3 Wholesale Electric Markets

Overview

Electricity is a physical product – the flow of electrons. It is a secondary energy source in that it results from the conversion of other energy forms such as natural gas, coal or uranium, or the energy inherent in wind, sunshine or the flow of water in a river. It may not be visible, but it can be turned on and off and measured.

Quick Facts: Measuring Electricity

Electricity is measured in terms of watts, typically in kilowatts (1,000 watts) or megawatts (1,000 kilowatts).

A kilowatt (or watt or megawatt) is the amount of energy used, generated or transmitted at a point in time. The aggregation of kilowatts possible at a point in time for a power plant, for example, is its capacity. The aggregation of kilowatts used at a point of time is the demand at that point.

The number of kilowatts used in an hour (kilowatt-hour or kWh) is the amount of electricity a customer uses or a power plant generates over a period of time. Kilowatt-hours are used to bill customers.

Electric markets have retail and wholesale components. Retail markets involve the sales of electricity to consumers; wholesale markets typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. This paper focuses on wholesale markets, although it addresses retail demand and other instances where retail markets strongly influence wholesale markets.

Much of the wholesale market and certain retail markets are competitive, with prices set competitively. Other prices are set based on the service provider's cost of service. For wholesale markets, FERC either authorizes jurisdictional entities to sell at market-based rates or reviews and authorizes cost-based rates.

In competitive markets, prices reflect the factors driving supply and demand – the physical fundamentals. In markets where rates are set based on costs, these fundamentals matter as well. Supply incorporates generation and transmission, which must be adequate to meet all customers demand simultaneously, instantaneously and reliably.

Consequently, key supply factors affecting prices include fuel prices, capital costs, transmission capacity and constraints and the operating characteristics of power plants. Sharp changes in demand, as well as extremely high levels of demand, affect prices as well, especially if less-efficient, more-expensive power plants must be turned on to serve load.

Background

Electricity on Demand

In the United States and other developed countries, consumers expect electricity to be available whenever they need it. Electricity use has grown enormously as consumers now consider not only refrigerators, TVs and hair dryers but also computers, iPods and other electronic devices as necessities. Consumers also expect to pay reasonable prices for the electricity they use.

Meeting these customer expectations is challenging. With few exceptions, electricity cannot be stored, in any appreciable quantities, and thus must be produced as needed. Further, unlike most other markets, electricity's historical inelastic demand does not move with prices. To provide electricity on demand, electric system operations have to be planned and conducted with that goal in mind. Lacking storage and responsive demand, operators must plan and operate power plants and the transmission grid so that demand and supply exactly match, every moment of the day, every day of the year, in every location.

The Drive for Enhanced Value

The electric industry has met this growing demand with increasing efficiency. Between 1929 and 1967, the national average cost of electricity for residential customers plummeted from about 60¢/kWh to 10¢/kWh (in 2005 dollars), and remains around there today. How did the industry achieve such tremendous cost savings and then keep the real price of electricity flat over the past 40 years? Part can be explained by greater efficiency – power plants use less fuel, and new techniques make it cheaper to extract the coal and natural gas that fuels generators. Another part of the answer, though, stems from changes in the way the industry is organized and operated.

Economies of Scale

Electric power is one of the most capital intensive industries. Generation alone can account for roughly 65% of a customer's electric bill. Spreading these relatively fixed costs over more customers helps bring down the cost that each customer pays.

Thomas Edison's first street lighting project in the 1880s grew to electrifying whole neighborhoods, towns and cities. Providing service over larger areas allowed utilities economies of scale in generating technology. The cost per unit of production dropped as power plants grew larger and larger. The companies building these facilities were basically self-contained – they owned and operated the generation, transmission and distribution facilities. Power lines were built from their generation to their population, or load, centers. These companies were vertically integrated.

One downside of larger generating units is that they are difficult to replace if they experience unexpected shutdowns. For a single utility building a new and larger unit, the only way to ensure reliable service is to build two units – creating a capacity reserve. When coal and nuclear unit sizes grew to 500 or 1,000 MW, building two units became very expensive for any individual company.

Reserve Sharing, Interconnection and Power Pools

The solution to high reserve costs was to share reserves with adjacent utilities. Instead of building two large units, utilities could buy from their neighbors in times of need, and cut their costs significantly. To facilitate reserve sharing, utilities built major interconnecting transmission lines large enough to deliver power in case of a major generator outage. Today's bulk power grid began as a way to maintain reliable service while lowering costs.

As more utilities share reserves, the smaller the reserves each must carry, and the lower the costs. The value of reserve-sharing agreements led to the formation of power pools, the forerunners of today's regional transmission organizations (RTOs).

Coordinating reserves also led to closer coordination of other utility functions, such as the process of determining which generating units to use, called unit commitment. Operators want to commit just enough capacity for the next day to ensure reliability but no more than needed, to minimize costs. This began a new phase of using economies of scale in system operations encompassing whole regions of the country.

Regional coordination also was spurred by special circumstances, particularly in the West. Large federally owned dams on the Columbia and Colorado rivers generate power from the spring runoff of melting mountain snow. When the reservoirs are full and the turbines are spinning, there is not enough local demand to use the power. Since the hydropower was cheaper than any alternative, long distance transmission lines were built to deliver the excess power from the Northwest and Southwest to load centers in California.

With the transmission interconnections in place, northwestern utilities found that they could get cheaper power from southern power generation at other times of the year. These seasonal and regional disparities in availability and price provide for a lively bilateral trading market.

In the 1960s, the electric industry created an informal, voluntary organization of operating staff to aid in coordinating the bulk power system. Then, in 1965, the largest power blackout until that time hit the northeastern United States – including New York – and southeastern Ontario, Canada, affecting 30 million people. The blackout led to the development in 1968 of the National Electric Reliability Council (NERC), shortly thereafter renamed the North American Electric Reliability Council. and nine regional reliability councils. Rather than serving as a pool or other entity for sharing resources, NERC focused on reliability. In 2006, using authority granted in the U.S. Energy Policy Act of 2005, FERC certified NERC as the electric reliability organization for the United States, and reliability standards became mandatory and enforceable.

Optimizing Unit Commitment and Economic Dispatch

The industry also reduced costs by using computers and communication technology to optimize system operations. Utilities use algorithms for optimizing the commitment of their generating units, while RTOs' day-ahead market software does this for suppliers bidding into their markets.

In real time, demand is changing all the time. Without storage and responsive demand, the output of some generators must change to follow constantly changing demand. This is known as load following. Utilities use economic dispatch to optimize the use of these units and minimize real-time costs.

Economy Energy Trade

Since transmission interconnections were built primarily for the rare need to deliver reserves in emergencies, the industry had excess transmission capacity. This allowed utilities to use the lines to trade power. Major utilities generally owned sufficient capacity to meet their own peak power needs. However, sometimes the cost of operating their marginal generation was higher or lower than that of their neighbors. Transmission availability provided opportunities for utilities to save money by buying energy when it was cheaper than generating and selling energy to utilities with higher costs. This is called economy energy trading.

Evolving Public Policies

Different public policy theories have shaped the electric power industry over its history. All of these public policies are still in play to some extent today. Five concepts that helped shape the electricity industry and markets are outlined below.

Not-for-Profit Utilities

One of the first approaches to ensuring customer value was to depend on nonprofit electric providers. In the early days of the industry, electrification started in towns and cities. In many places, this utility service was provided by the municipal government. The federal government stepped in to develop and market the nation's significant hydroelectric resources. The Depression-era rural electrification program relied on customer-owned rural electric cooperatives and low-interest government loans. There are currently more than 1,700 municipal and almost 900 cooperative utilities in the United States.

Regulated Natural Monopolies

A second model for operating power systems was investor-owned regulated monopolies. In the early days of the industry, while many cities went the municipal route, many investor-owned utilities were also starting up. These private utilities are regulated, typically by a state agency. Initially, they agreed to be regulated to overcome a lack of retail competition, and were granted exclusive service territories (franchise). Today, regulation focuses on mitigating market power, among other things, because many utility functions are seen as natural monopolies.

State regulators approve a utility's investments in generation and distribution facilities, either in advance of construction or afterwards when the utility seeks to include a facility's costs in retail rates. Some states eventually developed elaborate integrated resource planning (IRP) processes to determine what facilities should be built.

Power Pools

Power pools are multilateral arrangements with members ceding operational control over their generating units and transmission facilities to a common operator. Members provided incremental cost data about their units and system status data to the operator. The operator ran an energy management system that used the unit cost data to optimize on a multilateral basis unit commitment and economic dispatch.

PJM began in 1927 for utilities to share their generating resources, forming the world's first power pool. The New York Power Pool was formed in 1966 and the New England Power Pool in 1971 in response to the 1965 Northeast blackout. The Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) formed in 1941 to pool resources for the war effort.

Competition, Part 1: Competitive Generation and Open Access

The environmental movement and initiatives to open the airline and trucking industries to competition also helped shape the energy industry in the 1970s. A provision in President Carter's energy plan led to passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), which ushered in the next era.

PURPA established a program implemented by states and overseen by the FERC to encourage the use of efficient cogeneration (using the heat from industrial or other processes to generate electricity) and small scale renewable generation. FERC's role was to issue regulations for the program and certify that qualifying facilities (QFs) met statutory requirements. States administratively set the price to be paid to these generators at the cost the utilities would avoid by purchasing the power rather than generating it themselves.

Most states set their avoided cost rate so low that they got little QF capacity. However, California, Texas and Massachusetts set very generous avoided cost rates and were overwhelmed with QF capacity, much of which received prices that turned out to be higher than the actual costs avoided by the purchasing utility. The rapid growth and size of the QF industry surprised many policymakers and entrepreneurs, and got them thinking about the viability of generation independent of regulated monopolies.

In 1988, FERC proposed rules to allow states to set their avoided-cost rate based on an auction. Instead of taking all capacity at a set rate, states could set the rate based on bids to supply a certain amount of needed capacity. The Commission also proposed to open the avoided-cost auction up to independent power producers (IPPs) that did not qualify as QFs. In this way, a regulatory program was transformed into a competitive initiative.

Under the regulated monopoly model, utilities owning and operating transmission lines had no obligation to allow others to use them. This posed a significant barrier to the development of an independent power industry. The Commission started conditioning approval in merger cases with the voluntary provision of open transmission access. The Energy Policy Act of 1992 gave the Commission authority to grant transmission access on request. These approaches to open access resulted in patchwork transmission access.

By the mid-1990s, support for opening the transmission grid to all users encouraged the Commission to pursue a generic solution. Order 888 required mandatory open transmission access by all transmitting utilities and a reciprocity provision successfully extended open access to nonjurisdictional entities (municipal, cooperative and federal utilities).

Order 889 addressed matters needed to implement open access. The rule established the Internet-based Open Access Same-Time Information System (OASIS) for posting available transmission capacity and reserving transmission capacity. These rules required significant changes to utility control room operations and limited the ability of companies to share transmission-related information with their own power marketing operating units.

Competition, Part 2: Integrating Markets and Operations – RTOs

Order Nos. 888 and 889 were designed for an industry of bilateral energy markets, in which parties negotiated transactions among themselves. The open-access transmission tariff and rules did not work well for multilateral power pools open to independent power producers. This led to the development of independent system operators (ISO) and, subsequently, regional transmission organizations (RTO). This primer uses RTO to stand for both RTOs and ISOs.

RTOs did more than operate the transmission system and dispatch generation, however. They developed markets in which buyers and sellers could bid for or offer generation. The RTOs used the bid-based markets to determine economic dispatch.

Major parts of the country operate under more traditional market structures, notably the West (excluding California) and the Southeast. Notably, two-thirds of the nation's electricity load is served in RTO regions.

Electricity Demand

Americans use electricity for heat and light, to run machinery and to power a growing number of products such as televisions, radios, computers, hair dryers, cell phones and iPods. This use has been increasing, reaching 3,865 gigawatt-hours (GWh) of electricity in 2008. Demand dropped in 2009 with the recession, but has since regained its upward trend.

The bulk of the electricity generated is sold to consumers, known as end-users or retail customers. Some consumers generate some or all of the power they consume. Some of the electricity sold to retail consumers is generated by integrated investor-owned utilities, federal entities, municipally owned and co-operatively owned utilities that sell the power directly to consumers. The rest of the electricity ultimately consumed by retail customers is bought and sold through wholesale electric markets.

This primer focuses on wholesale markets, which generally involve the sale of electricity to entities that resell the power to retail customers. However, retail consumers' electric use shapes demand and, therefore, the wholesale markets.

Quick Facts: Measuring Electricity

Electric use is described in terms of quantity and time.

The unit of measure of the quantity used is the kilowatt (kW), or 1,000 watts. The maximum number of all the kilowatts used by consumers on an electrical system at a point of time is peak demand.

The amount of electricity a consumer uses over a period of time is described as the number of the kilowatt-hour (kWh) - 1,000 watts working for one hour. Consumers pay based on the number of kWh they consume in a billing period, typically a month.

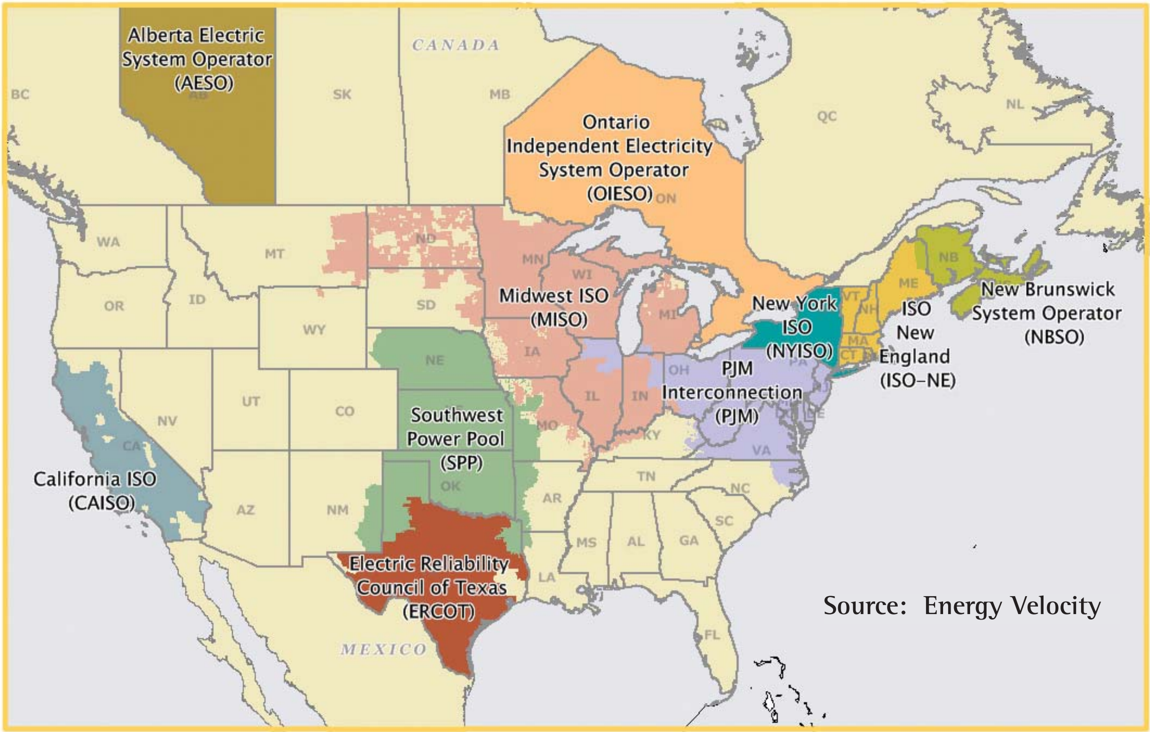
Source: EIA

Demand Characteristics

Demand is often characterized as baseload or peak. Baseload is demand that occurs throughout the day or throughout the year. Refrigerators, for example, may create baseload demand. Peak load is demand that shows up during part of the day or year, all at the same time – heating or air conditioning, for example.

Demand for electricity follows cycles, throughout the day and year. Regionally, electric demand may peak in either the summer or the winter. Spring and fall are typically shoulder months, with lower peak demand. Seasonal peaks vary regionally, although the highest levels of power load in almost all regions of the United States occur during heat waves and are most acute during the daily peak load hours reached in the late afternoon. However, a minority of regions reach their peak load when the weather is extremely cold. These are primarily areas with significant space-heating requirements and little summer air conditioning load. A majority of these systems are in the far northern areas of

North American Regional Transmission Organizations



the United States, where air conditioning load is not significant. South Florida's seasonal peak also occurs during the winter, when the population and tourism surges and uses more power than native Floridians do in the summer.

Daily demand typically peaks in the late afternoon, as commercial and domestic activities peak, and, in the winter, when lighting needs grow.

Electricity use also varies between weekdays and weekends. Commercial and industrial activities are lower on weekends and peoples' noncommercial activities change with their personal schedules. The load on different weekdays also can behave differently. For example, Mondays and Fridays, being adjacent to weekends, may have different loads than Tuesday through Thursday. This is particularly true in the summer.

Because demand historically has not varied with price and because storage options are limited, generation must rise and fall to provide exactly the amount of electricity customers need. The cost of providing power typically rises as demand grows, and falls as demand declines, so wholesale power prices are typically highest during peaks. Consequently, system planners, power marketers and traders all carefully track weather trends, economic growth and other factors to forecast power demand.

Demand Drivers

In general, the amount of electricity demanded is relatively insensitive to the price of electricity in the short-term (inelastic). One reason for this is that many customers – especially smaller customers – do not get price signals to which they can respond. Most residential customers are billed monthly on a preset rate structure. Large industrial customers, on the other hand, may receive real-time price signals.

Further, electricity is a necessity to most people and businesses. While they may be able to reduce their demand in the short-term – by turning down the thermostat or turning off lights, for example – electric consumers find it difficult to do without electricity altogether. There is little storage for electricity now and few realistic substitutes. Consequently, demand tends to drive price, especially when the system is stressed.

In the longer-term, options for reducing electricity use include switching to natural gas, installing insulation and implementing other energy efficiency measures. Larger consumers may consider building their own generation facilities.

Governments and businesses are also developing demand-response programs, which provide plans in which customers agree to reduce load in exchange for compensation.

Factors driving demand include demographics, climate and weather, economic activity and policies and regulations.

Demographics

Population levels affect demand, with greater population levels tending to increase electric consumption. Shifts in population also affect regional demand. Population flight in the 1980s from northern industrial regions – the Rust Belt – to warmer climates in the South affected residential consumption patterns. In the 1990s, consumption in the South surpassed that in the Midwest, making it the region with the greatest electric use.

Climate and Weather

Weather is the biggest factor driving demand. General climatic trends drive consumption patterns and therefore the infrastructure needed to ensure reliable service. Cold weather and short days drive winter demand in northern regions. Southern regions rely more on electric space heating, and, thus, see demand rise in the winter, although demand typically peaks in the summer with air conditioning load. In the winter, lighting contributes to the occurrence of peaks during the seasonally dark early morning and early evening hours.

Weather also can have extreme short-term effects on electricity usage. A sudden cold snap can drive heating use up quickly and a heat wave can push air conditioning loads. Other, less obvious weather patterns affect demand – rain and wind, for example, may result in sudden cooling, affecting heating or air conditioning.

Economic Activity

The pattern of socioeconomic life affects the cycle of electric use, with weekends and holidays showing a different pattern than weekdays. Demand typically rises as people wake up and go to work, peaking in the afternoon.

The health of the United States and regional economies also affects power demand. During periods of robust ac-

Quick Facts:
Heating and Cooling Degree Days

In the United States, engineers developed the concept of heating and cooling degree days to measure the effects of temperature on demand. Average daily temperatures are compared to a 65^{o} F standard - those in excess of 65^{o} yield cooling degree days; those below 65^{o} yield heating degree days. A day with an average temperature of 66^{o} would yield one cooling degree day.

tivity, loads increase. Similarly, loads drop during recessions. These changes are most evident in the industrial sector, where business and plants may close, downsize or eliminate factory shifts. In addition to reducing overall demand, these changes may affect the pattern of demand; for example, a factory may eliminate a night shift, cutting baseload use but continuing its use during peak hours. In some cases these effects can be significant.

Energy Policies and Regulations

State regulatory agencies set prices and policies affecting retail customer service. Some states are considering changes that would enable customers to receive more accurate price signals. They include, among other things, changing rate structures so that the rate varies with the time of day, or is even linked to the cost of providing electricity.

Efforts to reduce overall demand by improving energy efficiency are underway through several governmental and utility venues.

Retail Customer Mix

Most electric utilities serve different types of customers: residential, commercial and industrial. Each class uses electricity differently, resulting in a differing load profile, or the amount that each customer class uses and the daily shape of the load. If a consumer uses electricity consistently throughout the day and seasons, his load shape is flat, and the load will be baseload. Another consumer may use more at some times than others, resulting in baseload and peaks. Greater variability in demand is typically more expensive to serve, especially if the peak occurs at the same time other customers' use peaks. Consequently, the mix of customer types affects a region's overall demand.

Residential consumers form the largest customer segment in the United States at approximately 38 percent of electricty demand. Residential consumers use electricity for air conditioning, refrigerators, space and water hearing, lighting, washers and dryers, computers, televisions, cell phones and other appliances. Prices for residential service are typically highest, reflecting both their variable load shape and their service from lower-voltage distribution facilities, meaning that more power lines are needed to provide service to them.

Commercial use is the next largest customer segment at approximately 36 percent, and includes hotels and motels, restaurants, street lighting, retail stores and wholesale businesses and medical religious, educational and social facilities. More than half of commercial consumers' electric use is for heating and lighting.

Industrial consumers use about 26 percent of of the nation's electricity. This sector includes, for example, manufacturing, construction, mining, agriculture and forestry operations. Industrial customers often see the lowest rates, reflecting their relatively flat load structure and their ability to take service at higher voltage levels.

Transportation demand for electricity stems primarily from trains and urban transportation systems. This is less then 1 percent of electricty demand.

Load Forecasting

Demand is constantly changing, challenging grid operators and suppliers responsible for ensuring that supply will meet demand. Consequently, they expend considerable resources to forecast demand. Missed forecasts, where actual demand differs significantly from the forecast, can cause wholesale prices to be higher than they otherwise might have been.

Forecasts are necessary as well for the variety of actions that must occur if sufficient supply is to be available in the immediate or long term: planning the long-term infrastructure needs of the system, purchasing fuel and other supplies and staffing, for example. Load forecasts are also extremely important for suppliers, financial institutions and other participants in electric energy generation, transmission, distribution and trading.

Load forecasting uses mathematical models to predict demand across a region, such as a utility service territory or RTO footprint. Forecasts can be divided into three categories: short-term forecasts, which range from one hour to one week ahead; medium forecasts, usually a week to a year ahead; and long-term forecasts, which are longer than a year. It is possible to predict the next-day load with an accuracy of approximately 1%-3% of what actually happens. The accuracy of these forecasts is limited by the accuracy of the weather forecasts used in their preparation and the uncertainties of human behavior. Similarly, it is impossible to predict the next year peak load with the similar accuracy because accurate long-term weather forecasts are not available.

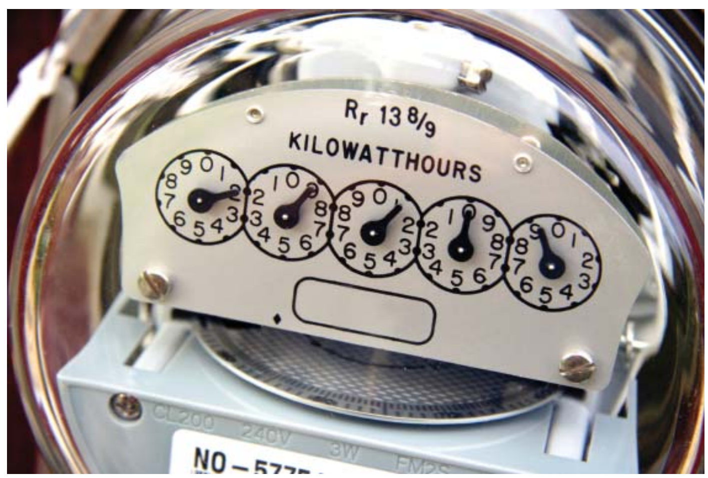
The forecasts for different time horizons are important for different operations within a utility company. Short-term load forecasting can help to estimate transmission system power flows and to make decisions that can prevent overloading of transmission systems. Timely implementation of such decisions leads to the improvement of network reliability and to the reduced occurrences of equipment failures and blackouts. Forecasted weather parameters are the most important factors in short-term load forecasts; temperature and humidity are the most commonly used load predictors.

The medium- and long-term forecasts, while not precise, take into account historical load and weather data, the number of customers in different customer classes, appliances used in the area and their characteristics, economic and demographic data, and other factors. For the next-year peak forecast, it is possible to provide an estimated load based on historical weather observations. Long-term forecasts are used for system infrastructure planning and are meant to ensure that there are sufficient resources available to meet the needs of the expected future peak demand. These forecasts are made for periods extending 10 to 20 years into the future.

Demand Response

Electric demand is generally insensitive to price, meaning that demand does not typically fall significantly when wholesale prices rise. However, some utilities and grid operators are developing ways to stimulate a response from consumers through demand-response programs.

Demand response (DR) is the ability of customers to respond to either reliability or price triggers by forgoing



power use for short periods, by shifting some high energy use activities to other times or by using onsite generation. The programs may use price signals or incentives to prompt customers to reduce their loads. The signals to respond to electric power system needs or high market prices may come from a utility or other load-serving entity, a regional transmission organization (RTO) or an independent DR provider. These programs are administered by both retail and wholesale entities.

DR has the potential to lower systemwide power costs and assist in maintaining reliability. It can be used instead of running power plants or to relieve transmission congestion There can also be environmental benefits because peaking units tend to be costly - and dirty - to run.

Demand response rewards consumers for reducing load during certain market conditions and at specific times. However, it is difficult to measure and quantify this reduction. Measuring and verifying the reduction requires development of consumers' baseline usage, against which their actual use is measured to determine the reduction in the event they are called to lessen their load. An accurate measure of their typical usage is important to prevent (or detect) gaming by participants.

Demand-Response Programs

Programs generally fall into three categories: curtailing, shifting or on-site generation.

Curtailing, or forgoing, involves reducing power use (load) during times of high prices or threats to reliability without making up the use later. For example, residential customers might turn off lights or raise thermostats during hot weather. Commercial facilities may turn off office equipment, lower building lighting or change thermostat settings by a few degrees.

Shifting involves moving or rescheduling high energy-use activities in response to high prices or DR program events to off-peak periods – evenings, nights or weekends. Industrial customers might reschedule batch production processes to evening hours or the next day. Commercial establishments may delay high-energy operations. Residential customers may wait until evening or night to use high-energy consuming appliances, such as clothes dryers or dishwashers. In shifting, the lost amenity or service is made up at a subsequent time.

On-site generation is when some customers may respond by turning on an on-site or backup emergency generator to supply some or all of their electricity needs. Although customers may have little or no interruption to their electrical usage, their net load and requirements from the power system are reduced. The ability to use on-site generation is most common for institutional customers, such as hospitals, large schools or data centers.

DR programs can be further distinguished by whether they are controlled by the system operator (dispatchable) or the customer (nondispatchable). Dispatchable demand response refers to programs that reduce customer energy use, such as direct load control of residential appliances or directed reductions to industrial customers. Dispatchable DR is used for reliability or economic reasons. Nondispatchable demand response lets the retail customer decide whether and when to reduce consumption in response to the price of power. It includes time-sensitive pricing programs based on rates that charge higher prices during high-demand hours and lower prices at other times.

As a result of technology innovations and policy directions, new types and applications of DR are emerging that encompass the use of smart appliances that respond in near real-time to price or other signals. These models may allow customers to respond more easily as they require little customer monitoring or interaction.

Demand Response in Retail Markets

Many states require utilities to use energy efficiency, DR or renewable resources. Energy Efficiency Resource Standards (EERS) in more than half of the states (plus Washington, D.C.) require utilities to achieve electric energy savings; many of these standards include peak load reduction targets. These mandates provide incentives for utilities to reduce customers' energy consumption, such as mechanisms that decouple profits from the amount of electricity sold, or performance bonuses for utilities that meet or exceed reduction targets.

Some states are implementing dynamic pricing, in which retail rates change frequently to better reflect system costs. Time-based rates depend on advanced meters at customer premises that can record usage. In time-of-use programs, customers are charged different prices at different times, with hours of peak demand costing more than off-peak hours.

In real-time pricing (RTP) programs, customers are charged prices reflecting the immediate cost of power. Industrial or very large commercial customers are often on RTP tariffs.

Critical peak pricing (CPP) uses real-time prices at times of extreme system peak, and is restricted to a small number of hours annually but features prices higher than time-of-use prices during the critical peak. Consumers do not know in advance when a critical peak might be called. A CPP program for residential customers uses a carrot without the stick: critical-peak rebates. Participating customers get rebates on their bills for responding to utility price-signals, but are not penalized if they do not lower use in those hours.

Wholesale Market Programs

Retail programs may aid RTOs, although the RTO may not be able to invoke them or even see specifically the amount of response that occurs. Wholesale-level DR occurs in the RTOs, which differ in how demand-response resources (DRR) may participate in their markets. Some RTOs permit DRR to participate in their markets as voluntary reliability resources. For example, NYISO has an emergency demand-response program, which permits DRR to participate through an aggregator or other interface party, and receive energy payments for providing curtailments when called.

DRR also can participate in wholesale markets as capacity resources and receive advance reservation payments in return for their commitment to participate when called. Resources that fail to perform when called are penalized.

Finally, DRR can bid into RTO day-ahead (DA) markets as energy resources, specifying the hours, number of megawatts and price at which they are willing to curtail. ISOs set minimum bid values – NYISO's program has a $75/MWh floor. In New York, a resource scheduled in the DA market is obligated to curtail, and failure to perform results in a penalty.

Some of the RTO DR comes from individual entities; the rest is accumulated through third-party aggregators, or curtailment service providers (CSPs), who recruit customers too small to participate on their own, such as schools, commercial chains or groups of residential customers. In aggregating small customers, CSPs have increased customer participation in many wholesale reliability and emergency programs. In NYISO's two incentive-based programs, CSPs increased their share of subscribed DRR to 77 percent in 2008 from 44 percent in 2003. CSPs were responsible for more than 60 percent of total DRR capacity, and 70 percent of new DRR in ISO-NE.

Demand-Response Use in Planning and Operations

Different DR programs can be used at various times to support planning and operations (see graphic, page 50). Energy efficiency programs that reduce baseload or peak demand over the long-term are incorporated into system planning. Dispatchable programs that are quickly implemented and targeted for short-term peak reductions – such as direct load control – lie on the other end of the spectrum, and are used in the moment of operation.

Electricity Supply and Delivery

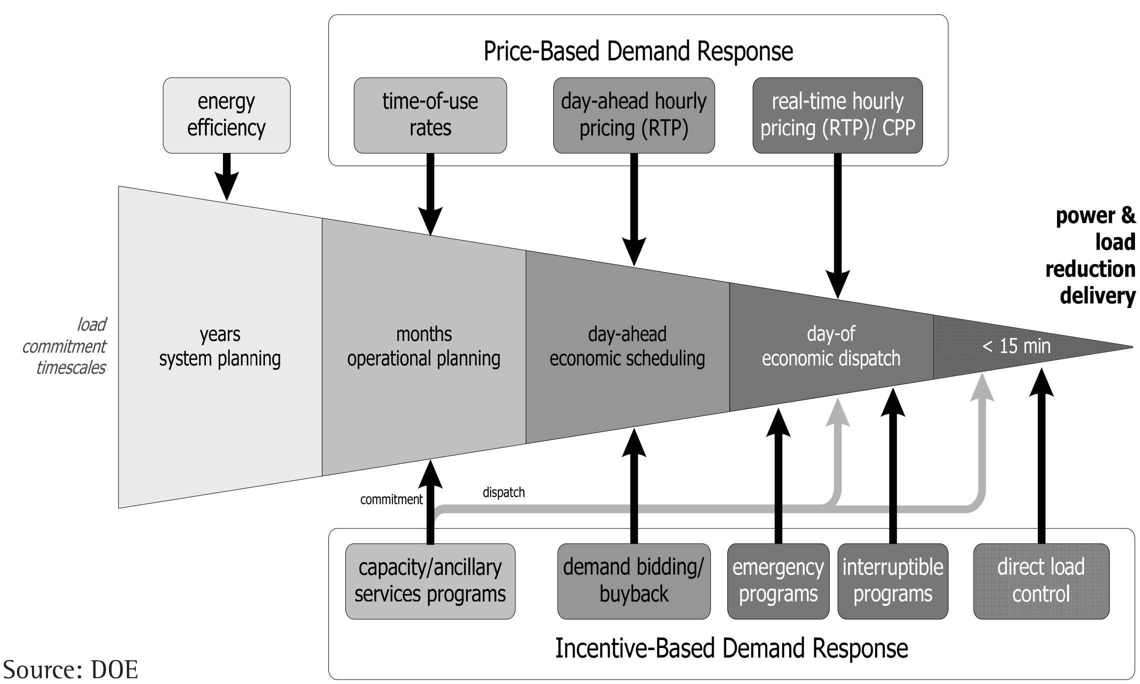
Unlike many other products, electricity cannot be stored in any appreciable quantities. Further, electricity is a necessity for most consumers, whose use responds little to price changes. Finally, electric equipment and appliances are tuned to a very specific standard of power, measured as voltage. Deviations in voltage can cause devices to operate poorly or may even damage them. Consequently, the supply side of the electric market must provide and deliver exactly the amount of power customers want at all times, at all locations. This requires constant monitoring of the grid and close coordination among industry participants.

Electricity service relies on a complex system of infrastructure that falls into two general categories: generation and the delivery services of transmission and distribution. Together, the power generation and high-voltage transmission lines that deliver power to distribution facilities constitute the bulk power system. Transmission and distribution facilities are also referred to as the power grid. These are coordinated and at times operated by a grid coordinator.

Nationally, the grid is split into three main sections – the Western, Eastern and Texas Interconnections. These sections operate independently and have limited interconnections between them.

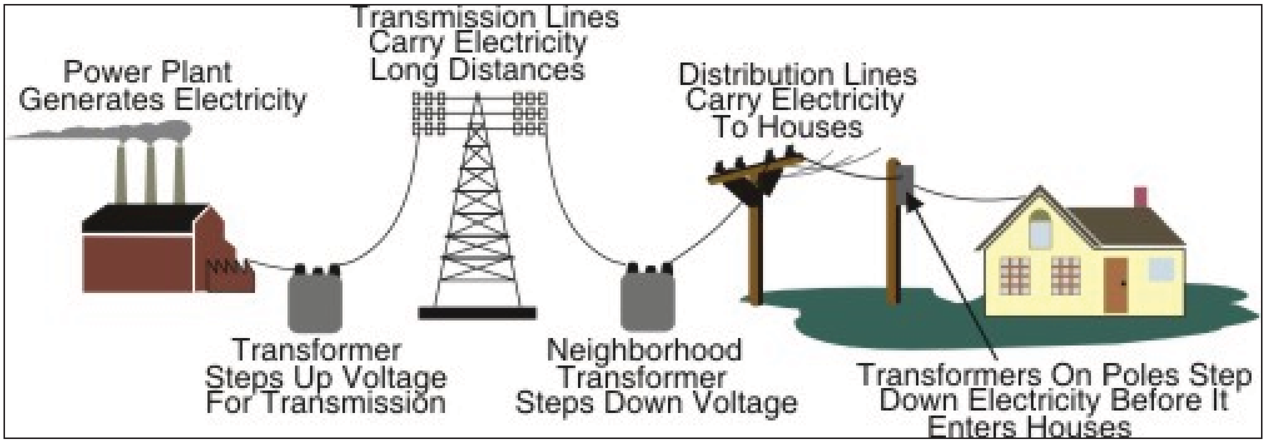
The nation, along with Canada and a small part of Mexico, is also divided into regional entities, (see map, page 51). The regional reliability entities fall under the purview of the North American Electric Reliability Corp. (NERC), which was designated by FERC as the nation's energy reliability organization and which develops standards, among other things, to ensure the grid's reliability. The standards, once issued by FERC, must be met by all industry participants – the standards are mandatory and enforceable. Consequently, the grid is designed and operated to meet these standards.

Demand-Response Program Use in Electric System Planning and Operations



Source: DOE

Electricity Service Schematic



Source: National Energy Education Development Project

NERC's regions include:

- Florida Reliability Coordinating Council (FRCC),
- Midwest Reliability Organization (MRO),
- Northeast Power Coordinating Council (NPCC),
- Reliability First Corporation (RFC),
- SERC Reliability Corp. (SERC),
- Southwest Power Pool (SPP),
- Texas Reliability Entity (TRE) and
- Western Electricity Coordinating Council (WECC)

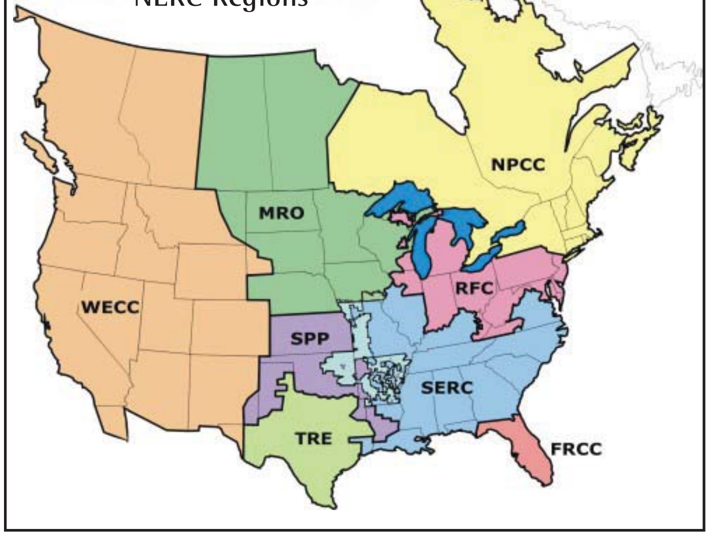
Generation

Power generators are typically categorized by the fuel they use and subcategorized by their specific operating technology. The United States has more than 1,000 gigawatts (GW) of total generating capacity. Coal, natural gas and nuclear dominate the power generation market.

Power plants each have differing costs and operational characteristics, both of which determine when, where and how plants will be built and operated.

Plant costs fall into two general categories: capital investment costs, which are amounts spent to build the plant, and operational costs, the amounts spent to maintain and run the plant. In general, there is a trade-off between these expenses: the most capital intensive plants are the cheapest to run – they have the lowest variable costs – and, conversely, the least capital intensive are more expensive to run – they have the highest variable cost. For example, nuclear plants produce vast amounts of power at low variable costs, but are quite expensive to build. Natural gas-fired combustion turbines are far less expensive to build, but are more expensive to run.

NERC Regions



Grid operators dispatch plants – or, call them into service – with the simultaneous goals of providing reliable power at the lowest reasonable cost. Because various generation technologies have differing variable costs, plants are dispatched only when they are part of the most economic combination of plants needed to supply the customers on the grid. For plants operating in RTOs, this cost is determined by the price that generators offer. In other areas, it is determined by the marginal cost of the available generating plants.

Construction of different generating technologies is subject to a number of issues, including community concerns, regional emission restrictions and the availability of fuels or other necessary resources:

- Wind plants are generally built in areas with the appropriate meteorological conditions. In most cases, these sites are located in rural areas with limited transmission access. For example, in West Texas, the transmission lines connecting wind farms with consumer centers in Dallas and Houston can become overloaded, requiring generators to curtail production.
- Coal plants have environmental characteristics that limit both their siting and operations. Specifically, they emit NO_x, SO_x, particulates, mercury and substantially higher levels of CO_2 than gas-fired plants. This has made financing these plants and siting them near urban centers difficult.
- There have been virtually no new nuclear plants built in the United States in the past 30 years. The technology of older plant designs became a source of concern following the accident at the Three Mile Island plant in the United States in 1977, the Chernobyl plant meltdown in Ukraine in 1986 and the Japanese earthquake, tsunami and nuclear plant destruction in 2011. New plant designs have been put forward over the past few years and are expected to be very expensive and controversial to build. Further, the disposition of high-level radioactive waste remains an unresolved problem, and the waste remains at plant locations.

Conventional Generation

Natural gas power plants: These feature three major technologies, each with its distinct set of market advantages and limitations. They are steam boilers, gas turbines and combined cycle generators. Natural gas fuels nearly a third of electricity generation.

Steam boiler technology is an older design that burns gas in a large boiler furnace to generate steam at both high pressure and a high temperature. The steam is then run through a turbine that is attached to a generator, which spins and produces electricity. Typical plant size ranges from 300 MW to 1,000 MW. Because of their size and the limited flexibility that is inherent in the centralized boiler design, these plants require fairly long start-up times to become operational and are limited in their flexibility to produce power output beyond a certain range. Furthermore, these plants are not as economical or easy to site as newer designs – which explains why none has been built in recent years.

Gas turbines (GT) are small, quick-start units similar to an aircraft jet engine. These plants are also called simple cycle turbines or combustion turbines (CT). GTs are relatively inexpensive to build, but are expensive to operate because they are relatively inefficient, providing low power output for the amount of gas burned, and have high maintenance costs. They are not designed to run on a continuous basis and are used to serve the highest demand during peak periods, such as hot summer afternoons. GTs also run when there are systemwide shortages, such as when a power line or generator trips offline. GTs typically have a short operational life due to the wear-and-tear caused by cycling. The typical capacity of a GT is 10-50 MW and they are usually installed in banks of multiple units.

Combined cycle power plants (CCPPs) are a hybrid of the GT and steam boiler technologies. Specifically, this design incorporates a gas-combustion turbine unit along with an associated generator, and a heat recovery steam generator along with its own steam turbine. The result is a highly efficient power plant. They produce negligible amounts of SO_2 and particulate emissions and their NO_x and CO_2 emissions are significantly lower than a conventional coal plant. CCPPs, on average, require 80 percent less land than a coal-fired plant, typically 100 acres for a CCPP versus 500 acres for comparable coal plant, and CCPPs also use modest amounts of water, compared to other technologies.

Coal plants: These generate more than one-third of the electricity in the United States. These facilities tend to be large, baseload units that run continuously. They have high initial capital costs and are also somewhat complex in their design and operations. However, coal plants have low marginal costs and can produce substantial amounts of power. Most of the coal-fired plants in the United States are owned by traditional utility companies and located in the Southeast and Midwest.

Oil-fired plants: These play a minor role in U.S. power markets. These facilities are expensive to run and also emit more pollutants than gas plants. These plants are frequently uneconomic and typically run at low capacity factors. Like gas-fired generators, there are several types of units that burn oil; primarily, these are steam boilers and combustion turbines.

Generally, two types of oil are used for power generation: number 2 and number 6 (bunker) fuel oil. Number 2 is a lighter and cleaner fuel. It is more expensive, but because it produces fewer pollutants when burned, it is better for locations with stringent environmental regulations such as major metropolitan areas. Conversely, number 6 fuel oil is cheaper, but considered dirty because of its higher emissions. It is highly viscous (thick and heavy) and it comes from the bottom of the barrel in the refining process.

Nuclear plants. These provide roughly 20 percent of the nation's electricity; there are 104 operating plants with a total capacity of 100 GW. These plants are used as baseload units, meaning that they run continuously and are not especially flexible in raising or lowering their power output. Nuclear plants have high capital and fixed costs, but low variable costs, which includes fuel cost. They typically run at full power for 18 month, which is the duration of a unit's fuel cycle. At that point, they are taken off-line for refueling and maintenance. Outages typically last from 20 days to significantly longer, depending on the work needed.

Following the Three Mile Island plant accident in 1977, there was a cessation in the development of new plants. Most projects under construction in 1977 were finished, albeit with tremendous cost overruns. The last unit built in the United States came online in 1996.

Renewable Generation

Renewable resources use fuels that are not reduced or used up in the process of making electricity. They generally include biomass, geothermal, hydropower, solar, onshore and offshore wind, hydrokinetic projects, fuel cells using renewables and biogas.

Renewable generation provides a small percent of total U.S. capacity and generation. Even in 2009, when total U.S. electric output fell, average renewable generation grew 12% and wind output grew 28%, spurred by state regulations and federal tax credits. As renewable generation becomes a larger percentage of generation resources, integrating them into the operating power grid has presented challenges.

Capacity: Wind and solar capacity have grown faster than other renewable resources in recent years. Geothermal has more installed capacity than solar, but is growing more slowly. Wind added the second highest amount of capacity after gas-fired generation in 2009 and 2010.

Additions are usually reported in megawatts of nameplate capacity. Actual capability varies from the nameplate for any unit type due to age, wear, maintenance or ambient conditions. But as renewable resources are often weather-dependent, their capacity factors – the ratio of average generation to the nameplate capacity for a specific period – have been much lower (as low as 30 percent) than for fossil-fuel-fired generation. Markets care about the difference between nameplate and capacity factor values when they evaluate capacity available to cover expected load. Prior to sufficient operating experience with a renewable technology, markets usually estimate capacity value conservatively.

Average capacity factors for new renewable resources in early 2010 were 34-35 percent for large wind projects, 74 percent for geothermal, 15-21 percent for commercial solar photovoltaic (PV), 35 percent for concentrating solar power (CSP) without storage (or 43-45 percent with storage technology) and 63 percent for biomass. Capacity factors have risen with technological innovation and improved manufacturing processes.

Characteristics: Wind power is the fastest-growing renewable resource, in part due to earlier cost declines and technology improvements as well as earlier receipt of federal tax credits. A 1.5-MW wind turbine was the most frequently installed size in 2009, although 2.3-MW turbines later became more common. Wind is largely pollution-free and can be located on farms and ranches.

Because the best wind resources are often far from load centers, insufficient transmission presents a challenge to delivering its output. Other market challenges for future wind development include its variable output, which is often inversely correlated to demand (seasonally and daily); system operators' inability to dispatch wind resources to meet load increases; difficulties related to accurately forecasting its ramping; and the need for companion generation (usually fossil-fueled) to be available to balance wind generation when the wind is not blowing.

Geothermal energy taps into reservoirs of steam and hot water deep beneath the earth's surface to produce power. The best resources are in the intermountain West. Geothermal potential is determined by thermal conductivity, thickness of sedimentary rock, geothermal gradient, heat flow and surface temperature. While geothermal power was less than 0.4 percent of U.S. generation in 2009, it was 11 percent of nonhydro renewable output in April 2010. California hosts more than 80 percent of U.S. operating capacity. The five states with the most geothermal capacity in development are California, Nevada, Oregon, Utah and Idaho.

Solar energy transforms sunlight into electricity using one of two technologies: photovoltaic (PV) or concentrating solar power (CSP). PV modules, or panels, transform sunlight directly into power using silicon wafers or nonsilicon thin-film technologies. They can be installed on roofs of buildings or at ground-level PV farms. CSP plants use a two-step process to transform the sun's energy. First, mirrors direct sunlight towards a receiver that captures the heat. CSP then employs a thermal process to create steam, driving an engine or turbine to produce electricity. CSP plants, which are dispatchable, can include low-cost energy storage that extends their availability later in peak hours.

PV growth has been highly concentrated as a result of state policy incentives: 10 states have 95% of PV capacity; California alone has more than 50 percent. Annual PV additions rose to more than 100 MW beginning in 2006, spurred by tax incentives in the Energy Policy Act of 2005. More recent growth was spurred by falling costs, technology innovation, expanded federal tax benefits and an increase in state policies promoting investment.

In 2010, 432 MW of CSP was operational and 81 MW was under construction. Seven western and southwestern states have extensive CSP potential: Utah, New Mexico, Arizona, Nevada, Texas, California and Colorado. Developing that potential will require overcoming challenges of siting, transmission and the need for extensive water supplies to clean mirrors.

Hydroelectric power is created when the kinetic energy of falling water drives turbine generators, which convert the energy into electricity. There are two types of hydroelectric projects: conventional and pumped storage. Conventional projects, which use a dam in a waterway, can operate in a run-of-river mode, in which water outflow from the project approximates inflow, or in a peaking mode, in which the reservoir is mostly drained to generate power during peak periods when energy is more valuable. Pumped storage projects use bodies of water at two different elevations. Water is pumped into elevated storage reservoirs during off-peak periods when pumping energy is cheaper; the water is then used to generate power during peak periods as it flows back to the lower elevation reservoir. Pumped storage is the only significant commercially deployed electricity storage technology available today.

Biomass includes many waste byproducts, such as agricultural residues, landfill gas, municipal solid waste and wood resources. The largest biomass category is wood waste, burned for heat and power in the lumber, pulp and paper industries. Challenges to biomass production include impacts on food supplies (for example, converting corn into ethanol), conserving natural resources and minimizing water pollution. State policies on renewable generation differ on eligibility of biomass technologies.

Biogas energy is created through the anaerobic (without oxygen) bacterial decomposition of manure, which is turned into a gas containing 60-70 percent methane. Biogas recovery can be installed at farms anywhere, used to run farm operations and reduce methane emissions from natural manure decomposition.

Renewable Energy Policies

Renewable development is frequently tied to policies promoting their use because of their higher cost relative to other technologies. Financial incentives include tax credits, low-cost loans, rebates or production incentives. Federal funding of research and development (R&D) has played an important role in lowering costs or reducing the time it takes for renewable technologies to become commercially viable.

Congress has passed tax incentives to spur renewable resource investments. Wind, biomass, geothermal, marine and hydrokinetic project developers can receive federal production tax credits (PTC) based on a facility's production. It is an inflation-adjusted credit that runs for 10 years from the date a facility goes online. Initially set at 1.5¢/kilowatt hour (kWh), its value in 2010 was 2.1¢/kWh. To qualify, a facility has to be operational before the PTC expires.

Unlike other renewables projects, solar projects are eligible for a federal investment tax credit (ITC), worth 30 percent of a project's equipment and construction costs. The ITC begins the year a project starts commercial operation and depreciates over five years. The Emergency Economic Stabilization Act (2008), the legislation enacted to help shore up the U.S. financial system, extended the solar ITC for eight years, through 2016. It also expanded both the PTC and ITC to include utilities, which were previously ineligible for these credits. This change created the impetus for a model of utility owned and operated renewable generation, and led to a flurry of project announcements.

Provisions of the American Reinvestment and Recovery Act (ARRA) of 2009 extended the PTC and gave developers new options. It extended the credit for wind to 2012 and for other eligible technologies to 2013, and gave PTC-qualified developers the option to claim the 30 percent ITC on a project-by-project basis for the PTC's current duration.

Due to the economic crisis, ARRA gave developers another option for projects that began construction by the end of 2010 – they could apply for Treasury-administered cash grants, which monetized the ITC's value up front. ARRA funds helped support renewable energy research and development and aided capacity growth in 2009, despite the economic downturn.

State renewable portfolio standards (RPS) and renewable energy standards (RES) have been significant drivers in the growth of investment in renewable generation. An RPS requires a certain percentage of energy sales (MWh) to come from renewable resources. Percentages usually increase incrementally from a base year to an ultimate target. Currently, 29 states plus Washington, D.C., have an RPS and six states have renewable goals without financial penalties for nonachievement. As utilities build more renewable-powered generation, the markets in which they participate continue to address the integration of renewable output into their day-ahead and real-time operations and model expected growth as part of their long-term transmission-planning processes.

To encourage the development of distributed generation (DG), or the production of electricity at the site of consumption, and solar power, 16 states plus Washington, D.C., created RPS carve-outs or set-asides to give an extra boost to these resources, which are not yet cost-competitive with other renewables.

Renewable energy certificates (RECs) allow state regulators to track compliance with mandatory RPS targets or verify progress in voluntary state renewable programs. They also allow compliance entities to purchase credits – subject to state imposed limits on amount and price - if they have not generated or bought enough renewable energy to meet their annual requirements. Each reported megawatt-hour (MWh) of eligible generation results in a system-issued REC with a unique identification number to prevent double-counting. Each REC includes attributes such as generator location, capacity, fuel-type and source, owner and the date when operations began.

States and local utilities offer a variety of financial incentives for renewable energy to complement policy mandates. These include tax credits for in-state manufacture of renewable energy equipment, consumer rebates for purchase and installation of renewable generation or production incentives. Production incentives include extra credits for solar output based on RPS solar set-asides and feed-in tariffs.

Five states, two municipal utilities and Ontario, Canada, adopted or expanded feed-in tariffs (FITs) in 2009 to support their energy and environmental goals. Also called feed-in rates or advanced renewable incentives, these programs typically are designed to encourage development of new small- and medium-sized renewable generation projects by residential and independent commercial developers.

FITs require utilities to buy the renewable generation at a fixed rate that is higher than that provided to other generators, under multiyear contracts. This enables smaller distributed renewable generators to avoid having to participate in renewable portfolio standard (RPS) auctions or other competitive procurements and compensates them for more expensive technologies. The utility passes the costs of the program to its customers.

Transmission

The alternating current (AC) power grid operates like an interconnected web, where, with a few exceptions, the flow of power is not specifically controlled by the operators on a line-by-line basis. Instead, power flows from sources of generation to consumers across any number of lines simultaneously, following the path of least resistance. There are a limited number of direct current (DC) lines, which are set up as specific paths with definite beginning and end points for scheduling and moving power. These lines are controllable by operators and have other characteristics that make them attractive to grid planners and operators, such as providing greater grid stability and lower line losses. However, DC lines cost significantly more than AC lines to construct. Consequently, DC lines are typically built for certain specialized applications involving moving large amounts of power over long distances, such as the Pacific Intertie, which extends between the Northwest and California.

Transmission lines provide a certain amount of resistance to the flow of power as electricity travels through them. This resistance is not unlike the wind resistance that a car must overcome as it travels along a highway. The resistance in power lines creates losses: the amount of power injected into a power line diminishes as it travels through the line. The amount of these losses is contingent on many factors, but typically equals several percent of the amount put into the system.

Transmission Service

FERC requires that public utilities that own transmission lines used in interstate commerce offer transmission service on a nondiscriminatory basis to all eligible customers. The rates and terms of service are published in each utility's Open Access Transmission Tariff (OATT). One type of service is point-to-point service. This service involves paying for and reserving a fixed quantity of transmission capacity and moving power up to the reservation amount from one location, the point of receipt (POR), to another location, the point of delivery (POD). Depending on availability, customers may purchase point-to-point service for durations of one hour to multiple years. The price for the service is cost-based and published in the OATT. In cases where there are multiple parties desiring transmission, it is allocated to the party willing to purchase it for the longest period of time. Capacity reassignment is the term for the resale of point-to-point transmission capacity in the secondary market.

Transmission holders may want to sell capacity in the secondary market because it is unneeded, or to make a profit. Capacity reassignment has been permitted since 1996. Beginning in 2007, resellers have been permitted to charge market-based prices for capacity reassignments, as opposed to the original cost-based price at which they purchased the capacity. The number of capacity reassignments increased from around 200 in 2007 to almost 32,000 in 2009. Most of the transactions were hourly, although capacity can also be reassigned on a daily, monthly or yearly basis.

If the market price of energy is greater at the POD than at the POR, the transmission has value. The transmission holder can capture this value by using the transmission – buying energy at the POR, moving it to the POD and selling it. Alternatively, the transmission holder can sell the transmission through a capacity reassignment. Thus, the price of a capacity reassignment should be equal to the expected price differential between the POD and the POR.

Grid Operations

Grid operators dispatch their systems using the least costly generation consistent with the constraints of the transmission system and reliability requirements. The dispatch process occurs in two stages: day-ahead unit commitment, or planning for the next day's dispatch, and economic dispatch, or dispatching the system in real time.

Day-Ahead Unit Commitment

In the unit commitment stage, operators decide which generating units should be committed to be online for each hour, typically for the next 24-hour period. This is done in advance of real-time operations because some generating units require several hours lead time before they are brought online. In selecting the most economic generators to commit, operators take into account forecast load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels and the minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and nonfuel operating costs and the cost of environmental compliance.

Also, forecast conditions that can affect the transmission grid must be taken into account to ensure that the optimal dispatch can meet load reliably. This is the security aspect of commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction and weather conditions. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to replace less-expensive units.

System and Unit Dispatch

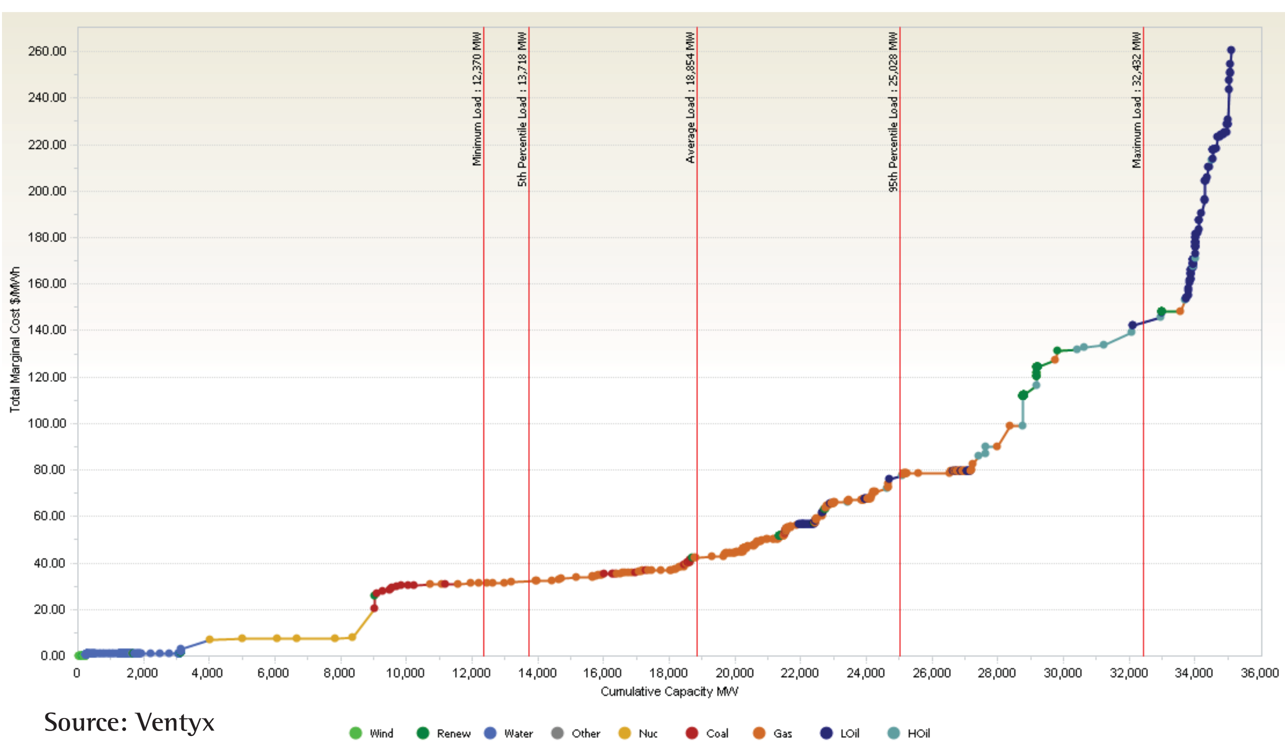
In the system dispatch stage, operators must decide in real time the level at which each available resource from the unit commitment stage should be operated, given the actual load and grid conditions, so that overall production costs are minimized. Actual conditions will vary from those forecast in the day-ahead commitment, and operators must adjust the dispatch accordingly. As part of real-time operations, demand, generation and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 hertz. This is typically done by automatic generation control (AGC) to change the generation dispatch as needed.

The chart below is a depiction of the supply curve of the power plants for the New York ISO (NYISO). This is also commonly called the supply stack. In it, all of the plants in the NYISO system are shown sorted according to their marginal cost of production. Their cost of production is shown on the vertical axis. The cheapest ones to run are to the left and the most expensive to the right.

Dispatch in the NYISO, for example, first calls on wind plants, followed successively by hydro, nuclear and coal-, gas- and oil-fired generators. This assumes that the plants have sufficient resources – enough wind for the wind powered generators or enough river flow for the hydroelectric plants, for example – and that sufficient transmission capability exists to deliver plant output and meet reliability needs.

In addition, transmission flows must be monitored to ensure that flows stay within voltage and reliability limits.

New York ISO Supply Stack



Source: Ventyx

If transmission flows exceed accepted limits, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch or shedding load. Operators may check conditions and issue adjusted dispatch instructions as often as every five minutes.

Ancillary Services

Ancillary services maintain electric reliability and support the transmission of electricity. These services are produced and consumed in real-time, or in the very near term. NERC and regional entities establish the minimum amount of each ancillary service that is required for maintaining grid reliability.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal, typically every few seconds. The changes are designed to maintain system frequency at 60 hertz. Failure to maintain a 60-hertz frequency can result in collapse of an electric grid.

Operating reserves are needed to restore load and generation balance when a generating unit trips off line. Operating reserves are provided by generating units and demand resources that can act quickly, by increasing output or reducing demand, to make up a generation deficiency. There are three types:

1. ***Spinning reserves*** are primary. To provide spinning reserve a generator must be on line (synchronized to the system frequency) with some unloaded (spare) capacity and be capable of increasing its electricity output within 10 minutes. During normal operation these reserves are provided by increasing output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. Synchronized reserve can also be provided by demand-side resources.

2. ***Nonspinning reserves*** come from generating units that can be brought online in 10 minutes. Nonspinning reserve can also be provided by demand-side resources.

3. ***Supplemental reserves*** come from generating units that can be made available in 30 minutes and are not necessarily synchronized with the system frequency. Supplemental reserves are usually scheduled in the day-ahead market, allowing generators to offer their reserve energy at a price, thus compensating cleared supply at a single market clearing price. This only applies to ISO/RTOs, and not all reliability regions have a supplemental reserve requirement.

Black start generating units have the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators have this capability. These are the first facilities to be started up in the event of a system collapse or blackout to restore the rest of the grid.

Reactive power. Electricity consists of current, the flow of electrons, and voltage, the force that pushes the current through the wire. Reactive power is the portion of power that establishes and maintains electric and magnetic fields in AC equipment. It is necessary for transporting AC power over transmission lines, and for operating magnetic equipment, including rotating machinery and transformers. It is consumed by current as it flows. As the amount of electricity flowing on a line increases, so does the amount of reactive power needed to maintain voltage and move current. Power plants can produce both real and reactive power, and can be adjusted to change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage.

Weather

Weather is the single greatest driver of electric demand and, thus, is a major factor in grid operations. System operators therefore rely heavily on weather forecasts to ensure they have the right generation in the right locations to run the grid reliably.

Weather affects grid operations in other ways, as well. Primary among these is on the productivity of certain types of power generators: wind and hydroelectric. Wind turbines' power output changes with wind availability and speed, which affects cost of wholesale power.

Hydroelectric plants rely on rain and snowfall to provide the river flow needed for their output. Geographically, this is most important in the Pacific Northwest, where seasonal hydro plant output is a critical source of power. Rain and the melting of winter snowpack feed the Columbia and Snake river systems. Surplus power from these generators is typically exported to California to help meet summer peak demand and provide a combination of increased reliability and lower prices.

Temperature can also affect the output of other power plants and capacity of transmission lines. Specifically, thermal plants that use a turbine – coal, gas, oil and nuclear plants – become less efficient at higher temperatures. Additionally, the capacity of transmission lines is limited by heat because the conductive material used in fabrication becomes more electrically resistant as they heat up, limiting their throughput.

Markets and Trading

Overview

Markets for delivering power to consumers in the United States are split into two systems: traditional regulated markets and market-regulated markets run by regional transmission organizations (RTOs), which include independent system operators (ISOs).

In general, RTOs use their markets to make operational decisions, such as generator dispatch. Traditional systems rely on management to make those decisions, usually based on the cost of using the various generation options.

Trading for power is also split into over-the-counter (OTC) or bilateral transactions, and RTO transactions. Bilateral transactions occur in both traditional systems and in RTO regions, but in different ways.

Pricing in both RTO and traditional regions incorporate both cost-of-service and market-based rates.

Bilateral Transactions

Bilateral or OTC transactions between two parties do not occur through an RTO. In bilateral transactions, buyers and sellers know the identity of the party with whom they are doing business.

Bilateral deals can occur through direct contact and negotiation, through a voice broker or through an electronic brokerage platform, such as the IntercontinentalExchange (ICE). The deals can range from standardized contract packages, such as those traded on ICE, to customized, complex contracts known as structured transactions.

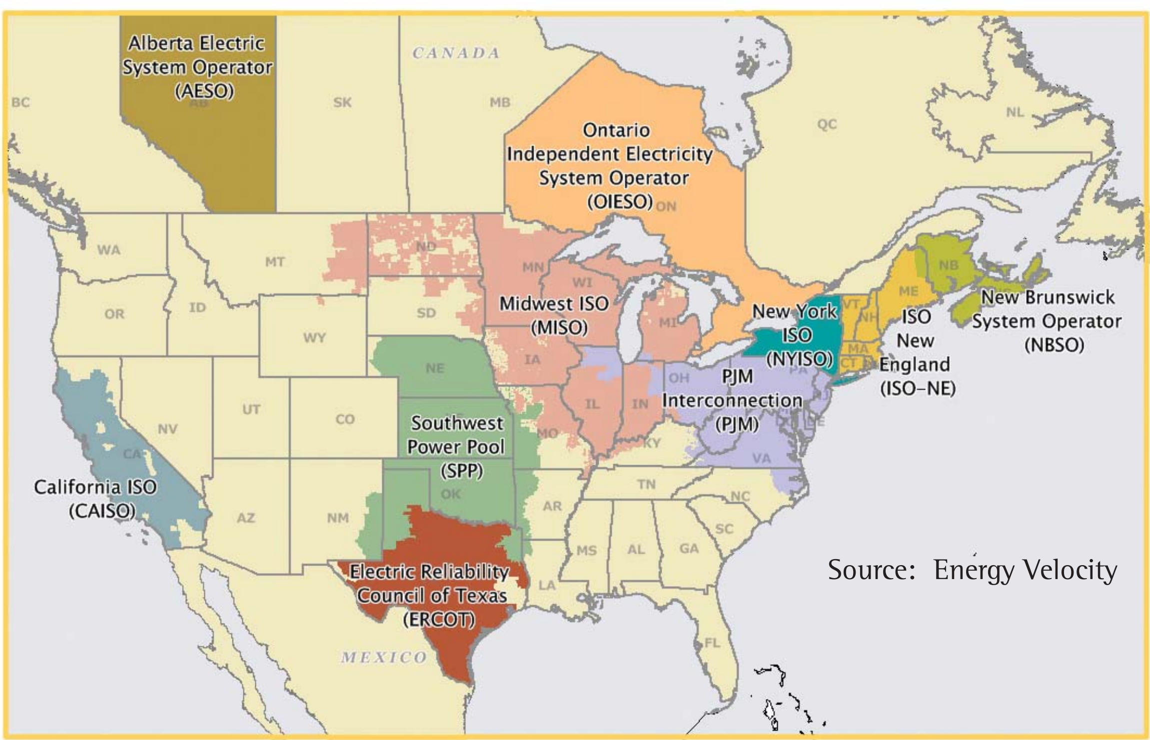
Whether the trade is done on ICE, directly between parties or through another type of broker, the trading of standard physical and financial products, such as next-day on-peak firm or swaps, allows index providers to survey traders and publish price indexes. These indexes provide price transparency.

Physical bilateral trades involving the movement of the energy from one point to another require that the parties reserve transmission capacity to move the power over the transmission grid. Transmitting utilities are required to post the availability of transmission capacity and offer service on an Open Access Same-Time Information System (OASIS) website. Traders usually reserve transmission capacity on OASIS at the same time they arrange the power contract.

When it comes time to use the reservation to transfer power between balancing authorities, one of the parties to the transaction submits an eTag electronically to Open Access Technology International (OATI), NERC's eTag contractor. OATI will process the tag and send it to all parties named on the eTag. This ensures the orderly transfer of energy and provides transmission system operators the information they need to institute curtailments as needed. Curtailments may be needed when a change in system conditions reduces the capability of the transmission system to move power and requires some transactions to be cut or reduced.

Bilateral physical transactions conducted in RTOs are settled financially. Generators offer their power into the RTO markets, and load is served through the power dispatched by the RTO. The RTO then settles bilateral transactions based on the prices in the contracts and the prices that occurred in the RTO markets.

North American Regional Transmission Organizations



Cost-Based Rates

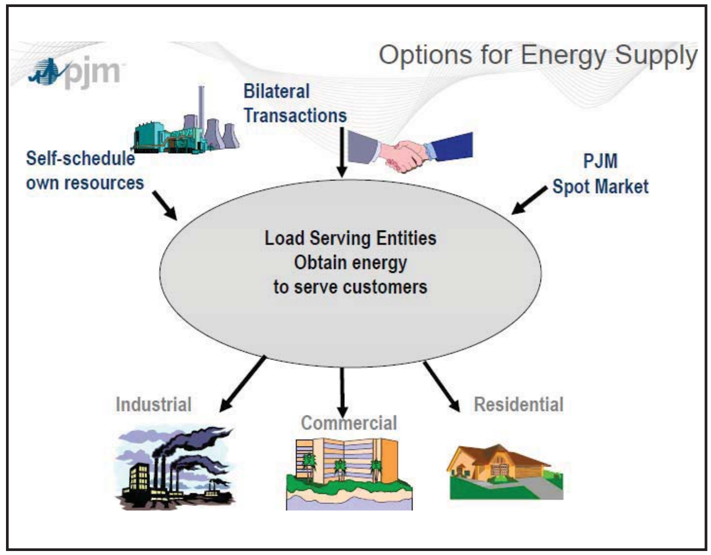
Cost-based rates are used to price most transmission services and some electricity when the Commission determines that market-based rates are not appropriate, or when an entity does not seek market-based rate authority. Cost-based rates are set to recover costs associated with providing service and give a fair return on capital. Cost-based rates are typically listed in a published tariff.

The following are major inputs to setting cost-based electricity rates:

- Determining used-and-useful electricity plants. This may include generation facilities, transmission facilities, distribution plants and office and related administration facilities.
- Determining expenses from the production, transmission and distribution of electricity, including fuel and purchased power, taxes and administrative expenses.
- Establishing a fair return on capital, known as the cost of capital. This includes determining the cost of debt, common equity, preferred stock and commercial paper and other forms of short-term borrowing such as lines of credit used to finance projects and provide cash for day-to-day operations.
- Allocating electric plant and other expenses among various customer classes and setting the rate structure and rate levels.

Market-Based Rates

Under market-based rates, the terms of an electric transaction are negotiated by the sellers and buyers in bilateral markets or through RTO market operations. The Commission grants market-based rate authority to electricity sellers that demonstrate that they and their affiliates lack or have adequately mitigated horizontal market power (percent of generation owned relative to total generation available in a market), and vertical market power (the ability to influence the cost of production for competitive electricity suppliers). Wholesale sellers who have market-based rate authority and who sell into day-ahead or real-time markets administered by a RTO do so subject to the specific RTO market rules approved by the Commission and applicable to all market participants. Thus, a seller in such markets not only must have an authorization based on analysis of that individual seller's market power, but it must abide by additional rules contained in the RTO tariff.



Supplying Load

Suppliers serve customer load through a combination of self-supply, bilateral market purchases and spot purchases. In addition to serving load themselves, load-serving entities (LSEs) can contract with others to do so. The choices are:

- Self-supply means that the supplying company generates power from plants it owns to meet demand.
- Supply from bilateral purchases means that the load-serving entity buys power from a supplier.
- Supply from spot RTO market purchases means the supplying company purchases power from the RTO.

LSEs' sources of energy vary considerably. In ISO-NE, NY-ISO and CAISO, the load-serving entities divested much or all of their generation. In these circumstances, LSEs supply their customers' requirements through bilateral and RTO market purchases. In PJM, MISO and SPP, load-serving entities may own significant amounts of generation either directly or through affiliates and therefore use self-supply as well as bilateral and RTO market purchases.

Traditional Power Markets

Traditional wholesale electric markets exist primarily in the Southeast, Southwest and Northwest. About 40 percent of all retail customers are in traditional wholesale markets where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers. Utilities in these markets are frequently vertically integrated – they own the generation, transmission and distribution systems used to serve electric consumers. They may also include federal systems, such as the Bonneville Power Administration, the Tennessee Valley Authority and the Western Area Power Administration. Utilities in traditional regions have the following responsibilities:

- Generating or obtaining the power needed to serve customers (this varies by state);
- ensuring the reliability of its transmission grid;
- balancing supply and demand instantaneously;
- dispatching its system resources as economically as possible;
- coordinating system dispatch with neighboring balancing authorities;
- planning for transmission requirements within the utility's footprint; and
- coordinating its system development with neighboring systems.

Wholesale physical power transactions occur through bilateral markets.

Regional Markets

Introduction

Two-thirds of the population of the United States and more than one-half of Canada's population are served by electricity markets run by regional transmission organizations or independent system operators (RTOs/ISOs). There is little practical distinction between a RTO and an ISO. The main distinction between RTO/ISO markets and their predecessors (such as vertically integrated utilities, municipal utilities and co-ops) is that RTO/ISO markets deliver reliable electricity through competitive market mechanisms.

The basic functions of a RTO or ISO include the following:

- Ensure the reliability of the transmission grid;
- operate the grid in a defined geographic footprint;
- balance supply and demand instantaneously;
- operate competitive nondiscriminatory electricity markets;
- provide nondiscriminatory interconnection service to generators; and
- plan for transmission expansion on a regional basis.

In performing these functions, RTOs have operational control of the transmission system, are independent of their members, coordinate the maintenance of generation and transmission system, and oversee a transmission planning process to identify needed upgrades in both the near- and long-term.

RTOs/ISOs do not own transmission or generation assets; perform the actual maintenance on generation or transmission equipment; or directly serve end use customers.

Currently, seven RTOs/ISOs operate in the United States, listed below in order of the size of their peak load:

- PJM Interconnection (PJM); 145 GW (summer)
- Midwest ISO (MISO); 137 GW (summer)
- Electric Reliability Council of Texas (ERCOT); 63 GW (summer)
- California ISO (CAISO); 50 GW (summer)
- Southwest Power Pool (SPP); 47 GW (summer)
- New York ISO (NYISO); 34 GW (summer)
- New England ISO (ISO-NE); 27 GW (summer)

Market Operations

RTO operations encompass multiple services that are needed to provide reliable and economically efficient electric service to customers. Each of these services has its own parameters and pricing. The RTOs use markets to determine the provider(s) and prices for many of these services. These markets include the day-ahead energy market (sometimes called a Day 2 market), real-time energy market (sometimes called a Day 1 or balancing market), capacity markets (designed to ensure enough generation is available to reliably meet peak power demands), ancillary services markets, financial transmission rights (contracts for hedging the cost of limited transmission capability) and virtual trading (financial instruments to create price convergence in the day-ahead and real-time markets).

RTO Energy Markets

All but one RTO (i.e., SPP) electricity market has day-ahead and real-time markets. The day-ahead market schedules electricity production and consumption before the operating day, whereas the real-time market (also called the balancing market) reconciles any differences between the schedule in the day-ahead market and the real-time load while observing reliability criteria, forced or unplanned outages and the electricity flow limits on transmission lines.

The day-ahead energy market produces financially binding schedules for the production and consumption of electricity one day before its production and use (the operating day). The purpose of the day-ahead market is to give generators and load-serving entities a means for scheduling their activities sufficiently prior to their operations, based on a forecast of their needs and consistent with their business strategies.

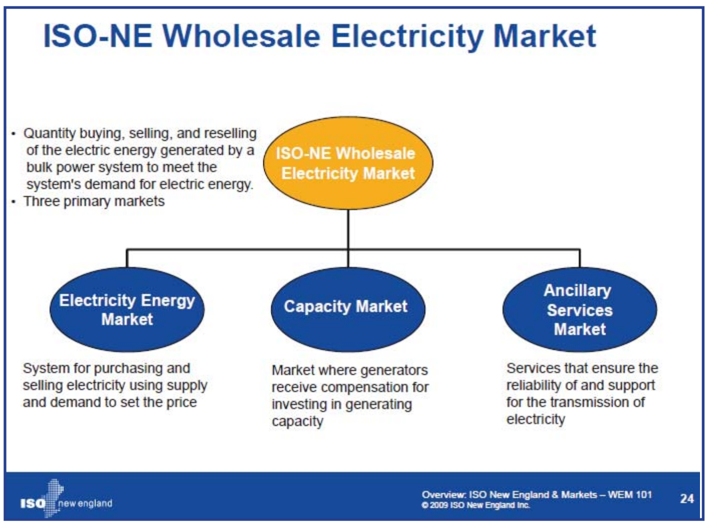
In day-ahead markets, the schedules for supply and usage of energy are compiled hours ahead of the beginning of the operating day. The RTO then runs a computerized market model that matches buyers and sellers throughout the geographic market footprint for each hour throughout the day. The model then evaluates the bids and offers of the participants, based on the power flows needed to move the electricity throughout the grid from generators to consumers. Additionally, the model must account for changing system capabilities that occur based on weather and equipment outages, plus rules and procedures that are used to ensure system reliability. The market rules dictate that generators submit supply offers and loads submit demand bids to the RTO by a deadline that is typically in the morning of the day-ahead scheduling. Typically, 95 percent of all energy transactions are scheduled in the day-ahead market, and the rest scheduled in real-time.

Generation and demand bids that are scheduled by the day-ahead market are settled at the day-ahead market prices. Inputs into setting a day-ahead market schedule include:

- Generator offers to sell electricity each hour;
- bids to buy electricity for each hour submitted by load-serving utilities;
- demand-response offers by customers to curtail usage of electricity;
- virtual demand and supply offers; and
- operational information about the transmission grid and generating resources, including planned or known

transmission and generator outage, the physical characteristics of generating resources including minimum and maximum output levels and minimum run time and the status of interconnections to external markets.

The real-time market is used to balance the differences between the day-ahead scheduled amounts of electricity based on day-ahead forecast and the actual real-time load. The real-time market is run hourly and in 5-minute intervals and clears a much smaller volume of energy and ancillary services than the day-ahead market, typically accounting for only 5 percent of scheduled energy. For generators,



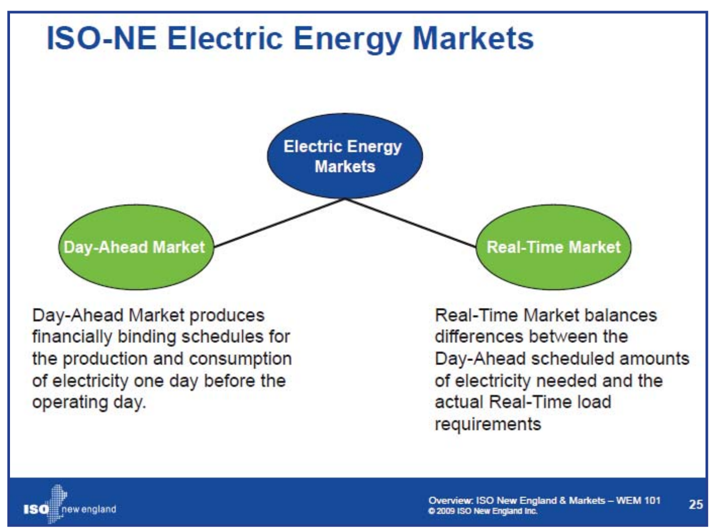
the real-time market provides additional opportunities for offering energy into the market. Megawatts over- or under-produced relative to the day-ahead commitments are settled at real-time prices.

Real-time market prices are significantly more volatile than the day-ahead market prices. This stems from demand uncertainty, transmission and generator forced outages and other unforeseen events. Because the day-ahead market generally is not presented with these events, it produces more stable prices than in real-time. Also, because the volumes in the real-time market are much smaller, there is an increased likelihood of supply and demand imbalances, which lead to both positive and negative price movements.

RTOs use markets to deal with transmission constraints through locational marginal pricing (LMP).

The RTO markets calculate a LMP at each location on the power grid. The LMP reflects the marginal cost of serving load at the specific location, given the set of generators that are being dispatched and the limitations of the transmission system. LMP has three elements: an energy charge, a congestion charge and a charge for transmission system energy losses.

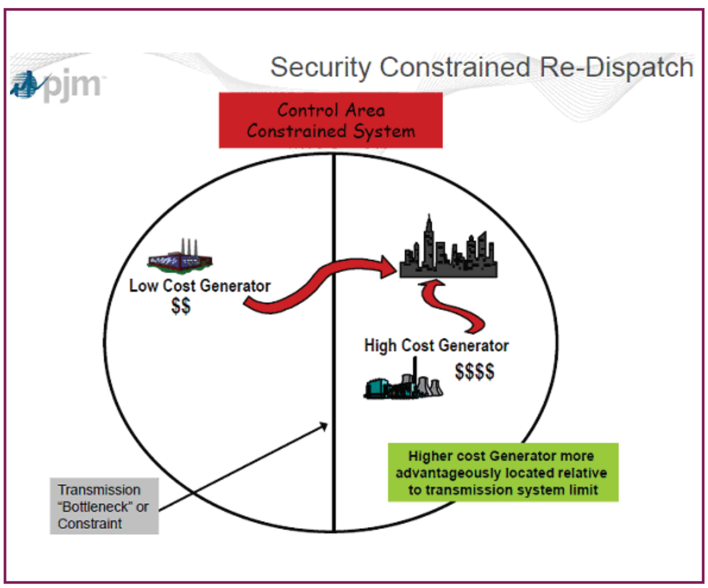
If there are no transmission constraints, or congestion, LMPs will not vary significantly across the RTO footprint. Transmission congestion occurs when there is not enough transmission capacity for all of the least-cost generators to be selected. The result is that some more expensive generation must be dispatched to meet demand, units that might not otherwise run if more transmission capacity were available.



When there are transmission constraints, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the LMP in that area. All sellers receive the LMP for their location and all buyers pay the market clearing price for their location.

The primary means used for relieving transmission congestion constraints is by changing the output of generation at different locations on the grid. The market-based LMP sends price signals that reflect congestions costs to market participants. That is, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (redispatch) the generation output to serve load. This change in dispatch to is known as security constrained redispatch (see chart).

This redispatch could be implemented by using nonmarket procedures such as transmission loading relief (TLR). North American Electric Reliability Corp. (NERC) established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded and power flows must be reduced to protect the network. A TLR is used to ration transmission capacity when the demand for transmission is greater than the available transmission capacity



(ATC). The rationing is a priority system that cuts power flows based on size, contractual terms and scheduling.

Scarcity pricing is a mechanism used by RTOs and ISOs to send price signals in the real-time market when there is a systemwide shortage of power reserves. These events occur when there is a shortage of power to meet system requirements to meet load and provide sufficient backup reserves. This can be caused by unexpectedly high power loads, supply disruptions or both.

RTOs follow one of four approaches to ensure that the market price for energy accurately reflects the value of energy during shortage periods:

- Increase the allowed bidding price of energy supply above normal levels during an emergency;
- Increase bid caps above the current level during an emergency for demand bids, while keeping generation offer caps in place;
- Establish a pricing structure for operating reserves that would raise prices as operating reserves grow short (demand curve); and
- Set the market-clearing price during an emergency for all supply and demand response resources dispatched equal to the payment made to participants in an emergency demand-response program.

Reliability must-run (RMR) units are generating plants that would otherwise retire but the RTO has determined they are needed to ensure reliability. They could also be units that have market power due to their location on the grid. RTO/ISOs enter into cost-based contracts with these generating units and allocate the cost of the contract to transmission customers. In return for payment, the RTO may call on the owner of an RMR generating unit to run the unit for grid reliability. The payment must be sufficient to pay for the cost of owning and maintaining the unit even if it does not operate.

The reason for developing capacity markets (described below) is in part to compensate generation owners for keeping these units in service where necessary, in addition to prompting the construction of new generation and use of demand response by consumers. Transmission upgrades can also reduce the need for RMR units by increasing generation deliverability throughout the RTO.

RTO Capacity Markets

RTOs, like other electric systems, are required to maintain adequate generation reserves to ensure that sufficient generation and demand-resource capacity are available to meet load and reliability requirements. LSEs have typically satisfied their reserve obligations with owned generation or bilateral contracts with other suppliers. Some RTOs have mechanisms to obtain capacity commitments, such as capacity auctions and capacity payments.

Most RTOs run a capacity market to allow LSEs a way to satisfy their reserve obligation. These markets cover short-term capacity, such as a month, season or year. PJM and ISO-NE run capacity auctions up to three years prior to when the capacity is needed. The near-term focus is consistent with providing payments to existing generation, or generation such as combustion turbines that can be sited and built within three years.

Financial Transmission Rights

Financial transmission rights (FTRs) are contracts that give market participants an offset, or hedge, against transmission congestion costs in the day-ahead market. They protect the holder from costs arising from transmission congestion over a specific path on the grid.

FTRs were originally developed in part to give native load-serving entities in the nascent RTOs price certainty similar to that available to traditional vertically integrated utilities operating in non-RTO/ISO markets. This practice continues, as FTRs are allocated to load-serving entities, transmission owners or firm transmission right holders in RTOs based on historical usage, and to entities that fund the construction of specific new transmission facilities. The details of the programs vary by RTO.

FTRs allow customers to protect against the risk of congestion-driven price increases in the day-ahead market in the RTOs and ISOs. Congestion costs occur as the demand for scheduled power over a transmission path exceeds that path's flow capabilities. For example, if the transmission capacity going from Point A (the source) to Point B (the sink) is 500 MW, but the RTO seeks to send 600 MW of power from Point A to Point B when calling on the least-cost generators to serve load, the path will be congested. This will cause the price at the source to decline or the price at sink to increase, or both, causing the congestion cost of serving point B from Point A to increase. By buying an FTR over the path from Point A to Point B, the FTR holder is paid the difference of the congestion prices at the sink and source, thus allowing it to hedge against the congestion costs incurred in the day-ahead market.

FTRs are acquired through allocations and purchases. FTRs can be purchased in the RTO-administered auctions or in the secondary market.

Allocations may stem from a related product, auction revenue right (ARR). ARRs provide the firm transmission capacity holders, transmission owners or LSEs with a portion of the money raised in the FTR auctions. In general, they are allocated based on historic load served and, in some RTOs, can be converted to FTRs. As with FTRs, ARRs, too, give eligible members an offset or hedge against transmission congestion costs in the day-ahead market. If converted to FTRs, the holder gets revenue from congestion. If kept as ARRs, the holder gets revenue from the FTR auction.

The main method for procuring FTRs is through an auction, which typically includes an annual (or multiyear) auction of one-year FTRs and monthly (or semiannually) auctions of shorter-term FTRs provided by existing FTR holders or made available by the RTO. The auctions are scheduled and run by the RTO, which requires bidding parties to post credit to cover the positions taken. FTR auction revenues are used to pay the holders of ARRs and assist the funding of future congestion payments to FTR holders. There is also a secondary market for FTRs (such as PJM's eFTR), but only a small number of transactions have been reported.

The quantity of FTRs made available by the RTO is bounded by the physical limits of the grid, as determined by a simultaneous feasibility test across all potential flowgates. This test is performed by the RTO prior to making FTRs available at auction, and takes into account existing FTR positions and system constraints. The resulting portfolio of FTRs allocated or offered at auction represents an absolute constraint on the size of the net positions that can be held by the market. Participants in FTR auctions can procure counterflow FTRs, which directly offset prevailing flow FTR capacity, thereby allowing the value at risk on a given path to exceed the physical limits of the line. However, such bids are physically constrained, as the net position held on the path must always conform to the simultaneous feasibility test.

Although FTRs are used by transmission providers and load-serving entities as a hedge, they can be purchased by any creditworthy entity seeking their financial attributes either as a hedge or as a speculative investment. In this regard, FTRs are similar to financial swaps that are executed as a contract for differences between two day-ahead LMPs (swaps are explained in the chapter on financial markets). However, FTRs are substantially different from swaps in that the quantity of FTRs is linked to physical constraints in the transmission grid, while the quantity of swaps is not. Further, FTRs are procured by allocation or FTR auction, while swaps are procured through financial over-the-counter markets or exchanges.

Variation in RTO FTRs

Five of the six FERC-jurisdictional RTOs trade FTRs or FTR equivalent products, with SPP planning to use FTRs in its future market design. However, the types and qualities of the rights traded across the organized markets vary, as do differences in the methods used to allocate, auction and transfer these rights. These attributes of the FTR markets are discussed below.

Flow Type: Prevailing Flow and Counterflow. A prevailing flow FTR generally has a source in an historic generation-rich location and a sink that is in a historic load-heavy location. Alternatively, the source of a prevailing flow FTR is on the unconstrained side of a transmission interface and the sink on the constrained side. Auction clearing prices for prevailing flow FTRs are positive. Conversely, a counterflow FTR often has a source in an historic load-heavy location and a sink that in an historic generation-rich location. As a result, auction clearing prices for counterflow FTRs are negative.

Peak Type: On-peak, Off-peak, 24-hour. FTRs can be purchased for either 16-hour on-peak blocks, 8-hour off-peak blocks or around-the-clock. Only PJM offers all three peak type products, whereas ISO-NE, MISO and CAISO offer on-peak and off-peak products. NYISO offers only the 24-hour product.

Allocated Rights. The five RTOs allocate transmission rights to transmission owners or load-serving entities within their markets. In PJM, MISO and ISO-NE, these are allocated as auction revenue rights (ARRs), which give their holders the right to receive a share of the funds raised during the FTR auctions. The CAISO allocates congestion revenue rights (CRR), which provide their holders a stream of payments based on the actual congestion occurring on associated paths. Finally, NYISO allocates both auction-based and congestion-based rights through multiple instruments. PJM and MISO allow ARR holders to convert all of these rights to FTRs; NYISO allows only a portion of ARR-equivalent instruments to be converted to its version of FTRs, called transmission congestion credits (TCCs). ISO-NE does not allow such conversions, while the CAISO's allocation is already in a form equivalent to an FTR. Converted ARRs are fully fungible in PJM, the MISO and NYISO; CAISO only allows the sale of allocated CRRs in its secondary market, and ISO-NE has no converted instruments to sell.

Auctioned Rights. All RTOs provide FTRs (or equivalent CRRs or TCCs) for sale to the public through two or more auctions held at various times of the year. The products sold vary by market and by auction, with some products made available only at specific auctions.

Secondary Markets. With the exception of the NYISO, each of the markets that auction FTRs also operates a bulletin board or similar venue designed to enable a secondary trading platform for FTRs. However, none of these platforms has had significant volume. NYISO offered to create a bulletin board for its participants if requested, but received no requests. The CAISO is the only market that requires the reporting of secondary FTR transactions; such transactions have not occurred despite the inability of CRR holders to resell their positions through the auction process.

Virtual Transactions

Virtual bids and offers (collectively, virtuals) are used by traders participating in the RTO markets to profit from differences between day-ahead and real-time prices. The quantity of megawatts (MW) purchased or sold by the trader in the day-ahead market is exactly offset by a sale or purchase of an identical quantity of MW in the real-time, so that the net effect on the market quantity traded is zero. Virtual trading is allowed in the five RTOs with day-ahead and real-time markets.

Although a trader does not have to deliver power, the transaction is not strictly financial. Virtual transaction can physically set the LMPs, the basis for payments to generators or from load.

For each hour, net virtual trades are added to the demand forecast for load if virtual demand is greater than virtual supply. This has the effect of raising the price in the day-ahead market and, more importantly, increasing the amount of generation resources procured by the RTO/ISO. Since these resources will be available to the real-time market, the failure of the virtual load to materialize will decrease the real-time demand below forecast, thus placing downward pressure on real-time prices. The placement of virtuals affects the dispatch of physical capacity.

The primary benefits of virtual transactions are achieved through their financial impact on the markets. Virtuals sometimes are referred to as convergence bidding, as a competitive virtual market should consistently cause the day-ahead and real time prices to converge in each hour.

The convergence of day-ahead and real-time prices within the RTOs is is intended to mitigate market power and improve the efficiency of serving load. Thus, virtuals have a physical impact upon the operations of the RTO, as well as on market participants that physically transact at the LMPs set in the day-ahead and real-time markets.

Transmission Operations

Each RTO's Open Access Transmission Tariff (OATT) specifies the transmission services that are available to eligible customers. Customers submit requests for transmission service through the Open Access Same-Time Information System (OASIS). RTOs evaluate each transmission-service

Transmission Rights by Transmission Grid

	PJM	MISO	ISO-NE	NYISO	CAISO
Name for Allocated Transmission Rights	***ARR***s	***ARR***s	***ARR***s	Multiple	CRR
Convertible to Congestion Rights?	Yes	Yes	No	Some	-
Name for Auctioned Congestion Rights	***FTR***s	***FTR***s	***FTR***	*TCCs*	*CRRs*
Congestion Right Auction Format					
Annual	Yes	Yes	Yes	No	Yes
Semiannual	No	No	No	Yes	No
Monthly	Yes	Yes	Yes	Yes	Yes
Congestion Right Auction Products:					
Multiyear	Yes	No	No	No	No
Annual	Yes	No	Yes	Yes	No
Semiannual	No	No	No	Yes	No
Quarterly	Yes	Yes	No	No	Yes
Monthly	Yes	Yes	Yes	Yes	Yes
Auction Allows Participant Resale?	Yes	Yes	Yes	Yes	No
Congestion Right Options	Yes	No	No	No	No
Formal Secondary ***FTR*** Market?	Yes	Yes	Yes	No	Yes

request using a model of the grid called a state estimator. Based on the model's estimation of the effects on the system, the request for transmission service is either approved or denied.

Transmission operators, including RTOs, offer two major types of transmission service: point-to-point service and network service. Network service generally has priority over point-to-point service. RTOs work with transmission owners to plan and coordinate the operation, maintenance and expansion of transmission facilities in order to provide network and point-to-point customers with transmission service.

Network transmission service is used for the transmission of energy from network generating resources to an RTO's network loads.

- Network transmission service enables network customers to use their generation resources to serve their network loads in a RTO.
- Network customers also can use the service to deliver economy energy purchases to their network loads.

Point-to-point transmission service uses an RTO's system for the transmission of energy between a point of receipt and a point of delivery, which can be into, out of, or through the RTO's Control Area. RTOs offer firm and nonfirm point-to-point transmission service for various lengths of time.

- Firm service has reservation priority over nonfirm point-to-point service.
- Nonfirm point-to-point transmission service is provided

from the available transmission capability beyond network and firm point-to-point transmission service.

Transmission Planning

RTOs have systemwide or regional planning processes that identify transmission system additions and improvements needed to keep electricity flowing. Studies are conducted that test the transmission system against mandatory national reliability standards as well as regional reliability standards. The North American Electric Reliability Corp. (NERC) is the organization responsible for setting national reliability standards.

RTO transmission planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations and other reliability problems. RTOs then develop transmission plans in collaboration with transmission owners to resolve potential problems that could otherwise lead to overloads and blackouts. This process culminates in one recommended plan for the entire RTO footprint.

Financial Policies

Financial settlement is the process through which payments due from customers and to generators are calculated. Market settlements depend on day-ahead schedules, real-time metering, interchange schedules, internal energy schedules, ancillary service obligations, transmission reservations, energy prices, FTR positions and capacity positions. For each market participant a customer invoice of charges and credits includes the costs of services used to serve load.

Generally, customers receive weekly or monthly invoices stating their charges and credits. Weekly invoices must be settled within a few days of being issued, while monthly invoices must be paid within either one or two weeks depending on the policies of each RTO. All payments are made electronically. Disbursements are made within several days of the date payments are due.

Credit Policies

Defaults by market participants in RTOs have generally been socialized, meaning that the cost is spread across the market. To minimize this risk, RTOs have credit policies in their tariffs, which contain provisions related to credit evaluations, credit limits, forms of collateral and the consequences of violations or defaults.

Regions

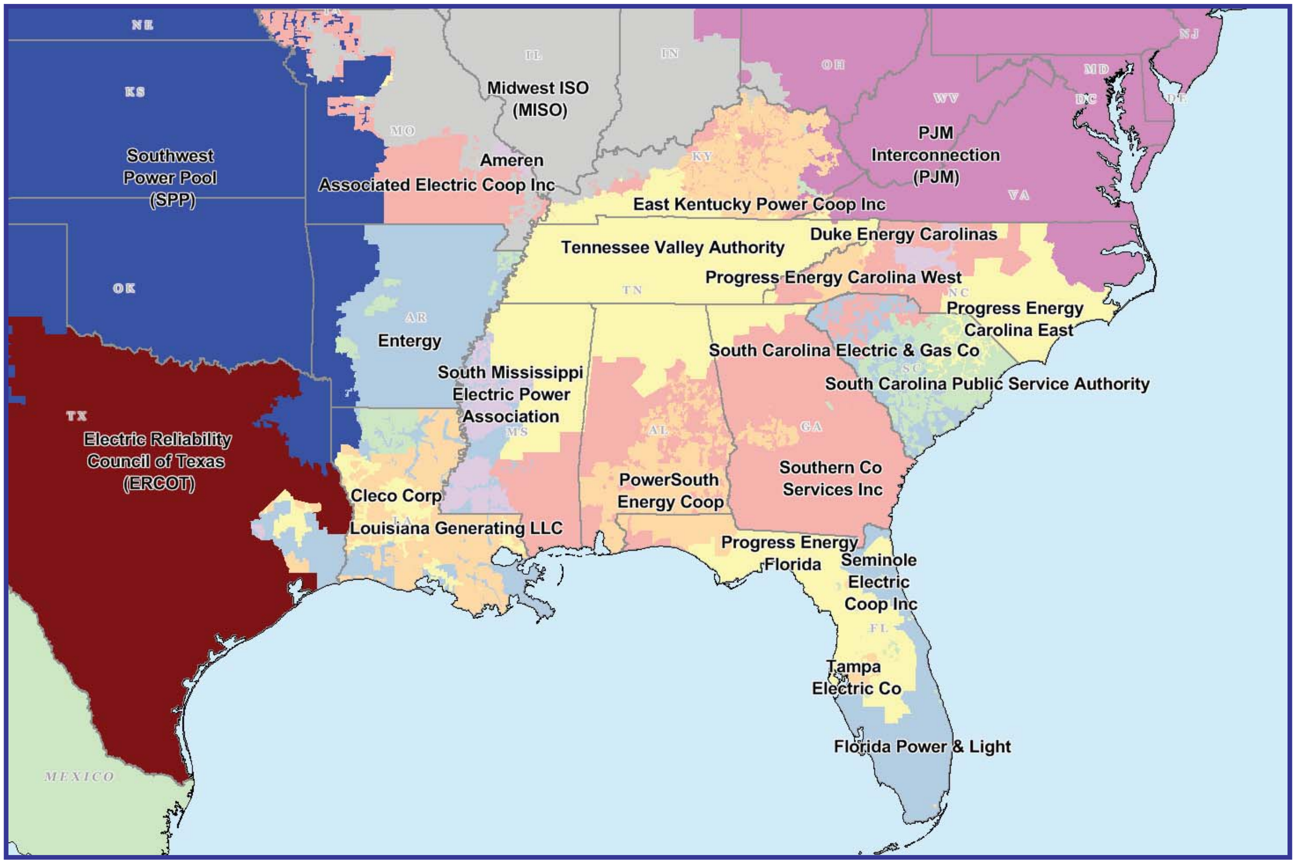
Markets vary around the United States by market type – traditional or RTO – generation types, customer use, climate, fuel costs, political and regulatory conditions, and other factors. Consequently, prices vary, driven by these market factors.

Southeast Wholesale Market

The Southeast electric market is a bilateral market that includes all or parts of Florida, Georgia, Alabama, Mississippi, Louisiana, Arkansas, Tennessee, North Carolina, South Carolina, Texas, Missouri and Tennessee. It encompasses all or part of two NERC regions: the Florida Reliability Coordinating Council (FRCC) and the Southeastern Electric Reliability Council (SERC). Major hubs include Entergy, Southern and TVA.

Southeastern power markets have their roots in the 1960s. In the wake of the Northeast Blackout of 1967, the Southeast began to build out its electric transmission grid; there now are several large transmission lines connecting large power plants to the grid. This was primarily to ensure reliability, but it also had economic consequences. Increased integration allowed utilities to more effectively share reserves, as well as the costs and risks of new plant construction.

Southeast Electric Regions



If a utility were building a large nuclear or coal- fired generating facility, it would be cost-effective to have reserve sharing agreements with neighboring systems that provided the backup or capacity reserves, rather than building reserves individually. In addition, a stronger grid allowed the output of large power plants to be deliverable throughout the region, thus allowing more than one utility to share in the ownership and the costs of building large new plants. This reduced the financial risks associated with ownership of large new generating facilities to any single utility, thus making ownership of large base-load coal and nuclear units more affordable to the utilities and less risky.

A stronger transmission system also allowed for more economic transactions, including both spot transactions and long-term firm power deliveries. External sales resulted in more efficient use of grid resources and reduced costs to both buyers and sellers.

Resource Base

Within the Southeast, the resource mix varies between the two NERC subregions. The FRCC uses more gas- and oil-fired generation than the rest of the Southeast, and it is the only area where oil is significantly employed. Gas is the marginal fuel in almost all hours in the FRCC. Within SERC, the Southern subregion has historically generated as much as 85 percent of its electricity from baseload coal and nuclear plants. In recent years, natural gas used for generating electricity has become increasingly popular. The pattern began to change as gas supplies increased and prices fell and natural gas-fired power plants began to displace older, less-efficient coal-fired generation.

The Entergy subregion uses gas to a much greater extent than the regional average; it is the marginal fuel more than 70 percent of the time. The TVA subregion has a significant amount of hydro and nuclear capacity and output, and very little dependence on gas. The VACAR subregion has the highest utilization of nuclear generation in the Southeast; 94 percent of this subregion's output is from baseload coal and nuclear facilities.

Trading and Markets

Physical and financial electricity products are traded using Entergy, Southern, TVA, VACAR and Florida price points. Volumes for these products remain low, especially in Florida, where merchant power plant development is restricted by a state statute.

Virtually all the physical sales in the Southeast are done bilaterally. Long-term energy transactions appear to be a hallmark of the Southeast; wholesale electricity transactions for a year or more outweigh spot transactions. Many long-term agreements involve full-requirements contracts or long-term purchase power agreements. Spot transactions accounted for less than one percent of overall supply and tend to occur during periods of system stress, usually summer heat waves or winter cold snaps. Even for a large company such as Southern Co., spot transactions occurred less than 30 percent of the time.

Wholesale spot power markets in the Southeast have little spot trading and lack transparency. The relative lack of spot trades yields little data on which to base price reporting. ICE reports no electric power price for Florida. And while another publisher reports one spot electric power price for Florida, on most days, there are no reported volumes. Given the bilateral nature of wholesale power transactions in the Southeast, and the small spot market, interest in financial power products in the Southeast is weak. As a result, ICE does not provide a financial swap product in the Southeast.

Despite the bilateral nature of the wholesale trade and the small size of the spot market, marketers do have some presence in the Southeast. For example, Constellation Energy Commodities Group contributes to the trading in the Southern region, being a participant in 41 percent of total marketer related sales. While Constellation does not own generation in Southern, it does have several multiyear agreements with generating units.

Unique Market Features

Southern Co. Auction

Since April 23, 2009, Southern Co. has been holding daily and hourly auctions for power within its balancing area. This balancing area encompasses the service territories of Southern Co. utilities: Georgia Power, Alabama Power, Mississippi Power and Gulf Power.

According to the auction rules, Southern must offer all of its available excess generation capacity into the auction, after regulation and contingency reserves are met. The offer prices are capped because the auction is intended to mitigate any potential ability of Southern to withhold its generation resources within its balancing area.

The products auctioned are day-ahead power and real-time power (an auction takes place an hour ahead of when the energy is scheduled to flow).

Offers to sell energy and bids to purchase energy are evaluated using the simple method of sorting offers in ascending order and bids in descending order.

The auction matches parties to facilitate a bilateral transaction that is ultimately independent of the auction. Thus, there is no collateral requirement necessary to participate in the auction. However, credit screening rules dictate that matches are made only between entities willing and able to do business with one another. The selection process is based on information that each entity submits to the auction administrator.

When the auction began in 2009, Southern Co. was the only participant that could sell into it. On Jan. 3, 2010, other entities were allowed to sell into the auction, and Southern became eligible to make purchases in the auction as well as sales. However, activity in the auction has been sparse since its inception.

Entergy Independent Coordinator of Transmission

Southwest Power Pool (SPP) serves as the independent coordinator of transmission (ICT) for Entergy Services. In this role, SPP oversees the operations of the Entergy transmission system and produces regional planning assessments.

Florida IPP rule

The Florida Public Service Commission's (PSC) competitive bidding rules require investor-owned utilities (IOUs) to issue requests for proposals for any new generating project of 75 MW or greater, exclusive of single-cycle combustion-turbines. The bidding requirement can be waived by the PSC if the IOU can demonstrate that it is not in the best interests of its ratepayers.

Western Regions

The power markets in the western United States are bilateral markets except in most of California. The West includes the Northwest Power Pool (NWPP), the Rocky Mountain Power Area (RMPA) and the Arizona, New Mexico, Southern Nevada Power Area (AZ/NM/SNV) within the Western Electricity Coordinating Council (WECC), a regional entity. These areas contain many balancing authorities (BAs) responsible for dispatching generation, procuring power, operating the transmission grid reliably and maintaining adequate reserves. Although the BAs operate autonomously, some have joint transmission-planning and reserve-sharing agreements.

Physical sales in western states are almost entirely bilateral sales, with a small amount sold into the California ISO's market. Trading in the western states differs from the rest of the country because financial players are active in the physical markets, as well as having a robust financial electricity market.

The volume of financial sales on ICE is roughly as large as physical sales. Physical sales in WECC are dominated by financial and marketing companies.

The NWPP is composed of all or major portions of the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada and Utah, a small portion of Northern California and the Canadian provinces of British Columbia and Alberta. This vast area covers 1.2 million square miles. It is made up of 20 BAs. The peak demand is 54.5 GW in summer and

63 GW in winter. There is 80 GW of generation capacity, including 43 GW of hydroelectric generation.

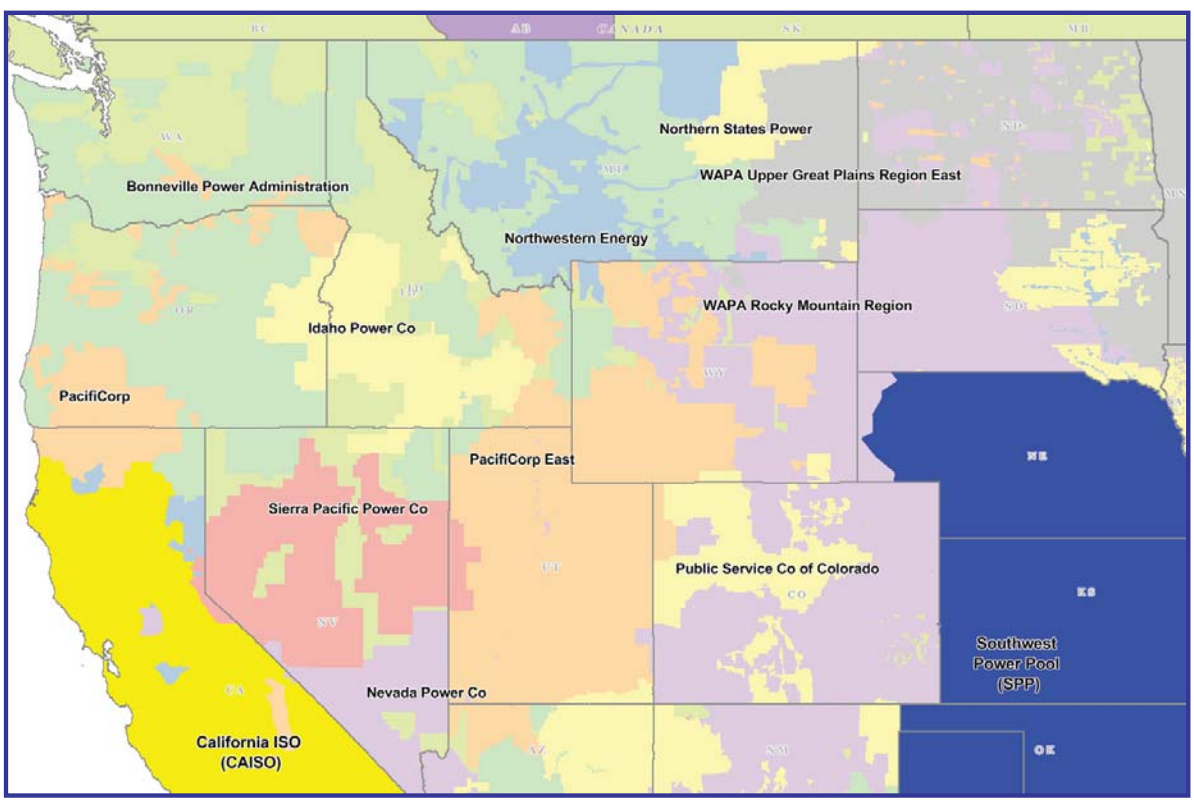
Resources

The NWPP has a unique resource mix. Hydro generation is more than 50 percent of power supply, compared to the U.S. average of only 6 percent of power supply. The hydro generation is centered around many dams, mostly on the Columbia River. The largest dam, the Grand Coulee, can produce as much power as six nuclear plants. Due to the large amount of hydroelectric generation, the Northwest typically has cheap power and exports power to neighboring regions, especially California, to the extent that there is transmission capacity to carry the power to more expensive markets.

The amount of hydropower produced depends on a number of factors, some natural and some controllable. On a seasonal basis, the intensity and duration of the water flow is driven by snowpack upriver in the mountains, the fullness of the reservoirs and rainfall. On a short-term basis, the power generation is influenced by decisions to release water locally and upstream to generate power, as well as local water-use decisions that have nothing to do with the economics of power generation, but are made for recreation, irrigation and wildlife considerations. The peak generation begins in the spring, when the snow melts, and may last into early summer.

When there is less water available, the Northwest may rely more on its coal and natural gas generation. It will

Northwest Electric Market



occasionally import power from neighboring regions when loads are high.

Trading and Markets

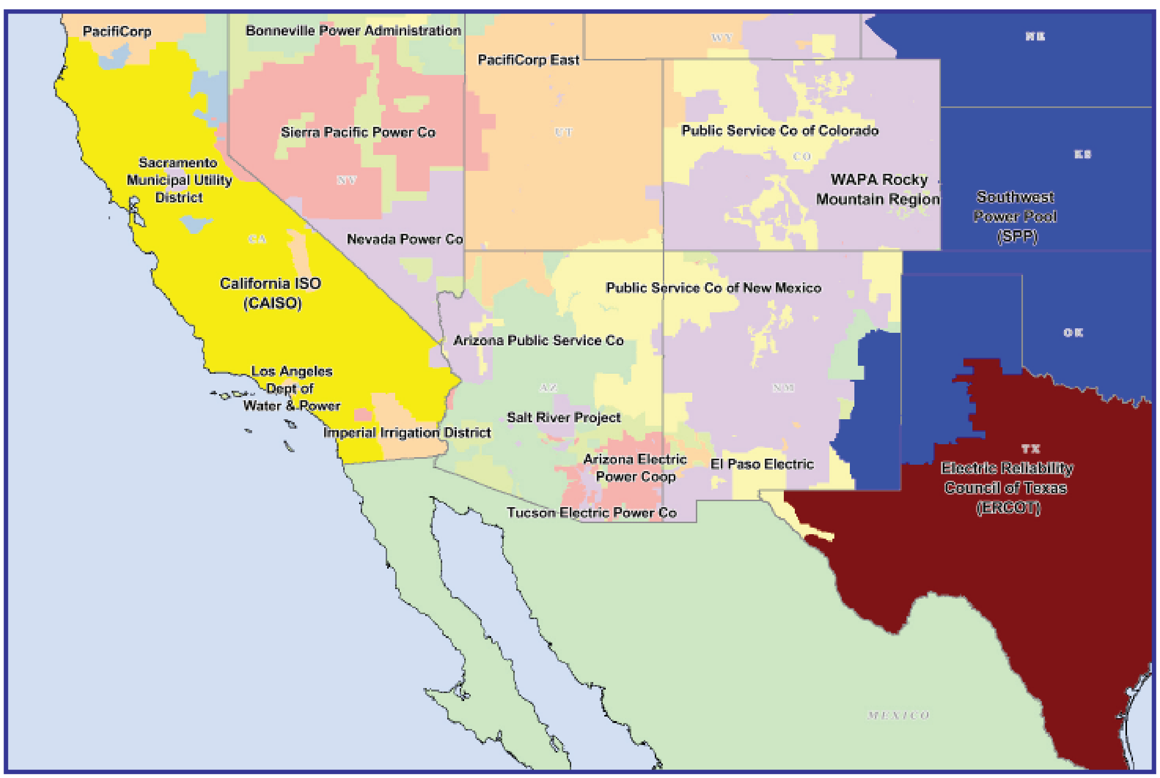
The water forecast affects the forward market for electricity in the Northwest. The daily water flow as well as weather conditions influence the prices in the daily physical market. When there is an abundance of hydro generation, the Northwest will export as much as possible on the transmission lines leading into California. Sometimes in off-peak hours there is so much generation that power prices are negative because the transmission lines are full and there is not enough local load to take all of the power.

The largest seller of wholesale power is the Bonneville Power Administration (BPA), a federal agency that markets the output from federally owned hydroelectric facilities and owns 75% of the region's high-voltage transmission. It meets approximately one-third of the region's firm energy supply, mostly with power sold at cost. BPA gives preference to municipal and other publicly owned electric systems in allocating its output.

Both the Alberta IESO and British Columbia Hydro are members of the NWPP. Net interchange between these two BAs and the United States tends to result in net exports from the United States into Canada. Net interchange between U.S. and Canadian balancing authorities represents about one percent of total NWPP load.

The IntercontinentalExchange (ICE) has four trading points

Southwest Electric Regions



in the Northwest: Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB) and Mona (Utah). Mid-C has the most traded volume by far, averaging more than 6,700 MW of daily on-peak physical trades in 2009. COB had almost 600 MW, NOB had 100 MW and Mona had 32 MW. Mid-C also has a fairly active physical forward market.

The Southwest electric market encompasses the Arizona, New Mexico, southern Nevada (AZ/NM/SNV) and the Rocky Mountain Power Area (RMPA) subregions of the Western Electric Coordinating Council (WECC). Peak demand is approximately 41 GW in summer and 29 GW in winter. There is 52 GW of generation capacity, composed mostly of gas and coal units.

The Southwest relies on nuclear and coal generators for baseload electricity, with gas units used as peaking resources. The coal generators are generally located in close

proximity to coal mines, resulting in low delivered fuel costs. Some generation is jointly owned among multiple nearby utilities, including the Palo Verde nuclear plant, a 4,000-MW unit, which has owners in California and the Southwest.

The AZ/NM/SNV region is summer-peaking and experiences high loads due to air conditioning demand. The daily high temperatures average above 100 degrees in June through August in Phoenix. However, power prices tend to be the highest when there is also hot weather in Southern California, creating competition for the generation resources.

CAISO

California Independent System Operator

Market Profile

Geographic Scope

CAISO is a California nonprofit public benefit corporation started in 1998 when the state restructured its electric industry. The CAISO manages wholesale electricity markets, centrally dispatching electricity generation and facilities. In managing the grid, CAISO provides open access to the transmission system and performs long-term transmission planning. It manages energy and ancillary markets in day-ahead and real-time markets and is responsible for regional reliability.

Peak Demand

CAISO's all-time peak load was 50 GW in summer 2006.

Import and Exports

About 25 percent of CAISO's energy is supplied by imports, principally from two primary sources: the Southwest (Arizona, Nevada and New Mexico) and the Pacific Northwest (Oregon, Washington and British Columbia). Imports from the Pacific Northwest generally increase in the late spring when hydroelectric production peaks from increases in winter snowmelt and runoff.

Market Participants

CAISO's market participants include generators, retail marketers and utility customers, ranging from the three big investor-owned utilities (IOUs), which include Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas &Electric (SDG&E), to municipalities and financial participants.

Membership and Governance

The CAISO has a board of governors that consists of five members appointed by the governor and confirmed by the California Senate. The board's role is to provide corporate direction, review and approve management's annual strategic plans and approve CAISO's operating and capital budgets.

CAISO uses an informal stakeholder process to propose solutions to problems that may ultimately require a filing at FERC. Unlike other RTOs, which have a formal committee structure, CAISO's stakeholder process generally consists of rounds of dialogue with stakeholders on major policy issues.

California Independent System Operator (CAISO)

Transmission

Owners

The Participating Transmission Owners (PTOs) in the CAISO control area include:

- Pacific Gas and Electric Co.,
- Southern California Edison,
- San Diego Gas and Electric, and
- Municipalities such as Vernon, Anaheim and Riverside.

Chronic Constraints

Areas of the system that are chronically constrained include the Humboldt region in the northwest corner of the state, import lines from the Southwest and Southern California (including San Diego).

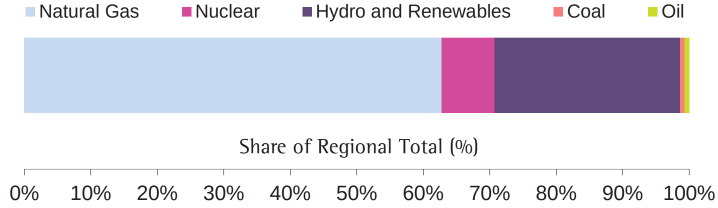
Transmission Planning

CAISO conducts an annual transmission planning process with stakeholders that includes both short-term and long-term projects.

Supply Resources

Generating Mix

By plant capacity, the generating mix includes these sources:



Demand Response

Demand-resource participation in the wholesale energy market is currently limited to a small amount of demand associated with water pumping loads. However, the market allows end-use loads that can be curtailed when directly dispatched in the real-time market to participate in the real-time energy and ancillary service (nonspinning reserve) markets. The California Public Utilities Commission is considering rules for allowing more retail demand-resource participation in the CAISO market.

Other demand response in California consists of programs for managing peak summer demands developed by the state's three major investor owned utilities. These demand-response programs are triggered based on criteria that are internal to the utility and not necessarily tied to market prices, although in early 2012 CAISO had a proposal pending at the Commission to integrate these reliability-based retail programs into its wholesale market.

Market Features and Functions

Energy Markets

Day-Ahead Market

The day-ahead market allows participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

From the offers and bids, CAISO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are said to clear, meaning they are scheduled for dispatch. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the locational marginal prices (LMP) for all locations.

Generator offers scheduled in the day-ahead settlement are paid the day-ahead LMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time market to replace what was not produced.

Likewise, wholesale buyers of electricity whose bids clear in the day-ahead market settlement pay for and lock in their right to consume the cleared quantity at the day-ahead LMP. Electricity use in real time that exceeds the day-ahead purchase is paid for at the real-time LMP.

Hour-Ahead Market

CAISO has an hour-ahead market for buying and selling imports and exports that it calls the hour-ahead scheduling process (HASP). HASP is designed to allow the ISO to re-optimize the market, given changes to internal supply and demand after the close of the day-ahead market.

In HASP, imports and exports between the ISO and neighboring regions are pre-dispatched 45 minutes before the start of each operating hour. These imports and exports are scheduled at a fixed level for the entire hour. However, resources within the CAISO and dynamic resources in neighboring regions (or balancing authority areas) can be dispatched every five minutes within each operating hour to meet real-time loads. A dynamic resource is a resource that is physically located in a neighboring region or balancing authority areas, yet is controllable by the CAISO market.

Real-Time Market

CAISO must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. While the day-ahead energy market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, to meet energy needs within each hour of the current day the CAISO operates a spot market for energy called the real-time market,

The real-time market uses final day-ahead schedules for resources within the ISO and final hour-ahead schedules for imports and exports as a starting point. It then re-dispatches resources every five minutes to balance generation and loads.

Prices resulting from the real-time market are only applicable to incremental adjustments to each resource's day-ahead schedule. Real-time bids can be submitted up to 75 minutes before the start of the operating hour.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission, and system-control equipment to support the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

CAISO procures four ancillary services in the day-ahead and real-time markets:

- Regulation up: Units providing regulation up must be able to move quickly above their scheduled operating point in response to automated signals from the ISO to maintain the frequency on the system by balancing generation and demand.
- Regulation down: Units providing regulation down must be able to move quickly below their scheduled operating point in response to automated signals from the ISO.
- Spinning reserve: Resources providing spinning reserves must be synchronized with the grid (online, or spinning) and be able to respond within 10 minutes. This is more reliable than nonspinning reserves because it is already online and sychronized.
- Nonspinning reserve: Resources providing nonspinning reserves must be able to synchronize with the grid and respond within 10 minutes.

Regulation up and regulation down are used continually to maintain system frequency by balancing generation and demand. Spinning and nonspinning resources are used to maintain system frequency and stability during emergency operating conditions (such as unplanned outage of generation or transmission facilities) and major unexpected variations in load. Spinning and nonspinning resources are often referred to collectively as operating reserves.

Capacity Markets

Capacity markets provide a means for load-serving entities (LSEs) to procure capacity needed to meet forecast load, or resource adequacy (RA) requirements, and to allow generators to recover a portion of their fixed costs. They also provide economic incentives to attract investment in new and existing supply-side and demand-side capacity resources needed to maintain bulk power system reliability requirements.

The CAISO does not operate a formal capacity market, but it does have a mandatory RA requirement. The program requires that LSEs procure 115 percent of their aggregate system load on a monthly basis, unless a different reserve margin is mandated by the LSE's local regulatory authority. The program provides deliverability criteria each LSE must meet, as well as system and local capacity requirements.

Resources counted for RA purposes must make themselves available to the CAISO day-ahead and real-time markets for the capacity for which they were counted.

Market Power Mitigation

In electric power markets, mainly because of the largely non-storable nature of electricity and the existence of transmission constraints that can limit the availability of multiple suppliers to discipline market prices, some sellers from time to time have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Market power may need to be mitigated systemwide or locally when the exercise of market power may be particularly a concern for a local area. For example, when a transmission constraint creates the potential for local market power, the RTO may apply a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

Reliability Must-Run

A reliability must-run (RMR) contract acts as an insurance policy, assuring that the CAISO has dispatch rights in order to reliably serve load in local import constrained areas. RMR contracts also help to mitigate any local market power that one or more units may have. The amount of generation capacity under RMR contracts dropped when local RA requirements were introduced. With more local resources being procured through RA contracts, the CAISO was able to significantly decrease its RMR designations in much of the system. Remaining generators with RMR contracts are located primarily in San Francisco and San Diego.

Financial Transmission Rights

As mentioned above, financial transmission rights (FTRs) give market participants an offset or hedge against transmission congestion costs in the day-ahead market. An FTR is a financial contract protecting the holder from costs arising from transmission congestion over a path or a source-and-sink pair of locations on the grid. An FTR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the specific FTR transmission path. FTRs were originally formulated to protect LSEs from price uncertainty while redistributing excess congestion charges due to constrained conditions.

A related product is an auction revenue right (ARR). ARRs provide the holders with an upfront portion of the money raised in the FTR auctions. In general, they are allocated based on historical load served and, in some RTOs, can be converted to FTRs. As with FTRs, ARRs give transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

FTRs in California are referred to as congestion revenue rights (CRRs). Other than the name, the products are identical. CRRs are monthly or quarterly products. CRRs can be bought at auction or allocated by CAISO. Allocated CRRs receive the congestion value for a specific path, similar to a converted FTR. CAISO also allocates open market CRR auction revenue to LSEs based on their physical participation in the market, similar to an ARR in other markets. Given that both allocated CRRs and allocated auction revenues are based on physical market presences, LSEs often receive both. Finally, CRR revenue insufficiency is not possible as LSEs will be charged uplift if any shortfall is present.

Virtual Transactions

CAISO implemented convergence bidding, or virtual bidding, on Feb. 1, 2011. With the virtual bidding market feature, market participants can take financial positions in the day-ahead market that are liquidated in the real-time market. Virtual bidding is unique in CAISO because virtual positions taken on the export and import interties settle against the hour-ahead price, while internal virtual positions settle against the real-time dispatch price. Market participants can engage in either virtual demand or virtual supply transactions. A virtual demand transaction is a bid to buy at the day-ahead price and offer to sell at the real-time price. A virtual supply transaction is a bid to sell at the day-ahead price and buy at the real-time price.

Virtual supply and virtual demand may be submitted at any eligible pricing node in the CAISO system and there is no requirement for physical generation or load. The financial outcome for a particular participant is determined by the difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears. Thus, through this financial arbitrage opportunity, virtual transactions in theory help to narrow the difference between the day-ahead and real-time prices.

Credit Requirements

Credit requirements are important in organized electricity markets in which RTOs must balance the need for market liquidity against corresponding risk of default. Defaults within these markets are particularly troubling because losses due to default are spread among all market participants. Thus, each RTO's tariff specifies credit rules needed to participate in the markets. These requirements provide for credit evaluations, credit limits, allowed forms of collateral and the consequences of violations or defaults.

Settlements

RTOs must invoice market participants for their involvement in their markets. Settlements is the process by which the RTO determines the amounts to be paid associated with buying and selling energy, capacity and ancillary services, and paying administrative charges.

The CAISO calculates, accounts for and settles all charges and payments based on received settlement quality meter data. The CAISO settles the following charges: grid management charge, bid cost recovery, energy and ancillary services, CRR charges and payments, among others. The CAISO settles for three periods: the day-ahead market, the HASP and the real-time markets.

ISO-NE

New England Independent System Operator

Market Profile

Geographic Scope

As the RTO for New England, ISO-NE is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts and related products, in addition to administering auctions for the sale of capacity.

ISO-NE operates New England's high-voltage transmission network and performs long-term planning for the New England system. ISO-NE serves six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

Peak Demand

New England's all-time peak load was 28 GW in 2006.

Import and Exports

ISO-NE is interconnected with the New York Independent System Operator (NYISO), TransEnergie (Québec) and the New Brunswick System Operator.

ISO-NE imports 12 percent of its annual energy needs from Québec. ISO-NE imports energy from and exports energy to NYISO.

New England receives imports from Québec and New Brunswick in most hours. Between New England and New York, power flows in alternate directions depending on market conditions.

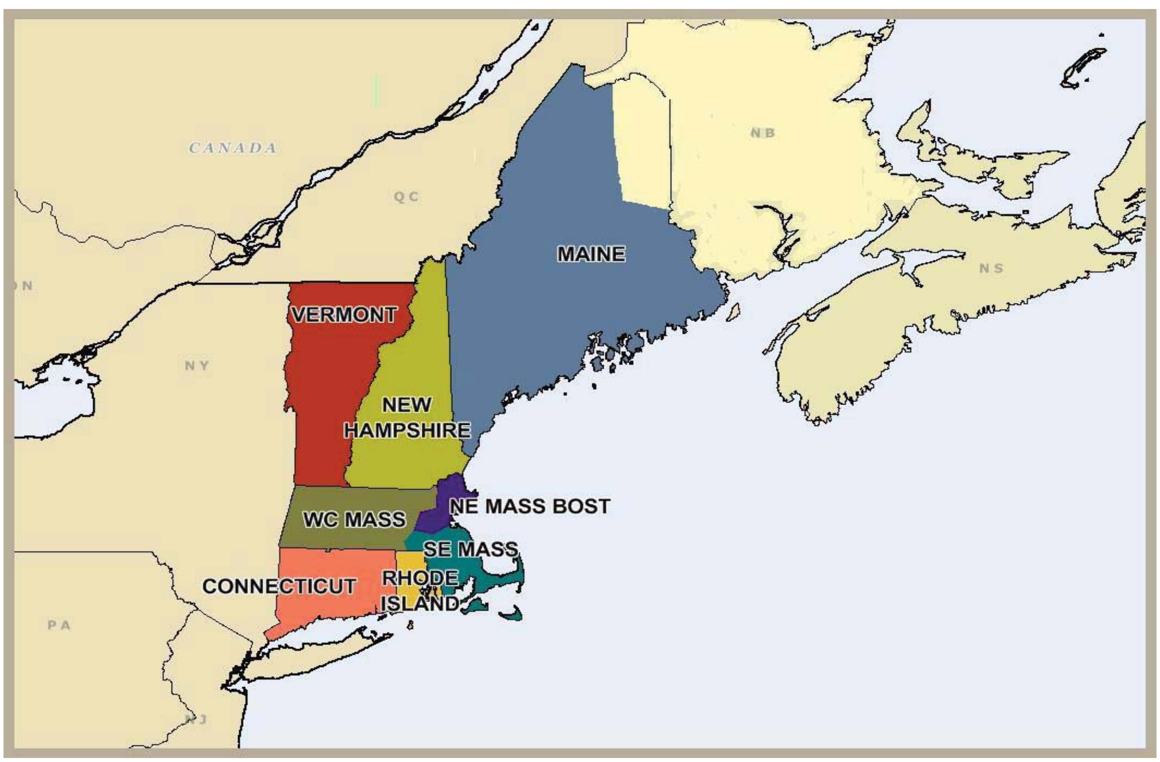
Market Participants

The New England Power Pool (NEPOOL) consists of six sectors: (1) end-user sector; (2) publicly owned entities; (3) supplier sector; (4) transmission sector; (5) generation sector; and (6) alternative resources.

Membership and Governance

ISO-NE is a not-for-profit entity governed by a 10-member, independent, nonstakeholder board of directors. The sitting members of the board elect people to fill board vacancies.

Independent System Operator of New England (ISO-NE)



Transmission

Owners

ISO-NE's transmission owners include:

- Bangor Hydro-Electric Co.,
- Central Maine Power Co.,
- New England Power Co.,
- Northeast Utilities System Cos.,
- NSTAR Electric Co.,
- Transmission Sector Provisional Group Member,
- The United Illuminating Co., and
- Vermont Electric Power Co. Inc.

Chronic Constraints

In 2009, New England completed a series of major transmission projects to improve reliability, including projects serving Boston, southwestern Connecticut and southeastern Massachusetts.

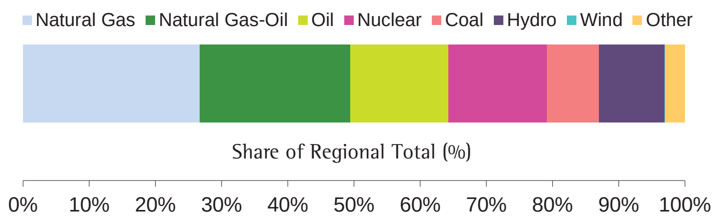
Transmission Planning

Each year, ISO-NE prepares a comprehensive 10-year regional system plan (RSP) that reports on the results of ISO system planning processes. Each plan includes forecasts of future loads (i.e., the demand for electricity measured in megawatts) and addresses how this demand may be satisfied by adding supply resources; demand resources, including demand response and energy efficiency; and new or upgraded transmission facilities. Each year's plan summarizes New England needs, as well as the needs in specific areas, and includes solutions and processes required to ensure the reliable and economic performance of the New England power system.

Supply Resources

Generating Mix

By plant capacity, the generating mix includes these sources:



Demand Response

Currently, ISO-NE administers five load-response programs for the New England wholesale electricity market. These include:

- **Real-Time 30-Minute Demand-Response Program:** These resources are required to respond within 30 minutes of the ISO's instructions.
- **Real-Time 2-Hour Demand Response Program:** This program requires demand resources to respond within two hours of the ISO's instructions.
- **Real-Time Profiled-Response Program:** These resources may be interrupted for anticipated capacity deficiencies within a specified time period and receive payment for a minimum of two hours.
- **Real-Time Price-Response Program:** These resources may interrupt (but are not required to do so) when they receive notice on the previous day. If they interrupt, they receive payment for the eligibility period.
- **Day-Ahead Load-Response Program:** An optional program that allows a participant in any of the real-time programs to offer interruptions concurrent with the day-ahead energy market. The participant is paid the day-ahead LMP for the cleared interruptions, and real-time deviations are charged or credited at the real-time LMP.

Market Features and Functions

Energy Markets

Day-Ahead

The day-ahead energy market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

In the day-ahead energy market, incremental offers and decremental bids (virtual supply offers and demand bids) can also be submitted, which indicate prices at which supply or demand are willing to increase or decrease their injection or withdrawal on the system. These INCs and DECs are tools market participants can use to hedge their positions in the day-ahead energy market.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are cleared and are scheduled. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the locational marginal prices (LMPs) for all locations.

Hour-Ahead

None.

Real-Time

ISO-NE must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. While the day-ahead energy market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, ISO-NE operates a spot market for energy, the real-time energy market, to meet energy needs within each hour of the current day.

ISO-NE clears the real-time energy market using supply offers, real-time load and offers and bids to sell or buy energy over the external interfaces. For generators, the market provides additional opportunities to offer supply to help meet incremental supply needs. Load-serving entities (LSEs) whose actual demand comes in higher than that scheduled in the day-ahead energy market may secure additional energy from the real-time energy market.

The real-time energy market financially settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Differences from the day-ahead quantities cleared are settled at the real-time LMP.

In real time, ISO-NE will issue dispatch rates and dispatch targets. These are five-minute price and megawatt signals based on the aggregate offers of generators, which will produce the required energy production. Market participants are, throughout the day, allowed to offer imports or request exports of electricity from neighboring control areas with at least one hour's notice.

Must-Offer Requirements

Market rules in RTOs include must-offer requirements for certain categories of resources for which withholding, a form of the exercise of market power, may be a concern. Where such rules apply, sellers must commit, or offer, the generators, and schedule and operate the facilities, into the applicable market.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

ISO-NE procures ancillary services via the forward reserve market and its regulation market. The forward reserve market compensates generators for making available their unloaded operating capacity that can be converted into electric energy within 10 or 30 minutes when needed to meet system contingencies, such as unexpected outages. The Regulation Market compensates resources that ISO-NE instructs to increase or decrease output moment by moment to balance the variations in demand and system frequency to meet industry standards. The specific ancillary services ISO-NE procures in its markets include the following:

- Ten-Minute Spinning Reserves: provided by resources already synchronized to the grid and able to generate electricity within 10 minutes.
- Ten-Minute Nonspinning Reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 10 minutes.
- Thirty-Minute Nonspinning Reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 30 minutes.
- Regulation: provided by specially equipped resources with the capability to increase or decrease their generation output every four seconds in response to signals they receive from ISO-NE to control slight changes on the system.

Specialized ancillary services that are not bought and sold in these ancillary service markets include voltage support and black-start capability. Voltage support allows the New England control area to maintain transmission voltages. Black-start capability is the ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power without assistance from a power system. ISO-NE procures these services via cost-based rates.

Capacity Markets

In ISO-NE's annual forward capacity auctions (FCA), both generator and demand resources offer capacity three years in advance of the period for which capacity will be supplied. The three-year lead time is intended to encourage participation by new resources and allow the market to adapt to resources leaving the market. Resources whose capacity clears the FCA acquire capacity supply obligations (CSOs). ISO-NE held its first two FCAs in 2008 for the 2010-11 and 2011-12 delivery years. The first full year of capacity market commitments began on June 1, 2010. A third auction was held in December 2009 for the 2011-13 delivery years. The FCA process includes the modeling of transmission constraints to determine if load zones will be import- or export-constrained.

Market Power Mitigation

In ISO-NE, mitigation may be applied for physical withholding, economic withholding, uneconomic production, virtual transactions or other conduct if the conduct has a material effect on prices or uplift payments. The market monitor uses defined thresholds to identify physical and economic withholding and uneconomic generation, as well as defined thresholds to determine whether bids and offers would, if not mitigated, cause a material effect on LMPs or uplift charges.

Reliability Must-Run

None.

Financial Transmission Rights

New England FTRs are monthly and annual products. ISO-NE holds FTR auctions and then allocates the auction revenue to LSEs based on historical load. ISO-NE is the only RTO to settle accounts weekly but revenue insufficiency is possible. Month-to-month surplus is carried over and used to fund any deficiencies, and the true-up period for accounts occurs once a year.

Virtual Transactions

In ISO-NE, any market participant may submit INCs or DECs into the day-ahead market.

MISO

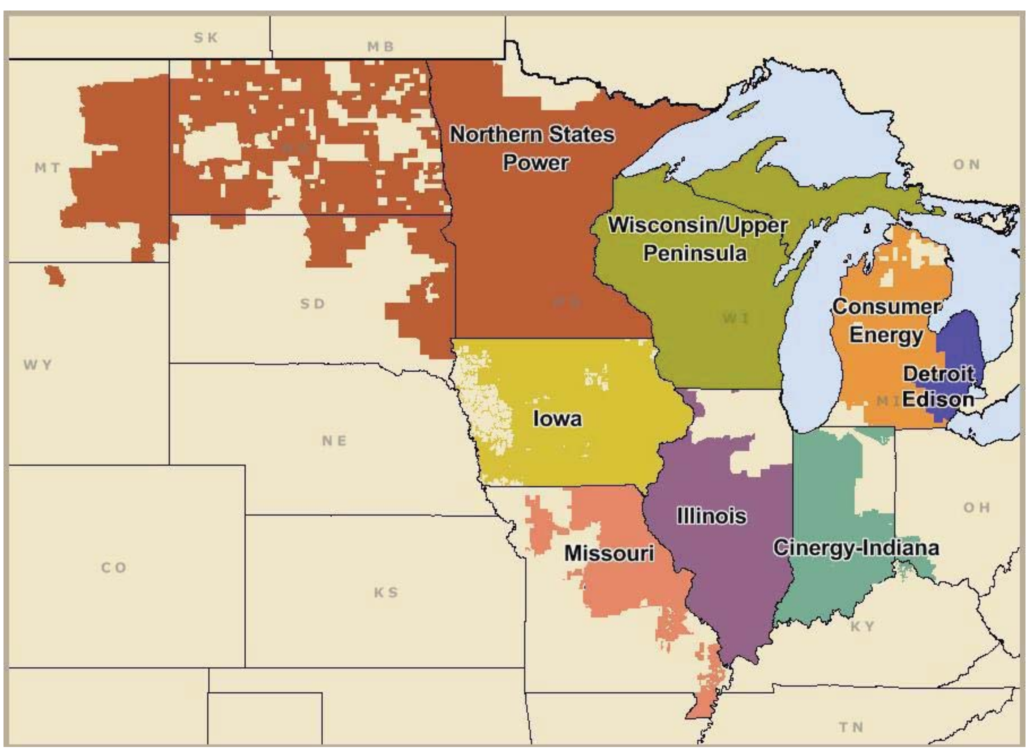
Midwest Independent System Operator

Market Profile

Geographic Scope

MISO operates the transmission system and a centrally dispatched market in portions of 13 states in the Midwest, extending from western Pennsylvania to eastern Montana and from the Canadian border to the southern extremes of

Midwest Independent System Operator (MISO)



Illinois and Missouri. The system is operated from a primary control center in Carmel, Ind., and a second control center in St. Paul, Minn., for the western region. MISO also serves as the reliability coordinator for additional systems outside of its market area, primarily to the north and northwest of the market footprint.

MISO was not a power pool before organizing as an ISO in December 2001. It began market operations in April 2005. In January 2009, MISO started operating an ancillary services market and combined its 24 separate balancing areas into a single balancing area.

Demand

MISO's peak demand was 116 GW in 2006.

Import and Exports

MISO has interconnections with the PJM and Southwest Power Pool (SPP) RTOs. It is also directly connected to TVA, the Western Area Power Administration and the electric systems of Manitoba and Ontario, plus several smaller systems. MISO is a net importer of power overall, but the interchange with some areas can flow in either direction, depending on the relative loads and prices in the adjoining regions. Manitoba Hydro supplies a large part of MISO's load with its excess capacity, particularly in the summer.

Market Participants

MISO includes 34 transmission owners, whose assets define the MISO market area. MISO's market participants include generators, power marketers, transmission-dependent utilities and load-serving entities.

Membership and Governance

An independent board of directors of eight members, including the president, governs MISO. Directors are elected by the MISO membership from candidates provided by the board.

An advisory committee of the membership provides advice to the board and information to the MISO stakeholders. Membership includes entities with an interest in MISO's operation, such as state regulators and consumer advocates, as well as transmission owners, independent power producers, power marketers and brokers, municipal and cooperative utilities and large-volume customers.

Transmission

Owners

The transmission owners in MISO include:

- Alliant Energy
- American Transmission Co.
- Ameren (Missouri and Illinois)
- American Transmission Systems
- Cinergy Services (Duke)
- Indianapolis Power and Light
- ITC
- Michigan Public Power Agency
- NSP Companies (Xcel)
- Northern Indiana Public Service Co.
- Otter Tail Power
- MidAmerican Energy

Chronic Constraints

MISO has certain pathways that are more likely to become congested, but the likelihood and pattern of congestion in any area is subject to weather patterns, wind production and interchange with external regions. When load is high in the eastern part of MISO and to the east in PJM, constraints occur on pathways from the Minnesota and Wisconsin areas through Chicago and across Indiana and Ohio. A particular congestion point with this pattern is northern Indiana. When colder weather hits Minnesota and the Dakotas, there is often congestion in the northern direction, particularly in Iowa. Higher wind production can cause localized constraints in some areas and can cause congestion in pathways from southern Minnesota and western Iowa moving eastward.

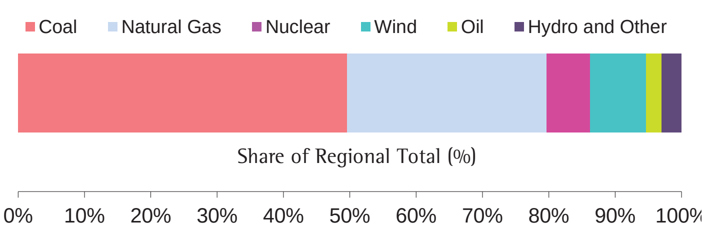
Transmission Planning

The main vehicle MISO uses for transmission planning is the Midwest ISO Transmission Expansion Plan developed by the MISO planning department in collaboration with transmission owners and other stakeholders who form the planning advisory committee. The plan is for two years. Once approved by the board, the plan becomes the responsibility of the transmission owners.

Supply Resources

Generating Mix

By plant capacity, the generating mix includes these sources:



Demand Response

Demand-side resources are able to participate in MISO's markets in providing capacity, energy in both the day-ahead and real-time markets and ancillary services.

Market Features and Functions

Energy Markets

Day-Ahead Market

The day-ahead market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

In the day-ahead market, incremental offers and decremental bids (virtual supply offers and demand bids) can also be submitted, although they are not associated with physical resources or actual load. These INCs and DECs are tools market participants can use to hedge their real time commitments or to arbitrage the day-ahead to real-time price spread.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are scheduled. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the locational marginal prices (LMPs) for all locations.

Generators and offers scheduled in the day-ahead settlement are paid the day-ahead LMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time marketplace to replace what was not produced.

Likewise, wholesale buyers of electricity and virtual demand whose bids to buy clear in the day-ahead market settlement pay for and lock in their right to consume the cleared quantity at the day-ahead LMP. Electricity use in real-time that exceeds the day-ahead purchase is paid for at the real-time LMP.

Hour-Ahead Market

Not applicable for MISO.

Real-Time Market

MISO must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. While the day-ahead energy market produces the schedule and financial terms for the bulk of the physical transactions, a number of factors usually change the day-ahead result. Thus, MISO operates a spot market for energy, the real-time energy market, to meet actual energy needs within each hour of the operating day.

The real-time market is prepared for at the conclusion of the day-ahead market on the day before the operating day. MISO clears the real-time energy market using supply offers, real-time load and external offers. For generators, the market provides additional opportunities to offer supply to help meet incremental needs. LSEs whose actual demand comes in higher than what was scheduled in the day-ahead market may secure additional energy from the real-time market.

The real-time energy market financially settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Participants either pay or are paid the real-time LMP for the amount of load or generation in megawatt-hours that deviates from their day-ahead schedule.

In real-time, MISO issues dispatch rates and dispatch targets. These are five-minute price and megawatt signals based on the aggregate offers of generators, which will produce the required energy production. Market participants are, throughout the day, allowed to offer imports or request exports of electricity from neighboring control areas by submitting transmission schedules into or out of MISO.

In real-time, generators can also deviate from the day-ahead clearing schedule by self-scheduling, which means that MISO will run a given unit without regard to the unit's economics unless running the unit presents a reliability concern.

During the operating day, the real-time market acts as a balancing market for load with physical resources used to meet that load. A market price for energy and for each of the ancillary services is calculated for each five-minute dispatch interval and the resulting five-minute prices are rolled into hourly prices for billing and payment. Differences in the real-time operation from the day-ahead clearing, including all virtual transactions, are settled at the real-time price.

Must-Offer Requirements

Market rules in RTOs include must-offer requirements for certain categories of resources for which withholding, which could be an exercise of market power, may be a concern. Where such rules apply, sellers must commit, or offer, the generators, and schedule and operate the facilities, in the applicable market.

In MISO, generators who supply capacity to meet the RTO resource adequacy requirement for load are required to offer into the day-ahead and real-time markets for energy and the ancillary services for which they are qualified.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

MISO procures ancillary services via the co-optimized energy and ancillary services market and includes the following services:

- Spinning Reserves: provided by resources already synchronized to the grid and able to provide output within 10 minutes.
- Supplemental (nonspinning) Reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 10 minutes.
- Regulation: provided by specially equipped resources with the capability to increase or decrease their generation output every four seconds in response to signals they receive to control slight changes on the system.

Capacity Markets

Capacity markets are a construct to provide assurance to government entities and to NERC a means for load-serving entities (LSEs) to prove they have procured capacity needed to meet forecast load and to allow generators to recover a portion of their fixed costs. They also provide economic incentives to attract investment in new and existing supply-side and demand-side capacity resources.

MISO maintains a monthly capacity requirement on all LSEs based on the load forecast plus reserves. LSEs are required to specify to MISO what physical capacity, including demand resources, they have designated to meet their load forecast. This capacity can be acquired either through bilateral purchase or self-supply. Additionally, MISO conducts a monthly auction to provide an opportunity for load that has not arranged all of its capacity to procure its needs from uncommitted resources.

Market Power Mitigation

In electric power markets, mainly because of the largely nonstorable nature of electricity and the existence of transmission constraints that can limit the availability of multiple suppliers to discipline market prices, some sellers from time to time have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Reliability Must-Run

None.

Financial Transmission Rights

Financial transmission rights (FTRs) give market participants an offset or hedge against transmission congestion costs in the day-ahead market. An FTR is a financial contract protecting the holder from costs arising from transmission congestion over a path or a source-and-sink pair of locations on the grid. An FTR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the specific FTR transmission path. FTRs were originally formulated to protect LSEs from price uncertainty while redistributing excess congestion charges due to constrained conditions. Other market participants such as financial-only participants may purchase FTRs through the RTO's auctions or through secondary market purchases.

MISO FTRs are monthly and annual products.

Virtual Transactions

A virtual transaction allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Cleared virtual supply (increment or virtual offers, or INCs) in the day-ahead energy market at a particular location in a certain hour creates a financial obligation for the participant to buy back the bid quantity in the real-time market at that location in that hour. Cleared virtual demand (decrement or virtual bids, or DECs) in the day-ahead market creates a financial obligation to sell the bid quantity in the real-time market. The financial outcome for a particular participant is determined by the difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears. Thus, through this financial arbitrage opportunity, virtual transactions in theory help to narrow the difference between the day-ahead and real-time prices.

MISO allows virtual bids and offers into its day-ahead energy market where the bids and offers are included in the determination of the LMP along with physical resource offers and actual load bids. Market participants whose virtual transactions clear in the day-ahead market, have their positions cleared in the real-time market at the real-time price. Virtual bids and offers are allowed in MISO at any pricing node or aggregate of pricing nodes.

Credit Requirements

Credit requirements are important in markets in which RTOs must balance the need for market liquidity against corresponding risk of default. Defaults within these markets are particularly troubling because losses due to default are borne among all market participants. Thus, each RTO's tariff specifies credit rules needed to participate in the markets. These requirements provide for credit evaluations, credit limits, allowed forms of collateral and the consequences of violations or defaults.

Settlements

RTOs must invoice market participants for their involvement in their markets.

The RTO determines the amount owed associated with buying and selling energy, capacity and ancillary services and paying various administrative charges.

Settlements for market activity in MISO are finalized seven days after the operating day and payable after 14 days.

NYISO

New York Independent System Operator

Market Profile

Geographic Scope

Prior to restructuring of the electric industry in the 1990s, New York's private utilities and public power authorities owned and operated New York's electric system. Operation of the electric grid was coordinated by a voluntary collaboration of the utilities and power authorities as the New York Power Pool (NYPP). The creation of the New York Independent System Operator (NYISO) was authorized by FERC in 1998. The formal transfer of the NYPP's responsibilities to the NYISO took place on Dec. 1, 1999.

The NYISO footprint covers the entire state of New York. NYISO is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity. NYISO operates New York's high-voltage transmission network and performs long-term planning.

Demand

NYISO's all-time peak load was 34 GW in 2006.

Imports and Exports

NYISO imports and exports energy through interconnections with ISO-NE, PJM, TransEnergie (Quebec) and Ontario.

Market Participants

NYISO's market participants include generators, transmission owners, financial institutions, traditional local utilities, electric co-ops and industrials.

Membership and Governance

NYISO is governed by an independent 10-member board of directors and management, business issues and operating committees. Each committee oversees its own set of working groups or subcommittees. These committees comprise transmission owners, generation owners and other suppliers, consumers, public power and environmental entities. Tariff revisions on market rules and operating procedures filed with the Commission are largely developed through consensus by these committees. The members of the board, as well as all employees, must not be directly associated with any market participant or stakeholder.

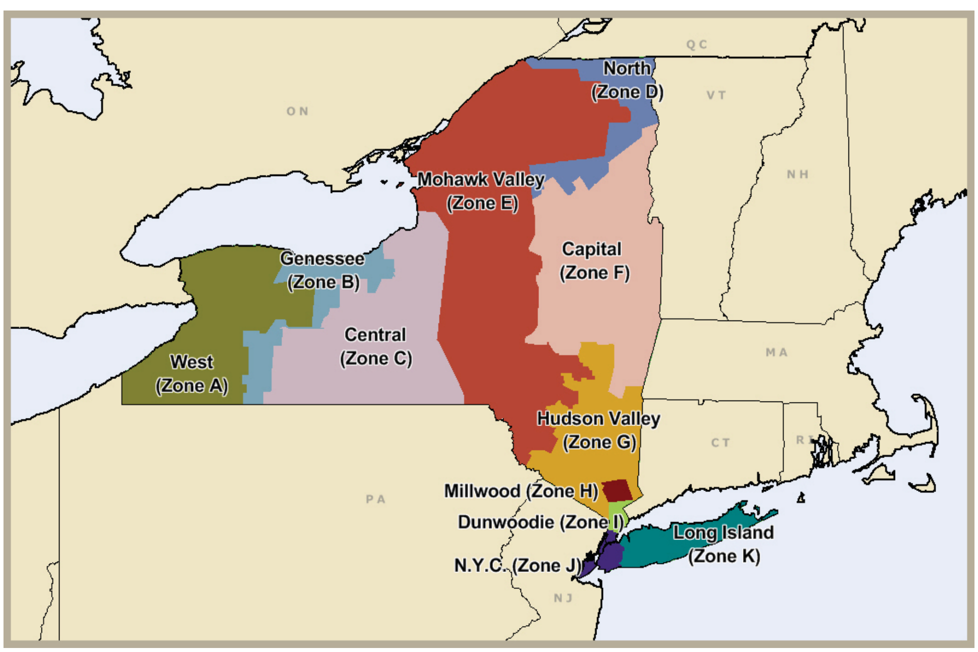
Transmission

Transmission Owners

NYISO's transmission owners include:

- Central Hudson Gas & Electric Corp.
- Consolidated Edison Co. of New York (ConEd)
- Long Island Power Authority (LIPA)
- New York Power Authority (NYPA)
- New York State Electric and Gas Corp. (NYSEG)
- National Grid
- Orange & Rockland Utilities
- Rochester Gas and Electric Corp.

New York Independent System Operator (NYISO)



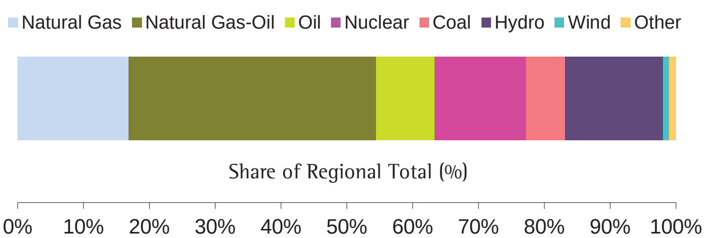
Chronic Constraints

The chronic transmission constraints in NYISO are in the southeastern portion of the state, leading into New York City and Long Island. As a result of their dense populations, New York City and Long Island are the largest consumers of electricity. Consequently, energy flows from the west and the north toward these two large markets, pushing transmission facilities near their operational limits. This results in transmission constraints in several key areas, often resulting in higher prices in the New York City and Long Island markets.

Supply Resources

Generating Mix

By plant capacity, the generating mix includes these sources:



Demand Response

NYISO has four demand-response (DR) programs: the emergency demand-response program (EDRP), the installed capacity (ICAP) special case resources program (SCR), the day-ahead demand-response program and the demand-side ancillary services program.

Both the emergency and special cases programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. Both programs are designed to reduce power usage by shutting down businesses and large power users. Companies, mostly industrial and commercial, sign up to take part in the programs. The companies are paid by NYISO for reducing energy consumption when asked to do so. Reductions are voluntary for EDRP participants. SCR participants are required to reduce power usage and as part of their agreement are paid in advance for agreeing to cut power usage on request.

NYISO's day-ahead DR program allows energy users to bid their load reductions into the day-ahead market. Offers determined to be economic are paid at the market clearing price. Under day-ahead DR, flexible loads may effectively increase the amount of supply in the market and moderate prices.

The ancillary services program provides retail customers that can meet telemetry and other qualifications the ability to bid their load curtailment capability into the day-ahead market or real-time market to provide reserves and regulation service. Scheduled offers are paid the marketing clearing price for reserves or regulation.

Market Features and Functions

Energy Markets

Day-Ahead Market

The day-ahead market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

In the day-ahead market, virtual supply offers and demand bids can also be submitted. These are tools market participants can use to hedge their positions in the day-ahead market.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below, and demand bids above, the identified price are scheduled. Offers and bids that clear are then entered into a pricing software system along with binding transmission constraints to produce the locational marginal prices (LMPs) for all locations. The NYISO refers to these as locational based marginal prices, or LBMPs.

Generators and offers scheduled in the day-ahead settlement are paid the day-ahead LBMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time marketplace to replace what was not produced.

Likewise, wholesale buyers of electricity and virtual demand whose bids to buy are accepted in the day-ahead market pay for and lock in their right to consume the cleared quantity at the day-ahead LBMP. Electricity used in real-time that exceeds the day-ahead purchase is paid for at the real-time LBMP.

Hour-Ahead Market

The hour-ahead market allows buyers and sellers of electricity to balance unexpected increases or decreases of electricity use after the day-ahead market closes. Bids and offers are submitted an hour ahead of time. Prices are set based on those bids and offers, generally for use in matching generation and load requirements, but those prices are advisory only. Hour-ahead scheduling is completed at least 45 minutes prior to the beginning of the dispatch hour after NYISO reviews transmission outages, the load forecast, reserve requirements and hour-ahead generation and firm transaction bids, among other things.

Real-Time Market

NYISO must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. While the day-ahead market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, NYISO operates a spot market for energy, the real-time energy market, to meet energy needs within each hour of the current day.

Real-time energy market outcomes are based on supply offers, real-time load and offers and bids to sell or buy energy. LSEs whose actual demand comes in higher than that scheduled in the day-ahead market may secure additional energy from the real-time market. For generators, the market provides additional opportunities to offer supply to help meet additional needs.

The real-time energy market financially settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Those who were committed to produce in the day-ahead are compensated at (or pay) the real-time LBMP for the megawatts under- or over-produced in relation to the cleared amount. Those who paid for day-ahead megawatts are paid (or pay) the real-time LBMP for megawatts under- or over-consumed in real-time.

Real-time dispatch of generators occurs every five minutes, as does the setting of the real-time prices used for settlement purposes. Market participants may participate in the day-ahead, hour-ahead, and the real-time market.

Must-Offer Requirements

Under the NYISO capacity auction rules, entities that offer capacity into an auction that is subsequently purchased by load are required to offer that amount of capacity into the day-ahead energy market. This rule ensures that capacity sold through the capacity auctions is actually delivered into the market.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

NYISO administers competitive markets for ancillary services that are required to support the power system. The two most important types of ancillary services are operating reserves and regulation. Operating reserves and regulation are typically provided by generators, but NYISO allows demand-side providers to participate in these markets as well. Operating reserve resources can either be spinning (online with additional ramping ability) or nonspinning (off-line, but able to start and synchronize quickly). NYISO relies on regulating resources that can quickly adjust their output or consumption in response to constantly changing load conditions to maintain system balance.

The NYISO relies on the following types of ancillary services:

- Ten-Minute spinning reserves: provided by resources already synchronized to the grid and able to provide output within 10 minutes.
- Ten-Minute nonspinning reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 10 minutes.
- Thirty-Minute nonspinning reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 30 minutes.
- Regulation: provided by resources with the capability to increase or decrease their generation output within seconds in order to control changes on the system.

Capacity Markets

Capacity markets provide a means for load-serving entities (LSEs) to procure capacity needed to meet forecast load and to allow generators to recover a portion of their fixed costs. They also provide economic incentives to attract investment in new and existing supply-side and demand-side capacity resources in New York as needed to maintain bulk power system reliability requirements.

In NYISO's capacity market, LSEs procure capacity through installed-capacity (ICAP) auctions, self-supply and bilateral arrangements based on their forecasted peak load plus a margin. The NYISO conducts auctions for three different service durations: the capability period auction (covering six months), the monthly auction and the spot market auction.

New York has capacity requirements for three zones: New York City, Long Island and New York-Rest of State. The resource requirements do not change in the monthly auctions and ICAP spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSE's load forecasts.

Market Power Mitigation

In electric power markets, mainly because of the largely nonstorable nature of electricity and the existence of transmission constraints that can limit the availability of multiple suppliers to discipline market prices, some sellers from time to time have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Market power may need to be mitigated on a systemwide basis or on a local basis. When a transmission constraint creates the potential for local market power, the RTO may apply a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market.

The categories of conduct that may warrant mitigation by NYISO include physical withholding, economic withholding and uneconomic production by a generator or transmission facility to obtain benefits from a transmission constraint. Physical withholding is not offering to sell or schedule energy provided by a generator or transmission facility capable of serving a NYISO market. Physical withholding may include falsely declaring an outage, refusing to offer or schedule a generator or transmission facility; making an unjustifiable change to operating parameters of a generator that reduces its availability; or operating a generator in real-time at a lower output level than the generator would have been expected to produce had the generator followed NYISO's dispatch instructions. Economic withholding is submitting bids for a generator that are unjustifiably high so that the generator is not dispatched.

NYISO will not impose mitigation unless the conduct causes or contributes to a material change in prices, or substantially increases guarantee payments to participants.

Virtual bidding is subject to mitigation under certain circumstances as well. NYISO may limit the hourly quantities of virtual bids for supply or load that may be offered in a zone by a market participant whose virtual bidding practices are determined to contribute to an unwarranted divergence of LBMPs (location-based marginal prices) between the day-ahead and real-time markets. If the NYISO determines that the relationship between zonal LBMPs in a zone in the day-ahead market and the real-time market is not what would be expected under conditions of workable competition, and that the virtual bidding practices of one or more market participants has contributed to this divergence, then a mitigation measure may be imposed.

Price Caps

NYISO does not have price caps. It employs a bid cap of $1,000/MWh for its day-ahead and real-time markets.

ICAP for New York City is subject to offer caps and floors. Offer caps in New York City are based on reference levels or avoided costs. Capacity from generators within New York City must be offered in each ICAP spot market auction, unless that capacity has been exported out of New York or sold to meet ICAP requirements outside New York City.

Local Market Power Mitigation

Generators in New York City are subject to automated market power mitigation procedures because New York City is geographically separated from other parts of New York; plus, generators in New York City have been deemed to have market power.

These automated procedures determine whether any day-ahead or real-time energy bids, including start-up costs bids and minimum generation bids, but excluding ancillary services bids, exceed the tariff's thresholds for economic withholding, and, if so, determine whether such bids would cause material price effects or changes in guarantee payments. If these two tests are met, mitigation is imposed automatically.

For example, the threshold for economic withholding regarding energy and minimum generation bids is a 300 percent increase or an increase of $100/MWh over the applicable reference level, whichever is lower. Energy or minimum generation bids below $25/MWh are not considered economic withholding. Regarding operating reserves and regulation bids, a 300 percent increase or an increase of $50/MW over the applicable reference level, whichever is lower, is the threshold for determining whether economic withholding has occurred. In this instance, bids below $5/MW are not considered economic withholding. If an entity's bids meet these thresholds, the applicable reference level is substituted for the entity's actual bid to determine the clearing price.

Reliability Must-Run

NYISO has no reliability must-run provisions.

Financial Transmission Rights

Financial transmission rights (FTRs) give market participants an offset, or hedge, against transmission congestion costs in the day-ahead market. The NYISO refers to FTRs as transmission congestion contracts (TCCs). Other than the name, FTRs and TCCs are essentially the same. An FTR is a financial contract protecting the holder from costs arising from transmission congestion over a path or a source-and-sink pair of locations (or nodes) on the grid. An FTR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the specific FTR transmission path. FTRs were originally formulated to protect LSEs from price uncertainty. Other market participants, including financial-only participants, may purchase FTRs through the RTO's auctions.

A related product is an auction revenue right (ARR), which provides the holders with an upfront portion of the money raised in the TCC auctions. In general, they are allocated based on historical load served. As with FTRs, ARRs give transmission owners and eligible transmission service customers an offset, or hedge, against transmission congestion costs in the day-ahead market.

Virtual Transactions

A virtual transaction is a specific kind of transaction that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Cleared virtual supply (virtual offers) in the day-ahead energy market at a particular location in a certain hour creates a financial obligation for the participant to buy back the bid quantity in the real-time market at that location in that hour. Cleared virtual demand (virtual bids) in the day-ahead market creates a financial obligation to sell the bid quantity in the real-time market. The financial outcome is determined by the difference between the hourly day-ahead and real-time LBMPs at the location at which the offer or bid clears. Thus, through this financial arbitrage opportunity, virtual transactions in theory help to narrow the difference between the day-ahead and real-time prices.

Virtual bidding in NYISO takes place on a zonal level, not a nodal level.

Credit Requirements

Credit requirements are important in organized electricity markets in which RTOs must balance the need for market liquidity against corresponding risk of default. Losses due to default are borne among all market participants. Thus, each RTO's tariff specifies credit rules needed to participate in the markets. These requirements provide for credit evaluations, credit limits, allowed forms of collateral and the consequences of violations or defaults.

Settlements

RTOs must invoice market participants for their involvement in their markets. Settlements is the process by which the RTO determines the amounts owed and to be paid associated with buying and selling energy, capacity, ancillary services and paying various administrative charges.

NYISO uses a two-settlement process for its energy markets. The first settlement is based on day-ahead bids and offers, which clear the market and are scheduled. The second settlement is based on the real-time bids and the corresponding real-time dispatch.

PJM

The PJM Interconnection

Market Profile

Geographic Scope

The PJM Interconnection operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to the transmission and performs long-term planning. In managing the grid, PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia. PJM's markets include energy (day-ahead and real-time), capacity and ancillary services.

PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection, or PJM. PJM became a fully functioning ISO in 1996 and, in 1997, it introduced markets with bid-based pricing and locational market pricing (LMP). PJM was designated an RTO in 2001.

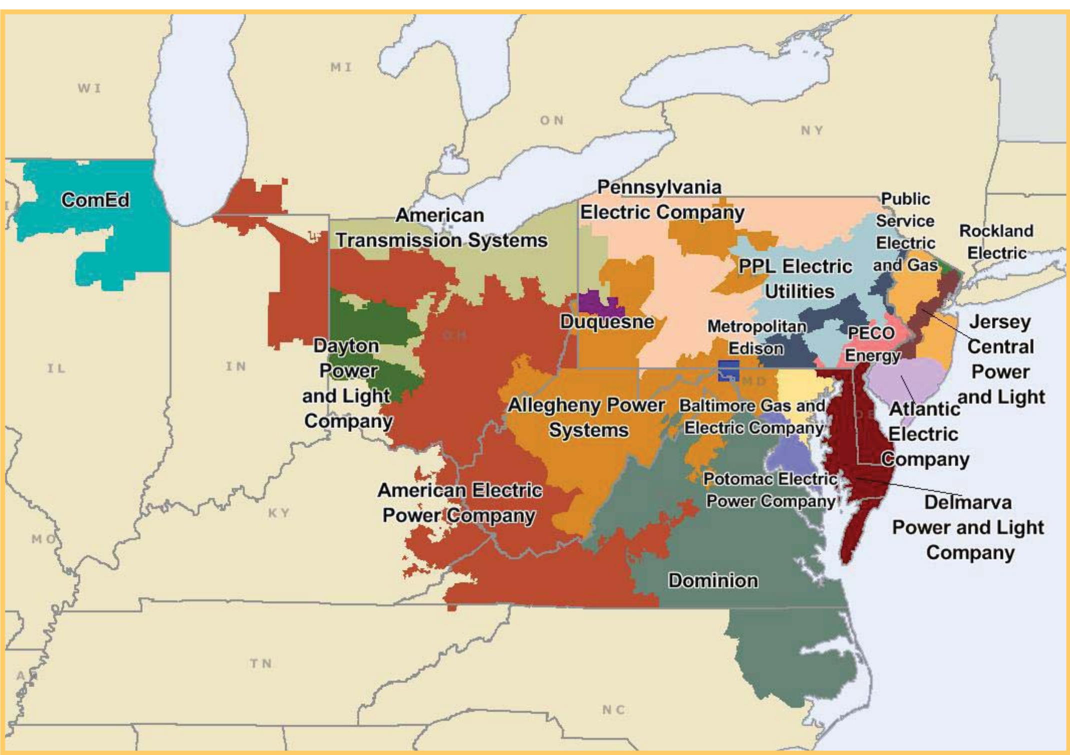
Demand

PJM's all-time peak load of 159 GW occurred in summer 2006.

Imports and Exports

PJM has interconnections with Midwest ISO and New York ISO. PJM also has direct interconnections with the Tennessee Valley Authority (TVA), Progress Energy Carolinas

PJM Regional Transmission Organization



and the Virginia and Carolinas Area (VACAR), among other systems. PJM market participants import energy from, and export energy to, external regions continuously. At times, PJM is a net importer of electricity and, at other times, PJM is a net exporter of electricity.

Market Participants

PJM's market participants include power generators, transmission owners, electric distributors, power marketers, electric distributors and large consumers.

Membership and Governance

PJM has a two-tiered governance model consisting of a board of managers and the members committee. PJM is governed by a 10-member board, nine of whom PJM members elect. The board appoints the tenth, the president and CEO, to supervise day-to-day operations. The board is generally responsible for oversight of system reliability, operating efficiency and short and long-term planning. The board ensures that no member or group of members exerts undue influence.

The members committee, which advises the board, is composed of five voting sectors representing power generators, transmission owners, electric distributors, power marketers and large consumers.

Transmission

Transmission Owners

The largest transmission owners in PJM include:

- AEP,
- First Energy,
- PSE&G,
- Dominion,
- Philadelphia Electric, and
- Commonwealth Edison.

Chronic Constraints

In general, transmission paths extending from generation sources in western PJM to load centers in eastern PJM tend to become constrained, particularly during peak load conditions. PJM's Mid-Atlantic markets rely on generation in the western part of PJM due to the retirements of eastern units and the location of new generation capacity in western areas, such as western Pennsylvania, West Virginia and eastern Ohio. Eastern PJM relies on transmission across Pennsylvania and up from southwestern PJM to import power from sources west and southwest. Eastern PJM relies on transmission capability to replace retired generation and to meet demand growth.

Congestion on the eastern interface also constrains power flows from the District of Columbia, Baltimore and Northern Virginia to New Jersey, Delmarva Peninsula and Philadelphia load centers. The high-voltage, bulk power transmission pathway within portions of the states of Pennsylvania, West Virginia, Virginia and Maryland serve the densely populated load centers of the metropolitan areas of Baltimore, the District of Columbia and Northern Virginia. The electricity needs of Washington-Baltimore-Northern Virginia are supplied not only by local generation but also by significant energy transfers to those areas.

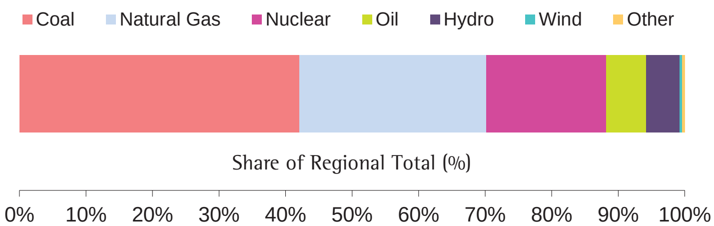
Transmission Planning

PJM's regional transmission expansion plan (RTEP) identifies transmission system additions and improvements needed to keep electricity flowing within PJM. Studies are conducted to test the transmission system against national and regional reliability standards. These studies look forward to identify future transmission overloads, voltage limitations and other reliability standards violations. PJM then develops transmission plans to resolve violations that could otherwise lead to overloads and blackouts.

Supply Resources

Generation Mix

By plant capacity, the generating mix includes these sources:



Demand Response

End-use customers providing demand response have the opportunity to participate in PJM's energy, capacity, synchronized reserve and regulation markets on an equal basis with generators. All demand-response programs can be grouped into emergency or economic programs. The emergency program compensates end-use customers who reduce their usage during emergency conditions on the PJM system. Participation in the emergency program may be voluntary or mandatory and payments may include energy payments, capacity payments or both. There are three options for emergency program registration and participation: energy only, capacity only and capacity-plus-energy.

The economic program allows end-use customers to reduce electricity consumption in the energy markets and receive a payment when LMPs are high. Under this program, all hours are eligible and all participation is voluntary. Participation in the program takes three forms: submitting a sell offer into the day-ahead market that clears; submitting a sell offer into the real-time market that is dispatched; and self-scheduling load reductions while providing notification to PJM. End-use customers participate in demand response in PJM through members called curtailment service providers, or CSPs, who act as agents for the customers. CSPs aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM. The payment is divided among the CSP and its retail customers based on private agreements between them.

Market Features and Functions

Energy Markets

Day-Ahead Market

The day-ahead market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real-time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

In the day-ahead market, incremental offers and decremental bids (virtual supply offers and demand bids) can also be submitted, which indicate prices at which supply or demand are willing to increase or decrease their injection or withdrawal on the system. These INCs and DECs are tools market participants can use to hedge their positions in the day-ahead market.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are said to clear, meaning they are scheduled. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the locational marginal prices (LMPs) for all locations.

Generators and offers scheduled in the day-ahead settlement are paid the day-ahead LMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time marketplace to replace what was not produced.

Likewise, wholesale buyers of electricity and virtual demand whose bids to buy clear in the day-ahead market settlement pay for and lock in their right to consume the cleared quantity at the day-ahead LMP. Electricity use in real-time that exceeds the day-ahead purchase is paid for at the real-time LMP.

Hour-Ahead Market

Not Applicable for PJM.

Real-Time Market

PJM must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. While the day-ahead energy market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, PJM operates a spot market for energy, called the real-time energy market, to meet energy needs within each hour of the current day.

PJM clears the real-time energy market using supply offers, real-time load and offers and bids to sell or buy energy over the external interfaces. Real-time LMPs are calculated at five-minute intervals based on actual grid operating conditions as calculated in PJM's market systems. Generators that are available but not selected in the day-ahead scheduling may alter their bids for use in the real-time energy market during the generation rebidding period from 4 p.m. to 6 p.m.; otherwise, their original day-ahead market bids remain in effect for the real-time energy market.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system. RTO/ISOs procure or direct the supply of ancillary services.

PJM operates the following markets for ancillary services:

- Regulation: corrects for short-term changes in electricity use that might affect the stability of the power system.
- Synchronized reserves: supplies electricity if the grid has an unexpected need for more power on short notice.
- Day-ahead scheduling reserves (DASR): allows PJM to schedule sufficient generation to preserve reliability during unanticipated system conditions throughout the operating day.

Regulation service matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal. In addition, PJM schedules operating reserves in the day-ahead market, and resources that provide this service are credited based on their offer prices. Reserve consists of 10-minute and 30-minute products.

Synchronized reserves are the equivalent of what is commonly referred to as spinning reserves, providing 10-minute reserves from a generator that is synchronized to the grid.

The DASR is the primary market mechanism for procuring the 30-minute reserves. A resource will only be assigned as amount of DASR corresponding to that amount of energy it could provide within 30 minutes of a request. If the DASR market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Futhermore, two ancillary services are provided on a cost basis: (1) blackstart service, which helps ensure the reliable restoration of the grid following a blackout; and (2) reactive power, which supports the voltages that must be controlled for system reliability, are provided at cost.

Capacity Markets

Capacity markets provide a means for load-serving entities (LSEs) to procure capacity needed to meet forecast load and to allow generators to recover a portion of their fixed costs. They also provide economic incentives to attract investment in new and existing supply-side and demand-side capacity resources in PJM as needed to maintain bulk power system reliability.

PJM's capacity market is called the reliability pricing model (RPM). The RPM market was implemented in 2007 and is designed to ensure the future availability of capacity resources, including demand-resources and energy-efficiency resources that will be needed to keep the regional power grid operating reliability. RPM market design is based on three-year, forward-looking annual obligations for locational capacity under which supply offers are cleared against a downward sloping demand curve, called the variable resource requirement (VRR) curve. The VRR curve establishes the amount of capacity that PJM requires its LSE customers to purchase, and the price for that capacity, in each capacity zone (locational delivery area). Under RPM, when a locational delivery area is transmission-constrained in the auction (i.e., limited in the amount of generation that can be imported into those areas), capacity prices generally rise in that area relative to the overall PJM footprint.

Annual auctions are referred to as base residual auctions (BRAs). LSEs that are able to fully supply their own capacity need can choose not to participate in the auctions. Most capacity is procured through self-supply and contracted (bilateral) resources and the auctions procure any remaining needed capacity. To mitigate the exercise of market power, the RPM market rules provide a test to determine whather each capacity seller has market power. If the seller fails that test, that seller's bid id capped so as to replicate that seller's avoidable or opportunity costs.

Market Power Mitigation

In electric power market, mainly because of the largely nonstorable nature of electricy and the existence of transmission constraints that can limit the availability of multiple suppliers to discipline markets, some sellers have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Market power may need to be mitigated on a systemwide basis or on a local basis where the exercise of market power may be a concern for a local area. For example, when a transmission constraint creates the potential for local market power, the RTO may apply a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

The structural test for implementing offer capping in PJM is called the three pivotal supplier test. Generation is subject to offer caps when transmission constraints occur such that generators are run out of merit order, which means that a higher-priced generator must be run due to a transmission constraint that prevents the use of available lower-priced generation. When units are dispatched out of merit, PJM imposes offer capping for any hour in which there are three or fewer generation suppliers available for redispatch that are jointly pivotal, meaning they have the ability to increase the market price above the competitive level.

Price Caps

PJM has a $1,000/MWh offer cap in the energy markets.

Financial Transmission Rights

Financial transmission rights (FTRs) give market participants an offset or hedge against transmission congestion costs in the day-ahead market. An FTR is a financial contract protecting the holder from costs arising from transmission congestion over a path or a source-and-sink pair of locations on the grid. An FTR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the specific FTR transmission path. FTRs were originally formulated to protect LSEs from price uncertainty while redistributing excess congestion charges due to constrained conditions. Other market participants such as financial-only participants may purchase FTRs through the RTO's auctions or through secondary market purchases.

A related product is an auction revenue right (ARR). ARRs provide the holders with an upfront portion of the money raised in the FTR auctions. In general, they are allocated based on historical load served and can be converted to FTRs. As with FTRs, ARRs, too, give transmission owners (and eligible transmission service customers) an offset or hedge against transmission congestion costs in the day-ahead market.

Virtual Transactions

A virtual transaction allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Cleared virtual supply (increment or virtual offers, or INCs) in the day-ahead energy market at a particular location in a certain hour creates a financial obligation for the participant to buy back the bid quantity in the real-time market at that location in that hour. Cleared virtual demand (decrement or virtual bids, or DECs) in the day-ahead market creates a financial obligation to sell the bid quantity in the real-time market. The financial outcome for a particular participant is determined by the difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears. Thus, through this financial arbitrage opportunity, virtual transactions in theory help to narrow the difference between the day-ahead and real-time prices.

Credit Requirements

Credit requirements balance the need for market liquidity against corresponding risk of default. Defaults within these markets are particularly troubling because losses due to default are borne by all market participants. PJM's tariff spells out the details for credit evaluations, credit limits, allowed forms of collateral and the consequences of violations or defaults.

To reduce financial risk, PJM's settlement cycle is seven days. The amount of unsecured credit allowed is $50 million for a member company and $150 million for an affiliated group. PJM does not allow unsecured credit in the FTR market.

Settlements

RTOs must invoice market participants for their involvement in their markets, including the amounts owed for buying and selling energy, capacity and ancillary services, and for paying administrative charges.

PJM has a two-settlement system, one each for the day-ahead and real-time energy markets.

SPP

Southwest Power Pool

Market Profile

Geographic Scope

The Southwest Power Pool Inc. (SPP) began operating in its real-time energy imbalance service (EIS) market on Feb. 1, 2007. Based in Little Rock, Ark., SPP manages transmission in nine states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma and Texas.

In addition to operating its EIS market and managing open-access transmission facilities, SPP is the reliability coordinator for the NERC regional entity. As such, SPP enforces NERC-approved reliability standards for users, owners and operators of the bulk power system; coordinates reliability within and with neighboring areas; and ensures adequate reserves are procured within the SPP region. The reliability area is larger than the market area.

SPP's EIS market footprint includes 16 balancing authorities. Its members include investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers and independent transmission companies.

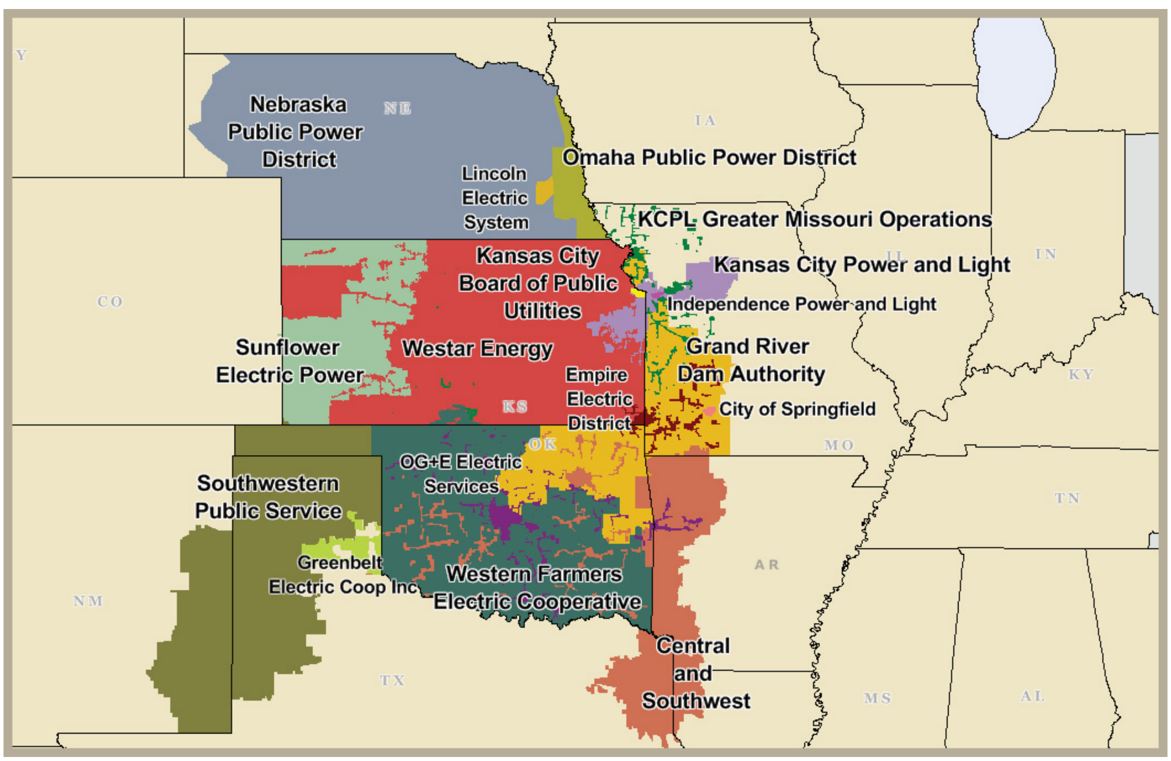
Demand

SPP's record peak demand of 48 GW occurred in August 2011.

Import and Exports

SPP has alternate-current (AC) interties with the Midwest

Southwest Power Pool (SPP)



ISO, PJM Interconnection, Tennessee Valley Authority and Entergy Inc., among other systems. Additionally, SPP has two direct-current (DC) interties with ERCOT and seven DC interties to the western interconnect through New Mexico, Kansas and Nebraska. At times, SPP is a net importer of electricity and, at other times, SPP is a net exporter of electricity.

Market Participants

SPP's market participants include cooperatives, independent power producers, investor-owned utilities, power marketers, municipals, state agencies and transmission owners. SPP considers a participant in the EIS market to be an entity that has a legal and financial obligation to SPP in the market. Market participants must have generation assets to participate in the EIS market, or must directly represent an asset owner. Asset owners include generation companies and load-serving entities.

Membership and Governance

SPP is governed by a seven-member board of directors, with six elected by the members to serve three-year terms, plus the SPP president, who is elected by the board.

Supporting the board is the members committee, which provides input to the board through straw votes on all actions pending before the board. The members committee is composed of up to 15 people, including four representatives from investor-owned utilities; four representatives of cooperatives; two representing municipal members; three representing independent power producers and marketers; and two representing state and federal power agencies. The board is required to consider the members committee's straw vote as an indication of the level of consensus among members in advance of taking any actions.

Transmission

Owners

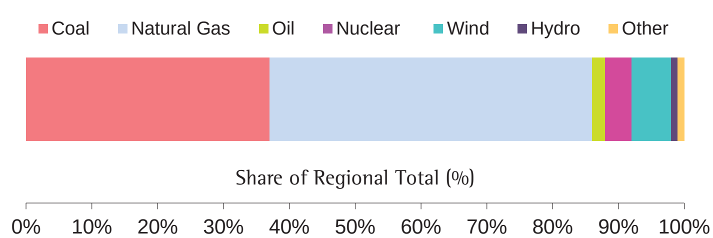
SPP transmission owners (TOs) are investor-owned utilities, municipals, cooperatives, state agencies and independent transmission companies. Some of the larger balancing authorities by installed capacity include:

- Southwestern Electric Power Co. (AEP West)
- OG&E Electric Services
- Westar Energy Inc.
- Southwestern Public Service Co. (Xcel Energy)
- Kansas City Power & Light Co. (Great Plains Energy)
- Omaha Public Power District
- Nebraska Public Power District
- KCP&L Greater Missouri Operations (Great Plains Energy)
- Empire District Electric Co.
- Western Farmers Electric Cooperative

Supply Resources

Generating Mix

By plant capacity, the generating mix includes these sources:



Market Features and Functions

Energy Markets

Day-Ahead

Not applicable.

Hour-Ahead

Not applicable.

Real-Time

SPP must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity.

SPP's EIS market provides market participants the opportunity to buy and sell wholesale electricity in real time. If a utility requires more energy than it scheduled, the market provides the utility another option to buy the additional energy at real-time prices to make up the difference and meet its demand. Thus, participants use the EIS market to obtain energy available and offered from other utilities. Entities wishing to provide energy will submit offers to the market.

SPP uses a security constrained economic dispatch (SCED) to determine the lowest cost increment of energy that can be delivered to each location, considering the submitted offers, transmission limitations and system topology. EIS market dispatch instructions are calculated for dispatchable resources, and locational imbalance prices (LIPs) are calculated for each settlement location (generation resource or load) on the system.

Resources are settled based on the LIP associated with their settlement location. Resources are only settled nodally. Load may choose to be settled either zonally or nodally. The LIPs are based on the resource offers and are locational.

Must-Offer Requirements

Not applicable.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system.

SPP does not offer an ancillary service market. However, it does require each transmission owner to provide or arrange for all of these services.

Capacity Markets

SPP does not offer a capacity market. However, it requires each market participant to have sufficient energy supply (capacity) to cover its energy obligations. SPP performs a supply adequacy analysis for each market participant based on a load forecast, resource plan, ancillary service plan and schedules received from market participants. This analysis is performed for each hour of the next operating day, with results available by 3 p.m. of the day prior to the operating day.

Market Power Mitigation

In electric power markets, mainly because of the largely nonstorable nature of electricity and the existence of transmission constraints that limit the availability of multiple suppliers to discipline market prices, some sellers have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Market power may need to be mitigated systemwide basis or locally.

Price Caps

Offers by market participants may not exceed $1,000/MW-hour. This limit remains in effect until such time as SPP demonstrates in a filing with the Commission that sufficient demand response exists in the EIS market to allow a higher offer curve price limit or removal of the safety-net price limit.

Local Market Power Mitigation

When any transmission constraint is binding in the EIS market, SPP will screen the offer curve associated with resources on the importing side of each constraint. If the resource's offer is greater than the offer cap, then SPP will substitute the resource's offer with its offer cap.

Additionally, there is no mitigation for physical withholding in the EIS market, as the market is voluntary. The market monitor monitors determines whether the decisions to participate in the EIS market have a significant adverse impact on market outcomes.

FTRs

Not applicable.

Virtual Transactions

Not applicable.

Credit Requirements

RTOs must balance the need for market liquidity against corresponding risk of default. Defaults within these markets are troubling because losses due to default are borne by all market participants. SPP's tariff specifies credit rules needed to participate in the markets. These requirements provide for credit evaluations, credit limits, allowed forms of collateral and the consequences of violations or defaults.

Settlements

RTOs must invoice market participants for their involvement in their markets. Settlement is the process by which the RTO determines the amounts owed associated with buying and selling energy, capacity and ancillary services, and paying administrative charges.

The SPP settlement process calculates the quantity of energy imbalance for each asset (generation resource or load), calculates invoice dollars for energy imbalances and allocates over-and under-collection of revenues to asset owners. Settlement statements are published for each operating day. The market is facilitated so that SPP remains revenue neutral.