

ENERGY PRIMER

A Handbook of Energy Market Basics

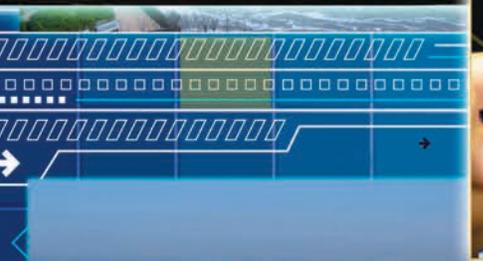
Electric Power



Natural Gas



Transmission



Market Trading



LNG



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November 2015



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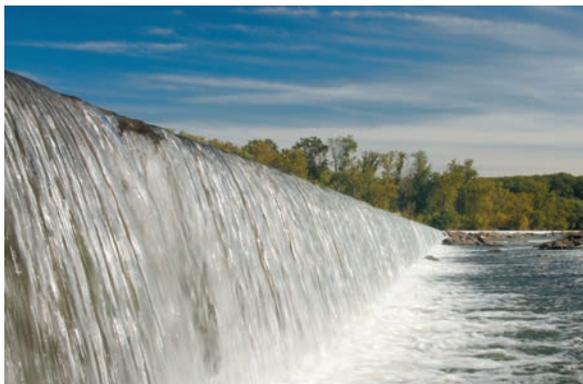
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1. INTRODUCTION

Natural gas, electricity, and oil are forms of energy that are of particular interest to the Federal Energy Regulatory Commission pursuant to its authority under the Natural Gas Act, the Federal Power Act, and the Interstate Commerce Act. This primer explores the workings of the wholesale markets for these forms of energy, as well as energy-related financial markets.

Natural gas is the second largest primary source of energy consumed in the United States, exceeded only by petroleum. A primary energy source is an energy source that can be consumed directly or converted into something else, like electricity. Roughly a third of the natural gas consumed in the United States goes into power plants for the production of electricity.

Electricity, a secondary energy source, results from the conversion of primary fuels such as fossil fuels, uranium, wind, or solar into a flow of electrons used to power modern life.

Crude oil and petroleum products are of interest to the Commission because it regulates the transport of oil by pipelines in interstate commerce.

Energy markets involve both physical and financial elements. The physical markets contain the natural resources, infrastructure, institutions and market participants involved in producing energy and delivering it to consumers. They also include the trading of and payment for the physical commodity - e.g., natural gas. The financial markets include the buying and sell-

ing of financial products derived from the physical energy. These financial markets also include market structures and institutions, market participants, products and trading, and have their own drivers of supply and demand. In general, physical and financial markets can be distinguished by the products and by the intentions of the market participants involved. Physical products are those whose contracts involve the physical delivery of the energy. Physical market participants are those who are in the market to make or take delivery of the commodity. Financial products usually do not involve the delivery of natural gas, electricity, or oil; instead, they involve the exchange of money.

Physical markets can be further differentiated by:

- Location: regions, nodes, zones or hubs
- Time frames: hourly, daily, monthly, quarterly or yearly
- Types of products: natural gas molecules or electrons, pipeline or transmission capacity and storage
- Nature of sales: retail sales involve most sales to end use customers; wholesale sales involve everything else

Physical Fundamentals

Much of the wholesale natural gas and electric power industry in the United States trades competitively; some markets are established through administrative processes based on the cost of providing service. In competitive markets, prices are largely driven by the economic concepts of supply and demand. Underlying the supply and demand for energy are physical fundamentals - the physical realities of how markets produce and deliver energy to consumers and how they form prices. These physical fundamentals will be covered in Chapter 2 (Wholesale Natural Gas Markets), Chapter 3 (Wholesale Electricity Markets), and Chapter 4 (U.S. Crude Oil and Petroleum Products Markets).

Wholesale natural gas and electricity markets differ from other competitive markets, however, in critical ways. While this primer focuses on wholesale markets, demand is ultimately determined at the retail level. Retail use is relatively inelastic in the short-term, although this may be less so with some larger customers. Retail use of natural gas or electricity exhibits some unique characteristics:

Limited customer storage options: Retail consumers have few options for storing natural gas and electricity. For natural gas, large consumers and entities that sell to retail consumers may be able to store gas, but smaller consumers do not have this option. For electricity, smaller consumers may have batteries, but nothing adequate to ensure refrigeration, for example. Without storage, consumers cannot buy when prices are low and use their stored product when prices rise. This limits consumers' response to changes in prices.

Substitutes: Retail consumers have few substitutes for natural gas or electricity, certainly in the short-term. If natural gas or electricity prices go up, consumers cannot quickly switch to a different product. Longer term, they may be able to switch to gas from electricity for heating, or they may be able to insulate or install new windows or take other steps to reduce their consumption of energy. In addition, demand-response programs can provide benefits to those who would reduce

their energy needs at certain times; this might include turning off air conditioning during the hottest part of a day in order to help reduce electric load.

Necessity: Unlike most other products, natural gas and electric service are necessities today, and a lack of service can mean customers without heat, the ability to cook or refrigerate food or the ability to run their businesses. Blackouts and other service disruptions create operating problems and hazards as well. Consumers cannot postpone the purchase of electricity or natural gas. They may be able to turn down their thermostats, but cannot eliminate consumption altogether for an extended period of time.

Because consumers have limited ability to reduce demand, supply must match demand instantaneously, in all locations.

For natural gas, this means production, pipelines and storage need to be sized to meet the greatest potential demand, and deliveries need to move up and down to match changes in consumption. Natural gas has underground and above-ground storage options and linepack, which involves raising the pressure in a pipeline to pack more molecules into the same space. Natural gas flows through a pipeline at velocities averaging 25 mph, depending on the pipeline and the configuration of related facilities, so new supply can take hours or days to reach its destination. That increases the value of market-area storage, which vastly reduces the distance and time needed for gas to reach consumers.

For electricity, storage is more limited, although technologies such as batteries and flywheels are being developed. Hydroelectric pumped storage is available in a few locations; this involves pumping water to high reservoirs during times of slack electricity demand, then letting the water flow downhill through electricity-generating turbines when demand for power rises. Generating plants, transmission and distribution lines, substations and other equipment must be sized to meet the maximum amount needed by consumers at any time, in all locations. For all practical purposes, electricity use is contemporaneous with electricity generation; the power to run a light bulb is produced at the moment of illumination.



Financial Markets and Trading

The energy industries are capital intensive, requiring access to financial markets to support daily operations, trading and investment programs. Access to financial markets requires maintaining an investment grade credit rating to support activities ranging from daily transactions to long-term development of infrastructure.

Financial markets are where companies and individuals go if they need to raise or invest money. They are important to energy markets in two key ways. First, they provide access to the capital needed for operations. Second, some natural gas- or electricity-related products may trade in commodity markets or, as derivative products (see below), in financial markets.

Natural gas and electricity are traded like commodities, just like metals, corn, wheat or oil. They may not be visible, but you can turn them on and off, and measure them. Commodity

markets began as ways for farmers to sell their products, or even a portion of their production before it was harvested, providing them with capital to continue operations.

Commodity markets evolved to provide other tools for farmers (and other commodity producers) to manage their risk, notably the risk of adverse changes in price. These financial products were derived from the physical products and are known as derivatives. Since their inception, trading in physical commodities and derivatives has attracted others to the market, such as speculators hoping to make a profit from changes in price.

The market for natural gas and electricity derivatives has grown enormously within the past decade, as competitive natural gas and electricity markets matured and investors came to see energy commodities as investments. This trading affects the physical markets in a number of ways, and is discussed in Chapter 5, Financial Markets and Trading.

Market Manipulation

Where there are markets, there will be those who attempt to manipulate the markets for their own benefit. These practices undermine the market's ability to operate efficiently, reduce other market participants' confidence in the markets and distort market outcomes, including prices. Some of these practices are discussed in Chapter 6, Market Manipulation.



Additional Information

This primer is written to be used either as a traditional text – read front to back – or as a reference guide. Consequently, some material is repeated in different sections and references are provided to other parts of the primer where a concept is addressed in greater detail.

Further information about various aspects of energy markets and FERC regulation can be found at www.ferc.gov; then click on Market Oversight. If you are reading this Energy Primer electronically, you can find the market oversight pages here: <http://www.ferc.gov/market-oversight/market-oversight.asp>

Google search also provides a quick path to information on specific FERC orders or to more general subjects (e.g., FERC regulation of natural gas pipelines).

2. WHOLESALE NATURAL GAS MARKETS

Natural gas markets have a significant effect on the economy and on the individuals who rely on the fuel for electric generation, manufacturing, heating, cooking and other purposes. The Department of Energy's Energy Information Administration (EIA) estimates that natural gas supplies 27 percent of the energy used in the United States, or about 26.1 trillion cubic feet (Tcf) of gas a year.

Under the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) has jurisdiction over the transportation and sale of natural gas and the companies engaged in those activities.

The natural gas market is an amalgamation of a number of subsidiary markets. There is a physical market, in which natural gas is produced, transported, stored and consumed. There is also a financial market in which physical natural gas is bought and sold as a financial product derived from physical natural gas. Natural gas markets are also regional, with prices for natural gas varying with the demand characteristics of the market, the region's access to different supply basins, pipelines and storage facilities.

Natural Gas

Natural gas is primarily methane, which is made of one carbon atom and four hydrogen atoms (CH₄), and is among the materials known as hydrocarbons. Natural gas is colorless and odorless in its natural condition. It is also highly combustible, giving off a great deal of energy and fewer emissions than fuels such as coal and oil. Natural gas occurs in geological formations in different ways: as a gas phase associated with crude oil, dissolved in the crude oil, or as a gas phase not associated with any significant crude oil. Natural gas is rich or wet if it contains significant natural gas liquids (NGL) – e.g., ethane, propane and pentane – mixed in with the methane. In contrast, natural gas is lean or dry if it does not contain these liquids. Processors remove water, liquefiable hydrocarbons and other impurities from the natural gas stream to make the natural gas suitable for sale. Natural gas liquids may be processed out and sold separately.

While natural gas is typically a gas, it can be cooled to a liquid and transported in trucks or ships. In this form, it is referred to as liquefied natural gas, or LNG.



Natural Gas Industry

As noted, the markets of the natural gas industry are both physical and financial. This chapter focuses on the physical natural gas markets, but it should be noted that financial markets can have significant impacts on the physical natural gas market.

For this discussion, the natural gas industry has three segments. The first is the supply segment, which includes exploration and development of natural gas resources and reserves, and production, which includes drilling, extraction and gas gathering. The second segment is the midstream sector, in which small-diameter gathering pipeline systems transport

the gas from the wellhead to natural gas processing facilities, where impurities and other hydrocarbons are removed from the gas to create pipeline-quality dry natural gas. The third segment is transportation, which includes intrastate and interstate pipeline systems that move natural gas through large-diameter pipelines to storage facilities and a variety of consumers, including power plants, industrial facilities and local distribution companies (LDCs), which deliver the natural gas to retail consumers.



Each component of the supply chain is critical in serving customers. The quantity of reserves and production can affect market participants' expectations about current and future supply, and thus can affect prices. Similarly, the availability of pipeline and storage capacity determines which supply basins are used and the amount of gas that can be transported from producers to consumers. All of these factors affect the supply chain, but they also affect the supply-demand balance, both nationally and regionally.

A natural gas hub can occur at the interconnection of two or more pipelines where natural gas is bought and sold. The benchmark hub used to reflect the U.S. natural gas market as a whole is the Henry Hub in Louisiana. Prices at other locations are frequently shown not as the actual price, but as the differential, or basis, to Henry Hub.

Regional differences in supply and demand result in different

prices for natural gas at various locations. Prices tend to be lowest in areas with low-cost production, ample infrastructure and limited demand – the Opal Hub in Wyoming, for example – and highest where production or transportation is limited and demand is high – Algonquin Citygate, in Massachusetts, for example. Transportation cost from supply to demand areas is also a factor in the regional price differentials.

The natural gas industry in the United States is undergoing a period of transition. Within the last decade, various factors have shifted the dynamics of supply and demand. These include, but are not limited to, the following:

1. Development of technology, like hydraulic fracturing and horizontal drilling, enables producers to access unconventional resources such as those in shale formations. This has vastly expanded supply and is increasing the amount of natural gas produced, which has reached levels not seen in 40 years. It also has moderated prices across the country. Notably, some of these resources are located close to eastern population centers, providing access to low-cost gas supplies with lower transportation costs.
2. Natural gas has become an investment opportunity as it is a traded commodity. As noted above, there are physical and financial investment markets. There are two distinct markets for physical natural gas: (1) a cash market, which is a daily market where natural gas is bought and sold for immediate delivery; and (2) a forward market, where natural gas is bought and sold under contract for one month or more in the future. The financial natural gas prices are often derived from the physical natural gas prices.
3. Natural gas demand for power generation is rising and is expected to increase significantly in the coming years. Power plant demand for natural gas reflects the environmental benefits of the fuel, the operating flexibility of natural gas-fired generators, and lower natural gas prices. Natural gas-fired power plants emit less air pollution than generators using coal or oil. These plants are also relatively easier to site, can be built in a range of sizes and

can increase or decrease output more flexibly than large baseload generators, such as nuclear or coal. This ability to change output quickly aids electric system operators in matching generation to customer loads, and enables operators to offset rapid changes in output from wind and other intermittent generators.

4. Pipeline expansions linking the new supply regions to markets are changing the relationships between prices in various regions. New interstate pipelines have enabled regions such as the Northeast and Mid-Atlantic to access new supply sources, expanded the amount of natural gas that can flow from traditional supply sources, and enhanced the amount that can flow overall. This has reduced prices and tempered extreme price movements during periods of peak demand.

Natural Gas Demand

Natural gas is already the fuel of choice for many sectors of the U.S. economy and, in 2014 it met about 27 percent of U.S. primary energy needs. Natural gas demand, however, can fluctuate substantially.

Over the long term, natural gas use is driven by overall economic and population growth, environmental policy, energy efficiency, technological changes and prices for natural gas and substitute energy sources such as oil, coal and electricity. In the short-term, demand stems from weather, economic activity, and competition from other fuel sources such as coal and oil.

Weather

Weather is the most significant factor affecting seasonal natural gas demand. Natural gas demand can also swing considerably within a given day, especially during periods of extreme temperatures. Short-term changes in weather, such as heat waves and winter storms, can send demand and prices soar-

ing – or dropping – within the course of a day, sometimes unexpectedly. This unpredictability challenges suppliers and pipelines, especially when pipelines are full.

Economic Activity and Growth

Economic growth can increase the amount of natural gas used by industry, power plants and commercial entities as consumers want more of their products and services. During a recession, gas use usually declines. On the other hand, economic growth may raise personal incomes and consumption of electric-powered consumer goods.

Structural changes in the economy can also affect natural gas demand. Declining manufacturing and growing service sectors result in changes in natural gas use, as does increased global competition. New markets for products and services may require additional natural gas; movement of manufacturing overseas may reduce it.

Daily and weekly economic activity creates cyclical demand patterns. During the work day, demand rises as people get up and go to work or school. Similarly, it declines as they go to sleep. On the weekend, demand tends to vary less over the course of the day.

Prices of Natural Gas and Coal

Just as a home-owner may decide to invest in a furnace and associated piping to use natural gas for heat, so, too, a power producer may decide to make long-term investments in natural gas-fired generators. These decisions requiring long-term capital investments are cheapest and easiest to make at the time a home or power plant is built, and are more complicated to change later. Thus, over the long term, demand for natural gas can be affected by the expected costs of alternative energy sources: the cost of a natural gas furnace versus an electric one; the cost of a coal-fired generating plant versus one fueled by natural gas.

In the short-term, the opportunity for fuel switching has been

significant in power generation. Electric grid operators have a choice as to which power plant to dispatch to meet increased electric demand. Dispatch is often based on the marginal cost of generation at each available plant in the generation fleet. Plants with lower marginal costs, such as nuclear, typically dispatch before plants with higher marginal costs, such as natural gas. As natural gas prices drop relative to coal prices, natural gas-fired generation can get dispatched sooner than coal-fired generation, increasing natural gas demand from the power sector.

Demographics and Social Trends

Long-term demand can also be affected by shifting demographics and social trends. Population growth in warmer climates and declines in the older industrial areas of the North have affected natural gas use. So has the trend toward larger houses.



Today, most households have a proliferation of appliances and devices that consume electricity, and continue to add more as they become more energy efficient. As the trend in generation of electricity is for a greater share to be fueled by natural gas, natural gas demand can increase from rises in electricity demand.

Environmental Concerns and Energy Efficiency

Natural gas has relatively fewer environmental problems compared with other fossil fuels, and, consequently, it is increasingly used for power generation. In addition to helping urban areas meet air quality goals, natural gas generation has not experienced as much negative public sentiment as have nuclear and coal-fired generators, making it feasible to site gas-fired generators closer to load centers. Growth in wind and other intermittent generation technologies benefit when coupled with natural gas generation, which is able to ramp up and down quickly to complement variable output.

The natural gas emissions profile has also encouraged some urban mass transit bus systems, West Coast port operations and other vehicle fleets to shift to natural gas from gasoline or diesel fuel.

Customer Sectors and Demand

In 2007, natural gas used for electric generation overtook gas-for-industrial load to become the largest customer class for natural gas. In 2014, according to the EIA, power generation used 8.2 Tcf of the 24.6 Tcf of natural gas delivered to consumers. Industrial, residential, and commercial consumers used 7.8 Tcf, 5.1 Tcf, and 3.5 Tcf, respectively.

Each customer sector contributes differently to overall demand, both in terms of the amount that demand varies over a cycle and whether its peak demand coincides with the overall system peak. Residential demand, for example, can be highly variable in colder climates, and its peak coincides with the overall system peak. Power generation's peak does not coincide with the winter gas-demand peak, but in fact its growing use of natural gas to produce electricity for air conditioning has created robust summer demand, which competes with gas supply that traditionally would flow into underground storage for later use in the winter. Industrial demand stays relatively constant year-round.

In the short term, residential and commercial natural gas use tends to be inelastic – consumers use what they need regardless of the price. Power plant demand, on the other hand, is more price-responsive as natural gas competes with other fuels, especially coal, in the production of electricity. Price inelasticity implies that a potential for price spikes exists during periods of supply constraint.



Consequently, the mix of customers in a region can affect system operations and costs. Pipelines and other equipment need to be sized to account for peak demand. Demand that stays fairly constant presents fewer operational challenges and usually enjoys lower prices. Highly variable demand will result in pipelines and equipment being used at less than full capacity for much of the year, and prices for service may be more expensive, both because the pipelines may become

constrained during peak times and because the capacity is not fully used throughout the year.

Power Generation

Generation demand can soar at any time; gas-fired generators can change their output quickly, and are frequently called on to change their output due to changes in demand or when problems occur elsewhere in the power grid. Generating plants tend to consume more natural gas in the summer to meet air conditioning loads, but power demand can also climb in the winter to provide electric heating and lighting. Generation demand can also be influenced by the relative prices for natural gas and other fuels, especially coal. Since late 2008, natural gas-fired generators generally have been dispatched before some coal plants because of the decrease in natural gas prices.

Industrial

Natural gas as a fuel is used to produce items such as steel, glass, paper, clothing and brick. It also is an essential raw material for paints, fertilizer, plastics, antifreeze, dyes, photographic film, medicines and explosives. Industrial load tends to show the least seasonal variation of natural gas use, but industry is sensitive to economic pressures.

Residential

Despite population growth, natural gas used in the residential sector for home furnaces, water heaters, clothes dryers and stoves has remained fairly flat over the past decade as appliances and homes have become more energy efficient. Much of the year-to-year demand variation in this sector can be attributed to the weather during a particular year. A year with a long, cold winter will see higher gas demand than a year with a mild winter, especially in cold-winter regions where demand soars during winter months as consumers turn on their furnaces. Slightly more than half of the homes in the United States use natural gas as their main heating fuel.

Commercial

Like the residential sector, commercial consumption experiences year-to-year variation based on weather. Commercial consumers include hotels, restaurants, wholesale and retail stores and government agencies, which use natural gas primarily for heat. Consequently, its demand varies over the seasons, weeks and days.

Natural Gas Supply

Natural Gas Resources, Reserves and Production

The amount of natural gas in the ground is estimated by a variety of techniques, taking into account the technology available to extract the gas. Estimating the technically recoverable oil and natural gas resource base in the United States is an evolving process. Analysts use different methods and systems to make natural gas estimates. Natural gas supplies are characterized as resources, proved reserves and production (See Quick Facts box).

Quick Facts: Resources and Proved Reserves

- **Resources** - Total natural gas estimated to exist in a particular geological area. The estimated size of resources is different from the amount of natural gas that can or will be produced from that area.
- **Proved reserves** - Estimated amount of natural gas that, based on analysis of geologic and engineering data gathered through drilling and testing, can be reasonably projected to be recoverable under existing economic and operating conditions. Since economic and operating conditions change constantly, the estimates for proven reserves also changes often.



Resources is the largest category, which describes the total potential of natural gas supply. Proved reserves consider the feasibility and economics of extracting the natural gas. Lastly, production describes the amount of natural gas removed from the ground.

Natural gas is located underneath the surface of the earth. Natural gas is characterized by the type of basin or rock formation in which it lies. Conventional natural gas is found in porous rock formations, and in the United States is the traditional source of natural gas.

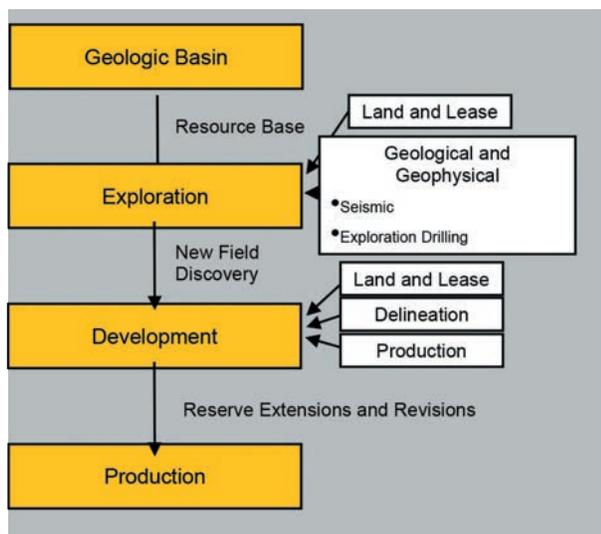
Unconventional natural gas, on the other hand, is found in shale, coal seams and tight, low-permeability rock formations. In 2007, the National Petroleum Council (NPC) defined unconventional gas as “natural gas that cannot be produced at economic flow rates or in economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore or by using multilateral wellbores or some other technique to expose more of the reservoir to the wellbore.”

In the past few years, improvements in drilling technology have enabled producers to access unconventional supplies, notably shale, yielding significant increases in production and raising the estimate of proved reserves. Estimates of re-

sources in 2014 amounted to approximately 2,853 Tcf (which included reserves).

This domestic growth in resources and reserves has translated into greater natural gas production, which has grown more than 35 percent since 2005, to more than 70 billion cubic feet per day (Bcfd) in 2014. Most of the growth came from shale gas, which now accounts for 50 percent of natural gas resources.

Gas Exploration and Development Process



Source: FERC staff

Worldwide, the United States accounts for one-tenth of global natural gas technically recoverable resources. Most of the natural gas resources are in the Middle East – Iran, Qatar and Saudi Arabia – followed by the United States and Russia.

Rig Count and Rig Productivity

A measure of exploration, the rig count measures the number of rotary drilling rigs actually drilling for oil and gas. These measures are compiled by several companies active in drilling operations. Historically, rig counts were used as a rough predictor of future production. However, improvements in drilling technology and practices have caused a decoupling

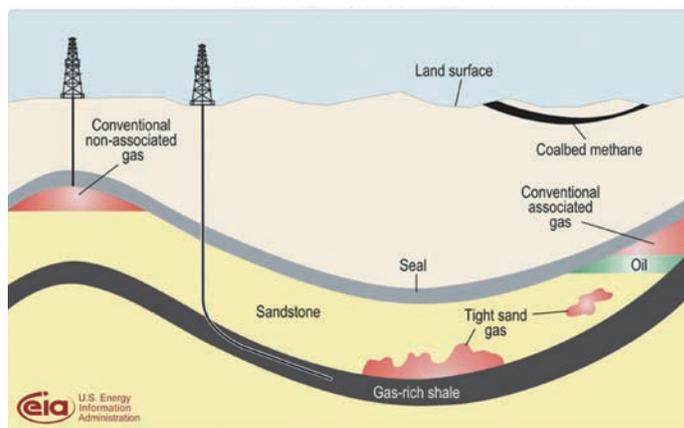
between rig count and production. The oil and gas rig count peaked at 4,530 on Dec. 28, 1981. Since then, rig count has decreased by over 80 percent while rig productivity has increased substantially, according to Baker Hughes Inc. Within the total rig count, the use of horizontal drilling rigs, used in the production of natural gas and oil in shale formations, has been growing for years, while the traditional vertical rig count has steadily declined.

The adoption of horizontal drilling has significantly increased production per rig, making comparison of rig counts over time problematic because horizontal rigs are considerably more productive than vertical rigs.

Conventional and Unconventional Natural Gas

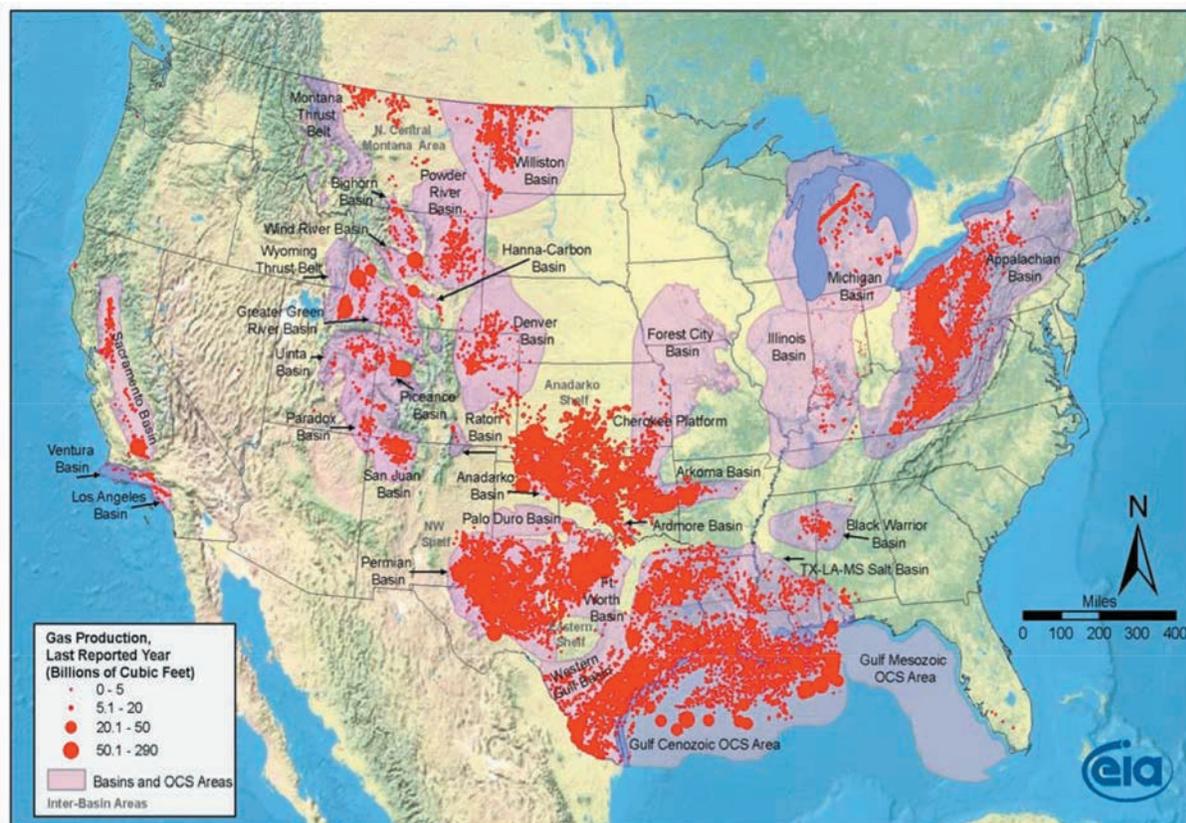
Natural gas is a fossil fuel. Natural gas historically has been found in underground reservoirs made when organic material was buried and pressurized. The remains of that organic material were trapped in the surrounding rock as oil or natural gas. Natural gas and oil are often found together. The depth of the organic materials and the temperatures at which they are buried often determine whether the organic matter turns into oil or natural gas. Generally, oil is found at depths of 3,000 to 9,000 feet; organic materials at greater depths and higher temperatures result in natural gas.

Schematic Geology of Natural Gas Resources



Source: EIA

Gas Production in Conventional Fields, Lower 48 States



Source: EIA

Natural gas basins are frequently referred to as conventional or unconventional basins or plays. These basins differ in the geology of the basin and the depth at which gas can be found. The schematic illustrates differing geologic formations in which natural gas can be found.

Conventional Natural Gas

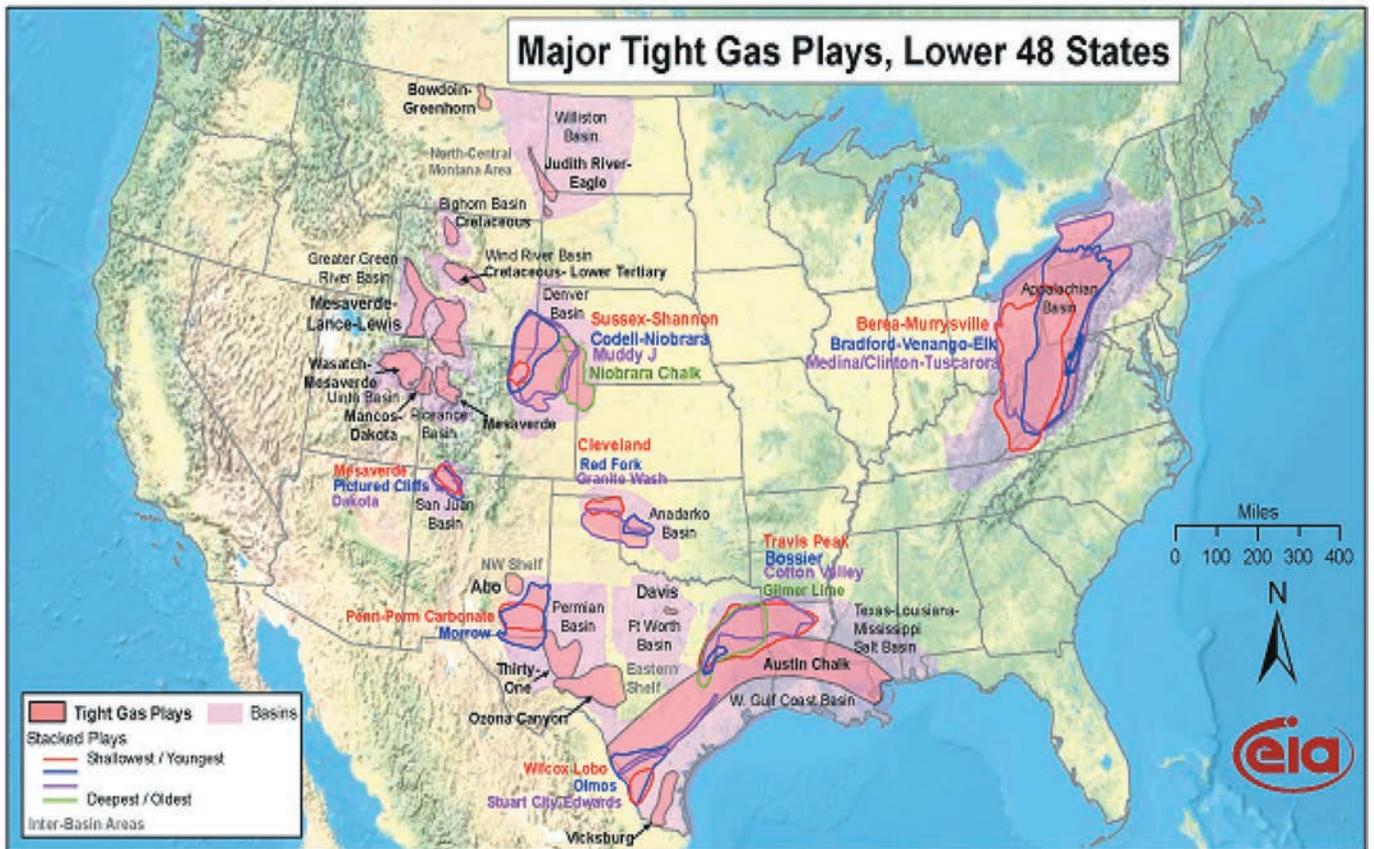
Natural gas historically has been produced from what is traditionally known as conventional natural gas resources, which provided most of the country's supply needs for more than a century. Conventional gas is found in geological basins or reservoirs made of porous and permeable rocks, holding significant amounts of natural gas in the spaces in the rocks.

Conventional resources have been found both on land and offshore (see map), with the major fields in an arc from the Rocky

Mountains to the Gulf of Mexico to Appalachia. The largest conventional fields reside in Texas, Wyoming, Oklahoma, New Mexico and the federal offshore area of the Gulf of Mexico. In 2000, offshore natural gas production represented 24 percent of total U.S. production; by 2013 that amount had fallen to less than 5 percent.

Federal offshore natural gas wells are drilled in the ocean floor off the coast of the United States in waters that are jurisdictional to the federal government. Most states have jurisdiction over natural resources within three nautical miles of their coastlines; Florida and Texas claim nine nautical miles of jurisdiction.

Roughly 4,000 oil and gas platforms are producing in federal waters at water depths approaching 7,500 feet (at total well depths of 25,000-30,000 feet) and at distances as far as 200



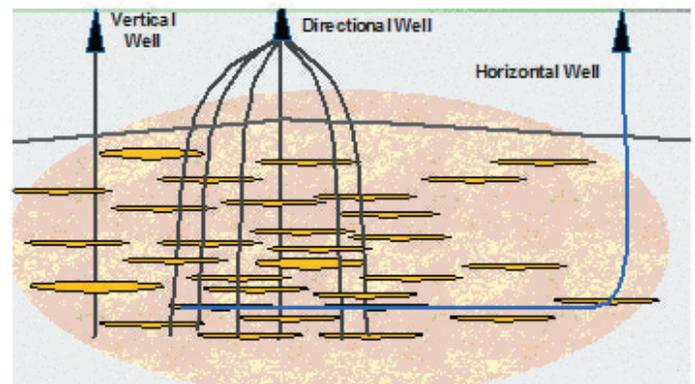
Source: EIA

miles from shore, the EIA reports. Most of these offshore wells are in the Gulf of Mexico.

Offshore production has been going on for decades. As close-in, shallow-water wells became less economic to produce, companies looked to reserves at greater water depth. Technological improvements contributed to continuing production from deep offshore wells.

Unconventional Natural Gas

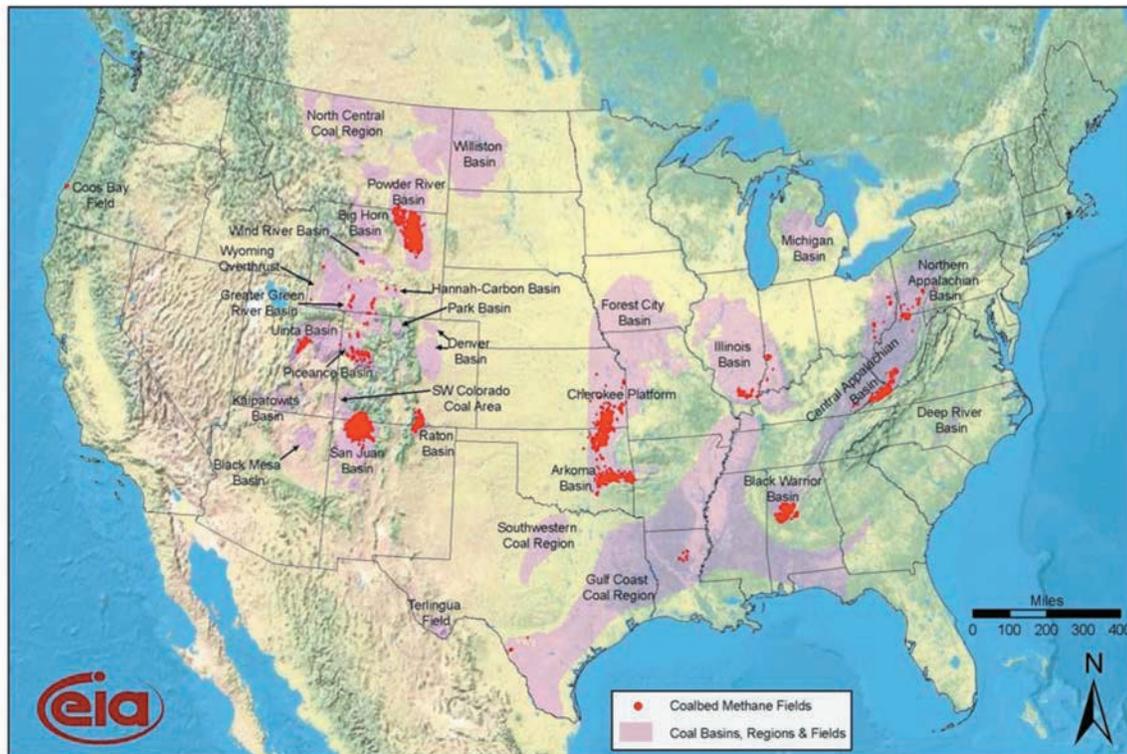
In recent years, innovations in exploration and drilling technology have led to rapid growth in the production of unconventional natural gas. This term refers to three major types of formations where gas is not found in distinct basins, but is trapped in shale, tight sands or coal seam formations over large areas.



Source: EIA

The presence of natural gas in these unconventional plays has been common knowledge for decades, but it was not until the early 1990s, when after years of experimenting in the Barnett

Coalbed Methane Fields, Lower 48 States



Source: EIA

Shale in Texas, George Mitchell and Mitchell Energy Co. developed a new drilling technique that made production in these types of formations economically feasible. The new technology included horizontal and directional wells, which allow a producer to penetrate diverse targets and increase the productivity of a well. Directional wells allow the producer to tap these resources through multiple bores. The horizontal wells have a vertical bore, but then move horizontally through the rock to access more supply. These new drilling technologies greatly improved the likelihood of a successful well and the productivity of that well.

As of 2014, production from unconventional reserves supplied nearly two-thirds of U.S. gas needs.

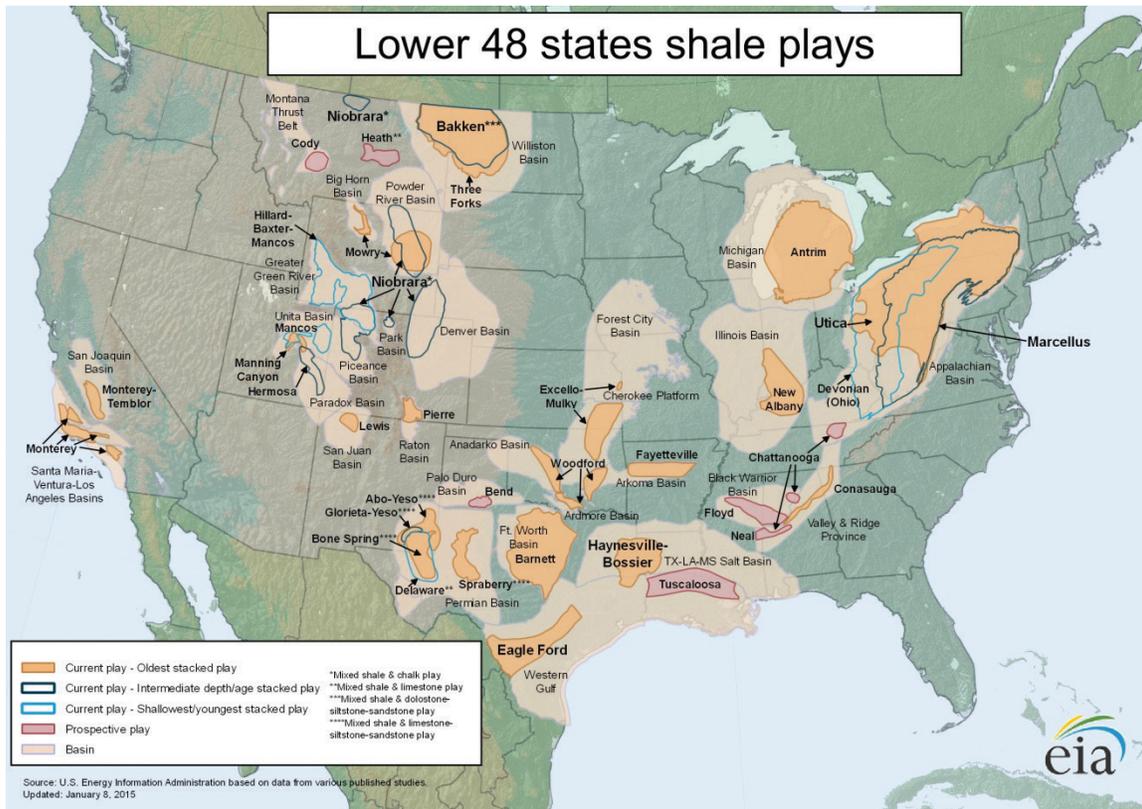
Tight sands gas is natural gas contained in sandstone, siltstone and carbonate reservoirs of such low permeability that it will not naturally flow when a well is drilled. To extract tight sands gas, the rock has to be fractured to stimulate production.

There are about 20 tight sands basins in the United States (see map); as of 2012, annual production was about 5 Tcf, or about one-fifth of U.S. domestic production.

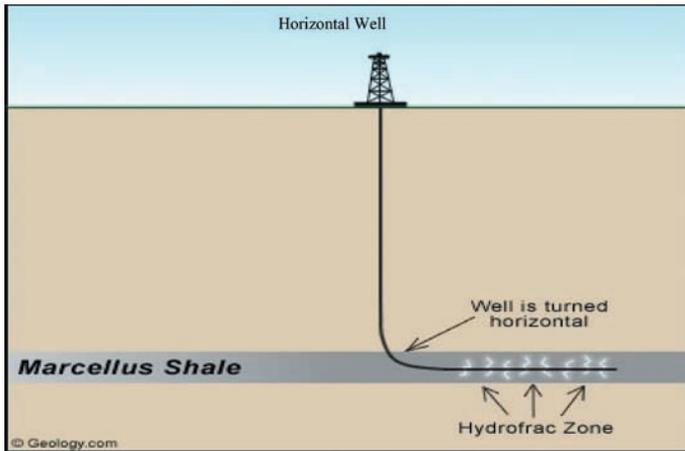
Coalbed methane (CBM) is natural gas trapped in coal seams. Fractures, or cleats, that permeate coalbeds are usually filled with water; the deeper the coalbed, the less water is present. To release the gas from the coal, pressure in the fractures is created by removing water from the coalbed.

The coalbed methane resource of the United States is estimated to be more than 700 Tcf, but less than 100 Tcf of that may be economically recoverable, according to the U.S. Geological Survey. Most CBM production in the United States is concentrated in the Rocky Mountain area, although there is significant activity in the Midcontinent and the Appalachian area.

Shale gas is found in fine-grained sedimentary rock with low permeability and porosity, including mudstone, clay stone and



Source: EIA



Source: Geology.com

what is commonly known as shale. These rock conditions require a special technique known as hydraulic fracturing (fracking) to release the natural gas. This technique involves fracturing the rock in the horizontal shaft using a series of radial explosions and water pressure (see graphic).

In the past decade the processes for finding geological formations rich in shale gas, or shale plays, have improved to the point that new wells almost always result in natural gas production. Improved exploration techniques coupled with improved drilling and production methods have lowered the cost of finding and producing shale gas, and have resulted in a significant increase in production. In 2014, shale gas accounted for about 45 percent of total gas production, with expectations of significant increases in the future.

As of 2014, the six major shale plays in the United States are Barnett, Fayetteville, Woodford, Haynesville, Eagle Ford, and Marcellus (see map on next page). Other shale formations are seeing heavy exploration activity and are expected to become major contributors of natural gas supply in the near future. The shale plays are widely distributed through the country, which has the added advantage of putting production closer to demand centers, thus reducing transportation bottlenecks

and costs.

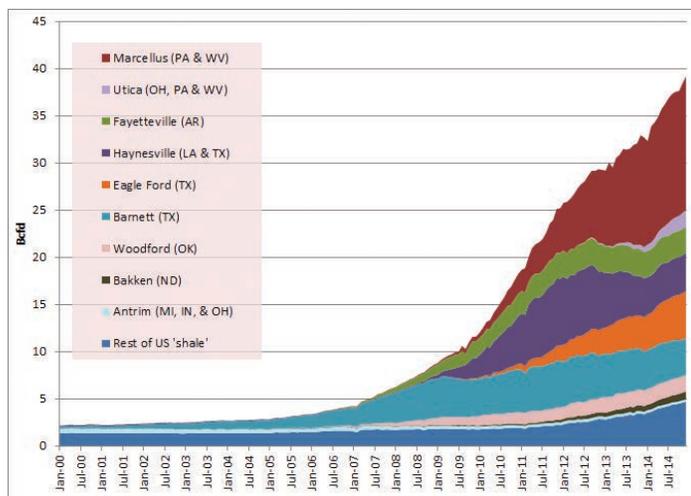
Many shale reservoirs contain natural gas liquids, which can be sold separately, and which augment the economics of producing natural gas.

The Shale Revolution

The estimated resources, proven reserves and production of shale gas have risen rapidly since 2005, and shale is transforming gas production in the United States. In 2013, according to EIA, shale gas made up 40 percent of gross production of natural gas, and has become the dominant source of domestically produced gas. By comparison, coalbed methane accounted for 5 percent of production, while 18 percent of the natural gas came from oil wells and 38 percent was produced from natural gas wells.

New shale plays have increased dry shale gas production from 1 Tcf in 2006 to over 12 Tcf in 2014. Wet shale gas reserves, those rich in oil and/or natural gas liquids account for about 20 percent of the overall United States natural gas reserves. According to the EIA, shale gas will account for about 53 percent of United States natural gas production in 2040.

Shale Gas Production by Region



Source: Derived from EIA data

Shale gas well productivity has improved considerably over the past 10 years, with technological advances in drilling and fracking technology reducing exploration, drilling, and producing costs. Rising well productivity and falling costs have resulted in larger amounts of shale gas production at lower natural gas prices.

The presence of NGL in many shale gas plays adds to shale gas well profitability. NGL prices are more closely linked to oil prices than natural gas prices and natural gas wells with high liquids content are therefore more profitable than wells producing natural gas alone. A typical barrel of NGL might contain 40-45 percent ethane, 25-30 percent propane, 5-10 percent butane and 10-15 percent natural gasoline. This can make shale gas wells less sensitive to natural gas prices than wells producing just natural gas.

The Marcellus Shale formation in Appalachia is of particular note because of its location, size and resource potential, according to the Potential Gas Committee at the Colorado School of Mines. Marcellus Shale has estimated gas resources reaching 549 Tcf, and it extends from West Virginia to New York, near the high population centers of the Northeast and Mid-Atlantic. Although Marcellus Shale has been producing significant amounts of gas only since 2008, production has been prolific with high initial well pressures and high production rates.

Growing gas production in Marcellus has already made an impact on U.S. gas transportation. As more gas has flowed out of Marcellus, less gas has been needed from the Rockies or the Gulf Coast to serve the eastern United States. This new production has contributed to a reduction in natural gas prices and the long-standing price differentials between the Northeast and other parts of the United States. It has also caused imports from Canada to decrease.

Environmental concerns present the greatest potential challenge to continued shale development. One issue involves the amount of water used for hydraulic fracturing and the disposal of the effluent used – chemicals and sand are combined with water to create a fracturing solution, which is then pumped

into deep formations. Some companies recycle the returned water, which allows them to reuse such water. Concerns have also been raised regarding the potential risks and health hazards associated with wastewater (especially when stored at ground level in holding ponds) seeping into drinking water.

FERC Jurisdiction

Section 1(b) of the Natural Gas Act (NGA) exempts production and gathering facilities from FERC jurisdiction. Moreover, the Wellhead Decontrol Act of 1989, Pub. L. No. 101-60 (1989); 15 U.S.C. § 3431(b)(1)(A), completely removed federal controls on new natural gas, except sales for resale of domestic natural gas by interstate pipelines, LDCs or their affiliates. In Order No. 636, FERC required interstate pipelines to separate, or unbundle, their sales of gas from their transportation service, and to provide comparable transportation service to all shippers whether they purchase natural gas from the pipeline or another gas seller.

Imports and Exports

Net natural gas imports play an important role in regional U.S. markets, accounting for about 1,181 Bcf, or 4 percent, of the natural gas used in the United States in 2012. The natural gas pipeline systems of the United States and Canada are integrated, and about 98 percent of imports came from Canada, according to the EIA, while 2 percent was imported as liquefied natural gas (LNG).

Imported natural gas flows into the United States via pipelines at numerous points along the U.S. border with Canada. Imports from Canada have been of strategic importance in the Northeast and the West, which were traditionally far from the major domestic production centers. However, imports from Canada have been declining as U.S. shale production has increased. Net U.S. gas imports fell from a high of 3,785 Bcf in 2007 to 1,181 Bcf in 2014. EIA estimates that imports will continue to decrease as shale-gas production increases.

The United States also exports natural gas to Canada and Mexico, and it still occasionally exports LNG to Japan.

Natural Gas Import Entry Points



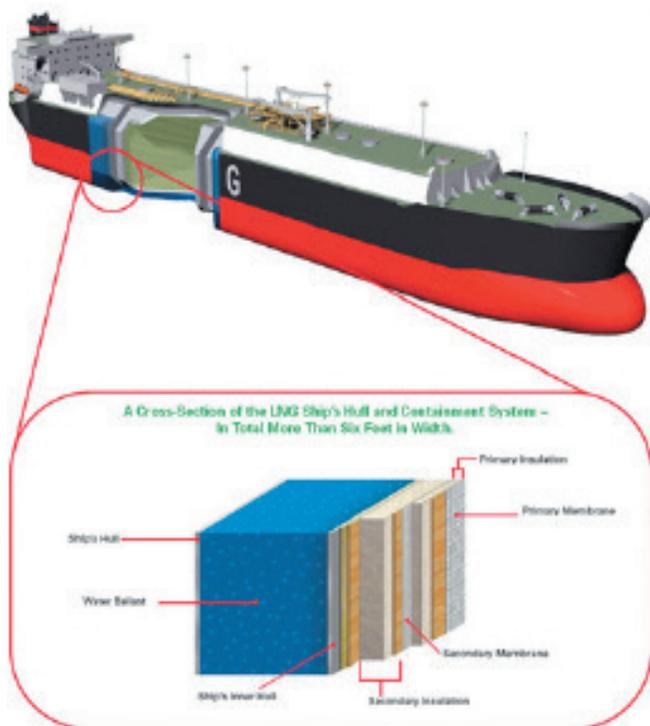
Source: Derived from Velocity Suite, ABB

Liquefied Natural Gas

Liquefied natural gas (LNG) is natural gas cooled to minus 260 degrees Fahrenheit to liquefy it, which reduces its volume by 600 times. LNG may be transported in ships and trucks to locations not connected by a pipeline network.

FERC Jurisdiction

The FERC has exclusive authority under the NGA to authorize the siting of facilities for imports or exports of LNG. This authorization, however, is conditioned on the applicant's satisfaction of other statutory requirements not administered by FERC for various aspects of the project. In addition, the Department of Energy has authority over permits to import and export.



Source: BP

The LNG Supply Chain

Natural gas is sent to liquefaction facilities for conversion to LNG. These facilities are major industrial complexes, typically costing \$2 billion, with some costing as much as \$50 billion.

Once liquefied, the LNG is typically transported by specialized ships with cryogenic, or insulated, tanks.

When LNG reaches an import (regasification) terminal, it is unloaded and stored as a liquid until ready for sendout. To send out gas, the regasification terminal warms the LNG to return it to a gaseous state and then sends it into the pipeline transportation network for delivery to consumers. Currently, over 95 Bcfd of regasification capacity exists globally, more than 2.5 times the amount of liquefaction capacity. Excess regasification capacity provides greater flexibility to LNG suppliers, enabling them to land cargoes in the highest-priced markets.



The cost of the LNG process is \$2-\$5 per million British thermal units (MMBtu), depending on the costs of natural gas production and liquefaction and the distance over which the LNG is shipped. Liquefaction and shipping form the largest portion of the costs. Regasification contributes the least cost of any component in the LNG supply chain. The cost of a regasification facility varies considerably; however, the majority of these costs arise from the development of the port facilities and the storage tanks. A 700-MMcfd regasification terminal may cost in the range of \$500 million to \$800 million.

The various components of the LNG process are broken out on the following page.



Exploration & Production
\$0.60-1.20/MMBtu



Liquefaction
\$0.90-1.30/MMBtu



Shipping
\$0.50-1.80/MMBtu



Storage & Regasification
\$0.40-0.60/MMBtu

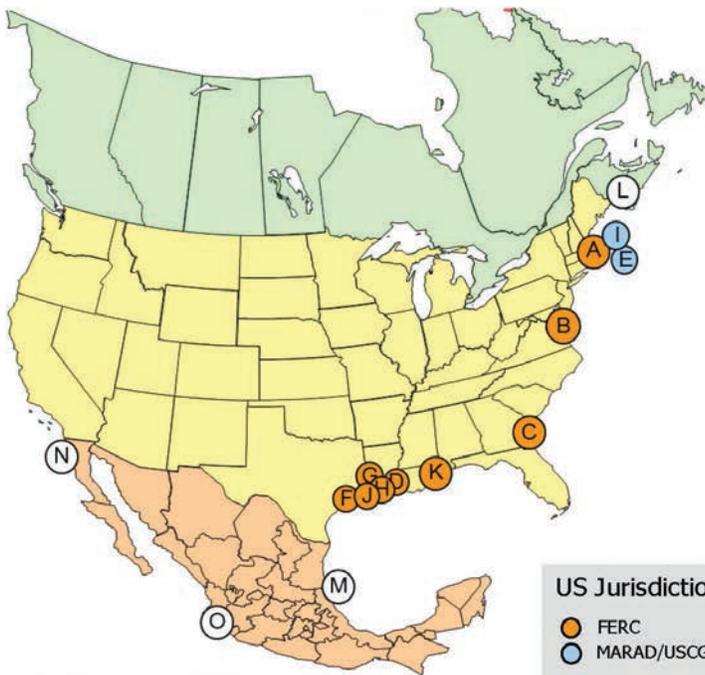
Total Cost = \$2.40-4.90/MMBtu

Source: CEE based on industry and government reports

LNG in the United States

The United States is second to Japan in LNG regasification capacity. As of 2014, there were 11 LNG receiving or regasification terminals in the continental United States, with approximately 19 Bcfd of import capacity and 100 Bcf of storage capacity. All of these facilities are on the Gulf or East coasts, or just offshore. In addition, the United States can import regasified LNG into New England from the Canaport LNG terminal in New Brunswick, Canada, and into Southern California from the Costa Azul LNG terminal in Mexico's Baja California.

North American LNG Import/Export Terminals-Existing



As of January 6, 2015

Note: There is an existing import terminal in Peñuelas, PR. It does not appear on this map since it can not serve or affect deliveries in the Lower 48 U.S. states.

★ Authorized to re-export delivered LNG

U.S.

- A. Everett, MA :** 1.035 Bcfd (GDF SUEZ - DOMAC)
- B. Cove Point, MD :** 1.8 Bcfd (Dominion - Cove Point LNG)
- C. Elba Island, GA :** 1.6 Bcfd (El Paso - Southern LNG)
- D. Lake Charles, LA :** 2.1 Bcfd (Southern Union - Trunkline LNG)
- E. Offshore Boston:** 0.8 Bcfd, (Excelerate Energy – Northeast Gateway)
- F. Freeport, TX:** 1.5 Bcfd, (Cheniere/Freeport LNG Dev.)★
- G. Sabine, LA:** 4.0 Bcfd (Cheniere/Sabine Pass LNG)★
- H. Hackberry, LA:** 1.8 Bcfd (Sempra - Cameron LNG)★
- I. Offshore Boston, MA :** 0.4 Bcfd (GDF SUEZ – Neptune LNG)
- J. Sabine Pass, TX:** 2.0 Bcfd (ExxonMobil – Golden Pass) (Phase I & II)
- K. Pascagoula, MS:** 1.5 Bcfd (El Paso/Crest/Sonangol - Gulf LNG Energy LLC)

Canada

- L. Saint John, NB:** 1.0 Bcfd, (Repsol/Fort Reliance - Canaport LNG)

Mexico

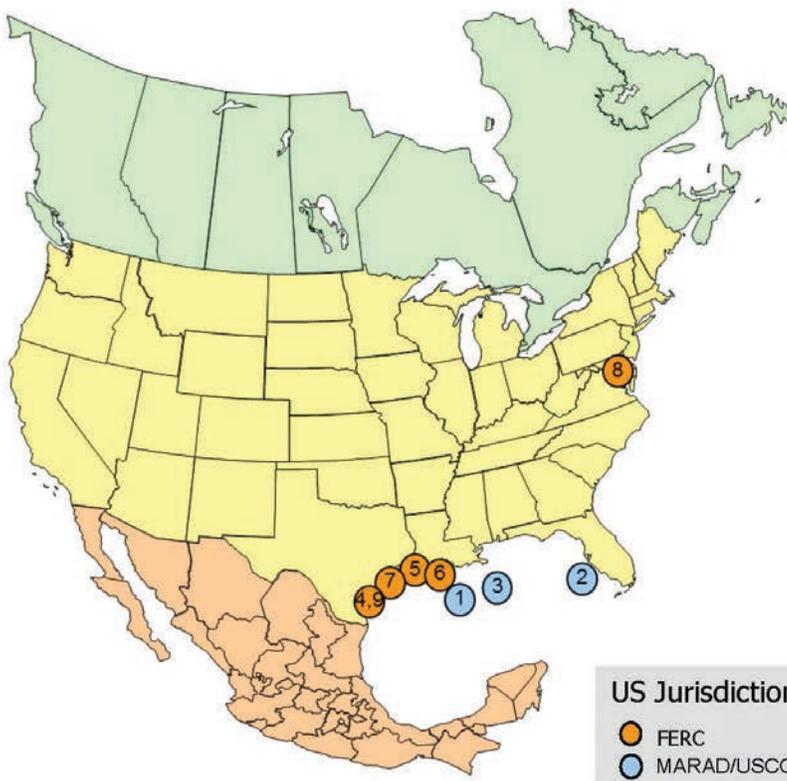
- M. Altamira, Tamulipas:** 0.7 Bcfd, (Shell/Total/Mitsui – Altamira LNG)
- N. Baja California, MX:** 1.0 Bcfd, (Sempra – Energia Costa Azul)
- O. Manzanillo, MX:** 0.5 Bcfd (KMS GNL de Manzanillo)

Source: FERC staff

Between 2003 and 2008, the United States met 1-3 percent of its natural gas demand through LNG imports, according to the EIA. LNG imports peaked at about 100 Bcf/month in the summer of 2007. Growth in relatively low-cost U.S. shale gas production has trimmed U.S. LNG imports, affecting Gulf Coast terminals the most. Today, most LNG enters the United States under long-term contracts (about half of the total) coming through the Everett (Boston) and Elba Island (Georgia) LNG terminals. The remainder of the LNG enters the United States

under short-term contracts or as spot cargoes. LNG prices in the United States generally link to the prevailing price at the closest trading point to the import terminal. During 2011-14, the growth in shale gas production led to proposals to export significant volumes of domestically produced LNG. As of January 2015, several LNG export facilities have been approved, but none have yet begun operations. Since 1969, small quantities of LNG have been shipped from Alaska to Pacific Rim countries.

North American LNG Import/Export Terminals-Approved



As of January 6, 2015

Source: FERC staff

Import Terminal

APPROVED - NOT UNDER CONSTRUCTION

U.S. - MARAD/Coast Guard

1. **Gulf of Mexico:** 1.0 Bcf/d (Main Pass McMoRan Exp.)
2. **Offshore Florida:** 1.2 Bcf/d (Hoegh LNG - Port Dolphin Energy)
3. **Gulf of Mexico:** 1.4 Bcf/d (TORP Technology-Bienville LNG)
4. **Corpus Christi, TX:** 0.4 Bcf/d (Cheniere - Corpus Christi LNG) (CP12-507)

Export Terminal

APPROVED - UNDER CONSTRUCTION

U.S. - FERC

5. **Sabine, LA:** 2.76 Bcf/d (Cheniere/Sabine Pass LNG) (CP11-72 & CP14-12)
6. **Hackberry, LA:** 1.7 Bcf/d (Sempra - Cameron LNG) (CP13-25)
7. **Freeport, TX:** 1.8 Bcf/d (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction) (CP12-509)
8. **Cove Point, MD:** 0.82 Bcf/d (Dominion - Cove Point LNG) (CP13-113)

APPROVED - NOT UNDER CONSTRUCTION

U.S. - FERC

9. **Corpus Christi, TX:** 2.14 Bcf/d (Cheniere - Corpus Christi LNG) (CP12-507)

Natural Gas Processing and Transportation

Most domestic natural gas production in the United States occurs in regions well away from major population centers. To get gas from the wellhead to consumers requires a vast network of processing facilities and 2.5 million miles of pipelines. In 2014, this network delivered more than 26 Tcf of natural gas to millions of customers. The U.S. natural gas system can get natural gas to and from almost any location in the Lower 48 states.

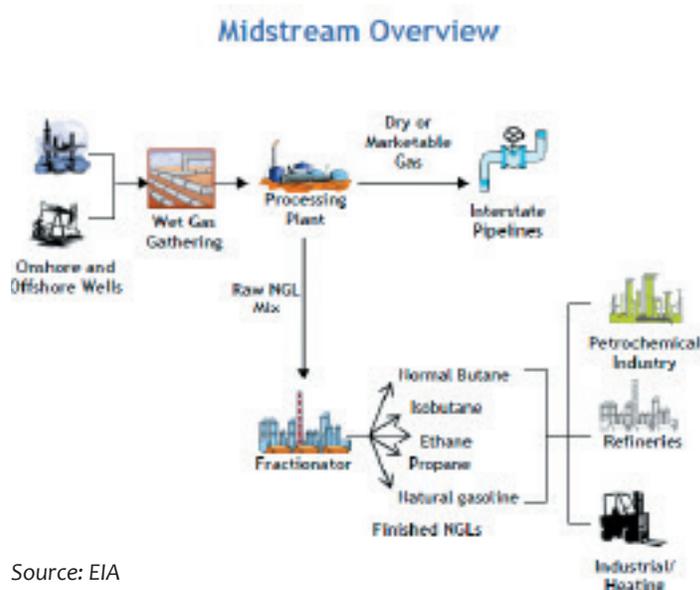
Efficient markets require that this network be robust and allow consumers access to gas from more than one production center. Supply diversity tends to improve reliability and moderate prices, while constraints increase prices.

Processing

The midstream segment of the natural gas industry between the wellhead and pipelines is shown in the graphic. This segment involves gathering the gas from the wellhead, processing the gas to remove liquids and impurities and moving the processed (dry) natural gas to pipelines and the extracted liquids to a fractionator that separates the liquids into individual components. The liquids are used by the petrochemical industry, refineries and other industrial consumers. There were about 500 gas processing plants operating in the United States in 2010.



The composition of raw, or wellhead, natural gas differs by region. Consequently, processing will differ depending on the quality of the natural gas. Natural gas may be dissolved in oil underground but separated out from the oil as it comes to the surface due to reduced pressure. In these instances, the oil and gas are sent to separate processing facilities. Where it does not separate naturally, processing is required.



Source: EIA

Once a well is completed and production starts, the natural gas moves into gathering pipelines, typically small-diameter lines that move the gas from the wellhead to either a processing plant or a larger pipeline.

Processing is required when the natural gas and oil do not separate naturally. At the processing plant, wet natural gas is dehydrated, and additional products and contaminants (such as sulfur and carbon dioxide) are extracted. The hydrocarbon liquids, extracted as natural gas liquids, are high-value products used in petrochemical applications. Once processing extracts the NGL, the stream is separated into individual components by fractionation, which uses the different boiling points of the various hydrocarbons to separate them. Once processing is complete, the gas is of pipeline quality and is ready to be moved by intrastate and interstate pipelines.

FERC Jurisdiction

The NGA gives the FERC comprehensive regulatory authority over companies that engage in either the sale of natural gas for resale or its interstate transportation. The Commission regulates market entry through Section 7 of the NGA, 15 U.S.C. § 717f, by issuing certificates of public convenience and necessity, subject to such conditions as the Commission deems appropriate, authorizing natural gas companies to transport or sell natural gas. To this end, the FERC reviews applications for the construction and operation of interstate natural gas pipelines. In its application review, the FERC ensures that the applicant has certified that it will comply with Department of Transportation safety standards. The FERC has no jurisdiction over pipeline safety or security, but actively works with other agencies with safety and security responsibilities. The Commission regulates market exit through its authority to abandon certificated service, 15 U.S.C. § 717f(b).

Natural Gas Transportation

Interstate pipelines account for 63 percent of the natural gas pipeline miles in the United States and carry natural gas across state boundaries. Intrastate pipelines account for the remaining 37 percent, and have similar operating and market characteristics.

The interstate network moves dry natural gas from producing areas to LDCs, large industrial customers, electric power plants and natural gas storage facilities. The pipelines, which range in diameter from 16 inches to as large as 48 inches, move gas between major hubs to lateral lines. Laterals, which range in diameter from 6 inches to 16 inches, distribute gas to retail customers.

The large pipelines are known as mainline transmission pipelines. The pipe used for major pipelines typically consists of strong carbon steel sufficient to meet standards set by the American Petroleum Institute. The pipe is coated to reduce corrosion. Smaller distribution lines, which operate under much lower pressures, may be made of plastic materials, which provide flexibility and ease of replacement.

Nearly one-sixth of all natural gas transmission pipelines, by mileage, are located in Texas. More than half are located in nine states: Texas, Louisiana, Kansas, Oklahoma, California, Illinois, Michigan, Mississippi and Pennsylvania.

Compressor stations, located every 50-100 miles along the pipe, add to or maintain the pressure of the natural gas, propelling it down the pipeline. Natural gas travels through pipelines at high pressures, from 200 pounds per square inch (psi) to 1,500 psi.

The natural gas is compressed by turbines, motors or engines. Turbines and reciprocating natural gas engines use some of the gas from the line to fuel their operations; electric motors rely on electricity.

Natural Gas Infrastructure

The United States natural gas market is accommodated by extensive infrastructure:

- Roughly 303,000 miles of wide-diameter, high pressure inter- and intrastate pipelines make up the mainline pipeline transportation network, run by more than 210 companies.
- More than 1,400 compressor stations maintain pressure on the natural gas pipeline network.
- More than 5,000 receipt points, 11,000 delivery points and 1,400 interconnection points implement the flow of gas across the United States.
- Nearly three dozen hubs or market centers provide addition interconnections.
- Over 400 underground natural gas storage facilities increase the flexibility of the system.
- 49 locations enable natural gas to be imported or exported via pipelines.
- There are 9 LNG import facilities and 100 LNG peaking facilities (stored gas held for peak demand periods).
- More than 1,300 local distribution companies deliver natural gas to retail customers.

Source: EIA

Metering stations are placed along the pipelines to measure the flow of natural gas as it moves through the system.

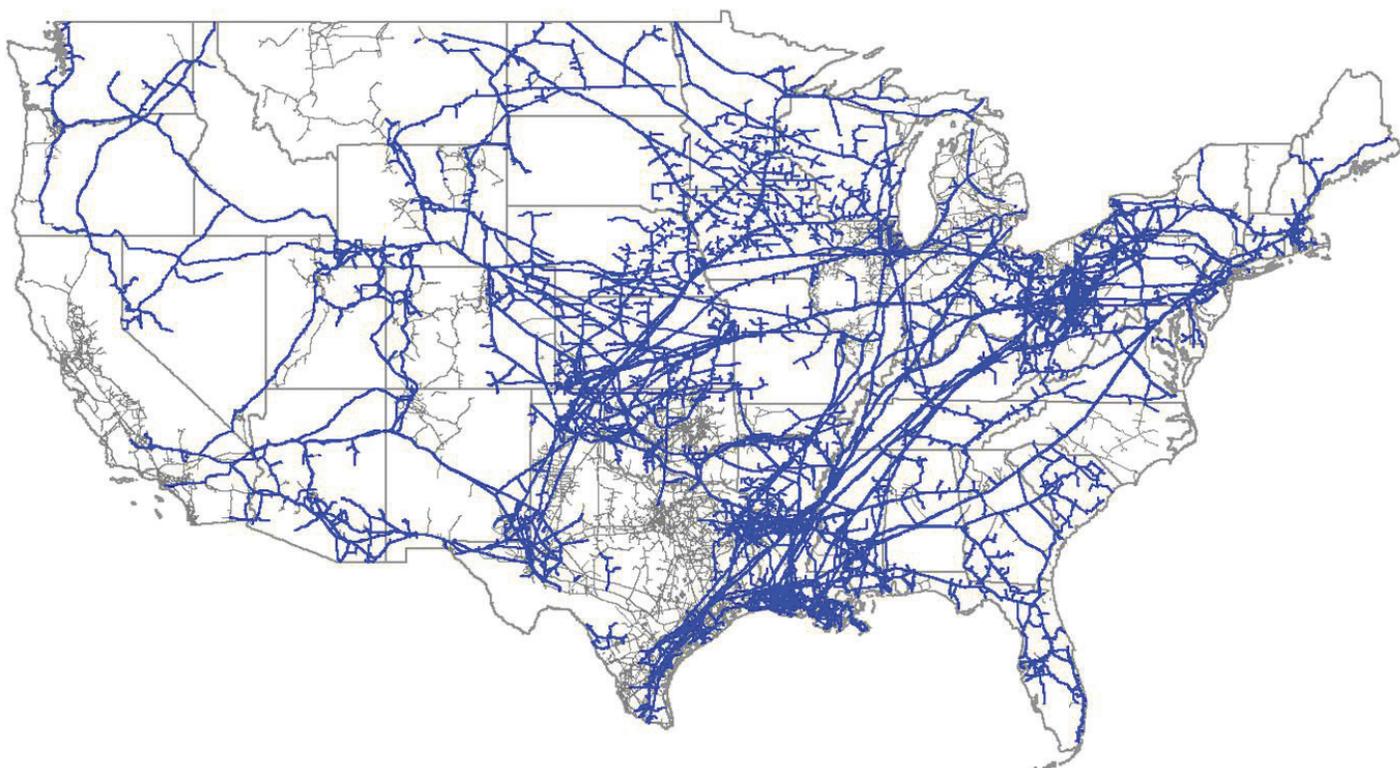
Movement of natural gas along a pipeline is controlled in part by a series of valves, which can be opened to allow the gas to move freely or closed to stop gas flow along a section of pipe. Large valves may be placed every 5 to 20 miles along the pipeline.

Pipeline operators use supervisory control and data acquisition (SCADA) systems, to track the natural gas as it travels through their systems. SCADA is a centralized communication system that collects, assimilates and manages the meter and

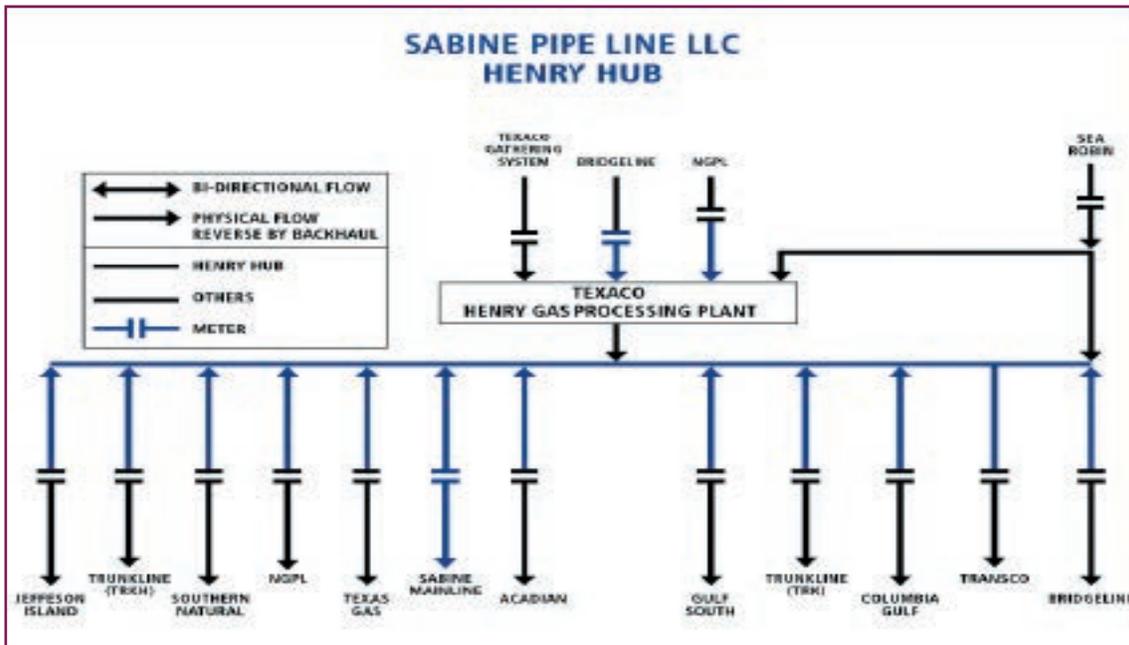
compressor station data. SCADA also conveys this information to the centralized control station, allowing pipeline engineers to know what is happening on the system at all times.

As the product moves closer to the consumption areas, it may be stored in underground facilities. Plentiful storage capacity adds flexibility to the pipeline and distribution systems and helps moderate prices by providing an outlet for excess gas during periods of low demand, and readily accessible supply in periods of high demand. Some natural gas can also be stored in the pipelines as linepack, in which more molecules of gas are held in a segment of pipeline under greater-than-normal pressure.

Natural Gas Transportation System



Source: Derived from Velocity Suite, ABB



Source: Sabine Pipeline, LLC

Hubs

A key part of the pipeline distribution network is the natural gas hub. Typically, a hub is a specific point where pipeline interconnections allow the transfer of gas from one pipeline to another.

There are dozens of natural gas hubs in the country, with over 20 major hubs. The Henry Hub is the dominant benchmark point in the physical natural gas market because of its strategic location in the Gulf Coast’s producing area and the number of pipeline connections to the East Coast and Midwest consumption centers. It is located in south central Louisiana, in the town of Erath, where more than a dozen major natural gas pipelines converge and exchange gas. The Henry Hub has 12 delivery points and 4 major receipt points.

Gas as a physical product can be bought and sold at the Henry Hub or other hubs around the country in daily and monthly markets. In addition, the New York Mercantile Exchange (Nymex) established a natural gas futures contract centered at

the Henry Hub in 1990 that gained widespread acceptance and is generally used as the reference price for natural gas in the United States.

Distribution lines typically take natural gas from the large transportation pipelines and deliver the gas to retail customers. While some large consumers – industrial and electric generation, for example – may take service directly off a transmission pipeline, most receive their gas through their local gas utility, or LDC. These companies typically purchase natural gas and ship it on behalf of their customers, taking possession of the gas from the pipelines at local citygates and delivering it to customers at their meters. This distribution involves a network of smaller pipelines – more than two million miles, according to the U.S. Department of Transportation.

FERC Jurisdiction

The NGA requires that interstate natural gas pipelines charge just and reasonable rates for the transportation and sale of

natural gas. To promote compliance with this mandate, the NGA requires gas pipelines to file rate schedules with the FERC and to notify the FERC of any subsequent changes in rates and charges. On submission of a tariff revision, the FERC may hold a hearing to determine whether the pipeline has met its burden to show that the amended rates and charges are just and reasonable.

Under Sections 4 and 5 of the NGA, 15 U.S.C. §§ 717c and 717d, the Commission regulates the rates and other terms of jurisdictional transportation and sales, ensuring that rates and charges for such services, as well as all rules, regulations, practices, and contracts affecting those rates and charges, are just and reasonable and not the product of undue discrimination (15 U.S.C. §§ 717c(a) and (b)).

Pipeline Services

Customers or shippers may choose among a variety of services on interstate pipelines. One is firm transportation capacity, or primary market service, in which an agreement is executed directly between the pipeline and a customer for a year or more, relying on primary receipt and delivery points. Shippers with firm transportation service generally receive priority to ship for the contracted quantity.

A second type of transportation service a shipper can contract for is interruptible transportation service. Interruptible transportation service is offered to customers under schedules or contracts on an as-available basis. This service can be interrupted on a short notice for a specified number of days or hours during times of peak demand or in the event of system emergencies. In exchange for interruptible service, customers pay lower prices.

A secondary market for firm transportation rights enables shippers to sell their pipeline capacity to a third party through the FERC's capacity release program. Services offered in the primary market can be offered in the secondary market by the holder of the primary service. Released capacity offers market participants the opportunity to buy and sell from each other as well as from the pipeline. Holders of primary capacity can

release segments rather than their full holdings, provided segmentation is operationally feasible on the interstate pipeline's system.

Interstate pipelines also provide "no-notice service" under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty. If a shipper has firm storage and transportation service, that shipper can schedule in the day-ahead market and yet have the ability and the right to physically take a different quantity than what was scheduled without incurring imbalance penalties. No-notice service is particularly valuable during periods of high demand when transportation capacity may be completely used. This service is especially helpful to LDCs that must serve their load without knowing their exact load level each day. No-notice service is generally priced at a premium to firm transportation service. Shippers may temporarily release this service to other parties, using FERC-approved capacity release guidelines.

Interstate Transportation Rates

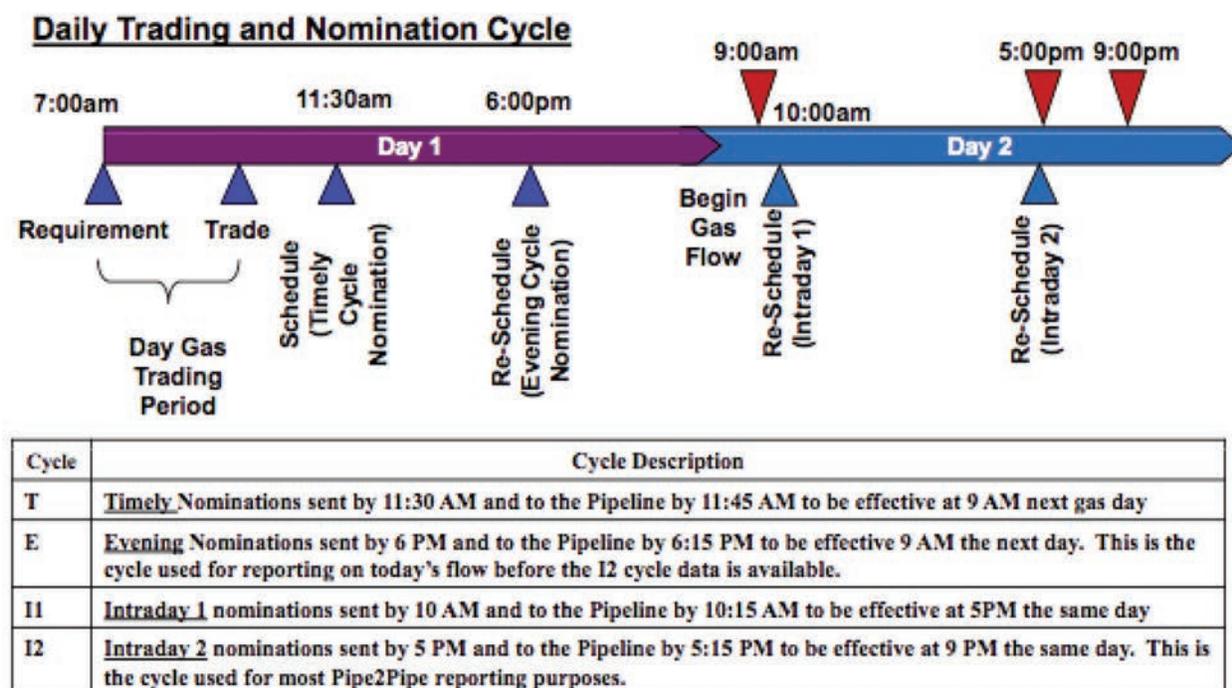
Pipeline transportation rates can be priced on zones or miles, or be a fixed postage stamp rate. In zonal pricing, the price of transportation varies by the location of the receipt and delivery points, across a series of zones.

Under postage stamp rates, shippers pay the same rate for transportation regardless of how far the gas is moved, similar to the way a postage stamp costs the same amount regardless of whether a letter is sent to New York or California. Pipelines using postage stamp rates include Northwest Pipeline, Colorado Interstate Gas and Columbia Gas Transmission.

With mileage-based rates, shippers pay based on the distance between where the gas enters the pipeline and where it is taken out of the pipeline. The rate is designed to reflect the distance involved in transporting the gas. Gas Transmission Northwest (GTN) uses mileage-based rates.

Other pipelines use hybrid or mixed-rate systems. Northern Natural Gas, for example, uses a combination zonal rate for upstream receipts and a postage stamp rate for market area deliveries.

Pipeline Capacity Scheduling



Source: Bentek Energy LLC

Scheduling

Pipelines have rigorous schedules that shippers must follow. Typically, shippers nominate gas in the day-ahead market, and may update their nominations at various points during the day in which the natural gas flows. The Pipeline Capacity Scheduling graphic illustrates a particular schedule.

Pipeline Usage or Load Factor

Load factor measures the use of a pipeline network. It is the average capacity used at a given point or segment relative to a measurement of maximum or peak available capacity. Customers with a 100 percent load factor use their maximum capacity every day; one with a 50 percent load factor uses its capacity only half the time. Different types of customers use pipeline capacity differently. Historically, industrial customers have exhibited high load factors and residential customers that primarily rely upon seasonal gas to heat homes have had lower load factors.

Pipelines are accustomed to serving different demands, which can affect how much of their capacity is used at various times. For example, Kern River Gas Transmission has operated at around 93 percent of capacity since 2005, while Algonquin Gas Transmission's capacity factor is considerably less. Algonquin's pipeline is used more seasonally than Kern River's, reflecting the seasonal demand in the Northeast.

Park and Loan Service

Park and loan service (PAL) is a way for shippers to balance their takes of gas with their supply, by providing a short-term load-balancing service to help shippers meet their load. Using the PAL service, shippers can take less gas than scheduled, thus parking their excess supply in the pipeline at times when the demand is lower than anticipated. If demand is higher than expected, shippers can adjust their take upward, in effect borrowing gas from the pipeline.

PAL characteristics include:

- Park and loan services typically generate low revenue and are offered with the lowest service level priority among all pipeline services.
- Rates are based on costs associated with providing the services, such as plant costs if the services are offered.
- Market centers, or hubs, routinely offer these services.
- Charges are usually commensurate with interruptible service rates.
- Pipelines earn minimal revenue from park and loan.

Pipeline Constraints and Capacity Growth

Pipeline capacity limits the supply that can be delivered to a specific region and is, therefore, a key factor in regional prices.

In recent years, the natural gas pipeline network has expanded significantly, removing bottlenecks and providing access to previously unreachable supply areas.

A considerable amount of new pipeline capacity has been added in recent years to the Northeast. As Northeast production ramped up in 2008 and 2009, annual pipeline capacity additions in the region rose to 2.6 Bcfd in 2009 along with the production increases. Pipeline capacity additions moderated in 2010 and 2011 until surging again to reach annual additions of 2.9 Bcfd in 2012 and 2.6 Bcfd in 2013. Much of this new capacity was targeted at improving access to shale gas.

Building a pipeline project requires careful planning, as the projects typically entail significant costs that must be recovered over years of operations. However, unanticipated changes in supply and demand patterns can have unexpected effects on even the best-planned projects. For example, one of the largest additions to the natural gas infrastructure came when the 1.8-Bcfd Rockies Express Pipeline (REX) was completed in 2009. REX was designed to move natural gas from Wyoming to eastern Ohio in order to relieve pipeline constraints that bottled up production and depressed prices in the Rockies, while at the same time providing needed supplies into the East. When REX first went into service, Rockies producers saw a rise in prices. The Rockies gas flowing eastward

displaced gas from the Permian Basin. Permian natural gas, in turn, began moving to the Southern California market. Consequently, regional price differences moderated. However, the rapid increase in Marcellus Shale production pushed Rockies supplies away from the Northeast and caused flows on REX to decrease sharply, putting the pipeline at financial risk. In 2014, REX began the process of reversing flows on parts of the pipeline to move natural gas from the east to the Midwest. This development is making more Rockies natural gas available to Western Markets, and more midcontinent production available for the Gulf Coast and Southeast states.

Other projects are operating as designed. New pipelines to increase the flow of Barnett Shale gas into the interstate network have reduced congestion across the Texas-Louisiana border.

The Florida Panhandle and Northern California used to be some of the most frequently constrained regions of the country, but each has received significant new pipeline capacity. Expansion of Florida Gas Transmission in 2011 added about 800 MMcfd, a boost of 33 percent, of gas transmission capacity to peninsular Florida. The 680-mile, 42-inch-diameter Ruby Pipeline, which began operations in 2011, now flows Rockies gas from Opal, Wyo., to Malin, Ore.

Local Distribution

Distribution lines typically take natural gas from the large interstate pipelines and deliver the gas to retail customers. While some large consumers – industrial and electric generators, for example – may take service directly off an interstate pipeline, most receive their natural gas through their LDC. LDCs typically purchase natural gas and ship it on behalf of their customers. They take possession of the natural gas from interstate pipelines at local citygates and deliver the natural gas to their customers at the customer's meter. According to the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration, this distribution involves a network of smaller pipelines totaling more than two million miles, as well as smaller scale compressors and meters.

Some states allow competition in natural gas service at the

local level. In these circumstances, natural gas marketers purchase the natural gas and arrange for it to be shipped over both the interstate pipeline network and the LDC system.

Natural Gas Storage

Although natural gas production rose steadily from 2005 through 2014 because of the increase in shale gas production, day-to-day production remains relatively steady throughout the year. Demand, however, changes considerably with the seasons. Natural gas storage enables producers and purchasers to store gas during periods of relatively low demand – and low prices – then withdraw the gas during periods of relatively higher demand and prices.

Working gas storage capacity, as tracked by EIA, was more than 4,100 Bcf in 2014. The amount injected or withdrawn is the difference between demand and production. Storage capacity adds flexibility to pipeline and distribution systems and helps moderate prices by providing an outlet for excess gas during periods of low demand. Storage facilities also provide a readily accessible supply in periods of high demand. Some natural gas can also be stored in the pipelines as linepack, in which more molecules of gas are held in a segment of pipeline under greater-than-normal pressure.

EIA’s weekly storage report provides a high-level snapshot of the natural gas supply and demand balance. EIA releases its storage report at 10:30 a.m. on Thursdays. The price for natural gas futures can change dramatically within seconds of the report’s release. If the reported injection or withdrawal significantly differs from market expectations, the price for natural gas futures may rise or fall.

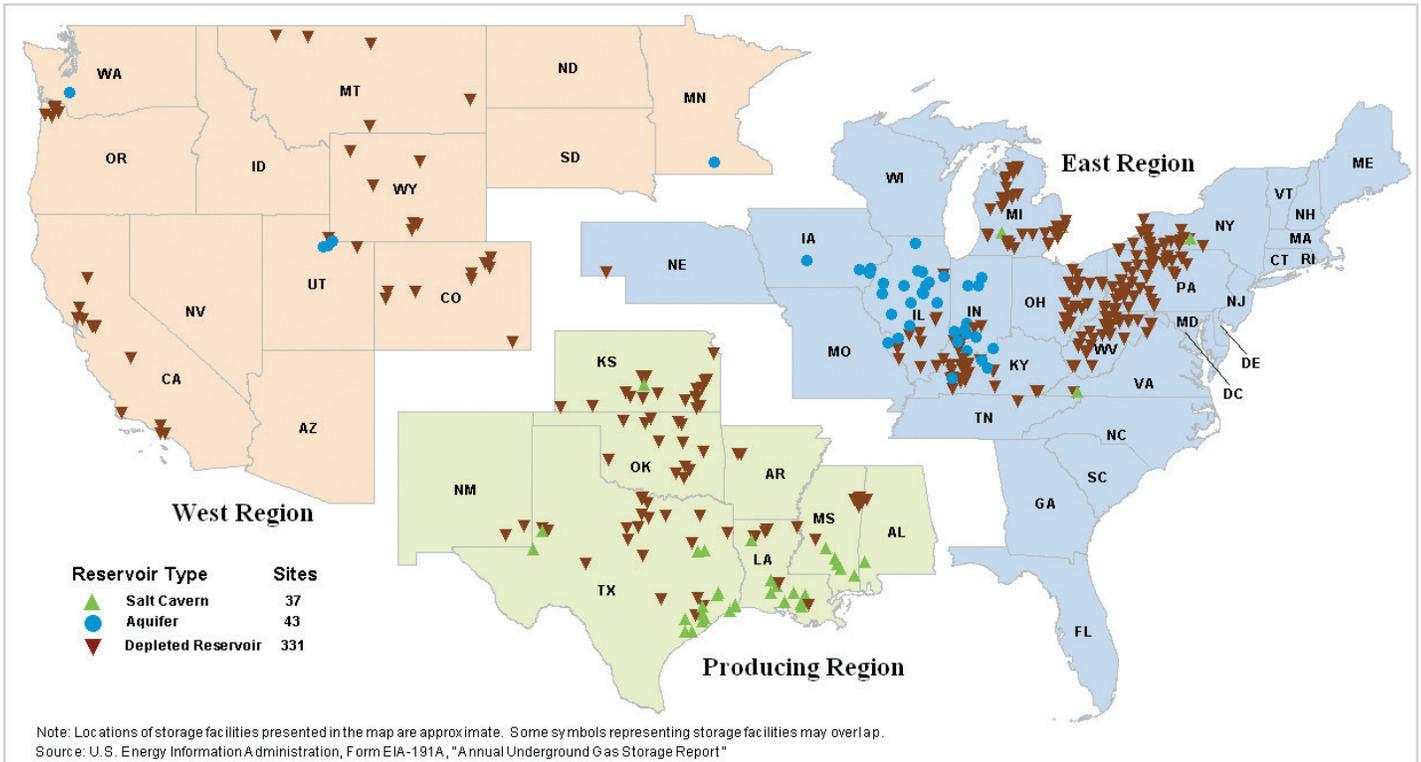
Storage Facilities

The bulk of the storage capacity in the United States is below ground. Differing cost and operational characteristics affect how each facility is used:

- Deliverability rate is the rate at which inventory can be withdrawn. The faster the natural gas can be removed from storage, the more suitable the storage facility is to helping serve rapidly changing demand.
- Cycling capability is the ability of the resource to quickly allow injections and withdrawals, which is useful for balancing supply and demand. Salt caverns tend to have high withdrawal and injection rates, enabling them to handle as many as a dozen withdrawal and injection cycles each year. LNG storage also demonstrates these capabilities.



Underground Natural Gas Storage Facilities in the Lower 48 States



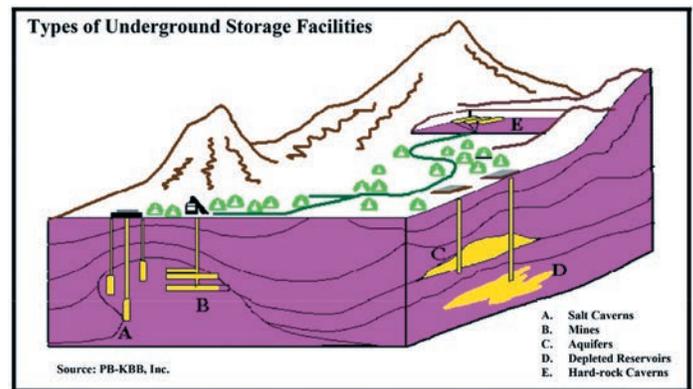
Natural gas in an underground storage facility is divided into two general categories, working gas and base gas. Base gas is the volume of natural gas, including native gas, needed as a permanent inventory in a storage reservoir to maintain adequate reservoir pressure and deliverability rates throughout the withdrawal season. Working gas is the volume of gas in the reservoir above the designed level of base gas and that can be extracted during the normal operation of the storage facility.

Most of the nation's gas storage is in depleted reservoirs (former oil and gas fields). These facilities reuse the infrastructure – wells, gathering systems and pipeline connections – originally created to support the field when it was producing. About 50 percent of total capacity goes to base gas used to maintain operating pressure at the facility, and inventory usually turns over once or twice a year.

Other storage facilities reside in aquifers that have been transformed into gas storage facilities. These are mostly in the Mid-

west. These aquifers consist of water-bearing sedimentary rock overlaid by an impermeable cap rock. Aquifers are the most expensive type of natural gas facility because they do not have the same retention capability as depleted reservoirs. Therefore, base gas can be well over 50 percent of the total gas volume. This makes the facility more sensitive to withdrawal and injection patterns, so inventory usually turns over just once a year.

Types of Underground Storage Facilities



Salt cavern formations exist primarily in the Gulf Coast region. These air- and water-tight caverns are created by removing salt through solution-mining, leaving a cavern that acts as a pressurized vessel. Little base gas is required, which allows inventory to turn over as many as a dozen times during the year, and results in high injection and withdrawal rates. This flexibility attracted new development, resulting in the growth of salt cavern storage through 2008. Salt caverns generally hold smaller volumes than do depleted-reservoir or aquifer gas storage facilities.

Natural gas may also be stored in above-ground tanks as LNG. There is LNG storage at all of the onshore LNG-receiving terminals, and there are about a hundred standalone LNG storage facilities in the United States, as well. LNG ships can also serve as storage, depending on timing and economics. LNG storage is highly flexible, allowing multiple inventory turns per year with high injection and withdrawal rates.

Regional Storage

The EIA divides the United States into three storage regions: producing, East and West. Just over half of the underground storage in the United States, 2,200 Bcf, sits in the East near population centers. Much of this is in aquifers and depleted fields. Almost 1,500 Bcf sits in the producing region, which has not only depleted fields but also the greatest concentration of more-flexible salt cavern storage. The remaining 600 Bcf is in the West, primarily in depleted fields, for total working gas capacity of almost 4,300 Bcf. Depending on storage levels at the end of the previous winter, and the temperatures over the injection season, U.S. working gas in storage will generally be between 80 and 90 percent full when the official winter season begins on November 1.

Storage Service and Uses

Approximately 120 entities – including interstate and intrastate pipeline companies, LDCs and independent storage service providers – operate the nearly 400 underground storage facilities active in the continental United States, according to

the EIA. Facilities operated by interstate pipelines and many others are operated on an open-access basis, with much of the working gas capacity available for lease on a nondiscriminatory basis.

The ability to store large quantities of natural gas improves reliability and usually has a moderating influence on natural gas prices. Storage inventory augments natural gas supply during the winter, and acts as an additional demand component during the summer injection season. The storage injection season typically starts April 1 and continues through Oct. 31, when demand for gas heating is lowest. Storage withdrawals generally start in November and last throughout the winter.

The ability to use storage to provide for winter peaks creates an intrinsic storage value. This is the value from buying during cheaper periods of the year for use during higher-cost seasons. Depleted reservoirs or aquifers – with limited ability to turn over inventory – support this type of use. Local distribution companies or pipelines store their gas in these facilities to ensure adequate supplies for peak seasons, balance load and diversify their resources.

Storage may be priced at cost-based or market-based rates. Pricing mechanisms for low-cycling depleted fields and aquifers may use a traditional cost-of-service structure, including:

- Capacity charges for firm contract rights to physical storage capacity
- Deliverability charges for transportation to and from the storage facility
- Withdrawal charges for the removal of gas from storage
- Injection charges for the injection of gas into storage

A salt cavern, with its ability to turn over inventory frequently and quickly, allows for additional uses, enabling users to capture extrinsic value. Many salt dome facilities can cycle between injection and withdrawal at almost a moment's notice, giving users greater flexibility. Entities leasing storage capacity may move gas in and out of storage as prices change in attempts to maximize profits or minimize costs. Storage may be a component in producer or consumer hedging strategies, helping them to manage the risk of price movements.



Further, storage helps shippers avoid system imbalances and associated penalties, and supports swing gas supply services, which are short-term contracts that provide flexibility when either the supply of gas from the seller, or the demand for gas from the buyer, are unpredictable. Storage also facilitates title transfers and parking and lending services. This helps shippers balance daily receipts and deliveries, manage their overall supply portfolio or take advantage of price movements. Consequently, storage operators have begun offering a more varied menu of services, and users have begun using storage as a commercial tool and as part of a comprehensive supply portfolio strategy.

Merchant storage, frequently using salt caverns, uses market-based prices, recognizing the dynamics affecting value at any given point in time. Prices often take into account the prices at which the Nymex futures contracts are trading. They may also reflect the storage volume, the number of times the gas will be cycled, the length of the contract and the timeframe it

covers and the maximum daily quantity that may be injected or withdrawn. Energy marketers have increasingly used these facilities as they try to profit from price volatility. It is also attractive to shippers, industrial consumers with uncertain loads and gas-fired generators whose needs change rapidly.

Pipelines also offer storage service, both firm and interruptible, as part of their open access transportation service under FERC rules. Rates are rarely market-based. Instead, prices are based on cost of service, with rates containing reservation and usage components for firm service and a usage component for interruptible.

Market Effects

Storage can mitigate large seasonal price swings by absorbing natural gas during low demand periods and making it available when demand rises.

Further, storage levels can affect the market's expectations about prices during the coming winter high-demand season. The amount of gas in storage in November is a key benchmark of the gas industry's ability to respond to changes in winter weather. Higher storage levels tend to reduce forward prices; lower storage levels tend to increase them, all other market conditions being equal.

FERC Jurisdiction

The underground storage of natural gas has historically been critical in assuring that the needs of natural gas customers are met. The Energy Policy Act of 2005 added a new section to the Natural Gas Act stating that the Commission may authorize natural gas companies to provide storage and storage-related services at market-based rates for new storage capacity, even though the company cannot demonstrate it lacks market power (15 U.S.C. § 717c(f)). To make this authorization, the FERC must determine that market-based rates are in the public interest and are needed to encourage the construction of new capacity, and that customers are adequately protected.

Natural Gas Markets and Trading

The natural gas industry in the United States is highly competitive, with thousands of producers, consumers and intermediate marketers. Some producers have the ability to market their natural gas and may sell it directly to LDCs, to large industrial buyers and to power plants. Other producers sell their gas to marketers who aggregate natural gas into quantities that fit the needs of different types of buyers and then transport the gas to their buyers.

Most residential and commercial customers purchase natural gas from a LDC. In contrast, many industrial customers and most power plants have the option to purchase natural gas from a marketer or producer instead of from the LDC, thereby avoiding any LDC charges.

Interstate pipelines do not buy and sell natural gas and are limited to providing transportation and storage services only. As noted, interstate pipelines transport natural gas at rates approved by the FERC.

Natural Gas Marketers

Most gas trading in the United States is performed by natural gas marketers. Any party engaging in the sale of natural gas can be termed a marketer; however, marketers are usually specialized business entities dedicated solely to transacting in the physical and financial energy markets. It is commonplace for natural gas marketers to be active in a number of energy markets, taking advantage of their knowledge of these markets to diversify their business.

Marketers can be producers of natural gas, pipeline marketing affiliates, LDC marketing affiliates, independent marketers, financial institutions, or large-volume users of natural gas. Some marketing companies may offer a full range of services, marketing numerous forms of energy and financial products, while others may be more limited in their scope. For instance, most marketing firms affiliated with producers do not sell natural gas from third parties; they are more concerned with sell-

ing their own production and hedging to protect their profit margin from these sales.

Generally speaking, there are five categories of marketing companies: major nationally integrated marketers, producer marketers, small geographically focused marketers, aggregators and brokers.

The major nationally integrated marketers offer a full range of services, and market numerous different products. They operate on a nationwide basis and have large amounts of capital to support their trading and marketing operations. Producer marketers are those entities generally concerned with selling their own natural gas production or the production of their affiliated natural gas production company. Smaller marketers target particular geographic areas and specific natural gas markets. Many marketing entities affiliated with LDCs are of this type, focusing on marketing gas for the geographic area in which their affiliated distributor operates. Aggregators generally gather small volumes from various sources, combine them, and sell the larger volumes for more favorable prices and terms than would be possible selling the smaller volumes separately. Brokers are a unique class of marketers because they never take ownership of natural gas themselves. They simply act as facilitators, bringing buyers and sellers of natural gas together.

All marketing companies must have significant backroom operations in addition to the core trading group. These support staff are responsible for coordinating everything related to the sale and purchase of physical and financial natural gas, including arranging transportation and storage, posting completed transactions, billing, accounting and any other activity that is required to complete the purchases and sales arranged by the traders.

In addition to the traders and backroom staff, marketing companies typically have extensive risk-management operations. The risk-management team is responsible for ensuring that the traders do not expose the marketing company to excessive risk.



Market Hubs

Natural gas is priced and traded at different locations throughout the country. These locations, referred to as market hubs, exist across the country and are located at the intersections of major pipeline systems. The price at which natural gas trades differs across the major hubs, depending on the supply and demand for natural gas at the particular points. The difference between the Henry Hub price and another hub is called the location differential, or basis. In addition to market hubs, other major pricing locations include citygates. Citygates are the locations at which distribution companies receive gas from a pipeline. Citygates at major metropolitan centers can offer another point at which natural gas is priced.

In addition to being the country's benchmark hub, the Henry Hub is also the delivery point for the Nymex natural gas futures contract. Changes in price at the Henry Hub provide a good indicator of how prices are generally changing across the country.

Basis usually reflects the variable cost to transport gas between the Henry Hub and another hub. Basis can change, sometimes dramatically, depending on local market conditions, and can widen considerably when pipelines between two points are congested. Basis in excess of transportation costs results from pipeline constraints and lack of pipeline competition. The gas price at a hub in Florida, for example,

would be the price at the Henry Hub and the basis to the Florida hub.

Physical Trading of Natural Gas

Natural gas contracts are negotiated between buyers and sellers. There are many types of natural gas contracts, but most share some standard specifications, including specifying the buyer and seller, the price, the amount of natural gas to be sold (usually expressed in a volume per day), the receipt and delivery point, the tenure of the contract (usually expressed in number of days beginning on a specified day) and other terms and conditions. The special terms and conditions usually outline such things as the payment dates, quality of the natural gas to be sold, and any other specifications agreed to by both parties.

Natural gas contracts are negotiated between buyers and sellers over the phone or executed on electronic bulletin boards and e-commerce trading sites.

There are three main types of natural gas contracts: swing contracts, baseload contracts, and firm contracts:

- Swing (or interruptible) contracts are usually short-term contracts between one day and a month in length. These contracts are the most flexible, and are usually put in place when either the supply of gas from the seller, or the demand for gas from the buyer, are unreliable.
- Baseload contracts are similar to swing contracts. Neither the buyer nor seller is obligated to deliver or receive the exact volume specified. However, it is agreed that both parties will attempt to deliver or receive the specified volume, on a best-efforts basis.
- Firm contracts are different from swing and baseload contracts in that both parties are legally obligated to either receive or deliver the amount of gas specified in the contract. These contracts are used primarily when both the supply and demand for the specified amount of natural gas are unlikely to change.

Price Discovery

Spot (Cash) Market

The U.S. natural gas marketplace has a highly competitive spot, or cash, market where brokers and others buy and sell natural gas daily. The daily spot market for natural gas is active, and trading can occur 24 hours a day, seven days a week. The map on the next page shows some of the points where natural gas for next-day physical delivery is actively traded on the Intercontinental Exchange (ICE). Some of these points are market centers, where brokers actively trade and prices are established. In addition to these market centers, natural gas is actively traded at many other locations, including segments of individual pipelines and locations where pipelines interconnect with LDCs.

Spot market transactions are normally conducted on electronic exchanges or by telephone, with the buyer agreeing to pay a negotiated price for the natural gas to be delivered by the seller at a specified delivery point on the next day. Natural gas spot prices reflect daily supply and demand balances and can be volatile.

Bidweek

Bidweek is the name given to the last five business days of a month. This is the week when producers sell their core production and consumers buy natural gas for their core needs for the upcoming month.

Index Prices

Several publications, such as Platts Gas Daily, Natural Gas Intelligence and Natural Gas Week, survey the market for daily transaction prices that are used to form and publish a daily index that is made available the night before or the morning of the next business day. Many market participants also report their bidweek prices to publications, which convert these prices into monthly locational price indexes that are available on the first business day following the last day of bidweek. These daily and monthly indexes, in turn, are used as the basis for pricing for those firms that do not choose to enter into

fixed-price contracts (or are prohibited from using them by state or local regulators).

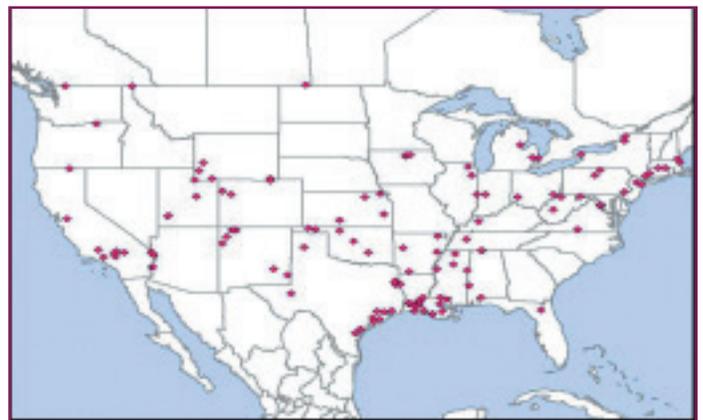
The Financial Market

In addition to trading physical natural gas, there is a significant market for natural gas derivatives and financial instruments in the United States. In the financial market, market participants are interested in profiting from the movement of the price of natural gas rather than delivering or receiving natural gas. The pricing and settlement of these financial products are tied to physical natural gas. It is estimated that the value of trading that occurs on the financial market is at least a dozen times greater than the value of physical natural gas trading.

Derivatives are financial instruments that derive their value from an underlying fundamental – in this case, the price of natural gas. Derivatives can range from being quite simple to being exceedingly complex. Traditionally, most derivatives are traded on the over-the-counter (OTC) market, which is essentially a group of market players interested in exchanging certain derivatives among themselves.

More information on financial markets appears in Chapter 5.

Hubs for Physical Trading on ICE



Source: Derived from Intercontinental Exchange data

3. WHOLESALE ELECTRICITY MARKETS

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 and, in larger quantities, megawatt-hour or MWh) is the amount of electricity a customer uses or a power plant generates over a period of time.

Electricity 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. Because FERC has jurisdiction over the wholesale markets, and not the retail markets, this paper focuses on wholesale electricity 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. Where rates are set based on costs, market fundamentals matter as well because changes in supply and demand will affect consumers by influencing the cost and reliability of electricity. Supply incorporates generation and transmission, which must be adequate to meet all customers demand simultaneously, instantaneously and reliably.

Consequently, key supply factors that affect 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.



Electric Power Industry

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 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 percent 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 amount of 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.

Coordinating exchanges of energy and 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 to ensure reliability, but no more than is needed. 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 power 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, shortly thereafter renamed the North American Electric Reliability Council (NERC) 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 day-ahead market software does this for suppliers bidding into regional transmission organization 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 next.

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 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 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.

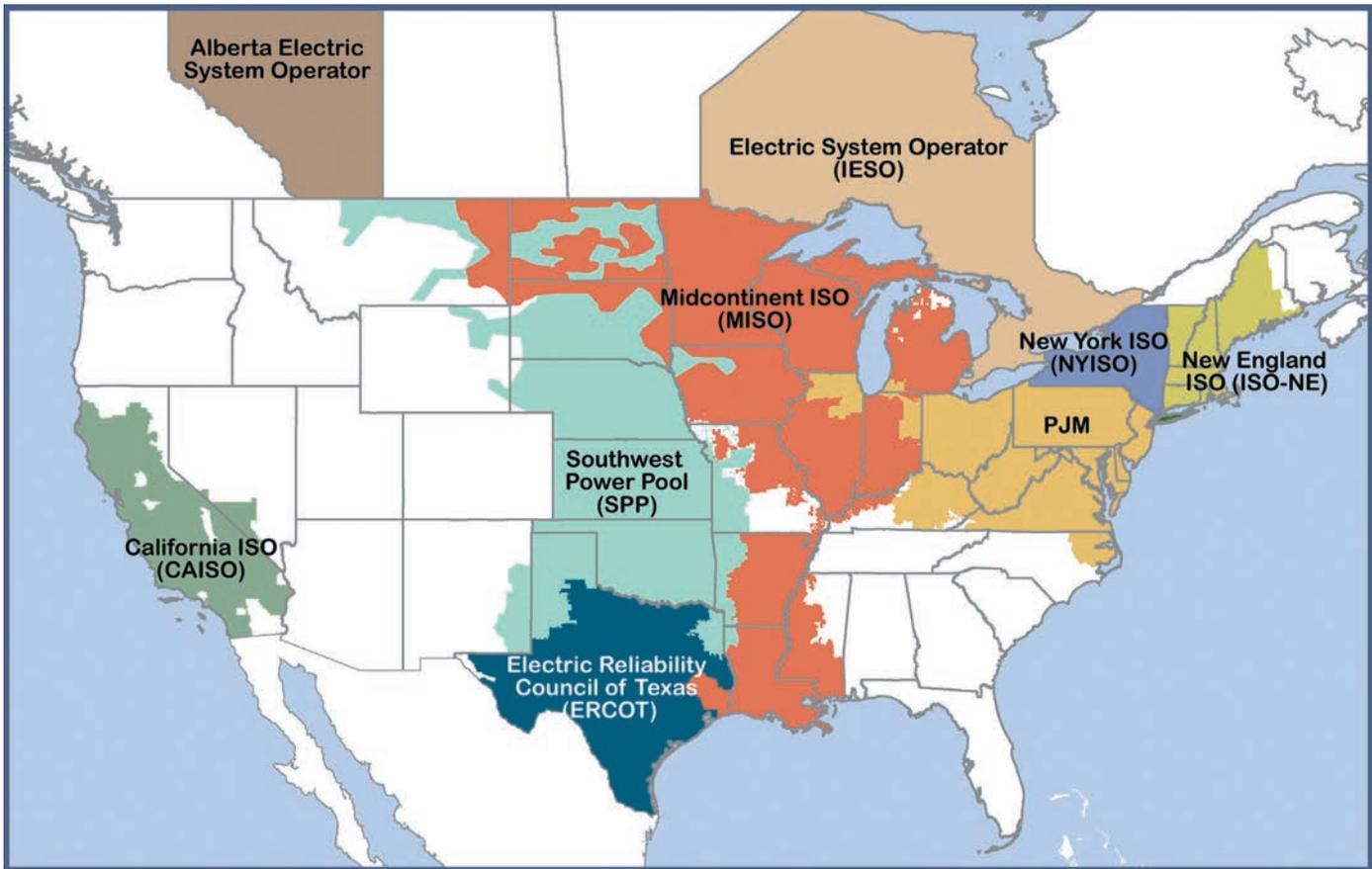
In 1988, FERC proposed rules to allow states to set their avoided-cost rate based on an auction. Instead of taking all capacity at a set rate, states could set the rate based on bids to supply a certain amount of needed capacity. The Commission also proposed to open the avoided-cost auction up to independent 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 No. 888 required mandatory open transmission access by all transmitting utilities and a reciprocity provision successfully extended open access to non-jurisdictional entities (municipal, cooperative and federal utilities).

Order No. 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.

North American Independent System Operators and Regional Transmission Organizations



Source: Velocity Suite, ABB

Competition, Part 2: Integrating Markets and Operations – RTOs

While the industry had historically traded electricity through bilateral transactions and power pool agreements, Order No. 888 promoted the concept of independent system operators (ISO). Along with facilitating open-access to transmission, an ISO would operate the transmission system independently of, and foster competition for electricity generation among, wholesale market participants. Several groups of transmission owners formed ISOs, some from existing power pools.

Close on the heels of Order No. 888, the Commission, in Order No. 2000, encouraged utilities to join regional transmission organizations (RTO) which, like an ISO, would operate the

transmission systems and develop innovative procedures to manage transmission equitably. The Commission's proceedings in Orders Nos. 888 and 2000, along with the efforts of the states and the industry, led to the voluntary organization of ISOs and RTOs. Each of the ISOs and RTOs subsequently developed a full scale energy and ancillary service market in which buyers and sellers could bid for or offer generation. The ISOs and RTOs used the bid-based markets to determine economic dispatch. Throughout the subsequent sections of the primer, the term RTO is used to stand for both ISOs and RTOs.

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, and cell phones. This use has been increasing, reaching over 3,860 gigawatt-hours (GWh) of electricity in 2014. Demand dropped in 2009 with the recession, but has since recovered. Subsequent to the recession, the trend in use has been flatter.

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 electricity markets.

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.

The amount of electricity consumed (demand) is continuously varying and 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, which are most acute during the daily peak load hours that occur during 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 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.

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, because higher levels of demand require activation of increasingly more expensive sources of power generation, and reductions as demand declines. As a result, power prices are typically highest during periods of peak demand. This causes system planners, power marketers and traders to 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 – electricity 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 may provide reduced rates or other compensation to customers who agree to reduce load in periods of electric system stress.

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 electricity 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 electricity use.

Climate and Weather

Weather is one of the primary factors 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 electricity 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 overall level of economic activity also affects power demand. During periods of robust activity, 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.

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°F standard - those in excess of 65° yield cooling degree days; those below 65° yield heating degree days. A day with an average temperature of 66° would yield one cooling degree day.

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, the load shape is flat, and the load will be base-load. 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 37 percent of electricity demand. Residential consumers use electricity for air conditioning, refrigerators, space and water heating, lighting, washers and dryers, computers, televisions 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 office buildings, hotels and motels, restaurants, street lighting, retail stores and wholesale businesses and medical, religious, educational and

social facilities.

More than half of commercial consumers' electricity use is for heating and lighting.

Industrial consumers use about 27 percent 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 than 1 percent of electricity 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 to 3 percent 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.

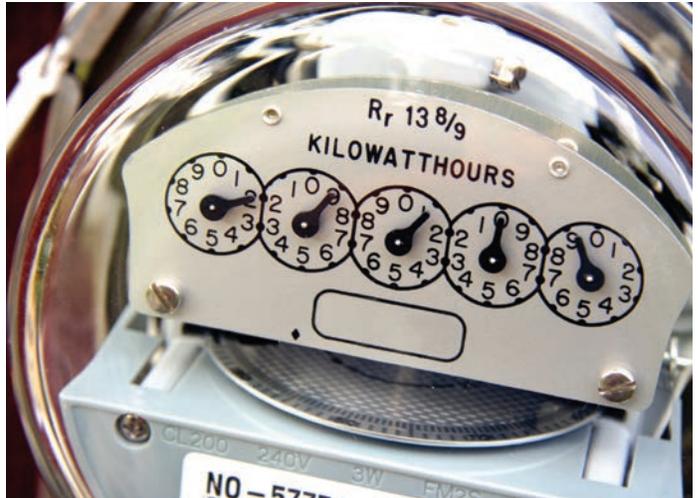
The medium- and long-term forecasts, while not precise, take into account historical load and weather data, the number of customers in different customer classes, appliances used in the area and their characteristics, economic and demographic data, and other factors. For the next-year peak forecast, 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

Electricity demand is generally insensitive to price, meaning that demand does not typically fall when wholesale prices rise. This occurs for several reasons, including that most end use consumers of electricity are not exposed to real-time electricity prices. However, some utilities and grid operators are developing ways to stimulate a response from consumers through demand-response programs.

Demand response (DR) is the reduction in consumption of electricity by customers from their expected consumption in response to either reliability or price triggers where the customer forgoes power use for short periods, shifts some high energy use activities to other times, or uses 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, an 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.

Curtailling, 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 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. DRR also can participate in wholesale electricity 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. Additionally, some DRR bids into RTO day-ahead (DA) markets as energy resources, specifying the hours, number of megawatts and price at which they are willing to curtail. RTOs set minimum bid values.

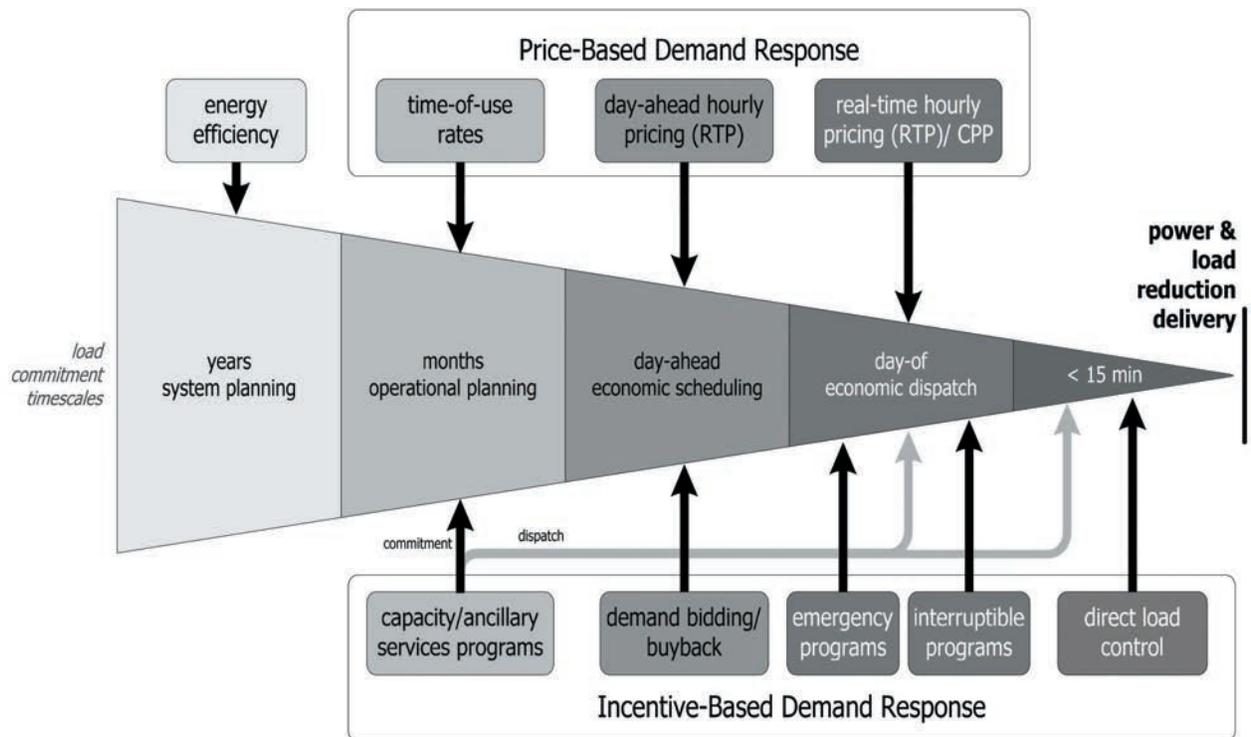
Some of the RTO DR comes from individual entities; the rest is accumulated through third-party aggregators, or curtailment service providers (CSPs), who recruit customers too small to participate on their own, such as schools, commercial chains

or groups of residential customers. In aggregating small customers, CSPs have increased customer participation in many wholesale reliability and emergency programs.

Demand-Response Use in Planning and Operations

Different DR programs can be used at various times to support planning and operations (see graphic). 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.

Demand-Response Program Use in Electric System Planning and Operations



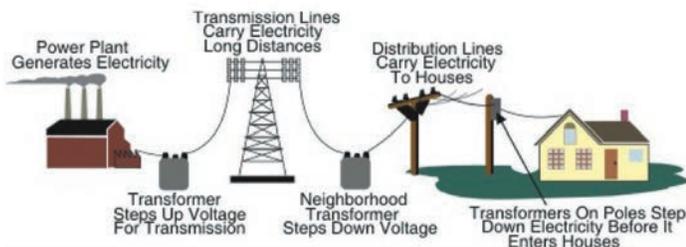
Source: U.S. Department of Energy

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 electricity 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.

Electricity Supply and Delivery



Source: National Energy Education Development Project

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.

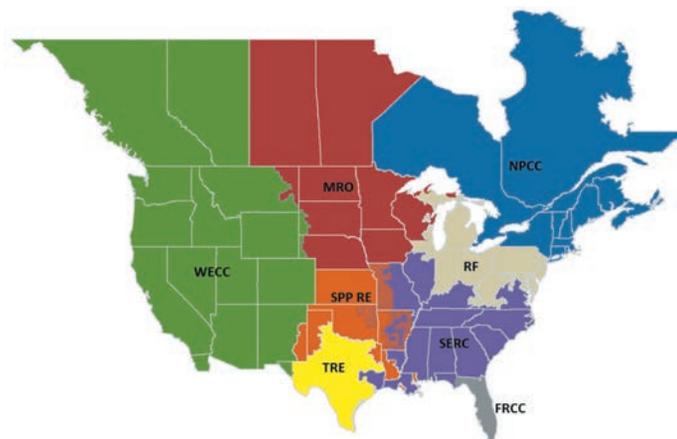
The nation, along with Canada and a small part of Mexico, is also divided into regional entities. The regional reliability entities fall under the purview of NERC, which was designated by

FERC as the nation’s energy reliability organization and which develops standards, among other things, to ensure the grid’s reliability. The standards, once approved 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.

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)
- Western Electricity Coordinating Council (WECC)

NERC Regions



Source: North American Electric Reliability Corporation

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.

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 CO₂ 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 and a few are under construction. The disposition of high-level radioactive waste remains an unresolved problem, and the waste remains at plant locations.

Conventional Generation

Natural gas power plants 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 generally not as economical or easy to site as some newer technologies – which explains why few have 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 system-wide 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 SO₂ and particulate emissions and their NO_x and CO₂ 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 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 located in the Southeast and Midwest.

Oil-fired plants generally produce only a small amount of the total electricity generated in the 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 provide roughly 20 percent of the nation's electricity; there are close to 100 operating units with a total capacity of approximately 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 or 24 months, 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.

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, an important part of total U.S. capacity and generation, accounted for 13 percent of 2014 electricity generation. As total generation from all fuels has remained relatively constant in the recent years, renewable generation's share has risen, spurred by state regulations and federal tax credits. As renewable generation becomes a larger per-

centage of generation resources, integrating them into the operating power grid has presented challenges.

Wind and solar capacity have grown faster than other renewable resources in recent years. Wind capacity grew ten-fold (from approximately 6 GW to 65 GW) between 2003 and 2014. Utility-scale solar capacity more than tripled (from approximately 3.1 GW to 10 GW) between 2012 and 2014.

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 lower (for example, approximately 30 percent), depending on the technology type, 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. Capacity factors have risen with technological innovation and improved manufacturing processes.

Wind generation is among the fastest-growing renewable resources, in part due to cost declines and technology improvements as well as earlier receipt of federal tax credits. Increases in average hub heights and rotor diameters have increased average wind turbine capacity.

Because the best wind resources are often far from load centers, obtaining sufficient 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 generation 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. Geothermal generation increased 14 percent from 2006 to 2014, but it decreased from 15 to 6 percent of non-hydro renewable output, due to the growth of other renewables. California hosts more than 80 percent of U.S. operating capacity.



Solar generation 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 increased greatly as a result of policy incentives and cost declines. Annual PV installations increased nearly

tenfold from 2009 to 2013 as PV system costs decreased. PV growth has been relatively concentrated; 10 states had 90 percent of PV capacity in 2014, while California alone had over half.

By the end of 2014, 1,760 MW of CSP was operational. 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 generation is powered by the kinetic energy of falling water that 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 generation includes production from many waste by-products, 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 provided tax incentives to spur renewable resource investments. Originally enacted in 1992, wind, biomass, geothermal, and other forms of renewable generation have been able to receive federal production tax credits (PTC) based on a facility's production. An inflation-adjusted credit, the PTC generally has a duration of 10 years from the date the facility goes online. The credit was initially set at 1.5¢/kilowatt hour (kWh) and its value in 2013 was 2.3¢/kWh or 1.1¢/kWh, depending on the type of qualifying resource. The PTC has been renewed and expanded numerous times, most recently at the end of 2014.

Another form of tax credit for renewables, including solar and other select renewable energy projects, has been a federal investment tax credit (ITC). The ITC has generally been for 30 percent of a project's equipment and construction costs.

Following the financial crisis of 2008, the American Reinvestment and Recovery Act (ARRA) provided developers with 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 eight 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.

Seven states mandate feed-in-tariffs (FITs) 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 me-

dium-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 350 in 2007 to 30,000 in 2012. 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

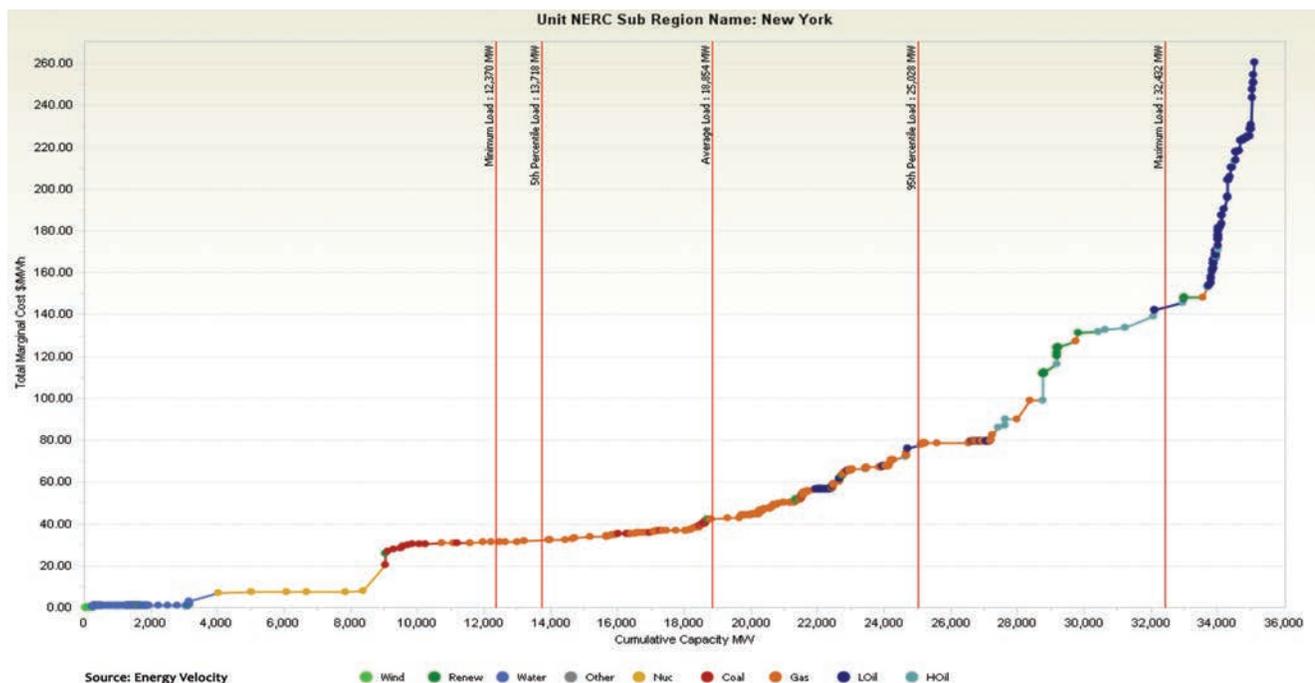
In the system dispatch stage, operators must decide in real time the level at which each available resource from the unit commitment stage should be operated, given the actual load and grid conditions, so that overall production costs are minimized. Actual conditions will vary from those forecast in 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 market supply curve of the power plants for the New York Independent System Operator (NYISO). This is also commonly called the supply stack. In it, all of the plants in the New York market 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 New York, 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.

Market Supply Curve for NYISO (Illustrative)



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

- **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.
- **Nonspinning reserves** come from generating units that can be brought online in 10 minutes. Nonspinning reserve

can also be provided by demand-side resources.

- **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 shut-down 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 electricity 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.

Wholesale Electricity 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 RTOs.

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.

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.

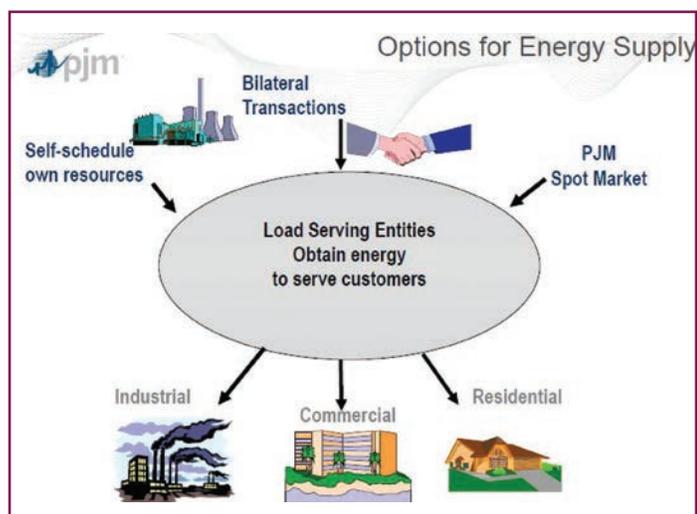
Market-Based Rates

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 erect barriers to entry or 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.



Source: PJM Interconnection

LSEs' sources of energy vary considerably. In ISO-NE, NYISO 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 Wholesale Electricity Markets

Traditional wholesale electricity markets exist primarily in the Southeast, Southwest and Northwest 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 electricity consumers. They may also include federal systems, such as the Bonneville Power Administration, the Ten-

nessee Valley Authority and the Western Area Power Administration. Wholesale physical power trading typically occurs through bilateral transactions. 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
- Coordinating its system development with neighboring systems

Regional Electricity Markets

Two-thirds of the population of the United States is served by electricity markets run by regional transmission organizations or independent system operators (this primer uses RTO to stand for both RTOs and ISOs). The main distinction between RTO markets and their predecessors (such as vertically integrated utilities, municipal utilities and co-ops) is that RTO markets deliver reliable electricity through competitive market mechanisms.

The basic functions of an RTO 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
- 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, transparently manage transmission congestion, 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 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 operate in the United States, listed below in order of the size of their peak load:

- PJM Interconnection (PJM), 165 GW (summer of 2011)
- Midcontinent ISO (MISO), 126 GW (summer of 2011)
- Electric Reliability Council of Texas (ERCOT), 68 GW (summer of 2011)
- California ISO (CAISO), 50 GW (summer of 2006)
- Southwest Power Pool (SPP), 48 GW (summer of 2011)
- New York ISO (NYISO), 34 GW (summer of 2013)
- New England ISO (ISO-NE), 28 GW (summer of 2006)

RTO Markets and Features

RTO market 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 RTO electricity markets have 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 bids and supply offers
- 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.



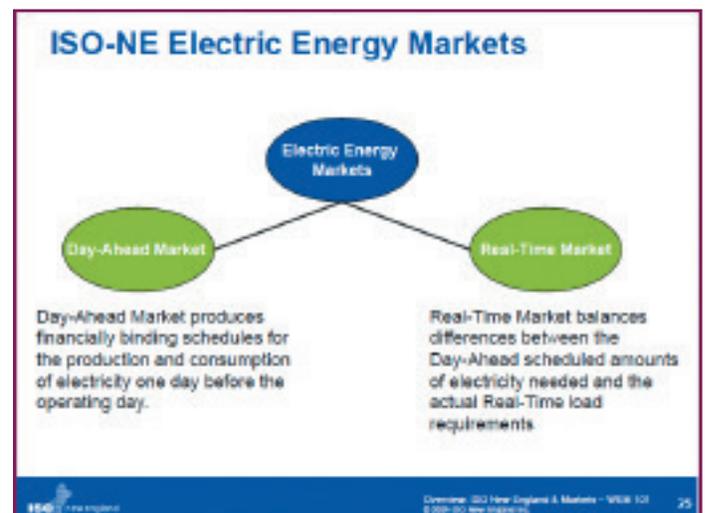
Source: ISO New England

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 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.



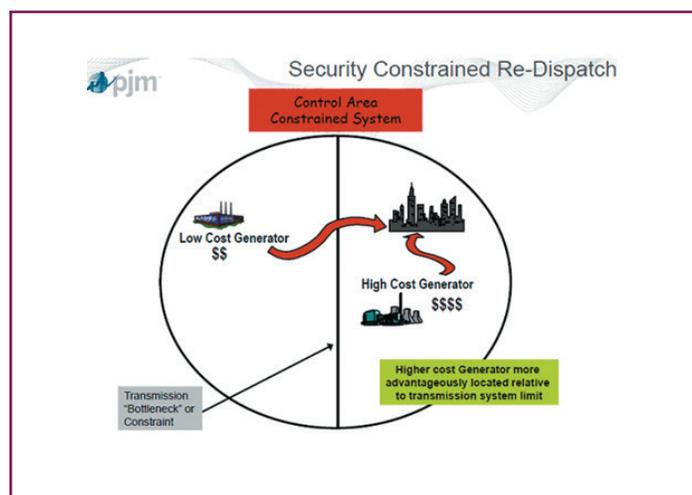
Source: ISO New England

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 congestion 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 is known as security constrained redispatch.

This redispatch could be implemented by using nonmarket procedures such as transmission loading relief (TLR). 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.



Source: PJM Interconnection

Scarcity pricing is a mechanism used by RTOs 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)
- 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. RTOs 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.

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 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. 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, the 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

All six FERC-jurisdictional RTOs trade FTRs or FTR equivalent products. 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 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. NYISO offers only the 24-hour product. The other RTOs

offer on-peak and off-peak products.

Allocated Rights: The RTOs allocate transmission rights to transmission owners or load-serving entities within their markets. In PJM, MISO, SPP, 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 differ-

ences 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.

Although a trader does not have to deliver power, the transaction is not strictly financial. Virtual transactions 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. Since these resources will be available to the real-time market, the fact that virtual load does not carry forward into the real-time market 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 theoretically 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 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 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 Rights by Transmission Grid

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

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.

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 recom-

mended plan for the entire RTO footprint.

Financial Policies

Financial settlements is the process through which payments due from customers and to generators are calculated. Such 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

Credit requirements are important in organized electricity markets in which RTOs must balance the need for market liquidity against corresponding risk of default. 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 Region

The Southeast electricity market is a bilateral market that includes all or parts of Florida, Georgia, Alabama, Mississippi, North Carolina, South Carolina, 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 Intero 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.

If a utility were building a large nuclear or coal-fired gener-

ating 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.

Resources

Within the Southeast, the resource mix varies between the

two NERC subregions. The FRCC uses more natural gas- and oil-fired generation than the rest of the Southeast, and it is the only Southeast area where oil is significantly employed. Natural 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 TVA sub-region has a majority of its capacity and output in coal and nuclear, while the VACAR sub-region has the highest utilization of nuclear generation in the Southeast. Over 70

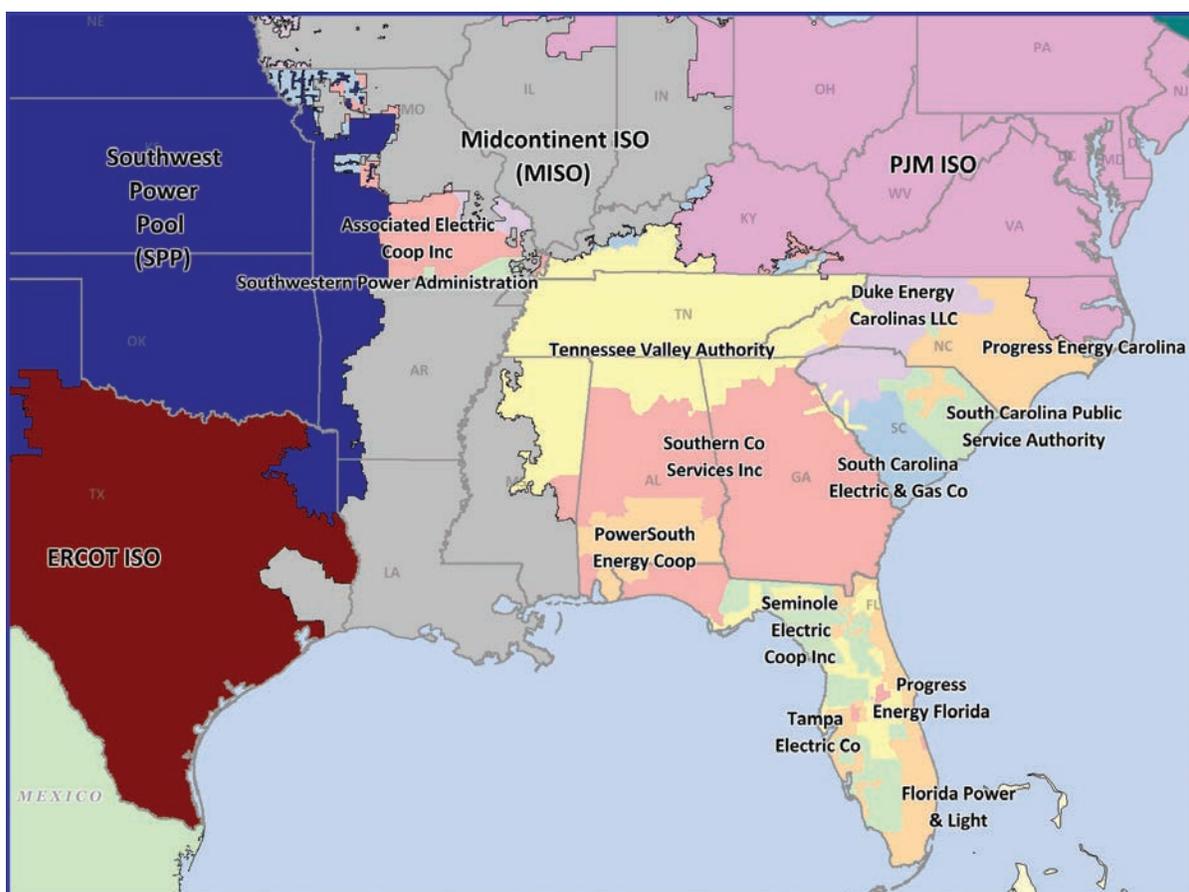
percent of this subregion’s output is from baseload coal and nuclear facilities.

Trading and Market Features

Physical and financial electricity products are traded using Into 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

Southeast Electric Region



Source: Velocity Suite, ABB

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 20 percent of the time.

Wholesale spot power markets in the Southeast have relatively 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 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, marketers contribute to the trading, as they have entered into multiyear agreements with generating units.

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.

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 Wholesale Market Regions

The power markets in the western United States are primarily bilateral markets. A key exception is most of California and portions of Nevada, which operate under CAISO. 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.

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 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 occasionally import power from neighboring regions when loads are high.



Trading and Market Features

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 percent 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 Electric System Operator 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.

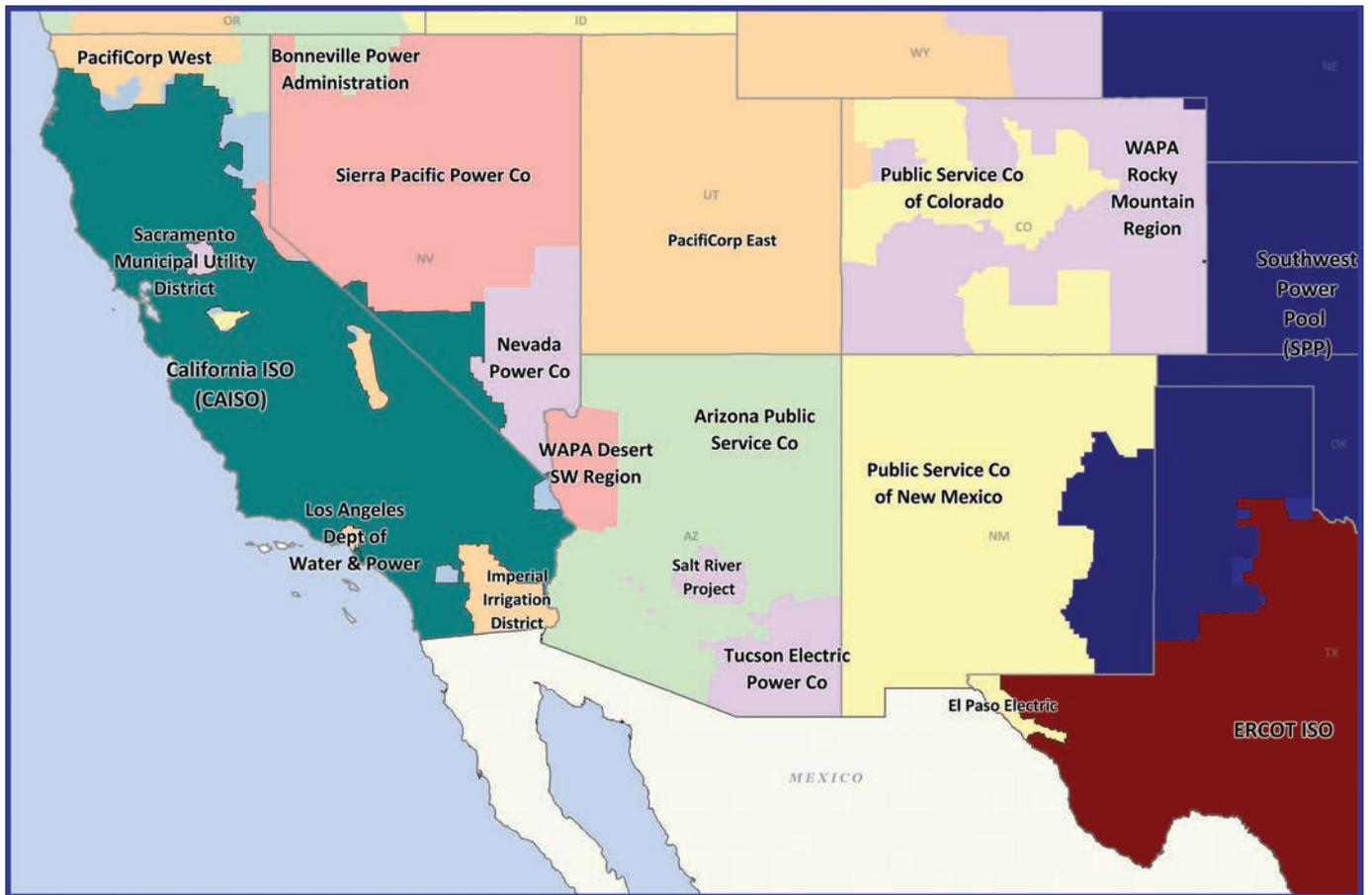
The ICE has four trading points in the Northwest: Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB) and Mona (Utah). Mid-C has the most traded volume by far, averaging more than 6,200 MW of daily on-peak physical trades in 2013. COB had nearly 1,000 MW, NOB had over 800 MW and Mona had 530 MW. Mid-C also has a fairly active physical forward market.

Southwest Electric Region

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 42 GW in summer. There are approximately 50 GW of generation capacity, composed mostly of gas and coal units.

The Southwest relies on nuclear and coal generators for base-load electricity, with gas units generally 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 plant with three units totaling approximately 4,000 MW, which has owners in California and the Southwest.

Southwest Electric Region



Source: Velocity Suite, ABB

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 power industry. The CAISO manages wholesale electricity markets, centrally dispatching electricity generation 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

Up to about one-third 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 investor-owned utilities (IOUs), which include Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and others such as the Valley Electric Association, to some municipal utilities 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.

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,
- Valley Electric Association
- Municipal utilities such as Vernon, Anaheim and Riverside

Chronic Constraints

Load pockets that are chronically constrained include San Diego, Los Angeles Basin, and North Coast/North Bay (San Francisco).

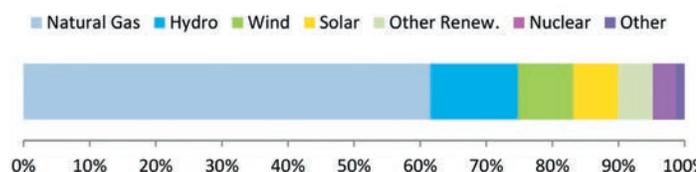
Transmission Planning

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

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Demand Response

Demand response participation in the wholesale energy market is currently limited to a small amount of demand associated with water pumping loads. Other demand response in California consists of programs for managing peak summer demands operated by the state’s electric utilities. In general, these demand-response programs may be triggered based on criteria that are internal to the utility or when CAISO issues a Flex Alert. Flex Alerts also inform consumers how and when to conserve electricity usage.

Market Features

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.

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 sched-

ule. 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 imports and exports as a starting point. It then operates a fifteen minute market to adjust resource schedules, and then a five minute market 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 synchronized.
- 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 de-

mand. 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 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.

Special Provisions for Resources Needed to Ensure Grid Reliability

An 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 near the San Francisco and Los Angeles areas.



Financial Transmission Rights

As discussed earlier in this chapter, FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. In California, FTRs are referred to as Congestion Revenue Rights (CRR). A CRR is an instrument that entitles the CRR holder to a payment for

costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The CRR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. 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.

Virtual Transactions

CAISO's market includes a virtual transactions feature, termed convergence bidding, that allows more participation in the day-ahead price-setting process, allows participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time energy markets. CAISO's convergence bidding includes both virtual supply and virtual demand transactions. A virtual supply transaction is an offer to sell at the day-ahead price and a bid to buy at the real-time price. A virtual demand transaction is a bid to buy at the day-ahead price and an offer to sell at the real-time price. The virtual supply offer and the virtual demand bid 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.

Credit Requirements

CAISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. CAISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions

– e.g., CAISO must review the entity’s request relative to various creditworthiness-related specifications such as tangible net worth, net assets, and credit rating.

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 conducts settlements for a grid management charge, bid cost recovery, energy and ancillary services, CRR charges and payments, among other charges. The CAISO settles for both the day-ahead market and the real-time market.

CAISO – PacifiCorp Energy Imbalance Market

On Nov. 1, 2014, CAISO began operation of an energy imbalance market (EIM) with PacifiCorp’s two balancing authority areas, PacifiCorp East (PACE) and PacifiCorp West (PACW). CAISO extended its existing real-time market into the PacifiCorp to automatically dispatch resources to meet intra-hour changes in energy demand and supply. Resources participate in the EIM voluntarily and only resources that register to participate may actually bid into the EIM for the 15- and 5- minute market runs. Load buys imbalance energy directly from the EIM. For example, PacifiCorp, the largest LSE in PACE and PACW areas, buys imbalance energy through the EIM. Other entities that may purchase imbalance energy include wind generators that seek to match their generation supply with contracted demand.

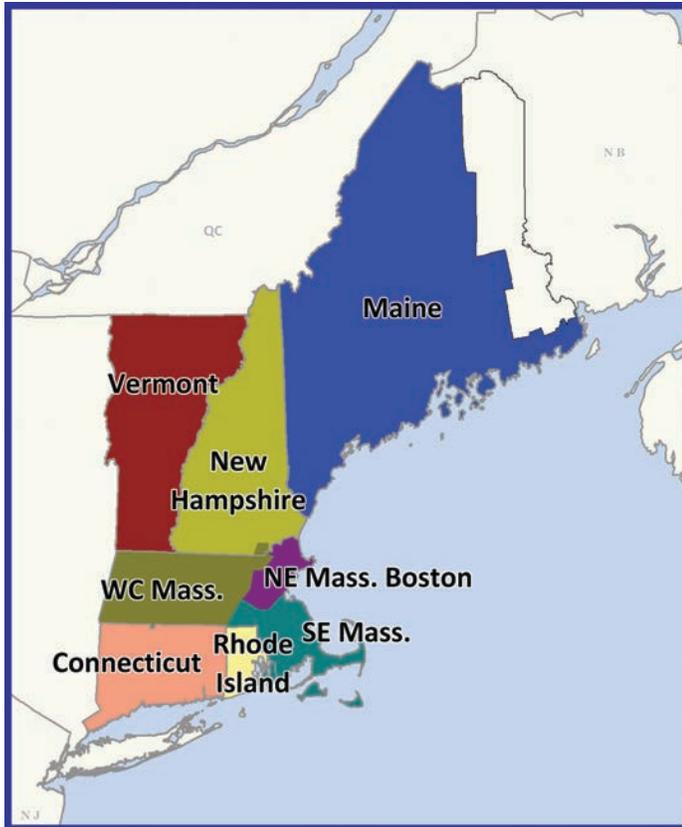
The three balancing authorities – CAISO, PACE, and PACW –



may transfer imbalance energy through a limited amount of transmission capability. Consequently, prices and supply are largely determined by resources within each area. CAISO’s Department of Market Monitoring serves as the market monitor for the EIM. While the CAISO’s operations remain under the CAISO Board of Governors, an EIM Transitional Committee advises CAISO’s board of governors and is developing a proposal for long-term EIM governance. Among other benefits, the EIM may provide a broader footprint for incorporating renewable generation and an opportunity to improve the economic efficiency of generation dispatch.

ISO-NE

New England Independent System Operator



Source: Velocity Suite, ABB

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 summer 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 around 15 percent of its annual energy needs from Québec, NYISO, and New Brunswick. 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, non-stakeholder board of directors. The sitting members of the board elect people to fill board vacancies.

Transmission Owners

ISO-NE's transmission owners include:

- Central Maine Power Co.
- New England Power Co.
- Northeast Utilities System Cos.
- NSTAR Electric Co.
- The United Illuminating Co.
- Vermont Electric Cooperative Inc.

Chronic Constraints

Constraints in the ISO-NE are concentrated in the Northeast Massachusetts-Boston zone. However, New England completed a series of major transmission projects in 2009 to improve reliability, including projects serving Boston, southwestern Connecticut and southeastern Massachusetts. Fur-

thermore, it continues to assess and bolster its transmission system.

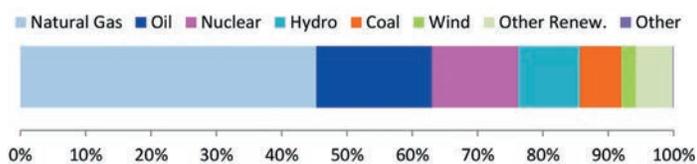
Transmission Planning

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

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Demand Response

Currently, ISO-NE administers the following demand-response programs for the New England wholesale electricity market:

- **Real-Time Demand Response Resources (RTDR):** These resources are required to respond within 30 minutes of the ISO's instructions.
- **Real-Time Emergency Generation Resources (RTEG):** Resources that the ISO calls on to operate during a 5 percent voltage reduction that requires more than 10 minutes to implement. They must begin operating within 30 minutes of receiving a dispatch instruction.
- **Transitional Price-Response Demand:** An optional program that allows market participants with assets registered as RTDRs to offer load reductions in response to day-

ahead LMP. 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

Energy Markets

Day-Ahead Market

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 DEC 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 LMPs for all locations.

Real-Time Market

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. 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 Auction (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. 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.

Special Provisions for Resources Needed to Ensure Grid Reliability

When a resource owner requests to withdraw from the capacity market (termed a "delist bid") or to retire the resource (termed a "non-price retirement request"), the ISO evaluates whether the resource is needed for reliability, such as when a resource's withdrawal could lead to a violation of a reliability requirement – e.g., inadequate reserve margins or a loss of electric system stability.

In New England, the resource owner has the option to retire the unit or continue to operate it while the ISO works with regional stakeholders to find alternate supply or engineering solutions that could allow the resource to retire and still maintain grid reliability. Alternative solutions might include obtaining emergency sources of generation or more expensive generation from outside the region. If no other alternative is available, the ISO may compensate the unit through certain payment provisions of the capacity market or by entering into a cost of service agreement with the resource owner while other options are pursued.

Financial Transmission Rights

New England FTRs are monthly and annual products that provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead energy market. An FTR is an instrument that entitles the FTR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. The RTO holds FTR auctions to allow market participants the opportunity to acquire FTRs or to sell FTRs they currently hold. In New England, ARR represents the right to receive revenues from the FTR auctions. ISO-NE allocates ARRs to both LSEs, in relation to historic load, and to entities who make transmission upgrades that increase the capability of the transmission system.

Virtual Transactions

New England's market includes a virtual transaction feature. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. In ISO-NE's terminology, virtual transactions consist of market participants submitting increment offers and decrement bids in the day-ahead energy market. An increment offer is an offer to sell energy at a specific location in the day-ahead energy market which is not associated with a physical supply. An accepted increment offer results in scheduled generation at the specified location in the day-ahead energy market. A decrement bid is a bid to purchase energy at a specific location in the day-ahead energy market which is not associated with a physical load. An accepted decrement bid results in scheduled load at the specified location in the day-ahead energy market. The participant receives the day-ahead LMP for each megawatt of virtual supply that clears in the day-ahead energy market and is financially obligated to pay the real-time LMP at the same location. Conversely, the participant pays the day-ahead LMP for each megawatt of cleared virtual demand and receives the real-time LMP at that location.

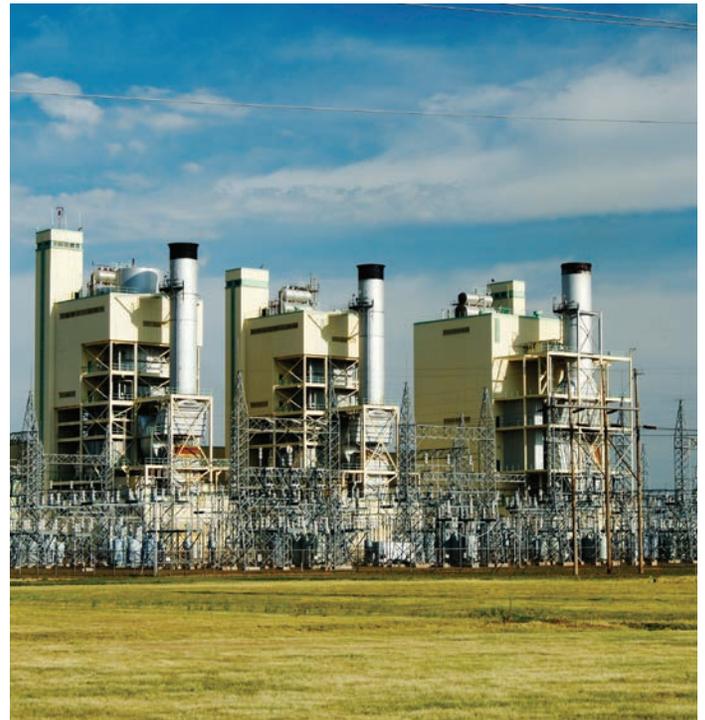
Credit Requirements

ISO-NE's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. ISO-NE assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. ISO-NE establishes a credit limit for each market participant in accordance with tariff formulas that include various creditworthiness-related specifications such as tangible net worth and total amounts due and owing to the ISO-NE market.

Settlements

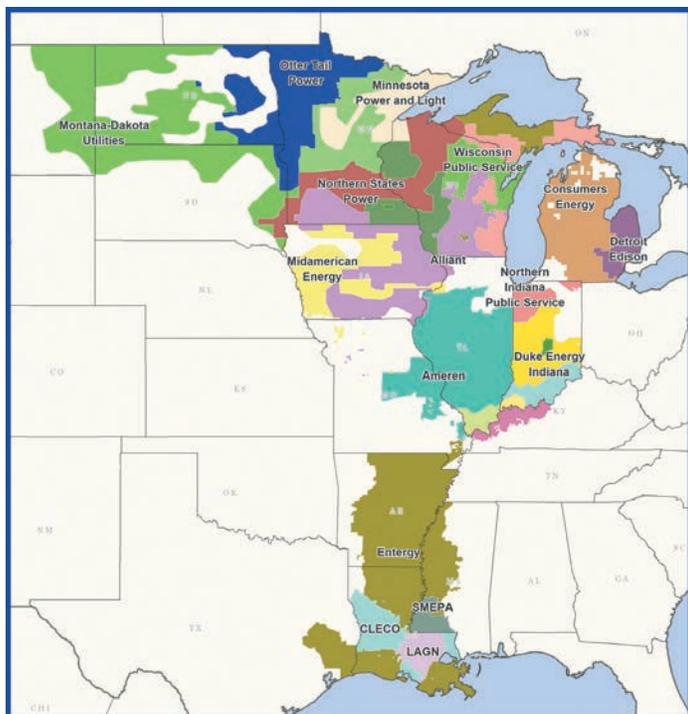
RTOs must invoice market participants for their involvement in their markets. Settlements is the process by which the RTO determines the amounts to be paid associated with buying and selling energy, capacity and ancillary services, and paying administrative charges.

ISO-NE calculates, accounts for and settles all charges and payments based on received settlement quality meter data. The RTO conducts settlements for transactions related to the various wholesale electricity markets, market products, and other services including energy, capacity, ancillary services, FTR charges and payments, among other charges. The RTO settles for both the day-ahead and real-time markets.



MISO

Midcontinent Independent System Operator



Source: Velocity Suite, ABB

Market Profile

Geographic Scope

MISO operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi. The system is operated from three control centers: Carmel, Indiana; Eagan, Minnesota; and Little Rock, Arkansas. 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. In 2013, the RTO began operations in the MISO South region, including the utility footprints of Entergy, Cleco, and South Mississippi Electric Power Association, among others, in parts of Arkansas, Mississippi, Louisiana, and Texas.

Peak Demand

MISO's all-time peak load was 126 GW in summer 2011, prior to the MISO South integration and prior to the move of Duke Energy Ohio and Kentucky to PJM.

Import and Exports

MISO has interconnections with the PJM and Southwest Power Pool (SPP) RTOs. It is also directly connected to Southern Co., TVA, the Western Area Power Administration, 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 approximately 40 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
- Duke
- Cleco
- Entergy
- 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. 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. New Orleans and east Texas are also two constrained areas in MISO South. Additionally, constraints arise between Missouri and Arkansas, which connects the MISO Midwest with MISO South.

Transmission Planning

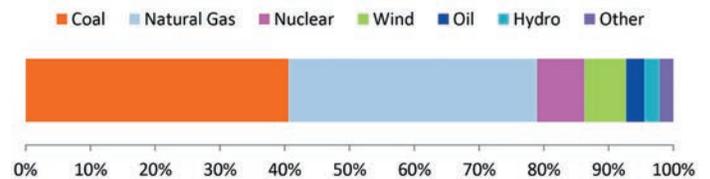
The main vehicle MISO uses for transmission planning is the MISO Transmission Expansion Plan developed by the MISO planning department in collaboration with transmission owners and other stakeholders who form the planning advisory

committee. The plan is for two years. Once approved by the board, the plan becomes the responsibility of the transmission owners.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

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

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.

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 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 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 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 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 an annual 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 an annual capacity auction, bilateral purchase, or self-supply.

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.

Special Provisions for Resources Needed to Ensure Grid Reliability

In MISO, a power plant owner seeking to retire or suspend a generator must first obtain approval from MISO. MISO evaluates plant retirement or suspension requests for reliability need, and System Support Resource (SSR) designations are made where reliability is threatened. Once an agreement has been reached, SSRs receive compensation associated with remaining online and available.

Financial Transmission Rights

MISO FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the

day-ahead market. An FTR is an instrument that entitles the FTR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. Payments, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the selected FTR transmission path. MISO FTRs are monthly and annual products.

The RTO holds FTR auctions to allow market participants the opportunity to acquire FTRs, sell FTRs they currently hold, or to convert ARR to FTRs. ARRs provide LSEs, and entities who make transmission upgrades, with a share of the revenues generated in the FTR auctions. MISO allocates ARRs to transmission customers relative to historic usage, or upgraded capability, of the transmission system.

Virtual Transactions

MISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. 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.

MISO allows virtual bids and offers into its day-ahead 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

MISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions – e.g., the RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

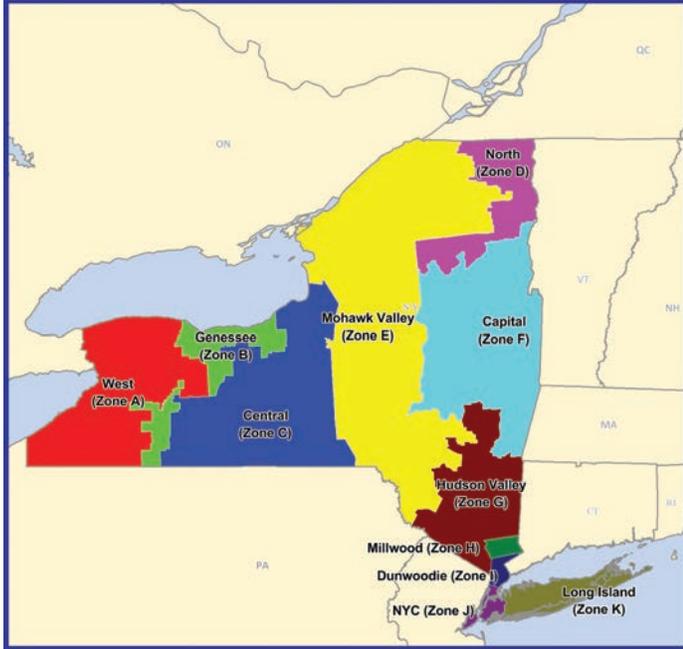
Settlements

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



Source: Velocity Suite, ABB

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.

Peak Demand

NYISO's all-time peak load was 34 GW in summer 2013.

Imports and Exports

NYISO imports and exports energy through interconnections with ISO-NE, PJM, TransEnergie (Quebec) and Ontario. Under a long-term agreement, approximately 1,000 MW of electricity regularly flows from the Consolidated Edison (Con Ed) territory in upstate New York through PSEG territory in PJM, to New York City utilizing phase angle regulator-controlled lines. This is commonly referred to as the Con Ed-PSEG Wheel and is an important source of power for NYISO.

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 Owners

NYISO's transmission owners include:

- Central Hudson Gas & Electric Corp.
- Consolidated Edison Co. of New York
- 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.

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.

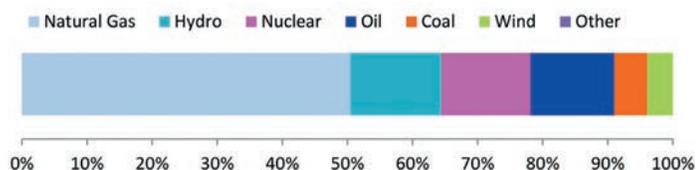
Transmission Planning

NYISO conducts a biennial transmission planning process with stakeholders that includes both short-term and long-term projects.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

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 (DADRP) and the Demand-Side Ancillary Services Program (DSASP).

Both the emergency and special cases programs can be de-

ployed 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 DADRP 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 DSASP 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

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 LMPs for all locations. The NYISO refers to LMPs 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 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 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 trans-

mission 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 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 ar-

rangements 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 four zones: New York City, Long Island, Lower Hudson Valley, 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 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 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.

Price Caps

NYISO has an offer cap of \$1,000/MWh for its day-ahead and real-time markets.

Capacity 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.

Special Provisions for Resources Needed to Ensure Reliability

Generation owners within New York seeking to retire or suspend a generator must first obtain approval from state regulators. After an assessment, if the generator is found to be necessary for reliability purposes, the local transmission owner can be compelled to reach a contract (Reliability Support Services Agreement) with the generator where compensation provisions are included to continue operation of the plant until the reliability need is resolved.

Financial Transmission Rights

FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. The NYISO refers to FTRs as Transmission Congestion Contracts (TCCs). A TCC is an instrument that entitles the holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations (or nodes) on the grid. The TCC also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. Payments, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the selected FTR transmission path.

A related product, ARRs, provide their holders with a share of the revenue generated in the TCC auctions. In general, ARRs are allocated based on historical load served. As with TCCs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.



Virtual Transactions

NYISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. 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. Virtual bidding in NYISO takes place on a zonal level, not a nodal level.

Credit Requirements

NYISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. NYISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions – e.g., NYISO must review the entity's request relative to various creditworthiness-related specifications such as investment grade or equivalency rating and payment history.

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



Source: Velocity Suite, ABB

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.

Peak Demand

PJM's all-time peak load was 165 GW in summer 2011.

Imports and Exports

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

The largest transmission owners in PJM include:

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

Chronic Constraints

The largest constraints are in the Eastern Hub of PJM (New Jersey, Southeast Pennsylvania, and Delaware) and Northern Ohio. 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 and thus on transmission across Pennsylvania and up from southwestern PJM to import power from sources west and southwest.

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.

In recent years, transmission congestion has not been as severe, due to upgrades to the transmission system, including construction of new transmission lines. Additionally, the availability of lower-cost natural gas has helped reduce the need for the eastern portion of PJM to import power from the west.

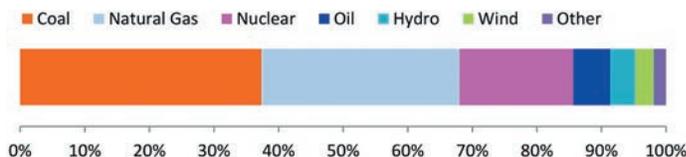
Transmission Planning

PJM's Regional Transmission Expansion Plan 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

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Demand Response

End-use customers providing demand response have the opportunity to participate in PJM's energy, capacity, synchronized reserve and regulation markets. PJM's DR 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 an offer into the day-ahead market that clears; submitting an 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

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.

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 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 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.

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 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 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 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.

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 an 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.

Furthermore, 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.

Capacity Markets

Capacity markets provide a means for 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 reliably. 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 whether each capacity seller has market power. If the seller fails that test, that seller's bid is capped so as to replicate that seller's avoidable or opportunity costs.

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 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.



Special Provisions for Resources Needed to Ensure Grid Reliability

A generator owner who wishes to retire a unit must request from PJM to deactivate the unit at least 90 days in advance of the planned date. The owner includes in the request an estimate of the amount of project investment necessary to keep the unit in operation. PJM, in turn, analyzes if the retirement would lead to a reliability issue. Additionally, the RTO estimates the period of time it would take to complete transmission upgrades necessary to alleviate the reliability issue.

If PJM requests the unit to operate past the desired deactivation date, the generator owner may file with FERC for cost recovery associated with operating the unit until it may be deactivated. Alternatively, the owner may choose to receive avoided cost compensation calculated according to PJM's tariff.

Financial Transmission Rights

FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. An FTR is an instrument that entitles the holder to

a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. Payments, or charges, are calculated relative to the combined difference in congestion prices in the day-ahead and real-time markets across the selected FTR transmission path.

A related product, ARRs, provide their holders with a share of the revenue generated in the FTR auctions. In general, ARRs are allocated based on historical load served and can be converted to FTRs. As with FTRs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

Virtual Transactions

PJM's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. 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. Up-to-congestion (UTC) transactions are another type of transaction that may be submitted in the day-ahead energy market between any two buses either within PJM or between a bus within PJM and an external interface. UTC positions are liquidated in the real-time energy market.

Credit Requirements

PJM’s tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions – e.g., the RTO must review the entity’s request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

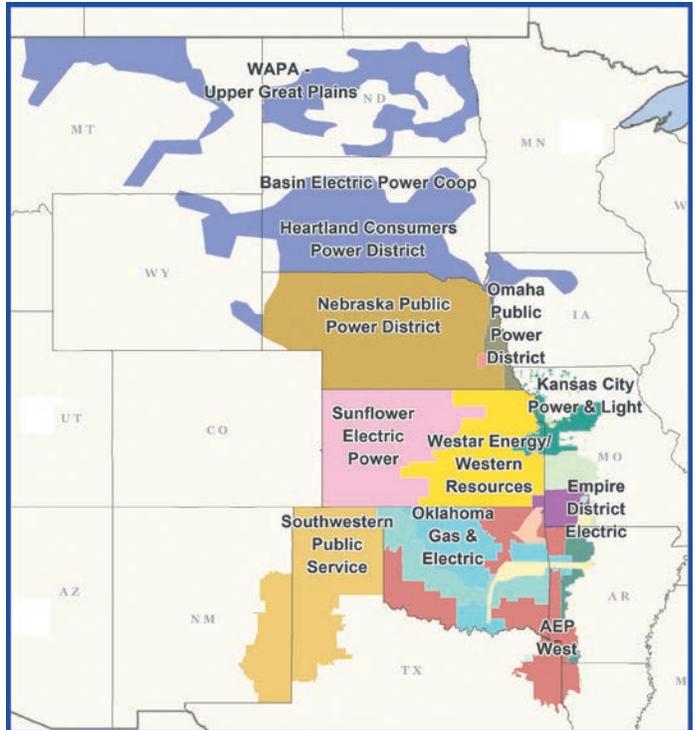
Settlements

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



Source: Velocity Suite, ABB

Market Profile

Geographic Scope

Founded as an 11-member tight power pool in 1941, Southwest Power Pool (SPP) achieved RTO status in 2004, ensuring reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices for its members. Based in Little Rock, Ark., SPP manages transmission in 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Its membership is comprised of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers and independent transmission companies.

In 2007, SPP began operating its real-time Energy Imbalance Service (EIS) market. In the same year, SPP became a FERC-approved Regional Entity. The SPP Regional Entity serves as the reliability coordinator for the NERC region, overseeing compliance with reliability standards.

In March 2014, SPP implemented its Integrated Marketplace that includes a day-ahead energy market, a real-time energy market, and an operating reserve market. SPP's Integrated Marketplace also includes a market for Transmission Congestion Rights. The SPP Integrated Marketplace co-optimizes the deployment of energy and operating reserves to dispatch resources on a least-cost basis.

In 2015, SPP expanded its footprint incorporating the Western Area Power Administration – Upper Great Plains region, the Basin Electric Power Cooperative, and the Heartlands Consumer Power District. The expansion nearly doubled SPP's service territory by square miles, adding more the 5 GW of peak demand and over 7 GW of generating capacity.

Peak Demand

SPP's all-time peak demand of 48 GW occurred in summer 2011.

Import and Exports

SPP has interties with MISO, PJM, and Tennessee Valley Authority, among other systems. Additionally, SPP has two direct-current (DC) interties with ERCOT and seven DC interties to the western interconnect through New Mexico, Colorado, Nebraska, South Dakota and Montana. 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, municipal utilities, state agencies, transmission owners, financial participants, and a federal power marketing administration.

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 entities 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 Area Power Administration – Upper Great Plains
- Western Farmers Electric Cooperative

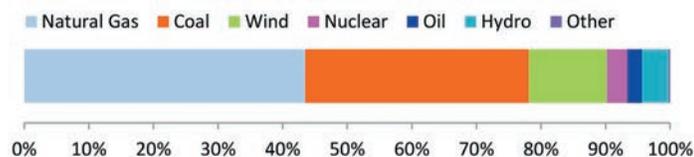
Transmission Planning

SPP conducts its transmission planning according to its Integrated Transmission Planning process, which is a three-year planning process that includes 20-year, 10-year, and near-term assessments designed to identify transmission solutions that address both near-term and long-term transmission needs. The Integrated Transmission Planning process focuses on identifying cost-effective regional transmission solutions, which are identified in an annual SPP Transmission Expansion Plan report.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Market Features

Energy Markets

Day-Ahead

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.

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 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.

Real-Time

SPP 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, SPP operates a spot market for energy called the real-time market.

The real-time market uses final day-ahead schedules for resources within the RTO and imports and exports as a starting point. It then operates a five-minute market to balance generation and loads.

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 SPP, 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.

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

- Regulation Up reserves: Resources providing this Regulation Up must be able to move quickly above their scheduled operating point in response to automated signals from the RTO to maintain the frequency on the system by balancing generation and demand.
- Regulation Down reserves: Resources providing Regulation Down must be able to move quickly below their scheduled operating point in response to automated signals from the RTO to maintain the frequency on the system by balancing generation and demand.
- Spinning Reserves: Resources providing Spinning Reserves are already synchronized to the grid and available to serve load within a short period following a contingency event such as an unexpected failure or outage of generator, transmission line, or other electrical element.
- Supplemental Reserves: Resources that are on-line and/or off-line but capable of being synchronized to the grid and fully available to serve load following a specified period following a contingency event.

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 non-storable 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 de-

sign mechanism to ensure competitive offers even when competitive conditions are not present. Market power may need to be mitigated on a systemwide basis or locally.



SPP applies a set of behavioral and market outcomes 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 – i.e., offer prices close to short-run marginal costs. SPP’s mitigation test includes a local market power test, a pivotal supplier test, and a market impact test. Where mitigation measures are triggered by the tests, SPP generates a mitigated market solution that the RTO then uses for dispatch, commitment, and settlement purposes.

Price Caps

SPP employs an offer cap of \$1,000/MWh.

Special Provisions for Resources Needed to Ensure Grid Reliability

SPP prepares annual reliability studies as part of its system planning responsibilities. In the event that studies reveal a potential constraint on SPP's ability to deliver power to a local area on the transmission system, the RTO works with regional stakeholders to find alternate transmission, operating procedure, or generation solutions for the constraint and thus maintain grid reliability. SPP parties will determine an appropriate sharing of the costs, and, if unable to reach agreement, the RTO will submit a proposed cost sharing arrangement to the Commission for approval.

Financial Transmission Rights

Financial FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. SPP refers to FTRs as Transmission Congestion Rights (TCRs). A TCR is an instrument that entitles the holder to receive compensation, or requires the holder to pay a charge, for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. A TCR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the selected TCR transmission path. SPP TCRs are monthly and annual products.

A related product, ARRs, provide their holders with a share of the revenue generated in the TCR auctions. In general, ARRs are allocated based on historical load served. As with TCRs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

Virtual Transactions

SPP's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transac-

tions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. 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 LMPs at the location at which the offer or bid clears.

Credit Requirements

SPP's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions – e.g., the RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and various financial measures.

Settlements

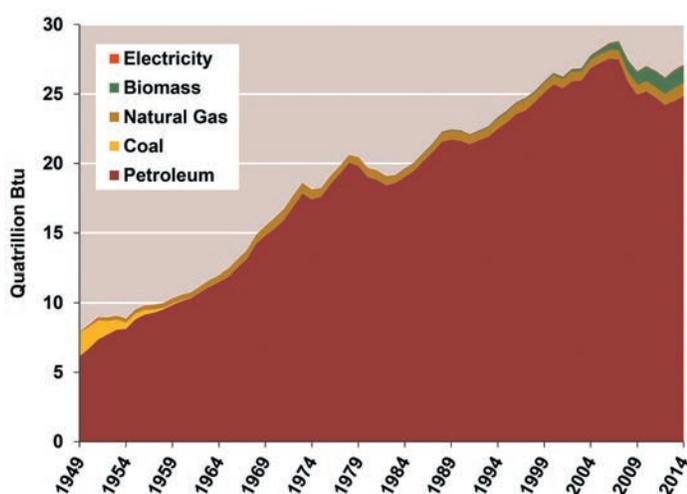
RTOs must invoice market participants for their involvement in their markets. Settlement is the process by which the RTO determines the amounts owed associated with buying and selling energy, capacity and ancillary services, and paying administrative charges.

SPP has a two-settlement system, one each for the day-ahead and real-time markets. The SPP settlement process calculates quantities of energy, ancillary services, TCRs, virtual transactions, among other market features.

4. U.S. CRUDE OIL & PETROLEUM PRODUCTS MARKETS

Petroleum, or crude oil, and its derived petroleum products play a key role in the U.S. economy, accounting for approximately one third of primary energy consumption in the U.S. in 2014. Its role is especially important in the transportation sector where, despite a steady increase in non-petroleum transportation fuels since 2000, petroleum products accounted for 92 percent of all transportation fuels in 2014. The remaining 8 percent consisted of biomass fuels (ethanol and biodiesel), natural gas, and electricity.

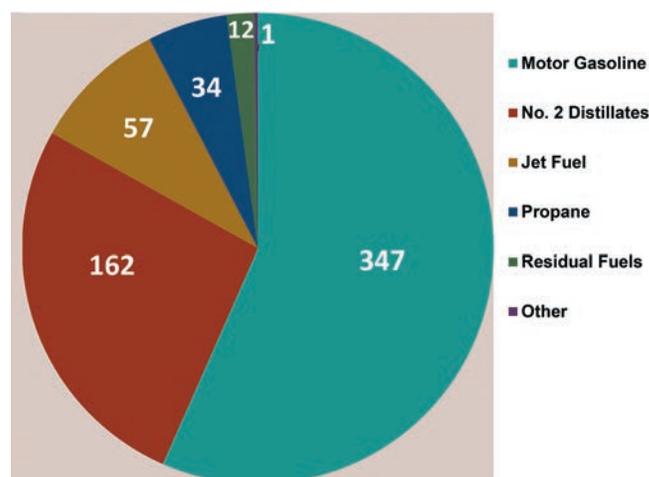
Petroleum Accounts for Most of the Energy Consumption in the Transportation Sector



Source: Derived from EIA data

Unlike methane, the primary component of pipeline grade natural gas, petroleum is not consumed in its natural form; instead, it is refined into a number of products that can be used for numerous applications. In the U.S., the largest share of crude oil, approximately 90 percent, is consumed as transportation fuels, including gasoline, diesel, and jet fuel. Other uses include heating, power generation, and petrochemical feedstocks used to manufacture a variety of products including plastics, pharmaceuticals, fertilizers, and construction materials.

U.S. Petroleum Products Supply in 2014 (Million gallons/day)



Source: Derived from EIA data

Petroleum is both produced domestically and imported from a number of countries. The same is true for petroleum products, especially gasoline, diesel fuel, and jet fuel. The percent of imported petroleum and petroleum products has been decreasing in recent years as U.S. crude oil production from shale has increased. Nearly 50 percent of U.S. crude oil production comes from Texas and North

FERC Jurisdiction

The Federal Energy Regulatory Commission's jurisdiction over the oil markets is limited to setting pipeline transportation rates and ensuring open access in the pipeline system.

Dakota, although significant amounts are produced in other states. U.S. refineries, which convert the crude oil into usable products, are found throughout the country, but are heavily concentrated on the Gulf Coast.

Petroleum

Unlike natural gas, which is a simple molecule consisting of 1 carbon atom and four hydrogen atoms (CH₄), petroleum as found in the ground is a mixture of hydrocarbons that formed from plants and animals that lived millions of years ago. Crude oil exists in a liquid form in underground pools or reservoirs,

Density of an Oil (API Gravity)

The density, or “weight,” of an oil is one of the largest determinants of its market value (another key characteristic is sulfur content – see text box, “Sweet or Sour?”). The density of an oil is often referred to as “light” or “heavy” and is measured using API gravity. API gravity is determined using the specific gravity of an oil, which is the ratio of its density to that of water (density of the oil/density of water) at 60 degrees Fahrenheit. Oils are generally classified as:

Light – API > 31.1 Medium – API between 22.3 and 31.1
Heavy – API < 22.3 Extra Heavy – API < 10.0

However, specific oils may be categorized differently depending on the region where they are produced and how the oil is referred to by commodity traders.

Though specific gravity is a unitless number, API gravity values in practice are often referred to as degrees. The API gravity of West Texas Intermediate is said to be 39.6 degrees. API gravity moves inversely to density, which means the denser an oil the lower its API gravity. An API of 10 is equivalent to water, which means oils with an API above 10 will float on water while oils with an API below 10 will sink.

in tiny spaces within sedimentary rocks, and near the surface in tar (or oil) sands. In its natural state, crude oil ranges in density and consistency, from very thin, light-weight and volatile fluidity to extremely thick, semi-solid heavy-weight oil. Its color can vary from a light golden yellow to a deep black.

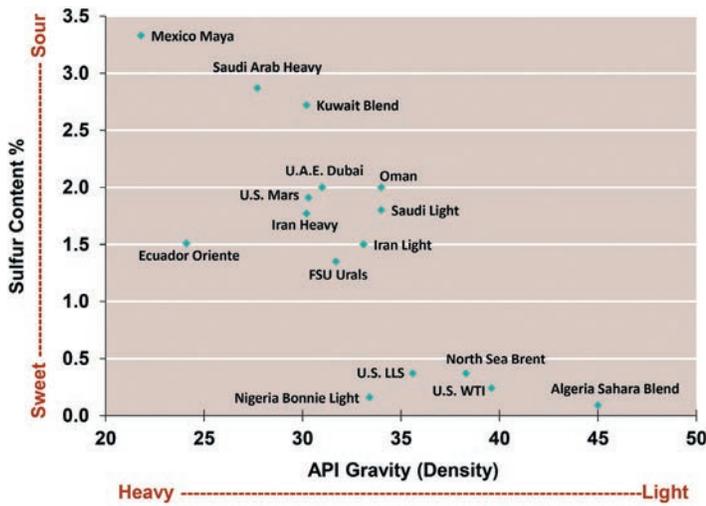
Benchmark Crude Oil

A benchmark crude oil is a specific crude oil that is widely bought and sold at well-traded locations with commonly posted prices. Other quality crude oils are traded with reference to benchmark crude oils and the pricing is typically adjusted using agreed-upon price differentials that take into account such factors as API gravity, sulfur content, and transportation costs – e.g., from production areas to refineries. WTI oil and Brent are two major benchmark crude oils with WTI used in the U.S. and Brent used in global trade. A third major benchmark, Dubai, is mostly used in Asian trade.

Different countries, regions, and geological formations produce different types of crude, which are generally described as light or heavy, depending on their viscosity, and sweet or sour, depending on their sulfur content. As a rule, heavy oils are sour as they contain more sulfur. West Texas Intermediate (WTI), the U.S. pricing benchmark, is a light, sweet oil delivered at Cushing, Oklahoma. The Brent oil benchmark, also a light, sweet oil, is a basket of North Sea oils used to set crude oil and petroleum prices around the world. By contrast, Mexico’s Maya crude is both heavy and high in sulfur (sour).

Crude oils that are light and sweet usually command higher prices than heavy, sour crude oils. This is partly because gasoline and diesel fuel, which typically sell at a significant premium to heavier products produced in the refining process, are more easily and cheaply produced using light, sweet crude oil. Processing the light, sweet grades require far less sophisticated and energy-intensive refining processes.

Density and Sulfur Content of Selected Crude Oils

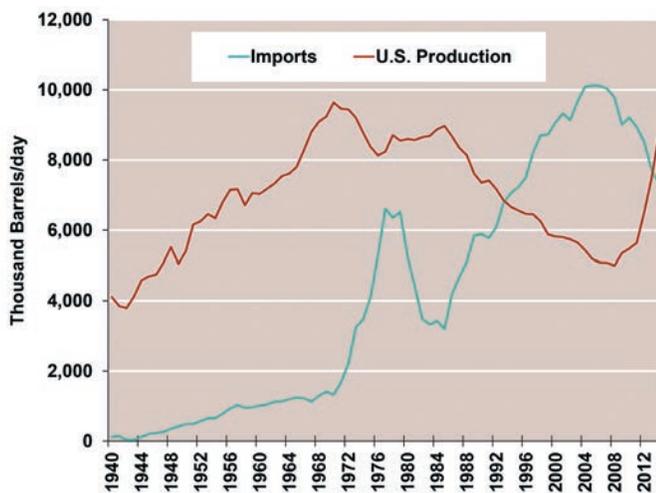


Source: Derived from EIA data

U.S. Crude Oil Supply

In 2014, the U.S. consumed approximately 16 million barrels per day (MMbd) of crude oil, of which 54 percent was produced domestically, a reversal from recent years when imports made up the majority of the supply. Between 1994 and 2013, the U.S. imported most of its crude oil. Imports peaked in 2006 at 10.1 MMbd, or 67 percent of total supply.

U.S. Crude Oil Supply – Increased Production Displaces Imports



Source: Derived from EIA data

Sweet or Sour?

The terms sweet and sour refer to the sulfur content of crude oil. Early prospectors would taste oil to determine its quality, with low sulfur oil tasting relatively sweet. Crude is considered sweet if it contains less than 0.5 percent sulfur.

Sweet crude is easier to refine and safer to extract and transport than sour crude. Because sulfur is corrosive, sweet crude also causes less equipment damage to refineries and thus results in lower maintenance costs over time. Due to these factors, sweet crude commands a price premium over sour.

Major sources of sweet crude include the Appalachian Basin in Eastern North America, Western Texas, the Bakken Formation of North Dakota and Saskatchewan, the North Sea of Europe, North Africa, Australia, and the Far East including Indonesia.

Sour crude oil has greater than 0.5 percent sulfur and some of this will be in the form of hydrogen sulfide, known for its “rotten egg” smell. Hydrogen sulfide is considered an industrial hazard and, thus, sour crude has to be stabilized via removal of hydrogen sulfide before it can be transported by oil tankers.

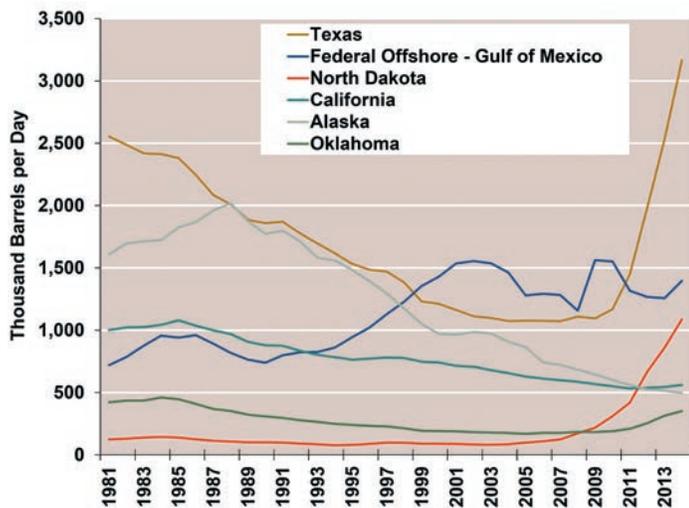
Sour crude is more common in the Gulf of Mexico, Mexico, South America, and Canada. Crude produced by OPEC Member Nations also tends to be relatively sour, with an average sulfur content of 1.77 percent.

Driving the increase in domestic oil production are the same developments that resulted in sharp increases in natural gas production, horizontal drilling and high-pressure hydraulic fracturing (fracking). To date, the most prolific example of success in this technology is in the Bakken Shale in North Dakota. Between 1990 and 2005, production in North Dakota averaged 89,000 barrels per day (Mbd). Production began to grow in 2006, as companies started to apply the horizontal drilling and fracking techniques. By 2014, production had reached 1.1 MMbd, making North Dakota the second biggest crude oil producing state in the country.

In addition to North Dakota, other major producing locations in the U.S. include Texas, offshore locations in the Gulf of Mexico, California, Oklahoma, and Alaska. Texas, the largest producing state, also experienced a substantial increase in output with the application of the new technologies. Texas onshore production fell steadily between 1980 and 2007, when it averaged 1.1 MMbd. However, production began to ramp up as companies targeted oil rich shale formations, including the Eagle Ford Shale and the Permian Basin. Production in the Permian Basin, one of the oldest oil producing formations in Texas, had been in decline prior to the implementation of the new extraction techniques. By 2014, Texas production had reached 3.2 MMbd.

One important attribute of rising crude oil production from shale is that the majority of the output consists of light, sweet oil. Approximately 90 percent of the nearly 3.0 MMbd growth in production from 2011 to 2014 consisted of light, sweet grades. This is important as it helps determine refinery investments and operations and, thus, influences the types of crude oil that are imported and processed in U.S. refineries.

Top Five U.S. Crude Oil Producing Locations



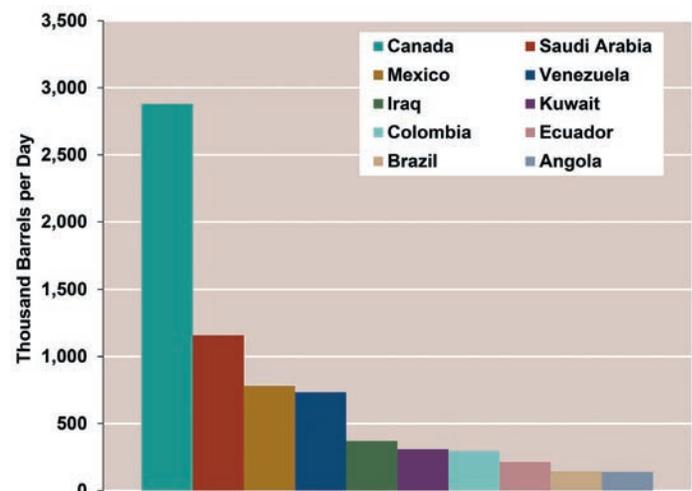
Source: Derived from EIA data

Offshore production in the Gulf of Mexico averaged 1.4 MMbd in 2014. However, it peaked in 2003 and has remained relatively flat for the past 15 years. Producing crude oil from off-

shore deposits is more technically challenging and costly than on-shore, and over the past few years producers have opted to shift investments to the shale formations.

Imports are also an important component to U.S. crude oil supply, accounting for 46 percent of U.S. supply, or 7.3 MMbd in 2014 (excluding petroleum products). The largest foreign supplier of crude oil (excluding petroleum products) is Canada, which in 2014 accounted for 2.9 MMbd or almost 47 percent of total imports. In Canada, unconventional oil production methods have resulted in robust production from the oil sands region in Alberta. The second largest supplier was Saudi Arabia, with 1.2 MMbd, followed by Mexico, Venezuela, and Iraq.

Top Ten Foreign Suppliers of Crude Oil to the U.S. in 2014



Source: Derived from EIA data

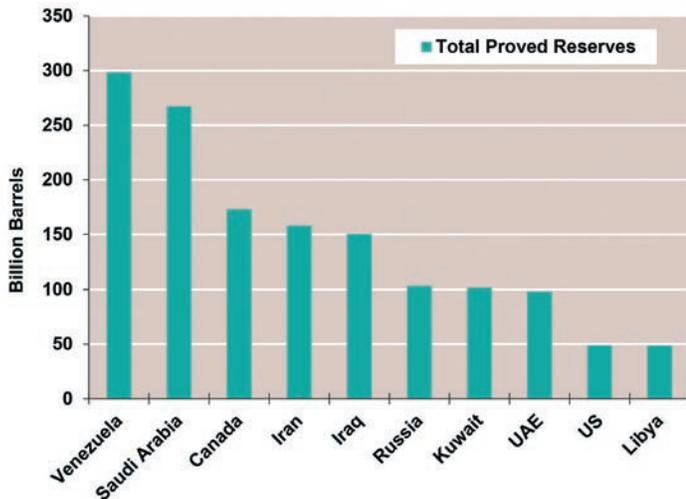
Petroleum Reserves

At the end of 2014, there were an estimated 1,700 billion barrels of proved reserves in the world. The U.S. accounted for 49 billion, or 2.9 percent of these reserves. That is sufficient to last approximately 53 years at current production levels, according to BP's "Statistical Review of World Energy" (June

2015). Proved reserves fluctuate as new geological supply sources are discovered, as the technology to produce from known sources advances, and as price fluctuations change the economics of particular resources. For example, the discovery of the pre-salt oil deposits offshore Brazil increased global proved reserves by adding a new potential source of production. The advances in horizontal drilling and slick water fracturing technology increased the size of proved reserves in the U.S. and other countries by making shale oil technically recoverable. Proven reserves also increased when crude oil consistently traded above \$100/barrel between 2008 and 2014, as the high prices made drilling in high cost areas economic.

Proved Oil Reserves
Estimated quantities of oil that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

In 2014 Most of the World's Proved Oil Reserves were in the Middle East



Source: Derived from BP Statistical Review of World Energy 2015 data

Although two of the top three countries by proved reserves are Venezuela and Canada, most of the world's proven reserves are in the Middle East. Five countries, Saudi Arabia, Iran, Iraq, Kuwait, and the United Arab Emirates, together hold 46 percent of all proved reserves. In addition, of the top

10 countries in proved reserves, seven are members of the Organization of Petroleum Exporting Countries (OPEC), an inter-governmental organization of oil-producing countries. This geopolitical and geographic concentration is an important factor as will be discussed later in this chapter.

Crude Oil Refining

As of January 1, 2012, the U.S. had more than 17.3 MMbd of refinery capacity. For historical reasons dating back to gasoline rationing during World War II, the U.S. is divided into five geographical regions called Petroleum Administration for Defense Districts, or PADDs. Approximately 44 percent, or 7.7 MMbd of refining capacity, is located along the Gulf Coast, in PADD 3.

Petroleum Administration for Defense Districts



Source: EIA

Most of the largest and more modern refineries are situated along the coast of Texas, Louisiana, Mississippi, and Alabama. Many refineries are located close to the traditional crude oil production or import centers in the Gulf Coast or near major population centers where demand for refined products is greatest, including California and the areas near Philadelphia, New York City, and Chicago.

In general, crude oil refining involves processing crude oil through distillation facilities where the crude oil is heated and separated into its lighter and heavier components. The heat

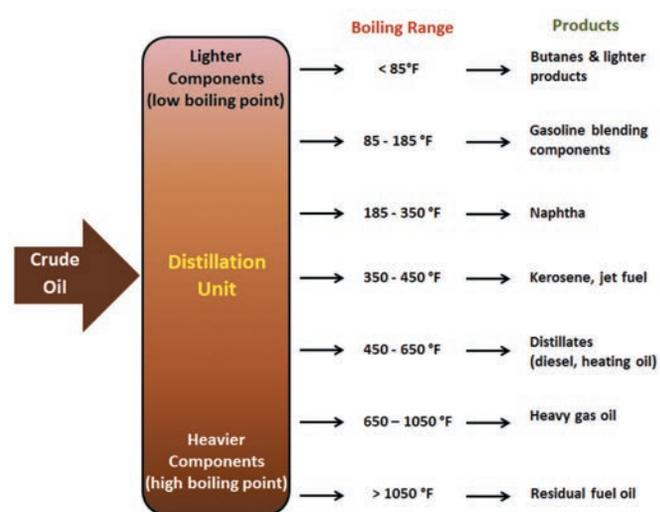
Continental U.S. Refineries – Top 50 by Capacity



Source: Derived from EIA data

causes the lighter, more volatile molecules to rise and, as they cool, the heavier components such as heavy fuels and residual fuels settle into trays and are carried out of the unit into their own processing streams. The lighter molecules rise higher in the unit and are processed into light products such as gasoline and naphtha. Depending on the refinery configuration, heavier components may be further processed to yield higher amounts of the more valuable light products. Breaking down the heavier products into lighter ones requires more specialized and expensive equipment and processes such as catalytic crackers and cokers.

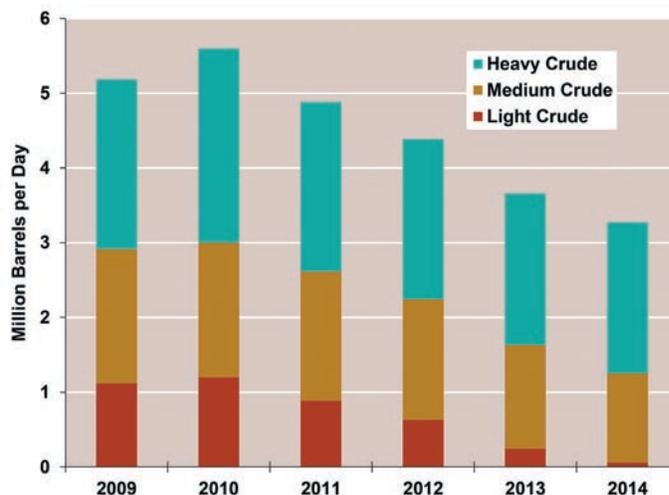
Basic Crude Oil Distillation Unit & Product Output



Source: Derived from EIA data

The growth in production of light, sweet oil from shale is changing the makeup in the types of crude processed at U.S. refineries. During the 1990s when domestic U.S. crude oil production was declining, refineries along the Gulf Coast spent billions of dollars to reconfigure their equipment and operations to handle imports of heavy, sour crude oil from Mexico and Venezuela. Despite these upgrades, refineries in the region still imported and processed as much as 1.3 MMbd of light, sweet crude oil, more than any other region of the country. Beginning in 2010, improvements to the crude oil distribution system and sustained increases in production in the region (in the Permian and Eagle Ford basins) allowed more domestic crude oil to reach the Gulf Coast refining centers, significantly reducing the need for imports of light crude. Since September 2012, imports of light, sweet crude oil to the Gulf Coast have regularly been less than 200,000 bbl/d. Similarly, Gulf Coast imports of light, sour crude also declined and have been less than 200,000 bbl/d since July 2013.

Imports of Crude Oil into the U.S. Gulf Coast



Source: Derived from EIA data

Crude Oil and Petroleum Products Transportation

There are more than 190,000 miles of petroleum pipelines in the U.S. Because of increased shale production, crude oil pipeline mileage grew 8,174 miles or 15.5 percent between 2009 and 2013. Crude pipelines move oil from the production fields and import terminals to refineries for processing into various products. Products pipelines then distribute the fuels to various parts of the country.

Colonial Pipeline Company is the largest pipeline in the U.S.; transporting 844 billion barrel-miles (one barrel transported one mile) of petroleum products in 2014. It is one of the most important products pipelines in the country as it carries supply from the refining centers in Texas and Louisiana to the major demand centers along the U.S. east coast. It transports approximately 100 million gallons per day of gasoline, diesel fuel, jet fuel, and other products from Houston, Texas to Linden, New Jersey on a 5,500-mile network, crossing 13 states. The second largest pipeline, with 583 billion barrel-miles transported in 2014 is Enbridge Energy. This pipeline begins in the oil sands producing region in Alberta, Canada, and transports 53 percent of the Canadian crude oil that comes into the U.S. Once in the U.S., it moves the crude oil from North Dakota to Chicago and south into Cushing, Oklahoma. A distant third-largest pipeline is the TransCanada Keystone Pipeline, which in 2014 transported 210 billion barrel-miles of crude oil from Canada into the U.S. mid-continent and the Gulf Coast. This is a different pipeline from the proposed TransCanada Keystone XL.

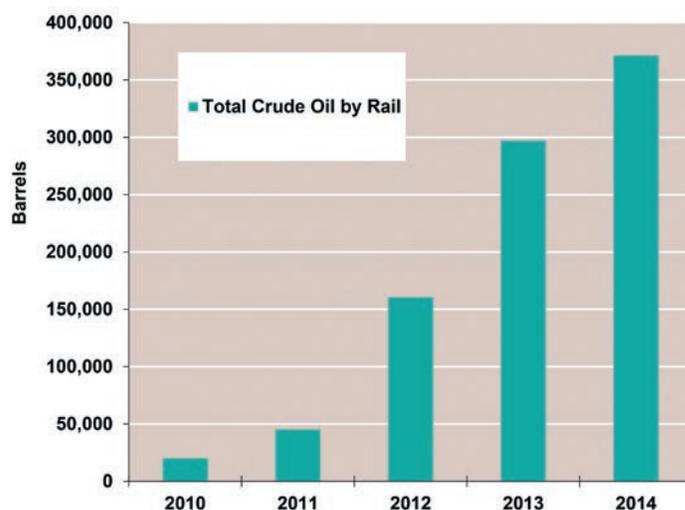
Regulation of crude oil and petroleum product pipelines falls under a number of government entities. The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for regulating and ensuring the safe and secure movement of hazardous materials to industry and consumers by all modes of transportation, including pipelines. Its Office of Pipeline Safety ensures safety in the design, construction, operation and maintenance, and spill response of oil and natural gas pipelines and other hazardous liquid transportation pipelines.

FERC's jurisdictional responsibilities regarding crude oil and petroleum product pipelines include:

- Regulation of rates and practices of oil pipeline companies engaged in interstate transportation
- Ensuring the furnishing of pipeline transportation to shippers on a non-discriminatory and non-preferential basis
- Establishment of just and reasonable rates for transporting crude oil and petroleum products by pipeline

Changes in U.S. production dynamics in recent years, specifically the growth of crude oil production in areas not traditionally served by oil pipelines, such as the Bakken Shale formation in North Dakota, have taxed the current pipeline system. As a result, the country has experienced a sharp increase in transportation of crude oil by rail, despite the fact that pipeline transportation is more economic than rail. An advantage of rail transportation, however, is that companies can ramp-up capacity quickly and have more flexibility in origin and delivery points. The largest oil-by-rail movements have originated from PADD 2, specifically in North Dakota. In 2014, more than 262,000 barrels, or 71 percent of all inter-PADD movement came from PADD 2. The majority of those barrels were shipped to PADD 1, likely to feed refineries in the Philadelphia area. Additionally, approximately 50,000 barrels were imported or exported to Canada via rail.

Crude-by-Rail Volumes in the U.S. and Canada

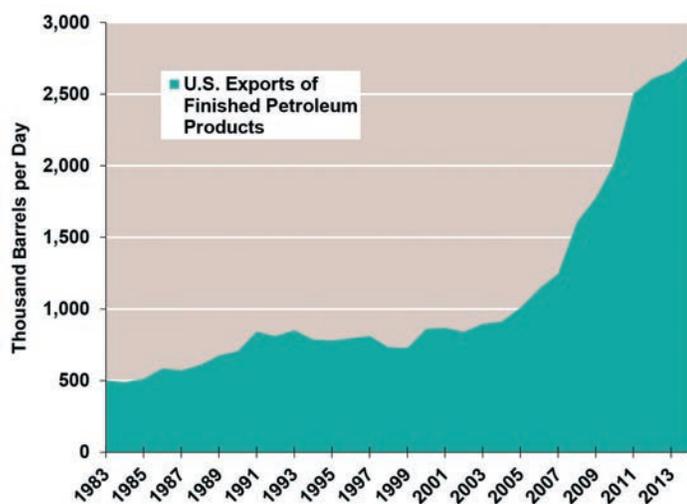


Source: Derived from EIA data

The rise of oil-by-rail shipments has raised some safety issues, as there have been a number of serious and, at times, fatal incidents involving oil-laden rail cars. The U.S. Department of Transportation has worked with the rail and oil industry on new regulations involving car design and train operations.

Two Federal statutes limit the movement of crude oil and crude oil products. First, the Jones Act of 1916, 46 U.S. Code § 55102, generally prohibits any foreign built or foreign-flagged vessel from engaging in trade that begins at any point within the United States and delivers commercial cargo to any other point within the United States. Because of the limited numbers of oil and petroleum products vessels that meet the Jones Act requirements, the ability to move crude oil and refined products between marine ports is in short supply. That means, for example, that producers are limited in their ability to move crude oil to the Gulf Coast via pipeline and then ship it to East Coast refiners. Likewise, Gulf Coast refiners are limited in their ability to move refined products up the East Coast via waterborne vessels.

U.S. Exports of Finished Petroleum Products



Source: Derived from EIA data

A second statute, § 754.2 – Crude Oil, enacted during the 1970s oil crisis, requires licensing of U.S. crude oil exports. Although this statute is widely referred to as the oil export ban, it

allows for various types of exports including petroleum products, exports of slightly refined crude oil condensate, shipments of crude oil owned by a company to an affiliate refinery in Canada, and heavy-for-light crude oil swaps with Mexico. U.S. exports of petroleum products rose substantially with the increase of production of oil from shale. In 2000 the U.S. exported 868,000 barrels of finished products. This number had increased to 2.8 million barrels by 2014.

Crude Oil and Petroleum Products Demand

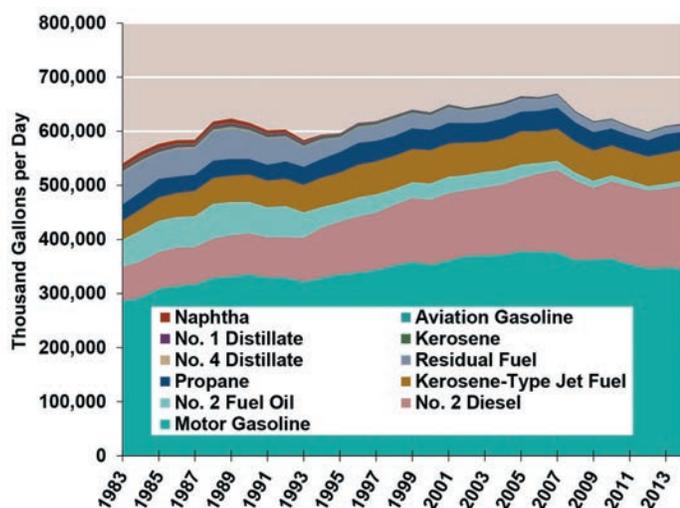
The largest demand category for petroleum products in the U.S. is the transportation sector. Motor gasoline alone made up 56 percent of petroleum products sold by prime suppliers into the U.S. market. The second largest is No. 2 distillate, which made up 26 percent of prime supplier sales in 2014, and which includes diesel fuel, also used in the transportation sector, mostly by long distance freight trucking. No. 2 distillates also include fuel oil, used for space heating and, in a lesser capacity, for electric generation. The next largest demand category is another transportation sector fuel, jet fuel, which accounted for 9 percent of sales. All told, demand from the transportation sector accounts for approximately 90 percent of all petroleum products consumed in the U.S.

Other petroleum products include: propane used for space heating and in petrochemical processes; kerosene used in heating and lighting; No. 1 fuel oil, which can be blended into heating fuel or diesel fuel; No. 4 fuel oil used for commercial heating and power generation; residual fuels used in power generation and ship boilers; and asphalt used to build roads.

Prime Suppliers

Companies that produce, import, or transport products across State boundaries, to sell to local distributors, retailers, or end users. Prime supplier sales are a good proxy for demand.

Gasoline and No. 2 Distillates Account For Most of the Petroleum Use in the U.S.

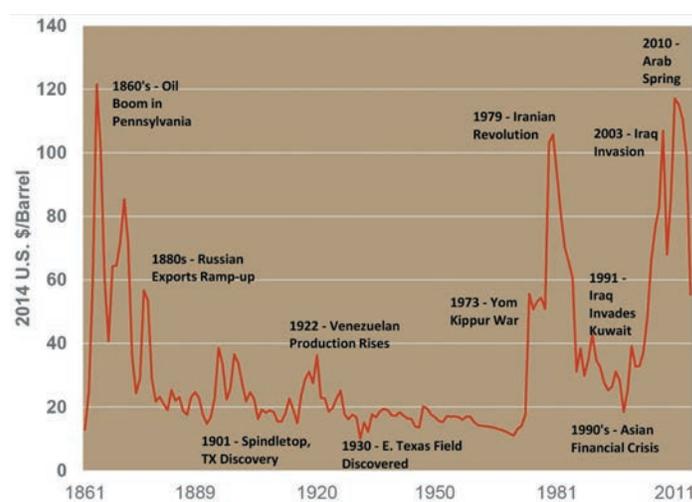


Source: Derived from EIA data

Crude Oil and Petroleum Products Markets and Trading

Because of limited oceangoing transportation options, U.S. natural gas markets have historically been shielded from international supply and demand developments. Crude oil and petroleum products are traded globally, and their prices are greatly influenced by global supply and demand, geopolitical and economic factors, and the policies of OPEC. Many of the countries in the top 10 oil suppliers to the U.S., such as Iraq, Colombia, Kuwait, Russia, and Venezuela, have a history of political unrest or governance issues. These factors can affect production, reduce supply, and cause prices to rise. As a result, world oil prices have experienced periods of great volatility, driven by supply and demand fundamentals, external shocks, and speculative trading.

Geopolitical and Economic Events Drive Crude Oil Volatility



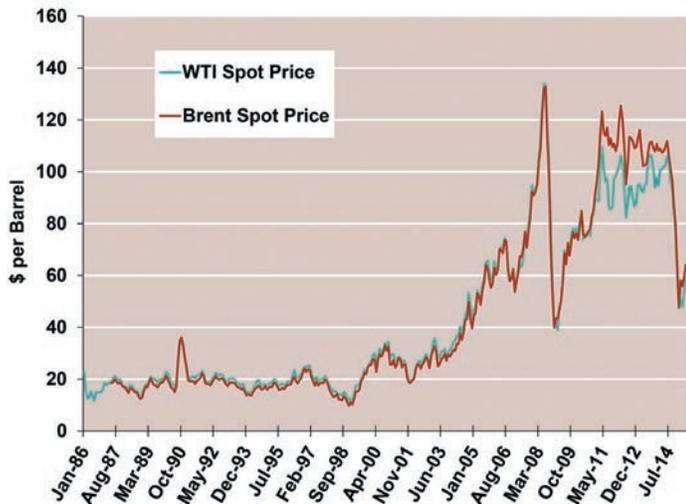
Source: Derived from BP Statistical Review of World Energy 2015 data

Note: Prices for 1861-1944 are U.S. average; for 1945-1983 are Arabian Light posted at Ras Tanura; for 1984-2014 are Dated Brent; and 2015 are Brent as of Q3 2015

As a global commodity, crude oil's price on the world markets is set by the traders who buy and sell the commodity. Although crude oil trades at various locations around the world, most trades are based on or derivative to a handful of benchmark crude prices, such as WTI, Brent, and Dubai. There are also benchmarks for petroleum products, including New York Harbor in the U.S., Amsterdam-Rotterdam-Antwerp (ARA) in Europe, and Singapore in Asia.

From 1987 through 2010, WTI and Brent traded within a few cents of each other, with WTI generally commanding a small price premium. However, the sudden and sharp increase in production of shale oil in the U.S. resulted in an oversupply at Cushing, causing WTI prices to drop below Brent. Between 2011 and 2014, Brent commanded a premium, reaching as high as \$27/barrel in September 2011. The Brent premium shrank in 2015, as world prices fell significantly because of a combination of lower demand, particularly from China, and growing supply from North America and other producers around the world.

New Oil Production from Shale Drives Down Oil Prices



Source: Derived from EIA data

Despite being a widely traded commodity, the price of crude oil is not completely determined by the free market. Member countries of OPEC produce much of the oil traded around the world, and OPEC attempts to control oil prices by managing production by its member countries. Each member country has production targets that OPEC lowers to reduce world supply and drive prices up, or increases to drive prices down. The largest OPEC producer is Saudi Arabia. Other member countries include Iran, Iraq, Kuwait, Venezuela, Qatar, Libya, the United Arab Emirates, Algeria, Nigeria, Ecuador, and Angola.

As of 2015, OPEC member countries produced about 40 percent of the world's crude oil, and OPEC's oil exports accounted for about 60 percent of the total petroleum traded internationally. The actions of OPEC, particularly in member countries with substantial spare capacity, can and do affect oil prices.



5. FINANCIAL MARKETS AND TRADING

Financial markets affect physical natural gas and electricity markets in key ways. In the past decade, the commodity markets associated with natural gas and electricity expanded, both in terms of volumes traded and the types of products offered. One result from this expansion has been to alter the traditional relationship between physical and financial markets. The traditional view was that physical markets affect financial; financial products derive their value from physical products. Today, the relationship is bidirectional. Physical markets continue to affect financial markets, but now, financial markets can affect physical markets – including prices – as well.

This chapter explores natural gas and electricity commodity and capital markets.

Financial Markets and Mechanisms

Financial markets are not physical locations like grocery stores where one can go to experience the financial marketplace. Instead, they are an array of products, mechanisms, and participants that together flesh out the marketplace.

As mentioned, financial markets differ from physical markets in that no physical delivery occurs. This does not mean financial markets contain only investors and speculators; physical market participants enter the financial market to hedge. Similarly, it does not mean that financial markets involve only contracts that contain financial payout instead of physical delivery. Financial traders may use longer term physical contracts, but in a way that ensures no delivery will be required. Physical and financial markets are often closely intertwined and use the same market mechanisms.

Consequently, one good way to understand financial markets is to look at the market participants, products, market mechanisms and trading that together constitute the market.

Market Mechanisms

Transactions in both physical and financial markets are conducted through exchanges or over-the-counter (OTC). In the case of electricity, trades may also be conducted in regional transmission organizations (RTOs are addressed in Chapter 3).

Exchanges

Trading on exchanges is subject to the rules of the exchange as well as laws and regulations. Exchange-traded contracts are standardized, meaning that specifications for the product's quality, quantity, and location are established in advance by the exchange. Exchange rules typically permit bidirectional trading, or the ability to buy or sell with equal ease.

Trading in exchanges is conducted through electronic platforms, websites on which traders can buy and sell, or through trading pits where traders actively call out orders to buy and sell, known as open outcry.

Natural gas and electricity are traded on commodity exchanges such as the Nymex, the world's largest physical commodity futures exchange. In addition to other commodities, including metals and agricultural products, Nymex facilitates the sale and purchase of physical and financial natural gas products as well as financial power contracts. The ICE also offers natural gas and electricity products, as well as emissions allowances among a host of other commodities. Nodal Exchange offers locational (nodal) futures contracts to participants in the organized electricity markets. Nodal Exchange allows participants to trade electricity contracts for forward months, at RTO hubs, zones and nodes.

Margin, or equity contributed as a percentage of the current market value of a commodity contract(s), allows market participants the ability to trade without having to pay cash for the full value of the trade. Effectively, someone who trades on margin borrows much of the money used to buy or sell from the exchange or brokerage house. The trader posts collateral

by putting down a certain amount of money or percentage of the trade value in cash or other items of value acceptable to the exchange.

Over-the-Counter (OTC) Markets

OTC markets are any markets that are not exchanges or RTOs. Transactions are not required to be standardized but rather can range from complicated individual negotiations for one-off structured contracts to standard products traded through an electronic brokerage platform. The ability to tailor a contract to the exact needs of the counterparties is one of the chief benefits of OTC contracts.

OTC power contracts can be traded in either traditional or RTO power markets.

OTC transactions are conducted through direct negotiations between parties or through brokers. Brokers range from voice brokers to electronic brokerage platforms. Unlike an exchange, an electronic brokerage platform matches specific buyers and sellers, and is not anonymous.

Products may be negotiated individually or may be standardized. Many negotiations start with a standardized contract, such as the natural gas contract developed by the North American Energy Standards Board (NAESB), and then modify it. Others start from scratch. Individually negotiated deals are called structured contracts. Two commonly used contracts for electricity are the Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement and the WSPP Agreement (WSPP was formerly known as the Western Systems Power Pool). To be tradable, a contract must include terms and conditions that make it attractive to more than one entity. Consequently, complicated, one-off contracts negotiated to meet the need of an individual seller and buyer may have little or no resale value. Typically, the standardized contracts traded on exchanges or electronic brokerage platforms are designed to be of interest to many market participants.

In OTC markets, contracts are bilateral – i.e., the process of negotiating the completion of a purchase or sale is between the two market participants.

Regional Transmission Organizations

Electricity is also bought and sold through RTOs. In general, RTOs operate their markets to support the physical operation of the electric grid under their control, including making decisions about what generation to dispatch to meet customer demand. RTO markets are multilateral; buyers and sellers are not matched individually against each other. RTOs allow for bilateral physical transactions, although each RTO handles these differently. RTOs provide settlement services, although this differs from the settlement offered by exchanges.

Also, RTOs use the word clearing to refer to the matching of supply and demand – to clear the market means the RTO accepts sufficient generation offers to meet demand. If a generator's offer in the day-ahead market clears, it means that generation was offered at or below the market clearing price and was chosen to generate the next day. RTOs maintain credit policies and allocate the costs of defaults or other performance failures across market participants.

RTO markets may have elements that are similar in nature to financial transactions. One of these is virtual transactions (often referred to only as virtuals). For example, a trader may offer generation in the day-ahead market, and the generation does not show up in the real time market. As a result, the trader is paid for his generation offer in the day-ahead market, based on day-ahead prices, but effectively has to pay to replace his power in the real-time market, paying the real-time price. Financial participants can participate in virtuals; they use the physical product (generation offers or demand bids) in a way that results in no physical delivery. Virtuals are financial contracts, directly integrated into the RTO's operation of its physical market; they affect physical supply and demand, and prices. Virtuals are discussed further in Chapter 3.

RTOs may also offer financial transmission rights (FTRs) programs, also discussed in Chapter 3. Typically, a transmission owner that turns over operation of its transmission to the RTO wants certainty over its ability to flow electricity and about the cost of transmission. Because the RTOs operate using markets, this certainty cannot be provided directly. FTRs and similar instruments are designed to provide some degree of

financial compensation to these transmission owners and firm rights holders. FTRs are linked to the physical operation of the RTO's system in that the expected capacity of the transmission is used to determine the total capacity of FTRs offered.

FTRs compensate the transmission owners or firm rights holders in a couple of ways. First, the RTOs auction additional FTRs to others in the market, including financial participants who have no interest in buying, selling or transmitting physical power. The proceeds of the auction are returned to some of transmission owners or firm rights holders. The auction also determines a value for any FTRs held by the transmission owners or firm rights holders. FTRs can be bought and sold; the auction price gives an indication of their value for price discovery.



Other Market Mechanisms and Concepts

Leverage is the use of a small position to control or benefit a larger position. It increases the potential return, but also increases risk. Leverage can occur when a trader uses margin to trade.

Leverage can be used in other ways. As discussed in Chapter 6, some traders may try to use leverage to manipulate the market. For example, traders may use a smaller position in the physical market to benefit a larger position in the financial market. They may buy a financial product whose price is derived from a physical product. Then, they may try to buy or

sell or otherwise influence the price of the physical product. If they succeed, their financial position benefits.

Liquidity refers to the trading and volumes occurring in a market. A market is said to be liquid if trading and volumes are such that any trader can liquidate his position at any time, and do so without affecting the prices. A market is thin if it has little trading or volume; in these instances, trading may affect prices. The benefits of liquidity are often used to justify practices that increase trading or volumes. However, not all trading or volumes are uniformly beneficial to markets and other market dynamics need to be taken into account.

Markets may not be uniformly liquid. For example, the market for the Nymex natural gas futures contract is generally thought to be liquid. However, when the United States Natural Gas Fund became extremely large, its monthly process of getting out of the current contract and into the next involved selling and buying an extremely large volume of contracts at one time. If these transactions affected prices, then the market was affected.

Open interest is the total number of futures contracts in a delivery month or market that has been entered into and not yet liquidated by an offsetting transaction or fulfilled by delivery. By the expiration of the settlement period, the open interest in contracts (both in terms of the total number of contracts and the number of counterparties) rapidly decreases, so that a given number of contracts will represent an increasing share of the outstanding prompt-month contracts.

Clearing is a process in which financial or physical transactions are brought to a single entity, the clearing house, which steps into the middle of the transaction and becomes the counterparty to each buyer and seller. The clearing house assumes the risk that either the buyer or seller will fail to perform its obligations. Generally, clearing is used to manage counterparty risk. Clearing houses maintain rules about the creditworthiness of traders, collateral that must be posted and, of course, fees that must be paid for the service.

Settlement occurs at the end of a trading period, when the contract expires. At this time, delivery is to be made for a

physical contract (physically settled) or a financial payout made for a financial contract (financially settled). Settlement occurs both in exchanges and in OTC trades. In OTC transactions, settlement occurs under the terms agreed upon by the parties. On exchanges, settlement occurs in a documented process and timeframe established by the exchange.

For example, every day at the close of Nymex trading, the natural gas futures contracts for forward months settle. The final settlement for a given month occurs three business days prior to the start of the month of delivery (the prompt month). The contract expires and the last-day settlement (LD settlement) is calculated based upon the trading in the last half-hour. LD settlement is the final price for that particular futures contract term. The last day for trading option contracts is the day before the futures contract expires.

Most market participants avoid trading during the settlement period. As the time to termination approaches, price risk and volatility may increase, while market liquidity and the remaining open positions (open interest) are decreasing. For the Nymex natural gas futures contract, most market participants either liquidate or roll their open long or short positions well before the settlement period. Rolling is the process of liquidating the current month's contract before it expires and purchasing a comparable position in the upcoming month. The trader holds the same number of contracts, but the contract month held changes as time passes and contracts expire.

Daily settlement prices are used to revalue traders' position to the current market price, for accounting and for margin calculations. Daily and LD settlement prices are also reported in publications and indexes, and are used for price discovery.

Mark-to-market (MTM) provides that at the end of each trading day, all trading positions are revalued to current market prices. This results in financial and accounting gains and losses. Traders can remove money resulting from gains from their accounts or use them for further trading; they do not have to liquidate their positions to get the money. Losses reduce the value of a trader's position, and may reduce the amount of collateral the trader needs to be able to trade on margin. If so,

this may result in a margin call from the exchange or broker.

Mark-to-market is also an accounting transaction, in that a company's or trader's accounts are revalued daily to reflect changes in asset price. Losses can reduce the book value of a company or trader, and can affect its creditworthiness.

Trading is the buying and selling of contracts. Trades and transactions are virtually synonymous. Both refer to the buying and selling of power or natural gas.

Short selling is the selling of contracts a trader does not own, on the assumption that the trader will buy offsetting contracts prior to the contracts' expiration. This can be done on an exchange or other market that allows for bidirectional trading. Short selling has been of concern for potential market manipulation – traders sell a contract to drive the price down, and then buy when the price is low. Short selling is one of the ways market participants can trade futures financially – they sell the future, then buy it before the contract expires so the contracts net out and the trader faces no delivery obligation.

A **position** is the net holdings of a participant in a market. A trader's position in a specific instrument is combined purchases and sales of that contract. A trader's overall position is the combination of all positions in all contracts the trader owns. A trader's position is often referred to as the trader's commitment in the market.

Liquidating a position is the process of getting rid of a position. A trader who owns a contract will sell it to liquidate it. A trader who has sold a contract short will buy a contract to liquidate it. After liquidation, the trader holds no contracts.

Position limits have been imposed on ICE and Nymex exchanges according to specific formulas, in accordance with regulations and proposed rules of the Commodity Futures Trading Commission. The position limits may restrict the number of shares a trader may hold in a particular investment at any point in time, during the month the contract expires, or during some period closer to settlement. For example, the CME Group (CME) imposes accountability levels for any one month and for all months, and has limits for expiration-month

positions. CME's accountability for the Nymex Henry Hub natural gas futures contract are 12,000 contracts for all months, 6,000 contracts for one month and 1,000 contracts in the expiration month. Trading entities can petition to have these waived or modified.

Volumes give an indication as to the nature of the activity occurring in the market at any point in time. Volume can be expressed in a number of ways. It can be the number of transactions executed during a specified period of time or the volume of the product contained in the contracts.

Volumes give market participants information about what is going on in the market. For example, if many Nymex contracts are traded, and the number of trades is relatively few, market participants know that a relatively few traders are making high-volume trades. Conversely, if a high number of Nymex contracts are traded and the number of trades is also high, then at least some of the trading is being done in small volumes. This could result from broad interest in the market – lots of active traders – or it can result from relatively few traders making a lot of trades.

Market Participants

Financial markets are used by many types of participants. These markets present an opportunity for physical players, producers and marketers to buy or sell some physical products or to hedge physical supplies and obligations with physical or financial products. Investors, speculators and investment funds also use these physical and financial products for financial gain.

Products

Products, for purposes of trading, are contracts — also known as securities or instruments — that can be bought and sold. Contracts for physical trading in natural gas or electricity markets provide for the delivery of natural gas or electricity. The actual molecules of gas or electrons may be delivered as a result of the contract. Financial contracts do not provide for delivery of a product; instead, they provide a financial payout.

Consequently, what traders buy and sell are contracts giving them a right or obligation. For physical contracts, this is the obligation to deliver or take delivery of natural gas or electricity in exchange for payment. For financial contracts, it is the right to a payout in exchange for payment, although the net value may vary over time from a net benefit to a net loss.

Other physical and financial products give traders rights to buy or sell a contract in the future at a given price – an option to buy or sell.

The word derivative is used for a category of contracts whose value is derived from some other physical or financial product or contract. Standardized derivative contracts trade on exchanges such as Nymex. Financial contracts are derivatives.

Futures contracts are derivatives of the physical contract and options on futures are derivatives of futures contracts. As futures contracts approach expiration, their price should, in theory, converge to spot prices – to derive their price from spot prices. However, at other times, futures contracts are simply the price parties are willing to pay for natural gas at some point in the future and may not derive their value from any other product or contract. Such expiring futures contracts may affect spot prices.

Instrument Basics

Each instrument is traded in its own market and is identified by the market name, such as spot or futures. Each market and instrument has characteristics such as timeframe, location, contract type, product conveyed by the contract and, for swaps, the mechanism for determining the payout.

Product conveyed: Each contract specifies what is being bought and sold. For physical contracts, this would be natural gas or electricity. For derivatives, it may be a payout derived from natural gas or electricity prices. All contracts conveying or derived from natural gas, for example, would be in natural gas markets.

Time: Each contract has a number of time elements. The trade date is the date on which the contract is written (typically the date the trade is executed).

The expiration day is the last day for a contract, after which it is no longer available to be bought and sold; it is often the same day as the settlement day. Exchanges and electronic brokerage platforms may also impose a termination date, the last date on which a contract may be traded.

Physical contracts also specify the delivery day(s) or month – the day(s) or month during which the product is to be delivered.

For physical products, begin and end dates are the dates for which a physical product (natural gas or electricity) is to be delivered. For financial products, these dates address the contracts whose prices are used to set the payout. For example, a next-day physical gas deal may have a trade date of Aug. 7, a begin date of Aug. 8 and an end date of Aug. 8. A monthly product may trade on Aug. 7, its trade date; the flow of natural gas would have a begin date of Sept. 1 and an end date of Sept. 30.

For the Nymex natural gas futures contract, the termination day and settlement day are the third-to-last business day of the month before the month in which the gas is to be delivered. The settlement period occurs from 2 p.m. to 2:30 p.m. on the termination day.

Short-term or spot contracts provide for delivery or payout during the current or next day; the price for these contracts is known as the spot price.

Daily physical contracts are for delivery on a given day or set of days.

Electricity physical and financial contracts may also specify peak or off-peak delivery, with the peak or off-peak hours defined by the contract.

Contracts for delivery a month or more into the future are forward contracts, or if they are traded on exchanges, futures contracts. The Nymex natural gas futures contract, for example, provides for the delivery of 10,000 MMBtu of natural gas in the month specified by the contract. Contracts are offered for every month over the next 12 years.

Monthly contracts are referred to by how close they are to expiring. Spot month is the current month. Prompt month is the month after the spot month or current month – it is the next trading month. For trading in January, February is the prompt month.

Another time element is the delivery or payout period, such as daily, next day or monthly. Monthly contracts generally are for delivery in equal parts over a month at a specified price for gas and for the contracted amount in each hour for power.

Location: All physical contracts specify the location where the natural gas is to be delivered, such as the Henry Hub in Louisiana. Financial contracts also have a locational element, determined by the underlier. For example, if a financial derivative uses the Nymex natural gas contract as its underlier, the derivative's locational element is the Henry Hub.

For natural gas, the locations are referred to as market hubs, which are located at the intersection of major pipeline systems. For power, contracts are often based on locations known as nodes, zones or hubs. For gas, the principal hub and pricing point is the Henry Hub, which is used for all Nymex natural gas futures contracts and is the reference point for overall prices in the United States. Prices for other locations are often references as a difference from the Henry Hub, known as basis.

Products traded on exchanges and preset products traded on OTC electronic brokerage platforms such as ICE use standardized locations or pricing points. Locations for other OTC transactions use whatever location the counterparties to the contract desire. For physical contracts, the location must be physically viable. For financial products, it can be whatever the parties desire (although complicated locations make pricing more difficult due to the lack of reference points for price discovery).

Quantity: All physical contracts specify the amount of natural gas or electricity to be delivered. For contracts traded on an exchange or for preset contracts traded on an OTC electronic brokerage platform, the quantity is predetermined and specified in the contract. For bilateral contracts traded in OTC markets, the quantity contained in the contract can be anything

the parties want it to be. For standardized products traded on electronic brokerage platforms, the quantity is fixed.

Price: The price paid for a contract is usually that set by the market and is usually known at the time the contract is bought or sold.

Fixed prices are known at the time the transaction is entered into – it is the price at which the seller agrees to sell and the buyer agrees to buy. Contracts sold at fixed prices are typically paid for at the time of purchase.

Floating prices are set by formulas pegged to something whose price is not currently known but which will be known at the time the contract expires, such as an index. For example, a price may be tied to the average of the all of the daily prices at a location over the course of a month, typically as published in an index. An index contract is a commonly traded instrument based on major trading points, such as the Houston Ship Channel or the Henry Hub.

Spot price is a cash market price for a physical commodity that is available for immediate (next day) delivery, and may be reported to publishers for indexes.

Standardized forward contracts and futures contracts are traded for every month, years into the future; the Nymex natural gas futures contract is traded more than eight years into the future although only the first few years may be very liquid – i.e., actively traded. Each of those contracts for which trading has occurred has a price. Together, the prices for future contract months creates a trajectory of prices known as forward or futures curves.

The settlement price is effectively the final official reported price for certain contracts and is an average of prices for trades occurring during the settlement period. For example, the natural gas futures contract settlement price is made during the contract's 30-minute settlement period – the last 30 minutes of trading on the contract's termination day. The settlement price forms the basis for the payout for financial derivatives that use the contract as its underlier, as well as for margin calls and for reporting to index publishers.

Physical Products

Physical products involve an obligation to physically deliver. Power products include energy, transmission (firm and non-firm) and ancillary services. Electric energy products include spot transactions, full requirements sales and bundled services, among others. Natural gas products include the natural gas molecules themselves, transportation and storage.

Forward products are contracts for physical delivery in future months traded through the OTC market (including electronic brokerage platforms). If the product is traded on an exchange, it is known as a futures contract.

A futures contract is a standardized forward contract traded on a regulated exchange. Each contract represents the same quantity and quality of the underlying physical commodity, valued in the same pricing format, to be delivered and received at the same delivery location. In addition, the date of delivery and receipt is the same for all contracts traded for a particular calendar month. The only element of a futures contract that is subject to change when it is bought or sold is the price.

For the natural gas industry, the dominant futures contract is the Nymex natural gas futures contract. For this contract, the standard contract specifications are the delivery location – Sabine Pipeline Hub at the Henry Hub in Louisiana; the term – monthly; and the quantity – 10,000 MMBtu delivered equally over the course of the month. Not all forward contracts have fixed prices. Some involve trades executed now to buy or sell at some point in the future, at a price to be set in the future. One example of this is a forward physical index contract. This OTC contract obligates one party to buy the underlying commodity or security and the other party to sell it, for a delivery price to be determined when a specific index sets at some known date in the future. Many natural gas purchases are made under forward physical index contracts; among other things, it may provide state regulators with some assurance that the price paid is reasonable.

Forward and futures contracts with fixed prices can be used for price discovery, hedging or speculating. They may be

traded by any of the participants listed earlier. Physical participants may use forwards or futures to obtain gas or electricity for delivery in some future month, or may use them to manage the risk of – or, hedge – their physical positions. Futures contracts that go to delivery lose their anonymity at settlement. However, only a small fraction – often, less than one percent – of futures contracts go to delivery.



Financial traders may buy or sell futures contracts for financial purposes, as exchanges have bidirectional trading – markets in which trader can buy and sell contracts with equal ease. Bidirectional trading allows the sale of contracts a trader does not own, known as short sales. A financial trade may buy a forward or future, then either sell the contract later or neutralize it by obtaining an offsetting contract. Because the two offset, the trader has no physical delivery obligation. Most Nymex natural gas futures contracts do not go to delivery.

Physical products can be combined to create different physical positions for use in physical and financial trading. A price spread can be created using forwards priced at indexes for two different hubs. The trader would buy physical natural gas at one index and sell at another. For example, the trader buys gas priced at the Houston Ship Channel index (and would have to take delivery of the gas there) and sells gas at the Texas

East M-3 index (and would have to deliver it there). The trader earns the difference between the two contracts. A physical spread carries with it the obligation to make or take physical delivery of natural gas at both points, so pipeline capacity would be required to actually move gas between these points.

A financial trader could also execute this trade, but would have to unwind both positions before delivery.

Indexes are formally published for both natural gas and power using a methodology posted by the publisher. An index may be used to set the price for settlement of floating price contracts. Indexes are also used by a variety of market participants to inform their decisions in the many steps in the electricity or natural gas supply chain or in trading, known as price discovery. Data used in indexes are submitted voluntarily by firms involved in trading. Indexes are commonly formed using volume-weighted average prices.

Financial Products

Financial contracts do not provide for the delivery of a product, but instead provide a financial payout. This is often based on the value of some physical or financial product specified by the contract, called the underlier. The value of these financial contracts is derived from the value of the physical or financial instrument specified in the contract as the basis for payout; as such, they are derivatives.

A key benefit of financial products is that they have no physical delivery and they are self-liquidating. Speculators who trade futures have to undo their position to eliminate the delivery obligation. One who trades derivatives, on the other hand, does not bear the complications of unwinding positions; the individual can simply wait for expiration and receive or pay the contract's payout.

Swaps

A key financial contract structure used in natural gas and electricity markets is the swap, or contract for differences. A swap is an exchange of one asset or liability for a similar asset or

liability. It may entail buying on the spot market and simultaneously selling it forward. Swaps also may involve exchanging income flows. Swaps may include calendar spreads or basis spreads which reflect expectations of time or locational price variances. Physical instruments cannot be swaps because parties to physical goods pay or receive money in exchange for delivery of the physical good. However, the exchange of money in terms of payment and payout constitutes a swap.

Options

An options contract conveys a right (but not the obligation) to buy or sell something else. It comes in two forms: the right to buy or the right to sell something at a specified price at or before a specified date. The buyer buys the right – the option – to buy or sell in the future; the seller (or writer) sells the obligation to sell or buy if the buyer exercises his right.

An option to buy is known as a call option; an option to sell is a put option. The price paid to buy or sell the option is known simply as the option's price. The price at which the option may be exercised is the strike price. Electing to buy or sell the underlying commodity or security is known as exercising the option.

Options traded on exchange or electronic trading platforms may be traded up to their expiration. Consequently, the owner of an option may sell it rather than exercise the option or let it expire.

Traders buy and sell options for a number of reasons. First, they provide a risk management tool akin to insurance. Second, traders may use options traded on exchanges or electronic trading platforms to speculate. For example, a speculator may trade an option and hope to gain from price movements, akin to how they might trade other contracts, such as futures. If a trader buys an option, the trader can sell it up to expiration and pocket the difference between the purchase price and the sales price. Further, as in futures, the seller of an option traded on an exchange can offset his obligation by purchasing the offsetting option, thereby eliminating the risk of the contract going to delivery.

Finally, traders may use options to boost their trading income or to reduce the volatility of their returns. Options require less money up-front than a futures contract or swap, which can be a benefit to traders with limited funds.

Trading and Transacting

Trading Mechanics

Market prices are the collective result of individual trades. Open interest is the aggregation of traders' positions.

Trading is the buying and selling of contracts. A trade is a single purchase or sale. A position is the accumulated unexpired contracts purchased or sold, at a point in time. Traders may have positions in each contract, as well as an overall position reflecting all their contracts.

Trading requires a buyer and a seller, each willing to transact for a price. A buyer bids a price he or she is willing to pay to purchase a contract; this is the bid price. A seller offers a product for sale; the price at which the seller offers it is the offer price.

These prices may or may not be the same. When they differ, the distance between them is the bid-offer or bid-ask spread. This spread is the difference between the highest price at which buyers are currently willing to buy (the highest bid) versus the lowest price at which sellers are currently willing to sell (the lowest offer). For example, if a buyer bids \$7 and the seller offers at \$10, the bid-ask spread is \$3.

Trading Concepts

Traders need to know how their trades and positions will be affected by market changes. One way this is done is by considering whether a trade or position benefits or loses when prices go up or down. A position is long if it benefits from increases in price. It is short if it benefits from falling prices. If it is neutral, benefitting from neither a rise nor a fall in prices, it is said to be flat.

For example, a trader who purchases a Nymex natural gas futures contract is going long; that contract will benefit from increases in price. A trader who sells the contract is going short; the trader will benefit from falling prices.

The concept of being long or short applies to other forms of transactions. Absent anything else, a generator is long electricity; a consumer short electricity. If the generator obtains a contract to sell electricity to the consumer at its cost of generating, the generator is flat.

The task of identifying long or short is not always easy. A trader may have a variety of positions in a number of contracts, some long and some short. How the overall position benefits from swings in prices depends on each of the components and how they interact with each other.

Trading Strategies

Traders decide what products to trade, how to trade them and in which combinations. Their strategies will depend on their objectives. Broadly, market participants trade to accomplish any of three objectives: to buy or sell physical products, such as natural gas or electricity; to manage the risk of their physical positions, or hedge; or to make money.

Hedging

Market participants with physical positions are in the market to buy and sell natural gas and electricity to enhance profitability of their physical operations. These physical operations determine their individual risks and hedging needs, and each physical market participant has a risk position related to its business role in the physical delivery and consumption of natural gas and electricity. A natural gas producer has different risks and therefore different hedging objectives than an LDC that needs to purchase gas to resell to retail consumers.

An LDC, for example, is concerned with obtaining sufficient volumes to serve variable customer demand and in the price paid for those volumes. A producer may be concerned about selling all output (unless the output may be stored), and about the revenues obtained from the gas sale. Physical market participants may have other concerns as well. Producers

may need a predictable cash flow to support their financing. LDCs may be concerned with state regulators determining that their gas purchasing practices were imprudent.

Such concerns drive both procurement and sales decisions as well as risk management decisions. The two are often closely interconnected. For example, an LDC needs to buy enough gas to meet extremely variable retail demand, but not too much. An LDC also wants a price that regulators and consumers will see as reasonable. Consequently, LDCs usually develop a procurement and risk management – hedging – strategy taking these factors into account.



To purchase sufficient quantities, an LDC may create a portfolio of supplies, with a block of firm supply to meet minimum daily needs. An LDC trader may also decide to buy in the spot market to meet demand peaks. An LDC may diversify the sources of gas, both to improve reliability of supply but also to diversify its price.

An LDC may also manage risk financially. In the commodities and securities markets, a hedge is a transaction entered into for the purpose of protecting the value of the commodity or security from adverse price movement by entering into an offsetting position in a related commodity or security. Hedging is used when describing the purpose of entering into a transaction with the intent of offsetting risk from another related transaction.

Speculation

Traders seeking to make money fall into a couple of categories: investors and speculators. These categories are distinguished by the strategies they use to profit from the market. Investors are relatively passive; they are in the market to benefit from long-term price movements and to diversify a broader portfolio. Speculators actively seek to gain from price movements.

Trading Analysis

In deciding whether to trade, both hedgers and speculators pay attention to what is going on in the market, and develop their own view of where the market is likely to go. They may develop complicated forecasts as the basis for decisions on a number of transactions: whether, when and where to build a merchant power plant, how to hedge natural gas production, and of course, when to buy and sell in the markets.

Two general schools influence traders' thinking when analyzing markets for trading opportunities. The first is fundamental analysis, which takes into account physical demand and supply fundamentals including production, pipeline and transmission capacity, planned and unplanned outages, weather and economic and demographic changes. Changes in information about fundamentals (or changes in perceptions of fundamentals) alter traders' views of the supply-demand balance, and therefore, of prices. Fundamental analysis is used often to determine the impacts of longer term trends in the physical market – the development of shale gas supplies, for example.

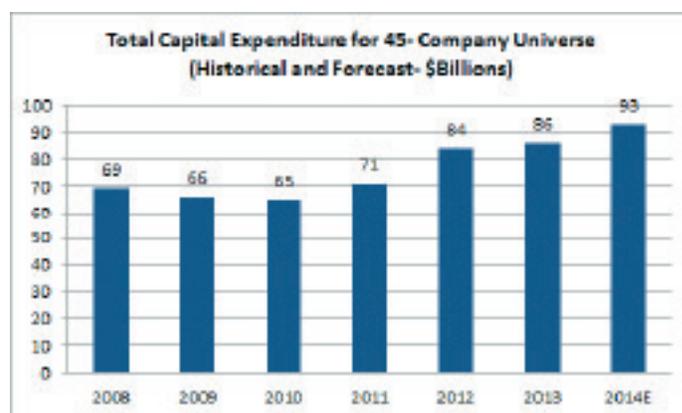
The second school of thought is technical analysis, which forecasts price movements based on patterns of price changes, rates of change, changes in trading volumes and open interest, without regard to the underlying fundamental conditions. Instead of looking at the market for a physical good, technical analysis looks at trading and price changes. These quantitative methods have become a dominant part of market analysis. Technical analysis is used most often to determine short-term movements and trends, helping traders time their buys and sells.

Capital Markets

Capital markets provide the money to make investments in infrastructure such as power plants or natural gas pipelines, to operate plants and companies and to trade or conduct transactions. Access to capital depends both on the health of capital markets and also on the perceived riskiness of the entity seeking the capital. To measure relative riskiness, many providers of capital look at different measures, including credit ratings assigned by the three major crediting rating firms: Standard and Poor's (S&P), Moody's and Fitch.

Capital Expenditures

One effect capital markets have on energy markets is in capital spending – undertaking work or investments that require capital. The 2009 recession and shake-up in capital markets took a toll on capital spending as financial commitments to infrastructure fell for the first time in years, but spending has been rising since 2011 (see bar chart).



Source: SNL Energy

The electric industry makes up the bulk of the capital expenditures expected by energy companies. The majority of the electric industry's spending has been on electric transmission & distribution and generation.

Types of Capital

Capital comes from two general sources of financing – debt and equity.

Debt financing involves borrowing money to be repaid over time, along with interest at a fixed or variable interest rate. With debt, the investor does not become an owner of the company. Some common types of debt include bonds – securities that companies issue in financial markets with maturities (when the loan has to be repaid) of more than a year; shorter term debt issued by companies through financial markets; and bank loans, such as lines of credit. A revolving line of credit is an assurance from a bank or other institution that a company may borrow and repay funds up to some limit at any time. Municipal and cooperative utilities typically use debt; they have no ownership to sell.

Characteristics of debt include:

- Capital obtained through debt must be repaid or refinanced.
- Debt may be short-term, such as lines of credit from banks or corporate paper, or it may be long-term.
- Companies must make their interest payments and repayment on schedule, or the debt holders can take action, including forcing the company into bankruptcy. A company must generate sufficient cash through its operations or through other financing to make these payments.
- Interest gets paid before equity dividends.
- Interest payments are tax deductible.
- Debt gives lenders little or no control of the company (unless it gets into financial trouble).
- Debt can leverage company profits; similarly, it can magnify losses.
- Lenders are typically conservative, wanting to minimize downside risks.
- Borrowers may be required to pay collateral to secure debt. Debt without collateral is known as unsecured debt.

Equity financing is money provided in exchange for a share in the ownership of the business. A company does not have to repay the capital received, and shareholders are entitled to benefit from the company's operations, perhaps through dividends.

- Equity capital can be kept by the company indefinitely.
- Companies can issue shares in the company – stock – through financial markets. They may also use private eq-

uity – money from venture capital firms or private investment companies that buy into a company and which may or may not take an active role in operating the company.

- The most common form of stock is common stock, which does not require regular payments, but it may receive dividends; investor-owned utilities typically pay dividends.
- Equity does not provide a tax deduction to the company; dividends and other payouts are not tax deductible.
- Stockholders and private equity investors get a say in how the company is operated and may impose restrictions.
- Equity investors may be more willing to assume higher risks in return for a higher potential returns. Utilities are typically considered fairly conservative investments. Natural gas producers attract a more risk-inclined investor.
- The return required to attract equity is higher than the interest paid to debt holders.
- Equity capital does not require collateral; it gets a share in the company.
- Additional equity capital infusions may dilute, or reduce, the value of existing shares.

Companies often try to match the type of financing with the investment they are making. Pipelines, power plants and transmission facilities are long-lived assets. They are typically financed using long-term capital, such as stock and long-term bonds, which can have 30-year maturities.



Other capital is needed to conduct day-to-day operations. Some of the cash needed to fund operations comes from a company's revenues. However, revenues do not always come in when payments are due. Consequently, companies also rely on working capital. This can include some long-term capital from stocks and medium- and long-term bonds. Short term investments and day-to-day operations also rely on commercial paper and bank loans to cover day-to-day cash needs. If a company faces significant problems, it may have to issue especially high-priced debt – junk bonds – to obtain financing. These are bonds issued by entities lacking investment grade credit ratings (see below). In the past few years, marketers and financial institutions have taken an interest in the energy industry, and have provided another source of equity financing.

Credit Ratings

Not all companies (or governments) present the same riskiness to investors. Investors, traders and others consider the risks their counterparty may present, including the risk of default. One standardized tool used to assess relative risk is the credit rating. Credit rating agencies, such as Standard and Poor's, Moody's and Fitch, assess a company's riskiness every time it wants to issue bonds. A credit rating represents the likelihood that an issuer will default on its financial obligations and the capacity and willingness of a borrower to pay principal and interest in accordance with the terms of the obligations. Many organizations, including RTOs, consider bond ratings, among other things, when setting their credit policies, which determine with whom companies may transact and whether the counterparty will need to post collateral. Each credit rating agency has its own way of assessing risk, reflected in the rating system they use.

Ratings by Industry Sector

Electric utilities largely are rated investment grade, with ratings of BBB or better.

Merchant generators include generating companies that are completely unaffiliated with integrated utilities (and are known as independent power producers, or IPPs) and those

that are affiliated but which receive at least half their cash flow from competitive power sales. The affiliated companies typically have higher ratings; S&P views the integrated merchants' business profile scores as strong or satisfactory. S&P typically rates IPPs fair or weak.

The midstream sector of the natural gas industry, which contains pipelines, processing plants and storage facilities, is also typically rated investment grade. Midstream companies' ratings average BBB and are said by rating agencies to have a stable outlook.



6. MARKET MANIPULATION

Following the energy crisis in the western United States early last decade, Congress enacted the Energy Policy Act of 2005 (EPAct 2005), which added anti-manipulation provisions to the Federal Power Act, 16 U.S.C. § 824v (2012), and the Natural Gas Act, 15 U.S.C. § 717c-1 (2012). To implement these anti-manipulation provisions, the Commission issued Order No. 670, adopting the Commission's Anti-Manipulation Rule, which has been codified as 18 C.F.R. § 1c (2014). Recognizing that other regulators have long prohibited manipulation of other markets such as securities and commodities, the Commission draws from the experience of sister federal agencies in implementing the Commission's anti-manipulation authority.

The Anti-Manipulation Rule applies to any entity, which the Commission has interpreted to mean any person or form of organization, regardless of its legal status, function or activities, and prohibits (1) using a fraudulent device, scheme or artifice, or making any untrue statement of a material fact or omitting to state a material fact necessary to make a statement that was made not misleading, or engaging in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter (that is, an intentional or reckless state of mind); (3) in connection with a transaction subject to FERC jurisdiction. The Commission need not show reliance, loss causation, or damages to prove a violation.

The prohibition is intended to deter or punish fraud in wholesale energy markets. The Commission defines fraud in general terms, meaning that fraud includes any action, transaction or conspiracy for the purpose of impairing, obstructing or defeating a well-functioning market. Fraud is a question of fact that is to be determined by all the circumstances of a case. In Order No. 670, the Commission found it appropriate to model its Anti-Manipulation Rule on Securities and Exchange Commission (SEC) Rule 10b-5 in an effort to prevent (and where appropriate, remedy) fraud and manipulation affecting the markets the Commission is entrusted to protect. Like SEC Rule 10b-5, FERC's Anti-Manipulation Rule is intended to be a broad antifraud catch-all clause.

The Commission made clear in Order No. 670 that a duty to speak to avoid making untrue statements or material omissions would arise only as a result of a tariff or Commission order, rule or regulation. However, the Anti-Manipulation Rule

extends to situations where an entity has either voluntarily or pursuant to a tariff or Commission directive provided information but then misrepresents or omits a material fact such that the information provided is materially misleading.

To violate the Anti-Manipulation Rule, one must also act with a sufficient state of mind, that is, level of intent. Intentional conduct or recklessness (known as scienter) is enough to satisfy the Rule.

The Commission also stated that for conduct to violate the "in connection with" element of the Rule, there must be a sufficient nexus between an entity's fraudulent conduct and a jurisdictional transaction. In committing fraud, the entity must have intended to affect, or have acted recklessly to affect, a jurisdictional transaction.



Manipulation comes in many varieties. As a federal court of appeals has stated in the context of commodities manipulation, “We think the test of manipulation must largely be a practical one.... The methods and techniques of manipulation are limited only by the ingenuity of man.” *Cargill, Inc. v. Hardin*, 452 F.2d 1154, 1163 (8th Cir. 1971). The Commission recognized this reality by framing its Anti-Manipulation Rule broadly, rather than articulating specific conduct that would violate its rules. While manipulative techniques may be “limited only by the ingenuity of man,” the following are broad categories of illustrative manipulations that have surfaced in the securities and commodities markets (including the energy markets) over the years. The borders of these categories are flexible and some can belong to multiple categories, such as wash trading (i.e., buying and selling identical stocks or commodities at the same time and price, or without economic risk). Traders may also combine elements of various schemes to effect a manipulation.

Manipulative Trading Techniques and Cross-Product Manipulations

A number of manipulative trading techniques that have arisen in securities and commodities trading may be subject to the Commission’s Anti-Manipulation Rule. Traders may seek to inflate trading volumes or trade at off-market prices to serve purposes such as maintaining market confidence in a company’s securities or to move a security’s price to trigger an option. Marking the close is a manipulative practice in which a trader executes a number of transactions near the close of a day’s or contract’s trading to affect the closing or settlement price. This may be done to obtain mark-to-market marks for valuation, to avoid margin calls, or to benefit other positions in related instruments. Banging the open is a similar practice in which a trader buys or sells a large quantity at the opening of trading to induce others to trade at that price level and to signal information on fundamentals. Other manipulative trading techniques exist, and practices like wash and round-trip trading that are discussed in more detail below fit under this description as well.

Manipulators have grown more sophisticated with the expanded use of derivative products, whose value is set by the price of transactions in a related product. Many of the manipulative schemes that staff from FERC’s Office of Enforcement (Enforcement staff) has investigated and prosecuted are cross-product schemes in which an entity engages in price-making trades in the physical market, often at a loss, with the intent to affect the settlement price of price-taking derivative instruments. Cross-product manipulation is also referred to as related-position manipulation. Such trading can violate the Anti-Manipulation Rule because the trading is not undertaken in response to supply-and-demand fundamentals but rather is undertaken to benefit another position. Such trading could be considered to undermine the functioning of jurisdictional markets.

Key to understanding cross-product manipulation is that financial and physical energy markets are interrelated: physical natural gas or electric transactions can help set energy prices on which financial products are based, so that a manipulator can use physical trades (or other energy transactions that affect physical prices) to move prices in a way that benefits his overall financial position. One useful way of looking at manipulation is that the physical transaction is a “tool” that is used to “target” a physical price. For example, the physical tool could be a physical power flow scheduled in a day ahead electricity market at a particular “node” and the target could be the day-ahead price established by the market operator for that node. Or the physical tool could be a purchase of natural gas at a trading point located near a pipeline, and the target could be a published index price corresponding to that trading point. The purpose of using the tool to target a physical price is to raise or lower that price in a way that will increase the value of a “benefiting position” (e.g., Financial Transmission Right or FTR product in power markets, a swap, a futures contract, or other derivative).

Usually, increasing the value of the benefiting position is the goal or motive of the manipulative scheme. Understanding the nature and scope of a manipulator’s benefiting financial positions—and how they relate to the physical positions—can be a key focus of manipulation cases. The Commission’s

Anti-Manipulation Rule is an intent-based rule: a finding of manipulation requires proving that the manipulator intended (or in some cases, acted recklessly) to move prices or otherwise distort the proper functioning of the energy markets the Commission regulates. A company can put on a large physical trade that may affect market prices, but if the purpose of that trade is to hedge risk or speculate based on market fundamentals—rather than, for example, the intent to move prices to benefit a related financial position—this conduct, without more, would not violate the Commission’s Anti-Manipulation Rule.

Information-Based Manipulations

Many manipulative schemes rely on spreading false information, which involves knowingly disseminating untrue information about an asset’s value in order to move its price. A well-known scheme is the pump and dump, in which a participant spreads a rumor that drives the price up and then sells the shares after the price rises. In the energy markets, a common way to misrepresent a commodity’s value is to misrepresent the price of the commodity or its level of trading activity. False reporting and wash-trading schemes were well-documented information-based manipulations that took place in the early 2000s and contributed to the western energy crisis. False reporting occurs when a market participant submits fictitious transactions or information to a price-index publisher to affect the index settlement price. Another form of information-based manipulation involves providing misinformation through conduct that is intended to misrepresent a market participant’s characteristics, circumstances, or intentions, in order to receive a benefit, payment, or award for which it would not be eligible but for the misleading conduct. This includes engaging in trading strategies that are intended to create market results that are inconsistent with the purpose of the transactions.

Similarly, wash trading may involve actual but offsetting trades for the same (possibly nonmarket) price and volume between the same market participants such that no economic

exchange takes place; however, it may falsely inflate trading volumes at a price level and give the impression of greater trading activity. False reporting and wash trading have resulted in a number of criminal prosecutions by the Department of Justice.

Withholding

Withholding is the removal of supply from the market and is one of the oldest forms of commodities manipulation. The classic manipulation of a market corner involves taking a long contract position in a deliverable commodity and stockpiling physical supply to force those who have taken a short position to buy back those positions at an inflated price.

Withholding played an important role in the western power crisis that engulfed California in 2000. Market participants, particularly Enron, exploited supply-demand imbalances and poor market design. Generation operators scheduled maintenance outages during peak demand periods, which is an example of physical withholding. In addition, transmission lines were overscheduled to create the appearance of congestion in an effort to reduce the supply of electricity. The result of these efforts in combination with economic withholding and information-based schemes discussed above was that wholesale electricity prices soared. Utilities such as Pacific Gas & Electric (PG&E) and Southern California Edison were unable to pass on these high prices to their retail customers because of state price caps. The crisis led to widespread blackouts, heavy losses to the state’s economy and the bankruptcy, in April 2001, of PG&E.

Economic withholding, which also contributed to the western power crisis, is similar to physical withholding, but rather than turning off a generator or stockpiling a physical commodity, the manipulator sets an offer price for a needed resource that is so high that the resource will not be selected in the market. For example, a generator in a constrained market such as New York City could purposely set its offer price high enough that it would not be called on to run. This scheme would create a shortage of generation and, thus, would raise prices for the

benefit of the rest of its generation fleet or its financial positions. As withholding is intended to benefit a market participant's overall portfolio, it is similar to cross-product manipulation, discussed above.

Representative Matters

The following representative matters involve at least one of the types of manipulative schemes described above. Each of these matters has either been resolved through settlement or is currently pending before a district court or administrative law judge.

Barclays Bank, PLC, Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith (Barclays and Traders)

On July 16, 2013, the Commission issued an order determining that Barclays and Traders violated the Commission's Anti-Manipulation Rule and assessed civil penalties of \$435 million against Barclays and \$18 million against the Traders.¹ The Commission also ordered Barclays to disgorge \$34.9 million plus interest in unjust profits. The Commission found that Barclays and Traders engaged in loss-generating trading of next-day, fixed-price physical electricity on the ICE with the intent to benefit financial swap positions at primary electricity trading points in the western United States. In sum, Barclays undertook fixed-price, Day-Ahead physical trades at various Western trading points – tool – to intentionally change the ICE daily index – the target – for the benefit of its financial swap positions whose price was based on that index – the benefiting position.

Barclays and Traders elected to challenge the penalty in federal district court, and Enforcement staff filed an action to affirm the Commission's assessment in the United States District

¹ *Barclays Bank PLC, Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith*, 144 FERC ¶ 61,041 (2013) (order assessing civil penalties).

Court for the Eastern District of California on October 9, 2013. The matter is pending before that court.

BP America, Inc. and Affiliates

On August 5, 2013, the Commission issued an order to show cause and notice of proposed penalty to BP.² In that proceeding, Enforcement staff alleged that BP made uneconomic sales at Houston Ship Channel and took steps to increase its market share at Houston Ship Channel as part of a manipulative scheme to suppress the Houston Ship Channel Gas Daily index, and that this scheme was motivated by a desire to benefit certain physical and financial positions held by BP whose price was set by the same index. In sum, as cross-product manipulation, Enforcement staff alleged that BP undertook trades at Houston Ship Channel – the tool – with the intent to alter the price of the Houston Ship Channel Gas Daily index – the target – to increase the value of physical and financial positions whose prices were set by the index – the benefiting positions. On May 15, 2014, the Commission set the matter for hearing to determine whether BP's conduct violated the Anti-Manipulation Rule.³

Constellation Energy Commodities Group

In 2012, the Commission approved a settlement with Constellation Energy Commodities Group (CCG) in which CCG agreed to disgorge \$110 million in unjust profits and pay a civil penalty of \$135 million. Enforcement staff had alleged that CCG entered into significant loss-generating physical and virtual day-ahead transactions in electricity markets in and around New York State with the intent to move day-ahead price settlements to benefit financial swap positions that received their prices from those settlements.

² *BP America Inc.*, 144 FERC ¶ 61,100 (2013).

³ *BP America Inc.*, 147 FERC ¶ 61,130 (2014).

Deutsche Bank Energy Trading (Deutsche Bank)

On January 22, 2013, the Commission approved a settlement between the Office of Enforcement and Deutsche Bank, in which Deutsche Bank agreed to disgorge \$172,645 in unjust profits and pay a civil penalty of \$1.5 million. In the settlement, Enforcement staff concluded that Deutsche Bank violated the Commission's Anti-Manipulation Rule, through cross-product manipulation in which it traded physical exports at Silver Peak that were not profitable with the intent to benefit its Congestion Revenue Rights (CRR) position. Deutsche Bank had a CRR position at the 17-MW Silver Peak intertie that started to lose money. To stem those losses, Deutsche Bank submitted export bids to change the price at Silver Peak, as that price affected the value of Deutsche Bank's CRR position. By changing that price, Deutsche Bank diminished its losses on the CRR position. Deutsche Bank consistently lost money on its export at Silver Peak, but those losses were offset by the avoided losses on its CRR position. In sum, as cross-product manipulation, Deutsche Bank traded physical exports – the tool – to alter the price at the Silver Peak – the target – to diminish its losses on its CRR position – the benefiting position.

ISO-NE Day-Ahead Load Response Program (DALRP)

Based on an Enforcement investigation of Rumford Paper Company (Rumford), Lincoln Paper and Tissue LLC (Lincoln), Competitive Energy Services, LLC (CES), and Richard Silkman, the Commission in July 2012 issued each subject an order to show cause alleging that their conduct related to the DALRP in the ISO New England market (ISO-NE) violated the Commission's Anti-Manipulation Rule. The Office of Enforcement and Rumford settled the allegations against the company, which the Commission approved in March 2013.⁴ On August 29, 2013,

⁴ *Rumford Paper Co.*, 142 FERC ¶ 61,218 (2013) (order approving stipulation and consent agreement).

the Commission issued Orders Assessing Civil Penalties to Lincoln, CES, and Silkman, finding that the subjects fraudulently inflated load baselines and repeatedly offered load reductions at the minimum offer price in order to maintain the inflated baseline.⁵ Enforcement staff found that the scheme involved uneconomic energy purchases that served no legitimate purpose and were designed to increase DALRP payments that would not have otherwise been obtained. The Commission determined that this scheme misled ISO-NE, inducing payments to these entities based on the inflated baselines for load reductions that never occurred.

The Commission ordered Lincoln to pay \$5 million in civil penalties and approximately \$379,000 in disgorgement; CES to pay \$7.5 million in civil penalties and approximately \$167,000 in disgorgement; and Silkman to pay \$1.25 million in civil penalties. None of the respondents paid the amounts assessed by the Commission. Enforcement staff filed two petitions in the United States District Court for the District of Massachusetts on December 2, 2013 seeking review and affirmance of the Commission's orders. These petitions are pending.



⁵ *Lincoln Paper and Tissue, LLC*, 144 FERC ¶ 61,162 (2013) (order assessing civil penalty); *Competitive Energy Services, LLC*, 144 FERC ¶ 61,163 (2013) (order assessing civil penalty); *Richard Silkman*, 144 FERC ¶ 61,164 (2013) (order assessing civil penalty).

JP Morgan Ventures Energy Corporation (JPMVEC)

On July 30, 2013, the Commission approved a settlement between the Office of Enforcement and JPMVEC resolving an investigation of JPMVEC's bidding practices.⁶ JPMVEC paid \$285 million in civil penalties, \$124 million in disgorgement to CAISO ratepayers, and \$1 million in disgorgement to MISO. In addition, the company agreed to waive its claims that CAISO owed it money from two of the strategies that Enforcement staff had investigated, and to conduct a comprehensive external assessment of its policies and practices in the power business.

Enforcement staff determined that JPMVEC violated the Commission's Anti-Manipulation Rule by engaging in twelve manipulative bidding schemes in CAISO and MISO. These schemes distorted a well-functioning market in several ways, including but not limited to, misleading CAISO and MISO into paying JPMVEC at rates far above market prices; submitting bids that were expected to, and did, lose money at market rates, as they were not driven by the market forces of supply and demand; defrauding the ISOs by obtaining payments for benefits that JPMVEC did not deliver; and displacing other generation and influencing energy and congestion prices.

⁶ *In Re Make-Whole Payments and Related Bidding Strategies*, 144 FERC ¶ 61,068 (2013).

Louis Dreyfus Energy Services L.P. (Louis Dreyfus)

On February 7, 2014, the Commission approved a settlement between the Office of Enforcement, Louis Dreyfus, and one of its traders, Xu Cheng.⁷ Under the terms of the settlement, Louis Dreyfus agreed to disgorge \$3,334,000 in unjust earnings, plus interest, and pay a civil penalty of \$4,072,257. Cheng, who had previously crafted and described the manipulative scheme in his doctoral dissertation, agreed to pay a civil penalty of \$310,000. In addition, Louis Dreyfus prohibited Cheng from virtual trading anywhere in the United States, and agreed that he would not be permitted to resume such trading for at least two years.

In the settlement, Enforcement staff concluded that Louis Dreyfus violated the Commission's Anti-Manipulation Rule when it made certain virtual trades in MISO with the intent to increase the value of its nearby FTR position. Louis Dreyfus established an FTR position near the Velva node. Louis Dreyfus earned little or no profit on that FTR position, until it started to place virtual demand bids at the Velva node to benefit the FTR position. Louis Dreyfus consistently lost money on those virtual demand bids, but that loss was offset on its gains on its FTR position. In sum, as cross-product manipulation, Louis Dreyfus submitted virtual demand bids – the tool – to alter the price at the Velva node – the target – to increase the value of its FTR position – the benefiting position.

⁷ *MISO Virtual and FTR Trading (Louis Dreyfus Energy Services)*, 146 FERC ¶ 61,072 (2014).

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