of generating power, which includes fuel costs, operation and maintenance for generators, and reimbursement for the capital cost of generators).

**Exhibit 15-2 SPP average wholesale electricity price 2009, 2010, and 2011 ($/MWh)**

| Price | 2009 | 2010 | 2011 |
|---|---|---|---|
| Energy | $ 27.49 | $ 31.33 | $ 29.28 |

Data Source: *2011 State of the Market*[123]

## 15.2 SPP Products and Services

SPP manages competitive markets that provide energy services and reliability services through the Energy Imbalance Service and Transmission Service markets. In 2011, the wholesale energy market aggregated billings of $1.28 billion across SPP's 32 market participants and the transmission service aggregated billings of $865 million.[123]

### 15.2.1 Energy Imbalance Service Market

SPP's main role as an RTO is to coordinate an energy market throughout the service area, which consists of facilitating the continuous buying, selling, and delivery of wholesale electricity, providing dispatch requests to generators, and acting as a data clearinghouse. In addition to acting as a clearinghouse for bilateral power contracts, SPP manages a real-time market for power delivery that is called the Energy Imbalance Service (EIS) market. Participation in EIS is voluntary and does not include all SPP members. It includes only those members that agreed to the SPP Tariff, Market Protocols, and other governing documents. Only 10 to 20 percent of all electricity is purchased in EIS. SPP "clears the market," i.e., coordinates which generators will operate at what time and at what price to meet real-time electricity demand. The price of electricity is based on the cost of bringing the next marginal unit of electricity on line at specific locations throughout the SPP. This method of calculating electricity price is called locational imbalance price (LIP) and it is analogous to locational marginal price in other ISOs/RTOs.[124] SPP has used the LIP since 2007.

### 15.2.2 Transmission Service Market

SPP establishes a transmission service market to provide use of the regional transmission grid. Transmission lines are owned by different companies, and SPP's function is to provide a single place where utilities can reserve the rights to move electricity on the transmission grid, by reserving transmission service.

[123] SPP. (2012). *2011 State of the Market*. Retrieved on November 30, 2012, from http://www.spp.org/section.asp?pageID=86

[124] SPP. (2011). *Locational Imbalance Pricing*. Retrieved on January 4, 2011, from http://www.spp.org/publications/LIP/lmp/1.html

### 15.2.3 Tariff Administration

As an RTO, SPP is responsible for administering its "Open Access Transmission Tariff." This tariff is filed with FERC and outlines how SPP will determine rates for transmission service, evaluate and approve requests for transmission service, perform transmission impact studies, and coordinate use and administration with other transmission providers in the region, among other activities. With FERC's approval of the tariff, SPP is the sole decision-making authority on the provision of transmission service in accordance with the tariff. However, in a case when a dispute cannot be solved internally by a senior designated representative of the transmission provider and a senior representative of the transmission customer, the dispute may be submitted to arbitration.[125] The arbitrators are selected by the parties or by the American Arbitration Association if the parties cannot agree on the selection. The arbitrators are subject matter experts that do not have any business or financial relationship with the parties.

## 15.3 SPP Integrated Marketplace

SPP electricity markets are evolving and the next generation of the market will be the integrated marketplace. It will include a day-ahead market with transmission congestion rights, reliability unit commitment, a real-time balancing market that will replace the existing EIS, and an operating reserve (supplemental, spinning, and regulation reserve) market. The integrated marketplace is expected to be launched March 1, 2014. However, participants in the market will have to be ready in May 2013.

On October 18, 2012, FERC conditionally approved SPP's proposed integrated marketplace structure.[126] The proposed structure will consolidate the sixteen balancing authorities in the SPP area into a single balancing authority operated by SPP. SPP still must submit additional documents that will illustrate that the new market is adequately prepared and the transmission between the existing and new market is well planned. They also have to submit additional filings to comply with FERC orders, such as demand response provision. SPP has to file an informal report fifteen months after the market startup to evaluate the effectiveness of the new market structure.

## 15.4 SPP Generation Profile

While SPP does not own or directly operate power generation facilities, it is responsible for managing scheduled outages for maintenance and maintaining reliable electricity service at the lowest cost possible, as provided by the different generators on the system. Thus, to maintain reliability, SPP continually evaluates the fuel mix of generation assets in the region. As seen in Exhibit 15-3, the majority of the region's power comes from coal generation facilities.

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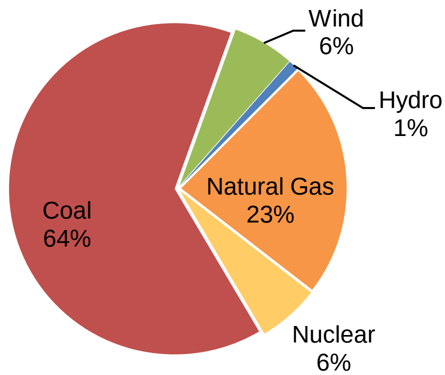
[125] SPP. (2013). *Open Access Transmission Tariff, Sixth Revised Volume No. 1*. Retrieved on January 17, 2013, from http://www.spp.org/publications/SPP_Tariff.pdf

[126] SNL Financial. (2012). *FERC conditionally approves SPP's proposed new integrated marketplace – October 18, 2012*. Retrieved on November 30, 2012, from http://www.snl.com/interactivex/article.aspx?id=16023245&KPLT=6

**Exhibit 15-3 SPP generation (MWh) by fuel type (data through December 2012)**




Data Source: *Fast Facts: Handout with basic SPP facts*[122]

The natural gas units were marginal units[127] fifty-five percent of the time and the coal-fired units were marginal units forty-five percent of the time. This was a significant change from 2010 when the natural gas units were marginal units sixty-two percent of the time and the coal units were marginal units thirty-eight percent of the time.[128]

[127] A marginal unit is a unit that sets system electricity price.

[128] SPP. (2011). *2010 State of the Market*. Retrieved on November 30, 2012, from http://www.spp.org/publications/2010-State-of-the-Market-Report.pdf

# 16 North American Electric Reliability Corporation

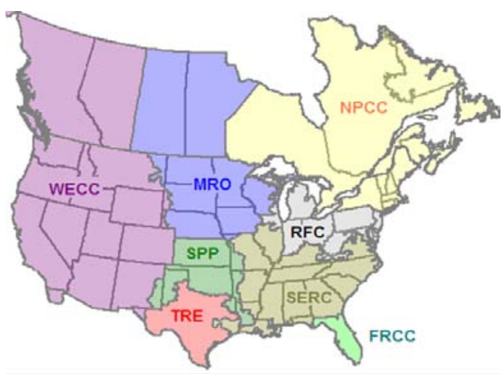
The North American Electric Reliability Corporation (NERC) is an international, non-government, independent, not-for-profit organization that operates as an electric reliability organization (ERO) to improve the reliability[129] and security of the North American bulk power system.[130] NERC is overseen by the U.S. Federal Energy Regulatory Commission (FERC) in the U.S. and governmental authorities in Canada. NERC activities include:

- Developing and enforcing reliability standards
- Monitoring the bulk power system in real time
- Assessing the bulk power system reliability and adequacy
- Investigating disturbances and abnormal events on the bulk power system
- Coordinating physical and cyber security needs
- Auditing owners, operators, and users for preparedness
- Providing education, training, and certification for industry personnel

NERC has about 600 members. The membership is open to all entities, such as utilities (investor-owned, state or municipal, cooperative, federal or provincial, and transmission-dependent), merchant electricity generators, electricity marketers, customers (large and small end-use), independent system operators and regional transmission organizations, government representatives, and regional entities that are interested in the reliability of the bulk power system.

NERC works with eight regional entities (Exhibit 16-1) to improve the reliability and stability of the bulk power system. The regional entities are established to develop and enforce compliance with the reliability standards within their region. NERC oversees the activity of the regional entities to be sure that delegated functions are consistent across North America.

**Exhibit 16-1 NERC regional entities**




FRCC - Florida Reliability Coordinating Council
MRO - Midwest Reliability Organization
NPCC - Northeast Power Coordinating Council
RFC - Reliability*First* Corporation
SERC - SERC Reliability Corporation
SPP - Southwest Power Pool Regional Entity
TRE - Texas Reliability Entity
WECC - Western Electricity Coordinating Council

*Map developed by NETL. Source: ABB Velocity Suite*[131]

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

[130] North American Reliability Corporation. (2012). *About NERC*. Retrieved on November 29, 2012, from http://www.nerc.com/page.php?cid=1

[131] ABB Velocity Suite. (2012). *Intelligent Map – US NERC Regions*. Retrieved on November 29, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx

Members of the regional entities consist of utilities (investor-owned, state, municipal, cooperative and provincial), federal power agencies, independent power producers, electricity marketers, and customers.

## 16.1 NERC History

In 1963, the Eastern Interconnection was formed. At the same time, the North American Power Systems Interconnection Committee (NAPSIC), an interregional organization (and NERC precursor), was established. It was a voluntary group of utility system operators that developed criteria and guidelines for reliable operation of the interconnected grid.

In 1965, the largest blackout in the history of the northeastern United States and southeastern Ontario, Canada, occurred. It started at Sir Adam Beck Station, Ontario, Canada, and affected parts of Ontario in Canada, New York, New Jersey, Connecticut, Massachusetts, Rhode Island, New Hampshire, and Vermont (Exhibit 16-2).[132] The blackout revealed a weakness of a large interconnected system: a small outage (disturbance) in one section of the grid can quickly spread around and interrupt supply to a large geographical area. It also revealed that utilities often have different operating standards and procedures.

**Exhibit 16-2 Area affected by blackout**

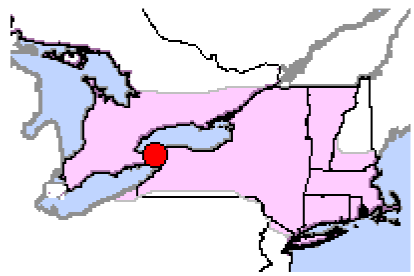


*Image developed by NETL.*

In 1967, the U.S Federal Power Commission (FERC precursor) submitted to Congress the U.S. Electric Power Reliability Act of 1967 to enhance the reliability and efficiency of the bulk power system.[133] It was recommended to develop a new mechanism for coordination among utilities, to establish regional councils to coordinate planning of the bulk power system, and to submit all extra-high-voltage (at that time it was 200 kV) projects to the Commission for approval. The legislation has never been enacted. In the final report about the 1965 blackout, the Commission recommended to establish:

> […] A council on power coordination made up of representatives from each of the nation's Regional coordinating organizations to exchange and disseminate information on Regional coordinating practices to all of the Regional organizations, and to review, discuss, and assist in resolving matters affecting interregional coordination. […][134]

On June 1, 1968, twelve regional and area organizations formed the National Electrical Reliability Council (NERC) comprised of nine regional reliability organizations. At that time, NERC was responsible only for regional planning coordination guidelines.[130] In 1980, NAPSIC

[132] Blackout History Project. (2000). *Needed: More Purpose, Not Just More Electricity*. Retrieved on November 29, 2012, from http://blackout.gmu.edu/archive/life_11_19_1965/life_11_19_65_052.html

[133] Archives and Special Collections Library. (2011). *Congressional Record – Senate – The Electric Power Reliability Act of 1967*(Page 15322, June 12, 1967). Retrieved on November 29, 2012, from http://abacus.bates.edu/muskie-archives/ajcr/1967/Reliable%20Power.shtml

[134] North American Reliability Corporation. (2010). *NERC Operating Manual*. Retrieved on November 29, 2012, from http://www.nerc.com/page.php?cid=1%7C117%7C161%7C226

became part of NERC after which NERC become responsible for both the planning and operating reliability of the bulk power system. In 1981, NERC changed the name to the North American Electric Reliability Council after Canada became a member. Over time, NERC's criteria and guidance became policies with both requirements and guidelines; however, NERC did not have the authority to enforce them. In 1997, NERC started working on transferring its planning guidelines to planning standards. In 2002, NERC's operating polices and planning standards became mandatory and enforceable, in Ontario. In 2004, NERC published the first version of 90 measurable, still-voluntary standards.[130] The U.S. Energy Policy Act of 2005 called for creation of a self-regulatory electric reliability organization that would develop and enforce the reliability standards. In 2006, NERC was established as the electric reliability organization of the U.S. In 2007, NERC changed its name to the North American Electric Reliability Corporation, representing a very large cross-section of the industry; FERC approved NERC's delegated agreements with eight regional entities that will monitor, develop, and enforce compliance with NERC standards within their geographic area; and compliance with NERC standards become mandatory and enforceable in the U.S.[130]

## 16.2 NERC Today

Today, NERC has about 600 members from a large cross-section of the industry that are split in twelve different membership categories. They offer their knowledge and expertise about reliable planning and operation of the bulk power system, and participate in NERC committees (Exhibit 16-3).[130] NERC is governed by a twelve-member independent Board of Trustees. The Member Representatives Committee (about 24 representatives from 12 membership categories) is a connection between NERC members and the Board.[130]

**Exhibit 16-3 NERC committees**

| Committee | Function |
|---|---|
| **Member Representatives Committee** | • Elects independent trustees<br>• Votes on amendments to the Bylaws<br>• Provides advice and recommendations to the Board with respect to the purpose and operations of the Corporation |
| **Compliance and Certification Committee** | • Engages with, supports, and advises the Board regarding compliance, registration, and certification programs<br>• Monitors NERC's compliance with the Rules of Procedure regarding the Reliability Standards development process |
| **Critical Infrastructure Protection Committee** | • Coordinates NERC's security initiative |
| **Operating Committee** | • Executes the policies, directives, and assignments of the Board<br>• Advises the Board on operating reliability matters<br>• Maintains a work plan with the business and strategic plans of NERC |
| **Personnel Certification Governance Committee** | • Oversees the policies and processes used to implement and maintain the integrity and independence of the Corporation's System Operator Certification Program |
| **Planning Committee** | • Promotes the reliability of the interconnected bulk electric systems<br>• Assesses and encourages resource adequacy<br>• Provides a forum for addressing planning and adequacy issues<br>• Advises the Board on issues related to bulk electric system transmission planning and reliability, and resource adequacy |
| **Reliability Issues Steering Committee** | • Assists with establishing a common understanding of the scope, priority, and goals for the development of solutions to address issues of strategic importance to bulk power system reliability<br>• Helps NERC and industry to focus on the critical issues |
| **Standards Committee** | • Oversees the development of NERC reliability standards |

NERC developed more than a hundred reliability standards that are enforceable.[130] They define operating and planning requirements that will provide a reliable bulk power system. These standards belong to one of the 14 standard groups that ensure:

- **Resource and demand balancing**
  - Maintenance of interconnection frequency within predefined limits
  - Recovery from system disturbances
  - Adequate operating reserve requirements
- **Communications**
  - Adequate, effective, and reliable communication between reliability communicator, balancing authorities, system operator, and generator operator
- **Critical infrastructure protection**
  - All sabotage is reported
  - Identification and protection of critical cyber assets
- **Emergency preparedness and operations**
  - Development, maintenance, and implementation of an emergency plan
  - Existence of load-shedding and system-restoration plans
  - Analysis of disturbances to minimize repeated occurrence of the event
- **Facilities design, connections, and maintenance**
  - Proper connection of elements to facilities
  - Management of transmission vegetation

    - Proper maintenance of transmission
- **Interchange scheduling and coordination**
    - Properly scheduled interchanges that do not impact system reliability
- **Interconnection reliability operations and coordination**
    - Placement of qualified authorities, facilities, and tools to mitigate critical conditions
    - Wide-area visibility of the coordinator reliability area
    - Conduct of next-day reliability studies
    - Monitoring of critical parameters of the system
- **Modeling, data, and analysis**
    - Accurate calculation of available system capability, capacity benefit, and transmission reliability margin
    - Consistent procedure and modeling of the system
- **Nuclear safety**
    - Safe operation and shutdown of nuclear power plants
- **Personnel performance, training, and qualifications**
    - Adequate training, proper credentials, and competency of responsible personnel for reliable operation of the bulk power system
- **Protection and control**
    - Coordination and operation of system protection
    - Analysis, testing, and maintenance of protection systems
    - Proper design, maintenance, and operation of special protection systems
- **Transmission operations**
    - Capability of reliability entities  in order to return system to normal condition during an emergency
    - Assessment necessary data and development of plans for reliable system operation
    - Monitoring of critical operating parameters in real time
- **Transmission planning**
    - Development of the reliable transmission system under normal and contingency (loss of one or more than one elements of the system) conditions
    - Compliance of each regional reliability organization with planning criteria
- **Voltage and reactive power**
    - Monitoring, controlling, and maintaining of voltage levels, reactive power flows, and reactive resources within applicable limits in real time
    - Generators provide necessary reactive power and voltage support to maintain scheduled voltage
    - Up-to-date service of all automatic voltage regulators and power system stabilizers

NERC also develops and maintains regional reliability standards. When the regional standards are approved, they become part of the NERC reliability standards and they are enforceable. The regional reliability standards allow some flexibility around enforcing a single standard to all regions, and they are used to accommodate regional differences.

# 17 Glossary of Terms

### A

*Adequacy* – See *Resource Adequacy.*

*Ancillary Services* – Services necessary to ensure and support the reliability of the transmission of electricity across the grid. The ancillary services include operating reserve, frequency regulation (i.e., maintaining system frequency within a set range), and voltage control (i.e., maintaining system voltage within a set range).

*Ancillary Services Market Administrator* – An entity that manages services necessary to support the reliable operation of the transmission system and provision of electricity at appropriate frequency and voltage levels. [135]

*Ancillary Service Shadow Price* – The cost of having to procure one additional megawatt for a given ancillary service. See also: *Shadow Price* and *Regulation Market Clearing Price.*

*Assets* – Individual units (generators), plants, load acting as a resource (controllable load and demand response resource) and load zones.[136]

*Automatic Voltage Regulator (AVR)* – A device on a generation resource or a control system at the facility of a generation resource used to automatically control the voltage to an established voltage set point.[137]

### B

*Balancing Authority* – An entity that integrates resource plans regionally and maintains, in real time, the balance of electricity resources and electricity demand.[135]

*Bid* – A request to sell or purchase megawatts at a specific location submitted into the wholesale market.[138] See also: *Demand Bid* and *Generation Bid.*

*Bilateral Contracts* – A contract between two parties for the sale and delivery of a service (i.e., energy, capacity, and/or ancillary services) without going through the wholesale market that provides price and other terms and conditions. These contracts may be internal or external to the ISO/RTO area. The ISO/RTO must be aware of the contract in order to maintain reliability.

*Black Start Capability* – The ability of generating unit to start without support of the transmission grid.[138] See also: *Black Start Unit.*

*Black Start Service* – An ancillary service provided by a generation resource able to start without support of the transmission grid.[137] See also: *Black Start Unit.*

[135] United States Government Accountability Office. (2008). Electric Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance. Retrieved on September 16, 2011 from http://www.gao.gov/new.items/d08987.pdf

[136] SPP. (2011). Glossary. Retrieved on October 25, 2011 from http://www.spp.org/glossary.asp?letter=E

[137] ERCOT. (2011). Glossary. Retrieved on October 25, 2011 from http://www.ercot.com/glossary

[138] ISO New England. (2011). Glossary. Retrieved on October 25, 2011 from http://www.iso-ne.com/support/training/glossary/

*Black Start Unit* – A generating unit that has the ability to be started without outside electricity supply.[138] Black Start units are necessary to re-energize the transmission system following a system-wide blackout. They must have the ability to re-energize an electrical bus, to provide real and reactive power capability for a period of time identified by restoration requirements, and provide frequency and voltage control under varying load.[139]

*Blackout* – A period where no electric service is available in a particular area.

*Brownout* – An intentional or unintentional drop in voltage in a transmission and/or distribution grid. The name is coming from a fact that when voltage drops lightning dims slightly. The intentional brownout is used to reduce load during an emergency.[140]

*Bulk Power System* – The interconnected electrical generating resources, transmission facilities, tie lines with neighboring systems, and associated equipment used to produce and transmit electric energy, generally operated at 100 kV or higher.[135] See also: *Power System.*

*Bus/Electrical Bus* – A physical transmission element that serves as a common connection for two or more elements such as: loads, lines, transformers, generators and other transmission devices and equipment.[141,137,142]

## *C*

*Capability* – The maximum load that a generating unit or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.[136]

*Capability Period* – One of two specific time periods within a power year for buying and selling electric capacity. A power year is split into capability periods because different demand requirements exist during the year and the output of generator resources is seasonally dependent (temperature, wind, etc.). A RTO/ISO determines the duration of the capability period. For example, in ISO New England, the summer capability period is June 1 through September 30; the winter capability period is October 1 through May 31.[138] In New York ISO, the summer period is May 1 through October 31; the winter period is November 1 through April 30.

*Capacitor* – A device whose primary purpose is to introduce reactive power into an electrical circuit. Shunt capacitors are normally used to produce reactive power for voltage control. Series capacitors are normally used to reduce the effective reactance of a circuit.[143] See also: *Reactive Power* and *Inductor*.

*Capacity* – The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station or system is rated by the manufacturer.[136]

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[139] Entergy. (2011). *Transmission System Facts.* Retrieved on October 25, 2011 from http://www.entergy.com/energydelivery/transmission_system_facts.aspx

[140] Steven Blome. (2007). *Electric Power System Basics: For the Nontechnical Professional*, IEEE Press Series on Power Engineering.

[141] Potomac Economics. (2011). *2010 State of the Market Report for the MISO Electricity Market*, June 2011

[142] Nodal Exchange. (2011). *Glossary.* Retrieved on March 25, 2011 from http://www.nodalexchange.com/resource_center/glossary.php

[143] PJM. (2011). *Glossary.* Retrieved on October 25, 2011 from http://www.pjm.com/Home/Glossary.aspx

*Capacity Auction/ Forward Capacity Auction* – An annual auction of the Forward Capacity Market during which the price for capacity will be set based on required capacity quantity that will satisfy the region's unforced capacity obligation.[135,137]

*Capacity Market* – A market in which load-serving entities make capacity payments to providers (owners of generators and demand resources) to ensure the long-term availability of sufficient capacity for the reliable operation of the bulk power grid. Capacity markets use a capacity auction process to procure sufficient capacity for the delivery year.

*Capacity Market Administrator* – Administers a system to procure a sufficient portfolio of supply and demand resources to meet future electricity needs and encourage investment.[135]

*Capacity Payments* – A payment received in exchange for making electrical capacity available.[144]

*Capacity Zone* – A zone determined before each capacity auction. Each export-constrained zone and any import-constrained zone for which the amount of capacity projected to be installed in a load zone is less than that load zone's forecasted local sourcing requirement.[138] See also: *Local Sourcing Requirement*.

*Clearing Price* – See *Market Clearing Price.*

*Congestion* – A condition that arises on the transmission system when one or more restrictions prevent the economic dispatch of electric energy from serving load.[135]

*Congestion Cost/Cost of Congestion* – Costs that are approximately equal to the difference in locational marginal prices across the congested interface, multiplied by the transfer amount.[141]

*Congestion Revenue Right (CRR)* – A financial instrument that entitles the holder to be charged or to receive compensation, depending on the instrument, when the transmission grid is congested in the Day-Ahead Market or in the Real-Time Market.[137] It is used in CAISO and ECROT. See also: *Financial Transmission Rights* and *Transmission Congestion Contracts*

*Contingency* – The unplanned disconnection of a power system element, such as a transmission facility or a generator, from the system.[138]

*Control Area* – An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: 1) match, at all times, the power output of the generators within the electric power system(s), and capacity and energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s); 2) maintain scheduled interchange with other Control Areas; 3) maintain the frequency of the electric power system(s) within reasonable limits; and 4) provide sufficient generating capacity to maintain operating reserves.[138]

*Cost-based Payment/Cost-based Service* – Payment/Service in which offers shall not exceed the variable cost of producing energy or other service.[143]

*Cost of New Entry* – As a concept, the price of capacity in $/kW-month or $/MW-day that is needed to attract sufficient new capacity.[138]

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[144] Energy Network Operations Center. (2011). *Glossary*. Retrieved on October 25, 2011 from http://www.enernoc.com/our-resources/glossary

*Curtailment Service Provider* – A company that serves as an intermediary between utilities and customers, pooling together groups of customers who participate in demand response programs to reduce energy usage during periods of peak demand. More commonly known as Demand Response Aggregators.[145] See also: *Demand Response Aggregators.*

*Customer* – An entity that "does business" with ISO/RTO, such as a transmission customer or market participant.[138]

**D**

*Day-Ahead Market (DAM)* – A forward market in which hourly (typically) prices are calculated for energy delivery to a specific location based on generation offers, demand forecasts, and scheduled bilateral power sales.

*Day-Ahead Market Administrator* – Administers a forward market where electricity is bought and sold for use the following day based on projected customer needs.[135]

*Delivery Year* – Planning period for which resources are being committed and for which a constant load obligation for the entire region exists. For example, the 2007/2008 Delivery Year in PJM corresponds to the June 1, 2007 – May 31, 2008 planning period.[143]

*Demand* – The amount of electrical power used; the level of electricity consumption at a particular time measured in megawatts.[138] See also: *Load.*

*Demand Bid / Demand Offer* – A request to purchase an amount of electric energy at a specific location.[138]

*Demand Curve* – A graphic representation of the relationship between energy price and the quantity of the energy demanded. It is drawn with price on the vertical axis of the graph and quantity demanded on the horizontal axis.[146] See also: *Supply Curve.*

*Demand Resource* – A source of capacity whereby a customer reduces the demand for electricity from the bulk power system, such as by using energy-efficient equipment, shutting off equipment, and using electricity generated on site.[138] See also: *Demand Response and Interruptible Load for Reliability Resources*.

*Demand Response* – End-use customers' reduction of their use of electricity in response to power grid needs, economic signals from a competitive wholesale market or special retail rates.[143] See also: *Demand Resource and Interruptible Load for Reliability Resources*.

*Demand Response Aggregators* – A company that serves as an intermediary between utilities and customers, pooling together groups of customers who participate in demand response programs to reduce energy usage during periods of peak demand. Also known as Curtailment Service Providers.[145] See also: *Curtailment Service Providers.*

*Deregulation* – Elimination of some or all regulations from a previously regulated industry or sector of an industry.[147] See also: *Restructured Electric Industry*.

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[145] LOBOS. (2013). *Glossary*. Retrieved on February 25, 2013 from http://enerliance.com/support/terms-definitions/

[146] Business Dictionary. (2013). *Demand Curve.* Retrieved on January 10, 2013 from http://www.businessdictionary.com/definition/demand-curve.html

*Dispatch* – Electronic or verbal instructions to generators, transmission facilities, and other market participants to start up, shut down, raise or lower generation, change interchange schedules, or change the status of a dispatchable load in accordance with applicable contracts or demand bid parameters.[148]

*Dispatch Signal* – The control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by ISO/RTO in accordance with the offer data.[143]

*Distribution Lines* – Low-voltage electric power lines (typically <35 kV).[138]

*Distribution System / Distribution Grid / Distribution Network* – A system for the delivery of energy from the transmission grid to customers.[137]

**E**

*Electric Energy* – The ability of an electric current to produce work (heat, light, another form of energy); the generation or use of electric power over a specified time, usually expressed in gigawatt-hour (GWh), megawatt-hour (MWh), or kilowatt-hour (kWh).[138] See also: *Energy*.

*Electric Industry* – An industry that produces and delivers electric energy, often known as power, or electricity.

*Electric Power* – The rate at which electric energy is transferred or used to do work, measured in watt (W) or kilowatt (kW – thousands of watts) or megawatts (MW – millions of watts).[138] See also: *Units of Electricity.*

*Electric Reliability Organization* – The organization certified by FERC to establish and enforce reliability standards for the bulk-power system, subject to FERC review.[149] See also: *North American Electric Reliability Corporation (NERC)*

*Electricity Consumer* – An entity such as a person, State agency, or Federal agency, to which electric energy is sold other than for purposes of resale.[149]

*Electricity Market / Energy Market* – A system for purchasing and selling electricity using supply and demand to set the price. In general, electricity markets include electric energy markets, capacity markets, and ancillary services markets, a part of which are regulation markets and operating reserve markets.[135] See also: *Energy Market*, *Power Market* and *Wholesale Electric Energy Market.*

*Electricity (Power) Marketers* – Business entities engaged in buying and selling electricity. Power marketers do not usually own generating or transmission facilities. Power marketers take ownership of the electricity and are involved in interstate trade. These entities file with FERC for status as a power marketer.[148]

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[147] U.S. Energy Information Administration. (2013). *Glossary*. Retrieved on January 10, 2013 from http://www.eia.gov/tools/glossary/index.cfm

[148] California ISO. (2011). *Glossary of Terms and Acronyms.* Retrieved on October 25, 2011 from http://www.caiso.com/Pages/glossary.aspx?View={02340A1A-683C-4493-B284-8B949002D449}&FilterClear=1

[149] Public Utility Regulatory Policies Act of 1978. (2012). *16 USC Sec. 2602*. Retrieved on March 26, 2013 from http://uscode.house.gov/download/pls/16C46.txt

*Electricity Supplier* – Companies supplying electricity to the consumers. See also: *Generating Companies* and *Electricity (Power) Marketers.*

*Energy* – The generation or use of electric power over a specified time, usually expressed in gigawatt-hour (GWh), megawatt-hour (MWh), or kilowatt-hour (kWh).[138] See also: *Electric Energy*.

*Energy Efficiency Resources* – An energy resource capable of yielding energy and demand savings that can displace electricity generation, such as from coal, natural gas, nuclear power, wind power, and other supply-side resources.[150]

*Energy Imbalance Service (EIS)* – Energy supplied by others when actual electricity production (or usage) is different from expected production (or usage). EIS is the dollar amount associated with the Imbalance Energy (IE). EIS is calculated by taking the amount of IE and multiplying by the price at a specific point on the energy grid.[136]

*Energy Imbalance Service (EIS) Market* – Unique to the Southwest Power Pool (SPP), the EIS Market provides market participants a mechanism necessary to offer their resources into the marketplace for use in eliminating the imbalance energy. In the EIS marketplace, SPP owns the responsibility of accounting for and financially settling all EIS amounts.[136] The EIS Market will be replaced with a real-time market when a new market structure is launched in 2014. See also: *Imbalance Energy*.

*Energy Market /Electric Energy Market* – A system for purchasing and selling electric energy using supply and demand to set the price.[135] See also: *Electricity Market*, *Power Market* and *Wholesale Electric Energy Market.*

**F**

*Federal Energy Regulatory Commission (FERC)* – An independent commission that regulates the interstate transmission of electricity, natural gas, and oil. As part of that responsibility, FERC regulates the transmission and wholesale sales of electricity in interstate commerce; reviews certain mergers and acquisitions and corporate transactions by electricity companies; reviews the siting application for electric transmission projects under limited circumstances; licenses and inspects private, municipal, and state hydroelectric projects; protects the reliability of the high voltage interstate transmission system through mandatory reliability standards; monitors and investigates energy markets; enforces regulatory requirements through imposition of civil penalties and other means; and also administers accounting and financial reporting regulations and conduct of jurisdictional companies.[138, 151]

*Federal Power Agencies* – Any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy.[152]

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[150] ACEEE. (2013). *Energy Efficiency as a Resource*. Retrieved on January 10, 2013 from http://aceee.org/topics/energy-efficiency-resource

[151] Federal Energy Regulatory Commission (FERC). (2011). *What FERC does.* Retrieved on October 25, 2011 from http://www.ferc.gov/about/ferc-does.asp

[152] Cornel University Law School. (2013). *16 USC § 796 – Definitions*. Retrieved on January 10, 2013 from http://www.law.cornell.edu/uscode/text/16/796

*FERC Order 888/889* – The two orders made in 1996 by the US Federal Energy Regulatory Commission establishing the U.S. Federal Energy Regulatory Commission's legal authority to require utilities owning transmission lines to permit the use of their transmission assets by third parties.[153] FERC Order 888 required opening access to transmission lines to competing power generators, the unbundling of functional charges, and establishing a mechanism for recovery of "stranded costs." Issued in conjunction with Order 888, FERC Order 889 facilitated competitive markets by assuring transparency, accuracy, and consistency in sharing of information critical to making intelligent competitive decisions.[154] Order 889 established a common standard of conduct among power industry participants. In order to prevent gaming or obscuring of information, Order 889 required accounting systems for transmission, distribution, and generation facilities to be separate. Additionally, FERC Order 889 obligated all investor-owned utilities to share the availability of transmission capacity, ancillary services, scheduling of power transfers, economic dispatch, current operating conditions, system reliability, and responses to systems conditions on an Open Access Same-Time Information System (OASIS; formerly referred to as Real-Time Information Networks). See also: *Independent System Operator (ISO), Regional Transmission Organization (RTO)* and *FERC Order 2000.*

*FERC Order 2000* – The order made in 1999 by the US Federal Energy Regulatory Commission mandating the creation of Regional Transmission Organizations throughout the United States, albeit participation is voluntary.[155] The intent of FERC Order 2000 was to remove the residual barriers to a competitive market. Order 2000 delineated several of FERC's expectations such as regional operation of high-voltage transmission, elimination of discriminatory practices leaving minimal economic or operational obstacles to trade, open access to the network and information about the network (e.g., OASIS), and true access and exit from the transmission network establish ease of opportunity. To meet these expectations, Order 2000 established that RTOs should have full independence from market participants, as well as responsibility and authority regarding short-term grid stability, operational control of all transmission assets in their region, and an appropriate regional configuration. In support of these characteristics, each RTO assumed key market and technical functions within its area, such as design and administration of tariffs, management of congestion and parallel path flows, and continual development of OASIS, monitoring the market, and planning and expansion of transmission assets. See also: *Independent System Operator (ISO), Regional Transmission Organization (RTO)* and *FERC Order 888/889.*

*Financial Transmission Rights (FTR)* – A financial instrument that a market participant can buy to hedge the price risk of day-ahead congestion caused by constraints on the transmission

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[153] Federal Energy Regulatory Commission. (1996). Order No. 888: Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Retrieved on September 16, 2011from http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp

[154] Federal Energy Regulatory Commission. (1996). Order No. 889: Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct. Retrieved on September 16, 2011 from http://www.ferc.gov/legal/maj-ord-reg/land-docs/order889.asp

[155] Federal Energy Regulatory Commission. (1999). Order No. 2000: Establishment of Regional Transmission Organizations Proposals. Retrieved on September 16, 2011 from http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf

system. FTR holders have a right to receive, or an obligation to pay, the dollar amounts associated with congestion based on the amount of electric energy (MW) flowing between two specific locations.[135] It is used in PJM, ISO-NE and MISO. See also: *Congestion Revenue Right* and *Transmission Congestion Contracts*

*Forced Outage* – An outage results in the immediate reduction in output or unavailability of a generating unit due to a failure. A reduction in output or removal from service of a generating unit in response to changes in market conditions does not constitute a forced outage.[143] See also: *Maintenance Outage,* Outage, *Planned Outage and Scheduled Outage.*

*Forward Capacity Auction/Capacity Auction* – An annual auction of the Forward Capacity Market during which the price for capacity will be set based on required capacity quantity that will satisfy the region's unforced capacity obligation.[135,137]

*Frequency* – The rate of oscillation (cycles/second) of the alternating current in an electrical power system, measured in hertz (Hz). In the United States, the frequency rate is 60 Hz.[138]

*Frequency Control* – A generation control where the objective is to utilize all regulating generators to control frequency at a scheduled level.[143]

*Frequency Regulation* – The capability of maintaining electric frequency close to 60 Hz. A system operator has to continuously balance electricity supply with load to maintain the proper frequency by sending a control signal to generators to increase or decrease its power output in response to frequency deviation.[143] See also: *Frequency Response.*

*Frequency Response* – The capability of a specific resource, with appropriate telecommunications, control and response capability, to increase or decrease its output in response to a regulating control signal to control for frequency deviations.[143] See also: *Frequency Regulation.*

## G

*Generating Unit* – An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered.[148]

*Generation* – The production of electric energy from other sources of energy, expressed in megawatt (MW).[138] See also: *Supply.*

*Generation Assets* – See *Generation Resource* and *Generator.*

*Generation Companies* – An entity that owns or operates generating plants. The generation company may own the generation plants or interact with the short-term market on behalf of plant owners.[148] See also: *Electricity Supplier.*

*Generation Interconnection* – A process that includes any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the standard large generator interconnection procedures.[148]

*Generation Resource* – A generator capable of providing energy or ancillary service.[137] See also: *Generator.*

*Generation Scheduling* – A computer optimization program used by a scheduling coordinator to schedule generation resources required for future operating periods.[143]

*Generator* – The seller of energy or ancillary services produced by a generating unit.[148] A facility that produces only electricity, commonly expressed in kilowatt-hour (kWh) or megawatt-hour (MWh). Electric generators include electric utilities and independent power producers.[148] See also: *Generation Resource.*

*Generator Bid* – The quantity (MWh) and a price ($) at or above which a generator has agreed to sell the next increment of energy for a specified interval of time.[148] See also: *Bid.*

*Generator Operator* – An operator that controls, operates, or maintains generators to generate electric power.

## H

*Hour-Ahead Market* – Market in which prices for energy delivery are calculated for the next hour delivery, typically in 15 minute increments, based on current supply and forecasted demand.[137]

*Hub* – An aggregation of generator and load nodes that is traded as a single contract node.[142] It is a specific set of predefined nodes for which locational marginal prices are calculated and used to establish a reference price for electric energy purchases and the transfer of day-ahead adjusted load obligations and real-time adjusted load obligations and for the designation of Financial Transmission Rights.[135] See also: *Node* and *Load Zone.*

*Hub Price* – The price calculated as an average of the prices at all of the nodes defined of the hub. These nodes are electrically connected and are located in an area that has little congestion within it and therefore has a price that reflects the overall energy price.[156] See also: *Nodal Price* and *Zonal Price.*

## I

*Imbalance Energy (IE)* – The difference between what actually happens for each generator and load and what they prearranged through schedules. Mathematically the IE can be expressed as follows: IE =Actual Production or Usage - Scheduled Production or Usage.[136] See also: *Energy Imbalance Service (EIS).*

*Incremental Auctions* – Allow for an incremental procurement of resource commitments to satisfy either an increase in the region's unforced capacity obligation due to a load forecast increase, or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, or decrease in the nominated value of a planned demand resource.[137] Also referred to as an reconfiguration auction in ISO New England. See also: *Reconfiguration Auction*.

*Independent Coordinator of Transmission (ICT)* – FERC approved Reliability Coordinator for grid security and stability and planning functions.[139]

*Independent Market Monitor* – An entity selected to monitor the wholesale electric market to detect and prevent market manipulation strategies and recommend measures to enhance the efficiency of the wholesale market.[137]

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[156] ISO-NE. (2013). *Locational Marginal Pricing.* Retrieved on February 25, 2013 from http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/lmp/index-p3.html

*Independent Power Producer (IPP)* – A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and which is not an electric utility.[148]

*Independent System Operator (ISO)* – An ISO performs similar duties to a Regional Transmission Organization (RTO). The ISO was FERC's initial attempt (as suggested in FERC Orders 888/889) to encourage the creation of independent organizations that would be responsible for managing a regional transmission grid, and provide open access to the grid. Open access to the grid means that all qualified companies would have the ability to put power onto the grid, regardless of who owned the particular transmission lines used. ISOs include: California ISO (CAISO), Midwest ISO (MISO), New York ISO (NYISO), ISO New England (ISO-NE), PJM, ERCOT, and Southwest Power Pool (SPP). See also: *Regional Transmission Organization (RTO), System Operator, FERC Order 888/889* and *FERC Order 2000.*

*Inductor/Reactor* – A device with the primary purpose to introduce inductance into an electrical system. Shunt reactors are normally used to absorb reactive power for voltage control. Series reactors are normally used to increase the effective reactance on a circuit to limit fault current.[143] See also: *Reactive Power* and *Capacitor*.

*Installed Capacity* – A generator or load facility that is capable of supplying and/or reducing the demand for energy in a control area for the purpose of ensuring that sufficient energy and capacity are available to meet the reliability rules. The installed capacity requirement includes a margin of reserve in accordance with the reliability rules.[157]

*Interconnection Study* – Any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the standard large generator interconnection procedures.[148]

*Interruptible Load for Reliability Resources* – A resource with a demonstrated capability to provide a reduction in demand.[143] See also: *Demand Resource and Demand Response*.

*Investor-Owned Utility* – A utility owned by private investors, as opposed to one owned by a public trust or agency; a commercial, for-profit utility as opposed to a co-op or municipal utility. They are usually subject to different regulations than publicly-owned utilities and co-ops, and they pay taxes as corporate citizens.[158]

## L

*Load* – The amount of electrical power used; the level of electricity consumption at a particular time measured in megawatt. See also: *Demand.*[138]

*Load Forecasting* – A process used to determine load obligations calculations. The load forecasts include weather data and hourly load data.[136]

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[157] New York ISO. (2011). *Glossary.* Retrieved on October 25, 2011 from http://www.nyiso.com/public/markets_operations/services/customer_support/glossary/index.jsp

[158] Potomac Economics. (2011). *2010 State of the Market Report for the ERCOT Wholesale Electricity Markets,* August 2011.

*Load Serving Entities (LSE)* – Entities that secure energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.[159]

*Load Shedding* – The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations.[143]

*Load Zone/ Zone* – An aggregation of all the load nodes within a specific area.[135] Typically, zones represent the vertical integrated utility territories.[136] See also: *Node* and *Hub.*

*Local Sourcing Requirement* – The portion of the total capacity requirement of the load in a capacity zone that must be purchased from resources within that zone after accounting for the capacity that can reliably be imported into that zone.[138]

*Locational Based Marginal Pricing (LBMP)* – See *Locational Marginal Price.*

*Locational Imbalance Price (LIP)* – The cost of bringing the last unit of the commodity – the one that balances supply and demand – to market. LIP recognizes that this marginal price may vary at different times and locations based on transmission loading.[160]

*Locational Marginal Price (Pricing) (LMP)* – The calculated price of electric energy at a node, load zone, reliability region, and the hub.[135]

*Loop Flow* – See *Parallel Path Flow.*

*Loss of Opportunity Costs* – A difference in net compensation from the energy market between what a unit receives when providing regulation or synchronized reserve and what it would have received for providing energy output.[143]

## M

*Maintenance Outage* – The scheduled removal from service, in whole or in part, of a generating unit, transmission line, or other facility in order to perform necessary repairs on specific components of the facility.[143] See also: *Forced Outage, Outage, Planned Outage and Scheduled Outage.*

*Marginal Price/Marginal Cost* – A price/cost (or increase in total price/cost) required to produce one additional unit of output.[139]

*Marginal Unit* – Marginal units are the generating units that set the locational marginal price.[161] Those are the last dispatched (the most expensive) units required to meet demand.[158] When there is congestion in the system, there can be more than one marginal unit.[161]

*Market-based Service* – A service where a price for a product or service is based upon existing market conditions. The price is set by an agreement between a buyer and seller.[162]

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[159] North American Reliability Corporation. (2011). *Glossary of Terms Used in NERC Reliability Standards.* Retrieved on February 25, 2012 from http://www.nerc.com/files/Glossary_of_Terms_2011August4.pdf

[160] SPP. (2011). *Imbalance Pricing.* Retrieved on October 25, 2011 from http://www.spp.org/publications/LIP/lmp/9.html

[161] Monitoring Analytics. (2013). Marginal Fuel Posting. Retrieved on Janaury12, 2013 from http://www.monitoringanalytics.com/data/marginal_fuel.shtml

*Market Clearing Price* – The price in a market at which supply equals demand. All demand prepared to pay at least this price has been satisfied and all supply prepared to operate at or below this price has been purchased.[148]

*Market Clearing Quantity* – Intersection of the supply curve and demand curve.

*Monitoring Analytics* – PJM's independent market monitor. See also: *Independent Market Monitor.*

*MWh* – A megawatt produced or consumed for one hour. See also: *Units of Electricity*.

**N**

*Nodal Price* – The price for electric energy received or furnished at a node for any given hour.[138] See also: *Hub Price* and *Zonal Price.*

*Node (or Nodal)* – A physical location on a transmission grid where electricity is delivered or withdrawn.[137] It is a point on the transmission system for which nodal prices are calculated.[138] Node can designate one such location, or groups of such locations designated as hubs or zones.[138] See also: *Hub* and *Load Zone.*

*North American Electric Reliability Corporation (NERC)* – A non-profit organization that operates to improve the reliability and security of the bulk power system in North America; develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. As the Electric Reliability Organization, NERC is subject to audit by FERC and governmental authorities in Canada.[163]

**O**

*Open Access* – Non-discriminating access to the transmission lines.

*Open Access Same-Time Information System (OASIS)* – The electronic posting system for transmission access data that that allows all market participants to view the data simultaneously.[148]

*Operating Day* – The daily 24-hour period beginning at midnight for which transactions on an energy market are scheduled.[143]

*Operating Reserve* – A capability above firm system demand required to balance shorter-term deviations between system load and generation, correct load forecasting errors, handle forced outages and recover from a contingency. It consists of spinning and non-spinning reserve.[23] See also: *Types of Reserves.*

*Out-of-Merit Commitment or Out-of-Merit Capacity (OOMC)* – A committed capacity required for system reliability requirements.[158]

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[162] Business Dictionary. (2013). *Market-based Service.* Retrieved on January 10, 2013 from http://www.businessdictionary.com/definition/market-based-pricing.html

[163] North American Reliability Corporation. (2011). *About NERC*. Retrieved on October 25, 2011 from http://www.nerc.com/page.php?cid=1

*Out-of-Merit Dispatch or Out-of-Merit Energy* – Energy provided by a resource selected outside the market bidding process to resolve a reliability or security event.[141]

*Outage* – The period during which a generating unit, transmission line, or other facility is out of service.[148] See also: *Forced Outage, Maintenance Outage, Planned Outage and Scheduled Outage*,

*Outage Coordination* – A business processes used to schedule and approve maintenance outages.

## P

*Parallel Path Flow/Loop Flow* – The unscheduled transmission flows that occur on adjoining transmission systems when power is transferred in an interconnected electrical system.[155]

*Peak/ Peak Demand* – The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.[143]

*Planned Demand Resource* – A demand resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing a reduction or control, on or before the start of the delivery year for which the resource is to be committed.[137]

*Planned Generation Capacity Resource* – A generation capacity resource participating in the generation interconnection process for which Interconnection Service is scheduled to commence on or before the first day of the delivery year for which the resource is to be committed.

*Planned Generator Outage* – See *Planned Outage.*

*Planned Outage* – The scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair.[148] See also: *Forced Outage*, *Maintenance Outage*, *Outage and Scheduled Outage*.

*Planner* – A person who works with stakeholders to develop overall plans for new transmission needed to meet future projected electricity demand.[135]

*Planning Reserve* – An adequate reserve margin that is essential for maintaining bulk power system reliability by providing system operators with the flexibility needed to withstand unexpected generation or transmission outages and deviations from the demand forecast.[169]

*Potomac Economics* – An independent market monitor for the Midwest ISO, ERCOT, New York ISO and ISO New England.[141, 158] See also: *Independent Market Monitor*.

*Power* – See *Electric Power.*

*Power Generator* – See *Generator.*

*Power Market* – A place to buy and sell electricity.[138] See also: *Electricity Market*, *Energy Market* and *Wholesale Electric Energy Market.*

*Power Marketing Administration/Authorities (PMA)* – Federally-chartered entities that own power generation facilities (typically hydropower plants), and can own transmission assets. PMAs typically sell power to cooperative-owned utilities or municipally-owned utilities, but can also sell to investor-owned utilities or federal agencies. There are four PMAs across the U.S.: the Bonneville Power Administration the Southwestern Power Administration, the Southeastern Power Administration, and the Western Area Power Administration.[164]

*Power Pool* – An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.[148]

*Power System* – The elements of an electrical system, including generation units, transmission lines, distribution lines, substations, and other equipment.[138] See also: *Bulk Power System.*

*Power System Stabilizers* – A device that is installed on generation resources to maintain synchronous operation of the power system under transient conditions such as loss of transmission lines due to overloading or weather conditions, loss of a generator, or the loss of major load.[137]

*Price Cap* – The maximum wholesale electricity price that can be received/paid by market participants.

*Price Signal* – A message sent to customers in the form of a price charged for electricity; usually indicates a message intended to produce a particular result. As an example, increasing prices during periods of shortage is a price signal to customers to cut back on energy consumption during these periods.[165]

*Price Volatility Make-Whole Payments* – Provides assurances to suppliers that they will not be financially harmed by responding to prices and following dispatch signals.[141]

*Public Utility Commission (PUC)/Public Service Commission (PSC)* – A state level governing body that regulates the rates and services of a utility (e.g., electric, natural gas, telecommunication, water, transportation).

*Publicly Owned Utility* – A utility operated by a municipality to serve residents or by a cooperative to serve its members. Municipally owned utilities do not necessarily serve all customers within the city limits and sometimes serve customers outside their boundaries. Cooperative utilities, which are owned and operated by and for their members, frequently are located in rural areas.

## R

*Reactive Power* – A quantity that is only defined for alternating current electric systems. The product of voltage and the out-of-phase component of alternating current. Reactive power, usually measured in MVAr, is produced by capacitors and similar devices and is absorbed by inductors and similar devices.[138] Reactive power is used to compensate for voltage drops and it is typically provided closer to the load. See also: *Capacitor* and *Inductor*.

*Real-Time Market* – A market in which prices for energy delivery are calculated for immediate delivery, typically in five-minute increments, based on current operating conditions of supply and demand. See also: *Spot Market*.

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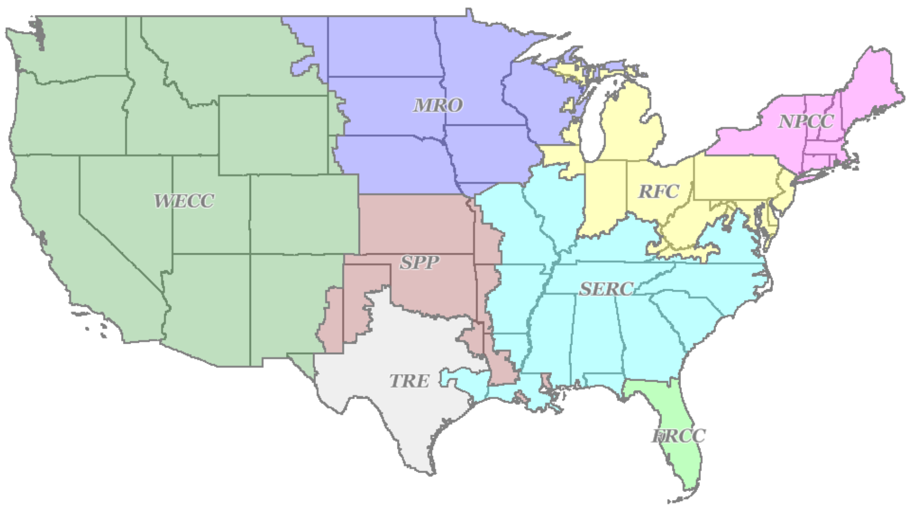
[164] U.S. Department of Energy. (2011*). Power Marketing Administration.* Retrieved on October 25, 2011 from http://energy.gov/offices

[165] EnergyVortex. (2011). *Energy Dictionary – Price Signal.* Retrieved on October 25, 2011 from http://www.energyvortex.com/energydictionary/price_signal.html

*Real-Time Market Administrator* – Administers a market where electricity is bought and sold at prices determined in real time to satisfy the difference between projected needs and actual demand. Many of the markets price electricity differently at various locations across the region in order to reflect the costs associated with congestion.[135]

*Reconfiguration Auction* – An auction of the Forward Capacity Market whereby capacity supply obligations are traded monthly, seasonally, and annually to clear supply offers and demand bids for each capacity zone.[138] Also referred to as an incremental auction in PJM. See also: *Incremental Auction*.

*Regional Entity* – An entity that has responsibility to enforce NERC's and the regional reliability standards, and perform other standards-related functions assigned by NERC.[166] NERC works with eight regional entities: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability*First* Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP), Texas Reliability Entity (TRE) and Western Electricity Coordinating Council (WECC).




*Map created by NETL. Source: ABB Velocity Suite*[167]

*Regional Grid Operator* – See *Regional Transmission Organization* and *Independent System Operator.*

*Regional Reliability Organizations* – An entity that ensures that a defined area of the bulk electric system is reliable, adequate and secure.[159] See also: *Regional Entity*.

*Regional Transmission Organization (RTO)* – An RTO is typically responsible for managing the operations of a transmission grid in a particular geographic area, and can also facilitate markets including the purchase and sale of wholesale power. RTO formation was encouraged by FERC

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[166] North American Reliability Corporation. (2011). *Company Overview: FAQ*. Retrieved on October 25, 2011 from http://www.nerc.com/page.php?cid=1%7C7%7C114

[167] ABB Velocity Suite. (2012). *Intelligent Map – US NERC Regions*. Retrieved on November 29, 2012, from https://velocitysuite.globalenergy.com/Citrix/MetaFrame/auth/login.aspx

Order 2000, and requires the organization to satisfy twelve characteristics and functions to be certified by FERC as the RTO. RTOs include: ISO New England, PJM, Midwest ISO and Southwest Power Pool. See also: *Independent System Operator (ISO)*, *FERC Order 888/889* and *FERC Order 2000.*

*Regulated Industry (Utility)* – An industry that provides electricity within a designated franchised service area. This includes investor-owned electric utilities that are subject to rate regulation, municipal utilities, federal and state power authorities, and rural electric cooperatives.[148] See also: *Utility* and *Vertically Integrated Utility*.

*Regulation* – See *Frequency Regulation.*

*Regulation Down* – An ancillary service that provides capacity decrease as a response to signals from a system operator within three to five seconds to respond to changes in system frequency.[137] See also: *Frequency Regulation.*

*Regulation Market Clearing Price* – The shadow price of supplying the last MW of regulation needed in the area, thus satisfying its regulation requirement constraint. The shadow price is obtained through a simultaneous co-optimization of Regulation, Synchronized Reserve, and Energy to minimize overall production cost. The co-optimized result ranks all available regulating resources in ascending merit order price, where merit order is the offer plus lost opportunity cost, simultaneously determining the least expensive set of resources necessary to provide regulation and synchronized reserve for the operating hour while taking into account any resources self-scheduled to provide any of these services.[137] See also: *Shadow Price.*

*Regulation Up* – An ancillary service that provides capacity increase as a response to signals from a system operator within three to five seconds to respond to changes in system frequency.[137] See also: *Frequency Regulation.*

*Reliability* – The assurance that power is available even under adverse conditions, such as unplanned outages of generation or transmission lines.[138]

*Reliability Coordinator* – A coordinator that ensures the real-time operating reliability of the transmission system.[138] There are 15 Reliability Coordinators in the US and Canada.

*Reliability Must Run Contract* – A contract with a generation resource that would not otherwise be operated except that it is necessary to provide voltage support, stability, or management of localized transmission constraints.[141]

*Reliability Pricing Model* – PJM's capacity market. See also: *Capacity Market.*

*Reliability Standards* – A requirement approved by FERC under Section 215 of the Federal Power Act to provide for reliable operation of the bulk power system. The term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.[148] A reliability standard that is applicable to a specific region is called regional reliability standard.

*Renewable Portfolio Standards (RPS)* – A mechanism to increase renewable energy generation. An RPS requires electric utilities and other retail electric providers to supply a specified minimum amount of customer load with electricity from eligible renewable energy sources.

Currently, states with RPS requirements/laws mandate that between 4 and 33 percent of electricity be generated from renewable sources by a specified date.[168]

*Reserve Margin* – A reserve that is roughly calculated as capacity minus demand, divided by demand.[169]

*Reserve Requirement /Reserve Obligation* – A predefined capacity that currently is not being used but that can be quickly available for the unexpected loss of generation.[143] See also: *Types of Reserves*.

*Resource* – Any source of electric energy that increases the availability of capacity (in megawatt), such as a generator, a dispatchable load, a demand-response resource, or an electricity import or external transaction.[138]

*Resource Adequacy* – The ability of a bulk electric power system to supply the aggregate electrical demand and energy requirements (i.e., the electrical loads of all the customers at all times plus external transaction sales to other control areas), taking into account scheduled and reasonably expected unscheduled outages of system devices (e.g., generators, transformers, circuits, circuit breakers, or bus sections).[138]

*Restructured Electric Industry* – An industry where the monopoly system of electric utilities has been replaced with competing sellers.[148]

*Restructuring* – The process of replacing a monopolistic system of electric utility suppliers with competing sellers, allowing individual retail customers to choose their supplier but still receive delivery over the power lines of the local utility. It includes the reconfiguration of vertically-integrated electric utilities.[148]

*Retail Electric Market* – A market where end-users can chose their supplier from competing retail electric providers.

*Retail Electric Provider (REP)/Supplier* – An entity that sells electric energy to retail customers but does not own or operate generation assets and is not a municipally-owned utility or an electric cooperative.[141]

*Retail Rate* – The price of electricity that end-users are paying.

*Revenue Sufficiency Guarantee* – Payments that ensure that the total market revenue a generator receives when its offer as-accepted is at least equal to its as-offered costs.[141]

## S

*Schedule* – A set of MWh values consisting of one value for each hour of a single day.[137]

*Scheduled Outage* – The shutdown of a generating unit, transmission line, or other facility for inspection or maintenance, in accordance with an advance schedule.[148] See also: *Forced Outage, Maintenance Outage, Outage* and *Planned Outage.*

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[168] EPA. (2011). *Renewable Portfolio Standard Fact Sheet.* Retrieved on October 25, 2011 from http://www.epa.gov/chp/state-policy/renewable_fs.html

[169] North American Reliability Corporation. (2011). *2011 Summer Reliability Assessments.* Retrieved on October 25, 2011 from http://www.nerc.com/files/2011%20Summer%20Reliability%20Assessment_FINAL.pdf

*Scheduling* – A process through which schedules for energy and Ancillary Services are submitted by market participants to a RTO/ISO. It also includes the MW of Energy of Generation and Demand cleared through the market clearing process set in the Day-Ahead Schedule for the next Trading Day.[141, 148]

*Shadow Price* – The cost sensitivity of the relevant binding regional constraint at the optimal solution, i.e., the marginal reduction of the combined Energy and Ancillary Services procurement cost associated with a marginal relaxation of that constraint.[148] Shadow price is applicable to any market where constraints exist. See also: *Ancillary Service Shadow Price* and *Regulation Market Clearing Price.*

*Service Area* – An area in which an electric utility is obligated to provide electric service to end-use customers.[148]

*Special Protection System* – An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability.[159]

*Spot Market* – A market that typically involves short-term, often interruptible contracting and immediate delivery of specified volumes of electric energy, as opposed to bilateral trading.[138] See also: *Real Time Market.*

*Supply* – Electricity delivered to the system.[138] See also: *Generation.*

*Supply Curve* – A graph showing the hypothetical supply of a product or service that would be available at different price points.[170] See also: *Demand Curve.*

*Synchronous Condensers* – A unit that is only capable of supplying reactive power that would not otherwise be operated except that it is necessary to provide voltage support.[137]

*System Contingency* – See *Contingency*.

*System Disturbance* – An unplanned event that produces an abnormal system condition; any perturbation to the electric system. Also, the unexpected change in the area control error caused by the sudden failure of generation or an interruption of load.[138]

*System Operator* – An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.[143] A system operator can also be an entity responsible for the reliability and operation of its "local" transmission system.[138] The entity is charged with coordination of market transactions, system-wide transmission planning, and network reliability.[137] See also: *Independent System Operator (ISO).*

*System Protection* – A set of actions that protect bulk power systems from faults through the isolation of faulted parts from the rest of the system.

*System Restoration* – Restoring supply to the bulk power system following a major disturbance, outage or blackout.

[170] Investor Words. (2013). *Supply Curve*. Retrieved on October 25, 2011 from http://www.investorwords.com/5812/supply_curve.html

## T

*Tariff* – The rates and pricing schedule for electricity, as well as the terms of service, including reliability standards approved by the state or federal regulatory organization.

*Transmission Capability* – The overall capacity of interregional or international power lines, together with the associated electrical system facilities, to transfer power and energy from one electrical system to another.[148]

*Transmission Congestion* – See *Congestion.*

*Transmission Congestion Contracts (TCC)* – The right to collect or obligation to pay Congestion Rents associated with a single MW of transmission between a specified point of injection and point of withdrawal. TCCs are financial instruments that enable energy buyers and sellers to hedge fluctuations in the price of transmission. It is used in NYISO.[23] See also: *Congestion Revenue Right* and *Financial Transmission Rights*.

*Transmission Constraints* – A limitation on one or more transmission elements that may be reached during normal or contingency system operations.[159]

*Transmission Line Capacity* – Maximum amount of power that can be sent over a transmission line.

*Transmission Owner* – The entity that owns and maintains transmission facilities.[159]

*Transmission Right* – See *Financial Transmission Right.*

*Transmission Service* – The right to use high-voltage transmission lines to transfer power from a generator to a consumer.[142]

*Transmission Service Charges* – Payments to transmission asset owners based on the utilization of the owner's transmission lines.

*Transmission Service Provider* – Administers the transmission tariff and provides transmission services, receives and processes transmission service requests, and determines available capacity.[138]

*Transmission System / Transmission Grid* – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.[159]

*Types of Reserves* – *Operating Reserve* – Generation available in 30 minutes. *Synchronized or Spinning Reserve* – Reserve capability that can be converted fully into energy within 10 minutes or customer load that can be removed from the system within 10 minutes of the request from the dispatcher, and must be provided by equipment electrically synchronized to the system. *Non-Synchronized* – reserve available in 10 minutes that is not synchronized with the system. *Secondary Reserve* – Reserve available in 10 to 30 minutes.[137]

## U

*Unit Commitment* – The process of determining which generating units will be committed (started) to meet demand and provide ancillary services in the near future (e.g., the next trading day).[148]

*Units of Electricity* – Real power is measured in watt (W) or kilowatt (kW; 1kW = 1,000 W) or megawatt (MW; 1MW = 1,000 kW = 1,000,000 W). Reactive power is measured in mega-volt-ampere reactive (MVAr), energy is measured in watt-hour (Wh) or kilowatt-hour (kWh; 1kWh =

1,000Wh) or megawatt-hour (MWh; 1MWh = 1,000 kWh = 1,000,000 Wh) and apparent power in megavolt-ampere (MVA). See also: *Electric Power.*

*Uplift* – A variety of non-market-based expenses such as out-of-merit energy dispatch, out-of-merit commitment, replacement reserve services, reliability must run contracts, price volatility make-whole payments, and revenue sufficiency guarantees.[141]

*Utility* – A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated. Types of electric utilities include investor owned, cooperatively owned, and government owned (federal agency, state, provincials, municipals, and public power districts).[143] See also: *Investor-Owned Utility*, *Publicly Owned Utility* and *Federal Power Agencies.*

## V

*Vertically Integrated Utility* – A single company that owns and manages the power generating facilities, transmission and distribution lines, and retail sale of power.[171] See also: *Utility* and *Regulated Utility.*

*Voltage Control* – The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.[143]

*Voltage Management* – See *Voltage Control.*

*Voltage Support* – Services provided by generating units or other equipment such as shunt capacitors, static VAr compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.[148]

## W

*Wholesale (Electric Energy, Power) Market* – The buying, selling, and reselling of the electric energy generated by a bulk power system to meet the system's demand for electric energy.[138] See also: *Electricity Market*, *Energy Market* and *Power Market.*

*Wholesale Market Price* – The price in a market at which supply equals demand. All demand prepared to pay at least this price has been satisfied and all supply prepared to operate at or below this price has been purchased.[148]

## Z

*Zonal Price* – The hourly price for electric energy received in a defined load zone calculated using a load-weighted average of the locational marginal prices for the nodes within the load zone.[138] See also: Nodal Price and Hub Price.

*Zone* – See Load Zone.

[171] Willis, H.L, and Philipson, L., 2005. *Understanding Electric Utilities and Deregulation,* 2nd ed., Boca Raton, FL: CRC Press.