Energy Primer

A Handbook for Energy Market Basics

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation

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The Energy Market Primer was originally issued in 2012 and has been updated several times since its first issuance. This update to the Energy Market Primer is the result of the combined efforts of many dedicated individuals throughout the Federal Energy Regulatory Commission (FERC or Commission). The team consisted of individuals from the Commission's Office of Energy Policy and Innovation, Office of Enforcement, Office of Energy Market Regulation, and Office of External Affairs. We specifically wanted to recognize the primary contributors to each chapter.

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Federal Energy Regulatory Commission
Office of Energy Policy and Innovation

Lance was instrumental in the creation and publication of the Energy Market Primer. He will forever be remembered as a dedicated public servant whose knowledge of energy markets was unsurpassed.

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INTRODUCTION

Natural gas, electricity, and crude oil are forms of energy that are of particular interest to the Federal Energy Regulatory Commission (FERC) 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.

Energy markets consist of 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. The financial markets include the buying and selling of financial instruments that derive value from the price of the physical commodity. These financial markets have their own set of market structures and institutions, market participants, and traded products which 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.

Much of the wholesale natural gas and electric power industry in the United States trades competitively, while some markets and their prices 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 1 (Wholesale Natural Gas Markets), Chapter 2 (Wholesale Electricity Markets), and Chapter 4 (U.S. Crude Oil and Petroleum Products Markets).

The significant shift in the U.S. fuel mix has heightened the importance over the past decade of the interdependence of the natural gas and electric systems. Given the importance of natural gas in electricity generation, integration of market operations between the natural gas and electricity industries is critical. The primer provides an overview of natural gas and electric system interdependencies in Chapter 3, Gas-Electric Interdependency.

Market participants buy and sell energy based financial contracts for a number of reasons. Physical market participants, such as producers and large consumers, usually use financial contracts to manage price risk and to protect against price volatility. That is, financial contracts can serve as a tool for managing risk akin to insurance. Other market participants use the energy markets to speculate, or to assume a market risk in hope of profiting from market fluctuations. Additionally, companies turn to the capital markets if they need to raise or invest money. This primer explores the market participants, products, market mechanisms and trading at work for natural gas and electricity in the financial markets in Chapter 5, Financial Markets and Trading.

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.

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 navigate to the Market Oversight tab. You can find the market oversight pages here: https://www.ferc.gov/market-assessments.

Chapter 1
Wholesale Natural Gas Markets

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 (DOE) Energy Information Administration (EIA) estimates that natural gas supplies approximately 32 percent of the energy used in the U.S.[1] Under the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) has jurisdiction over the transportation and sale of natural gas in interstate commerce 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 that focuses on the purchase and sale of financial instruments whose price is linked to the price of natural gas in the physical market, but that rarely result in the physical delivery of natural gas. Additionally, natural gas markets are 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.

FERC Jurisdiction

FERC is responsible for the regulation of the siting, construction and/or abandonment of interstate pipelines, gas storage facilities, and Liquified Natural Gas (LNG) terminals, regulation of the transmission and sale of natural gas for resale in interstate commerce, establishing rates for pipeline and storage services and assessing the safe operation and reliability of LNG facilities. We explain FERC's jurisdiction over natural gas related activities in more detail throughout this chapter.

Natural Gas

Natural gas is primarily methane, which is a molecule 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 pure form, but is often odorized with mercaptan or other odorants to allow for easy detection. 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, as a gas dissolved in the crude oil, as a gas phase not associated with any significant crude oil, or as a supercritical fluid. Natural gas is "rich" or "wet" if it contains significant amounts of natural gas liquids (NGL) – e.g., ethane, propane and pentane[2]– mixed with the methane. In contrast, natural gas is "lean" or "dry" if it consists of mostly methane.[3] Excess NGLs are separated from the methane and sold separately. Natural gas reservoirs often contain other elements and compounds, such as carbon dioxide, hydrogen sulfide, nitrogen, helium, water, dissolved salts, and other dissolved gases. The natural gas is further processed to remove the impurities from the methane to make the natural gas suitable for sale. 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.

1 Derived from EIA, *Monthly Energy Review*, *Primary Energy Consumption by Source*, *Table 1.3* (accessed August 2022), https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

2 Natural gas liquids (NGLs) are hydrocarbons—in the same family of molecules as natural gas and crude oil— composed exclusively of carbon and hydrogen. Ethane, propane, butane, isobutane, and pentane are all NGLs. There are many uses for NGLs, including inputs for petrochemical plants, burned for space heat and cooking, and blended into vehicle fuel.

3 Dry gas contains "insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use." Society of Petroleum Engineers, *Glossary of Terms Used in Petroleum Reserves and Resources Definitions* (n.d.), https://www.spe.org/en/industry/terms-used-petroleum-reserves-resource-definitions/.

Natural Gas Industry

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 a significant influence on the physical natural gas market.

The natural gas industry has three major segments, the upstream (supply), the midstream (transportation), and the downstream (consumption). The upstream segment includes exploration, which is the process of attempting to find accumulations of natural gas resources, production, which includes recovering natural gas resources through drilling and extraction at the wellhead, and finally gathering. Gathering entails using small diameter pipeline systems to transport the gas from the wellhead to local pooling points or to natural gas processing facilities, where impurities and NGLs are removed to create pipeline-quality natural gas. The midstream segment includes transportation on intrastate and interstate pipeline systems that move natural gas through large-diameter pipelines to storage facilities and a variety of consumers. The downstream segment includes large gas consumers, such as power plants and 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. More specifically, the differences in supply and demand result in different prices for natural gas at various locations. Prices have historically tended to be lower in regions supplied by multiple production areas with robust pipeline infrastructure, such as the Gulf Coast, Southwest, and Midwest. In contrast, prices tend to be highest in areas where production or transportation and storage are limited and demand is high, such as New England and Southern California. Transportation costs and limitations in pipeline capacity from supply to demand areas are generally the major factors driving regional price differentials.

Various factors have shifted the dynamics of natural gas supply and demand since 2007, when shale gas production began to grow significantly. These include, but are not limited to:

1. Development of modern hydraulic fracturing and horizontal drilling techniques that have enabled producers to access unconventional resources, such as those in shale formations. These techniques have expanded the amount of available economically accessible natural gas reserves and have increased domestic natural gas production. These newer resources are located closer to eastern population centers and have provided those regions with access to lower cost natural gas supplies and transportation costs.
2. Natural gas demand for power generation has expanded considerably over the past decade. Power plant demand for natural gas reflects the operating flexibility of natural gas-fired generators and the environmental benefits of the fuel. Natural gas-fired power plants emit less air pollution than power plants 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 flexibly. The ability to quickly change output provides electric system grid operators with the flexibility to support variations in output from renewable energy resources, changes in demand from customer load, as well as unexpected power system events and disruptions.
3. Pipeline expansions linking the new supply regions to markets have enabled regions such as the Northeast and Mid-Atlantic to access new supply sources, expanding the amount of natural gas that can flow from traditional supply sources, and enhancing the amount of natural gas that can flow to markets.

4. Rising natural gas production combined with increasing international natural gas demand has led to the construction of several LNG export terminals. As a result, U.S. LNG export capacity and international cargo deliveries have grown significantly since 2016.

Natural Gas Demand

Natural gas is the fuel of choice for many sectors of the U.S. economy. 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, natural gas demand can fluctuate substantially due to 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, which can 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 soaring – or dropping – within the course of a day, sometimes unexpectedly. The weather's unpredictability challenges suppliers and pipelines, especially when demand is high and 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, natural gas use typically declines.

Structural changes in the economy can also affect natural gas demand, such as varying levels of manufacturing and service sector activity. Additionally, new domestic markets for products and services may increase the consumption of natural gas, whereas movement of manufacturing overseas may reduce demand. Lastly, demand for exports of natural gas, to Mexico and Canada via pipeline and globally via LNG shipping, have also had a significant effect on aggregate demand.

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 homeowner may decide to invest in a furnace and associated piping to use natural gas for heating, so, too, a power producer may decide to make long-term investments in natural gas-fired generators. Decisions requiring long-term capital investments are easiest to make at the time a home or power plant is being built and are more complicated to changelater. 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 choices as to which power plant to dispatch to meet electric demand. As explained in greater detail in the electric chapter, dispatch is often based on the marginal cost of generation at each available plant in the generation fleet. While the degree to which these fuels are used varies regionally, plants with lower marginal costs, such as nuclear plants, are typically dispatched before plants with higher marginal costs, such as natural gas plants. As natural gas prices drop relative to coal prices, natural gas-fired generation may be dispatched ahead of 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 population declines in certain areas of the North have affected natural gas use. So has the trend toward larger houses, which have greater heating and cooling needs, yet are generally more energy efficient.

ENVIRONMENTAL CONCERNS AND ENERGY EFFICIENCY

Natural gas emits much fewer pollutants than other competing fossil fuels, including carbon and other greenhouse gases, which has been an important factor in some decisions to use natural gas for power generation. This is particularly significant in states and regions that have experienced challenges in meeting air quality standards.

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

On an annual basis, power generation makes up about 37 percent of total U.S. natural gas demand.[4] Industrial, residential, and commercial consumers represent approximately 27 percent, 15 percent, and 11 percent of total U.S. natural gas demand, respectively.[5] An additional 6 percent is used for lease and plant fuel operations and 3 percent is used for pipeline and distribution activities.[6] See FERC's *State of the Markets Report* and *Seasonal Assessments* for analyses on recent natural gas demand sector trends.[7]

Each customer sector has a unique demand profile, both in the amount that the demand varies over a season 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 overall winter gas-demand peak, but the use of natural gas to produce electricity for air conditioning has created robust summer demand, which competes with natural gas supply that traditionally would flow into underground storage for later use. Industrial demand is fairly 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. Price inelasticity implies that a potential for price spikes exists during periods of supply constraints. In the longer term, residential and commercial natural gas use can change, with changes in space heating or cooking from fuel oil to natural gas (increasing demand for natural gas) or from natural gas to electric (decreasing demand for natural gas).

Consequently, the mix of customers in a region can affect system operations and costs. Pipelines and other equipment are sized to account for peak demand. Load that has fairly constant demand presents fewer operational challenges to suppliers 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. As a result, the cost to provide service may be higher because the pipelines may become constrained during peak times and because the capacity is not consistently utilized.

POWER GENERATION

Natural gas-fired generators can flexibly manage their output and are frequently called on to respond to changes in demand or when called upon by power grid operators. Seasonally, generating plants tend to consume more natural gas in the summer to meet air conditioning loads, but also increase output in the winter to provide electric heating and lighting. Generation demand can also be influenced by the

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4 Derived from EIA, *Natural Gas Consumption by End Use, U.S., Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

5 *Id.*

6 *Id.*

7 *See* FERC, *Reports & Analyses* (n.d.), https://www.ferc.gov/reports-analyses.

relative prices for natural gas and other fuels, especially coal. Since late 2008, natural gas-fired generators generally have been dispatched before many of the less efficient coal plants because of the relatively low natural gas prices seen over the past decade. In 2016, electricity generation from natural gas overtook coal generation for the first time on an annual basis.[8]

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, medicines, and explosives. As noted earlier, industrial load tends to show the least seasonal variation of natural gas use.

RESIDENTIAL

Despite population growth, natural gas used in the residential sector has remained fairly flat over the past decade. This has primarily occurred because homes and appliances like furnaces, water heaters, and clothes dryers have become more energy efficient. Slightly more than half of the homes in the U.S. use natural gas as their main heating fuel.[9] Separately, 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.

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, including seismic studies and drilling exploration wells. Estimating the technically recoverable oil and natural gas resources in the U.S. is an evolving process. Analysts use different methods and systems to make natural gas estimates. Natural gas supplies are broadly characterized as resources, proved reserves, and production.

Resources, the largest category of supply, refers to the quantity of a natural resource that is known to exist with a reasonable degree of certainty and can be extracted using existing or feasibly commercial technology. Proved reserves are a subset of resources which are known to exist with a reasonable degree of certainty and can be economically extracted under current or assumed prices. Resources and proved reserves are dynamic as both change when new natural resources are discovered via exploration, as natural resources are extracted, and as prices fluctuate. All estimates of proved reserves involve some degree of uncertainty, which depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate. According to the Society of Petroleum Engineers, "proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with a reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions,operating methods, and government regulations."[10] Lastly, production describes the amount of a natural gas that is actually extracted over a period of time.

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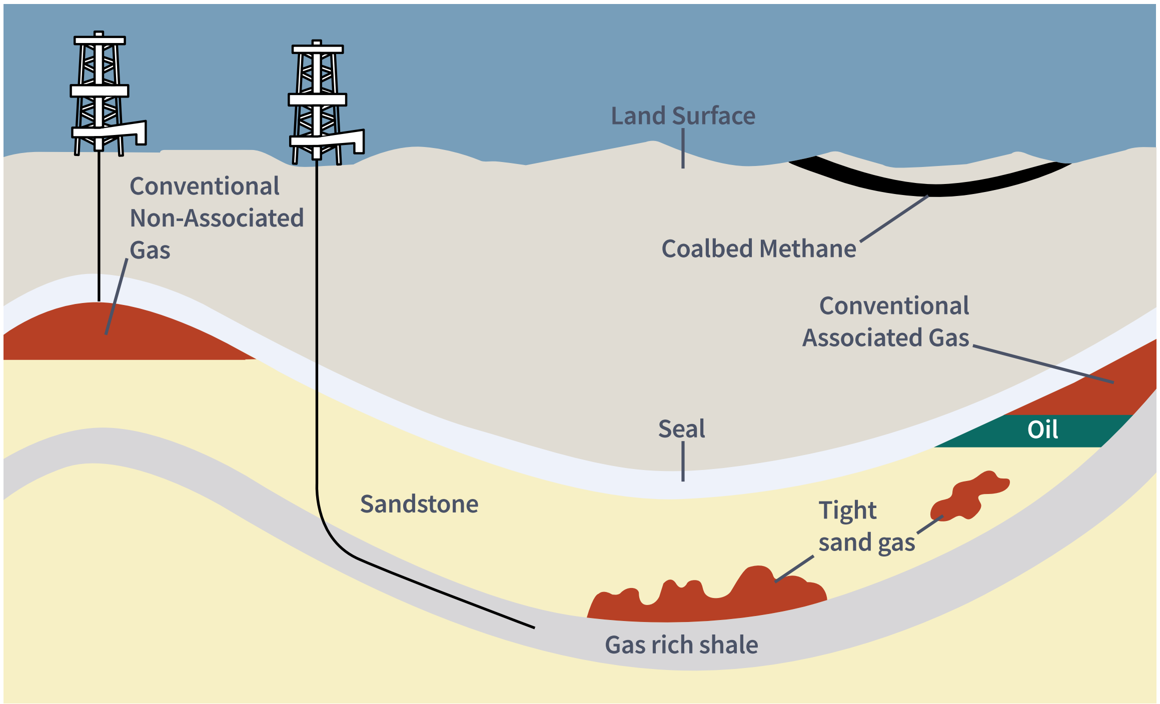
8 *See* EIA, *Total Energy, Electricity, Table 7.2b Electricity Net Generation: Electric Power Sector* (accessed October 2022), https://www.eia.gov/totalenergy/data/browser/?tbl=T07.02B.

9 EIA, *Natural gas explained* (May 24, 2022), https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.

10 Probabilistic reserves are often used, for instance a P90 reserve figure indicates there should be at least a 90 percent probability that quantities actually recovered will equal or exceed the estimate. Society of Petroleum Engineers, World Petroleum Congresses, and American Association of Petroleum Geologists, Guidelines for the Evaluation of Petroleum Reserves and Resources, at 45 (2001), https://www.spe.org/industry/docs/Guidelines-Evaluation-Reserves-Resources-2001.pdf.

Figure 1-1: Schematic Geology of Natural Gas Resources



Source: U.S. Energy Information Administration and U.S. Geological Survey[11]

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 completely removed federal controls on new natural gas and eventually all wellhead price controls, except sales for resale of domestic natural gas by interstate pipelines, LDCs, or their affiliates.[12] 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.

UNCONVENTIONAL AND CONVENTIONAL NATURAL GAS

Natural gas is a fossil fuel. It has historically been found in underground reservoirs formed when organic material was buried and pressurized. The remains of that organic material were trapped in the surrounding rock as oil or natural gas, and the two fuels 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. Oil is generally found at depths of 3,000 to 9,000 feet, while organic materials at greater depths and higher temperatures result in natural gas.

11 EIA, *Today in Energy*, *The geology of natural resources* (February 14, 2011), https://www.eia.gov/todayinenergy/detail.php?id=110.

12 Pub. L. No. 101-60 (1989); 15 U.S.C. § 3431(b)(1)(A). The Natural Gas Wellhead Decontrol Act of 1989 amended the Natural Gas Policy Act of 1978 to declare that the price guidelines for the first sale of natural gas do not apply to: (1) expired, terminated, or post-enactment contracts executed after the date of enactment of this Act; and (2) certain renegotiated contracts. Specifically, as of May 15, 1991, the act, decontrolled natural gas produced from newly spudded wells and also repealed permanently wellhead price controls beginning on January 1, 1993.

Natural gas basins are frequently referred to as unconventional or conventional 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.

UNCONVENTIONAL NATURAL GAS

Innovations in exploration and drilling technology have led to rapid growth in the production of unconventional natural gas. The majority of unconventional natural gas production in the U.S. comes from shale and tight sands.

Unconventional natural gas is a found in shale, and tight, low-permeability rock formations (also referred to as tight sands) and coal seams (also referred to as coal beds). The National Petroleum Council (NPC) defines unconventional gas as "natural gas that cannot be produced at economic flow rates nor in economic volumes 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 [13]

SHALE AND TIGHT SANDS

Shale gas is natural gas found in fine-grained sedimentary rock with low permeability, including mudstone, clay stone, and what is commonly known as shale. Natural gas in shale formations tends to concentrate in natural fractures and the rock adjacent to them. Historically, extraction of natural gas from shale formations has been difficult to achieve. Growth in shale resources is discussed further below (see "The Shale Revolution").

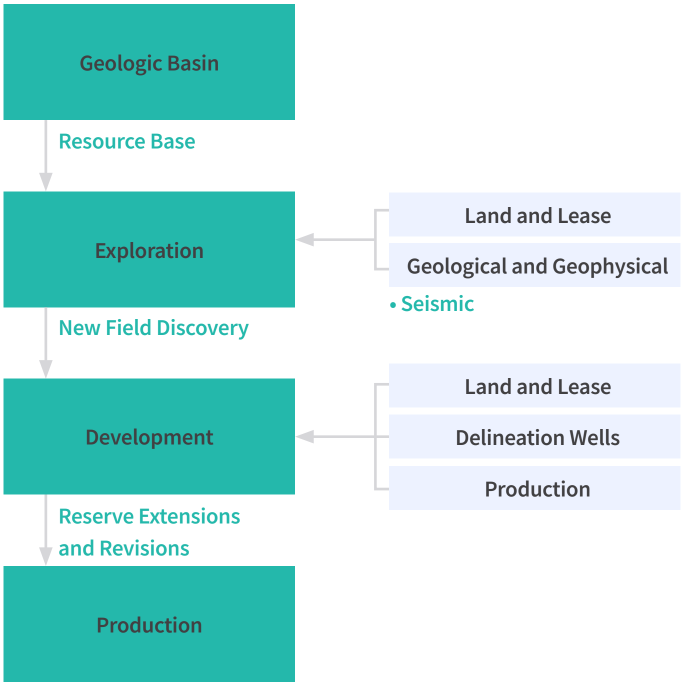
Tight sands gas is natural gas contained in sandstone, siltstone, and carbonate reservoirs of such low permeability that it will not naturally flow at economic production rates when a well is drilled. There are about 20 shale and tight sands basins in the U.S. (see map).

Horizontal and Directional Drilling with Hydraulic Fracturing

The presence of natural gas in unconventional plays had been common knowledge for decades. Historically, the lower permeability of rock in shale formations typically yielded too little natural gas for a company's investment when using traditional drilling methods. In the early 1990s, after years of experimenting in the Barnett Shale in Texas, George Mitchell and Mitchell Energy Co. developed new techniques that made production from these types of formations more economically feasible. The new techniques combined horizontal drilling with slickwater hydraulic fracturing (slickwater hydraulic fracturing fluids are water-based fluids, generally containing a friction reducer, that facilitate rapid pumping of the fluid into the well), allowing Mitchell to drill into specific target areas and release the natural gas trapped in the formation. Horizontal drilling allows producers to target the specific cross-sections of rock formations where the natural gas is trapped, greatly improving the likelihood of a productive well.

13 *See* National Petroleum Council Global Oil & Gas Study, *Topic Paper #29 Unconventional Gas*, at 5 (July 18, 2007), http://www.energybc.ca/cache/naturalgas/www.npc.org/Study_Topic_Papers/29-TTG-Unconventional-Gas.pdf.

Figure 1-2: Natural Gas Exploration and Development Process



Source: FERC staff, 2012

Growth in shale gas in particular has been substantial since 2007 and has contributed to a significant increase in U.S. proved natural gas reserves. Proven shale reserves are approximately 13 times larger than 2007 levels.[14]

Shale and tight sands 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. Since 2007, the processes for finding geological formations have improved, and producers have accumulated knowledge of subsurface oil and gas deposits over that span of time. As a result, most wells targeting shale and tight sands formations result in drill contact with formations and successful new 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.

The largest gas producing unconventional shale plays in the U.S. are the Appalachia, Permian, Haynesville, Eagle Ford, Anadarko, Niobrara, and Bakken basins (see map below for shale locations).[15] Other shale formations have experienced heavy exploration activity and depending on economic conditions may become major contributors of natural gas supply.

THE SHALE REVOLUTION

The estimated resources, proven reserves, and production of shale gas has risen rapidly since 2005, and the development of shale gas has transformed gas production in the U.S. Shale gas continues to be the dominant source of domestically produced gas, providing 70 percent of the gross production of natural gas. By comparison, coalbed methane accounts for about 2 percent of production, while nearly 11 percent of the natural gas came from oil wells and 17 percent was produced from conventional natural gas wells.[16]

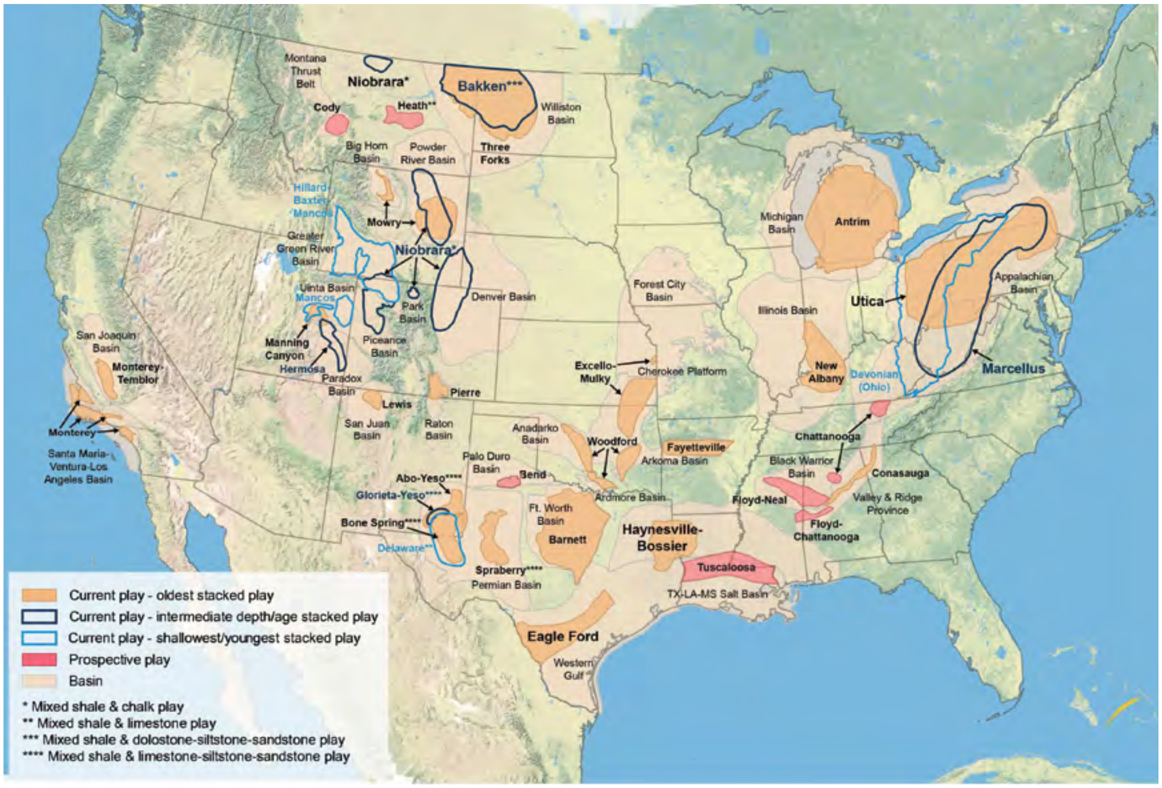
Production from shale gas plays is 13 times larger than 2007 levels.[17] According to the EIA, shale gas and production from tight formations will account for greater than 92 percent of U.S. natural gas production by 2050.[18]

SHALE GAS PRODUCTION BY REGION

Shale gas well productivity improved considerably since 2007, with technological advances in drilling and fracking technology reducing exploration, drilling,

14 Derived from EIA, *U.S. Shale Proved Reserves, Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/hist/res_epg0_r5301_nus_bcfa.htm.
15 *See* EIA, *Drilling Productivity Report, Production by Region* (accessed October 2022), https://www.eia.gov/petroleum/drilling/#tabs-summary-2.
16 Derived from EIA, *Natural Gas Gross Withdrawals and Production, U.S., Annual-Million Cubic Feet* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_prod_sum_dc_NUS_mmcf_a.htm.
17 Derived from EIA, *Natural Gas Gross Withdrawals and Production, Gross Withdrawals from Shale Gas, Annual-Million Cubic Feet* (accessed October 2022), https://www.eia.gov/dnav/ng/NG_PROD_SUM_A_EPG0_FGS_MMCF_A.htm.
18 *See* EIA, *Annual Energy Outlook 2022, Table 14. Oil and Gas Supply* (March 3, 2022), https://www.eia.gov/outlooks/aeo/tables_ref.php.

Figure 1-3: Lower 48 States Shale Plays



Source: U.S. Energy Information Administration[19]

and production expenses. Rising well productivity and falling costs resulted in larger amounts of shale gas production at lower costs to the producers.

The presence of NGLs, or natural gas liquids, in addition to natural gas in many shale gas plays, may add 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 often 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 (gasoline derived from natural gas).[20] This can make the production of NGLs from so-called "wet shale gas wells" less sensitive to natural gas prices than wells solely producing natural gas, as NGLs tend to trade at higher prices than natural gas. Thus, there may be an incentive to drill from wet shale gas wells even when natural gas prices are relatively low because of the relatively high value of the associated NGLs that are also produced when drilling.

The Marcellus Shale formation in Appalachia is particularly noteworthy because of its location, size and resource potential. The formation extends from West Virginia to New York, near the high population centers of the Northeast and Mid-Atlantic. Although the Marcellus Shale has produced gas for decades, it has produced significant amounts of gas only since 2008, where production has been prolific, with high initial well pressures and high production rates.

19 EIA, *Maps: Exploration, Resources, Reserves, and Production* (June 2016), https://www.eia.gov/maps/images/shale_gas_lower48.pdf.

20 *See* EIA, *NGL 101 – The Basics* (June 6, 2012), https://www.eia.gov/conference/ngl_virtual/eia-ngl_workshop-anne-keller.pdf.

The growth in production in the Marcellus Shale has significantly affected U.S. natural gas transportation. As more natural gas has flowed out of Marcellus, less has been needed from the Rockies or the Gulf Coast to serve the eastern U.S. This has resulted in changing flow patterns of natural gas on pipelines that traditionally served eastern and midwestern markets. In some instances, pipelines that transport natural gas into northeastern markets and have relied on production from outside of the region, have reversed flow direction to export natural gas produced in the Marcellus and Utica to markets across the U.S.

COALBED METHANE

Coalbed methane (CBM) is natural gas trapped in coal seams. Coalbeds are usually filled with water that naturally enter coal seams through fractures in the formation; 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. While the venting of methane from coal mines had been in practice for years, commercial production of this resource began in earnest in the 1980s. According to a U.S. Geological Survey released in October 2000, there is more than 700 Tcf of domestic CBM, but less than 100 Tcf of it may be economically recoverable.[21] Most CBM production in the U.S. is concentrated in the Rocky Mountain area, although there is also some activity in the Midcontinent and Appalachian area.

CONVENTIONAL NATURAL GAS

Natural gas has been historically produced from what is traditionally known as conventional natural gas resources. These supplies are found in geologica basins or reservoirs made of porous and permeable rock, holding significant amounts of natural gas in spaces in the rock.[22] For more

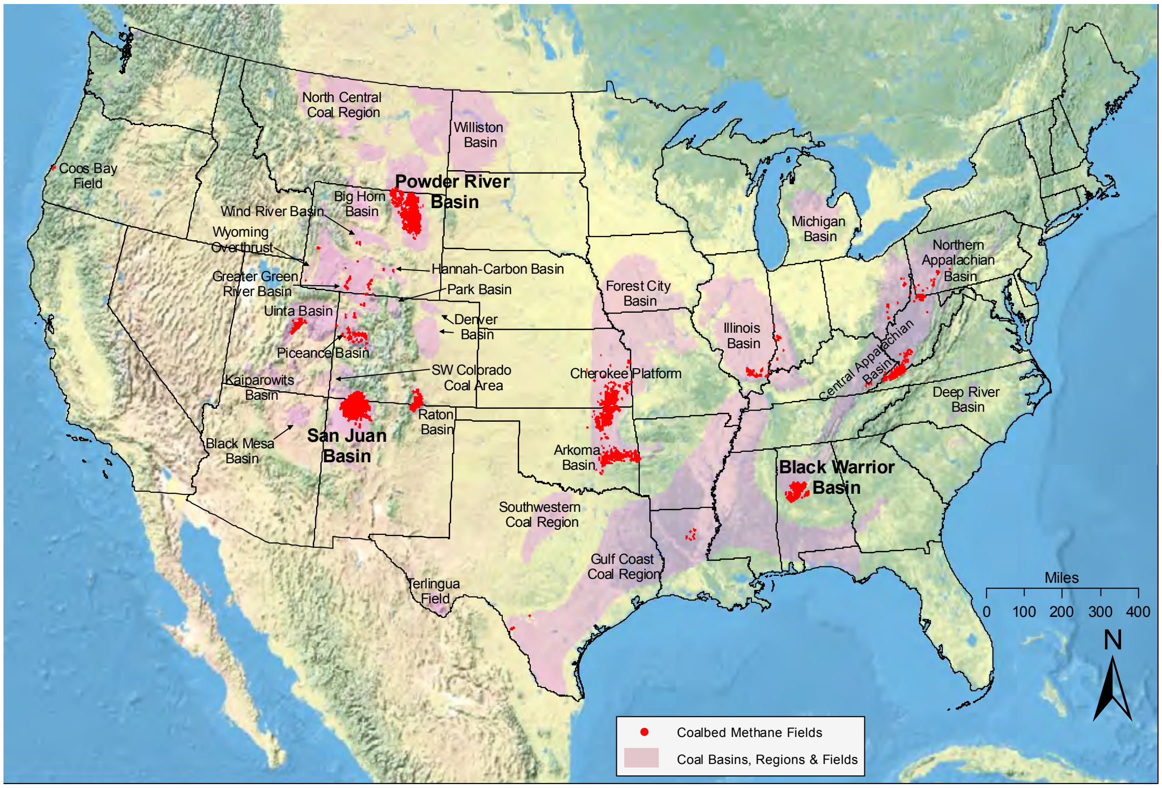
Rig Count and Rig Productivity

The rig count is used to measure exploration activity by assessing the number of rotary drilling rigs actively drilling for oil and gas. 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 adoption of horizontal drilling significantly increased production per rig, making historical comparisons of rig counts problematic as horizontal rigs are considerably more productive than vertical rigs. 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.

21 *See* U.S. Geological Society, *Coal-Bed Methane: Potential and Concerns* (October 2000), https://pubs.usgs.gov/fs/fs123-00/fs123-00.pdf.

22 Permeability refers to the ability of a porous medium to transport a fluid. The natural gas found in permeable rock formations contains trapped or slowly migrating natural gas molecules, where the migration of the gas molecules takes place over the course of millions of years.

Figure 1-4: Coalbed Methane Fields, Lower 48 States



Source: U.S. Energy Information Administration[23]

than a century, up until the early 2000s, nearly all of the country's production of natural gas was obtained from conventional sources.

Conventional resources have been found both on land and offshore (see map below), 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; it has since fallen to 3 percent of total U.S. production.[24]

Federal offshore natural gas wells are drilled into the ocean floor off the coast of the U.S. 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.[25]

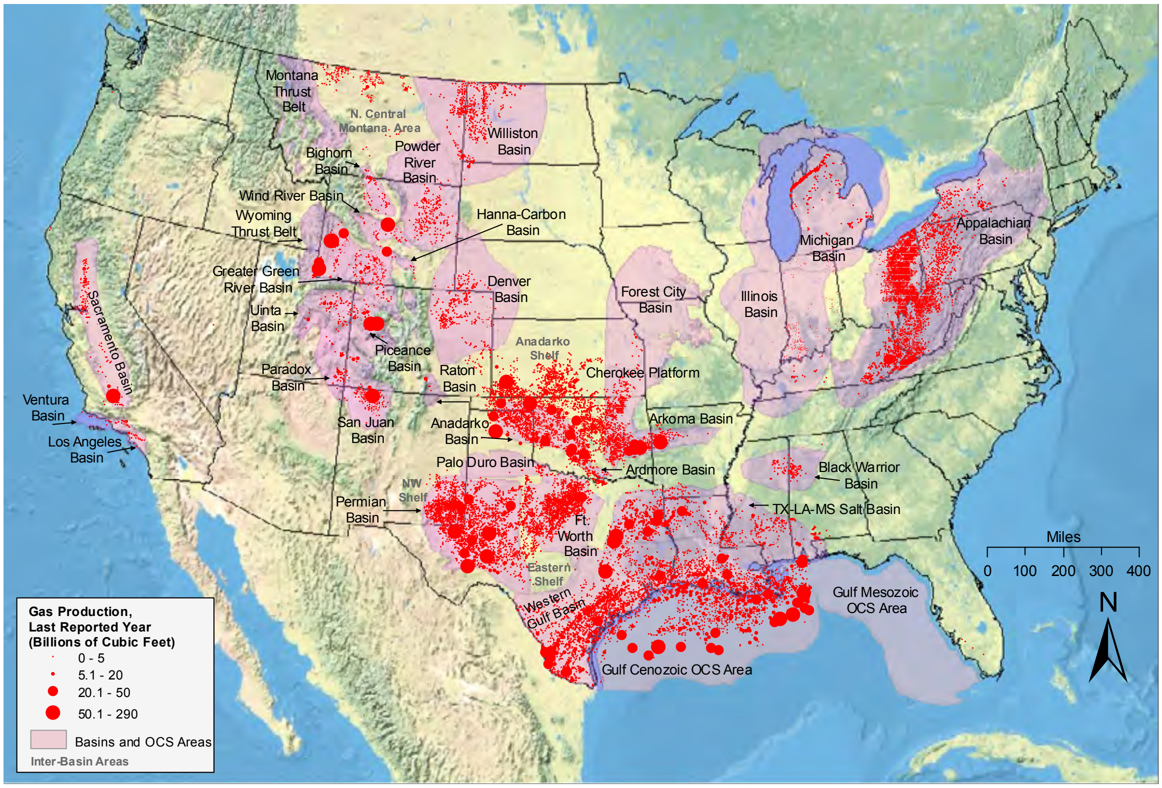
Roughly 1,650 oil and gas platforms are producing in federal waters at water depths approaching 7,500 feet (at total well depths of 25,000-30,000 feet) and at distances

23 EIA, *Maps: Exploration, Resources, Reserves, and Production* (April 8, 2009), https://www.eia.gov/oil_gas/rpd/coalbed_gas.pdf.

24 Derived from EIA, *U.S. Natural Gas Gross Withdrawals and Production* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm.

25 Florida and Texas were provided an exemption to the federal government's jurisdiction over natural resource beyond three nautical miles of state coastlines, up to a 9 nautical mile limit, because each state proved the further boundary based on its constitution or laws prior to when it came into the Union or was approved by Congress. *See* Submerged Lands Act of 1953. 43 U.S.C. § 1301-1315 at § 1312 (2002).

Figure 1-5: Gas Production in Conventional Fields, Lower 48 States



Source: U.S. Energy Information Administration[26]

as far as 200 miles from shore.[27] Most of these offshore wells are in the Gulf of Mexico.

Offshore wells have produced natural gas 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.

IMPORTS AND EXPORTS

The U.S. has historically been a net importer of natural gas by pipeline from Canada, with shipments of LNG from foreign nations playing an important role in serving pipeline capacity-constrained regions during periods of peak natural gas demand. However, the increase in U.S. natural gas production, spurred by the shale revolution, has reduced the need for imports and enabled greater exports.

Net natural gas imports peaked in 2007, when natural gas imports represented approximately 20 percent of the natural gas used in the U.S.[28] Since then, imports have declined and now represent approximately 9 percent of total U.S. consumption.[29] The vast majority of imports are delivered by pipeline from Canada, with additional waterborne shipments of liquefied

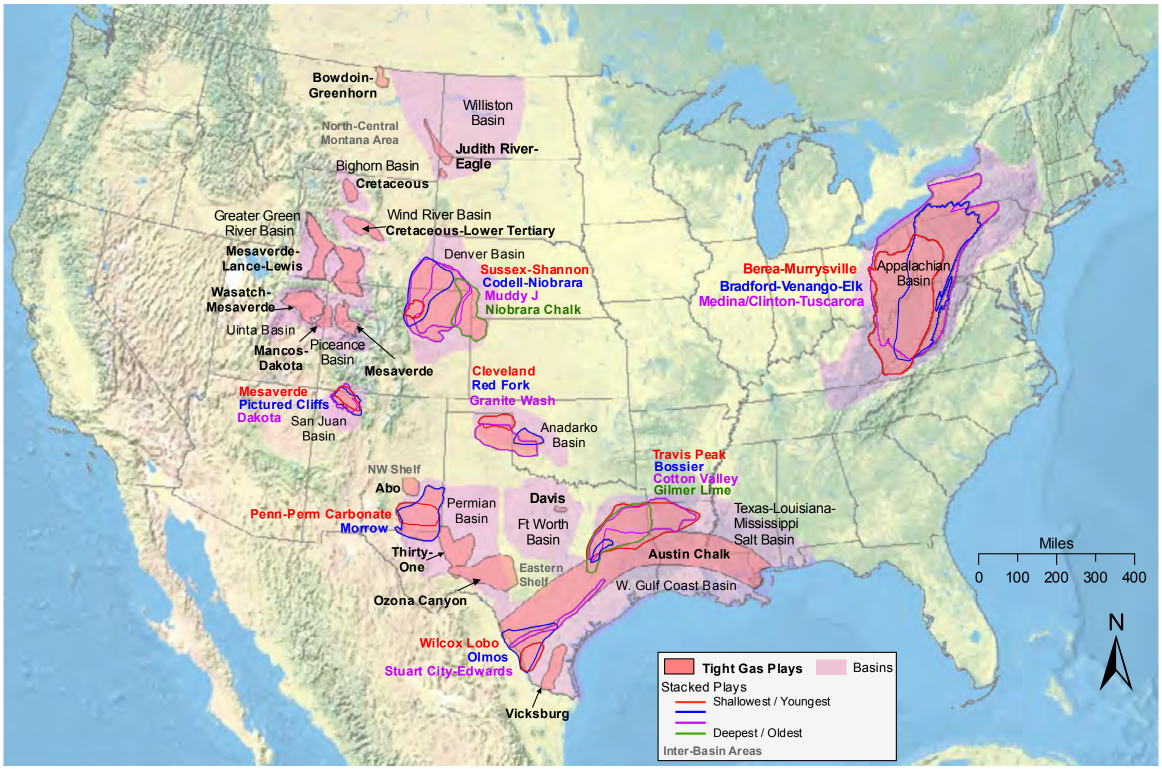
26 EIA, *Maps: Exploration, Resources, Reserves, and Production* (April 8, 2009), https://www.eia.gov/oil_gas/rpd/conventional_gas.pdf.

27 Derived from Bureau of Safety and Environmental Enforcement, Offshore Statistics by Water Depth, Totals table (accessed October 2022), https://www.data.bsee.gov/Leasing/OffshoreStatsbyWD/Default.aspx.

28 Derived from EIA, *Natural Gas Summary, Imports and Exports, U.S., Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

29 *Id.*

Figure 1-6: Major Tight Gas Plays, Lower 48 States



Source: U.S. Energy Information Administration[30]

natural gas from Trinidad and Tobago and other gas-exporting nations.[31]

Although the U.S has flowed natural gas through pipelines to Canada and Mexico for decades, total exports only began to rise following the first large scale exports of LNG that started in 2015 and ramped up in 2016 (see discussion on LNG following). Since then, exports have risen by nearly 4 times its 2016 levels.[32] As a result of these developments, the U.S. became a net exporter of natural gas in 2017 for the first time since 1957.[33] FERC staff provides locations for existing, FERC-approved and proposed LNG Import and Export terminals on FERC's website.[34]

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. The volumetric reduction makes it possible to economically transport natural gas in ships and trucks to locations not connected by a pipeline network.

FERC JURISDICTION

FERC has exclusive authority under section 3 of the NGA, 15 U.S.C. § 717b, to authorize applications for the siting, construction, expansion, and operation of facilities for imports or exports of LNG. This

30 EIA, *Maps: Exploration, Resources, Reserves, and Production* (June 6, 2010), https://www.eia.gov/oil_gas/rpd/tight_gas.pdf.

31 Derived from EIA, U.S. Natural Gas Imports by Country*, Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/NG_MOVE_IMPC_S1_A.htm.

32 *See* EIA, *U.S. Natural Gas Exports and Re-Exports by Country, Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm.

33 Derived from EIA, *Natural Gas Summary, Imports and Exports, U.S.*, *Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

34 *See* FERC, *Existing and Proposed Terminals* (October 26, 2022), https://www.ferc.gov/natural-gas/lng.

authorization, however, is conditioned on the applicant's meeting of other statutory requirements not administered by FERC for various aspects of the project. In addition, the DOE has authority over the issuing of permits to import and export the commodity. The U.S. Coast Guard (USCG) [35] and Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA)[36] also have regulatory authority over LNG facilities. Under NGA section 3, FERC shares ongoing oversight over the safety of LNG facilities in operation.

THE LNG SUPPLY CHAIN

Natural gas is sent through the pipeline network to liquefaction facilities for conversion to LNG. These liquefaction facilities, which convert methane from a gas to a liquid, are major industrial complexes, typically costing $10 billion or more, with some costing as much as $50 billion.[37] 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 the 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, global regasification is approximately 2.15 times the amount of liquefaction capacity.[38] Excess regasification capacity provides greater flexibility to LNG suppliers, by enabling them to deliver cargoes to the highest-priced markets.

The cost of the LNG process is $2-$10 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 LNG supply chain costs, while regasification is the least of any of the cost components. 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, which converts methane from a liquid to a gas, may cost $500 million or more.[39]

LNG IN THE UNITED STATES

The U.S. was historically an importer of LNG, with greater regasification capacity than any other country except Japan. As of 2022, there were 10 LNG receiving or regasification terminals in the continental U.S., with approximately 18 Bcfd of import capacity.[40] All of these facilities are on the Gulf or East coasts, or just offshore. Additionally, the U.S. can import regasified LNG via pipeline into New England from the Saint John LNG terminal (formerly Canaport) in New Brunswick, Canada. The Energia Costa Azul LNG terminal in Baja California, Mexico, which became operational in 2008, provided for the flow of re-gasified LNG from Mexico into Southern California. In 2019, Energia Costa Azul received DOE

35 The USCG exercises regulatory authority over LNG facilities which affect the safety and security of port areas and navigable waterways. Specifically, the USCG is responsible for matters related to navigation safety, vessel engineering and safety standards, and all matters pertaining to the safety of facilities or equipment located in or adjacent to navigable waters up to the last valve immediately before the receiving tanks. The USCG also has authority for LNG facility security plan review, approval, and compliance verification and siting as it pertains to the management of vessel traffic in and around the LNG facility.

36 PHMSA has exclusive authority to establish and enforce safety regulations for onshore LNG facilities. PHMSA inspects LNG facilities and operators to enforce compliance with the safety standards for LNG facilities used in the transportation of gas by pipeline.

37 *See, for example*, Cheniere Energy Partners, L.P., Annual Report, SEC Form 10-K, at 4 (February 24, 2017), https://www.sec.gov/Archives/edgar/data/1383650/000138365017000011/cqp2016form10-k.htm#s569b7029a90e4dd19894f10c84a51e70.

38 Derived from International Group of LNG Importers, *The LNG Industry: GIIGNL Annual Report 2022, Key Figures 2021*, at 4, https://giignl.org/wp-content/uploads/2022/05/GIIGNL2022_Annual_Report_May5.pdf.

39 EIA, *Understanding Natural Gas and LNG Options*, at 218 (November 2016), https://www.energy.gov/sites/prod/files/2016/12/f34/Understanding%20Natural%20Gas%20and%20LNG%20Options.pdf.

40 *See* FERC, *North American LNG Import Terminals – Existing, Approved not Yet Built, and Proposed* (October 26, 2022), https://www.ferc.gov/natural-gas/lng.

authorization to export natural gas from the U.S. to Mexico and re-export LNG to Free Trade Agreement (FTA) and Non-FTA countries.

Between 1999 and 2012, the U.S. met between 1 to 3 percent of its natural gas demand through LNG imports.[41] LNG imports to the U.S. peaked at about 99 Bcf/month in the spring of 2007.[42] Subsequently, competition from relatively low-cost U.S. shale gas production has trimmed imports, affecting Gulf Coast terminals the most. Currently, less than 1 percent of U.S. natural gas demand is met through LNG imports.[43] Roughly 90 percent of the total LNG delivered to the United States and Puerto Rico was under long-term contracts in 2021.[44] The remainder of the LNG enters the U.S. under short-term contracts or as spot cargoes. The cost for the natural gas commodity to be liquified and exported is generally tied to the closest trading hub to where the terminal is located. For instance, the cost of natural gas feeding into the Sabine Pass export terminal may be priced off of the Henry Hub trading point.[45]

Starting in 2010, numerous proposals to export domestically produced LNG were prompted by increased U.S. natural gas production, largely due to shale gas. No large-scale liquefaction facilities existed in the continental U.S. at the time, though the now non-operational Kenai LNG plant in Nikiski, Alaska had produced small volumes since the late 1960s. Cheniere's Sabine Pass LNG was the first LNG export terminal in the lower 48 US states, shipping its first cargo in 2015. The facility is a large LNG terminal which is capable of processing over 4.55 Bcfd of natural gas. Sabine Pass was formerly an import terminal, from which the developers utilized common facilities like docks and storage tanks to add liquefaction trains.

LNG export capacity continues to grow. FERC staff tracks existing and proposed LNG export terminals. As of 2022, there were seven export terminals operating in the continental U.S., with approximately 14 Bcfd of export capacity. See FERC's website for up-to-date information on LNG export terminal projects.[46]

Natural Gas Processing and Transportation

Most natural gas production must be transported via pipeline to natural gas consumers. To get gas from the wellhead to consumers requires a vast network of processing facilities and a national network of the more than 2.6 million miles of pipelines.[47]

Efficient markets require this network to be robust and allow consumers to access gas from more than one production center. Supply diversity tends to improve reliability and moderate prices, while supply constraints have the effect of increasing prices during peak demand periods.

FERC JURISDICTION

The NGA gives FERC comprehensive regulatory authority over companies that engage in either the sale in interstate commerce of natural gas for resale or the transportation of natural gas in interstate commerce. FERC regulates entry into the transportation market by

41 Derived from EIA*, Natural Gas Summary, Imports and Exports, Consumption, U.S., Annual (*accessed *October 2022),* https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

42 Derived from EIA, *Natural Gas Summary* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

43 Derived from EIA, *Natural Gas Summary, Imports and Exports, Consumption, U.S., Annual* (accessed October 2022), https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

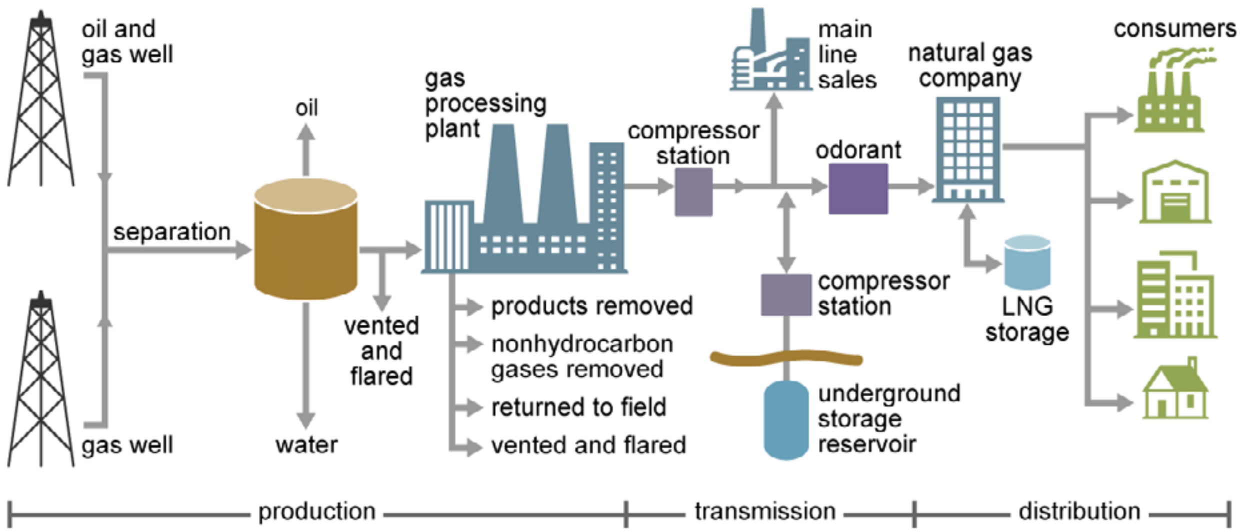
44 Derived from Department of Energy, Office of Fossil Energy and Carbon Management, *LNG Monthly 2021* (accessed December 2021), https://www.energy.gov/fecm/articles/lngmonthly-2021.

45 The Sabine Pass export terminal is located along the coast of the Gulf of Mexico in Cameron Parish, Louisiana. The Henry Hub trading point represents natural gas shipped from the distribution hub in Erath, Lousiana.

46 *See* FERC*, North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (October 26, 2022)*,* https://www.ferc.gov/natural-gas/lng.

47 *See* U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration*, 2010+ Pipeline Mileage and Facilities, Gas Pipeline Miles by System Type* table (January 28, 2020), https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities.

Figure 1-7: Natural Gas Production and Delivery



Source: U.S. Energy Information Administration[48]

issuing certificates of public convenience and necessity under section 7 of the NGA, 15 U.S.C. § 717f, subject to such conditions as FERC deems appropriate. To this end, FERC reviews applications for the construction and operation of interstate natural gas pipelines. FERC has no jurisdiction over pipeline safety or security, but actively works with other agencies (such as USCG and PHSMA) with safety and security responsibilities, particularly when FERC is overseeing restoration efforts along the pipeline right-of-way which may take years after a pipeline goes into service. Applicants for a certificate must certify in their applications that they will comply with PHMSA safety standards. The USCG provides FERC with a recommendation on the suitability of the waterway to support marine traffic associated with the proposed LNG facility. FERC also regulates market exit through its authority to abandon certificated service and facilities, 15 U.S.C. § 717f(b).

PROCESSING

The midstream segment of the natural gas industry, between the wellhead and pipelines, is shown in the graphic above. This involves gathering the gas from the wellhead, processing the gas to remove liquids and impurities, and moving the processed (dry) natural gas to pipelines. The composition of raw, or wellhead, natural gas differs by region. Consequently, processing will differ depending on the quality of the natural gas.

Once a well is constructed 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. Natural gas may also be dissolved in oil underground, but separates out from the oil as it comes to the surface due to reduced pressure. In these instances, the oil and natural gas are sent to separate processing facilities. Where it does not separate naturally, processing is required.

At the processing plant, various products (NGLs) and contaminants (e.g., sulfur and carbon dioxide) are removed from the incoming wet natural gas stream and the gas is dehydrated. The extracted NGLs are then

48 EIA, *Natural Gas Explained: Delivery and Storage of Natural Gas* (February 18, 2020), https://www.eia.gov/energyexplained/natural-gas/delivery-and-storage.php.

Natural Gas Infrastructure

The United States natural gas market relies on extensive infrastructure:

- Roughly 303,000 miles of large-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.
- More than 20 hubs or market centers provide additional interconnections.
- Over 400 underground natural gas storage facilities increase the flexibility of the system.
- 49 Pipeline border crossings enable natural gas to be imported or exported.
- There are 10 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: U.S. Energy Information Administration[49]

separated into individual components by fractionation, which uses the different boiling points of the various hydrocarbons to separate them. The extracted liquids are high-value products used by the petrochemical industry, refineries, and other industrial consumers. Once processing is completed, the natural gas is of pipeline quality and is ready to be moved by intrastate and interstate pipelines. There were about 480 natural gas processing plants operating in the U.S. in 2017.[50]

NATURAL GAS TRANSPORTATION

Interstate pipelines account for approximately two thirds of the natural gas pipeline miles in the U.S. and carry natural gas across state boundaries. Intrastate pipelines account for the remaining one third, and have similar operating and market characteristics.[51]

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 generally range in diameter from 16 inches to as large as 48 inches, move gas between major hubs to lateral lines. Smaller diameter delivery laterals then transport gas to end-users and LDCs.

The large pipelines are known as mainline transmission pipelines and typically consist of steel sufficient to meet standards set by PHMSA. These pipes are also 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.

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49 EIA, *About U.S. Natural Gas Pipelines* (2007/2008), https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/index.html.

50 *Derived from* EIA, *Natural Gas Annual Respondent Query System, EIA-757 data through 2017* (January 2019), https://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP9&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen.

51 *See* U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *2010+ Pipeline Mileage and Facilities, Gas Distribution Pipeline Miles, Gas Gathering Pipeline Miles, and Hazardous Liquid Pipeline Miles and Tanks* tables (January 28, 2020), https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities.

Compressor stations are typically located every 50-100 miles along the pipe to add or maintain the pressure of the natural gas, propelling it through the pipeline. Natural gas travels through pipelines at high pressures, ranging from 200 pounds per square inch (psi) to 1,500 psi. The natural gas is compressed by turbines, motors, or engines. Most facilities power the compressors with turbines and reciprocating natural gas engines that use some of the gas from the line to fuel their operations, while others rely on very large electric motors.

See the EIA's website[52] for a map of interstate and intrastate pipelines and the Interstate Natural Gas Assocation of America's (INGAA) website[53] for an interactive map of major interstate natural gas pipelines in the U.S.

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

HUBS AND CITYGATES

A key element of the pipeline transmission and 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. Hubs also provide a convenient location to establish natural gas prices.

There are dozens of natural gas hubs in the country, with over 20 major hubs. The dominant benchmark point in the physical natural gas market is the Henry Hub, which is strategically located in the Gulf Coast's producing area at a series of pipeline connections to the East Coast and Midwest consumption centers. It is located in south central Louisiana, in the town of Erath, and comprised of 12 delivery points and 4 major receipt points. More than a dozen major natural gas pipelines converge and exchange gas at the Henry Hub.

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 offer another convenient point at which to price natural gas.

Physical natural gas 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[54] centered at the Henry Hub in 1990 that gained widespread acceptance and is generally used as the reference price for natural gas in the U.S.

Distribution lines typically take natural gas from the large transportation pipelines, reduce the pressure, odorize the gas, 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 natural 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 natural gas from the pipelines at local citygates and delivering it to customers at their meters.

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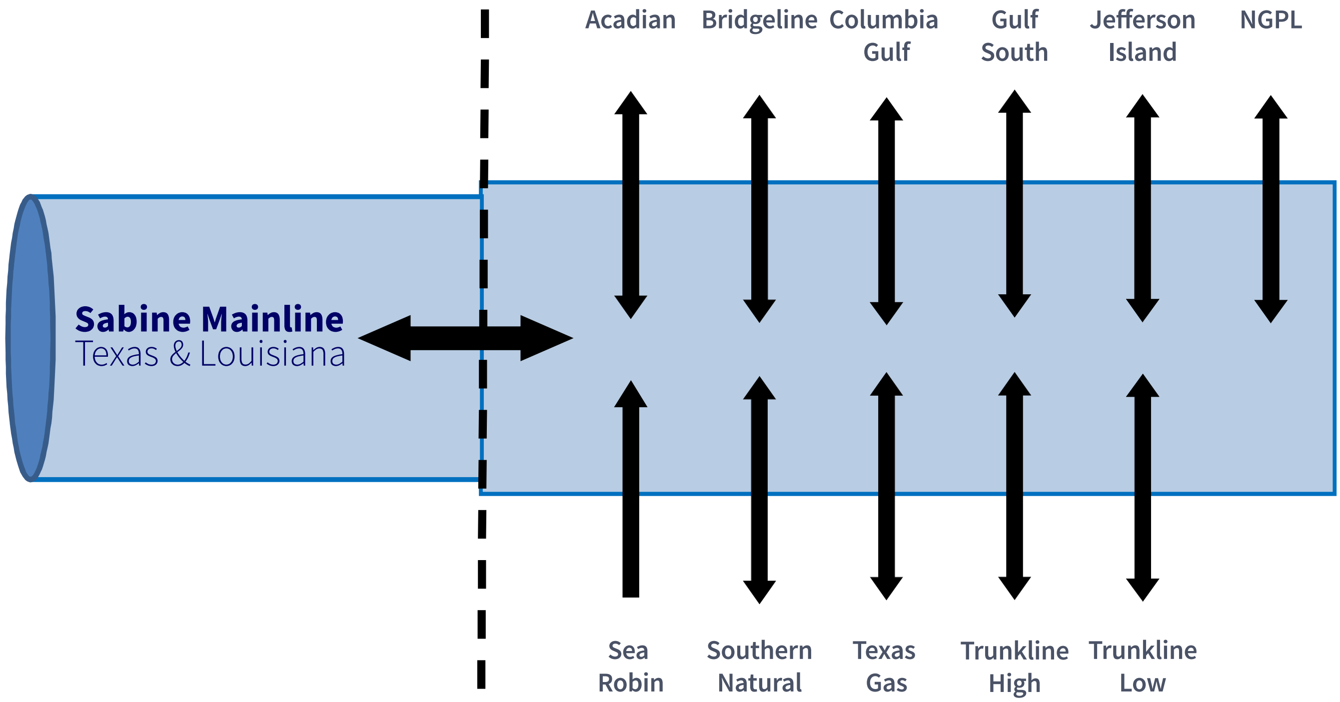
52 *See* EIA, *Natural gas explained, Natural gas pipelines* (November 5, 2021), https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php.

53 *See* INGAA*, Natural Gas Pipelines* (n.d.)*,* https://custom.envisionmaps.net/ingaa/default.html.

54 Futures contracts allow market participants to manage price risk and to protect against price volatility. See Chapter 5: Trading and Capital Markets for more information on futures contracts.

Figure 1-8: Sabine Pipe Line LLC., Henry Hub



NOTE: Arrows indicate direction of flow

Source: EnLink Midstream[55]

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.

PIPELINE SERVICES

Customers or shippers have a choice between a variety of services on interstate pipelines. One is firm transportation service in which an agreement is executed directly between the pipeline and a customer, providing the customer with rights to transport natural gas from primary receipt point(s) to delivery points. Shippers with firm transportation service receive priority to use their capacity over those customers without firm capacity.

A shipper can also contract for interruptible transportation service, which is offered to customers on an as-available basis. This service may not be available during periods of peak demand. Due to the interruptible nature of the service, customers pay lower rates than those that contract for firm service.

A secondary market for firm transportation rights enables shippers to sell their pipeline capacity to a third party through FERC's capacity release program.[56] 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 firm capacity can release segments rather than their full holdings, provided segmentation is operationally feasible on the interstate pipeline's system. In addition, firm capacity holders can also make deliveries on their own to secondary points on the pipeline system to the extent capacity is available.

55 *See* https://sabinepipeline.enlink.com/wp-content/uploads/2019/12/Sabine-Pipe-Line-LLC-Henry-Hub-Schematic-PDF.pdf.
56 *See* Order No. 636, FERC Stats. & Regs. ¶ 30,939 at P 88 (1992).

Some interstate pipelines also provide "no-notice service" which enables pipeline customers to receive delivery of natural gas on demand up to their firm entitlements on a daily basis without incurring daily balancing and scheduling penalties. No-notice service enables customers to receive natural gas volumes that have not been scheduled and thereby helps meet unexpected requirements caused, for example, by unexpected changes in temperature.[57] 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 and is provided through a combination of storage and transportation services. Shippers may temporarily release this service to other parties, using FERC-approved capacity release guidelines.

Finally, natural gas pools are points on a pipeline's system where natural gas suppliers aggregate supplies for sale to buyers. They can be physical points on the pipeline system, such as the Henry Hub in Louisiana, but they are most often "paper" points, such as the TCO Pool on Columbia Gas Transmission's system. A paper pool (also called a virtual point) is not a physical point but is used solely for nomination and scheduling purposes. Pooling is an administratively efficient process that allows suppliers to aggregate supply together at one location on the pipeline system, rather than having to tie each individual well or receipt point to a buyer, and deliver from the pool to multiple delivery points. Each interstate pipeline is required to have a pooling service and the service is often free. Natural gas prices are often set for the market at the major pooling points on the interstate pipeline systems. Thus, adding capacity to enable additional volumes to access pooling points benefits and enhances the efficiency of the domestic natural gas market.

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 natural gas pipelines to file rate schedules with FERC and to notify FERC of any subsequent changes in rates and charges. On submission of a pipeline tariff revision, 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, FERC regulates the rates, terms, and conditions 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)).

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 geographic zones, and the rate is fixed within each zone and across different zones. Transco Gas Pipe Line is an example of a pipeline that uses zonal pricing. Under postage stamp rates, shippers pay the same rate for transportation regardless of how far the natural 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), for example, uses mileage-based rates.

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

57 *Id*.

Figure 1-9: Pipeline Capacity Scheduling

Cycle	Cycle Description
T	**Timely:** Nomination sent by 1 p.m. (Central Clock Time), to be confirmed by 4:30 p.m., and to be effective for gas flow starting at 9 a.m. next gas day.
E	**Evening**: Nominations sent by 6 p.m., to be confirmed by 8:30 p.m. for gas flow at 9 a.m.
ID1	**Intraday 1**: Nominations sent by 10 a.m., to be confirmed by 12:30 p.m. for gas flow at 2 p.m.
ID2	**Intraday 2**: Nominations sent by 2:30 p.m. to be confirmed by 5 p.m. for gas flow at 6 p.m.
ID3	**Intraday 3**: Nominations sent by 7 p.m. to be confirmed by 9:30 p.m. for gas flow at 10 p.m.

Source: FERC[58]

Although pipelines are required to have a cost-based transportation rate stated in their tariff, many pipelines offer shippers service at negotiated rates. These negotiated rates are generally below the pipeline's cost-based rates, and pipelines are required to file these negotiated rate contracts with FERC

SCHEDULING

Pipelines have rigorous schedules that shippers must follow. Typically, shippers nominate natural gas deliveries 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 natural gas to heat homes have had lower load factors.

58 FERC, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, Order No. 809, FERC Stats. & Regs. ¶ 31,368, at Appendix (2015).

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 86 percent of capacity since 2005, while Algonquin Gas Transmission's (Algonquin) load factor can be considerably less at times. Algonquin's pipeline is used more seasonally than Kern River's, with Algonquin's pipeline utilization averaging 90 percent of the pipeline's capacity during the winter (nearing full utilization on very cold days) and averaging 77 percent during the summer, spring, and fall. This utilization pattern reflects the seasonal demand in the Northeast.[59]

PARK AND LOAN SERVICE

Park and loan service (PAL) is a way for shippers to balance their takes of natural 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 natural 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 natural 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.
- Market centers, or hubs, routinely offer these services.
- Charges are usually commensurate with interruptible service rates.

PIPELINE CONSTRAINTS AND CAPACITY GROWTH

Pipeline capacity limits the amount of natural gas supply that can be delivered to a specific region and, therefore, is a key factor in regional prices. In recent years, the natural gas pipeline network has expanded significantly, which has removed many bottlenecks and enabled access to previously unreached supply areas.

This development includes a considerable amount of new pipeline capacity in the Northeast, where natural gas production has increased significantly. New pipelines have also increased the flow of Barnett Shale gas into the interstate network and have reduced congestion across the Texas-Louisiana border.

New England, on the other hand, experiences pipeline constraints on peak demand days during the winter months. Most of the year, there is excess pipeline capacity into New England. However, when high demand from the power sector coincides with peak heating demand from LDC customers, customers without firm (priority) pipeline service compete for the scarce remaining pipeline capacity. This can lead to substantial price volatility in the natural gas spot market.

The Florida Panhandle and Northern California were also some of the most frequently constrained regions of the country, but each region constructed significant new pipeline capacity. Conversely, since 2018, natural gas production has outpaced pipeline capacity in the Permian Basin, the second largest shale gas-producing region in the U.S., due to associated natural gas production rising with increasing crude oil production.[60] In addition, technological advancements in drilling and completion techniques have continuously increased productivity of new wells in the Permian Basin since 2010.[61] The lack of available infrastructure to transport the abundant natural gas to high-demand regions has frequently contributed to prices at the local Waha Hub falling below prices at the Henry Hub.[62] To help reduce pipeline constraints, two new intrastate pipeline projects

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59 Derived from S&P Global Platts Natural Gas Pipeline Flow data (October 2022).

60 *See* EIA, *The Waha Hub natural gas price continues to fall below the Henry Hub price* (Sep. 20, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53919#.

61 *See* EIA, *Advances in technology led to record new well productivity in the Permian Basin in 2021* (Sep. 30, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54079.

62 *See* EIA, *The Waha Hub natural gas price continues to fall below the Henry Hub price* (Sep. 20, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53919#.

Kinder Morgan Energy Partners' Permian Highway Pipeline and WhiteWater's Whistler Pipeline, and one interstate pipeline project, Summit Midstream Partners' Double E Pipeline came online in 2021. The additional pipeline capacity in 2021 increased the amount of natural gas flowing out of the basin into nearby consuming regions and narrowed the price difference between the Waha Hub and the Henry Hub.[63] All three pipelines have announced expansion projects intended to further expand pipeline capacity.[64] In addition, Kinder Morgan's Gulf Coast Express Pipeline Expansion, and EnLink Midstream's Matterhorn Express Pipeline will likely add additional takeaway capacity in 2023 and 2024, respectively.[65] The Oasis Pipeline Modernization Project was completed in early 2023 will also add additional capacity.[66] The additional pipeline capacity in the Permian Basin would allow producers to flow additional natural gas to demand centers in Mexico and along the Texas Gulf Coast.[67]

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.[68] 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 natural 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 makes more Rockies natural gas available to western markets, and more Midcontinent production available for the Gulf Coast and Southeast states.

LOCAL DISTRIBUTION

Distribution lines typically take natural gas from the large interstate pipelines and deliver the natural 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. The LDCs typically purchase natural gas and ship it on behalf of their customers, taking 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 PHMSA, this distribution involves a network of smaller pipelines, as well as smaller scale compressors and meters.

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63 *Id*.

64 Summit Midstream Partners' Double E Pipeline's Red Hills Lateral was approved in February 2023.

65 *See* EIA*, EIA expects that natural gas production in the Permian Basin will increase in 2022 and 2023* (May 26, 2022)*,* https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/05_26/#itn-tabs-0.

66 *See* EIA, *Pipeline Projects announced to expand Permian Natural gas capacity* (August 4, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53319.

67 *See* EIA*, EIA expects that natural gas production in the Permian Basin will increase in 2022 and 2023* (May 26, 2022)*,* https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/05_26/#itn-tabs-0.

68 Tallgrass Energy and Phillips 66, *Rockies Express Pipeline (REX), Rockies Express System Map* (n.d.), https://pipeline.tallgrassenergylp.com/Content/REX/REX_FERC_Web_Map.pdf.

Natural Gas Storage

Although natural gas production has risen steadily since 2005 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 natural gas during periods of relatively higher demand and prices.

Working gas storage capacity, as tracked by EIA, totaled more than 4,844 Bcf in 2020.[69] The amount injected or withdrawn is the difference between production and demand. Storage capacity adds flexibility to pipeline and distribution systems and helps moderate prices by providing an outlet for excess natural 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. eastern time (ET) 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.

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 NGA stating that FERC 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, 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.

STORAGE FACILITIES

The bulk of the storage capacity in the U.S. 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.

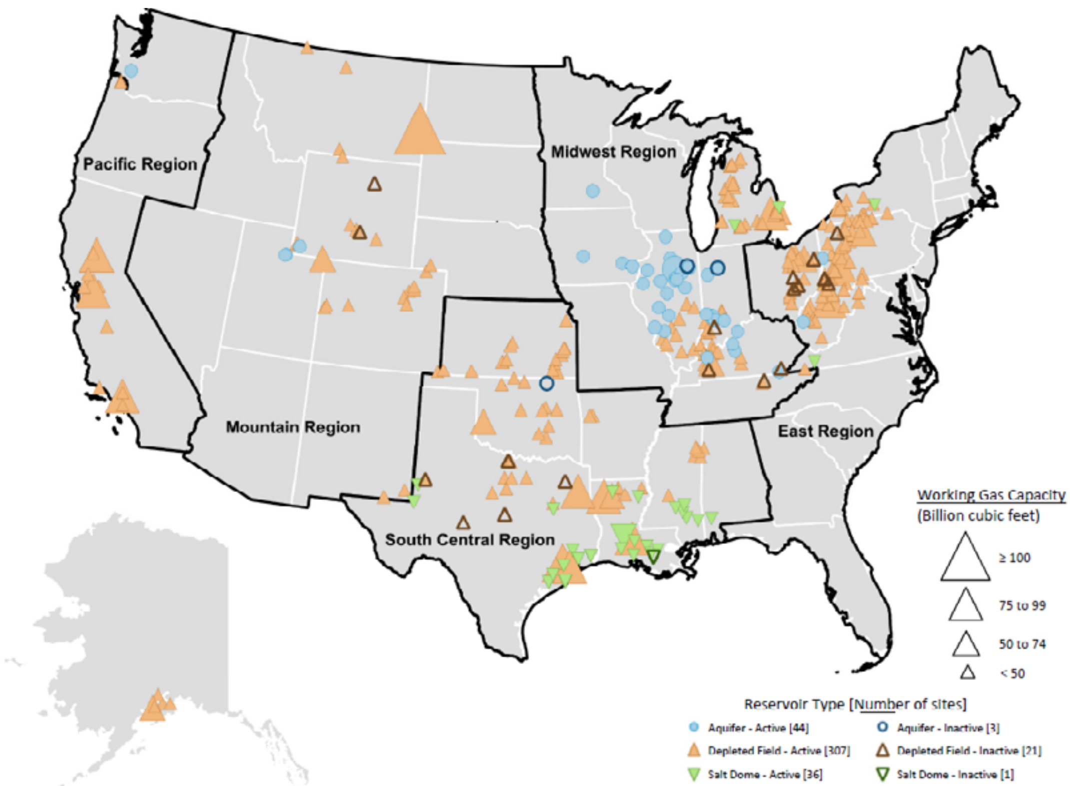
Natural gas in an underground storage facility is divided into two general categories, base gas and working gas. Base gas is the volume of natural gas, including native gas[70], needed as a permanent inventory in a storage reservoir to maintain adequate reservoir pressure and deliverability rates throughout the withdrawal season. Working gas is the volume of natural 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 natural gas storage is in depleted reservoirs (former oil and gas fields). These facilities reuse the infrastructure – wells, gathering systems,

69 *See* EIA, *Underground Natural Gas Storage Capacity, Total Working Gas Capacity, Annual* (October 2022), https://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SACW0_Mmcf_a.htm.

70 Native gas refers to natural gas found in its original or natural state in underground reservoirs. Native gas is not associated with crude oil or other hydrocarbon resources.

Figure 1-10: Underground Natural Gas Storage Facilities in the Lower 48 States



Source: U.S. Energy Information Administration[72]

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.

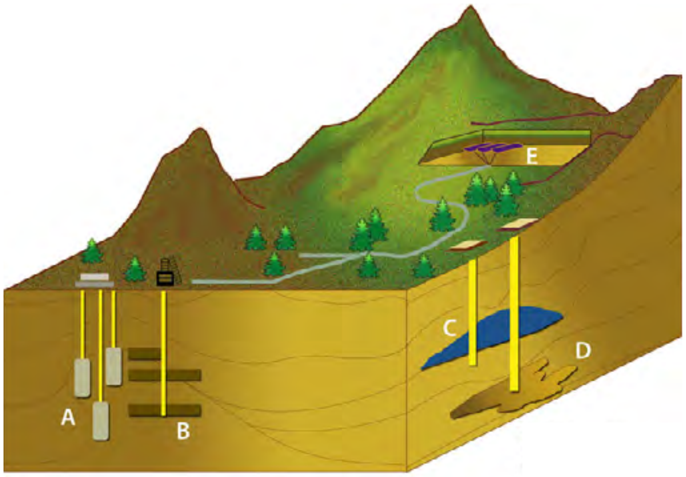
Other storage facilities reside in aquifers that have been transformed into natural gas storage facilities. These are mostly in the Midwest. These aquifers consist of water-bearing sedimentary rock overlaid by an impermeable cap rock. Aquifers are the most expensive type of natural gas facility because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

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 basegas 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. Salt caverns generally hold smaller volumes than 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 U.S., as well. LNG ships can also serve as storage, depending on timing and economics. LNG storage is

71 *See* EIA, *Map of Storage Facilities* (2020), https://www.eia.gov/naturalgas/ngqs/images/storage_2020.png.

Figure 1-11:Types of Underground Storage Facilities



A. **Salt Caverns**
B. **Mines**
C. **Aquifers**
D. **Depleted Reservoirs**
E. **Hard-Rock Caverns**

Source: U.S. Energy Information Administration[72]

highly flexible, allowing multiple inventory turns per year with high injection and withdrawal rates.

REGIONAL STORAGE

The EIA divides the U.S. into five storage regions: East, Midwest, South Central, Mountain, and Pacific.[73] Currently, about a third of the underground storage in the U.S. sits in the South Central region in a mix of depleted reservoirs, aquifers, and high-deliverability salt caverns. Close to one third of the South Central region's working gas capacity is in these purpose-built salt caverns. The East and Midwest each represent about a quarter of working gas capacity, generally near major population centers. The remaining roughly 1/5 of working gas capacity is located in depleted fields throughout the Mountain and Pacific regions.[74] 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 typically be between 80 and 90 percent full when the official winter season begins on November 1.

STORAGE SERVICE AND USES

Approximately 133 entities – including interstate and intrastate pipeline companies, LDCs, and independent storage service providers – operate the approximately 412 underground storage facilities active in the continental U.S.[75] Facilities operated by interstate pipelines and many others are operated on an open-access basis, with much of the working gas capacity available for use 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 October 31, when demand for natural 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 natural 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. FERC may approve market based rates for storage

72 *See* EIA, *The Basics of Underground Natural Gas Storage, Figure 1* (November 16, 2015), https://www.eia.gov/naturalgas/storage/basics/.
73 EIA, *Weekly Natural Gas Storage Report, Notes and Definitions* (n.d.), http://ir.eia.gov/ngs/notes.html.
74 Derived from EIA, *Underground Natural Gas Working Storage Capacity, data for November 2021* (August 31, 2021), https://www.eia.gov/naturalgas/storagecapacity.
75 Derived from EIA, *Natural Gas Annual Respondent Query System, EIA-191 data through 2021* (accessed October 2022), https://www.eia.gov/naturalgas/ngqs/#?report=RP7&year1=2021&year2=2021&company=Name.

operators that lack market power.[76] 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 natural gas from storage
- Injection charges for the injection of natural 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 contracting for storage capacity may move natural 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 natural 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 natural 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 natural 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 natural gas in storage in November is a key benchmark of the natural gas industry's ability to respond to changes in winter weather. Higher storage levels tend to reduce natural gas futures prices; lower storage levels tend to increase them, all other market conditions being equal.

Although the Shale Revolution has added significant supplies to the U.S. natural gas market, it has also reduced the seasonal value of natural gas somewhat. The price differentials between winter and summer have been reduced and this has had an impact on storage development in the U.S. Several storage developers that received a certificate from FERC have elected not to build their storage facility due to this development.

76 *See* Order No. 678, Rate Regulation of Certain Natural Gas Storage Facilities, 18 CFR Part 284 (2006).

Natural Gas Markets and Trading

The natural gas industry in the U.S. 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 natural gas to marketers who aggregate natural gas into quantities that fit the needs of different types of buyers and then transport the natural 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.

Historically, natural gas pipelines served as natural gas merchants, buying natural gas at the wellhead and selling the transportation and commodity as a bundled product directly to consumers. However, in 1992, FERC Order No. 636 restructured the natural gas market by regulating interstate pipelines as open access transporters.[77] Although interstate pipelines may buy and sell natural gas, they now do so for operational reasons and no longer act as merchants. As noted earlier, interstate pipelines transport natural gas at rates approved by FERC.

NATURAL GAS MARKETERS

Most natural gas trading in the U.S. 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 selling 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.

- 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 geographically focused marketers target particular regional areas and specific natural gas markets. Many marketing entities affiliated with LDCs are of this type, focusing on marketing natural 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.

77 *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* Order No. 636, FERC Stats. & Regs. ¶ 30,939 (1992).

Most marketing companies have significant operations capabilities 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. These companies also have risk-management operations that are responsible for ensuring that the traders do not expose the marketing company to excessive risk. These companies also have risk-management operations that are responsible for ensuring that the traders do not expose the marketing company to excessive risk.

HUB PRICES AND BASIS

Natural gas is traded at different locations throughout the country and the prices at specific hubs and citygates are determined by the relative supply and demand for natural gas at the particular locations. Additionally, the difference between the Henry Hub price and another hub (or citygate) is called the location differential, or basis.

Basis usually reflects the variable cost to transport natural 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 natural gas price at a hub in Florida, for example, would be the price at the Henry Hub and the basis to the Florida hub.

In addition to being the country's benchmark hub, the Henry Hub is also the delivery point for the NYMEX natural gas futures contract. Historically, changes in price at the Henry Hub provided a good indicator of how prices were generally changing across the country, however, over the past few years, the price at the Henry Hub as become less reflective of regional price trends outside of the Gulf Coast.

PHYSICAL TRADING OF NATURAL GAS

Physical natural gas contracts are negotiated between buyers and sellers. There are many types of physical natural gas contracts, but most share some standard specifications, including 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 points, the tenure of the contract (usually expressed in number of days, beginning on a specified day), and other terms and conditions. Other special terms and conditions can outline such things as the payment dates, quality of the natural gas to be sold, and any other specifications agreed to by both parties. Physical 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 physical natural gas contracts: swing contracts, baseload contracts, and firm contracts:

- Swing (or interruptible) contracts are usually short-term contracts between one day and one 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 natural gas from the buyer, are not guaranteed.
- 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 natural 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 in short-term deals for next-day delivery. The daily spot market for natural gas is active, and trading can occur 24 hours a day, seven days a week. These points include 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 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, when producers sell their core production and consumers buy natural gas for their core needs for the upcoming month. In 2021, some publications condensed the bidweek trading period to the first three days from within the full, five-day bidweek timeframe.[78]

INDEX PRICES

Several publications, such as Platts Gas Daily, Natural Gas Intelligence, and Natural Gas Week, survey the market for daily physical transactions that are used to form daily indices that are made available the night before or the morning of the next business day. Market participants voluntarily provide this information to publications, some of which also incorprate ICE trades in their indices. Many market participants voluntarily report their monthly bidweek transactions to publications as well. Publications convert these transactions 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 referenced in contracts 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 majority of the natural gas that is physically traded is priced off of index prices.

THE FINANCIAL MARKET

In addition to trading physical natural gas, there is a significant market for natural gas derivatives and financial instruments in the U.S. 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. Financial trades also market participants to hedge a price exposure without having to make or take physical delivery of the natural gas commodity. 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 were traded on the over-the-counter (OTC) market, although most are now traded via exchange-cleared, standardized contracts. Derivatives can be used to speculate, or seek to profit from market fluctuations, or to hedge price exposure in other financial or physical positions.

More information on financial markets appears in Chapter 5.

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78 *See* NGI, *NGI Adopting Three-Day Natural Gas Bidweek Trading Period, Making Other Changes to Price Index Listings* (May 7, 2021), https://www.naturalgasintel.com/ngi-adopting-three-day-natural-gas-bidweek-trading-period-making-other-changes-to-price-index-listings/.



Chapter 2
Wholesale Electricity Markets

WHOLESALE ELECTRICITY MARKETS

Electricity is a physical product – the flow of electrical power. 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. Electricity is not visible or directly observable, but it can be turned on and off and measured.

Quick Facts: *Measuring Electricity*

A key measure of electricity used in industry is the rate at which it is produced, transferred, or consumed – how much energy per unit of time a generator produces, with the units of electricity called watts. Similar measures are kilowatts (kW) – 1,000 watts, and megawatts (MW) – 1,000 kilowatts. A watt, kilowatt, or megawatt is a unit of power.

The amount of electric energy generated, transmitted, or used over time is measured as the number of watt-hours (also expressed as kilowatt-hours, megawatt-hours, or gigawatt-hours).

The amount of electricity a generator can produce in an hour is its capacity, which is typically noted as megawatts. For example, a generator with a capacity of 100 MW can produce 100 MW in an hour. The amount of power consumed at any location is the demand at that point.

Electricity markets have retail and wholesale components. Retail service involves the sales of electricity to consumers and may involve retail markets; wholesale markets typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. Because the Federal Energy Regulatory Commission (FERC) has jurisdiction over wholesale electric rates and not retail electric rates, this document focuses on wholesale electricity markets, although it does address retail demand and other instances where retail markets strongly influence wholesale markets.

Most wholesale electric markets rely upon competitive markets to set prices, but some prices are based on the service provider’s cost of service. For wholesale markets, FERC either authorizes jurisdictional entities to sell at market-based rates or at cost-based rates.

Both market-based and cost-of-service prices are affected by physical factors or conditions that drive electric supply and demand – these factors are known as physical fundamentals. For example, weather affects both supply and demand. Fuel costs, capital costs, transmission capacity and constraints, and the operating characteristics of power plants affect the cost at which supply can be provided. The actual price for power is determined by the interaction of supply and demand. For example, extreme heat can drive up demand and require grid operators to activate less-efficient, more-expensive power plants, and consequently drive prices up.

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 as consumers integrate various devices and amenities such as lighting, refrigerators and computers into their everyday lives. Consumers also expect to pay reasonable prices for the electricity that they use.

Meeting these customer expectations requires substantial effort and activity. While technology continues to develop and advance, electric markets can only store a portion of the electricity required to serve electric loads. Thus, the vast majority of electricity must be produced instantaneously as needed. Further, unlike most other markets, electricity's historically 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. In the absence of significant amounts of storage and price 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.

ECONOMIES OF SCALE

Electric power is one of the most capital-intensive industries. Generation, transmission and distribution require significant investment in capital intensive equipment, the costs of which are fixed. Spreading these significant 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 to take advantage of economies of scale and the cost per unit of production dropped as power plants grew larger and larger. The companies building these facilities were generally self-contained and not connected to each other. They owned and operated generation, transmission, and distribution facilities and were vertically integrated.

While successful for launching the electric utility industry, this market structure had limitations. The larger generating units were difficult to replace if they experienced unexpected shutdowns. As a result, the utilities held and maintained excess capacity in reserve (reserves) to ensure reliable electric service. These reserves were able to quickly replace electricity lost due to an unexpected shutdown or an unexpected increase in electric loads.

RESERVE SHARING

The solution to high reserve costs was to share reserves with adjacent utilities. Instead of building and maintaining all of the capacity required to provide energy and sufficient reserves, utilities were able to pool their reserves and could buy power from their neighbors in times of need cutting their costs significantly as a result. To facilitate reserve sharing, utilities built interconnecting transmission lines between their transmission systems to deliver electricity in the event of a generator outage or some other system disruption. Today's bulk power grid began as a way to maintain reliable service while lowering 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 to serve electric loads. Operators want to commit just enough capacity to ensure reliability, but no more than is needed. Over time, this coordination ultimately led to the creation of regional transmission organizations that use markets to determine the set of resources to reliably serve electric loads at least cost. These wholesale electricity markets operate over large 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 river systems generate power from the spring runoff of melting mountain snow. When the reservoirs are full and hydroelectric plants are generating plentiful amounts of power, there is not enough local demand to use the available supply. Since 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 these 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 introduced 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 reliable operation of the bulk electric system. Then, in 1965, the largest power blackout until that time hit the northeastern United States and southeastern Ontario, Canada, affecting 30 million people. The blackout led to the development of the National Electric Reliability Council in 1968, shortly thereafter renamed the North American Electric Reliability Council (NERC), and nine regional reliability councils.[74] Rather than serving as a power pool or other entity for sharing reserves, NERC focused on reliability. In 2006, using authority granted in the Energy Policy Act of 2005 (EPAct 2005), FERC certified NERC as the electric reliability organization for the United States, and reliability standards became mandatory and enforceable.

ECONOMY ENERGY TRADE

Transmission interconnections between adjacent utilities were originally built for the primary purpose of delivering reserves in emergencies. However, this created excess transmission capacity, since these events were rare. The interconnections allowed utilities to trade power, which became profitable when the marginal cost of operating their 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

Evolving public policies, regulatory constructs and organizational structures shaped the electric power industry over its history. Five concepts that helped shape the electricity industry and markets are outlined below, and still affect the industry today.

REGULATED MONOPOLIES

In the early years of the industry, investors provided funds and took ownership shares in the power stations and electric distribution systems. These utilities became regulated – typically by state agencies – to overcome concern they were natural monopolies in the areas they served, lacking competition, and to bring stability to a capital-intensive industry. Stability came from granting exclusive service territories (or franchises), transparent financial statements, and the formulaic setting of electricity rates that were subject to regulatory oversight and approval. Over time, many of the utilities issued stock, which gave stockholders a share of the company's ownership, commonly referred to as investor-owned utilities (IOUs). The regulatory model for setting electricity rates was almost exclusively cost of service-based until about 30 years ago. Today, retail electric rate regulation is largely still based on cost-of-service, while wholesale electric rate regulation has become increasingly market-based. State regulators are responsible for approving retail rates, as well as utilities' investments in generation and distribution facilities. Some states eventually developed elaborate integrated resource planning (IRP) processes to determine what facilities should be built.[75]

NOT-FOR-PROFIT UTILITIES

Another approach to serving customers emerged in the form of nonprofit electric providers. In the early years of the industry, electrification started in towns and cities

74 In 2006, the North American Electric Reliability Council changed its name to the North American Electric Reliability Corporation (also referred to as NERC).

75 For additional background and context on the early years of the electrification of the U.S., National Museum of American History, *Powering a Generation of Change, Emergence of Electrical Utilities in America* (2002), http://americanhistory.si.edu/powering/past/h1main.htm.

where utility service was provided by municipal power agencies or city governments. The federal government also stepped in to develop and market electricity from the nation's significant hydroelectric resources. Finally, the Depression-era rural electrification program promoted 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.

POWER POOLS

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

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

COMPETITION, PART 1: COMPETITIVE GENERATION AND OPEN ACCESS

Environmental policy 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 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. Such prices are referred to as avoided-cost rates.

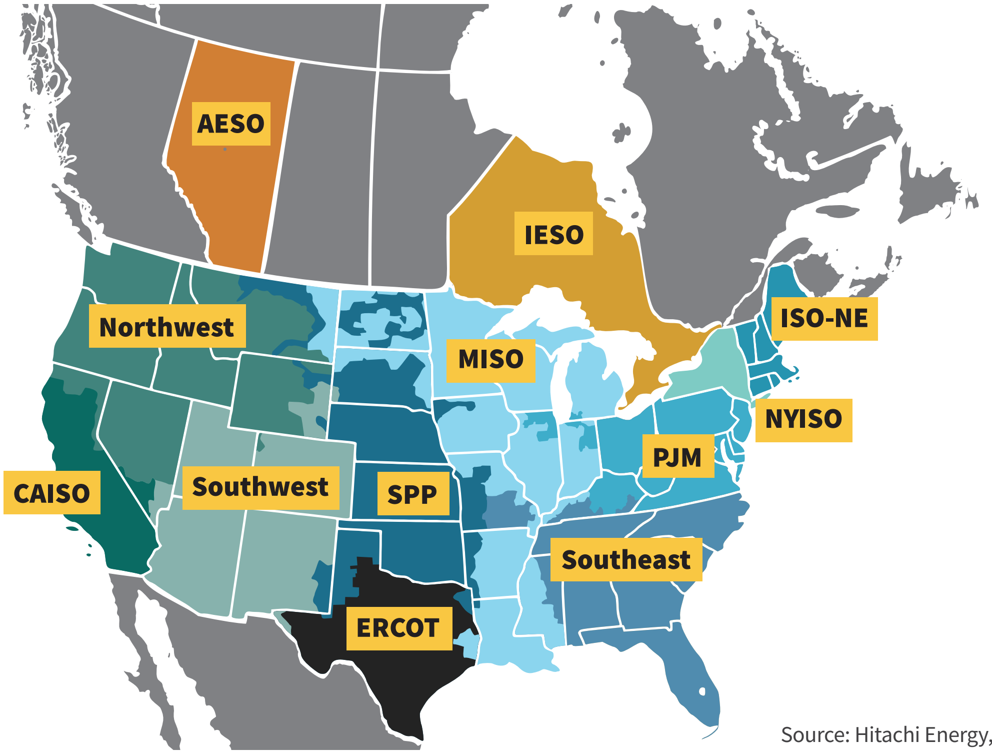
Most states set their avoided-cost rates so low that they got little QF capacity. However, California, Texas, and Massachusetts set relatively generous avoided-cost rates, and were overwhelmed with QF capacity, much of which received prices that turned out to be higher than the actual costs avoided by the purchasing utilities. 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.

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

By the mid-1990s, support for opening the transmission grid to all users encouraged FERC to pursue a generic solution. FERC issued Order No. 888 in 1996 and 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.

Figure 2-1: North American Regional Transmission Organizations, Independent System Operators and Bilateral Regions



Source: Hitachi Energy, Velocity Suite

COMPETITION, PART 2: INTEGRATING MARKETS AND OPERATIONS – ISOS AND 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 (ISOs). Along with facilitating open access to transmission, an ISO would operate the transmission system independently of wholesale market participants and foster competition for electricity generation. Several groups of transmission owners formed ISOs, some from existing power pools.

In Order No. 2000, FERC encouraged utilities to join regional transmission organizations (RTOs) which, like ISOs, would operate the transmission systems and develop innovative procedures to manage transmission equitably. FERC's proceedings in Order Nos. 888 and 2000, along with the efforts of the states and the industry, led to the voluntary formation of ISOs and RTOs. Each of the ISOs and RTOs subsequently developed full-scale energy and ancillary service markets in which buyers and sellers could bid for or offer generation. Both organizations use bid-based markets to determine economic dispatch. Throughout the subsequent sections of the primer, when referring to the organized RTO and ISO markets generally and collectively, the term RTO/ISO is used.

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

Electricity Demand

Americans consume electricity for an ever-increasing range of uses. While consumption has grown over the years, it varies annually based on many influences, such as weather, economic activity, and other factors. Total generation at utility-scale facilities reached 4,108,303 gigawatt hours in 2021.[76]

Vertically-integrated IOUs, federal entities, municipally owned, and electric cooperatives sell the majority of electric generation to retail consumers. Additionally, some retail consumers generate all or part of the power that they consume. The rest of the electricity ultimately consumed by customers is bought and sold through wholesale electricity markets.

DEMAND CHARACTERISTICS

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 considered 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 summer heat waves, in the late afternoon. However, a minority of regions reach their peak load when the weather is extremely cold. These are primarily areas with significant space-heating requirements and little summer air conditioning load, such as the far northern areas of the United States.

Throughout the year, and in most locations, 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 can also show distinct usage. For example, Mondays and Fridays, being adjacent to weekends, may have different loads than Tuesday through Thursday. This is particularly true in the summer.

Since supply 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. This is because higher levels of demand require activation of increasingly expensive sources of power generation, and reductions as demand declines. As a result, power prices are typically highest during periods of peak demand.

DEMAND DRIVERS

The amount of electricity demanded is insensitive to prices in the short-term. 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. Further, most customers – especially smaller customers – do not get price signals to which they can respond. A vast majority of residential customers are billed monthly on a preset rate structure. Large industrial customers, on the other hand, may receive real-time price signals.

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

As discussed below, utilities, at the direction of government, have developed demand-response programs, which can provide reduced rates or other compensation to customers who agree to reduce load in periods of electric system stress.

Climate and Weather

Weather is one of the primary factors affecting demand. General climatic trends drive long-term consumption patterns and therefore the infrastructure needed to ensure reliable service.

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 up air conditioning loads. Other, less obvious weather patterns affect demand

76 Derived from EIA, *Electric Power Annual, Table 3.1.A* (released November 8, 2022), www.eia.gov/electricity/annual/html/epa_03_01_a.html.

– rain and wind, for example, may result in sudden cooling, affecting heating or air conditioning usage.

Economic Activity

The overall level of economic activity affects power demand. During periods of robust activity, loads increase. Conversely, loads drop during recessions. These changes are most evident in the industrial sector, where businesses and plants may close, downsize, or eliminate factory shifts. In addition to reducing overall demand, these changes affect the pattern of demand; for example, a factory may eliminate a night shift, cutting off-peak use but continue its use of power during peak hours. In some cases, these effects can be significant. For example, the COVID-19 pandemic changed how consumers used electricity as communities and companies implemented social distancing and stay-at-home measures to combat the spread of COVID-19 in the spring of 2020. Electricity demand shifted from commercial and industrial uses to residential consumption. Overall, electricity demand in the U.S. dropped about 4% in 2020, as commercial and industrial demand dropped 6% and 8%, respectively, and residential demand rose 1%.[77]

Energy Policies and Regulations

State regulatory agencies, such as public utility commissions, oversee retail electric rates and set policies affecting retail customer service. Some states allow utilities to offer retail rate structures that enable customers to receive more accurate price signals. They include, among other things, rates that vary with the time of day and the cost of providing electricity.

Efforts to reduce overall demand by improving energy efficiency are also supported by governmental and utility programs. These include rebates for the purchase of energy efficient appliances and home improvements, as well as capacity market payments for load reductions, also known as demand response, that are made available in certain markets.

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. For example, a day with an average temperature of 66° would yield one cooling degree day.

Retail Customer Mix

Most electric utilities serve three distinct classes of customers: residential, commercial, and industrial. Each class uses electricity differently, resulting in a differing load profile, or the amount of energy each customer class uses throughout the day. If a consumer uses electricity consistently throughout the day and seasons, the load shape is flat. Another consumer may use more at some times than others. More variable demand is typically more expensive to serve, especially if the peak occurs at the same time as other customers' use peaks. Consequently, the mix of customer types affects a region's overall demand and costs.

77 EIA, *Short-Term Annual Outlook*, at 3 (January 2020).

Residential consumers form one of the top two customer segments in the United States at approximately 39 percent of electricity demand in 2021. 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 residential customers' load shape and their service from lower-voltage distribution facilities, meaning that more power lines and related assets are needed to provide service to them.

Commercial use, the next largest customer segment, represented approximately 35 percent of electricity demand in 2021.[78] This customer segment includes office buildings, hotels and motels, restaurants, street lighting, retail stores, 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 26 percent of the nation's electricity.[79] This customer segment includes manufacturing, construction, mining, agriculture and forestry operations. Industrial customers often see the lowest rates, reflecting their relatively flat load profile 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 total electricity demand.[80] However, state and federal policies that advance electrification of the transportation fleet are expected to increase electric load growth in the near future.

LOAD FORECASTING

Demand is constantly changing, which challenges grid operators and suppliers who are responsible for ensuring that supply will meet demand at all times. Consequently, they expend considerable resources to forecast demand.

Load forecasting uses mathematical models to predict demand across a region, such as a utility service territory or an RTO/ISO footprint. Forecasts can be divided into three categories: short-term forecasts, which range from one hour to one week ahead; medium-term 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 one to three percent of what will actually happen. The accuracy of these forecasts is limited by the accuracy of the weather forecasts used in their preparation and the uncertainties of human behavior.

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 reduced occurrences of equipment failures and blackouts. Forecasted weather parameters are the most important factors in short-term load forecasts, with temperature and humidity as the most commonly used load predictors.

The medium- and long-term forecasts 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 peak load based on historical loads and weather conditions. Long-term forecasts extending 10 to 20 years into the future 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.

Forecasts are necessary for the variety of actions that must occur to ensure that sufficient supply is available in the immediate and long term. These include the

78 Derived from EIA*, Electric Power Annual, Table 2.5* (November 7, 2022), www.eia.gov/electricity/annual/html/epa_02_05.html.

79 *Id*.

80 *Id*.

planning of long-term infrastructure, purchasing fuel and other supplies, and ensuring adequate staffing of specific personnel. Load forecasts are also extremely important for suppliers, financial institutions, and other participants in electric energy generation, transmission, distribution, and trading. Missed forecasts, when actual demand differs significantly from the forecast, can cause wholesale prices to be significantly higher or lower than they otherwise might have been.

DEMAND RESPONSE

Electricity demand is generally insensitive to price, meaning that demand does not typically fall when 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 have developed ways to stimulate a response from consumers through demand-response programs.

Demand response is the reduction in consumption of electricity by customers from their expected consumption levels, in response to either reliability needs or price signals. Customers will forego power use for short periods, shift some energy use from peak periods to other times, or use on-site generation in response to price signals or incentives for load reduction. 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/ISO, or an independent provider of demand response. Both retail and wholesale entities administer these programs. Demand response has the potential to lower system-wide power costs and assist in maintaining reliability. It can also mitigate system stress and allow operators to resolve shortages, avoid operating inefficient power plants, or relieve transmission congestion. There can also be environmental benefits, such as lower levels of power plant-related emissions that result from not operating peaking units.

Measuring and verifying the amount of reduced consumption during a demand response activation requires development of consumers' baseline usage, against which their actual use is measured.

Demand-Response Programs

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

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

Shifting involves moving or rescheduling high energy-use activities in response to high prices or demand response 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 customers respond by turning on an on-site or backup emergency generator to supply some or all of their electricity needs. Although these 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.

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

As a result of technological innovations and policy directions, new types and applications of demand response 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.

Retail Demand Response Programs

Utilities and third-party aggregators offer a variety of demand response programs that include time-based rates and interruptible contracts. Also, some states mandate energy efficiency resource standards that include peak load reduction targets.

Time-based rates include time-of-use rates and dynamic pricing. Time-based rates depend on advanced meters at customer premises that can record usage over short increments, typically groupings of hours or individual hours. In time-of-use programs, customers are charged different prices at different times of the day, with hours on or near peak demand costing more than off-peak hours. Dynamic pricing is a category of programs where rates change frequently to better reflect system costs. The practice of adjusting prices as costs change provides an incentive for consumers to shift load to other periods or to reduce peak load. One form of dynamic pricing is termed real-time pricing. In these programs, customers are charged prices reflecting the immediate cost of power. Industrial or very large commercial customers are the most likely to choose real-time tariffs.

Another form of dynamic pricing is critical peak pricing. These programs use real-time prices at times of extreme system peak but are restricted to a limited number of hours annually. They feature higher prices than time-of-use prices during the critical peak. Consumers do not know in advance when a critical peak might be called. Critical peak programs for residential customers typically use rebates as an incentive to participate in the program, but customers take the risk of paying higher prices or reducing load during critical peak periods. These programs seek to have customers respond to price signals, as opposed to penalizing them, if they do not lower their use in the critical peak hours.

Interruptible contracts are used by utilities to control load and address potential reliability issues, such as reducing stress on the electric system during heat waves. The two primary forms of this category of demand response are direct load control and interruptible rates. Direct load control entails the utility curtailing a portion of customer load as described above. Under interruptible rates, customers agree to turn off equipment or switch their energy supply to an on-site generator.

Energy efficiency resource standards exist in 25 states, while five states and the District of Columbia. have energy efficiency goals.[81] The standards typically require utilities to achieve electric energy savings, and many include peak load reduction targets. These mandates provide incentives for utilities to reduce customers' energy consumption and include mechanisms that decouple profits from the amount of electricity sold or performance bonuses for utilities that meet or exceed reduction targets.

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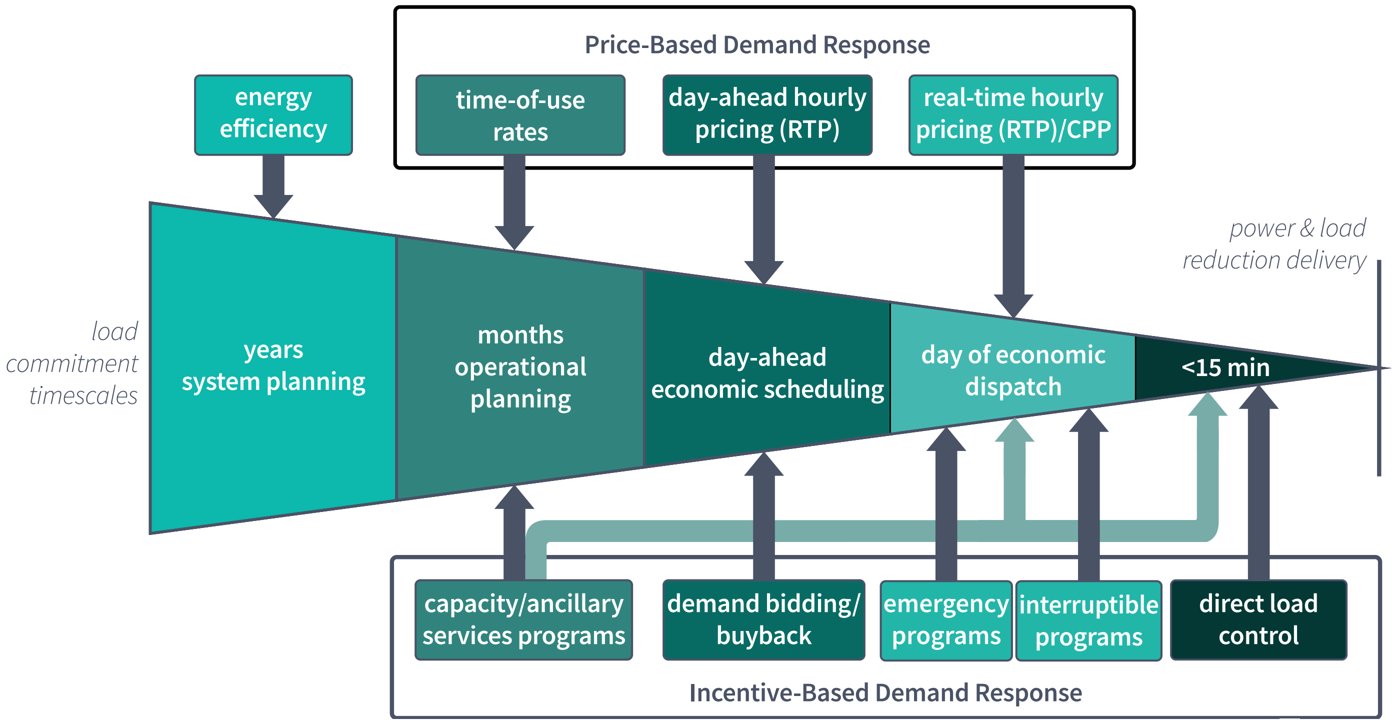
81 DSIRE, N.C. Clean Energy Technology Center, *Energy Efficiency Resource Standards (and Goals)* at 1 (September 2021), https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2021/09/Energy-Efficiency-Resource-Standards_Sept-2021.pdf.

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations



Source: U.S. Department of Energy[82]

Wholesale Market Demand Response Programs

On the wholesale level, market operators have some programs that dispatch the demand response resources. Other demand response programs are dispatched by the utilities or aggregators that sponsor the programs, rather than the market operator. Note that with most retail demand response programs, which can also aid wholesale markets, market operators may not be able to invoke them or even see the specific amount of response that occurs.

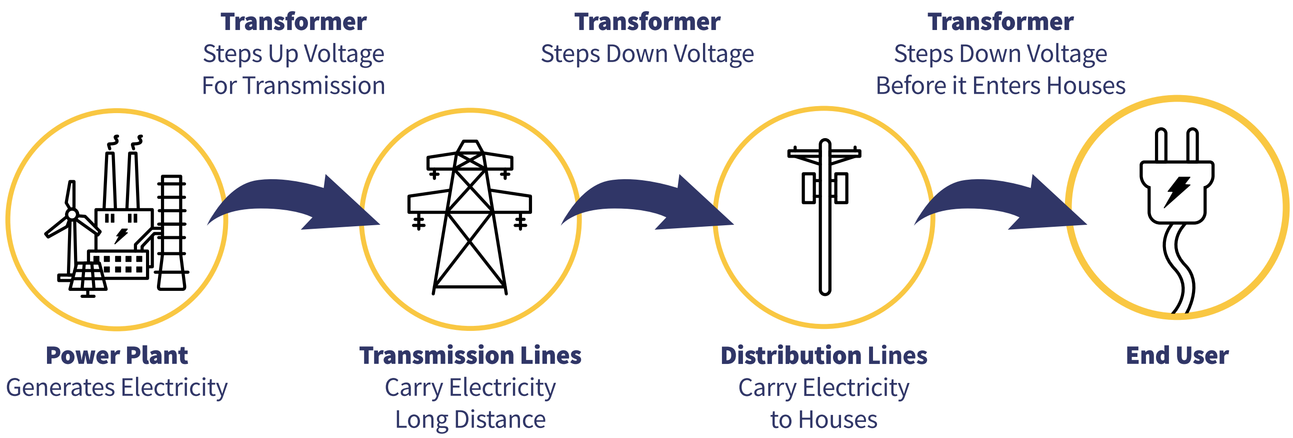
Demand response participation in RTO/ISOs has been encouraged in U.S. national energy policy and by various FERC orders.[83] Overall, approximately 30.8 GW of demand response participated in RTOs/ISOs in 2020.[84] These resources primarily participate in RTO/ISOs as capacity resources and receive advance reservation payments in return for their commitment to participate when called upon or activated. Additionally, demand resources may offer into the RTO/ISO day-ahead markets, specifying the hours, number of MWs and price at which they are willing to curtail.

82 U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*, at 15, (2006), https://www.energy.gov/oe/articles/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report.

83 EPAct 2005 included policy encouraging time-based pricing and other forms of demand response and the elimination of barriers to demand response participation in the energy, capacity, and ancillary services markets. Examples of FERC orders include Order No. 719, 128¶61,059, (July 16, 2009); Order No. 745, 134¶61,187 (March 15, 2011); and Order No. 2222, 174¶61,197, (March 18, 2021).

84 *See* FERC, *Assessment of Demand Response and Advanced Metering Staff Report,* at 3 (December 2021), https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering.

Figure 2-3: Electricity Supply and Delivery



Source: The NEED Project[85]

Some of the RTO/ISO demand response comes from individual entities; the rest is accumulated through third-party aggregators, or curtailment service providers, who recruit customers too small to participate on their own, such as schools, commercial chains or groups of residential customers. In aggregating small customers, curtailment service providers have increased customer participation in many wholesale reliability and emergency programs.

Demand Response and Energy Efficiency in Planning and Operations

Different demand response programs can be used at various times to support planning and operations (see Figure 2-2). Energy efficiency programs that reduce baseload or peak demand over the long-term are incorporated into system planning. Dispatchable programs that are quickly implemented and targeted for short-term peak reductions – such as direct load control – lie on the other end of the spectrum and are used in the moment of operation.

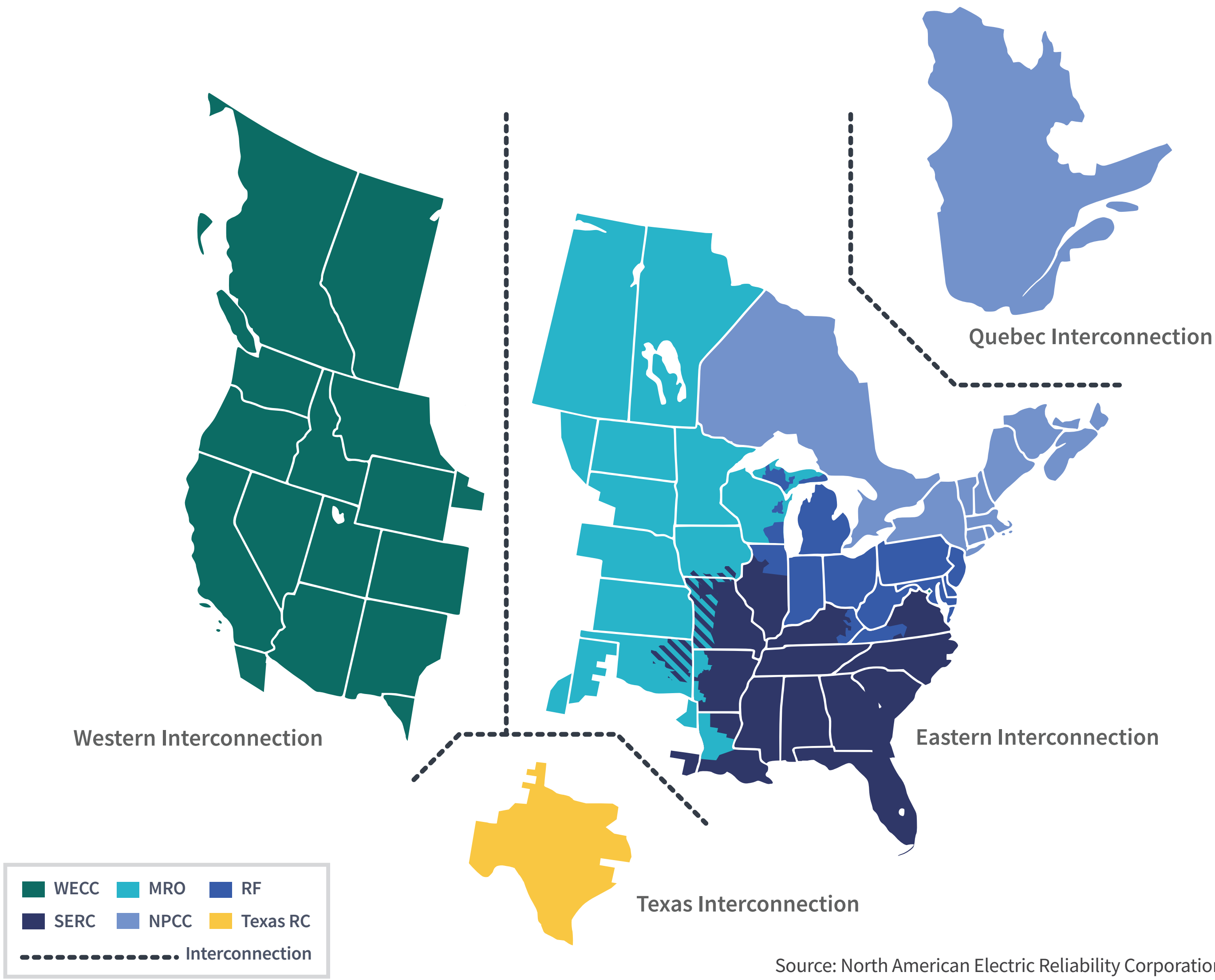
Electricity Supply and Delivery

Unlike many other products, electricity cannot be stored in any appreciable quantity relative to the total consumed across the country each day. Further, electricity is a necessity for most consumers, whose use responds little to price changes. Finally, electric equipment and appliances are tuned to very specific standards of power, measured as voltage and frequency. For example, 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 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.

85 National Energy Education Development Project, *Electricity,* at 56 (2017), http://www.need.org/Files/curriculum/infobook/Elec1S.pdf.

Figure 2-4: North American Electric Reliability Corporation Regions



Source: North American Electric Reliability Corporation

Nationally, the grid is geographically 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 for reliability purposes. The regional reliability entities fall under the purview of North American Electric Reliability Corporations (NERC), which was designated by FERC as the nation's electric reliability organization, and which develops and enforces mandatory reliability standards to better ensure the reliable operation of the nation's bulk-power system (the interconnected transmission grid). The reliability standards, once approved by FERC, must be met by applicable industry participants as designated in each reliability standard. Consequently, the grid is planned and operated to meet these standards.

NERC's regions include:

- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

FERC JURISDICTION

Under the Federal Power Act (FPA), FERC regulates the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. The FPA requires that every public utility file with FERC all rates and charges for any transmission or sale subject to the jurisdiction of FERC. Under Sections 205 and 206 of the FPA, 16 U.S.C. §§ 824d, 824e, FERC ensures that the rates and charges made, demanded, or received by any public utility for, or in connection with, the transmission or sale of electric energy subject to the jurisdiction of FERC, and all rules and regulations affecting, or pertaining to, such rates or charges are just and reasonable and not unduly preferential or unduly discriminatory.

GENERATION

Power generators are typically categorized by the fuel that they use and subcategorized by their specific operating technology. In 2021, the United States had approximately 1,218 GW of total generating capacity.[86] The majority of power generation is produced from coal, natural gas, nuclear fuels, and renewables.

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: more capital-intensive plants tend to be cheaper to run – they have lower variable costs – and, conversely, the least capital intensive plants tend to be more expensive to run – they have higher variable cost. For example, nuclear plants produce vast amounts of power at low variable costs but are expensive to build. Conversely, natural gas-fired combustion turbines are far less expensive to build but can be more expensive to run. Grid operators dispatch plants – or call them into service – with the simultaneous goals of providing reliable power at the lowest 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/ISOs, 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.

CONVENTIONAL GENERATION

Generation is often described as conventional or renewable (described further in the Renewable Generation section below). Conventional generation typically includes natural gas-, oil-, coal- or nuclear-powered generation.

Natural Gas-Fired Generation

Natural gas power plants consist of 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 U.S. 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 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.

86 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

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 NOx 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-Fired Generation

Coal plants produced approximately 22 percent of the electricity in the United States in 2021.[87] These facilities generate power by creating steam which is used to spin a very large turbine. These plants tend to be used as baseload units, meaning that they run continuously and are not especially flexible in raising or lowering their power output. They have high initial capital costs, with complex designs and operational requirements. 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 Generation

Oil 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 natural gas plants. They are frequently uneconomic and typically run at low-capacity factors. Like natural gas-fired generators, there are several types of units that burn oil; primarily, these are steam boilers and combustion turbines. Most dual-fuel power plants are located in the eastern half of the United States, especially on the East Coast.[88]

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 Generation

Nuclear plants provided roughly 19 percent of the nation's electricity in 2021, when 93 nuclear plants operated in the United States with a total capacity of approximately 100 GW.[89] Like generating units that use coal, nuclear plants tend to be large, baseload units that run continuously. 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, and are then taken offline for refueling and maintenance. Outages

87 EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities*, *Tables 3.1A. and 3.1.B*, (accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

88 Derived from Hitachi Energy, Velocity Suite data (Accessed March 28, 2023).

89 EIA, *Form EIA-860* (November 2022), www.eia.gov/electricity/data/eia860/.

typically last from 20 days to significantly longer, depending on the work needed. Of the 92 operating nuclear plants, most reside in the eastern United States. Only six are in the West, four in Texas. Illinois had the largest number of plants at 11, followed by Pennsylvania at eight, and South Carolina at seven.[90]

RENEWABLE GENERATION

Renewable resources use fuels that are naturally replaced, such as wind, solar, hydroelectric and geothermal or which use fuels that are readily replaceable, such as biomass and biogas.

Such generation (generation termed renewable generation or renewables) is an increasingly important part of total U.S. supply, accounting for 29 percent of electric energy produced in 2021.[91] As total generation from all fuels has remained relatively constant in recent years, renewable generation's share has risen, spurred by technological advancements, state policy, and federal tax credits.[92]

Wind and solar capacity have grown faster than other renewable resources in recent years. Wind capacity grew substantially, from approximately 10 GW in 2006 to 193 GW in 2021.[93] Utility-scale solar capacity grew even faster, from approximately 0.1 GW to 61 GW over the same period. [94]

Additions of renewable generation capacity are usually reported in megawatts of nameplate capacity. Actual capability varies from the nameplate for any unit type due to such factors as age, wear, maintenance and 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 generation. Grid operators pay close attention to the difference between nameplate and capacity factor values when they evaluate capacity available to cover expected load, however, capacity factors have risen with technological innovation and improved manufacturing processes.

Wind

Wind generation is among the fastest-growing renewable resource, in part due to cost declines and technology improvements, as well as 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 located far from load centers, obtaining sufficient transmission presents a challenge to delivering wind output. Other market challenges for future wind development include its variable output, which is often inversely correlated to demand (seasonally and daily); system operators' limited ability to dispatch wind resources to meet load increases; difficulties related to accurately forecasting its ramping; and the need for companion generation (usually fossil-fueled) or energy storage to be available to balance wind generation when the wind is not blowing.

Solar

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 cells made of silicon or thin-film materials. 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

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90 EIA, *Form EIA-860M* (February 2023), www.eia.gov/electricity/data/eia860M/.

91 Derived from EIA, *Electricity Annual* (September 2022), www.eia.gov/electricity/annual/html/epa_01_01.html.

92 Lawrence Berkeley National Lab, *U.S. State Renewables Portfolio and Clean Electricity Standards: 2023 Status Update* (June 2023), https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf.

93 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

94 *Id.*

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. Total PV generation for 2021 was 161.5 GW, with approximately two-thirds of that generation coming from utility-scale facilities and one-third from small-scale generation.[95]

By the end of 2021, 1.5 GW of CSP was operational – a decline from 2017 when CSP capacity was 1.8 GW.[96] Total CSP capacity is significantly lower than PV owing to PV's lower costs.[97] Seven western and southwestern states have extensive CSP potential: Utah, New Mexico, Arizona, Nevada, Texas, California and Colorado.[98] Developing that potential will require overcoming challenges of cost, siting, transmission, and the need for extensive water supplies to clean mirrors.

Hydroelectric

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. In 2021, total U.S. hydro-electric capacity (including conventional and pumped-storage capacity) reached 246 GW. Conventional hydro-electric capacity was 285.3 GW and pumped storage hydro-electric capacity was 5.1 GW.[99]

Geothermal

Geothermal generation taps into reservoirs of steam and hot water deep beneath the earth's surface to produce power. The majority of the plants are based in California and Nevada. Geothermal potential is determined by thermal conductivity, thickness of sedimentary rock, geothermal gradient, heat flow and surface temperature. Geothermal generation, which stood at 16 GW in 2021, increased from 0.6 GW in 2011, but has decreased as a portion of total renewable output, due to the growth of other renewables. California hosts about 76 percent of geothermal U.S. operating capacity.[100]

Biomass

Biomass generation includes power production from many waste byproducts, such as agricultural residues, landfill gas, municipal solid waste, and wood resources. The largest biomass category is wood waste, burned for heat and power in the lumber, pulp and paper industries. Challenges to biomass production include impacts on food supplies (for example, converting corn into ethanol), conserving natural resources, and minimizing water pollution. In 2021, net utility-scale power generation using biomass fuel sources was 54.3 GWh - composed of 36.5 GWh from wood and wood-derived fuels as well as 17.8 GWh from other biomass sources.[101]

95 Derived from EIA, *Electric Power Annual, Tables 3.1.A. and 3.1.B* (released November 7, 2022 and accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

96 Derived from EIA, See table 4.3 in *Electric Power Annual 2021 and Electric Power Annual 2017*, www.eia.gov/electricity/annual/html/epa_04_03.html and www.eia.gov/electricity/annual/archive/pdf/03482017.pdf.

97 *See* National Renewable Energy Laboratory, *Annual Technology Baseline* (July 2018), https://atb.nrel.gov/electricity/2018/summary.html

98 EIA, *Form EIA-860*, (September 13, 2018), https://www.eia.gov/electricity/data/eia860/.

99 Derived from EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities, Tables 3.1.A and 3.1.B* (accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

100 Derived from EIA, *Form EIA-860* (accessed November 2017), https://www.eia.gov/electricity/data/eia860/.

101 *Id.*

Biogas

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

Renewable Energy Policies

Renewable generation development is frequently tied to policies promoting their use, which include tax credits, low-cost loans, rebates and production incentives. Federal funding of research and development has played an important role in lowering the 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, federal production tax credits (PTC) are available for wind, biomass, geothermal, and other forms of renewable generation 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 PTC has been revised several times, most recently in August 2022 under the Inflation Reduction Act, which extended the PTC for projects that begin construction before 2025, including solar projects that had previously been excluded from the PTC program.[102] After 2024, the PTC becomes technology neutral and emission based, and phases out starting in 2032, or when the U.S. electricity sector emissions are 75% below 2022 levels. If projects over 1 MW meet certain labor requirements, their PTC is 2.6 c/kWh; if the projects do not meet the labor requirements, the PTC would be 0.3 c/kWh. A further 10% adder on the PTC and ITC can be obtained if a project uses U.S. steel and roughly half the of manufactured components (as measured by cost) are sourced in the United States.

Another form of tax credit for renewables, including solar and other types of projects, has been a federal investment tax credit (ITC). The ITC has generally been set at 30 percent of a project's equipment and construction costs. The Inflation Reduction Act also revised the ITC, with the same terms as for the PTC. Projects meeting labor requirements may receive a 30% ITC, otherwise the ITC drops to 6%. Projects may also receive a 10% increase in the ITC if they use U.S. components, as described for the PTC.

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 measured by megawatt-hours (MWh) to come from renewable resources. Percentages usually increase incrementally from a base year to an ultimate target. Currently, 30 states plus Washington, D.C., have an RPS with financial penalties for non-achievement.[103] As utilities and independent developers 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 incorporate the expected growth of renewable generation in their long-term transmission-planning processes.

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.

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102 Congress.gov, *H.R. 5376-Inflation Reduction Act of 2022*, (became law August 4, 2022) https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

103 Barbose, Galen. Lawrence Berkeley National Laboratory, *U.S. Renewables Portfolio Standards: 2021 Status Update: Early Release* (February 2021), https://eta-publications.lbl.gov/sites/default/files/rps_status_update-2021_early_release.pdf.

ELECTRIC STORAGE

Historically, utility-scale storage of electricity for later use had been limited to pumped-hydro storage facilities. Recent advances in technology have made other types of electric storage resources, including batteries and flywheels, more economically feasible. The lower costs and improved capabilities of electric storage, along with favorable state and federal policies, increased penetration of variable energy resources, and a continued focus on grid reliability have helped spur the development of electric storage resources.[104]

As of 2021, the combined capacities of utility-scale electric storage and battery storage represented less than 2 percent of total generating capacity in the United States.[105] The majority of storage capacity consists of pumped-hydro storage (21 GW in 2021), which has grown very slowly. Battery storage capacity, in contrast, has grown from 3 MW in 2016 to 4,482 MW in 2021.[106] EIA projects that total U.S. battery storage capacity could reach 30 GW by 2025.[107]

Electric storage projects are increasingly available to help balance supply and demand particularly during periods of high demand or excess supply. These resources can charge during periods of low demand or excess generation, when electricity is less expensive, and discharge when demand is high and electricity is more expensive. Batteries, flywheels, and other fast-acting electric storage technologies can also provide ancillary services which help maintain grid reliability. The vast majority of battery storage capacity in the electricity markets is used to provide ancillary services or capacity, because these applications provide the most revenue for storage owners.[108]

Some states have passed legislation to incentivize investment in storage projects. In 2013, California adopted targets for utilities to procure 1,325 MW of energy storage capacity by 2024 and subsequently increased the capacity requirement target and compressed the timeline for reaching that target.[109] As of May 2021, five states besides California also set energy storage requirements or targets: Oregon, Massachusetts, New York, New Jersey and Virginia. Additionally, some states which do not have formal energy storage requirements offer financial incentives such as grants and tax incentives, while others have begun requiring utilities to include storage in integrated resource plans.

DISTRIBUTED ENERGY RESOURCES

In Order No. 2222, the Commission defined Distributed Energy Resources (DERs) as any resource located on the distribution system, any subsystem thereof or behind a meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.[110] In most instances, these resources are located close to the

104 FERC has issued various orders to help remove barriers to the participation of electric storage resources in FERC-jurisdictional markets. *See, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, *Order No. 841, 162 FERC ¶61,127 (2018); Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222*, 172 FERC ¶ 61,247 (2020).

105 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

106 *Id.*

107 EIA, *U.S. battery storage capacity will increase significantly by 2025* (December 8, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54939#:~:text=As%20of%20October%202022%2C%207.8%20GW%20of%20utility-scale,add%20another%2020.8%20GW%20of%20battery%20storage%20capacity.

108 EIA, *U.S. Battery Storage Market Trends*, 13-15 (August 2021), https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

109 California Public Utilities Commission, *Energy Storage* (accessed December 1, 2022), www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-storage.

110 Order No. 2222, 172¶61,247, (September 17, 2020), at 4.

end user of power. While individual installations of DER tend to have capacities much smaller than that of central station power plants (for example DER installations may range from a fraction of a kW to systems producing less than 10 MW), the overall quantity of DER installations has grown tremendously, particularly in states with beneficial policies toward DERs.

One such policy is known as net metering, which is a system in which DERs are connected behind the meter to a distribution system and any surplus power is transferred onto the grid, allowing customers to offset the cost of power drawn from a distribution utility. Such surplus flow typically occurs during periods when the DER's production outstrips the customer's total demand. Under one measure of DER, as tracked by EIA, total net-metered capacity grew by approximately 277 percent between 2014 and 2020, from approximately 7.5 GW of capacity to 28.3 GW. The bulk of this capacity was solar PV, which made up 94 percent of net-metered capacity in 2020, with 62 percent of that capacity owned by residential customers.[111] In some cases, surplus power from a large DER or a set of net metered DERs may flow onto the transmission system.

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 also 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 such as the movement of large amounts of power over long distances, for example 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 including the voltage of the transmission facilities.

111 EIA, *Electric Power Annual* (December 2022), (March 2022), www.eia.gov/electricity/annual/html/epa_04_10.html.

Wholesale Electricity Markets and Trading

Electric markets encompass different organizational structures and different mechanisms for buying and selling power at the wholesale level. Electric systems for delivering power to consumers in the United States are split into two structures: traditional systems and those run by RTO/ISOs. Traditional systems are typically vertically integrated, rely on management to make operational decisions, and sell electricity to retail customers based on their cost of service. In general, RTO/ISOs use their markets to make operational decisions, such as generator dispatch, and to price the resulting electricity. Load-serving entities then buy the power through the RTOs/ISOs for resale to retail customers.

Both traditional systems and RTOs/ISOs conduct certain functions, although they may perform these functions in different ways. These include:

- Ensuring the electric grid operates reliably in a defined geographic footprint
- Balancing supply and demand instantaneously and maintaining sufficient operating reserves
- Dispatching system resources as economically as possible
- Coordinating system dispatch with neighboring balancing authority areas (BAAs)
- Planning for transmission in its footprint
- Coordinating system development with neighboring systems and participating in regional planning efforts
- Providing non-discriminatory transmission access

Buying and selling electricity in the wholesale markets – trading – occurs through bilateral and RTO/ISO transactions, as discussed below. Bilateral transactions occur in both traditional systems and in RTO/ISO regions. Pricing for bilateral transactions in both RTO/ISO and traditional regions incorporates both cost-based and market-based rates.

SUPPLYING LOAD

Load serving entities (LSE) serve customer load through a combination of self-supply, bilateral market purchases and purchases from RTO/ISO markets. Self-supply means that the LSE generates power from plants it owns or operates to meet demand. With bilateral purchases, the LSE buys power from a supplier. RTO/ISO market purchases means the supplying company purchases power through the RTO's/ISO's markets.

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

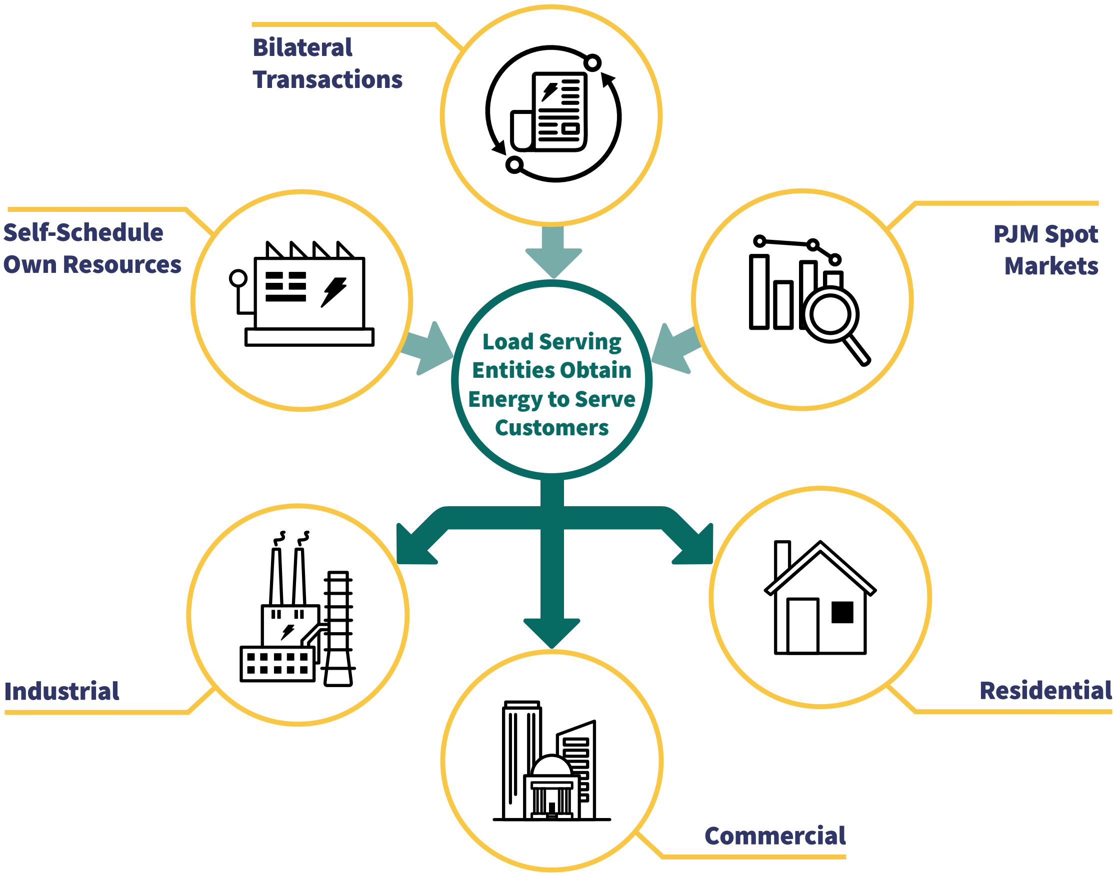
BILATERAL TRANSACTIONS

Bilateral transactions between two parties do not occur through an RTO/ISO and can occur through direct contact and negotiation, through a voice broker or through an electronic brokerage platform, such as the Intercontinental Exchange (ICE). The deals can range from standardized contract packages, such as those traded on ICE, to customized, complex contracts known as structured transactions. In bilateral transactions, buyers and sellers know the identity of the party with whom they are doing business.

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 indices provide price transparency.

Physical bilateral trades involving the movement of energy from one point to another require the parties to reserve transmission capacity to move the power over the transmission grid. Transmitting utilities are required to post the availability of transmission capacity and offer

Figure 2-5: Options for Energy Supply



Source: PJM Traditional Wholesale Electricity Markets

service on an OASIS website. Traders usually reserve transmission capacity on OASIS at the same time they arrange the power contract.

Transfers of power between Balancing Authority Areas (BAAs) require one of the parties to the transaction to submit a request for interchange, also known as an eTag.[112] The receiving BAA (the entity to which the power is transferred or sinks), or its agent, will process the eTag, ensure a reliability assessment has been completed, and send it to all parties named on the eTag. This ensures an orderly transfer of energy and provides transmission system operators with the information that they need to institute curtailments, as needed. Curtailments may be necessary when a change in system conditions reduces the capability of the transmission system to move power and requires some transactions to be reduced or cut.

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

112 A BAA is a collection of generation, transmission, and loads within the metered boundaries of the entity (a Balancing Authority) that is responsible for balancing load, generation, and net interchange between other BAAs. Glossary of Terms Used in NERC Reliability Standards (March 2022), https://www.nerc.com/files/glossary_of_terms.pdf.

COST-BASED RATES

Cost-based rates are used to price most transmission services and some electricity when FERC 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. These rates are typically listed in a published tariff.

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

- Determining used-and-useful electricity plant costs. This may include the cost of generation facilities, transmission facilities, distribution plants and office and related administration facilities.
- Determining expenses for 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/ISO market operations. FERC grants market-based rate authority to electricity sellers that demonstrate that they and their affiliates lack, or have adequately mitigated, horizontal market power (typically based on whether the seller is a pivotal supplier and on the percent of generation owned by the seller relative to the total amount of generation available in a market). Sellers must also show that they lack, or have adequately mitigated, 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 sell into day-ahead or real-time markets administered by an RTO/ISO do so subject to the specific RTO/ISO market rules approved by FERC. Thus, a seller in such markets must have an authorization from FERC and must also abide by the additional rules contained in the RTO/ISO tariff.

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). Each utility's OATT specifies the transmission services available. Customers submit requests for transmission service through the OASIS. Utilities 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.

The two most common types of transmission service are network and point-to-point service. Network service allows a transmission customer the use of the entire transmission network to deliver generation from specified resources to specified loads. The price for service is cost-based and published in the OATT. Network service has higher priority than point-to-point service.

Point-to-point 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). The POR and POD may be outside the transmission operator's footprint. Depending on availability, customers may purchase firm or non-firm point-to-point service for durations of one hour to multiple years.

Customers holding firm point-to-point transmission capacity may sell that capacity in a secondary market – such a sale is known as capacity reassignment. An entity holding transmission rights may want to resell that capacity to another transmission customer in the secondary market because it is unneeded, or to make a profit. Resellers of transmission capacity are permitted to charge market-based rates for capacity reassignments, instead of the original cost-based rate at which they purchased the capacity. Most capacity reassignments are hourly, although capacity can also be reassigned on a daily, weekly, monthly, or yearly basis.[113]

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 consistent with, and rarely exceed, the expected price differential between the POD and the POR.

Transmission Planning

Each transmission-operating utility must participate in regional planning processes that identify transmission system additions and improvements needed to maintain reliability. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. Planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems.

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. For RTOs/ISOs, the market determines a day-ahead unit commitment, then updates the unit commitment and dispatches in real time. Grid operators in traditional utilities plan for the next day's dispatch, then update and implement that dispatch in real time.

Dispatch Planning

Grid operators decide which generating units should be committed in advance of actual operations. For RTOs/ISOs, this is done, in part, through the day-ahead markets and forecasts. For operators in traditional utilities, this is done through various planning and forecasting processes. Planning dispatch in advance of real-time operations is needed because some generating units need to obtain fuel or require several hours of 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 each generating unit's cost factors, such as fuel and nonfuel operating costs, and the cost of environmental compliance.

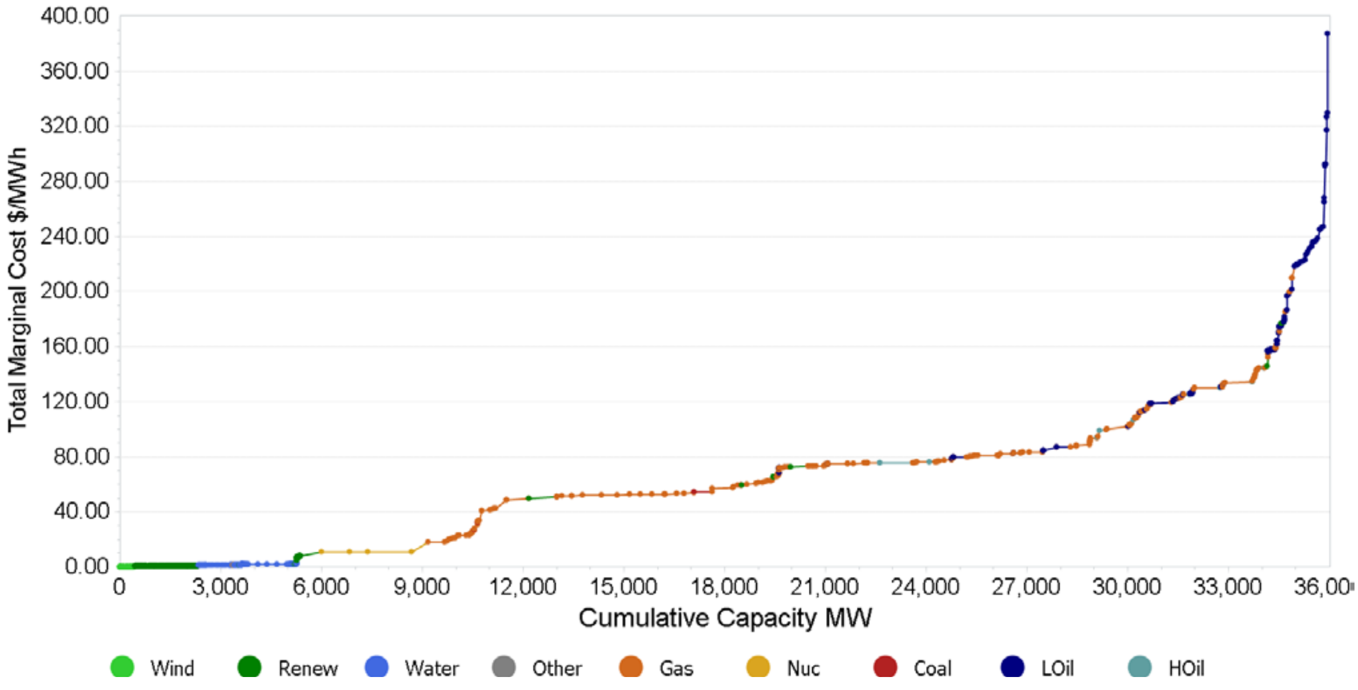
Forecast conditions can also affect how the transmission grid is optimally dispatched to reliably meet load. This is the security aspect of commitment analysis. The factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels 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 be called upon to replace less-expensive units.

System and Unit Dispatch

Grid operators must decide the actual level at which each available resource should be operated, given the actual real-time load and grid conditions, so that reliability is maintained and overall production costs are minimized. Actual conditions will vary from those forecast prior to real-time, and grid operators must adjust the dispatch accordingly. As part of real-time operations, demand, generation and interchange (imports and exports) must be continually kept in balance to maintain a system frequency of 60 hertz.

113 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), https://eqrreportviewer.ferc.gov.

Figure 2-6: Market Supply Curve for NYISO (Illustrative)



Source: Hitachi Energy, Velocity Suite[114]

This is typically done by automatic generation control (AGC) to change the generation dispatch as needed.

In general, dispatch occurs based on the cost of generation from given resources, with the lowest-cost resources dispatched first and the higher-cost resources dispatched last. The chart above is a depiction of the market supply curve for the New York Independent System Operator (NYISO). This is also commonly called the supply stack. In it, all the generating units 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 in terms of dollars per MWh. The cheapest units to run are to the left and the most expensive to the right.

Dispatch in New York, for example, first calls upon wind generating units, followed successively by hydroelectric, nuclear and coal-, gas- and oil-fired generating units. This assumes that the generating units 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 generator output and meet reliability needs.

In addition to these considerations, transmission flows must be monitored to ensure that the grid operates 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

114 Derived from Hitachi Energy, Velocity Suite, *Supply Curve Analyst, Form EIA 860, NERC Electric Supply and Demand database, FERC Form 1, FERC Form 714, ISO Load Data, Hitachi Energy Primary Research, et al* (February 2023).

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.[115]

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 to output are designed to maintain system frequency at 60 hertz. Failure to maintain a 60-hertz frequency can result in systemic failure of an electric grid.

Operating reserves are needed to restore load and generation balance when a supply resource trips offline. 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, non-spinning reserves and supplemental reserves.

Spinning reserves are provided by generators that are online (synchronized to the system frequency) with some unloaded (spare) capacity and capable of increasing its electricity output within a specified period, such as 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.

Non-spinning reserves are provided by generating units that are not necessarily synchronized to the power grid but can be brought online within a specified amount of time, such as 10 minutes. Non-spinning reserve can also be provided by demand-side resources.

Supplemental reserves are provided by generating units that can be made available within a specified amount of time, such as 30 minutes and are not necessarily synchronized with the system frequency.

Blackstart generating units have the ability to go from a shutdown condition to an operating conditi on and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators predominately have this capability. These are the first facilities to be started up in the event of a system failure 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 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 most important factor affecting the level 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

115 For additional information on the definitions of ancillary services, NERC, *Glossary of Terms Used in NERC Reliability Standards*, (March 2022), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

with wind availability and speed, which affects cost of wholesale power. Solar generation declines with cloud cover, which not only decreases available generation but can increase demand as behind-the-meter solar, such as residential and commercial installations, decrease their supply to retail users.

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 hydroelectric 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, increase reliability and lower prices.

Temperature can also affect the output of other power plants and capacity of transmission lines. 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 capability.

Traditional Electricity Systems

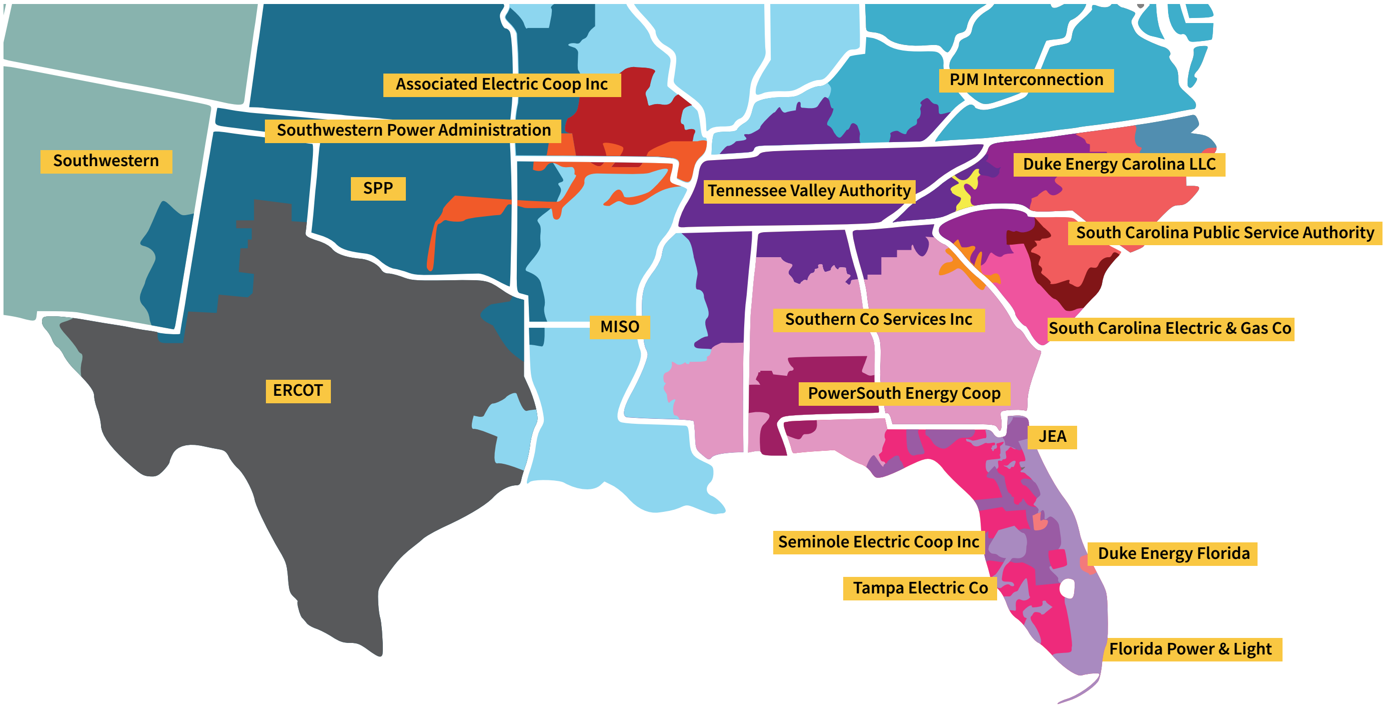
Traditional wholesale electricity markets exist primarily in the Southeast and the West outside of California, where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers. Utilities in these markets are frequently vertically integrated – 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 (BPA), the Tennessee Valley Authority and the Western Area Power Administration. Wholesale physical power trading typically occurs through bilateral transactions. In addition to the responsibilities listed in the overview to this section, a utility in a traditional region has the following responsibilities:

- Generating or obtaining the power needed to serve customers (this varies by state)
- Dispatching resources based on some cost minimizing algorithm
- Ensuring the reliability of the transmission grid

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 the Southeastern Electric Reliability Council (SERC) NERC region. Major hubs include Into Southern and the Tennessee Valley Authority (TVA). The Southeast region's hourly peak demand is greater than 203 GW.[116] While traditional bilateral trading continues in the Southeast, some utilities in the region have created a trading platform, the Southeast Energy Exchange Market (SEEM), discussed further below. Southern Company also conducts an auction for some of its available generation, also discussed further below.

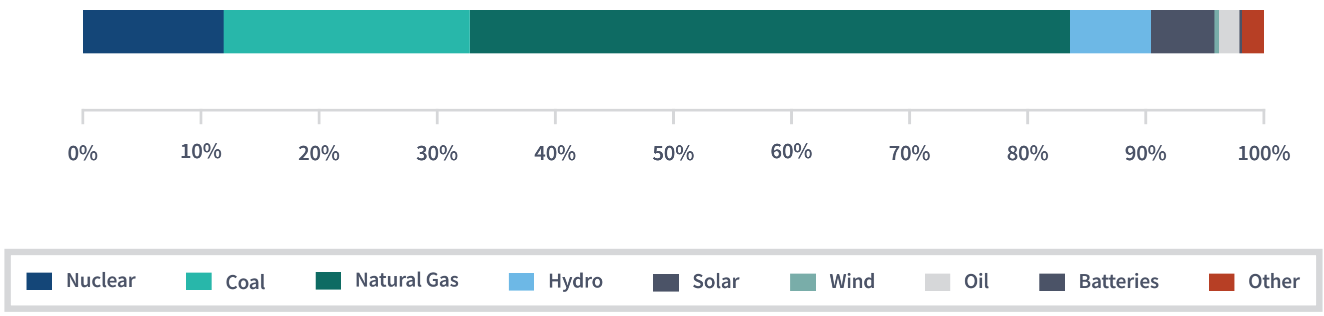
Figure 2-7: Southeast Electric Region



Source: Hitachi Energy, Velocity Suite

116 The hourly peak demand observed between 2000 and 2020. Based on FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report. Derived from the Balancing Authority Areas within the SERC NERC region, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-8: Southeast Electric Region Capacity Mix



Source: EIA Form 860-M[117]

Supply Resources

The total generating capacity in the Southeast Electric Region is over 256 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric and nuclear capacity are also substantial resources in the region.

The Southeast generates most of its electricity from coal, nuclear, and natural gas-fired plants, as shown in the bar chart above.

The TVA sub-region has a majority of its capacity and output from coal and nuclear, while the Virginia-Carolina (VACAR) sub-region has the highest utilization of nuclear generation in the Southeast.

TRADING AND MARKET FEATURES

Physical sales in the Southeast are done bilaterally and long-term energy transactions are particularly prominent, compared to short-term transactions. Many long-term agreements involve full-requirements contracts or long-term power purchase agreements. For example, Southern Company's short-term transactions account for around 30 percent of its total wholesale energy sales in 2021.[118]

Short-term energy is traded among various entities, including investor-owned utilities, municipal utilities, public utility districts, independent power producers, and marketers. Some of the largest sellers of short-term power include Southern Company, North Carolina Municipal Power Agency, Cargill, and Exelon.

Industry-referenced trading points for short-term bilateral transactions in the Southeast include the following locations: Into Southern, TVA, VACAR, and Florida. Volumes for short-term transactions can be low, particularly under normal weather conditions. Overall demand for short-term transactions tends to rise during periods of system stress, for example summer heat waves or winter cold snaps.

The Southeast has relatively low volumes of short-term trades compared to the Western regions. Thus, there is limited data on that price index publishers have on which to base their price reporting. Given the bilateral nature of wholesale power transactions in the Southeast, and a relatively small market for short-term transactions, interest in financial power products in the Southeast is weak.

117 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

118 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), https://eqrreportviewer.ferc.gov.

SOUTHEAST ENERGY EXCHANGE MARKET

The Southeast Energy Exchange Market (SEEM) launched on November 9, 2022. However, on July 14, 2023, the U.S. Court of Appeals for the D.C. Circuited remanded to FERC orders addressing the Seem. Consequently, the SEEM proposal is now pending before the Commission once again.

SOUTHERN COMPANY AUCTION

Southern Company has held daily and hourly auctions for power within its balancing area since April 2009 as a requirement of Southern Company's market-based rate tariff. This BAA encompasses the service territories of Southern Company utilities: Georgia Power, Alabama Power, Mississippi Power, and Gulf Power. The products included in the auction are day-ahead power and real-time power.

According to the auction rules, Southern Company must offer all of its available uncommitted thermal generation capacity into the auction, after regulation and contingency reserves are met. The auction is intended to mitigate the potential ability of Southern Company to exercise market power within its balancing authority area and certain adjacent balancing authority areas. In February 2017, Southern Company revised its market-based rate tariff to cap all market-based sales of less than one year outside of the auction at a cost-based tariff rate.[119]

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. Further, several entities buy and sell electricity in a regional, short-term markets run by CAISO, called the Western Energy Imbalance Market (WEIM), and the SPP-run Western Energy Imbalance Service (WEIS). CAISO and SPP are discussed further in the RTO and ISO Markets section. The West includes the Western Power Pool (WPP), the Rocky Mountain Power Area, and the Arizona, New Mexico, Southern Nevada Power Area within the Western Electricity Coordinating Council (WECC), a regional entity. These areas contain over 30 balancing authority areas responsible for dispatching generation, procuring power, operating the transmission grid reliably, and maintaining adequate reserves.[120]

NORTHWEST ELECTRIC REGION

The Northwest Electric Region is composed of the Northwest Power Pool (NWPP) NERC region in the northwestern section of the Western Electric Coordinating Council (WECC) NERC region. The hourly peak demand is approximately 49 GW[121]

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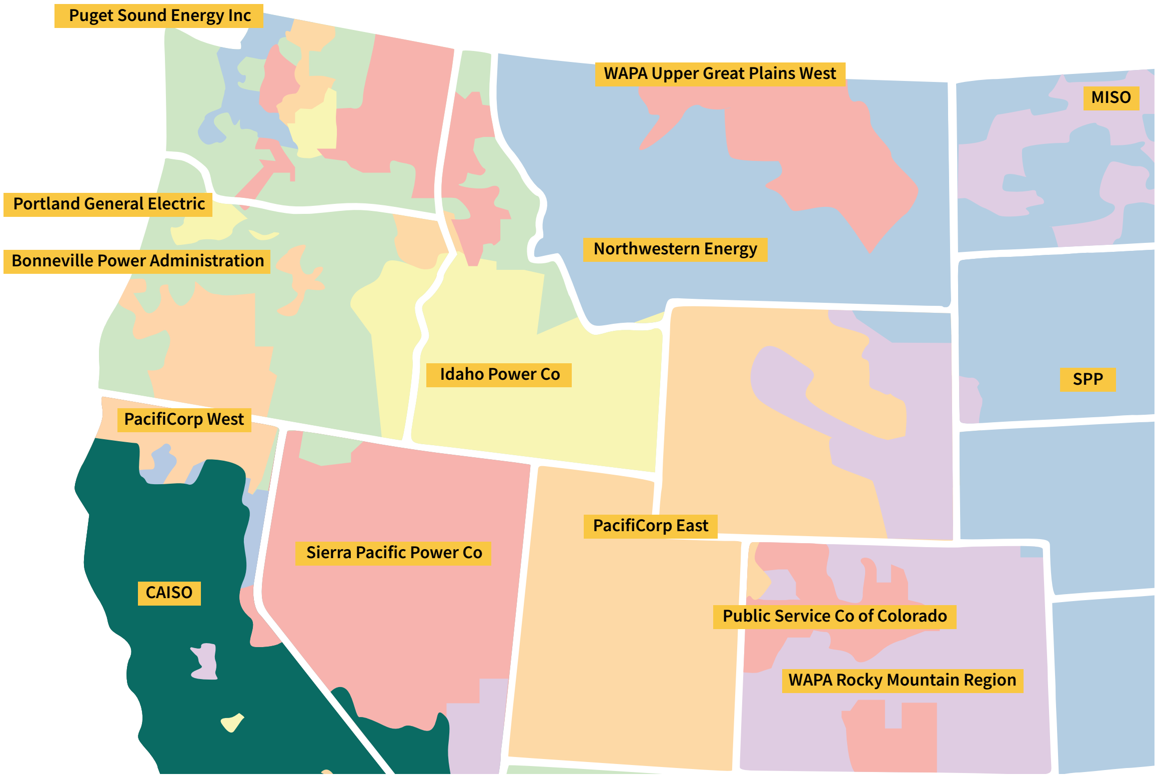
119 *Alabama Power Company*, 158 FERC ¶ 61,131 (2017) (February 2, 2017 Order) (order accepting market-based rate tariff revisions subject to condition).

120 Western Electricity Coordinating Council, *Western Interconnection Balancing Authorities* (accessed November 2022), https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Balancing_Authorities_JAN17.pdf&action=default&DefaultItemOpen=1.

121 The hourly peak demand observed in a given month between 2000 and 2020. Based on FERC Form 714, *Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the NWPP NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-9: Northwest Electric Region



Source: Hitachi Energy, Velocity Suite

Supply Resources

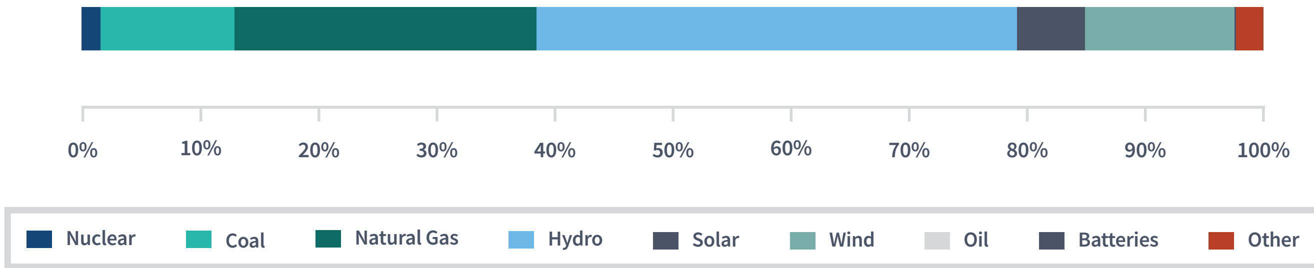
The total capacity in the Northwest Electric Region is approximately 79 GW and is primarily composed of hydroelectric, natural gas, and coal-fired generators, as shown in the bar chart below. Wind generator capacity is also a significant resource for the region.

The Northwest has a unique resource mix, as demonstrated in the bar chart below, with hydroelectric generation capacity comprising approximately 40 percent of the power supply, which is sourced from many dams that are in the Columbia River system. The largest dam, Grand Coulee, can produce up to as much power as six nuclear plants. Due to the large amount of hydroelectric generation, the Northwest typically has low-cost power during the spring and early summer. During these periods, the region exports power to neighboring regions, especially California, where power prices are typically higher.

The amount of hydroelectric power 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 levels of hydroelectric power generation output are influenced by decisions to release water locally and upstream to generate power, as well as local water-use decisions that are independent of the economics of the power markets, based on recreation, irrigation, and wildlife considerations, for example. The peak hydroelectric power generation period begins in the spring, when the snow melts, and may last into early summer. When less water is available, the Northwest may rely more on its coal and natural gas generation, and occasionally import power from neighboring regions, including Canada, when loads are high.

Figure 2-10: Northwest Electric Region Capacity Mix

Source: EIA Form 860-M



Trading and Market Features

The water forecast affects the forward market for electricity in the Northwest. Similarly, the daily water flow conditions influence the prices in the daily physical market. When there is an abundance of hydroelectric generation, the Northwest will export as much as possible on the transmission lines leading into California and elsewhere in the West. Sometimes in off-peak hours, more electricity is available than can move through transmission lines or be used locally, so electric prices become negative.

The largest seller of wholesale power in the region is the BPA, a federal agency that markets the output from federally owned hydroelectric facilities, as well as a non-federal nuclear plant and several other smaller non-federal power plants. BPA meets approximately one-third of the firm energy supply in its service territory and owns 75 percent of the region's high-voltage transmission.[122] BPA gives preference to municipal and other publicly owned electric systems in allocating and pricing its generation output.[123]

Two Canadian BAAs, Alberta Electric System Operator and British Columbia Hydro, are also substantial suppliers of energy to the United States via the Northwest Electric Region. These Canadian BAAs often import power to, and export power from, the United States, depending on market conditions. The Canadian BAAs generally import power from the United States when prices are low in order to save water in their hydroelectric reservoirs. The water is later released to generate and sell hydroelectric power during higher-priced periods[124]

The Northwest region trading points for bilateral transactions include Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB), and Mona (Utah). Of these, Mid-C is the most actively traded location.

SOUTHWEST ELECTRIC REGION

The Southwest electric market encompasses Arizona, New Mexico, and Southern Nevada in the WECC NERC region. The hourly peak demand is approximately 25 GW.[125]

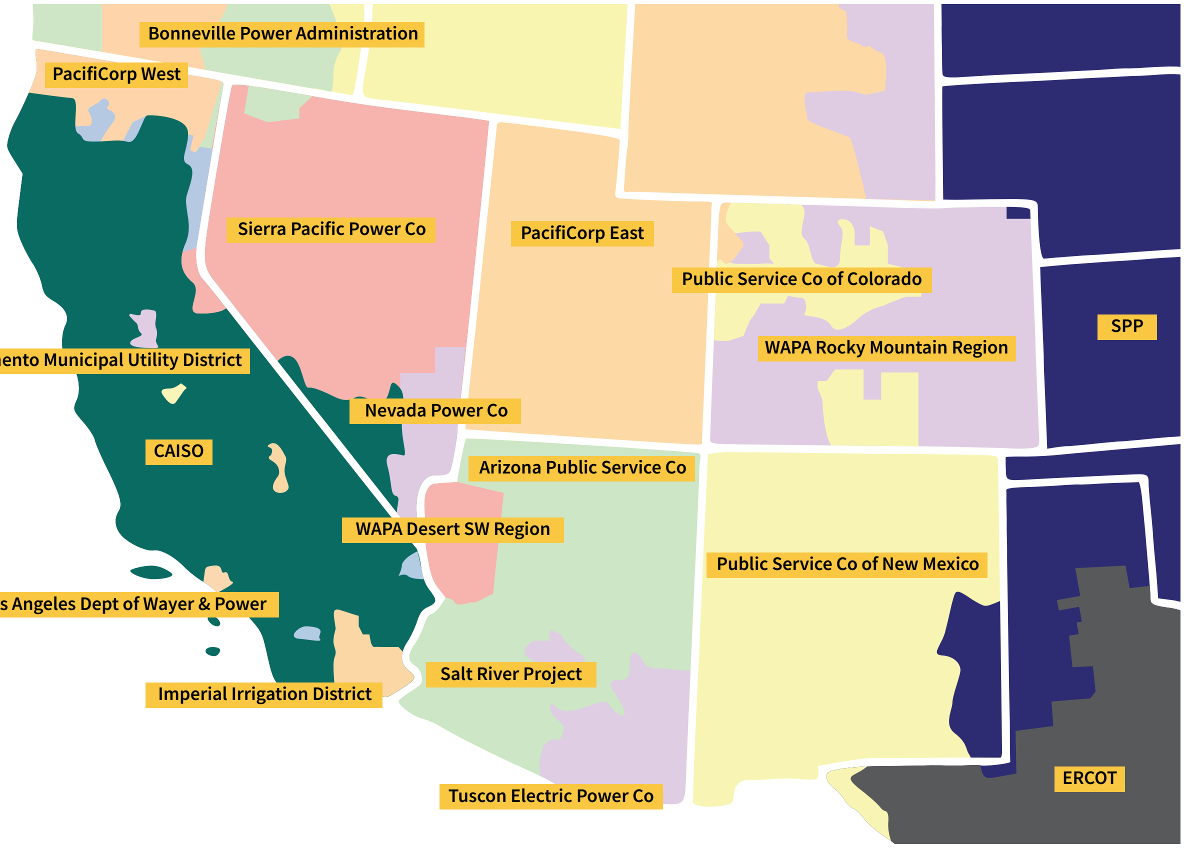
122 Bonneville Power Administration, *BPA Overview,* 45, https://energy.gov/sites/prod/files/2016/01/f28/0911review_ikakoula.pdf.

123 Bonneville Project Act, 16 U.S.C. §§ 832-832m (2000).

124 National Energy Board, *Market Snapshot: Which states trade electricity with British Columbia?* (September 2022) https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/; National Energy Board, *Market Snapshot: Why Canada is one of the world's largest electricity consumers* (August 2022), https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/

125 The hourly peak demand observed between 2000 and 2020. Based on *FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the AZ/NM/SNV NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-11: Southwest Electric Region



Source: Hitachi Energy, Velocity Suite

Supply Resources

The total capacity in the Southwest Electric Region is over 40 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric, wind, solar, and nuclear capacity account for the majority of the remaining capacity, as shown in the bar chart below.

The majority of generation in the Southwest is produced from natural gas and coal, as demonstrated in the bar chart above. 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,[126] which has owners in California and the Southwest.[127] The Southwest is also characterized by large amounts of solar capacity, as this region has the highest solar potential in the nation.[128]

Trading and Market Features

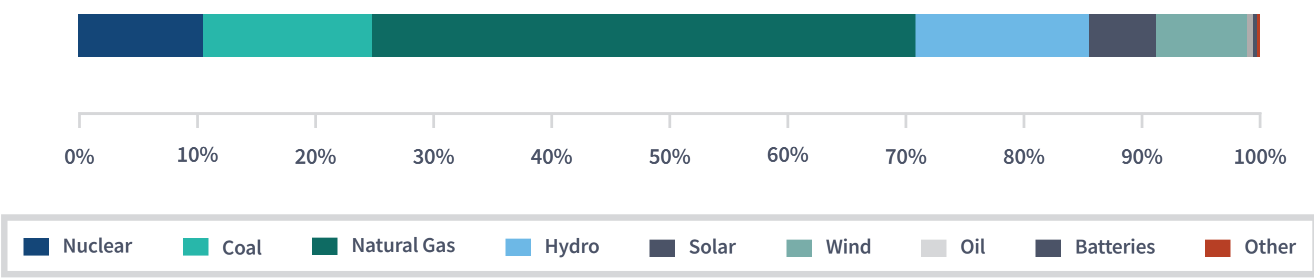
The Southwest region is summer-peaking and experiences peak loads coincident with air conditioning demand. The daily high temperature averages above 100 degrees from June through mid-September in Phoenix.

126 Derived from EIA, *Form EIA-860, 3-1-Generator_Y2021 Report*, (2021), https://www.eia.gov/electricity/data/eia860/.

127 Plant Operating License, Palo Verde, Unit 1, Current Facility Operating License NpF-41, Tech Specs, Revised 08/18/2022, https://www.nrc.gov/info-finder/reactors/palo1.html.

128 Western Electricity Coordinating Council, *State of the Interconnection*, at 9 (September 2017), https://www.wecc.biz/epubs/StateOfTheInterconnection/.

Figure 2-12: Southwest Electric Region Capacity Mix



Source: EIA Form 860-M[129]

However, power prices tend to be the highest when there is also hot weather in Southern California, creating competition for the region's generation resources. The Southwest trading points include Palo Verde, Four Corners, and West Wing. Of these, Palo Verde is the most actively traded location.

RTO and ISO Markets

Two-thirds of the population of the United States is served by electricity markets run by regional RTOs/ISOs. A key distinction between RTO/ISO markets and vertically integrated utilities, municipal utilities and co-ops is that RTO/ISO markets deliver electricity through competitive market mechanisms coordinated by a non-profit entity over a large geographic footprint. Further, RTOs/ISOs do not own or conduct maintenance on the transmission or other resources involved in providing electric service.

Currently, seven RTO/ISOs operate in the United States, listed below in order of the size of their all-time peak load.[130] FERC regulates all RTOs/ISOs except ERCOT. In addition to operating RTOs/ISOs, SPP and CAISO also operate regional short-term or imbalance energy markets, which, while not RTOs/ISOs, provide markets for real-time energy sales and purchases. SPP operates the WEIS and CAISO runs the WEIM, which are discussed at the end of the SPP and CAISO sections below.

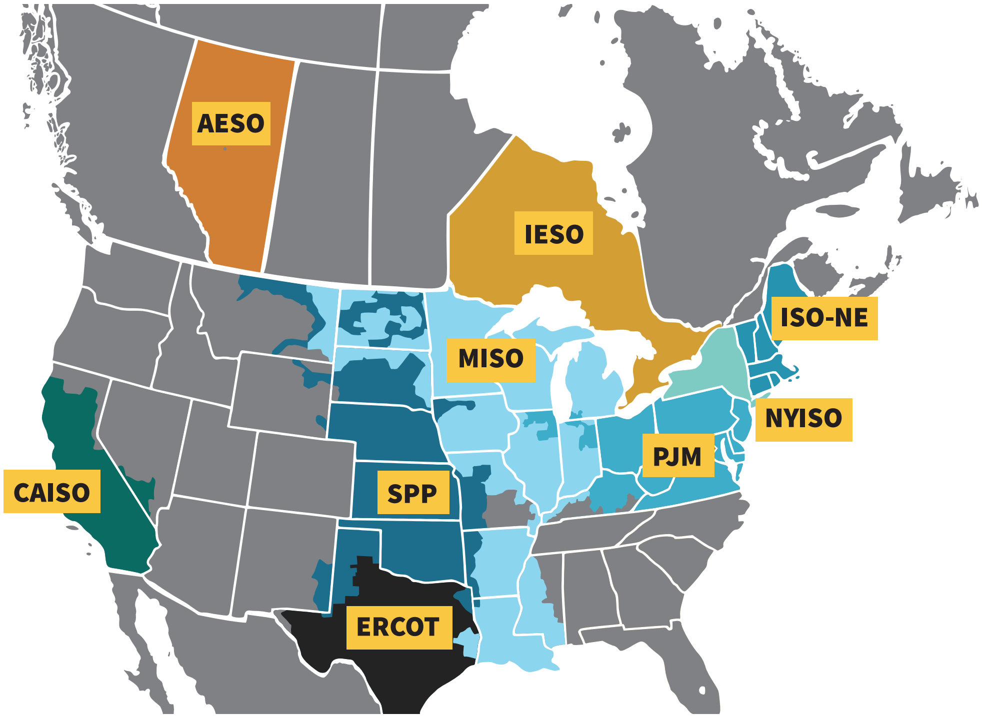
- PJM, 165 GW (summer of 2006)
- MISO, 127 GW (summer of 2011)
- ERCOT, 80 GW (summer of 2022)
- SPP, 53 GW (summer of 2022)
- CAISO, 52 GW (summer of 2022)
- NYISO, 34 GW (summer of 2013)
- ISO-NE, 28 GW (summer of 2006)

Unlike traditional electricity systems, RTOs/ISOs also operate competitive, nondiscriminatory electricity markets, which allow resource owners to offer resources and load-serving entities to submit bids for generation. These markets are the primary mechanism for dispatching resources, managing transmission congestion and pricing electricity. RTOs/ISOs work in conjunction with the resources and transmission-owning resources that participate in the RTO/ISO to maintain reliability. RTOs/ISOs also coordinate the maintenance of generation and transmission systems and oversee a transmission planning process to identify needed upgrades in both the near- and long-term.

129 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), https://www.eia.gov/electricity/data/eia860m/.

130 For source information on the peak load statistics for PJM Interconnection, Midcontinent ISO, Southwest Power Pool, California ISO, New York ISO, and New England ISO, see the individual region's description later in this chapter. For ERCOT, see *ERCOT, Fact Sheet*, (October 2022), https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf.

Figure 2-13: North American Regional Transmission Organizations and Independent System Operators



Source: Hitachi Energy, Velocity Suite

RTO/ISO FEATURES

All RTOs/ISOs function as non-profit entities that operate markets to dispatch and price electricity across a large, defined footprint. To do this, the RTOs/ISOs perform functions such as operating day-ahead and real-time markets, but also perform an array of functions not directly part of the markets, but essential to allow their efficient performance. For example, RTOs/ISOs manage the flow of payments between market participants. The next section discusses markets operated by RTOs/ISOs. The remainder of this section discusses key RTO/ISO support features or functions.

Governance

RTOs/ISOs, resource owners and operators, investor-owned, public and cooperative utilities, marketers and financial entities participate in the RTO/ISO under a governance structure and rules determined through RTO/ISO-run processes.[131] RTO/ISO governance typically involves a board of directors and stakeholder committees, which, among other things, review rule revisions. Rules underlying RTO/ISO functions are included in the RTO's/ISO's tariff and are subject to FERC's approval. Details on rule implementation can be found in RTO's/ISO's Business Practice Manuals.

Financial Policies

Financial settlement is the process through which payments due from customers, and to generators, are calculated. Such settlements are based upon day-ahead schedules, real-time metering, interchange schedules, internal energy schedules, ancillary service obligations, transmission reservations, energy prices, Financial Transmission Rights (FTR) positions, and capacity positions. Each market participant's invoice of charges and credits includes the costs of services used to serve load and the costs for operating the RTO/ISO.

131 Order No. 2000, *Regional Transmission Organizations*, 89¶61,285, (December 20, 1999).

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/ISO. All payments are made electronically.

While RTO/ISO energy and ancillary service markets operate to price electricity at a level that compensates resources for their energy supply and meet other requirements of their tariffs, instances do occur where additional cost recovery is needed – this is commonly known as uplift. The need for uplift may arise, for example, when unplanned transmission and generation outages occur, resulting in actual operations differing from the assumptions included in the market models underlying the energy and ancillary service markets.[132]

Credit Policies

RTOs/ISOs settle the many financial charges that are paid by, or to, market participants. As RTOs/ISOs are non-profit entities with no financial interest in the markets they operate, any financial shortfall or over-collection goes to the various market participants. To protect the RTO/ISO and its market participants, each RTO/ISO has tariff provisions and other policies to ensure that market participants have the ability to pay, known as credit policies.[133] Defaults by market participants in RTOs/ISOs are rare and the costs have generally been spread across the market. Credit policies contain provisions related to credit evaluations, credit limits, forms of collateral, and the consequences of violations or defaults.

Transmission Planning

RTO/ISOs coordinate transmission planning for their footprint as required under Order 1000, a comprehensive transmission rule issued by FERC in 2011.[134] Each of the RTO/ISOs has system-wide or regional planning processes that identify transmission system additions and improvements that are needed to keep electricity flowing. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. The RTO/ISO transmission planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems. RTO/ISOs then develop transmission plans in collaboration with transmission owners to resolve potential problems that could otherwise lead to overloads and blackouts. This process culminates in one recommended plan for the entire RTO/ISO footprint.

RTO/ISO MARKETS AND ASSOCIATED FUNCTIONS

RTOs/ISOs operate several markets and functions that address the physical supply of electricity and its pricing – energy and capacity markets. To physically provide the supply of electricity at all times in all places, RTOs/ISOs operate energy markets that LSEs use to procure energy and ancillary services. Some RTOs/ISOs also operate capacity markets, which, along with underlying resource adequacy rules, ensure sufficient capacity is available. RTOs/ISOs also operate financial markets associated with the energy markets – financial transmission rights and virtual transactions.

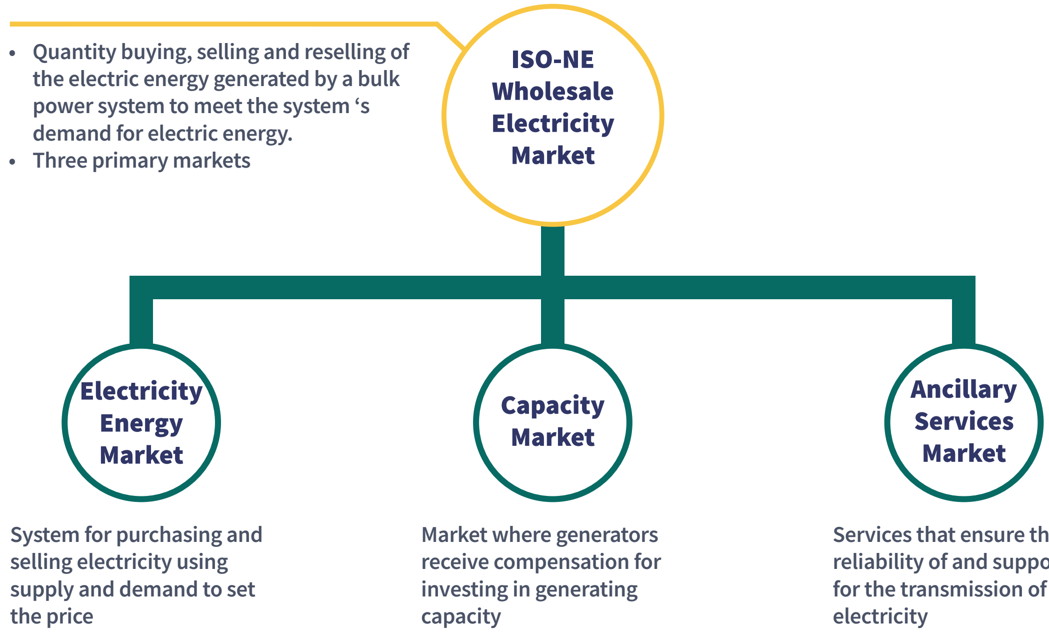
RTOs/ISOs must define rules and operate programs needed to ensure efficient market operations. The operations of the markets are discussed further below. Underlying these market operations are an extensive list of detailed rules and functions. For example, these rules detail what types of resources can participate, at limits on what prices resources can offer, and the operation of an independent market monitoring program:

132 Order No. 844, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 163¶61,041, (April 19, 2018).

133 Order No. 741, *Credit Reforms in Organized Wholesale Electric Markets*, 133¶61,060, (October 21, 2010).

134 Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 135¶61,051, (July 21, 2011).

Figure 2-14: ISO-NE Wholesale Electricity Market



Source: ISO-NE

Resource Participation In addition to generation, demand response resources (DR), DER, energy efficiency and batteries may participate in RTO/ISO markets.[135]

Offer Caps Each RTO/ISO caps a resource's supply offer at $1,000. If a resource's costs exceed $1,000, they may request authority to offer at a higher price that reflects their verified costs. Offers up to $2,000 may be used by the RTO/ISO to set the locational marginal price.[136]

Market Monitoring Each RTO/ISO must have independent market monitors which oversee various aspects of the RTO's/ISO's markets and performance, such as market power mitigation, assessment and referral of market manipulation and assessing and reporting on the competitiveness of market operations.[137]

Energy Markets

All RTOs/ISOs have day-ahead and real-time markets. The day-ahead market schedules electricity production, ancillary services commitments and consumption before the operating day, whereas the real-time market reconciles any differences between the schedule in the day-ahead market and the real-time conditions. Both the day-ahead and real-time markets reflect reliability criteria and infrastructure conditions, such as transmission topology and limitations, resource outages, and resource operating limits.

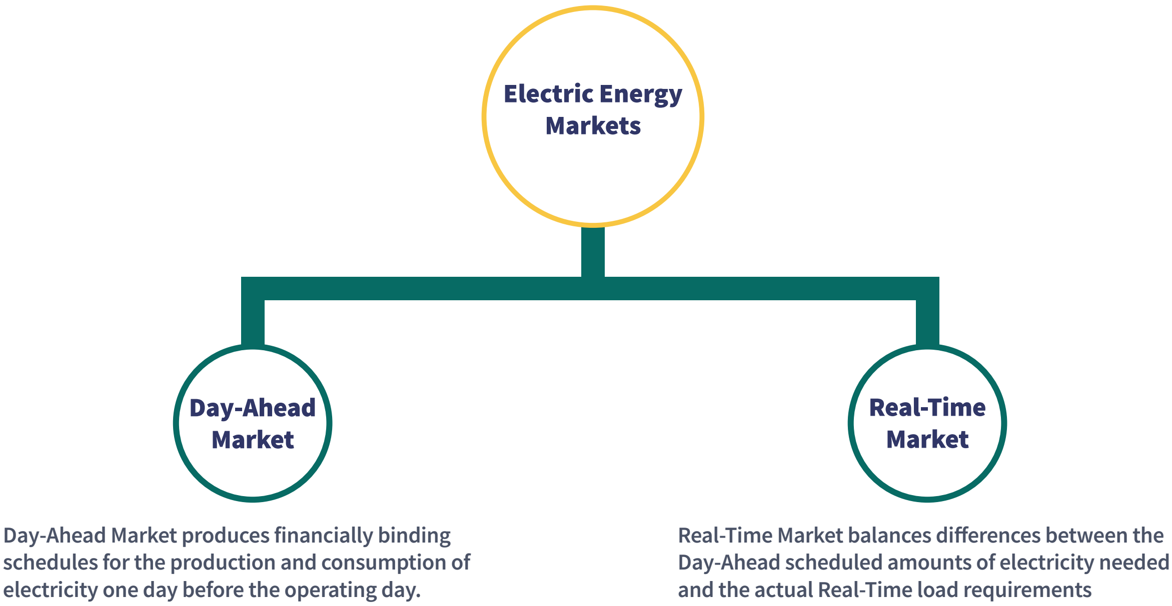
Energy markets operate to match the supply options offered by resource oprators to the demand bid in by LSEs and RTO/ISO demand forecasts. The market models select the most economic supply offers available,

135 Order No. 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172¶61,247; Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162¶61,127 (2018); Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 134¶61,187, (March 15, 2011).

136 Order No. 831, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157¶61,115, (November 17, 2016).

137 Order No. 719, *Wholesale Competition in Regions with Organized Electric Markets*, 125¶61,071.

Figure 2-15: ISO-NE Wholesale Electricity Market



Source: ISO-NE

recognizing physical resource and transmission limitation. The overall market price for electricity is determined by the highest offer accepted. However, transmission limitations may require the market to adjust the offers selected, which can change the price for different locations in the RTO/ISO – the locational marginal price (LMP). The RTO/ISO markets calculate the 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 resources that are being dispatched and the limitations of the transmission system. LMP has three elements: an energy charge, a congestion charge, and a charge for transmission system energy losses.

If there are no transmission constraints, known as transmission congestion, LMPs will not vary significantly across the RTO/ISO footprint. However, when transmission congestion occurs, LMPs will vary across the footprint because operators are not able to dispatch the least-cost generators across the entire region and some more expensive generation must be dispatched to meet demand in the constrained area.

When transmission is constrained, 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 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. Thus, 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 process is known as security-constrained economic dispatch.

This redispatch could be implemented by using non-market 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.

Day-Ahead Energy Markets

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 with sufficient lead time to procure fuel or bring up resources with longer start times. The day-ahead bids and offers are based on a forecast of loads and are consistent with resources' business strategies.

In day-ahead markets, offers of supply and demand bids are compiled hours ahead of the beginning of the operating day. The RTO/ISO then runs a computerized market model that matches demand and supply throughout the market footprint for each hour of the day. Additionally, the model must account for changing system capabilities that occur, based on weather and equipment outages, transmission and resource capabilities, and the rules and procedures that are used to ensure system reliability.[138] The market rules dictate that generators submit supply offers and that loads submit demand bids to the RTO/ISO by a deadline that is typically in the morning of the day-ahead scheduling. Typically, 95 percent of all load is scheduled in the day-ahead market and the rest is scheduled in real-time. Generation and demand bids that are scheduled in the day-ahead market are settled at the day-ahead market prices.

Inputs into setting a day-ahead market schedule include:

- Generators' offers to sell electricity for each hour
- Load-serving entities' bids to buy electricity for each hour
- 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 outages, the physical characteristics of generating resources including minimum and maximum output levels and minimum run time, and the status of interconnections to external markets.

Real-Time Energy Markets

The real-time market is used to balance the differences between the day-ahead scheduled amounts of electricity cleared in the day-ahead market and the actual real-time load and supply. The real-time market is run in five-minute intervals and clears a much smaller volume of energy and ancillary services than the day-ahead market (some RTOs/ISOs also run hour-ahead and 15 minutes- ahead of the operating interval). The real-time market also provides supply resources additional opportunities for offering energy into the market. When the real-time generation and load are different from the day-ahead cleared amount, the difference is settled at the real-time price.

Real-time market prices are significantly more volatile than day-ahead market prices. This stems from demand uncertainty, transmission and generator forced outages, and other unforeseen events. Since 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 can lead to both positive and negative price movements.

Ancillary Services

RTOs/ISOs procure ancillary services, which are described in the Electricity Supply and Delivery Section, through the day-ahead and real-time market dispatch. RTOs/ISOs primarily procure ancillary service through their market mechanisms, although they compensate blackstart and voltage service based on the cost of providing the service (cost-of-service). Changes in the

138 In evaluating which generators provide the power to meet hourly load, the market model assesses whether the power flows can travel without exceeding the physical capability of any transmission path. If the model shows such a violation of transmission capability, the combination of assigned generators will be changed in a process known as redispatch.

resources providing supply have necessitated changes in ancillary service procurement and compensation. For example, the advent of faster-ramping resources led to changes in compensation for frequency regulation.[139]

While not an ancillary service, ramping capacity is a service for which some RTOs/ISOs have developed products. The growth of renewable generation has increased the need for generation that can increase its production rapidly to offset swings in generation or load.

Shortage Pricing

RTO/ISO markets dispatch energy and ancillary services to meet demand and reserve requirements. However, the markets may find that not enough supply is available. If the RTOs/ISOs cannot procure sufficient generation to meet demand and reserve requirements in the real-time market, they trigger shortage pricing[140] to send price signals to incentivize resources to increase the supply offered. Shortage events can be caused by unexpectedly high electric loads, supply disruptions, or both.

The common method that RTO/ISOs employ to implement shortage pricing is through the use of an operating reserve demand curve. The demand curve specifies price levels for the degree of the shortages.[141] The price of the reserves, reflecting shortage as determined by the demand curves, sets the price for ancillary services and energy.

Market Power Mitigation

RTO/ISO energy and capacity markets are typically competitive, allowing the markets to set the price. However, situations may occur that result in certain resources being essential to serving demand, thus enabling those resources to increase prices in a specific area – in other words, the ability to exercise market power. Typically, this occurs when a transmission constraint limits the amount of electricity that can flow into an area, rendering generation located inside that area essential to serving that local load. RTOs/ISOs have mechanisms for determining whether such market power may occur, and if appropriate, to mitigate the price at which affected resources may offer their supply. RTO/ISO market power mitigation typically examines whether a resource has the potential to exert market power; whether they actually offer in a way that could be an exertion of market power (conduct test); and whether any potential exertion of market power actually affected the market price (impact test).

RTO/ISO Capacity Markets and Resource Adequacy

RTO/ISOs, like other electric systems, are required to maintain adequate generation and demand-resource capacity to meet load and reliability requirements. LSEs have typically satisfied their reserve obligations with owned generation or bilateral contracts with other suppliers. In general, LSEs are required to procure sufficient capacity to meet their load. Some RTOs/ISOs also have mechanisms through which LSEs can obtain capacity commitments, such as capacity auctions and capacity payments.

Most RTOs/ISOs run a capacity market that allows LSEs to satisfy their reserve obligation. The 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 capacity markets are intended to provide more certainty for investment in new capacity resources while including an opportunity for all resources to recover their fixed costs over time.

Other ISOs/RTOs, such as SPP and CAISO, rely on resource adequacy programs, in which the RTO/ISO determines the capacity each LSE is required to provide

139 Order No. 755, Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137¶61,064, (October 20, 2011).

140 Order No. 825, *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 155¶61,276 (June 16, 2016).

141 RTO/ISOs apply shortage pricing in the LMP for all intervals in which the operating software indicates that there is insufficient available energy to provide system or localized demand and reserves. *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 81 Fed. Reg. 42,882 (June 30, 2016), FERC Stats. & Regs. ¶ 31,384 (2016).

at different times of the year. These programs require each LSE to show the RTO/ISO that it has procured the required capacity for different times of the year.

Special Provisions for Essential Resource Retirements
Reliability must-run (RMR) units are generating plants that would otherwise retire but that the RTO/ISO has deemed necessary to ensure reliability. They can also be units that have market power due to their location on the grid. RTO/ISOs enter into cost-based contracts with these generating units and allocate the cost of the contract to transmission customers. In return for these payments to the generator, the RTO/ISO 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 reduce the need for RMR units by increasing generation deliverability throughout the RTOs/ISOs.

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.

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

FTRs allow customers to protect against the risk of congestion-driven price increases in the day-ahead market in the RTOs/ISOs. Specifically, FTRs grant their holders the right to day-ahead congestion revenues over specific paths and periods of time. Congestion costs occur as the demand for scheduled power over a transmission path exceeds that path's flow capabilities. This causes the price at the source to decline or the price at the 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 price components 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. Purchases take place in the RTO-administered auctions or in a secondary market. Allocations stem from a related product, the auction revenue rights (ARR). ARRs provide the firm transmission capacity holders, transmission owners or LSEs with the rights to revenue from the FTR auctions. In general, ARRs are allocated based on historical load served and, in some RTO/ISOs, ARRs can be converted to FTRs. If ARRs are converted to FTRs, the holder receives revenue from congestion. If ARRs are kept as such, the holder receives 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 semiannual) auctions of shorter-term FTRs provided by existing FTR holders or made available by the RTO/ISO. 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 historically only a small number of transactions have been reported.

The quantity of FTRs made available by the RTO/ISO 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/ISO 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.

FTRs can also be purchased by a creditworthy entity seeking their financial attributes 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 Chapter 5, Trading and Capital 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.

All six FERC-jurisdictional RTOs/ISOs trade FTRs or FTR-equivalent products. However, the types and qualities of the rights traded across the organized markets vary, as do 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 a historical generation-rich location and a sink that is in a historical 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 a historical load-heavy location and a sink in a historical generation-rich location. As a result, auction clearing prices for counterflow FTRs are negative; bidders are paid to take the counterflow FTR position.

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 RTO/ISOs offer on-peak and off-peak products.

Allocated Rights: The RTO/ISOs 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. CAISO allocates congestion revenue rights (CRR), which provide their holders a stream of payments based on the actual congestion occurring on associated paths. NYISO allocates both auction-based and congestion-based rights through multiple instruments. PJM and MISO allow ARR holders to convert all 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 CAISO's allocation is already in a form equivalent to an FTR. Converted ARRs are fully fungible in PJM, 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 vary by market and by auction, with some products made available only at specific auctions.

Secondary Markets: With the exception of 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.

Virtual Transactions

Virtual bids and offers (collectively, virtuals) are a form of financial trading used by market participants to hedge physical positions and by speculative traders to profit from differences between day-ahead and real-time prices. The quantity of MW purchased or sold in the day-ahead market is 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. A virtual trader pays (or is paid) the day-ahead price while being paid (or paying) the real-time price.

Although a trader does not have to deliver power, the transaction is not strictly financial as virtual transactions can set LMPs; the price is applied to physical as well as financial transactions. Virtual transactions can also affect the resource selection in the day-ahead market.

For each hour in the day-ahead market, virtual trades are added to the demand – day-ahead scheduled load – if virtual demand is greater than virtual supply. This has the effect of raising the price in the day-ahead market and, more importantly, increasing the amount of generation resources procured by the RTO/ISO. Since these generation 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 day-ahead scheduled load, 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/ISOs is intended to mitigate market power and improve the efficiency of serving load.

Figure 2-16: New England Independent System Operator

Source: Hitachi Energy, Velocity Suite

ISO-New England (ISO-NE)

MARKET PROFILE

ISO-NE serves the six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. 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.[142] ISO-NE operates the region's high-voltage transmission network and performs long-term planning for the New England system. ISO-NE operates its master control center in Holyoke, Mass.

Peak Demand

New England's all-time peak demand was 28 GW in summer 2006.[143]

Imports and Exports

ISO-NE is interconnected with the NYISO, TransEnergie (Québec), and the New Brunswick System Operator and imports around 15 percent of its annual energy needs. New England receives imports from Québec and New

142 ISO-New England Inc. Internal Market Monitor, *An Overview of New England's Wholesale Electricity Markets, A Market Primer* (June 5, 2023), https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

143 ISO New England, *Key Grid and Market Stats*, https://www.iso-ne.com/about/key-stats/.

Brunswick in most hours, and power flows in alternate directions between New England and New York, depending on market conditions.

Market Participants

The ISO-NE participants consist of end-users, IOUs, publicly owned utilities, generators, transmission owners, and financial institutions.

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.

NEPOOL is the principal stakeholder organization for the ISO-NE and is authorized to represent its more than 440 members in proceedings before FERC. It was organized in 1971 and its members include all the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users, and a merchant transmission provider.

Transmission Owners

ISO-NE's largest transmission owners include:

- Central Maine Power Company
- Cross Sound Cable Company, LLC
- Emera Maine, Inc.
- Eversource Energy Service Company
- Maine Electric Power Company
- National Grid USA
- NSTAR Electric Company
- The United Illuminating Company
- VT Transco, LLC

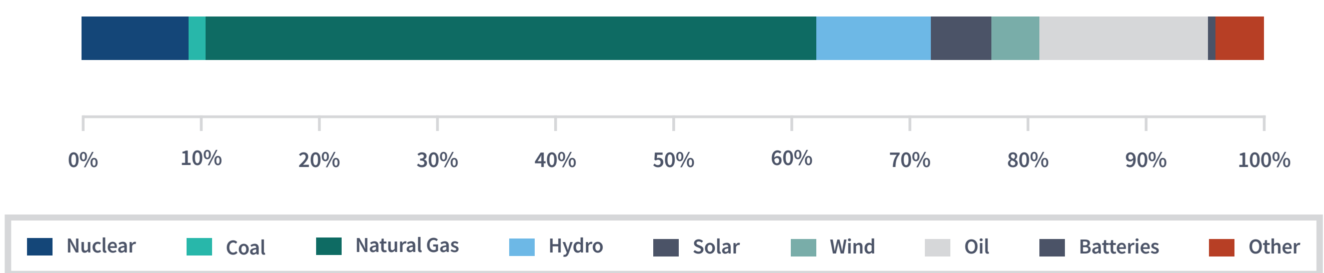
Chronic Constraints

Overall, transmission upgrades have reduced transmission constraints in ISO-NE. Constraints in ISO-NE may occur in regions affected by intermittent resources (notably wind), or by major interconnections with New Brunswick, Hydro-Quebec, and New York.[144]

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 (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. The plans also summarize the region's overall needs, as well as the needs in specific areas, and includes solutions and processes required to ensure the

Figure 2-17: ISO-NE Capacity Mix



Source: EIA Form 860-M[146]

144 ISO-New England Internal Market Monitor, *2021 Annual Markets Report* (May 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf.

145 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), https://www.eia.gov/electricity/data/eia860m/.

reliable and economic performance of the New England power system.

Supply Resources

The total capacity in ISO-NE is over 38 GW and is predominately composed of natural gas-fired, oil-fired, and nuclear generators, as shown in the bar chart below. The region has a substantial proportion of oil-fired generation that is a particularly important resource to address potential power plant fuel shortages in the winter months during periods of local natural gas market stress.

Demand Response

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 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.
- Price Responsive Demand (PRD): In June 2018, ISO New England launched a new PRD structure that fully integrates active demand resources into the regional wholesale electricity marketplace. With PRD, ISO-NE deploys its active demand resources as part of the energy dispatch and reserve-designation process along with generating resources. PRD incorporates demand response into the energy market, the reserves market and the capacity market.[146]

MARKET FEATURES

Energy Markets

ISO-NE operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, ISO-NE uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. ISO-NE procures and sets prices for ancillary services in the real-time and forward reserve markets.

Market Power Mitigation

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

Capacity Markets

ISO-NE's capacity market is termed the Forward Capacity Market (FCM). The FCM includes annual Forward Capacity Auctions (FCA) where 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 new resource entry by affording market participants additional time to plan and make decisions relative to the forward market prices. 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

146 ISO-NE, *Price-responsive demand explained: Q&A with Henry Yoshimura, ISO Director of Demand Resource Strategy* (June 6, 2018), http://isonewswire.com/updates/2018/6/6/price-responsive-demand-explained-qa-with-henry-yoshimura-is.html.

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.

The FCM includes rules known as Pay-for-Performance, which mandate performance-based financial incentives for capacity resources during times of system stress.[147] Under Pay-For-Performance, resource owners are subject to charges or incentive payments, based on performance during shortage conditions. Those resources unable to fulfill their CSOs are penalized and compensate the overperforming resources that relieve the capacity shortfall. ISO-NE additionally requires the owners of capacity resources to offer into the day-ahead and real-time energy markets.

Special Provisions for Essential Resource Retirements

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, such as 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 pairs 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, ARRs represent the right to receive revenues from the FTR auctions. ISO-NE allocates ARRs to both LSEs, in relation to historical 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, as generally described in the Virtual Transactions part of the RTO/ISO Features section.

Credit Requirements

ISO-NE's tariff includes credit requirements for participants that assist in mitigating the potential 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 then 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 to the ISO-NE market.

147 ISO-NE's Pay-For-Performance rules became effective June 1, 2018, for Forward Capacity Auction 9. ISO-NE, Internal Market Monitor, *2017 Annual Markets Report*, at 138 (2018), https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf.

Figure 2-18: New York Independent System Operator

Source: Hitachi Energy, Velocity Suite

New York Independent System Operator (NYISO)

MARKET PROFILE

The NYISO footprint covers the entire state of New York. 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 known as the New York Power Pool (NYPP). The creation of the NYISO was authorized by FERC in 1998. The formal transfer of the NYPP's responsibilities to the NYISO took place on Dec. 1, 1999. NYISO operates its system from control centers in Rensselaer, NY, and Guilderland, NY.

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. NYISO also serves as the reliability coordinator for its footprint.

Peak Demand

NYISO's all-time peak demand was 34 GW in summer 2013.[148]

Imports and Exports

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

Market Participants

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

Membership and Governance

NYISO is governed by an independent 10-member board of directors, ISO management, and the 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 FERC 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.

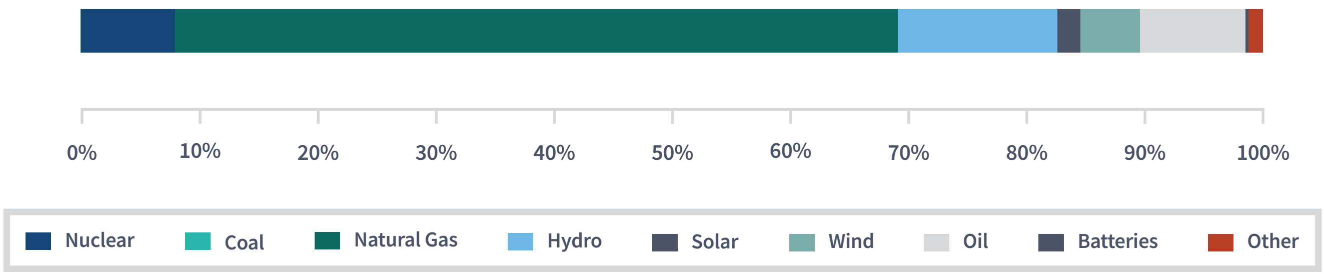
Transmission Owners

NYISO's largest transmission owners include:

- Central Hudson Gas & Electric Corp.
- Consolidated Edison Co. of New York
- Long Island Power Authority (LIPA)

148 New York Independent System Operator, Gold Book, *2022 Load & Capacity Data Report 67* (April 2022), https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/cd2fb218-fd1e-8428-7f19-df3e0cf4df3e.pdf.

Figure 2-19: NYISO Capacity Mix



Source: EIA Form 860-M[150]

- 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 towards these two large markets, frequently requiring transmission facilities to operate near their 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 as part of its Comprehensive System Planning Process. This work evaluates the adequacy and security of the bulk power system in New York over a ten-year study period. Reliability needs are addressed through the development of a reliability plan. Planning focuses on congestion on the bulk power system and possible projects to alleviate the congestion.

A component of NYISO's transmission planning includes evaluating proposals to meet transmission needs driven by public policy requirements identified by the New York Public Service Commission.

Supply Resources

The total capacity in NYISO is over 43 GW and is predominately composed of natural gas-fired, hydroelectric, nuclear and oil-fired generators, as shown in the bar chart below. The region's hydroelectric capacity is particularly important and includes the Niagara Falls and St. Lawrence facilities.

Demand Response

NYISO has four demand-response 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 case programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. The participants in these programs are paid by NYISO for reducing energy consumption when asked to do so and reductions are voluntary for EDRP participants.However, SCR participants are required to reduce power usage as part of their agreement and are compensated for this obligation.

149 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

NYISO's DADRP program allows energy users to bid their load reductions into the day-ahead market and offers that are determined to be economic are paid the market clearing price. Under day-ahead demand-response, 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 with the ability to bid their load curtailment capability into either the day-ahead market or real-time market to provide reserves and regulation service. Accepted offers are paid the market clearing price for the supplied reserves or regulation services.

MARKET FEATURES

Energy Markets

NYISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, NYISO uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day. NYISO refers to LMPs as locational-based marginal prices, or LBMPs.

NYISO's real-time market also offers an hour-ahead feature. The hour-ahead market allows buyers and sellers of electricity to balance unexpected increases or decreases of electricity consumption after the day-ahead market closes. Bids and offers are submitted an hour ahead of time and 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.

Ancillary and Other Services

NYISO co-optimizes ancillary services with the energy through its markets. Operating reserves and regulation are typically provided by generators, but NYISO also allows demand-side providers to participate in these markets.

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. RTOs procure or direct the supply of ancillary services to maintain the reliability of the transmission system.

Market Power Mitigation

ISO-NE conducts automatic market power mitigation in its day-ahead and real-time markets. This automated mitigation performs conduct and impact tests and applies mitigation where it deems appropriate. 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. NYISO does not impose mitigation unless the conduct causes or contributes to a material change in prices, or substantially increases guarantee payments to participants.

Generators in New York City are subject to automated market power mitigation procedures because New York City is frequently separated by transmission congestion from other parts of New York. Additionally, 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 cost bids and minimum generation bids, but excluding ancillary services bids, exceed the tariff's thresholds for economic withholding. The protocols also determine whether such bids would cause material price effects or changes in guaranteed payments. If these two tests are met, mitigation is imposed automatically, and the applicable reference level is substituted for the entity's actual bid to determine the clearing price.

Capacity Markets

NYISO's capacity market requires LSEs to procure capacity through installed-capacity (ICAP) auctions, self-supply or bilateral arrangements based on their forecasted peak load plus a margin. New York has capacity requirements for four zones: New York City, Long Island, Lower Hudson Valley, and New York-Rest of State. NYISO conducts auctions for three time periods: the capability period auction (covering six months), the monthly auction and the spot market auction. The resource requirements do not change in the monthly auctions and spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSEs' load forecasts.

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.

Capacity for New York City is subject to offer caps and floors. Offer caps in New York City are based on the projected clearing price for capacity in the spot market.[150] 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.[151]

Special Provisions for Essential Resource Retirements

Generation owners within New York that seek 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 with the generator that includes compensation to support continued operation of the plant until the reliability need is resolved.

Financial Transmission Rights

The NYISO refers to FTRs as Transmission Congestion Contracts (TCCs). A TCC is an instrument that entitles the holder to a payment for the 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. The payment, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the specified FTR transmission path.

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

Credit Requirements

NYISO's tariff includes credit requirements that 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. NYISO must review the entity's request relative to various creditworthiness-related specifications such as investment grade or equivalency rating and payment history.

150 New York Independent System Operator, Inc., NYISO *MST - Market Administration and Control Area Services Tariff (MST) - 23MST Att H - ISO Market Power Mitigation Measures - 23.2 MST Att H Conduct Warranting Mitigation at 625* (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf; New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.2 MST Att H at 705* (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

151 New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.4 MST Att H* at 708 (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

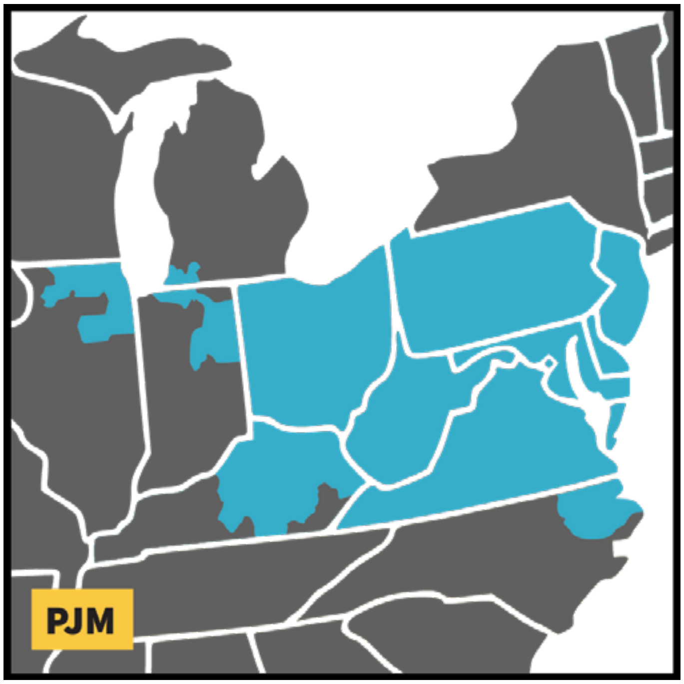
PJM

MARKET PROFILE

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 operates two fully functional dispatch centers at Valley Forge and Milford, Pennsylvania. The control rooms operate simultaneously with parallel operations. PJM operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to the transmission system it manages and performs long-term planning. 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. PJM was designated an RTO in 2001.

Figure 2-20: The PJM Interconnection



Source: Hitachi Energy, Velocity Suite

Peak Demand

PJM's all-time peak demand was 165.6 GW in summer 2006.[152]

Imports and Exports

PJM has interconnections with MISO and the NYISO. PJM also has direct interconnections with TVA, Progress Energy Carolinas and the VACAR, among other systems. PJM market participants import energy from, and export energy to, external regions continuously. PJM is a primarily a net exporter of electricity, but occasionally is a net importer during periods of system stress.

Market Participants

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

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

PJM transmission owners eligible to vote in PJM

152 PJM Interconnection, PJM 2021 *Annual Report, Summer Performance by the Numbers*, https://services.pjm.com/annualreport2021/operations/.

stakeholder proceedings include:

- Appalachian Power Company, AEP Subsidiary[153]
- AMP Transmission, LLC
- Dayton Power & Light Company, AES Subsidiary
- Duke Energy Business Services, LLC[154]
- Duquesne Light Company
- East Kentucky Power Cooperative, Inc.
- Exelon Business Services Company, LLC[155]
- ITC Interconnection LLC
- Linden VFT LLC
- Monongahela Power d/b/a Allegheny Power, First Energy Subsidiary [156]
- Neptune Regional Transmission System, LLC[157]
- PPL Electric Utilities Corporation, d/b/a PPL Utilities[158]
- Public Service Electric and Gas Company
- Rockland Electric Company
- Virginia Electric and Power Company

Chronic Constraints

The most severe constraints occur on 230 kV transmission facilities moving power south from Pennsylvania and New Jersey to Maryland, Delaware, and Virginia. Local congestion also occurs on low-voltage lines near load centers in northern Illinois, New Jersey, eastern Pennsylvania, central and eastern Maryland, northern Virginia, the District of Columbia, and Delaware.

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

The total capacity in PJM is over 219 GW and is predominately comprised of natural gas, coal, and nuclear generators, as shown in the bar chart below. Much of PJM's gas-fired capacity is located near the Marcellus and Utica shale formations. Of note, 40.6 gigawatts of coal-fired capacity are projected to retire in PJM between 2011 and 2026.[159]

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 demand response programs can be grouped into emergency or economic programs. The emergency program compensates end-use customers who reduce their usage during emergency conditions on the PJM system. Participation in the emergency program may be voluntary or mandatory and payments may include energy payments, capacity payments or both.

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

153 Transmission Companies represented: AEP Appalachian Transmission, AEP Energy Partners, AEP Energy, AEP Indiana Michigan Transmission, AEP Kentucky Transmission, AEP Ohio Transmission, AEP West Virginia Transmission, Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power, Ohio Valley Electric, PATH West Virginia Transmission, Transource Energy, Wheeling Power.

154 Transmission Companies represented: Duke Energy Kentucky, Duke Energy Ohio.

155 Transmission Companies represented: Commonwealth Edison, PECO Energy, Baltimore Gas and Electric.

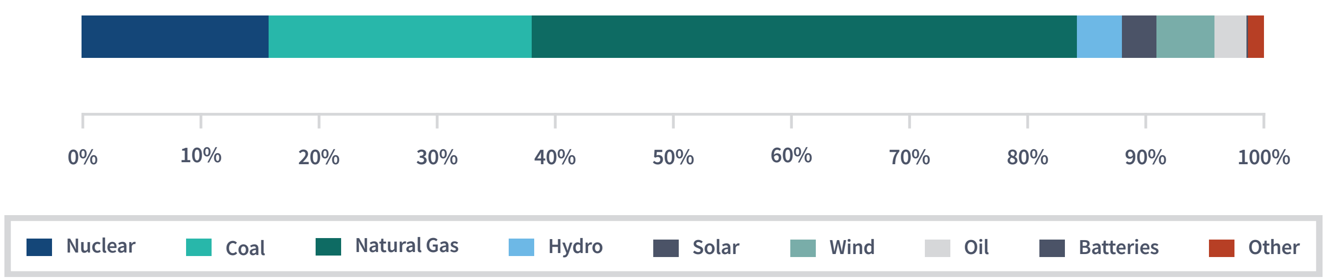
156 Transmission Companies represented: American Transmission Systems, Jersey Central Power & Light, Mid-Atlantic Interstate Transmission, PATH Allegheny Transmission, Potomac Edison, Trans-Allegheny Interstate Line, West Penn Power.

157 Transmission Companies represented: Hudson Transmission Partners.

158 Transmission companies represented: Louisville Gas and Electric, Kentucky Utilities.

159 Monitoring Analytics, *2022 Quarterly State of the Market Report, January Through June*, Section 12, p. 673 (https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q2-som-pjm-sec12.pdf).

Figure 2-21: PJM Capacity Mix



Source: EIA Form 860-M[161]

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 who act as agents for the customers. Curtailment service providers 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.

MARKET FEATURES

Energy Markets

Energy Markets: PJM operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, PJM uses 5-minute intervals. Generators that are available but not selected in the day-ahead scheduling may alter their offers 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 offers remain in effect for the real-time market.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. PJM procures most ancillary services via its energy markets. Blackstart service and reactive power are compensated on a cost-of-service basis.

Market Power Mitigation

PJM caps offers 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. This is called the Three Pivotal Supplier Test. When this occurs, generator offers are adjusted to price levels reflecting short-run marginal cost.

Capacity Markets

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. The 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 deliverability area or LDA). Under RPM, when an LDA is transmission-constrained in the auction (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.

160 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

Annual auctions are referred to as Base Residual Auctions (BRA). LSEs that are able to fully supply their own capacity needs can choose not to participate in the auctions. The largest amounts of capacity in PJM are procured through the BRA, with lesser quantities procured through self-supply and contracted (bilateral) resources.

Market power mitigation in PJM's capacity market includes rules delineating a must-offer requirement, offer caps, minimum offer prices, exceptions for competitive entry, among others. Demand resources and energy efficiency resources may be offered into RPM auctions and receive the clearing price without mitigation.

Specific RPM rules, termed Capacity Performance, provide performance incentives for power plants, demand response, and energy efficiency resources to provide electricity at peak demand regardless of extreme weather events and system emergencies. Capacity Performance rules provide performance bonus payments for resources that over-perform during system emergencies, and severe financial penalties for resources that do not perform during such events.

Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement option. The fixed resource option allows LSEs to meet their supply obligation outside PJM's capacity market, using, for example, resources they own.[161] Intermittent and capacity storage resources, including hydro, and demand response and energy efficiency, are also exempt from must-offer requirements. An administratively determined demand curve defines scarcity pricing levels and, with the supply curve derived from capacity offers, determines market prices in each BRA. Participation by load-serving entities is mandatory, except for those entities that elect the fixed resource requirement option. Also, any generator that has a commitment from the capacity market must submit an offer into the day-ahead energy market.

Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request permission from PJM to deactivate the unit at least 90 days in advance of the planned date. The request includes 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, PJM 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

PJM conducts auctions for selling and buying FTRs made available for the PJM transmission system. Proceeds from the auctions are paid to Auction Revenue Right (ARR) holders, where the ARRs are allocated to firm transmission service customers. PJM conducts its auctions on a long-term, annual, and monthly basis. In PJM, market participants are able to acquire financial transmission rights in the form of options or obligations. The RTO includes a secondary market for its FTRs, which facilitates bilateral trading of existing FTRs between PJM members through an internet-based computer application.

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. In addition to the types of transaction discussed above, PJM offers Up to Congestion (UTC) transactions, a spread bid. In a UTC transaction, a market participant submits an offer to simultaneously inject energy at a specified source and withdraw the same megawatt

161 PJM, *Securing Fixed Resources,* (accessed December 2, 2022), https://pjm.com/-/media/about-pjm/newsroom/fact-sheets/securing-resources-through-fixed-resource-requirement-fact-sheet.ashx.

quantity at a specified sink in the day-ahead marketand specifies the maximum difference in locational marginal prices (LMP) at the transaction's source and sink that the market participant is willing to pay. PJM accepts the bid if the day-ahead LMP differential, i.e., the difference in day-ahead LMPs at the sink and the source, does not exceed the participant's UTC transaction bid. 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 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. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

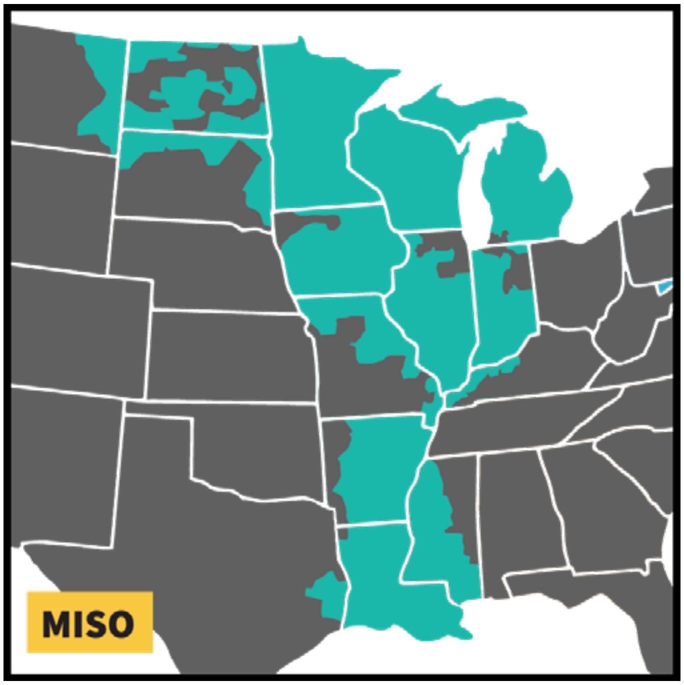
Midcontinent Independent System Operator (MISO)

MARKET PROFILE

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 areas 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 outsideof 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.

Figure 2-22: Midcontinent Independent System Operator



Source: Hitachi Energy, Velocity Suite

In January 2009, MISO implemented a market redesign that added auctioned and optimized ancillary services along with energy. As part of the market update, MISO 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 demand was 127 GW in summer 2011.[162]

Imports and Exports

MISO has interconnections with the PJM and SPP RTOs. It is also directly connected to Southern Company, TVA, the electric systems of Manitoba and Ontario, and several smaller systems. MISO is a net importer of power overall, but the interchange with some areas can flow

162 MISO, Corporate Fact Sheet, at 1 (June 2022), https://www.misoenergy.org/about/media-center/corporate-fact-sheet.

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 56 transmission owners, whose assets define the MISO market area. MISO's market participants include generators, power marketers, transmission-dependent utilities and load-serving entities.[163]

Membership and Governance

An independent board of directors of ten members, including the CEO, governs MISO. Directors are elected by the MISO membership from candidates provided by the board.[164]

MISO relies upon a stakeholder process that works to find collaborative solutions to problems faced by the RTO. These entities have an interest in MISO's peration and include state regulators, consumer advocates, transmission owners, independent power producers, power marketers and brokers, municipal and cooperative utilities and large-volume customers.

Transmission Owners

MISO's largest transmission owners include:

- 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 occurs in 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 two constrained areas in MISO South. Additionally, constraints frequently arise between MISO Midwest and 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 updated annually. Once approved by the board, the plan becomes the responsibility of the transmission owners.

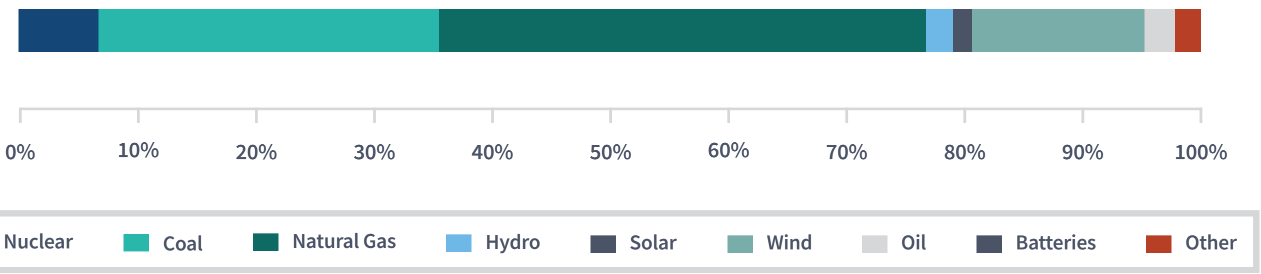
Supply Resources

The total capacity in MISO is over 197 GW and is predominately composed of coal and natural gas-fired generators, providing roughly 70 percent of the total capacity combined, as shown in the bar chart below. Nuclear and wind are also important resources for the region.

163 *Id.*

164 MISO, *Principals of Corporate Governance*, at 3, https://cdn.misoenergy.org/Principles%20of%20Corporate%20Governance110859.pdf.

Figure 2-23: MISO Capacity Mix



Source: EIA Form 860-M[165]

Demand Response

MISO has more than 12.2 GW of demand response resources, including behind-the-meter generation. A number of these resources are operated through local utility programs and are not under the direct control of MISO. MISO has provisions allowing demand-side resources to participate in the energy and reserve markets, but participation is a small part of demand response. Some of the demand response under MISO's direct control is only available under emergency conditions.[166]

MARKET FEATURES

Energy Markets

MISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. MISO's real-time market operates for 5-minutes intervals.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. MISO procures ancillary services via the co-optimized energy and ancillary services market.

In addition to ancillary services, MISO has implemented a ramping product that provides capacity that can increase output rapidly to help offset shifts in generation or load, known as the Ramp Capability Product (RCP).

Market Power Mitigation

When congestion occurs, there may be limits on the number of generators that can satisfy load in some areas, so that they may be able to exercise market power. In response, MISO may impose mitigation for those generators whose offers are significantly higher than their costs and have a significant impact on one or more LMPs. When these conditions are met, MISO reduces the generator's offer to an offer that is consistent with a competitive result.

Capacity Markets

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-side 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. For the capacity market, MISO is divided into 10 zones whose forecast demand must be met by internal generation, demand-side resources, or deliverable external capacity.

165 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

166 Potomac Economics*, 2021 State of the Market Report for the MISO Electricity Markets,* at 100 (June 2022), https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf.

Resources used to meet LSEs' annual capacity requirements must offer that capacity into MISO's energy markets and, when qualified, into the ancillary services markets, for each hour of each day for the entire planning year. Must-offer requirements support MISO's mitigation process by providing an objective measure with which to identify physical withholding.

Special Provisions for Essential Resource Retirements

Power plant owners that seek to retire or suspend a generator must first obtain approval from MISO. The RTO evaluates plant retirement or suspension requests against reliability needs, 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 holds FTR auctions to allow market participants the opportunity to acquire FTRs, sell FTRs that they currently hold, or to convert ARRs 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 historical usage, or upgraded capability, of the transmission system. MISO FTRs are monthly and annual products.

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 promote price convergence between the day-ahead and real-time markets.

These transactions are a component of the 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. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

Southwest Power Pool (SPP)

MARKET PROFILE

SPP's RTO manages transmission in fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Founded as an 11-member tight power pool in 1941, SPP achieved RTO status in 2004, ensuring reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices for its members. SPP operates through its control center in Little Rock, Ar.

SPP began operating its real-time Energy Imbalance Service (EIS) market in 2007. 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.

SPP implemented its Integrated Marketplace in March 2014 which 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.

Figure 2-24: Southwest Power Pool

Source: Hitachi Energy, Velocity Suite

SPP expanded its footprint in 2015, incorporating the Western Area Power Administration – Upper Great Plains region, the Basin Electric Power Cooperative, and the Heartland Consumers 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.[167]

SPP also operates a real-time energy imbalance market in the Western Interconnect, which is described further below.

Peak Demand

SPP's all-time peak demand of 53 GW occurred in summer 2022.[168]

Imports and Exports

SPP has interties with MISO, TVA, and other systems. Additionally, SPP has two DC interties with ERCOT and seven DC interties to the Western Interconnection through New Mexico, Colorado, Nebraska, South Dakota and Montana. At times, SPP is both a net importer and net exporter of electricity at times.

Market Participants

SPP's market participants include investor-owned utilities, generation and transmission cooperatives, independent power producers, municipal utilities, state authorities, independent transmission companies, power marketers, financial participants, and a federal power marketing administration.

Membership and Governance

SPP is governed by a board of directors representing and elected by its members. Supporting the board is the members committee, which provides non-binding input. The members' committee is composed of representatives from each sector of SPP's membership. The SPP Regional State Committee represents retail regulatory commissions from state agencies and provides input on matters of regional importance related to the development and operation of bulk electric transmission.

Transmission Owners

SPP's largest transmission owners include:

- American Electric Power
- Oklahoma Gas and Electric
- Westar Energy
- Southwestern Public Service (Xcel Energy)
- Great Plains Energy
- Kansas City Power & Light
- Omaha Public Power District
- Nebraska Public Power District
- Tri-State Generation and Transmission
- Empire District Electric
- Western Area Power Administration – Upper Great Plains
- Western Farmers Electric Cooperative

167 Southwest Power Pool, *Western, Basin, Heartland join Southwest Power Pool,* at 1 (October 2015), https://www.spp.org/about-us/newsroom/western-basin-heartland-join-southwest-power-pool/.

168 Southwest Power Pool, *Fast Facts*, https://www.spp.org/about-us/fast-facts/.

Chronic Constraints

SPP has certain pathways that are more likely to become congested, based on the physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, and the geographic differences in fuel costs. The eastern side of the SPP footprint has a higher concentration of load and congestion can occur when wind-powered generation from the west tries to travel across limited connections to the east. The most significant congestion has typically occurred in the Oklahoma and Texas Panhandle region.[169]

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

The total capacity in SPP is approximately 94 GW and is predominately composed of natural gas and coal-fired generators, as shown in the bar chart below. Wind is an important and growing resource in the region.

Demand Response

SPP allows demand response resources to register in its market.[170] As of December 31, 2021, 102 demand resources participated in SPP's markets, representing 176 MW of nameplate capacity. While the demand response resources can participate in SPP's markets, they are rarely dispatched.

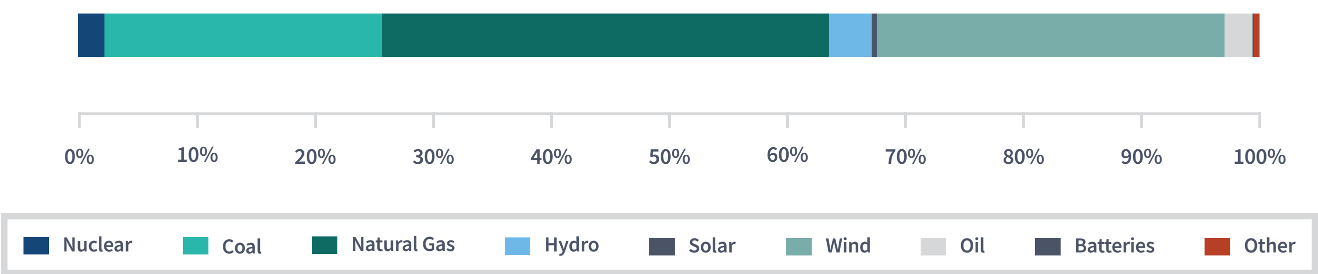
SPP allows Market Participants to register two types of demand response resources: Block Demand Response (BDR) resources and Dispatchable Demand Response (DDR) resources. BDR resources can participate in SPP's markets by providing energy and reserves in 60-minute blocks. DDR resources can participate in SPP's markets by providing energy, regulation, and reserves in 5-minute blocks.

MARKET FEATURES

Energy Markets

SPP operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. SPP's real-time market operates in 5-minute intervals.

Figure 2-25: SPP Capacity Resources



Source: EIA Form 860-M[171]

169 See Southwest Power Pool Market Monitoring Unit, *State of the Market 2022* (May 2022), at 202, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf.

170 SPP Market Monitor, State of the Market 2021 (May 10, 2021), at 49, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf.

171 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. SPP procures ancillary services via the co-optimized energy and ancillary services market. Separately, SPP has a ramping product to procure capacity that can quickly increase output to offset both anticipated and unforeseen future changes in generation or load within the hour, known as the Ramp Capability Product. SPP launched this ramp product in March 2022.

Market Power Mitigation

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 short-run marginal costs. SPP's mitigation test includes a local market power test, a conduct test, and a market impact test. Where mitigation measures are triggered by the tests, SPP generates a mitigated resource offer that the RTO then uses for dispatch, commitment, and settlement purposes.

Capacity Markets

SPP does not offer a capacity market. However, it requires each Load Responsible Entity (LRE) to have sufficient energy supply (capacity) to cover its energy obligations. SPP develops and implements policies and processes necessary to ensure resource adequacy and determines the amount of capacity each LRE must have available to meet its energy obligations. [172]

Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request that SPP study the retirement of the resource no less than one year from the expected retirement date. SPP will then conduct studies to examine the potential effects of the resource retirement including the need for transmission network upgrades, if any.

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

Financial Transmission Rights

SPP refers to FTRs as Transmission Congestion Rights (TCR). A TCR is an instrument that entitles the holder to receive compensation, or requires the holder to pay a charge, for costs that arise from 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 include monthly and annual products, as well as a long-term instrument called Long-Term Congestion Rights.

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 firm transmission rights. 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. In SPP, virtual bids are sometimes used in the day-ahead market as a placeholder or hedge for wind generation expected in the real-time market.

Credit Requirements

SPP's tariff includes credit requirements that a market participant needs to meet in order to participate in the

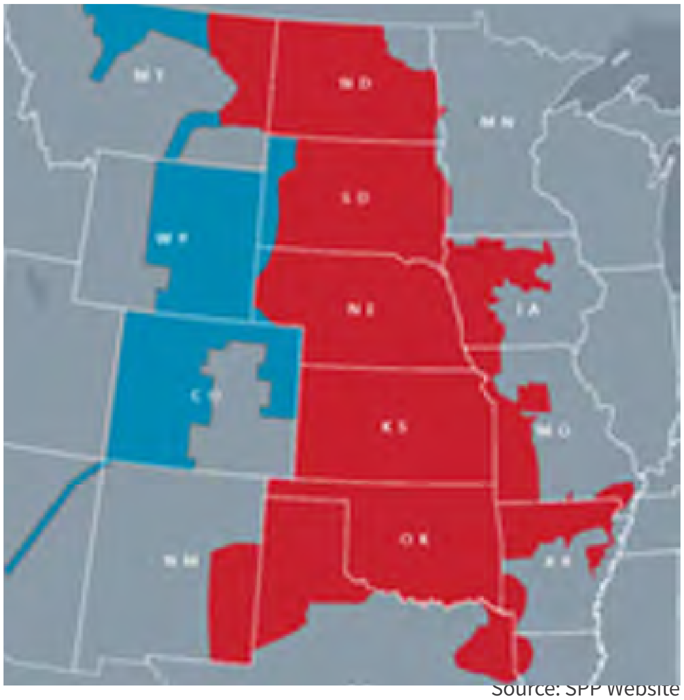
172 *Southwest Power Pool Market Monitoring Unit, State of the Market 2022 (May 2022), at 202*, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf

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 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. SPP must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and various financial measures.

Western Energy Imbalance Service (WEIS)

SPP launched its WEIS market in February 2021. The WEIS market balances generation and load regionally in real time for participants in the Western Interconnection. SPP's WEIS market centrally dispatches generation from participating resources every five minutes using the lowest-cost resource available to meet demand. As of August 2022, ten entities participate or plan to participate in the WEIS Market with three more anticipated to join in April 2023: Basic Electric Power Cooperative, BlackHills Energy (April 2023), Colorado Springs Utilities, Deseret Power Electric Cooperative, Guzman Energy, Municipal Energy Agency of Nebraska, Platte River Power Authority (April 2023), Tri-State Generation and Transmission Association, WAPA (Upper Great Plains West, Rocky Mountain, and Colorado River Storage Projects regions), and Xcel Energy (April 2023). The following map shows SPP's footprint in red and the WEIS in blue.

Figure 2-26: Western Energy Imbalance Service



Source: SPP website

California Independent System Operator (CAISO)

MARKET PROFILE

CAISO operates an ISO serving most of California and part of Nevada. CAISO is a California nonprofit public benefit corporation started in 1998 when the state restructured its electric power industry. CAISO manages wholesale electricity markets, centrally dispatching electric generators. 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. CAISO also operates a real-time energy imbalance market, the Western Energy Imbalance Market (WEIM), which is discussed further below. CAISO operates its grid out of its main control center in Folsom, CA.

Peak Demand

CAISO's all-time peak demand was 52 GW in summer 2022.[173]

Imports and Exports

Up to about one-third of CAISO's energy is supplied by imports, principally from 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

173 California ISO, *California ISO Peak Load History 1998 through 2022*, at 1 (n.d.), http://www.caiso.com/documents/californiaisopeakloadhistory.pdf.

late spring when hydroelectric production peaks from increases in winter snowmelt and runoff.

Market Participants

CAISO's market participants include load-serving investor-owned utilities, load-serving municipal utilities, generators, power marketers, utility customers, and financial entities.

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 provides corporate direction, reviews and approves management's annual strategic plans, and approves 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

CAISO's largest transmission owners include:

- Pacific Gas and Electric
- Southern California Edison
- San Diego Gas and Electric
- Valley Electric Association
- Municipal utilities such as Vernon, Anaheim, and Riverside

Chronic Constraints

CAISO has several locally constrained areas, typically near population centers and where transmission lines have relatively low voltage (115 kV and below). The locally constrained areas that have local capacity requirements include the Greater Bay Area, Greater Fresno, Sierra, Humboldt, Los Angeles Basin, San Diego, and North Coast/North Bay.

Transmission Planning

CAISO conducts an annual transmission planning

Figure 2-27: California Independent System Operator

Source: Hitachi Energy Velocity Suite

process with stakeholders that includes both short-term and long-term projects.

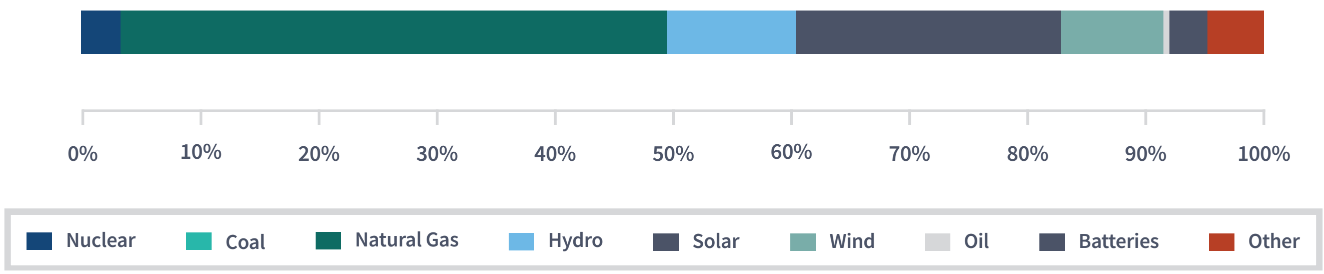
Supply Resources

The total capacity in CAISO is over 70 GW and is predominately composed of natural gas-fired and hydroelectric generators, as shown in the bar chart below. CAISO also has substantial renewable resources, including roughly half of the installed solar capacity in the U.S.

Demand Response

Demand response participation in the wholesale energy market includes programs entitled Proxy Demand Response, Reliability Demand Response Resources, and CAISO's Participating Load program. Proxy Demand Response allows for customer loads, aggregated by LSEs or third-party providers, to offer load reduction into CAISO's day-ahead, real-time, and ancillary services markets in return for compensation. Reliability Demand Response Resources allows customer loads, also aggregated by LSEs or third-party providers, to reduce load for compensation when triggered for

Figure 2-28: CAISO Capacity Mix



Source: EIA Form 860-M[175]

reliability-related events. Reliability Demand Response Resources can also offer into the day-ahead market. The Participating Load program allows the CAISO operators to directly curtail end-users' load, rather than through aggregators. This is a relatively small program that is primarily composed of the power demand from California's water pumping projects. Other demand response in California consists of programs for managing peak summer demands operated by the state's electric utilities. In general, activation of the utility demand response programs is based on criteria that are internal to the utility or when CAISO issues a Flex Alert. Flex Alerts also inform consumers of how and when to conserve electricity usage.

MARKET FEATURES

Energy Markets

CAISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. CAISO operates a 15-minute market to adjust schedules from those determined in the day-ahead market, then a 5-minute market to balance supply and load in real-time. Real-time bids can be submitted up to 75 minutes before the start of the operating hour.

CAISO also procures capacity in the real-time market to provide upward and downward ramping of generation in order to accommodate changes in net load with the Flexible Ramping Product.[175] This service provides compensation to the generators selected to provide the desired flexible ramping capability.[176]

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. CAISO procures ancillary services via its co-optimization of energy and ancillary services in its energy markets

In addition to ancillary services, CAISO has implemented a ramping product to procure capacity that can quickly increase output to offset changes in generation or load, known as the Flexible Ramping Product.

Market Power Mitigation

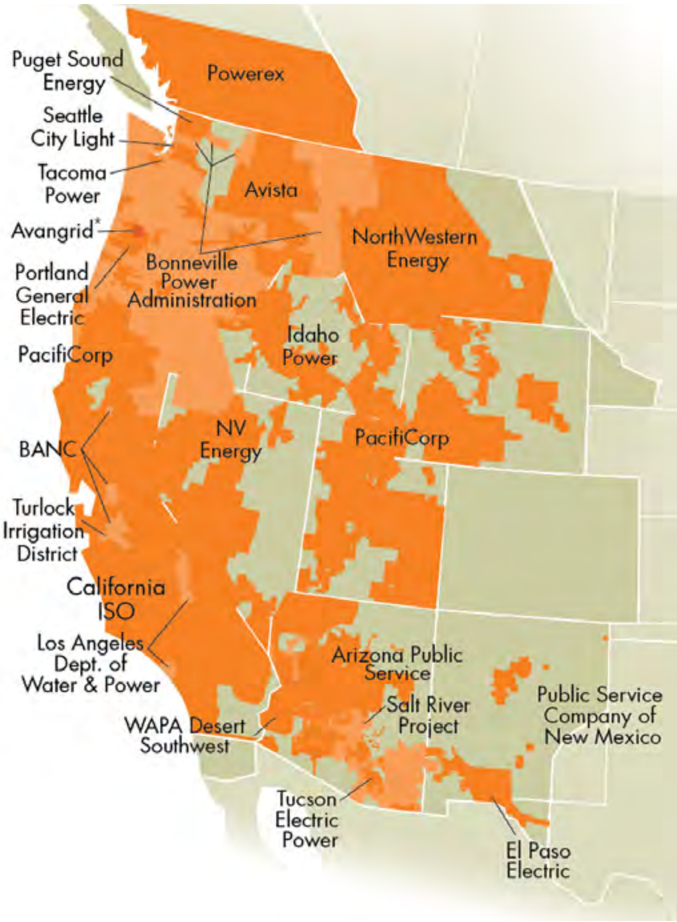
CAISO applies a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

174 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

175 Net load in CAISO is total market demand minus generation output from solar and wind resources.

176 CAISO describes ramping capability as a resource's ability to move from one energy output to a higher (upward ramp) or lower (downward ramp) energy output; *California Independent System Operator Corp.,* 156 FERC ¶ 61,226, at P 2 (2016).

Figure 2-29: Western Energy Imbalance Market



Capacity Markets

CAISO does not operate a formal capacity market, but it does have a mandatory resource adequacy (RA) requirement. The program requires LSEs to 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 that each LSE must meet, as well as system and local capacity requirements and flexibility requirements.

The CAISO market rules also include must-offer provisions pertaining to resources procured as RA resources. These resources must make themselves available to the CAISO day-ahead and real-time markets for the capacity for which they were counted.

Special Provisions for Essential Resource Retirements

CAISO employs RMR contracts to assure that it has the ability 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. Over time, CAISO has been 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

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 revenues 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. CAISO's convergence bidding includes both virtual supply and virtual demand transactions.

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

Western Energy Imbalance Market (WEIM)

On Nov. 1, 2014, CAISO began operation of an energy imbalance market (EIM) with PacifiCorp's two BAAs, PacifiCorp East and PacifiCorp West. The EIM is an extension of the CAISO's real-time market into other BAAs in the Western Interconnection. The market dispatches resources inside the participating entities' BAAs to meet intra-hour changes in their energy demand and supply. The EIM's imbalance energy helps the BAAs meet their energy demand in real-time. Overall, EIM energy represents about two to three percent of the energy used to meet load in the participating BAAs. With the balancing authorities in the Pacific Northwest, the EIM integrates low-cost hydroelectric power generation with the significant amount of solar and wind generation capacity in CAISO.

The EIM is a voluntary market where the participating balancing authorities can choose which resources to include in the market. The market participants have the flexibility to add and remove capacity from the EIM on an hourly basis. The transmission system operators for each participating BAA preserve the responsibility and flexibility to respond to events such as a sudden large imbalance between load and supply caused by a loss of a power plant or transmission line.

As of November 2022, the EIM consisted of the following LSEs and their respective BAAs: BPA, Puget Sound Energy, Portland General Electric, PacifiCorp West, PacifiCorp East, Idaho Power, NV Energy, Tucson Electric Power, Avista, NorthWestern Energy, Los Angeles Department of Water & Power, Public Service Company of New Mexico, Turlock Irrigation District, Salt River Project, Seattle City Light, Balancing Authority of Northern California, Idaho Power Company, Portland General Electric, Puget Sound, NV Energy, Arizona Public Service, and CAISO. Additionally, Powerex (the marketing arm of the Canadian utility, BC Hydro) joined the EIM, providing contributions of generation and load imbalance (the difference between generation supply and demand schedules).[177] Other balancing authorities have expressed interest in becoming EIM Entities.

The EIM provides a market mechanism for dispatching generation resources to meet imbalance energy needs along with a limited amount of power flows between the participating BAAs. The market dispatches generation based on the relative cost of the resources, resulting in cost savings for the participants. Before the EIM, a balancing authority such as PacifiCorp West or PacifiCorp East resolved imbalances between energy demand and supply in real-time by dispatching its resources and using ancillary services (mainly regulation). Under the EIM, by contrast, the market automates the dispatch of enough resource capacity within the BAAs, along with transmission flows between BAAs, to resolve energy imbalances.[178] The automated EIM sets LMPs at both 15-minute and 5-minute intervals.

Along with dispatch cost savings, the EIM also helps integrate renewable generation resources. Prior to the EIM, CAISO imported power from outside its service territory to balance load throughout most hours of the day. However, with the growth of solar and wind generation, particularly in California, there were periods when these resources were forced to curtail because there was too much energy offered into the market. Now, with the EIM, any excess power can be exported throughout the participating BAAs. In some hours, this results in power exports from CAISO to other BAAs.[179]

177 Powerex (BC Hydro) also makes transmission rights available to the EIM, providing its power to the EIM at the British Columbia-U.S. border

178 The EIM software calculates dispatch solutions for the EIM market area as a whole. Consequently, participating balancing authorities need not maintain high levels of reserves.

179 *See* Department of Market Monitoring – California ISO*, 2017 Annual Report on Market Issues & Performance,* at 118 (June 2018), http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf.

As the independent system operator of the EIM, CAISO addresses local market power mitigation at 5-minute and 15-minute intervals across the EIM area, which includes the non-CAISO balancing authority areas. CAISO also procures a Flexible Ramp Product to provide upward and downward flexible capacity to meet energy ramp requirements. In these respects, CAISO's operator responsibilities have grown in the EIM as enhancements to the market design have been implemented.

Chapter 3
Gas-Electric Interdependency

GAS-ELECTRIC INTERDEPENDENCY

The significant shift in the U.S. fuel mix has heightened the importance over the past decade of the interdependence of the natural gas and electric systems. Natural gas is now the largest source of U.S. electricity generation; in 2021, about 38.3 percent of utility-scale electricity generation in the U.S. (1.576 trillon kilowatt hours, kWh) was from natural gas.[181] In the same year, the electric power sector accounted for about 37 percent of total U.S. natural gas consumption. The amount of natural gas used for electricity generation (also known as power burn) has increased approximately 49 percent over the past decade.[182] The growth of power burn has been driven by plentiful, low-cost natural gas supply, the favorable economics of gas-fired combined cycle technology, and the relatively low emissions associated with gas-fired generation compared to other fossil fuels. Given the importance of natural gas in electricity generation, integration of market operations between the natural gas and electricity industries is critical. This section provides an overview of natural gas and electric system interdependencies. In addition, it discusses key issues pertaining to gas-electric harmonization[183] that FERC has addressed to ensure the coordinated, reliable, and efficient operation of both the interstate natural gas pipeline network and electricity systems.

FERC JURISDICTION

FERC has jurisdiction over many aspects of gas-electric harmonization, particularly on the electricity side, where it has authority over wholesale electricity markets. In addition, the North American Electric Reliability Corporation (NERC), the FERC-certified electric reliability organization responsible for reliability of the Bulk Power System, has conducted assessments and event analyses that have resulted in recommendations pertaining to gas-electric coordination.[184] Further, FERC may recommend that the North American Energy Standard (NAESB)[185] develop standards pertaining to the nation's natural gas system and bulk electric system, including gas-electric coordination, for adoption by FERC, which then become mandatory. FERC may consider reforms that require the wholesale electricity markets to account for conditions on the pipeline system. In comparison, however, FERC's ability to identify and assess risks on the reliability of natural gas transportation service in real time is limited. Furthermore, FERC lacks statutory authority to respond to natural gas transportation risks.

BACKGROUND

Natural gas usage for electricity generation (power burn) will likely remain relatively flat. The natural gas share of power burn is projected to continue in a constant range despite potential gains due to projected coal and nuclear generating unit retirements, as electricity generation capacity replacements for the expected retirements are increasingly met by generation from renewable sources. Renewable electric-generating technologies are projected to account for about 60 percent of cumulative electricity generation capacity additions through 2050, and natural gas-fired capacity accounts for almost the entire amount of remaining additions. These natural gas-fired generators

181 *See* EIA, *Electricity explained* (July 15, 2022), https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.

182 *See* EIA, *Natural gas explained* (December 6, 2022), https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.

183 The term "harmonization" encompasses interactive dynamics between gas and electric such as communication, coordination, and alignment of economic incentives facilitating cross-system reliability.

184 *See* section 215(g) of the Federal Power Act.

185 NAESB is an American National Standards Institute (ANSI) accredited, non-profit 501(c)(6) corporation formed with the support of the U.S. Department of Energy (DOE) for the purpose of developing voluntary business practice standards designed to promote more competitive and efficient natural gas and electric markets. NAESB complies with ANSI's requirements that its procedures are open to materially affected entities and that the standards represent a reasonable consensus of the industry without domination by any single interest or interest category.

will both provide energy and help generators.[186] The U.S. interstate natural gas pipeline system has a long history of reliably serving all customers, including electricity generators. Nevertheless, extreme winter weather events and associated disruptions and constraints to certain natural gas infrastructure over
the last several years have prompted FERC to research, assess, and take action on a number of issues arising from the growing interdependence of the natural gas and electricity markets. These disruptions including the Southwest Gas Outages in 2011, the Polar Vortex in 2014, the Aliso Canyon Storage Field leak in 2015, the Bomb Cyclone during the winter of 2017-2018, Winter Storm Uri in February of 2021, and Winter Storm Elliot in December of 2022, have led to questions regarding the adequacy of market structures and regulations to support the reliance of electricity generation on natural gas. This has in turn prompted FERC to address a number of issues arising from the interdependence of the natural gas and electricity markets.

As an initial exploration of these challenges, FERC convened five regional conferences throughout the month of August 2012, to solicit input from both industries regarding the harmonization of natural gas and electricity markets.[187] The conferences were structured around three sets of issues: scheduling and market structures/rules; communications, coordination, and information-sharing; and reliability concerns. Information gathered at the conferences confirmed that gas-electric interdependence concerns are more acute in some regions than others, with the discussion at each conference focusing on the circumstances and needs of each region. Notwithstanding the regional focus of the discussions, several topics emerged that were common to multiple regions. First, participants in many regions sought confirmation that sharing information in furtherance of enhancing gas-electric coordination would not run afoul of FERC's Standards of Conduct or be construed as engaging in undue discrimination or preference.[188] The Standards of Conduct are intended to prevent undue preferences in the providing of interstate transmission services by prohibiting marketing employees from receiving non-public transmission information. Second, several concerns were expressed regarding the misalignment of natural gas and electric scheduling practices, as well as application of FERC's no bump rule and pipeline capacity release rules.[189] Third, questions were raised in several regions regarding whether generators have appropriate incentives to deliver firm energy. Finally, industry representatives in multiple regions described steps they were considering to address reliability issues in the context of gas-electric coordination.

COMMUNICATION BETWEEN THE NATURAL GAS AND ELECTRIC INDUSTRIES

With electric generation's increased reliance on natural gas, it has become more important that the electric and nature gas sectors maintain robust communication to ensure that their systems are operated reliably and effectively. Communication between interstate natural gas pipelines and electric transmission operators can be essential to help ensure that electric transmission operators provide grid reliability and that interstate natural gas pipelines can meet contractual and operational obligations to all their shippers.

During the FERC-sponsored regional conference, natural gas and electric industry stakeholders pointed out that, historically, industry officials have been reluctant to share operational information because of concerns that doing so could be a violation of current laws, regulations, or tariffs, including FERC's prohibition on undue discrimination. Accordingly, multiple industry participants requested

186 *See* EIA, *Annual Energy Outlook* (March 3, 2022), https://www.eia.gov/outlooks/aeo/narrative/electricity/sub-topic-04.php.

187 *Coordination Between Natural Gas and Electricity Markets*, 141 FERC ¶ 61,125 (2012).

188 The Standards of Conduct govern communications between interstate natural gas pipelines and their affiliates that engage in marketing functions, and public utilities that own or operate electric transmission facilities and their affiliates that engage in marketing functions. *See* 18 CFR § 358.1(a) and (b) (2012).

189 Both rules are covered later in this section.

that, to facilitate the exchange of information between transmission operators, FERC should more clearly identify the types of operational information that may be shared between transmission operators and clarify that the sharing of such information does not violate the prohibition against undue discrimination.

To address these concerns, FERC issued Order No. 787[190] on November 15, 2013, which amended FERC regulations to provide authority for interstate natural gas pipelines and public utilities to share non-public, operational information with each other for the purpose of operational planning and promoting reliable service on both systems. Specifically, the order permits information-sharing for day-to-day operations, planned outages, and scheduled maintenance when, such information is provided for the purpose of promoting reliable service or operational planning.

SCHEDULING AND DISPATCH BETWEEN THE INTERSTATE NATURAL GAS PIPELINE AND WHOLESALE ELECTRIC INDUSTRIES

Natural gas-fired generators must coordinate their operations consistent with both natural gas and electric business practice timelines. Electric transmission operators are continuously and near instantaneously balancing supply and demand to ensure that the system remains in equilibrium. In contrast, due to the physical characteristics of interstate natural gas transmission,[191] pipelines require advance nominations to ensure they have sufficient line pack and storage available to meet the scheduled daily load of all their customers, including natural gas-fired generators, which may constitute significant load for a pipeline, and which generally rely on a just-in-time natural gas supply and pipeline delivery. While pipeline linepack[192] and storage provide some operational flexibility to pipelines to accommodate load swings throughout the day, short-term swings in demand by natural gas-fired electricity generators resulting from redispatch by electric transmission operators may be difficult to manage, particularly during times of coincident peak loads on interstate natural gas pipelines and electric transmission systems, such as during unusual cold weather events when end-use customers may rely on both natural gas and electricity.

A historical, key concern for the electric industry has been that natural gas-fired generators had insufficient time to procure natural gas pipeline transportation given that the day-ahead deadline to request pipeline transportation service was after or very close to the time that the generators receive their day-ahead dispatch instructions from the electricity market operator. In addition, intraday pipeline scheduling flexibility provided natural gas-fired generators in some regions with limited opportunities to revise pipeline nominations within the operating day to accommodate changes in load throughout the electric day. Finally, a third challenge was that the lack of alignment between the industries contributed to operational problems and logistical challenges resulting from the electric operating day extending over two Gas Days.[193]

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190 *Communication of Operational Information Between Natural Gas Pipelines and Transmission Operators,* Order No. 787, 78 Fed. Reg. 70,163, at P 2 (November 22, 2013), FERC Stats. & Regs. ¶ 31,350 (2013) (cross-referenced at 145 FERC ¶ 61,134), order on reh'g, Order No. 787-A, 147 FERC ¶ 61,228 (2014), *order dismissing request for clarification,* 152 FERC ¶ 61,051 (2015).

191 Natural gas transportation velocities through long-distance pipelines can rarely exceed 20 miles per hour (mph) under firm service or 50 mph under intermittent service.

192 "Linepack" refers to the volume of natural gas that can be "stored" in a natural gas pipeline.

193 The existing 24-hour operating day, or Gas Day, for interstate natural gas pipelines begins at 9:00 a.m. CCT and ends at 9:00 a.m. CCT the following day. All nominations for interstate natural gas pipeline transportation service are for a daily quantity to be transported over the 24-hour Gas Day. By contrast, with respect to electricity industry scheduling practices, most electric utilities use a 24-hour operating day that begins at 12:00 a.m. local time.

Table 3-1: Previous and Revised NAESB Natural Gas Nomination

Time Shifts -- All times CCT		Previous NAESB Standards	Revised NAESB Standards
Timely (Effective Next Day)	Nomination Deadline	11:30 AM	1:00 PM
Evening (Effective Next Day)	Nomination Deadline	6:00 PM	6:00 PM
Intraday 1 (Effective Current Day)	Nomination Deadline	10:00 AM	10:00 AM
Intraday 2 (Effective Current Day)	Nomination Deadline	5:00 PM	2:30 PM
Intraday 3 (Effective Current Day)	Nomination Deadline	None	7:00 PM

Through a multi-year effort that engaged industry stakeholders, FERC sought to facilitate the coordination of the scheduling practices of the natural gas and electric industries to accommodate the growing interdependency. To better align the scheduling of wholesale natural gas and electricity markets in light of increased reliance on natural gas for electricity generation, FERC issued Order No. 809 on April 16, 2015.[194] This order accepted NAESB's proposal to move the Timely Nomination Cycle nomination deadline for scheduling natural gas transportation from 11:30 AM CCT to 1:00 PM CCT to provide generators more time to acquire natural gas supply and pipeline transportation capacity after learning their electric dispatch obligations. The final rule also accepted NAESB's proposal to add an additional, third intraday nomination cycle at 7:00 PM CCT to provide greater flexibility for generators to obtain and schedule natural gas during the day of operation. This new "no-bump" intraday cycle[195] starts at 7:00 p.m. CCT, two hours later than the prior "no-bump" second intraday cycle, which was moved up to 2:30 p.m. CCT and which is "bumpable." Table 3-1 depicts the previous NAESB gas nomination timeline and the revised NAESB gas nomination timeline accepted in Order No. 809, effective April 1, 2016.

In related actions, on March 20, 2014, FERC instituted proceedings under section 206 of the Federal Power Act to ensure that regional transmission operator (RTO) and independent system operator (ISO) day-ahead scheduling practices conform with any revisions to the natural gas scheduling practices adopted by FERC in Order No. 809.[196] The Section 206 Order required each RTO/ISO to propose tariff revisions such that generators will receive dispatch instructions in sufficient time to be able to acquire natural gas and pipeline transportation by the start of the Timely Nomination Cycle and to complete RTO/ISO supplemental reliability dispatch in sufficient time for generators to use the Evening Cycle. Alternatively, RTOs/ISOs could show cause as to why existing scheduling practices should remain unchanged. FERC subsequently issued orders on all

194 *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities,* Order No. 809, 80 Fed. Reg. 23,198, at P 5 (April 24, 2015), FERC Stats. & Regs. ¶ 31,368 (2015) (cross-referenced at 151 FERC ¶ 61,049 (2015)), *order on clarification,* 152 FERC ¶ 61,095, *order on reh'g,* 152 FERC ¶ 61,212 (2015), *order on clarification,* 153 FERC ¶ 61,049 (2015).

195 The No-Bump Rule restricts firm shippers from bumping nominated and scheduled interruptible service during the last standard intraday nomination cycle of the Gas Day.

196 *Order Initiating Investigation into ISO and RTO Scheduling Practices and Establishing Paper Hearing Procedures,* 146 FERC ¶ 61,202, at P 1 (2014) (Section 206 Order).

RTO/ISO compliance filings in response to the Section 206 Order.[197]

FUEL ASSURANCE, ELECTRIC SYSTEM RELIABILITY, AND INCENTIVES TO DELIVER FIRM ENERGY

Natural gas-fired electricity generation is often not backed by primary firm pipeline transportation contracts. Firm pipeline contracts provide shippers of natural gas, including electricity generation operators, with an agreed-upon amount of capacity for the pipeline transportation of natural gas. Firm transportation service means that the service is not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm service. The pipeline's delivery of natural gas cannot be curtailed below the contracted quantity under a firm contract except under unforeseeable circumstances such as pipeline and compressor outages or system maintenance.

In contrast, interruptible contracts (also called IT or non-firm contracts) are lower-priority pipeline transportation arrangements. Under these contracts, the flow of natural gas to an electricity generator may be stopped or curtailed if firm contract holders use the available capacity. On peak natural gas demand days, interruptible transportation may be unavailable because firm customers will be using their full contractual entitlements, and pipelines therefore cannot schedule interruptible transportation service. Interruptible contracts are generally set up for short periods, often for next-day delivery. Interruptible contracts are less expensive than firm contracts, reflecting the higher risk of disrupted fuel receipts. Electricity generators may also use natural gas pipeline capacity released or sold by an existing firm capacity holder that is available seasonally or for limited periods of time to other shippers. Alternatively, the electricity generators may buy natural gas from a marketer that is, in turn, using released pipeline capacity. This resale market for pipeline capacity is called Capacity Release. FERC designed the posting and bidding procedure that gives pipeline shippers the ability to auction off all or a portion of their firm capacity for a designated period.[198]

FERC has identified generator access to sufficient fuel supplies and the firmness of generator fuel arrangements as a significant issue contributing to potentially poor generator performance and inefficient market operations. Electricity generators that rely on non-firm arrangements for fuel transportation face the risk of not procuring enough fuel on high demand days. However, firm contracts require generators to pay more for pipeline capacity, and thus ultimately result in higher fuel prices. As such, specific concerns have focused on the ability of RTO/ISO markets to address firm fuel supplies and their valuation. These issues have been considered in various venues. On November 20, 2014, FERC issued an Order (Fuel Assurance Order) directing each RTO/ISO to file a report on the status of its efforts to address market and system performance associated with "fuel assurance" issues, by February 18,

197 The Commission issued six orders accepting compliance filings from the RTOs/ISOs identified in the Section 206 Order. The Commission accepted compliance filings from California Independent System Operator, ISO New England, Inc., and New York Independent System Operator, Inc. without requiring scheduling changes because the ISOs were able to show cause as to why their existing scheduling practices did not need to be modified. The Commission accepted compliance filings from Midcontinent Independent System Operator, Inc., PJM Interconnection, L.L.C., and Southwest Power Pool, Inc., finding that the proposed tariff revisions would better align the ISO's/RTO's scheduling with that of the natural gas industry as discussed in the Section 206 Order. See California Independent System Operator Corporation, 153 FERC ¶ 61,315 (2015), ISO New England, Inc., 153 FERC ¶ 61,211 (2015), Midcontinent Independent System Operator, Inc., 154 FERC ¶ 61,276 (2016), New York Independent System Operator, Inc., 153 FERC ¶ 61,210 (2015), PJM Interconnection, L.L.C., 153 FERC ¶ 61,209 (2015), and Southwest Power Pool, Inc., 153 FERC ¶ 61,316 (2015).

198 The Commission's current pipeline capacity release program is designed to permit expeditious and flexible releases, in a transparent and not unduly discriminatory manner, to the shipper placing the highest value on the capacity. The Commission generally requires that a firm shipper (releasing shipper) sell its capacity by offering it for bid on the pipeline's website, with the capacity awarded to the highest bidder. A releasing shipper may release its firm capacity in whole or in part, on a permanent or short-term basis, and with "recall" provisions that allow the releasing shipper to interrupt the replacement shipper's use of the capacity under specified circumstances.

2015.[199] FERC explained that the term "fuel assurance" describes a range of generator-specific and system-wide issues, including the overall ability of resources to access sufficient fuel and the firmness of their fuel arrangements as necessary to maintain reliability in each RTO/ISO. Many of these issues were also previously identified in FERC's September 25, 2013, centralized capacity markets technical conference concerning the ability of capacity markets and resource adequacy constructs to procure and retain the resources necessary to meet future reliability. FERC observed at the time that most capacity markets failed to properly value fuel assurance because their auctions establish capacity prices based on economic bids, without taking into account fuel supply arrangements or the operational characteristics of the generators.[200] FERC further identified fuel assurance issues in the April 1, 2014 polar vortex technical conference, which explored the impacts on system performance and market operations of cold weather events occurring in the 2013/2014 winter and the actions taken by RTOs/ISOs to respond to those impacts.

FERC has approved tariff changes proposed by ISO New England (ISO-NE), and PJM to their capacity market rules to allow market participants to recover costs associated with the provision of fuel assurance.[201] These capacity market rule changes were designed to improve the performance of capacity resources by providing payments for superior performance and establishing penalties for poor performance. While neither the Pay for Performance program in New England nor the Capacity Performance program in PJM required a specific method of securing firm fuel supplies, the payments and penalties were designed to incentivize market participants to procure backup fuels, firm pipeline transportation, alternative generating capacity, demand response, or other methods of ensuring resources can produce electricity.

NATURAL GAS PIPELINE CAPACITY RELEASE REGULATIONS

As discussed in the previous section, electricity generators may use natural gas pipeline capacity released or sold by an existing firm capacity holder. FERC, on June 19, 2008, issued Order No. 712,[202] which approved significant changes to its natural gas pipeline capacity release regulations to strengthen competition and benefit consumers by providing natural gas users, producers, and marketers more options for how they transact as well as more accurate price signals on the market value of pipeline capacity.

More specifically, FERC revised its regulations governing interstate natural gas pipelines to reflect changes in the market for short-term transportation services on pipelines and to improve the efficiency of FERC's capacity release program. FERC allowed market-based pricing for short-term capacity releases[203] and facilitated asset management arrangements (AMAs)[204] by relaxing the prohibition on tying and on bidding requirements

199 *Order on Technical Conferences*, 149 FERC ¶ 61,145 (2014) ("November 20 Order").

200 *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators,* 149 FERC ¶ 61,145, at P 1 (2014).

201 *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,208 (2015); see also ISO New England Inc., 149 FERC ¶ 61,009 (2014).

202 *Promotion of a More Efficient Capacity Release Market,* Order No. 712, 123 FERC ¶ 61,286, at P 1 (2008), *order on reh'g,* Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008), *order on reh'g,* Order No. 712-B, 127 FERC ¶ 61,051 (2009).

203 The Commission found that the maximum rate ceiling previously applied to capacity release transactions denied releasing and replacement shippers the ability to negotiate transactions that reflect the market value of capacity at all times. Thus, providing the ability to negotiate capacity release transactions based on price differentials or at market clearing prices would help in providing short-term capacity to replacement shippers, such as natural gas-fired electricity generators.

204 AMAs provide significant benefits to many participants in the natural gas and electric marketplaces and to the secondary marketplace itself. They maximize the utilization and value of capacity by creating a mechanism for capacity holders to use third party experts to both (1) manage their natural gas supply arrangements and (2) use that capacity to make natural gas sales or re-releases of the capacity to others when the capacity is not needed to serve the releasing shipper. AMAs result in ultimate savings for end-use customers by providing for lower natural gas supply costs and more efficient use of the pipeline grid.

for certain capacity releases.[205] Finally, FERC waived its prohibition on tying and bidding requirements for capacity releases made as part of state-approved retail open-access programs.

RELIABILITY CONSIDERATIONS IN THE CONTEXT OF GAS-ELECTRIC COORDINATION

An issue related to fuel assurance, but with a broader scope, is the systemic risk to the electric system from a potential natural gas system disruption and how such risk can be mitigated. As natural gas use for power generation has grown, grid operators are beginning to consider the implications of natural gas system contingencies on the electric grid.

FERC has continued to address the systemic risk to the electric system from a potential natural gas system disruption and how these risks can be reduced. In February 2021, Winter Storm Uri, which impacted the central-United States, and particularly Texas, caused outages at electricity generating plants that resulted in millions of people being without heat or power for nearly four days and significant loss of life. Winter Storm Uri resulted in a combined 23,418 MW of manual firm load shed, the largest controlled firm load shed event in U.S. history.[206] Winter Storm Uri also caused a reduction of daily natural gas production, including the production necessary to keep many natural gas-fired power plants operational. Unplanned outages of natural gas wellheads due to freeze-related issues, loss of power, and facility shut-ins, as well as unplanned outages of natural gas gathering and processing facilities, resulted in a decline of natural gas available supply and transportation to many natural gas-fired generating units. Once natural gas supply outages began at the wellhead, they rippled throughout the natural gas and electric infrastructure, causing processing outages and reductions, pipeline declarations of Operational Flow Order (OFO)s[207] and force majeure, and outages and derates of natural gas-fired generating units. U.S. natural gas production in February 2021 experienced the largest monthly decline on record. Between February 8 and 17, 2021, the total natural gas production in the U.S. lower 48 states fell by 28 percent.[208]

Winter Storm Uri has contributed to FERC and NERC's renewed focus on critical infrastructure interdependencies. On February 16, 2021, FERC and NERC, announced a joint inquiry with the Regional Reliability Entities, to examine the root causes of the reliability events that have occurred throughout the county, in particular the regions served by the Electric Reliability Council of Texas, Inc. (ERCOT), Midcontinent Independent System Operator, Inc. (“MISO”), and Southwest Power Pool, Inc. (SPP). The inquiry’s final report was issued on November 16, 2021, and included 28 formal recommendations that seek to prevent a recurrence of the failures experienced during the February 2021 cold weather event.[209] One of the key recommendations, pertaining to gas-electric coordination, was that FERC consider establishing a forum to identify actions to improve the reliability of the natural gas infrastructure system as necessary to support the bulk power system, and to address recurring challenges stemming from natural gas-electric infrastructure interdependency. Accordingly, FERC and NERC encouraged NAESB to convene a forum to identify solutions to the reliability issues facing the nation’s natural gas system and bulk electric system. In response,

205 Tying refers to attempts by the releasing shipper to add additional terms or conditions to the release of pipeline capacity by tying the release of pipeline capacity to any extraneous conditions.

206 *See* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* at *9* (November 16, 2022), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

207 OFOs are notices issued by natural gas pipelines to protect the operational integrity of the facility. Pipelines typically invoke OFOs during high or peak-demand periods to maintain system pressure and reliable operations. The orders may either restrict service or require affirmative action by shippers.

208 *See* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* at 13 (November 16, 2022), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

209 *Id*.

NAESB convened a multi-meeting forum, beginning on October 21, 2022, to identify actions that would improve the reliability of the natural gas infrastructure system to support the bulk power system and to address ongoing challenges from the interdependency of natural gas-electric infrastructure in categories including:

1. Measures to improve gas-electric information sharing for improved system performance during extreme cold weather emergencies;
2. Measures to improve reliability of natural gas facilities during cold weather (freeze protection, electric supply); and
3. Measures to improve the ability of generators to obtain fuel during extreme cold weather events, when natural gas heating load and natural gas-fired generators both demand high amounts of natural gas while natural gas production may have decreased.

In a similar vein, on September 8, 2022, and on June 20, 2023, FERC convened forums to discuss the electricity and natural gas challenges facing the New England region.[210] Topics discussed included the historical context of New England winter gas-electric challenges and concerns and considerations for upcoming winters, such as reliability of gas and electric systems and fuel procurement issues. The forum also explored whether additional information or modeling of the electric and/or gas systems are needed to inform the development of solutions to these challenges.

Discussion centered around ISO-NE's significant reliability dependence on natural gas, along with natural gas pipeline constraints that shift peak fuel supply reliance to liquified natural gas (LNG) procurement. Participants observed that New England had thus far avoided a severe energy outage through actions such as incentives for stored fuels and winterization of facilities, along with timely coordination among ISO-NE, pipelines, and natural gas pipeline shippers that have been able to release their capacity or resell their natural gas supplies.

As another example of a severe weather event, Winter Storm Elliott, which occurred from December 23 -26, 2022, stressed regional electric grids across the U.S. in different ways. It contributed to power outages affecting millions of electricity customers. Although most of these outages were due to weather impacts on electric distribution facilities operated by local utilities, utilities in parts of the southeast were nevertheless forced to engage in rolling blackouts, and the bulk-power system in other regions was significantly stressed. FERC, NERC, and NERC's Regional Entities announced on December 28, 2022 that they would open a joint inquiry into the operations of the bulk-power system during the extreme winter weather conditions that occurred during Winter Storm Elliott. On November 7, 2023, FERC and NERC released the Winter Storm Elliott report which recommends the completion of cold weather reliability standard revisions and suggests improvements to reliability for U.S. natural gas infrastructure.[211]

210 *New England Winter Gas-Electric Forum,* Docket No. AD22-9-000, (September 8, 2022 and June 20, 2023).

211 *See* Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (October 2023), https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.

Chapter 4

U.S. Crude Oil and Petroleum Products Markets

U.S. CRUDE OIL AND PETROLEUM PRODUCTS MARKETS

Petroleum, or crude oil, and its derived products play a key role in the U.S. economy, accounting for approximately 24 percent of primary energy consumption in the U.S. in 2021.[180] Petroleum is not directly consumed in its natural form, but is distilled and refined into an array of products that can be used for various applications. These include fuels for transportation, power generation, and heating. Other applications include petrochemical feedstocks used to manufacture various products, such as plastics, pharmaceuticals, fertilizers, and construction materials. Petroleum is especially important in the transportation sector, where it accounted for 90 percent of all transportation fuels used in 2021.[181]

Petroleum and petroleum products, such as gasoline, diesel fuel, and jet fuel, are domestically produced and imported. The percent of imported petroleum and petroleum products has been decreasing in recent years as U.S. crude oil production from shale has increased. Approximately 79 percent of the domestic U.S. crude oil production comes from three states-- Texas, New Mexico, and North Dakota--and federal offshore fields located in the Gulf Coast (PADD 3).[182] U.S. refineries, which separate crude oil into usable products, are found throughout the country but are most heavily concentrated on the Gulf Coast. Total U.S. refining capacity peaked in 2020 but has since fallen for two consecutive years.[183]

FERC Jurisdiction

FERC's jurisdiction over the oil markets is limited to the setting of interstate oil pipeline transportation rates and ensuring open access to the interstate oil pipeline system.

FERC JURISDICTION

Under the Interstate Commerce Act (ICA), FERC regulates the transportation of oil in interstate commerce. The ICA requires that all charges made for the transportation of oil or oil products be just and reasonable, and not unduly discriminatory.[184] In this regard, FERC does not regulate the oversight of oil pipeline construction or oil pipeline safety.

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

- Regulating rates and practices of oil pipeline companies engaged in interstate transportation;
- Ensuring the provision of pipeline transportation to shippers on a non-discriminatory and non-preferential basis; and
- Establishing just and reasonable rates for transporting crude oil and petroleum products by pipeline.

Outside of FERC's jurisdictional responsibilities, the regulation of crude oil and petroleum product pipelines falls under a number of different government entities. The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) is

180 Derived from EIA, *Monthly Energy Review*, *1. Energy Overview*, *Table 1.2 Primary Energy Production by Source*, *Annual* (accessed October 2022), https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T01.02#/f=A&start=2017&end=2017&charted=1-2-3-4-6-13.

181 *Id., 2. Energy Consumption by Sector, Table 2.5 Transportation Sector Energy Consumption, Annual* (accessed October 2022), https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T02.05#/?f=A .

182 Derived from EIA, *Crude Oil Production, Annual-Thousand Barrels per Day* (accessed October 2022), https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.

183 *See* EIA, *Today in Energy, U.S. refinery capacity decreased during 2021 for second consecutive year* (June 29, 2022), https://www.eia.gov/todayinenergy/detail.php?id=52939.

184 *See* 49 App. U.S.C. §§ 1(5)(a) and 3(1).

responsible for regulating and ensuring the safe and secure movement of hazardous materials to industry and consumers by all modes of transportation, including pipelines. PHMSA's 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. Federal regulatory approval is not ordinarily required for siting of new crude oil and petroleum product pipelines, unless the pipelines cross federal lands. Generally, state and local laws are the primary regulatory factors for siting crude oil and petroleum product pipelines.

Petroleum Characteristics

Petroleum is a mixture of hydrocarbons that were primarily formed from plants and organisms that lived millions of years ago. It is found in tiny spaces within sedimentary rocks, in underground reservoirs, or near the surface in tar (or oil) sands. Crude oil is highly heterogeneous, and naturally ranges in density and consistency, depending on the geological setting. Its color can vary from a light golden yellow to a deep black.

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

Crude oil that is light and sweet usually commands higher prices than heavy, sour crude oil. This is partly because gasoline and diesel fuel, which typically sell at a significant premium to the heavier products produced in the refining process, are more readily and cheaply produced from light, sweet crude oil. However, individual refineries are optimized to process crude oil with specific properties, and deviations from any given refinery's optimal crude oil can significantly impact profitability. Thus, the value of a given crude oil can often be refinery specific.

Density of an oil (API Gravity)

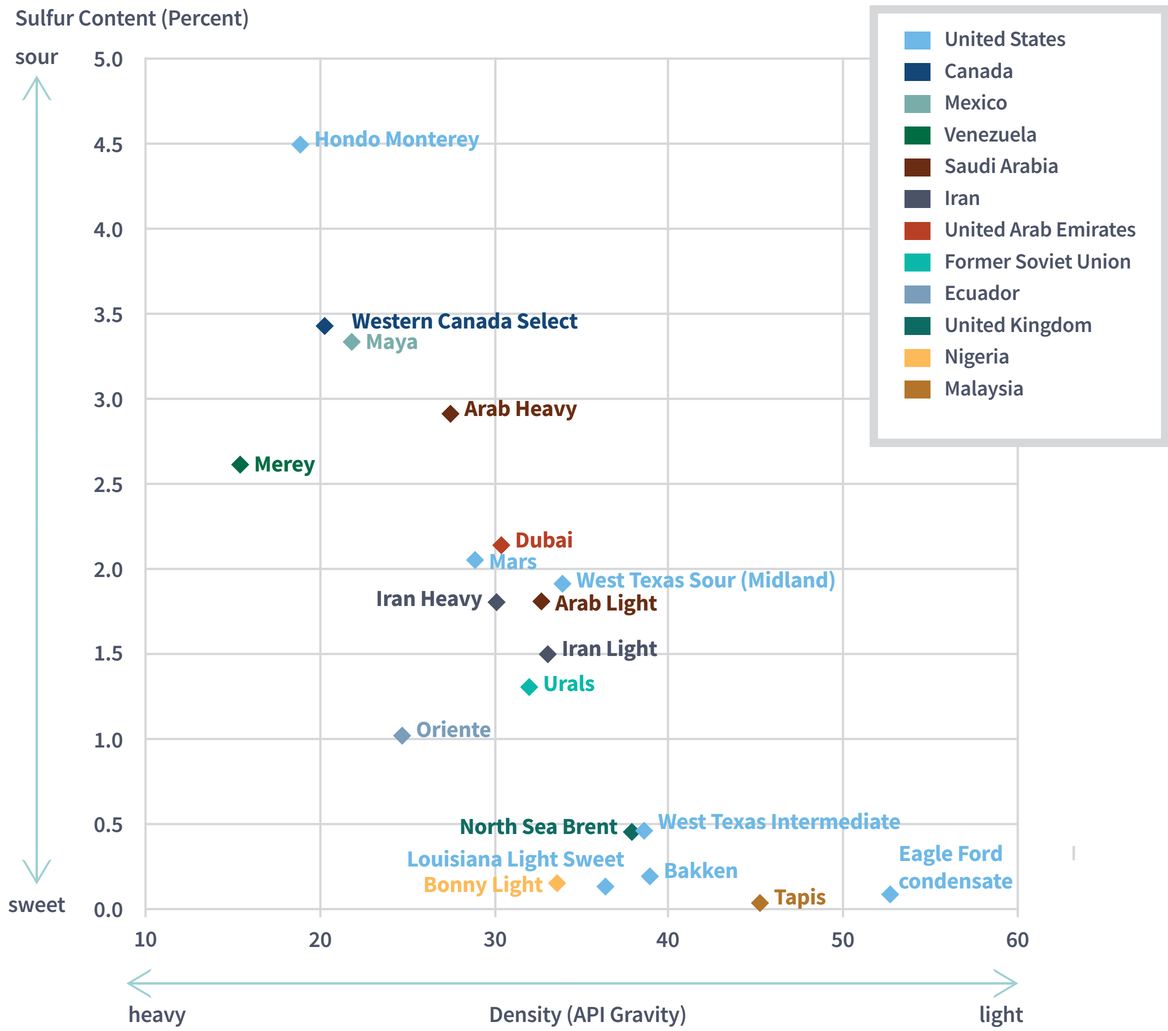
The density, or "weight," of an oil is one of the largest determinants of its market value (another key characteristic is sulfur content – see text box, "Sweet or Sour?"). The density of crude oil is often referred to as "light" or "heavy" and is measured using the American Petroleum Institute's (API) density index also known as API gravity. API gravity is determined using the specific gravity of crude 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 between 10 and 22.2	Extra Heavy – API < 10.0

However, crude oil may be categorized differently depending on the region where it is produced and how the crude 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 the density of crude oil, which means the denser an oil the lower its API gravity. An API of 10 is equivalent to water, which means crude oil with an API above 10 will float on water while crude oil with an API below 10 will sink. Crude oil that is light and sweet usually commands higher prices than heavy, sour crude oil.

Figure 4-1: Density and Sulfur Content of Selected Crude Oils



Source: EIA[185]

Benchmark Crude Oil

A benchmark crude oil is a specific product 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. WTI and Brent are two major benchmark crude oils. WTI is a U.S. benchmark crude and Brent is the most commonly used benchmark in global trade. A third major benchmark, Dubai, is mostly used in Asian trade

185 *See* EIA, *Today in Energy, Changing quality mix is affecting crude oil price differentials and refining decisions* (September 21, 2017), https://www.eia.gov/todayinenergy/detail.php?id=33012.

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 results in lower maintenance costs over time. Due to these factors, sweet crude commands a price premium over sour crude.

Major sources of sweet crude include the Appalachian Basin in Eastern North America, West Texas, the Bakken Formation of North Dakota and Saskatchewan, Saudi Arabia, the North Sea of Europe, North Africa, Australia, and parts of Asia, including Indonesia.

Sour crude oil has greater than 0.5 percent sulfur, with some of the sulfur in the form of hydrogen sulfide, known for its "rotten egg" smell. Hydrogen sulfide is considered an industrial hazard and, thus, sour crude must be stabilized by removing 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 Organization of Petroleum Exporting Countries (OPEC) member nations also tends to be relatively sour, with an average sulfur content of 1.77 percent.

U.S. Crude Oil Supply

PETROLEUM RESERVES

Crude oil resource estimates are categorized in several ways. The most certain is the category "proved reserves," which takes into account the potential to extract crude oil based on current technology and economic feasibility.

At the end of 2020, there were an estimated 38 billion barrels of proved crude oil and condensate reserves in the U.S.[186] While the measure can fluctuate from year to year, from 2009[187] to 2020, proved reserves increased by more than 40 percent. This growth was substantially driven by exploration and drilling in shale formations and technological advances, such as horizontal drilling and hydraulic fracturing (horizontal drilling and hydraulic fracturing were discussed in Chapter 1, Wholesale Natural Gas Markets).

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.

Shale and tight oil formations accounted for 48 percent of all U.S. crude oil proved reserves by the end of 2020.[188] The top areas in the country for proved crude oil reserves are in New Mexico and Texas (home to the Permian and Eagle Ford basins)

186 *See* EIA, *U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2020,* at 1 (January 2022), https://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf.

187 Derived from EIA, *U.S. Crude Oil, Natural Gas, Natural Gas Liquids Proved Reserves*, 2009 (November 30, 2010), https://www.eia.gov/naturalgas/crudeoilreserves/archive/2009/cr2009.html.

188 Derived from EIA, *U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2020*, at 13 (January 2022), https://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf.

and North and South Dakota (home to much of the Bakken and Three Forks formations).[189]

Outside the U.S., other top countries by proved reserves include Venezuela and Canada. As a region, most of the world's proved reserves are in the Middle East, including Saudi Arabia, Iran, Iraq, Kuwait, and the United Arab Emirates.[190]

DOMESTIC PRODUCTION AND IMPORTS

From the 1970s to the early 2000s, the U.S. imported a growing proportion of its crude oil supply and petroleum products, which peaked at 13.7 million barrels per day (MMbd), or 67 percent of total U.S. supply in 2005. However, improvements in domestic production that started in the late 2000s began a reversal of that trend. In 2021, imports of crude oil and petroleum products fell to 8.5 MMbd, or 34 percent of the total U.S. supply.

Crude oil imports to the U.S. came from over 65 countries in 2021. Canada was the largest foreign supplier to the U.S. supplying more than 51 percent of U.S. total imports, which included the robust output from the oil sands region in Alberta.[191] The second-largest supplier to the U.S. was Mexico, followed by Russia and Saudi Arabia.[192]

Just as the case with proved reserves, the increase in domestic oil production followed the successful commercialization of horizontal drilling and hydraulic fracturing. Texas has historically been the largest producer among the states and has also substantially increased its production output with shale oil from its Eagle Ford (South Texas) and Permian Basin (West Texas) formations. The overall production in Texas reached 4.8 MMbd in 2021, up from an average of 1.1 MMbd from 2000 through 2010.[193]

New Mexico, also home to the Permian Basin, produced 1.25 MMbd in 2021, the second most from an individual state, up from an average of only 0.17 MMbd between 2000 and 2010.[194] Finally, North Dakota, with its Bakken Shale, produced 1.1 MMbd in 2021, the third most from an individual state, up from an average of only 0.132 MMbd between 2000 and 2010.[195]

Because increases in shale production have driven nearly all U.S. oil production growth since 2008, most of the new supply is light, sweet oil, which has also affected refinery investments and operations. These refinery changes, likewise, tend to influence future changes in the types of crude oil imported and processed in U.S.

Crude Oil and Petroleum Products Demand

The largest demand sector for petroleum products in the U.S. is transportation, which accounted for approximately 90 percent of total domestic consumption in 2021. Among the specific product categories, motor gasoline alone made up 57 percent of petroleum products sold by prime suppliers into the U.S. market. The second largest was No. 2 distillate, accounting for 28 percent of sales, which includes diesel fuel, fuel

189 *Id*.

190 *See* BP, *Statistical Review of World Energy 2021*, at 16, https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-full-report.pdf.

191 Derived from EIA, *U.S. Imports by Country of Origin, Total Crude Oil and Products, Monthly-Thousand Barrels, U.S.* (accessed October 2022), https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbbl_m.htm.

192 *Id.*

193 Derived from EIA, *Texas Field Production of Crude Oil, Total Crude Oil and Products, Monthly-Thousand Barrels, U.S.* (accessed October 2022), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPTX2&f=A.

194 Derived from EIA, *New Mexico Field Production of Crude Oil, Annual* (accessed October 2022), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpnm1&f=a.

195 Derived from EIA, *North Dakota Field Production of Crude Oil, Annual* (accessed October 2022), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPND2&f=A.

oil for space heating, and, in a lesser capacity, oil for electric generation. The third-largest demand category was jet fuel, with nine percent of sales.[196]

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

Other petroleum products include propane used for space heating and in agricultural and 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 (includes No. 5 and No. 6 fuel oils) used in power generation and ship boilers; and asphalt used to build roads.

Crude Oil Refining

In 2021, the U.S. had over 17 MMbd of operating refinery capacity.[197] For historical reasons dating back to gasoline rationing during World War II, the country is divided into five geographical regions called Petroleum Administration for Defense Districts (PADDs).[198] The majority of U.S. refining capacity is located in the Gulf Coast, in PADD 3. In 2021, approximately 53 percent, or 9.3 MMbd of refining capacity was located in PADD 3.

Most of the larger and more modern refineries are situated along the Gulf Coast in Texas, Louisiana, Mississippi, and Alabama. Many refineries are located close to the traditional crude oil production areas, near import centers in the Gulf Coast or proximate to major population centers where demand for refined products is greatest, including California and the metropolitan areas of New York City and Chicago. However, shutdowns have reduced U.S. refinery capacity across the U.S. Six refineries closed or were converted to renewable diesel facilities between 2020 and 2021, totaling 750,000 barrels per day of lost capacity.[199] These closures or conversions were mainly due to reduced demand for crude oil distillation.

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. Distillation occurs in a fractionating column, which uses a temperature differential across the column to separate the liquid mixture into its component parts. The heat causes the lighter, more volatile hydrocarbon molecules to vaporize and rise. As they cool, the heavier components with higher boiling points, such as heavy fuels and residual fuels, liquefy and settle into trays where they 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 (a byproduct used in solvents). Depending on the refinery configuration, heavier components may be further processed to yield additional 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[200] and cokers[201].

196 Derived from EIA, *Prime Supplier Sales Volume*, *U.S.*, *Annual* (accessed October 2022), http://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_a.htm.

197 Derived from EIA, *Refinery Utilization and Capacity*, *U.S.*, *Annual* (accessed October 2022), https://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_a.htm.

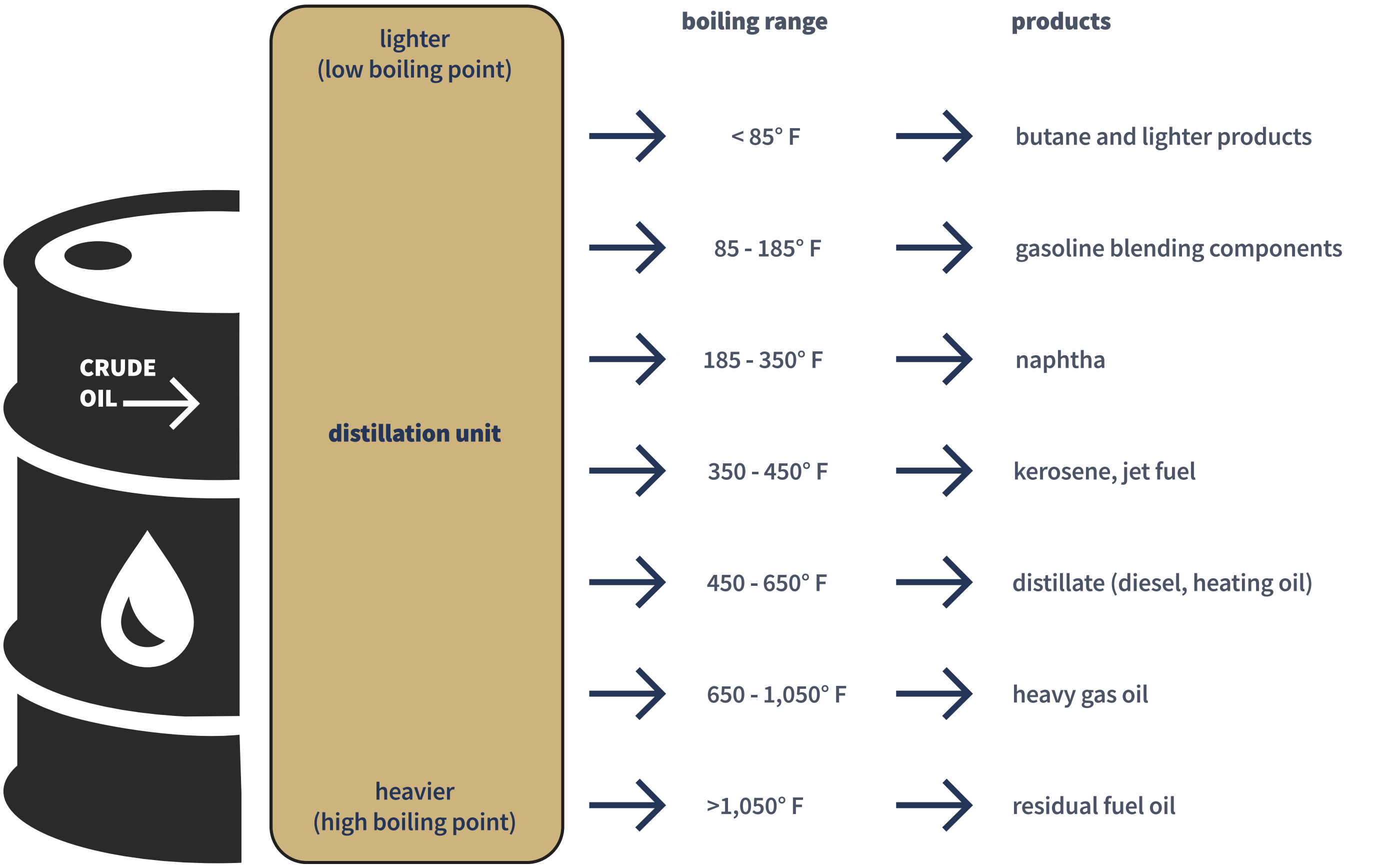
198 *See* https://www.eia.gov/petroleum/marketing/monthly/pdf/paddmap.pdf for a map of PADD locations.

199 Derived from EIA, *Annual Energy Outlook*, *Production* (accessed March 3, 2022), https://www.eia.gov/outlooks/aeo/narrative/production/sub-topic-03.php.

200 Catalytic cracking is the process used to convert high molecular weight hydrocarbon fractions of crude oil into gasoline, olefinic gases, and other petroleum products.

201 A coker is a machine that converts residual oil into low molecular weight hydrocarbon gases, naphtha, light and heavy gas oils, and petroleum coke.

Figure 4-2: Diagram of a Basic Distillation Unit



Source: EIA[202]

Crude Oil and Petroleum Products Transportation

There are nearly 150,000 miles of crude oil and petroleum product pipelines in the U.S.[203] Crude oil pipeline mileage grew by nearly 28,000 miles, or 23 percent, between 2012 and 2020, and was driven by increased shale production.[204] Crude pipelines move oil from the production fields and import terminals to refineries for processing. Pipelines then distribute the refined fuels to consumers across the country.

The operators of the three largest crude oil and liquids pipelines in North America are Enbridge Energy, Colonial Pipeline Company and Transcanada. Enbridge Energy operates one of the longest crude oil and liquids transportation systems in the world. Enbridge Energy's pipelines transported 1.1 trillion barrel-miles in 2021,

202 *See* EIA, *Oil: Crude and Petroleum Products Explained, The Refining Process* (August 14, 2018), https://www.eia.gov/energyexplained/oil-and-petroleum-products/refining-crude-oil.php#tab2.

203 Derived from API-AOPL, *Annual Liquids Pipeline Report*, at 45 (2021), https://liquidenergypipelines.org/Documents/en-us/1e14ec3b-9b98-46f3-aa54-808792b8a13a/1.

204 *Id*. and Derived from API-AOPL, *Annual Liquids Pipeline Report*, at 45 (2018), https://www.pipelaws.com/wp-content/uploads/sites/451/2018/05/2018-Annual-Liquids-Pipeline-Report-API-AOPL.pdf.

the most among crude oil pipelines.[205] Enbridge Energy's vast network of oil and liquids pipelines travel from Canada and North Dakota to the Midwest and Gulf Coast.[206] The second largest pipeline is Colonial Pipeline Company, with 722 billion barrel-miles transported in 2021.[207] It carries supply from the refining centers in Texas and Louisiana to the major demand centers along the U.S. East Coast. It also transports gasoline, diesel fuel, jet fuel, and other products from Houston, Texas to Linden, N.J. on a 5,500-mile network, crossing 13 states. A distant third-largest pipeline is the TransCanada Keystone Pipeline, which transported 239 billion barrel-miles of crude oil in 2021 from Canada to the U.S. Mid-Continent and the Gulf Coast.[208]

MOVEMENT OF CRUDE OIL WITHIN AND EXPORTS FROM THE U.S.

Two federal statutes have played a role in shaping the movement of crude oil and crude oil products. First, the Jones Act[209] generally prohibits any foreign-built or foreign-flagged vessel from engaging in trade that begins at any point within the U.S. and delivers commercial cargo to any other point within the U.S.[210] 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 domestic marine ports is periodically constrained. That means, for example, that producers can be 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 can be limited in their ability to move refined products up the East Coast via waterborne vessels.

The second was a ban on most exports of crude oil in a policy stemming from the 1970s oil crisis. While the ban was highly restrictive, certain licensed exports were allowed, including 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. The export ban was repealed in late 2015 as part of the Consolidated Appropriations Act of 2016.[211] Following the repeal, the U.S. exported 1.1 million barrels per day of crude oil to various countries in 2017, up from approximately 100 thousand barrels per day from 1975 through 2015, with Canada as the largest recipient of the exports.[212] In 2021, the U.S. exported nearly 3 million barrels per day of crude oil.

Crude Oil and Petroleum Products Markets and Trading

As a global commodity, crude oil's price on the world markets is set by the traders who buy and sell the commodity at various locations around the world. However, most trades are based on, or derivative to, a handful of benchmark crude prices, such as WTI, Brent, and Dubai. There are also benchmark locations for petroleum products, including New York Harbor in the

205 Derived from FERC, *2021/Q4 FERC Form 6*, at 600 (October 2022), Enbridge Energy Limited Partnership, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=94740646-9F0A-C0FE-9363-803547600000, Enbridge Pipelines (FSP) L.L.C., https://elibrary.ferc.gov/eLibrary/filedownload?fileid=4D1DAA66-FF9C-CE65-9097-80298B700000, Enbridge Pipelines (Southern Lights) LLC, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=1E0DC7DE-8645-C597-86FC-803DE5D00000, Enbridge Pipelines (Toledo) Inc., https://elibrary.ferc.gov/eLibrary/filedownload?fileid=A4795E1D-B912-CC17-91BF-802966E00000, Enbridge Transportation (IL-OK) L.L.C, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=655EE23C-DC4D-C0A7-93AB-802959200000, Enbridge Storage (Patoka) LLC, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=4F6065E6-3AF8-C503-9950-803DB3B00000.

206 *See* Enbridge Energy, *Infrastructure Map*, https://www.enbridge.com/Map.aspx#map:infrastructure,crudeInfrastructure.

207 Derived from FERC, 2021/Q4 FERC Form 6, at 600 (October 2022), Colonial Pipeline Company, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=9DDCCC5F-E2E1-C84F-9260-803E93F00000.

208 Derived from FERC, *2021/Q4 FERC Form 6*, at 600 (October 2022), TransCanada Keystone Pipeline, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=4A0CEFEC-C81F-C8E8-9161-801F47F00000.

209 The term "Jones Act" refers to section 27 of the Merchant Marine Act of 1920, 46 U.S.C. § 50101, *et seq.* (2012).

210 46 U.S.C. at § 55102.

211 Consolidated Appropriations Act, 2016, Division O – Other Matters, Title I, Sec. 101 (a – b).

212 *See* EIA, *This Week in Petroleum* (March 7, 2018), www.eia.gov/petroleum/weekly/archive/2018/180307/includes/analysis_print.php.

U.S., Amsterdam-Rotterdam-Antwerp (ARA) in Europe, and Singapore in Asia.

Domestic crude oil markets are more closely tied to global trends than U.S. natural gas markets because of the tremendous worldwide production of crude oil which enjoys relatively low shipping costs.[213] In comparison, natural gas faces additional costs to ship overseas because of the need for liquefaction and regasification facilities, which require multi-billion dollar investments.

World crude oil prices have historically experienced periods of great volatility, often driven by supply and demand fundamentals and external shocks, such as production disruptions related to geopolitical events and speculative trading. Crude oil prices rose following supply disruptions that occurred during international events such as the Arab Oil Embargo in 1973 and 1974, the Iranian Revolution, the Iran-Iraq War in the 1980s, and the Persian Gulf War in 1990 and 1991. For example, WTI spot prices were $4.31 per barrel (bbl) in June 1973, but by December 1974, crude oil prices reached $11.16/bbl, a 159 percent increase. Global economic events can also affect crude markets. For instance, during the recession of 2008 and 2009, the WTI benchmark reached $145.31/bbl on July 3, 2008 and, by December 23, 2008, the price had fallen to $30.28/bbl, a decline of nearly 80 percent due to falling earning projections and credit contractions that, a result of decreased demand. Similarly in a more dramatic fashion, the WTI benchmark seemingly collapsed overnight into negative territory from $18.31/bbl on April 17, 2020 to negative $36.98/bbl on April 20, 2020 due to the COVID-19 pandemic triggering an unprecedented demand shock for oil. The culmination of stay-at-home mandates, restricted travel, and closed economies created an oversupply that left producers scrambling to find space to store the crude oil. The reopening of the economy lifted prices from pandemic lows, eventually peaking at $123.64/bbl on March 8, 2022, due to heightened geopolitical tensions and speculation in Europe before coming back down to a steady $82.59/bbl on September 7, 2022.[214]

From 1987 through 2010, WTI and Brent benchmarks traded within a few cents of each other, with WTI benchmark generally commanding a small price premium. However, the sharp increase in production of shale oil in the U.S. resulted in a surge in supply at Cushing, causing WTI benchmark prices to drop below the Brent benchmark. Between 2011 and 2014, the Brent benchmark price reached a premium of $29/bbl in September 2011, but the spread narrowed to about $6/bbl by December 2017.[215] Crude oil became oversupplied at Cushing because of large increases in oil production that outpaced the development of transportation and storage infrastructure. The then-current ban on exports of crude oil further limited the options for addressing the supply pressures. Since 2011, the construction of additional infrastructure combined with the repeal of export restrictions has reduced the oversupply at Cushing and, in turn, narrowed the price differential between the WTI and Brent benchmarks, to an average of $2.72/bbl in 2021.

213 *See* EIA, *Low Tanker Rates Are Enabling More Long Distance Crude Oil and Petroleum Product Trade* (October 27, 2016), https://www.eia.gov/todayinenergy/detail.php?id=28532.

214 Derived from Federal Reserve Bank of St. Louis, *Crude Oil Prices: West Texas Intermediate (WTI) – Cushing, Oklahoma* (accessed October 2022), https://fred.stlouisfed.org/series/DCOILWTICO.

215 Derived from EIA, *Spot Prices (Crude Oil)* (September 6, 2018), https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

Chapter 5
Trading and Capital Markets

TRADING AND CAPITAL MARKETS

Restructuring of the energy markets and changes in the industry during the 1980s and 1990s resulted in the expansion of the commodity markets associated with natural gas and electricity. In particular, restructuring resulted in the growth of financial products that derive their value from the underlying energy products. Expansion in physical and financial market trading for natural gas and electricity has tightened the traditional relationship between these markets. As a result, activities in the physical markets affect values in financial markets. Likewise, activities in the financial markets can also affect values in the physical markets.

This chapter explores the trading of physical and financial contracts for natural gas and electricity. It also provides an overview of capital markets and their importance to investments in industry infrastructure.

Trading Physical and Financial Natural Gas and Electricity

Natural gas and electricity are often bought and sold using standardized contracts. The standard terms and conditions and standard product definitions of such contracts appeal to a wide variety of market participants because they need only negotiate on terms such as price, term, quantity and delivery point. Contracts can also be customized to meet the needs of individual buyers and sellers through a vast array of differing pricing and delivery mechanisms, as well as customized terms and conditions. Contracts in the physical and financial natural gas and electricity markets can also be referred to as instruments or securities.

In general, a physical contract provides an obligation to physically deliver natural gas or electricity in exchange for payment.[216] As discussed in Chapters 1 and 2 (Wholesale Natural Gas Markets and Wholesale Electricity Markets), producers and consumers of natural gas and electricity sell and buy energy products to manage price and volatility risk in a variety of their enterprise operations that include production, marketing, and meeting customer demand.

When a contract does not require the delivery of natural gas or electricity but instead provides a right to a financial payout in exchange for a payment, the contract is referred to as a financial contract or swap.[217] The payment is typically based on the underlying value of the physical commodity or index[218] of asset values or financial products specified by the contract. Under such a contract, the commodity or index is called the underlying or underlier. Because the value of the financial contract is derived from the value of the underlier, the contract is also called a derivative, which is a general term for a contract whose value is derived from some other physical or financial product.

Market participants buy and sell energy-based financial contracts for a number of reasons. As mentioned above, physical market participants, such as producers and consumers, typically use financial contracts to manage price risk and protect against price volatility. That is, financial contracts can serve as a tool for managing risk akin to insurance. Other market participants use the energy markets to speculate, or to assume a market risk in the hope of profiting from market fluctuations.

216 As discussed below, a buyer of a commodity under a physical contract may in many instances elect not to take delivery. The buyer may do so by reselling the commodity, where the reselling is referred to as obtaining an offsetting contract.

217 Many financial contracts are standardized, regulated products called cash-settled energy futures.

218 Indices are weighted average prices for a group of transactions over a given time frame at a specified location.

CONTRACT CHARACTERISTICS

Every contract, whether physical or financial, is identified by a number of characteristics, such as the product conveyed, location, timeframe, size or quantity, and the price or mechanism for determining the settlement. Additionally, there are different types of contracts based on uses and obligations of the participants, which are further described in the section below on Contract Types.

Product conveyed: Each contract specifies what is being bought and sold. For physical contracts, the product bought or sold would be natural gas or electricity. For derivatives, a payout may be derived from natural gas or electricity prices.

Location: Standardized contracts trade on exchanges and on Over the Counter (OTC) electronic brokerage platforms. For example, the InterContinental Exchange (ICE) offers trading of standardized physical contracts and cash-settled energy futures at predetermined locations or pricing points (exchanges and OTC transactions are discussed further below). Natural gas and electricity are traded at different locations throughout the country. Natural gas trading locations are usually located at the intersections of major pipeline systems, pipeline zones, near storage facilities, locations where local distribution companies (LDCs) receive natural gas from pipelines, and pooling points. Standard trading locations are referred to as market hubs. The Henry Hub is the U.S. natural gas benchmark hub and is also the delivery point for the New York Mercantile Exchange (NYMEX) natural gas futures contract. For electricity, contracts are often based on locations known as nodes, zones, or hubs. Examples of frequently traded electricity locations are the PJM Western Hub and the Mid-Columbia Hub. For physical contracts, the location must be physically viable – a location where natural gas or electricity can actually be delivered. Because financial contracts do not result in actual physical delivery, the contract may reference a location that is not physically viable – the location is only used in determining the price that will be paid for a specific quantity. Off-exchange bilateral OTC transactions can use any location desired by the counterparties. This allows traders to negotiate complex pricing mechanisms based on a number of locations.

Timeframe: Each contract has a number of time elements. The trade date is the date on which the contract is executed. The termination date is the last day of the contract term. The settlement date establishes when payment is due under the contract. Also, physical contracts specify the delivery day(s) or month – the day(s) or month during which the product is to be delivered. Physical and financial electricity contracts may also specify peak or off-peak delivery, with the peak or off-peak hours defined by the contract and reflecting the North American Energy Standards Board (NAESB) contract definitions.

For physical contracts, begin and end dates are the timeframe during which a physical product (natural gas or electricity) is to be delivered. Next-day physical natural gas contracts often have the same begin and end flow dates; however, on weekends and holidays, flow days can span multiple days for delivery. For example, a next-day physical natural gas contract may have a trade date of Thursday, August 25, a begin flow date of Friday, August 26, and an end flow date of Friday, August 26. The weekend strip may have a trade date of Friday, August 26, a begin flow date of Saturday, August 27, and an end flow date of Monday, August 29. A monthly physical natural gas contract may have a trade date of Thursday, August 25, a begin flow date of Thursday, September 1, and an end flow date of Friday, September 30. Monthly physical contracts are generally for delivery in equal parts per gas day over a month for natural gas and equal parts per hour for electricity. For financial contracts, the begin and end dates indicate the underlying natural gas or power days' index and settlement prices to be used in setting the payout for a specific quantity of natural gas or power.

Quantity: All physical contracts specify the amount of natural gas or electricity to be delivered. For standardized products traded on a futures exchange or on an OTC electronic brokerage platform, the quantity is predetermined and specified in the contract. For off-exchange contracts traded in OTC markets, the contract quantity can be any amount agreed upon by the parties.

Price: All physical contracts specify a price that will be exchanged for physical delivery. All financial contracts specify a price, or prices, which will determine a cash exchange between the two parties.

Fixed prices are known at the time a transaction is entered into. The fixed price is a set price at which the seller agrees to sell, and the buyer agrees to buy. A fixed price would be represented, for example, as $3 per million British thermal units (MMBtu) for natural gas or $30 per megawatt-hour (MWh) for electricity.

Floating prices are not known at the time a transaction is entered into but will be known at the time of settlement. For example, a price may be tied to the average of all the daily prices at a location over the course of a month, typically published as an index. Indices referenced in contracts in the natural gas market are published using a known methodology by a variety of index developers, such as S&P Global Commodity Insights (also known as Platts) or Natural Gas Intelligence (NGI).[219] NYMEX and other exchanges also post prices for standardized contracts that can be referenced in contracts. Electricity contracts often reference the Locational Marginal Prices (LMPs) set by the regional transmission organizations (RTOs) and independent system operators (ISOs) (see Chapter 2) or indices calculated by exchanges such as ICE.

Options contracts also include prices, such as a strike price and a premium. Options contracts are discussed in more detail in the following section.

CONTRACT TYPES

The most common contract types are forwards, futures, swaps, and options.

Physical Forward Contract: A forward contract is an agreement between two parties to receive or deliver a commodity at a specified time in the future. A forward contract is often used for physical delivery. The buyer pays an agreed-upon forward purchase price and the seller delivers the natural gas or electricity on the designated date. The product is physically settled with delivery.

Financial Forward Contract: Forward contracts may also be financially settled when no delivery of a commodity takes place, also known as a swap contract. A financially settled contract, also referred to as cash settled, has the parties paying and receiving in cash the loss or gain based on the price of the underlying product. A forward contract may also be traded off-exchange.

Cash Settled Energy Futures: After passage of the Dodd-Frank Act,[220] many financially settled energy contracts traded on electronic brokerage platforms are cleared cash, settled energy futures contracts.[221]

Physical Futures Contract: A futures contract is a standardized forward contract that is traded on an exchange, such as CME's NYMEX[222]. 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 specific time period of delivery and receipt is the same for all contracts traded for a particular calendar month. Because futures are interchangeable with one another

219 Data used for developing price indices is collected from market participants who voluntarily report the quantities and prices of their trades to the index developers. Some index developers incorporate trades from ICE in their indices.

220 The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 reformed the regulation of swaps. *See* https://www.cftc.gov/LawRegulation/DoddFrankAct/index.htm for more information.

221 *See* https://www.cmegroup.com/market-data/browse-data/cash-settled-futures.html for examples of cash-settled futures products.

222 The Group owns NYMEX. The CME Group offers a marketplace for derivatives composed of its exchanges: Chicago Mercantile Exchange (CME), New York Mercantile Exchange (NYMEX), Chicago Board of Trade (CBOT), and COMEX (formerly known as the Commodity Exchange, Inc.). See CME Group, Driving Global Growth and Commerce (n.d.), https://www.cmegroup.com/company/history/.

and are traded on centralized exchanges, futures markets generally are more liquid than forward markets.

Option Contract: An option is an instrument that gives its holder the right, but not the obligation, to buy or sell an underlying physical or financial contract at a set price for a set time period. The right to buy the underlying contract is called a call option, and the right to sell is called a put option. The price paid to buy or sell the option is known simply as the option's price or premium. The price at which the underlying contract may be bought or sold is the strike price. Electing to buy or sell the underlying commodity or security at the future date is known as exercising the option. An option's expiration date is the last date at which an option may be exercised. The options themselves may be bought or sold and are frequently standardized and traded on an exchange. Options traded on an exchange or an electronic trading platform may be traded up to the contract's expiration. The owner of an option may sell the option rather than exercise the option or may let it expire if it is not profitable to exercise it. Traders may use options to boost profits through more complex trading strategies or to reduce the volatility of their returns.

EXAMPLES OF CONTRACTS

Electricity Forward Contract

In the electric industry, the Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement is a commonly used contract that can be employed for forward sales of power. Transacting parties may make a bilateral sale by agreeing to transaction-specific values for price, quantity, delivery location, and period of delivery, among other details pertinent to the negotiated transaction. The terms of the transaction are documented on a transaction-specific confirmation.

NYMEX Natural Gas Futures Contract

For the natural gas industry, the dominant physical futures contract is the NYMEX Henry Hub Natural Gas (NG) Futures contract. For NYMEX's NG 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 flow month.

LD1 Future or Natural Gas (Henry Hub) Financial Future

The physically deliverable NYMEX NG contract has its prompt-month[223] strip expire on the third to last business day of the month. The NG contract's Last Day 1 (LD1) settlement price is set during a 30-minute settlement window on its expiration day from 2pm to 2:30pm Eastern Prevailing Time. The settlement price is used to settle the legs of many financial and physical contracts. The simplest contract is the cash settled LD1 future, also known as NYMEX lookalike contracts or Natural Gas Financial Futures product. These are simple fixed-for-float swap futures in which the buyer pays a price and receives the LD1 settlement price if taken to settlement. Such contracts allow a market participant to maintain or hedge a price exposure without having to make or take physical delivery of the natural gas commodity.

Natural Gas Basis Future

A basis swap contract or basis future is a financial instrument that provides payments calculated on the price difference between a month-ahead index at a given location and the Henry Hub LD1 settlement price. An example is the ICE Michcon Basis Futures contract, in which traders buy and sell the contract, which derives its price from the subtraction of the NYMEX Henry Hub Futures contract price from the Mich Con city-gate Inside FERC monthly price. Basis futures can trade strips of a single month or multiple months, the settlement is determined each month until the contract expires, and the standard contract size is 2,500 MMBtu per flow day. Traders can use natural gas financial basis contracts for either hedging or speculative trades.

Natural Gas Index Future

An index swap contract or index future is a financial

223 The prompt month is the futures contract that is closest to expiration, typically prompt-month refers to the next contract month.

instrument that provides payments calculated on the price difference between a given location's averaged day-ahead index for a month and that month's first-of-month index set in the bidweek just before the start of the month. The ICE Michcon Index Futures contract allows traders to buy and sell a contract that derives its price from the subtraction of the Mich Con city-gate Inside FERC monthly price from the average of the Mich Con city-gate Platts Gas Daily prices over the flow days of a given month.

Natural Gas Swing Future

A swing swap contract or swing future is a financial instrument that provides payments based on the location's day-ahead index. ICE's Michcon Swing Future contract allows traders to buy and sell a contract that derives its price from the average of the Mich Con city-gate Platts Gas Daily prices over specific flow days. In addition to trading as full month strips, swing futures can trade during the flow month, providing a balance-of-month strip for the remaining flow days in the month.

Natural Gas Fixed Price Future

A fixed price future is a financial instrument that provides payments based on the location's month ahead index. ICE's Michcon Fixed Price Future contract allows traders to buy and sell a contract which derives its price from the Mich Con city-gate Inside FERC monthly price.

Natural Gas Options Contract

A natural gas options contract, such as ICE's Option on SoCal Fixed Price Futures (the futures price for the Southern California Border trading hub published by the Natural Gas Intelligence index), gives the purchaser the right, but not the obligation, to buy a specified number of fixed price futures contracts at a predetermined price, at a future date. The put option gives the option buyer the right, but not the obligation, to sell the fixed price futures at a minimum selected floor (strike) price. A natural gas consumer, such as a gas-fired power plant, might buy a call option to protect against having to pay more for natural gas than the selected strike price. Similarly, a natural gas producer or marketer could use a put option to protect against price drops below the strike price as a means of ensuring the profitability of future natural gas production. Traders also use options to speculate on the price of the underlying commodity, in anticipation of future market prices or as part of more complex financial trades.

Forward and Futures Curves

Standardized forwards, futures, and swaps are traded for every month, years into the future. The NYMEX natural gas futures contract, for example, is traded more than eight years into the future although only the first few years are actively traded. Each of the monthly contracts for which trading occurs has a price. Together, the prices for future contract months create a trajectory of prices known as the forward or futures curve.

Markets for Trading Physical and Financial Natural Gas and Electricity

As mentioned above, contracts in both physical and financial markets are transacted through exchanges, OTC electronic brokerage platforms, or off-exchange. With exceptions for cleared physical futures or trading, physical trading on electronic brokerage platforms is generally bilateral and OTC. Off-exchange trading inherently occurs bilaterally OTC. In the case of electricity, transactions also take place in RTOs and ISOs (see Chapter 2 for more information on RTO/ISOs).

EXCHANGES

An exchange is a central marketplace where buyers and sellers trade commodities, derivatives, and other financial instruments. A market participant (e.g., a buyer or seller) does not interact directly with its counterparty on an exchange. Instead, the counterparties place their orders with the exchange, which then matches the buyer and seller anonymously. Exchange-traded contracts are standardized and the specifications for the contract, such as quantity and location, are established in advance by the exchange.

Historically, exchange trading occurred in trading pits where traders actively called out orders to buy and sell, known as open outcry. However, with the advent of electronic trading, open outcry has largely become obsolete, and most trading is now done electronically. Physical OTC trades on electronic brokerage platforms inherently require communication and coordination with a counterparty, which becomes known after a transaction. Electronic brokerage platforms trading in OTC markets provide an anonymized trading screen where buyers and sellers do not know their counterparty, and some platforms allow traders to communicate with bidding and offering counterparties in OTC products.

Natural gas and electricity are traded on exchanges and electronic brokerage platforms such as the NYMEX and ICE. In addition to energy contracts for natural gas and power, NYMEX facilitates the sale and purchase of financial and physical contracts for other commodities, including metals and agricultural products. ICE also offers natural gas and electricity contracts (both in cash-settled energy futures and physical OTC contracts), as well as emissions allowances. Nodal Exchange offers locational (nodal) futures contracts to market participants in the organized electricity markets, as well as electricity contracts for forward months at RTO hubs, zones, and nodes.

Margin is collateral contributed as a percentage of the current market value of a commodity contract. Margin allows market participants 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 another entity. The trader posts collateral by putting down a certain amount of money or percentage of the trade value in cash or other security acceptable to the exchange.

OVER-THE-COUNTER MARKETS

An OTC market is a market where buyers and sellers interact with one another, usually via electronic or telephone communications, and without the supervision of an exchange. In OTC markets, contracts are bilateral, meaning two market participants directly negotiate and complete a purchase or sale. OTC transactions are not required to be standardized; they range from complicated negotiations for one-off structured contracts to standardized contracts 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 markets. Nonetheless, standardized contracts can also be transacted OTC. Many negotiations begin with a standardized contract, such as the natural gas contract developed by the North American Energy Standards Board (NAESB), and are then modified.

OTC transactions may be conducted via brokers that include voice brokers (brokers who conduct most business by phone or instant messaging) and electronic brokerage platforms. Unlike an exchange, the broker performs the function of matching specific buyers and sellers. In OTC trades, buyers and sellers are not anonymous to one another.

RTO/ISO MARKETS

Electricity is also bought and sold through RTO/ISOs. In general, RTO/ISO markets are operated to support the physical operation of the electric grid, dispatching generation to meet customer demand. RTO/ISO markets are multilateral; buyers and sellers are not matched individually against each other. The overall level of buying, or demand, is matched to the overall level of selling, or generation. In matching generation and demand, RTOs/ISOs are considered to clear the market but the word clearing has a different meaning than other markets or exchanges. For RTOs/ISOs, clearing refers to the matching of supply and demand, or, put it another way, to clear the market means the RTO/ISO accepts sufficient generation offers to meet demand needs. In general, if a generator's offer in the day-ahead market clears, the generator's output was offered at or below the day-ahead locational marginal price, and the generator is expected to deliver power. RTO/ISOs also allow for bilateral physical transactions, although each RTO/ISO handles bilateral trades differently.

RTO/ISO markets have products that have some similarities to financial contracts. RTO/ISOs allow virtual transactions, such as virtual supply offers or virtual demand bids, which allow a market participant to trade financially on the expected price difference between an RTO/ISO's day-ahead and real-time markets. Virtual transactions (virtuals) are directly integrated into the operation of the physical market and affect physical supply and demand, and prices. However, virtual trades do not result in physical delivery. Chapter 2 provides additional information on virtuals.

Additionally, RTO/ISOs offer financial transmission rights (FTRs). FTRs and similar instruments are designed to provide financial compensation to offset transmission congestion costs over specific transmission paths. FTRs are allocated to transmission owners and auctioned to market participants by the RTO/ISOs on a periodic basis. The amount of available FTRs is linked to the physical operation of the transmission system and the amount of expected transmission capacity. FTRs are also discussed further in Chapter 2.

RTO/ISOs maintain credit policies to prevent default and, in the event of default, allocate the costs of defaults or other performance failures across market participants. RTO/ISO credit policies are discussed in Chapter 2 as well.

Trading Concepts and Terminology

Trading

Trading is the act of buying and selling a contract or contracts. A trade is a single consummated transaction.

Trading Volumes and Transactions

Trading volume refers to the total amount of a commodity traded or the number of related contracts that have changed hands in a given energy market for a given time period, such as a single trading day. Trading volumes give an indication of the nature of the market activity and traders may track increases or decreases in trading volumes over time to gauge the tendency for a price trend to continue.[224]

Market Prices, Bids, and Offers

The market price of a contract is the average price (or volume-weighted average price) of all individual trades for that contract. Trading requires a buyer and a seller, each willing to transact for a price. The price a buyer is willing to pay to purchase a contract is the bid price. The price at which the seller offers is the offer price. The prices at which buyers want to buy and sellers want to sell may not be the same. When the bid and offer prices differ, the difference between the prices is the bid-offer spread 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.

Spot Prices

The spot price is a cash market price for a physical commodity that is available for immediate delivery (generally next-day or intra-day for natural gas and day-ahead or real-time for electricity).

Settlement

Settlement is the exchange of physical commodities or currency to close out a physical or financial contract. For settlement, a contract will indicate if 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 on

224 Note that, with transactions involving standardized financial contracts such as an ICE natural gas swap futures contract, one can also readily determine a notional amount of energy volume represented by the number of trades because each contract trades a standardized amount of energy -- e.g., 2,500 MMBtu per contract.

Settlement Example

As mentioned above, the final settlement for the NYMEX natural gas (NG) futures contract 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 (LD1 settlement) price is based upon the trading in the last half-hour of the settlement day. LD1 settlement is the final price for that particular futures contract term. For the NYMEX natural gas futures contract, most market participants either liquidate or "roll" their positions well before the settlement period. Rolling is the process of (1) liquidating the current month's contract before the contract expires and (2) purchasing a comparable position in the upcoming contract month. The trader holds the same number of contracts, but the contract month changes as time passes and contracts expire. Rolling and liquidating NG contracts is necessary for market participants to avoid making or taking physical delivery of the commodity for the contract month. It is far more common for a market participant to roll or liquidate than physically settle an NG futures contract.

exchanges and for OTC transactions. On exchanges, futures settlements occur according to a documented process and timeframe established by the exchange, while OTC transaction settlement occurs under the terms agreed upon by the parties.

Most market participants liquidate or roll contracts prior to expiration day and avoid trading during the settlement period of a contract. As the time to contract expiration approaches, price risk and volatility may increase significantly, while market liquidity and the remaining open positions (open interest) may decrease. Market participants seeking to maintain price exposure or hedges through expiration frequently use cash-settled lookalike contracts.[225]

Daily settlement prices are used to revalue traders' positions to the current market price for accounting and for margin calculations. Daily and LD1 settlement prices are also reported in publications and indexes and are used for price discovery.

Mark-to-Market

Mark-to-Market is an accounting methodology that provides a daily update of the value of a portfolio of market positions, all revalued to current market prices. Mark-to-Market results in near real-time updates to financial and accounting gains and losses, even though a trader might not actually transact to cash out of the positions.

Position

A position is the accumulated unexpired contracts held at a given point in time. Traders may have positions in each contract, as well as an overall position reflecting the balance of all their contracts.

Long and Short Positions

Traders are always aware of their positions and are constantly evaluating how market changes will affect the value of their positions, for example, by knowing whether a position benefits or loses when prices go up or down. A trader would establish a long position when he or she purchases an asset. In other words, a long position generally benefits from price increases.[226] A trader would establish a short position when he or she sells an asset. A short position generally benefits

225 A lookalike contract is based on a futures contract traded on the New York Mercantile Exchange (NYMEX). It may be traded on other platforms such as ICE.

226 Note that a trader taking a long position by purchasing index gas benefits from declining index prices. A long position in physical or financial products where the buyer pays an index price benefits from declines in that index price.

from falling prices.[227] If a position is neutral, the trader benefits from neither a rise nor a fall in prices and the position is considered "flat."

Position Limits

Position limits are imposed on exchanges, such as ICE and NYMEX, in accordance with the rules of the Commodity Futures Trading Commission. The position limits restrict the number of contracts a trader may hold at any point in time, during the month that the contract expires, or during some period closer to settlement. For example, NYMEX imposes position limits, which it refers to as accountability levels,[228] for any one month, for all months, and for expiration-month positions. Accountability levels for the NYMEX Henry Hub natural gas futures contract are 12,000 contracts for all months, 6,000 contracts for one month and 2,000 contracts in the expiration month.[229] Trading entities can petition to have accountability levels waived or modified.

Clearing

Clearing is a process in which financial or physical transactions are brought to a single entity to manage counterparty risk. The entity (referred to as a clearinghouse) steps into the middle of the transaction and becomes the counterparty to each buyer and seller. The clearinghouse assumes the risk that either the buyer or seller will fail to perform its contractual obligations, and thus maintains rules about the creditworthiness of traders, collateral that must be posted and fees that must be paid for the service. NYMEX and ICE act as clearinghouses for transactions occurring on their platforms.

Liquidating

Liquidating a position is the process of making a position neutral or flat. This can be done by selling that position for cash, or by undertaking an opposite and equal transaction.[230] After liquidation of a futures position, the trader has no net position in a contract.

Liquidity

Liquidity refers to the market for a contract having sufficient trade volume so that traders can transact with substantial volume (e.g., to liquidate his or her position) at any time and to do so without, or with limited, effect on market price. A market would be considered to be thin, or less liquid, if the market experiences few transactions or little volume. In low liquidity instances, significantly large trades may result in a noticeable movement in the market price.

Open Interest

Open interest is the aggregation of all traders' existing, or open, positions. For example, in futures and options markets, open interest is the total number of futures or options contracts transacted in a given period (e.g., in the delivery month) or market that have not yet been liquidated by an offsetting transaction or fulfilled by delivery. As the number of existing contracts generally changes from day to day, open interest is often tracked by traders and analysts to assess trends in market activity pertaining to beginning (or opening) positions or ending (or closing) positions in the market. In physical futures markets, open interest (both in terms of the total number of contracts and the number of counterparties) rapidly decreases as contracts near expiration and are settled.

Trading Analysis and Strategy

In deciding whether to trade, both hedgers and speculators pay attention to what is going on in the

227 A trader taking a short position by selling index gas benefits from increasing index prices. A short position in physical or financial products where the seller receives an index price benefits from increases in that index price.

228 Accountability levels are trading limits related to the total number of futures contracts held. These levels are set by exchanges and cannot be exceeded without a request for modification or a waiver.

229 *See* CME Group, *Position Limits*, *NYMEX & COMEX Position Limits* (n.d.), http://www.cmegroup.com/market-regulation/position-limits.html for up to date information.

230 CME Group, *Understanding Futures Expiration & Contract Roll*, (accessed June 23, 2023), https://www.cmegroup.com/education/courses/introduction-to-futures/understanding-futures-expiration-contract-roll.html.

market and develop their own view of where the market is likely to go. Traders 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.

FUNDAMENTAL ANALYSIS

Two general schools of thought influence traders' thinking when analyzing markets for trading opportunities. The first is fundamental analysis, which considers physical demand and supply fundamentals including: production, pipeline and transmission capacity, planned and unplanned outages, as well as weather, 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.

TECHNICAL ANALYSIS

The second school of thought is technical analysis, which forecasts price movements based on patterns of price changes, rates of change, and 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 primarily looks at trading and price changes. Technical analysis is used most often to determine short-term movements and trends, helping traders time their buys and sells.

TRADERS' STRATEGY

A trader's strategy consists of a defined plan that includes decisions such as what contracts to trade and how to trade them. A trader's strategy will depend on the objectives of his or her company. Trading strategies in natural gas and electricity markets include activities such as buying or selling the physical product, managing the risk of physical and financial positions – also known as hedging--and attempting to make money through speculation.

Hedging

Hedging is the act of establishing an offsetting position with the intent of minimizing substantial losses should an original position lose its value. More specifically, market participants and traders with physical positions are exposed to potential gains or losses as market prices change over time. To manage this risk, market participants and traders may use any of a variety of transactions with opposing risk exposures to reduce or eliminate the original market risk. Traders frequently unwind hedges to lock in profits should a position gain in value.

A local distribution company (LDC) provides natural gas to end-use (retail) customers and is concerned with obtaining sufficient volumes of natural gas to serve variable customer demand at the lowest possible price. To ensure sufficient quantities and diversify the risk associated with price swings, an LDC trader 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 next-day market to meet demand peaks. Additionally, an LDC trader may diversify the sources of natural gas, both to improve the reliability of supply and to diversify its price. Physical market participants can also manage risk by trading financial contracts. Physical market participants may also hedge for other reasons, such as establishing a predictable cash flow to support financing or to show state regulators that purchasing practices are prudent.

Speculating

Speculators, or traders seeking to profit from financial or physical markets without any other underlying energy production or consumption requirements, may employ different strategies to profit from the market. Some traders may take a passive approach, seeking to benefit from long-term price movements or to diversify a broader portfolio. Others may buy and sell relative to short-or medium-term movements in prices or price spreads. Some market participants may use High Frequency Trading (HFT), a trading activity guided by computer algorithms that process many buy and sell orders in extremely short timeframes. HFT trades are executed in milliseconds and HFT trading programs can execute thousands and thousands of trades per day.

Capital Markets

Capital markets refer to the markets for ownership capital and debt. Capital markets provide the money needed to make investments in infrastructure such as power plants or natural gas pipelines, to operate plants and companies and to trade or conduct transactions. Most corporate financing is funded through a mixture of equity and debt capital.

Equity capital is most commonly raised through a direct sale of shares in a company to the public, after which shares may be traded on one or more stock exchanges. Note that, in recent years, a substantial amount of private equity has invested in the energy markets as well.

Debt capital may take the form of bonds, which are debt obligations sold directly to investors, and which typically specify a particular interest rate and a fixed time period. Companies may also borrow funds by employing a bank loan. Bank loans are frequently sold onward to investors through a process known as syndication.

EQUITY DEBT AND FINANCING

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

Characteristics of equity include:

- Equity capital can be kept by the company indefinitely.
- A company can issue shares in the company – stock – through financial markets. Companies may also use private equity – money from venture capital firms or private investment entities.
- The most common form of stock is common stock, which does not require regular dividend payments. Investor-owned utilities often issue preferred stock that entitles the holder to a fixed dividend, whose payment takes priority over that of common stock dividends.
- 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 higher potential returns. Electric utilities are typically considered fairly conservative investments. Natural gas producers generally attract more risk-inclined investors.
- The return required to attract equity is generally higher than the interest paid to debt holders.
- Equity capital does not require collateral; equity constitutes a share in the company.
- Additional equity capital infusions may dilute, or reduce, the value of existing shares.

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 must 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, since municipals and cooperatives 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 debt 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 debt payments.
- Interest gets paid before equity dividends. In the

event of bankruptcy, all debtholders are generally paid back in full before shareholders are compensated.

- Debt gives lenders little or no control of the company (unless the company gets into financial trouble).
- Debt can leverage company profits; similarly, debt can magnify losses.
- Lenders are typically conservative, wanting to minimize downside risks.
- Borrowers may be required to provide collateral to secure debt. Debt without collateral is known as unsecured debt.

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

Other capital is also 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, including 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, the company may have to issue higher-priced debt to obtain financing, which is a form of compensation to the lender in return for the added risk of lending. High-yield or junk bonds are issued by entities lacking investment grade credit ratings (see Credit Ratings, below).

CAPITAL EXPENDITURES

The overall stability of the capital markets – or the desire and ability of investors and lenders to provide capital – is an important issue for the overall health of the capital-intensive energy industry. The recession of 2008 and 2009 took a toll on capital spending as financial commitments to infrastructure fell for the first time in years, but spending has been rising since 2010 (see bar chart below).

The electricity industry makes the bulk of the capital expenditures in the utilities sector, specifically on electric transmission, distribution, and generation.

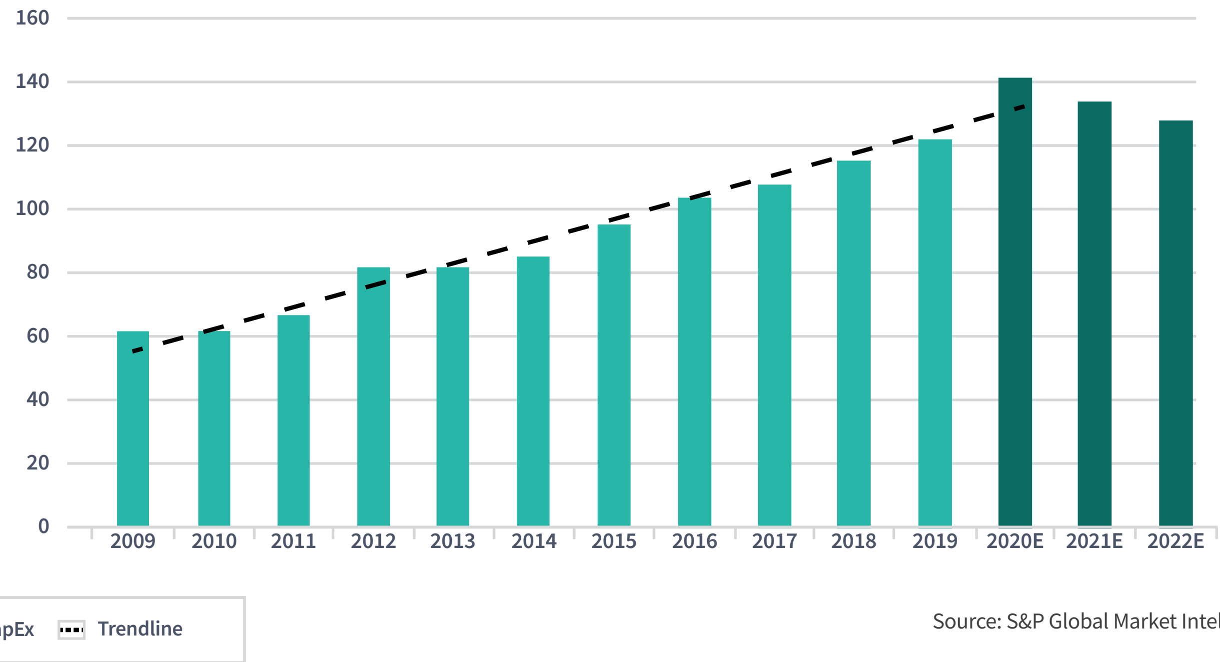
CREDIT RATINGS

Access to capital markets depends on the perceived riskiness of the entity seeking the capital.[231] To measure relative riskiness, many providers of capital look at different measures, including company financial reports, third-party analysis, and credit ratings assigned by the three major credit rating agencies -- Standard and Poor's (S&P), Moody's, and Fitch Ratings.

Not all market participants present the same level of riskiness. Market participants, such as investors and traders, consider the risks their counterparty may present, including the risk of default. One standardized tool used to assess relative risk is the credit rating. The credit rating agencies usually assess a company's Energy utility actual and estimated capital expenditures ($B) riskiness every time the company issues debt. A credit rating represents the rating agency's estimation of the likelihood that an issuer will be unable to repay its debt, as well as the capacity and willingness of the borrower to meet its financial obligations. Many organizations, including RTO/ISOs, consider credit ratings, among other things, when setting their credit policies, which determine with whom companies may transact and

231 In general, the risker a company is perceived to be, the higher rate of return an investor will require to invest in the equity or debt security of the company. Returns for an equity investor can come in the form of the return of capital through a dividend or stock buyback, or through an expectation of higher future profitability on which the investor will have a claim. Debt securities provide a return through the interest rate which accrues to the purchaser, known as the yield.

Figure 5-1: Actual and Estimated Capital Expenditures of Energy Utilities ($B)

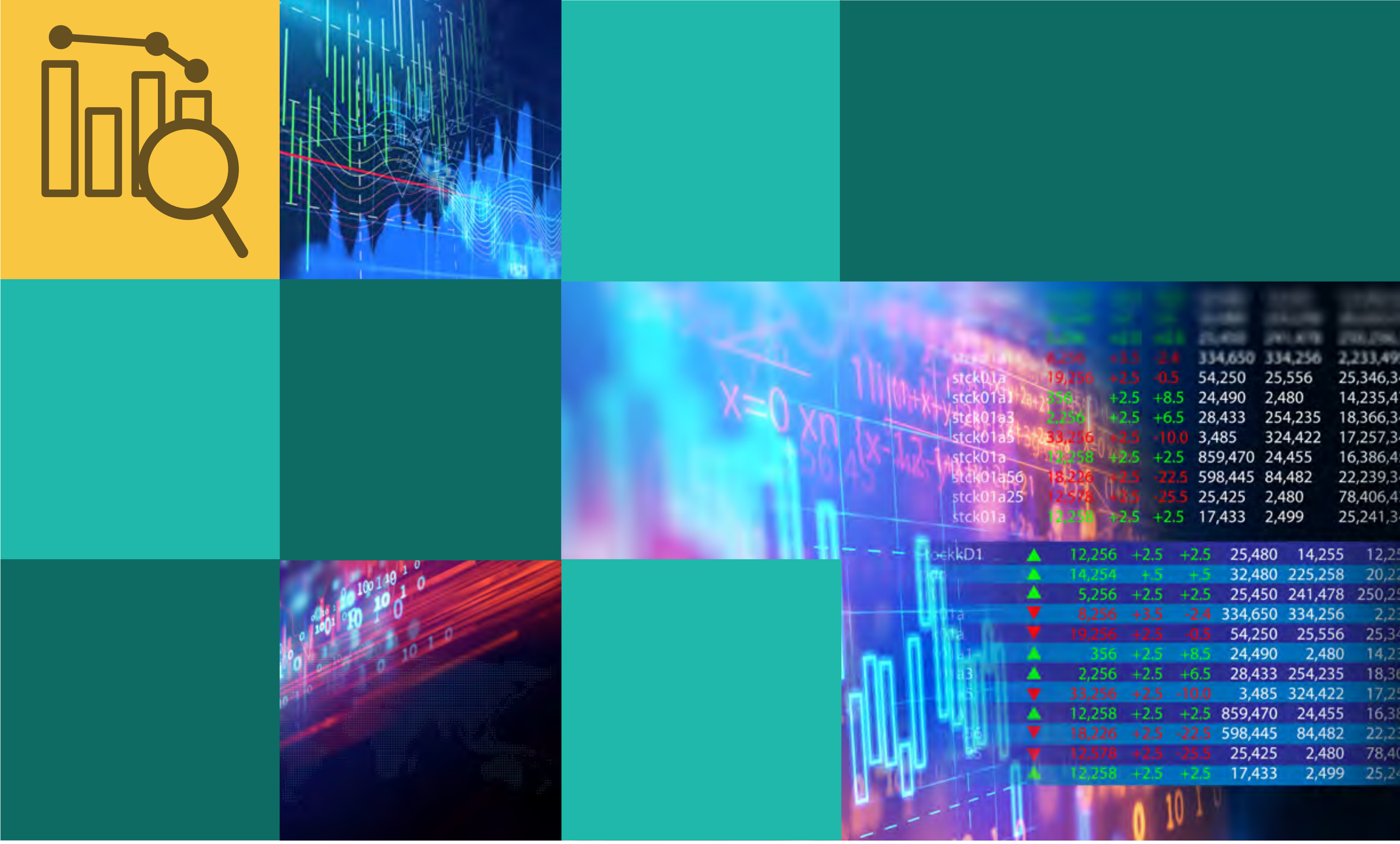


Source: S&P Global Market Intelligence[232]

whether the counterparty will need to post collateral. Each credit rating agency has its own way of assessing risk, reflected in the rating system the agency uses.

Credit quality tends to vary across industry sectors, may fluctuate over time, and is dependent both on the amount of debt issued by a company as well as the stability of a company's cash flow. As a result, companies with predictable income and capital expenditures, such as regulated electric utilities and natural gas LDCs, tend to have higher credit quality than companies subject to more variable cash flows. In contrast, merchant generators (known as independent power producers or IPPs) have experienced challenges with matching volatile cash flows against their capital and debt burdens. As a result, IPPs have experienced several credit rating downgrades and even bankruptcies over the past decade.

232 S&P Global Market Intelligence, *z*, at 1 (June 8, 2020).



Chapter 6
Market Manipulation

MARKET MANIPULATION

Following the Western Energy Crisis in the early 2000s,[233] 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 provisions, the Commission issued Order No. 670 in 2006,[234] adopting the Commission's Anti-Manipulation Rule, codified as 18 C.F.R. § 1c (2022). Recognizing that Congress and other federal regulators have long prohibited manipulation of other markets, such as securities and commodities markets, the Commission draws from the experience of sister federal agencies in implementing its anti-manipulation authority.

The Anti-Manipulation Rule applies to any "entity," which the Commission and courts have interpreted to cover both companies and individual people.[235] The Anti-Manipulation Rule 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 (intent, knowledge, or recklessness); (3) in connection with a transaction subject to Federal Energy Regulatory Commission (FERC) jurisdiction. Unlike in private lawsuits, the Commission need not show reliance, loss causation, or damages to prove a violation.[236]

To the extent that an allegation of manipulation depends on the actor's purpose, both the Commission and courts have found that a violation can occur even if the wrongful objective is not the actor's sole purpose. For example, the Commission and courts have found that a party can engage in market manipulation if its primary purpose was wrongful, even if that was not its only goal.[237]

The prohibition on market manipulation 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 to be determined by all the circumstances of a case. In Order No. 670, the Commission modeled its Anti-Manipulation Rule on Securities and Exchange Commission (SEC) Rule 10b-5 in an effort to prevent and deter 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 anti-fraud catch-all clause.

Manipulation comes in many forms. As a federal court of appeals explained in a commodities manipulation case, "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."[238] The Commission recognized this reality by framing its Anti-Manipulation Rule broadly, rather than articulating specific conduct that would violate the Rule. While not an exhaustive list, the most

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233 The Western Energy Crisis of 2000-2001 was a series of market conditions and events in the Western U.S. that included diminished power supplies due to drought, inadequate infrastructure, a flawed power market design, and market manipulation. *See* FERC, *Addressing the 2000-2001 Western Energy Crisis* (2010), www.ferc.gov/industries/electric/indus-act/wec.asp. *See also, e.g., Puget Sound Energy, Inc.,* 146 FERC ¶ 63,028, PP 5-16 (2014).

234 *Prohibition of Energy Market Manipulation*, Order No. 670, 114 FERC ¶ 61,047, at P 38, *reh'g denied*, 114 FERC ¶ 61,300 (2006).

235 *FERC v. Vitol Inc.,* 2021 WL 6004339, at *8 (E.D. Cal. December 20, 2021); *FERC v. Coaltrain Energy, L.P.,* 2018 WL 7892222, at **9–10 (S.D. Ohio March 30, 2018) (reviewing rationale and collecting prior cases).

236 Order No. 670, 114 FERC ¶ 61,047 at P 48 n.102 (2006) ("reliance, loss causation and damages are not necessary for a violation of the [Anti-Manipulation] Rule"); *ETRACOM LLC & Michael Rosenberg,* 155 FERC ¶ 61,284 (2016) (no requirement to prove causation).

237 *FERC v. Coaltrain Energy, L.P., et al.,* 501 F. Supp.3d 503, 531-35 (S.D. Ohio 2020); *FERC v. Coaltrain Energy, L.P., et al.,* 2018 WL 7892222, at **13-14 (S.D. Ohio March 30, 2018).

238 *Cargill, Inc. v. Hardin,* 452 F.2d 1154, 1163 (8th Cir. 1971).

common types of fraud in energy, other commodities, and securities markets in recent years are discussed below. The borders of these categories are flexible and a single scheme may include elements of multiple types of fraud.

In addition to the information provided here, the Commission's Office of Enforcement (Enforcement) staff has published a white paper providing additional background on the types of manipulative schemes discussed here.[239]

Manipulative Trading Techniques and Cross-Product Manipulation

Traders sometimes place trades not to profit from market forces but to achieve a different, improper goal. For example, a trader may engage in high-volume wash trading to create a false impression of strong market interest in the instrument.[240] In another unlawful strategy, a trader may buy or sell at uneconomic prices to move a price to trigger an option that will profit the trader.

Another common manipulative technique is "marking the close," in which a trader places transactions near the close of a trading period not to profit based on market forces but to affect the closing or settlement price. This may be done to drive up (or down) mark-to-market marks for valuation, to avoid margin calls, or to benefit positions in related instruments. "Banging the open" is a similar practice in which a trader buys or sells in large quantities at the opening of trading to induce others to trade at that price level and to create a false impression about how the market views fundamentals that day.

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 Enforcement staff has investigated and prosecuted are cross-product schemes in which an entity places trades in one market (e.g., the physical market), often at a loss, with the intent to affect the settlement price of derivative instruments (e.g., the financial market). Such trading can violate the Anti-Manipulation Rule because the trading is not undertaken in response to supply-and-demand fundamentals but rather to benefit another position. Trading for that purpose can 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 their overall financial position. One useful way of looking at this type of manipulation is that the transaction is a "trigger" that is used to "target" a price. Commonly, the trigger is a physical product, but cases have also arisen where the trigger was a financial product. For example, the trigger 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 trigger 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 trigger to target a price is to raise or lower that

239 *FERC Staff White Paper on Anti-Market Manipulation Enforcement Efforts Ten Years after EPAct 2005* (2016) (Enforcement Staff White Paper on Manipulation), *available at* https://www.ferc.gov/legal/staff-reports/2016/marketmanipulationwhitepaper.pdf.

240 Wash trading refers to offsetting trades that, as an economic matter, cancel one another out. *See Houlian Chen, Powhatan Energy Fund, LLC, HEEP Fund, LLC, CU Fund, Inc.,* 151 FERC ¶ 61,179 P 104 (2015) (Order Assessing Civil Penalties).

price in a way that will increase the value of a "benefiting position" (e.g., a Financial Transmission Right (FTR) product in power markets, a swap, a futures contract, or other derivative).

Usually, increasing the value of the benefiting position (i.e., increase profits or mitigate losses) 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 triggering transactions—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 acted intentionally, knowingly, or recklessly to impair, obstruct, or defeat the proper functioning of the energy markets the Commission regulates.[241]

The mere fact that a trade may move market prices does not by itself make the trade illegal. If a market-moving trade is placed for a legitimate purpose—such as to hedge risk or try to profit based on market fundamentals—the conduct, without more, would not violate the Commission's Anti-Manipulation Rule.

Information-Based Manipulation

Many manipulative schemes rely on spreading false information, which involves knowingly disseminating untrue information about an asset's value to move its price. A well-known scheme in the securities markets is the "pump and dump," in which a participant spreads a false, misleading, or exaggerated statement 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 forms of manipulation in the early 2000s and contributed to the Western Energy Crisis.[242] 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, 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 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 real 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.

Gaming

Many of the cases investigated and prosecuted by Enforcement staff concern gaming of tariff provisions or market rules. The Commission has made clear that gaming includes behavior that circumvents or takes unfair advantage of market rules or conditions in a deceptive manner that harms the proper functioning of the market and potentially other market participants or consumers. The prohibition on gaming is longstanding and applied to a number of pre-EPAct 2005 schemes including those that arose during the Western Energy Crisis.[243] More recently, the Commission has pursued numerous cases involving gaming, including,

241 Order No. 670, 114 FERC ¶ 61,047 at PP 49, 52-53 (2006).

242 The Commission's Report on the Western Energy Crisis is available here: [Addressing the 2000-2001 Western Energy Crisis | Federal Energy Regulatory Commission (ferc.gov)](#) (2003).

243 *See* Enforcement Staff White Paper on Manipulation 23-25.

as discussed below, *GDF Suez Energy Marketing NA, Inc.*, *JPMorgan Ventures Energy Corp.*, the *PJM Interconnection, L.L.C.* (*PJM*) *Up-To Congestion Cases*, *Golden Spread Electric Cooperative, Inc.*, and *GreenHat Energy, LLC*. In considering these cases, the Commission has found gaming to include effectively riskless transactions executed for the purpose of receiving a collateral benefit; conduct that is inconsistent or interferes with a market design function; and conduct that takes unfair advantage of market rules to the detriment of other market participants and market efficiency. In these cases, entities typically submit offers or bids that falsely appear to be based on normal market forces (i.e., supply and demand fundamentals) but are in fact aimed at different, improper objectives.

Withholding

Withholding is the removal of supply from the market and is one of the oldest forms of commodities manipulation. The classic manipulative scheme referred to as 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 Energy Crisis in the early 2000s. 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. These efforts, in combination with economic withholding (discussed below) and information-based schemes (discussed above), resulted in a dramatic rise in wholesale electricity prices. 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 precipitated widespread blackouts, impaired the state's economy, and led to PG&E's bankruptcy filing in April 2001.

Economic withholding, which also contributed to the Western Energy 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, raise prices for the benefit of the rest of its generation fleet or its financial positions.

Representative Matters

The following representative matters involve at least one of the types of manipulative schemes previously described. Each of these matters has either been resolved through settlement or is currently pending before a district court or on remand from a Court of Appeals.

BARCLAYS BANK, PLC (BARCLAYS) AND DANIEL BRIN, SCOTT CONNELLY, KAREN LEVINE, AND RYAN SMITH (TRADERS)

On July 16, 2013, the Commission determined that Barclays and the Traders violated the Commission's Anti-Manipulation Rule.[244] The Commission found that Barclays and the Traders engaged in loss-generating trading of day-ahead, fixed-price physical electricity on the InterContinental Exchange (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 to change the ICE daily index for the benefit of its financial swap positions whose price was based on that index.

244 *Barclays Bank PLC, Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith,* 144 FERC ¶ 61,041 (2013) (Order Assessing Civil Penalties).

Barclays and the Traders failed to pay the penalties assessed by the Commission. Enforcement staff filed an action to affirm the Commission's assessment in the United States District Court for the Eastern District of California on October 9, 2013. In May 2015, the court rejected defendants' motion to dismiss and ruled that the conduct alleged was actionable as manipulation, that the Commission had jurisdiction over the manipulative trading at issue, and that the Commission had authority to pursue individuals. Following a mediation under the court's supervision, Enforcement staff and defendants reached a settlement for $105 million. Barclays agreed to pay a $70 million civil penalty and $35 million in disgorgement.[245] The Commission approved the settlement on November 7, 2017.[246]

BP AMERICA, INC. AND AFFILIATES (BP)

On August 5, 2013, the Commission issued an order to show cause and notice of proposed penalty to BP.[247] In that proceeding, Enforcement staff alleged that BP made uneconomic natural gas 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. Enforcement contended that this was a cross-product manipulation scheme, motivated by a desire to benefit certain physical and financial positions held by BP whose price was set by the same index.

On August 13, 2015, Administrative Law Judge (ALJ) Carmen Cintron issued her Initial Decision finding that BP violated the Anti-Manipulation Rule and Section 4A of the NGA.[248] On July 11, 2016, the Commission issued an order affirming the ALJ's Initial Decision and directed BP to pay $20,160,000 in civil penalties and to disgorge unjust profits in the amount of $207,169 to the Low Income Home Energy Assistance Program of Texas for the benefit of its energy consumers.[249]

On August 10, 2016, BP sought rehearing of the Commission's July 16, 2016 order, and on December 11, 2017, filed a motion seeking to dismiss the action based on the five-year statute of limitations in 28 U.S.C. § 2462. On December 17, 2020, the Commission denied rehearing, provided a modified discussion reaching the same result, and denied the motion to dismiss based on the statute of limitations.[250]

BP appealed the Commission's orders to the Fifth Circuit Court of Appeals. On October 20, 2022, the Court of Appeals upheld the orders in most respects. The Court of Appeals held that the Commission could not base its market manipulation claims on BP's intrastate (entirely within Texas) transactions, but that the Commission properly rested, as an alternative basis for jurisdiction, on particular interstate transactions by BP. On market manipulation, the court affirmed the Commission's findings of manipulative conduct and intent, based on BP's changed trading behavior during the investigative period and the "suspicious nature" of BP's trading patterns. As for the Commission's penalty assessment, the court found that its jurisdictional ruling, resting on a smaller set of BP transactions, requires a new calculation. The court did not otherwise limit the agency's discretion on remand to revisit its calculation.

On July 7, 2023, the Commission approved a Stipulation and Consent Agreement resolving the Commission's case against BP.[251] In)the settlement, BP agreed to pay a civil penalty of $10,750,000 and agreed not to seek return of the $250,295 of disgorgement it already paid.

245 *FERC v. Barclays Bank PLC,* 105 F. Supp. 3d 1121 (2015).

246 *Barclays Bank PLC, Daniel Brin, Scott Connelly, and Karen Levine,* 161 FERC ¶ 61,147 (Order Approving Stipulation and Consent Agreement) (2017).

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

248 *BP America Inc.,* 152 FERC ¶ 63,016 (2015).

249 *BP America Inc.,* 156 FERC ¶ 61,031 (2016).

250 *BP America Inc.,* 173 FERC ¶ 61,239 (2020) (Order Addressing Arguments Raised On Rehearing).

251 *BP America Inc.,* 184 FERC ¶ 61,016.

CONSTELLATION ENERGY COMMODITIES GROUP (CCG)

On March 9, 2012, the Commission approved a settlement with CCG in which CCG agreed to disgorge $110 million in unjust profits and pay a civil penalty of $135 million.[252] Enforcement staff determined that CCG had employed a scheme of virtual and physical trading in the New York ISO (NYISO) market to move day-ahead prices in a direction that would benefit CCG's financial swap positions.[253] Although CCG's virtual and physical transactions were routinely unprofitable, they enabled CCG to make a $110 million profit on its swap positions. Enforcement determined that this manipulation of the physical and virtual markets caused widespread economic losses to market participants in the Day Ahead markets of ISO New England (ISO-NE) and NYISO.[254] Enforcement staff also determined that CCG violated 18 C.F.R. § 35.41(b) by providing inaccurate and misleading information to the NYISO. Specifically, Enforcement determined that CCG denied that its virtual transactions were related to its swap positions and instead told the NYISO that the transactions were independent of the swap positions and were based on market fundamentals. In addition to $245 million in monetary relief, CCG agreed to a variety of compliance measures, including (a) monitoring of profit and loss concentrations in virtual and physical trading and (b) advance documentation of the purpose of virtual transactions.

ETRACOM LLC (ETRACOM) AND MICHAEL ROSENBERG

On June 17, 2016, the Commission found that ETRACOM and Rosenberg violated the Commission's Anti-Manipulation Rule by implementing a scheme to submit virtual transactions for the purpose of economically benefitting ETRACOM's Congestion Revenue Rights (CRR) positions, which are similar to Financial Transmissions Rights in other ISOs.[255] Specifically, in May 2011, the Commission found that ETRACOM submitted continuous and uneconomic virtual supply offers at New Melones, a node near the eastern border of California Independent System Operator (CAISO), during every hour over an 18-day period with the intent to artificially lower prices there. Many of ETRACOM's virtual supply offers were placed near the offer floor of negative $30, and ETRACOM accumulated $42,000 in losses related to its virtual supply offers over that period. At the same time, the artificially-lowered prices increased the profit on ETRACOM's CRR positions at New Melones by over $315,000 during that period. The Commission assessed civil penalties against ETRACOM and Rosenberg of $2.4 million and $100,000, respectively. The Commission further directed ETRACOM to disgorge the $315,000 of unjust profits, with interest. ETRACOM and Rosenberg failed to pay the penalties assessed by the Commission. Therefore, on August 17, 2016, the Commission filed an action to affirm the Commission's assessment of penalties in the United States District Court for the Eastern District of California. On April 10, 2018, the Commission approved a settlement in which ETRACOM agreed to pay the full disgorgement amount (with interest)and a penalty of $1,500,508.[256]

GDF SUEZ ENERGY MARKETING NA, INC. (GDF SUEZ)

On February 1, 2017, the Commission approved a settlement with GDF Suez resolving an investigation relating to lost opportunity cost credits (LOCs) in the PJM market.[257] Under the terms of the settlement, GDF Suez agreed to pay a civil penalty of $41 million and to disgorge to PJM $40.8 million in unjust profits.

Enforcement staff concluded that GDF Suez violated the Commission's Anti-Manipulation Rule by targeting and

252 *Constellation Energy Commodities Group, Inc.,* 138 FERC ¶ 61,168 (2012).

253 For background about NYISO, *see* https://www.ferc.gov/power-sales-and-markets/rtos-and-isos/nyiso.

254 For background about ISO-NE, *see* https://www.ferc.gov/industries-data/electric/electric-power-markets/iso-ne.

255 *ETRACOM LLC and Michael Rosenberg,* 155 FERC ¶ 61,284 (2016) (Order Assessing Civil Penalties).

256 *ETRACOM LLC and Michael Rosenberg,* 163 FERC ¶ 61,022 (2018) (Order Approving Stipulation and Consent Agreement). For more information about PJM, *see* https://www.ferc.gov/industries-data/electric/electric-power-markets/pjm.

257 *GDF SUEZ Energy Marketing NA, Inc.,* 158 FERC ¶ 61,102 (2017) (Order Approving Stipulation and Consent Agreement).

inflating its receipt of LOCs. PJM pays LOCs to combustion turbine units that clear the day-ahead market but are not subsequently dispatched in the real-time market. During the period of GDF Suez's conduct (2011-2013), PJM calculated LOCs for combustion turbine units based on the difference between the real-time locational marginal price and the higher of a unit's price-based and cost-based offers in the day-ahead market. GDF Suez targeted and inflated its receipt of LOCs by discounting its offers below-cost to clear the day-ahead market at times when the units likely would not have cleared based on undiscounted offers and when GDF Suez expected that PJM would not dispatch the units in the real-time. This resulted in profits from LOCs when PJM did not dispatch the units and when they would have operated at a loss if dispatched. GDF Suez's discounted offers did not reflect the price at which it could economically generate power, but rather the price at which it could obtain a day-ahead award and then receive LOCs when the units could not have operated profitably.

ISO-NE DAY-AHEAD LOAD RESPONSE PROGRAM (DALRP)

Based on an Enforcement staff investigation of Rumford Paper Company (Rumford), Lincoln Paper and Tissue LLC (Lincoln), Competitive Energy Services, LLC (CES), and Richard Silkman (Silkman), the Commission, in July 2012, issued each subject an order to show cause alleging that their conduct related to the DALRP in the ISONE market violated the Commission's Anti-Manipulation Rule. Enforcement staff and Rumford reached a settlement of the allegations against the company, which the Commission approved in March 2013.[258] On August 29, 2013, 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 to maintain the inflated baseline.[259] The Commission 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. When 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 to affirm the Commission's orders. On April 11, 2016, the Court denied Lincoln's, Silkman's, and CES's motions to dismiss the Commission's petitions for failure to state a claim, but transferred the cases to the United States District Court for the District of Maine.[260] The Commission subsequently approved a settlement in which Lincoln agreed to a $5 million penalty, subject to certain conditions on account of its bankruptcy, and disgorgement of $379,016.[261] In 2020, the Commission settled its claims against Silkman and CES with a civil penalty of $708,159 against CES, a civil penalty of $600,000 against Silkman, and disgorgement of $166,841 from CES.[262]

JP MORGAN VENTURES ENERGY CORPORATION (JPMVEC)

On July 30, 2013, the Commission approved a settlement between Enforcement staff and JPMVEC resolving

258 *Rumford Paper Co.,* 142 FERC ¶ 61,218 (2013) (Order Approving Stipulation and Consent Agreement).

259 *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).

260 *FERC v. Silkman,* 177 F. Supp.3d 683 (D. Mass. 2016) (order regarding motions to dismiss); *FERC v. Silkman,* 2016 WL 1444604 (D. Mass. April 11, 2016) (order regarding transfer).

261 *Lincoln Paper and Tissue, LLC,* 155 FERC ¶ 61,228 (2016) (Order Approving Stipulation and Consent Agreement).

262 *Competitive Energy Services, LLC,* 173 FERC 61,176 (2020) (Order Approving Stipulation and Consent Agreement).

an investigation of JPMVEC's bidding practices.[263] Pursuant to the settlement, JPMVEC agreed to pay $285 million in civil penalties, $124 million in disgorgement to CAISO ratepayers, and $1 million in disgorgement to Midcontinent Independent System Operator (MISO) ratepayers. 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 agreed 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 RTOs/ISOs by obtaining payments for benefits that JPMVEC did not deliver; and displacing other generation and influencing energy and congestion prices.[264]

MAXIM POWER CORP. (MAXIM)

On May 1, 2015, the Commission assessed $5 million in civil penalties against Maxim and its affiliates and $50,000 against the individual employee principally responsible for the conduct, finding that Maxim's offers to ISO-NE for its Pittsfield, Mass., power plant were manipulative.[265] Although the Pittsfield plant could burn either natural gas or fuel oil, Maxim almost always burned natural gas because it was usually much cheaper to do so. In the summer of 2010, on hot days when it expected the Pittsfield plant to receive day-ahead awards for reliability, Maxim submitted offers to ISO-NE based on oil prices even though the unit actually burned natural gas. Because the unit was needed for reliability, Maxim received make-whole payments for costly oil that Maxim did not in fact burn, generating substantial profits for the firm.[266] Maxim also sent emails to ISO-NE's market monitor that, the Commission found, had falsely communicated that the unit was actually burning oil.

After Maxim failed to pay the assessed penalties, the Commission filed an action to affirm the Commission's assessment of penalties in the United States District Court for the District of Massachusetts. After the court denied Maxim's motion to dismiss,[267] the Commission, on September 26, 2016, approved a settlement negotiated by Enforcement staff and Maxim in which Maxim agreed to pay $4 million in disgorgement to ISO-NE and $4 million in civil penalties.[268] The settlement covered both the conduct at issue in the district court case and a separate strategy that Enforcement determined to be manipulative.

PJM UP-TO CONGESTION (UTC) CASES

In August 2010, the Commission opened an investigation into whether certain market participants were manipulating the PJM UTC market. Following three separate show-cause proceedings that commenced between May 2015 and May 2016, the Commission found certain trading by five entities and eight

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263 *In Re Make-Whole Payments and Related Bidding Strategies,* 144 FERC ¶ 61,068 (2013) (Order Approving Stipulation and Consent Agreement). For more information about CAISO, see https://www.ferc.gov/industries-data/electric/electric-power-markets/cais o. For more information about MISO, see https://www.ferc.gov/industries-data/electric/electric-power-markets/miso.

264 For background about RTOs and ISOs, *see* https://www.ferc.gov/power-sales-and-markets/rtos-and-isos.

265 *Maxim Power Corporation, Maxim Power (USA), Inc., Maxim Power (USA) Holding Company Inc., Pawtucket Power Holding Co., LLC, Pittsfield Generating Company, LP, and Kyle Mitton,* 151 FERC ¶ 61,094 (2015) (Order Assessing Civil Penalties).

266 Make-whole payments are designed to compensate units that are dispatched by ISO-NE even though the unit's offer prices are higher than market prices.

267 *FERC v. Maxim Power Corp.*, 196 F. Supp. 3d 181 (D. Mass. 2016).

268 *Maxim Power Corp., Maxim Power (USA), Inc., Maxim Power (USA) Holding Company Inc., Pawtucket Power Holding Company, LLC, and Pittsfield Generating Company, LP,* 156 FERC ¶ 61,223 (2016) (Order Approving Stipulation and Consent Agreement).

individuals to violate the Anti-Manipulation Rule and assessed civil penalties.[269] The manipulative trading involved the reservation of large volumes of transmission in connection with spread trades that were effectively wash trades or trades between points with de minimis or zero price spreads. The lack of price spreads allowed the traders to reserve exceptionally large volumes of transmission which, in turn, enabled the traders to claim certain credits that PJM was allocating to paid-for transmission.

When the respondents failed to pay the assessed penalties, the Commission filed three actions to affirm the Commission's penalty assessments: in the U.S. District Court for the Eastern District of Virginia seeking $28.8 million in penalties and $3.47 million in disgorgement against Powhatan Energy Fund, LLC (Powhatan) and other funds and $1 million against Houlian Chen; in the U.S. District Court for the District of Columbia seeking $14 million in penalties and $1.28 million in disgorgement against City Power Marketing, LLC (City Power) and $1 million in penalties from K. Stephen Tsingas (Tsingas); and in the U.S. District Court for the Southern District of Ohio seeking $26 million in penalties and $4.12 million in disgorgement against Coaltrain Energy, L.P (Coaltrain) and $12 million in total penalties from four individuals.

In *City Power*, the Court denied defendants' motion to dismiss, holding that the alleged conduct was actionable as manipulation and that the Commission could penalize individuals.[270] Subsequently, in February 2017, defendants settled for a $9 million penalty against City Power, a $1.42 million penalty against Tsingas, and $1.3 million in disgorgement.[271]

In *Coaltrain*, as in *City Power*, the court denied defendants' motions to dismiss, holding, among other things, that the Commission had alleged actionable manipulation, pled fraud with specificity, has jurisdiction over financially-settled transactions, and can penalize individuals.[272] After discovery, the court denied defendants' motions for summary judgment, while granting the Commission's motion for summary judgment on its claim that Coaltrain violated 18 C.F.R. § 35.41(b) by falsely denying the existence of key company documents.[273] The Commission settled the *Coaltrain* case in 2022 with an agreement by the defendants to pay back virtually all of the $4.1 million in unjust profits.[274]

The Commission settled its case against Houlian Chen for a $600,000 disgorgement payment to PJM, based on documentation of Chen's limited ability to pay.[275] After the other defendant, Powhatan, declared bankruptcy, the U.S. District Court for the Eastern District of Pennsylvania issued a default judgment against it for $3,465,108 in disgorgement and $16,800,00 in civil penalties.[276] The Court's order includes detailed findings based on the record evidence.[277]

GOLDEN SPREAD ELECTRIC COOPERATIVE, INC. (GOLDEN SPREAD)

In November 2021, the Commission approved a settlement agreement between Enforcement staff and Golden Spread, in which Golden Spread agreed to disgorge $375,000 and pay a civil penalty of $550,000

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269 *Houlian Chen, Powhatan Energy Fund, LLC, HEEP Fund, LLC, CU Fund, Inc.,* 151 FERC ¶ 61,179 (2015) (Order Assessing Civil Penalties); *City Power Marketing, LLC and K. Stephen Tsingas,* 152 FERC ¶ 61,012 (2015) (Order Assessing Civil Penalties); and *Coaltrain Energy, L.P., Peter Jones, Shawn Sheehan, Robert Jones, Jeff Miller, Jack Wells, and Adam Hughes 155* FERC ¶ 61,204 (2016) (Order Assessing Civil Penalties).

270 *FERC v. City Power Marketing, LLC,* 199 F. Supp. 3d 218 (D.D.C. 2016).

271 *City Power Marketing, LLC and K. Stephen Tsingas,* 160 FERC ¶ 61,013 (2017) (Order Approving Stipulation and Consent Agreement).

272 *FERC v. Coaltrain Energy, L.P., et al.,* 2018 WL 7892222 (S.D. Ohio March 30, 2018).

273 *FERC v. Coaltrain Energy, L.P., et al.,* 501 F. Supp.3d 503 (S.D. Ohio 2020).

274 *Coaltrain Energy, L.P.,* 181 FERC ¶ 61,031 (2022) (Order Approving Stipulation and Consent Agreement).

275 *Houlian Chen,* 177 FERC ¶ 61,076 (2021) (Order Approving Stipulation and Consent Agreement).

276 *FERC v. Powhatan Energy Fund, LLC,* 2023 WL 2603381 (E.D. Va. March 22, 2023).

277 *Id.*

to resolve Enforcement staff's allegations of market manipulation in the Southwest Power Pool (SPP).[278] Through its investigation, Enforcement staff determined that Golden Spread engaged in a scheme to wrongfully obtain make-whole payments from SPP. Make-whole payments in SPP are designed to ensure that a market participant's costs are met when market revenues are insufficient to cover the resource's short-run variable costs across an entire day. Golden Spread inflated its make-whole payments by choosing "self-commit" status (i.e., being a price taker) when Golden Spread expected the unit to be profitable, while offering in at market prices when it expected the unit to be unprofitable. By doing so, Golden Spread was able to obtain make-whole payments from SPP for the unprofitable hours, even though the unit was profitable across the day as a whole.

Enforcement staff concluded that Golden Spread's strategy signaled to the market that it was trading based on market fundamentals when, in fact, it was trading for the improper purpose of targeting and inflating make-whole payments.

GREENHAT ENERGY, LLP (GREENHAT), JOHN BARTHOLOMEW, KEVIN ZIEGENHORN, AND THE ESTATE OF ANDREW KITTELL

On November 5, 2021, the Commission issued an Order Assessing Civil Penalties against GreenHat, John Bartholomew (Bartholomew), Kevin Ziegenhorn (Ziegenhorn), and the Estate of Andrew Kittell (Kittell Estate).[279] The Commission found that GreenHat and the individual respondents violated section 222(a) of the FPA and the Commission's Anti-Manipulation Rule by: (1) engaging in a manipulative scheme in PJM by purchasing FTRs with virtually no upfront cash, planning not to pay for losses at settlement, and obtaining cash for the individual respondents by selling profitable FTRs to third parties; (2) purchasing FTRs based not on market considerations but to amass as many FTRs as possible with minimal collateral; (3) making false statements to PJM about money purportedly owed by a third party firm to try to convince PJM not to proceed with a planned margin call; and (4) submitting inflated bids into a PJM long-term FTR auction with the intent to artificially raise the clearing price of FTRs that the third party firm had purchased from GreenHat and offered for sale in the auction.[280] The Commission assessed civil penalties in the following amounts: $179,600,573 against GreenHat, $25 million against Bartholomew, and $25 million against Ziegenhorn. The Commission also directed GreenHat, Bartholomew, Ziegenhorn, and the Kittell Estate, jointly and severally, to disgorge unjust profits of $13,072,428, plus applicable interest.

The Commission filed suit against GreenHat, Bartholomew, Ziegenhorn, and the Kittell Estate in the U.S. District Court for the Eastern District of Pennsylvania on January 6, 2021. On August 19, 2022, the Commission approved two settlements that wholly resolved the matter: one with GreenHat and the Kittell Estate, and one with Bartholomew and Ziegenhorn.[281] GreenHat and the Kittell Estate agreed to pay $600,000 in disgorgement (based on ability to pay); Bartholomew and Ziegenhorn agreed to pay a total of $775,000 in disgorgement (also based on ability to pay); Bartholomew and Ziegenhorn agreed not to trade in Commission-jurisdictional markets for ten years, and never to trade in PJM; GreenHat agreed to entry of judgment of $179,600,573 in favor of PJM in a Texas state court lawsuit; and GreenHat agreed to dismiss its $62 million lawsuit against a third party firm, which was based on factual claims that the Commission determined to be false. All of the Defendants have paid the agreed amounts to PJM and the federal court lawsuit was dismissed in April 2023.

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278 *Golden Spread Electric Cooperative, Inc.,* 177 FERC ¶ 61,109 (2021). (Order Approving Stipulation and Consent Agreement). For background about SPP, *see* https://www.ferc.gov/industries-data/electric/electric-power-markets/spp.

279 *GreenHat Energy, LLC,* 177 FERC ¶ 61,073, at P 2 (2021) (Penalty Order).

280 *Id.* P 30.

281 *GreenHat Energy, LLC,* 180 FERC ¶ 61,109 (2022) (GreenHat and Kittell Estate) (Order Approving Stipulation and Settlement Agreement); *GreenHat Energy, LLC,,* 180 FERC ¶ 61,108 (2022) (Bartholomew and Ziegenhorn) (same).

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