Appendix

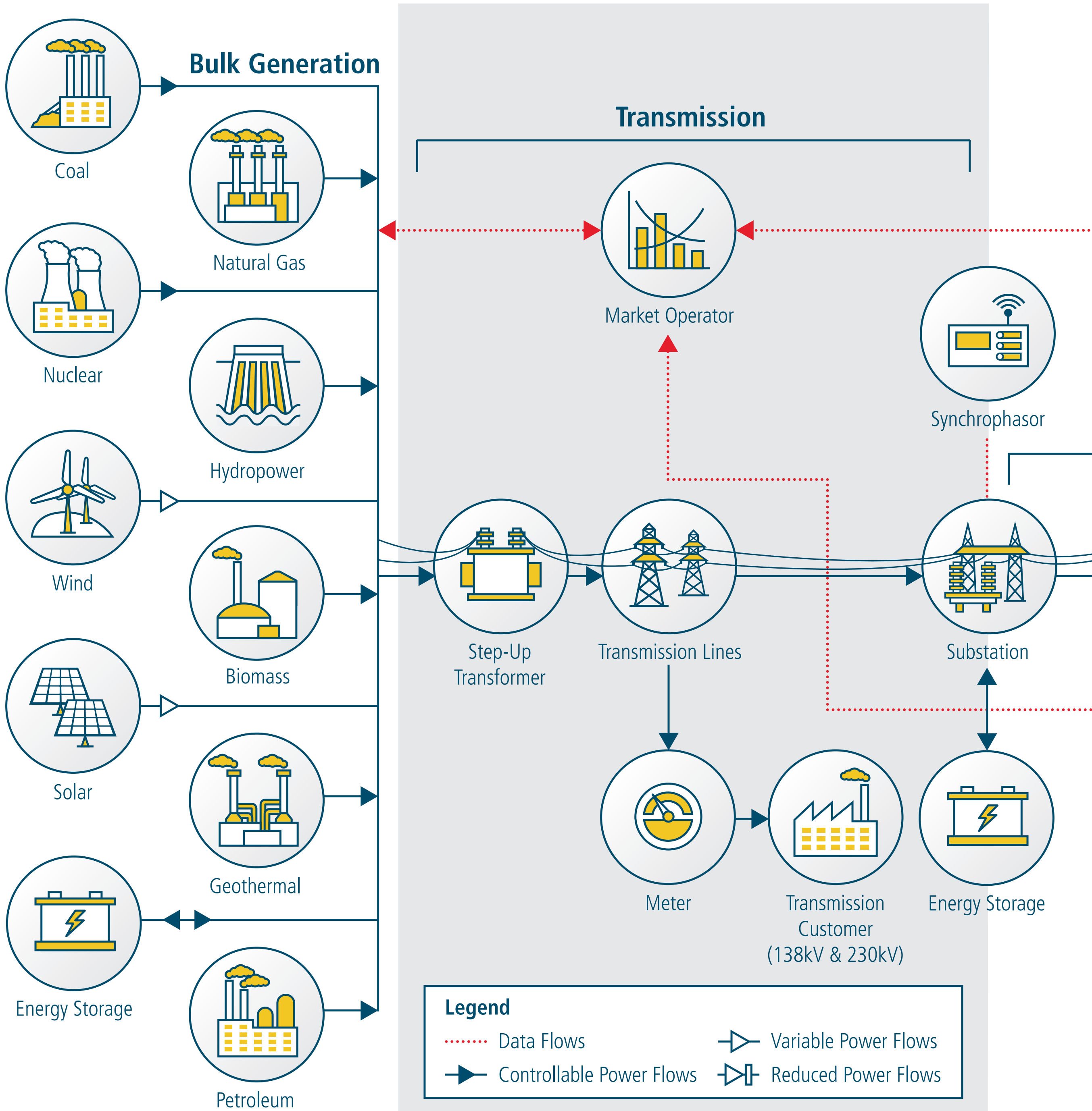
ELECTRICITY SYSTEM OVERVIEW

This appendix provides context for understanding the analysis and recommendations contained in the main body of the report. It is an overview of the Nation's existing electricity system, including its physical structure and elements, the history of its development, and major laws and jurisdictions governing its operation. It explores the Federal role in the resilience and security of the electric grid, and it describes the complex operations, business models, and market structures comprising the electricity system.

Elements of the Electricity System

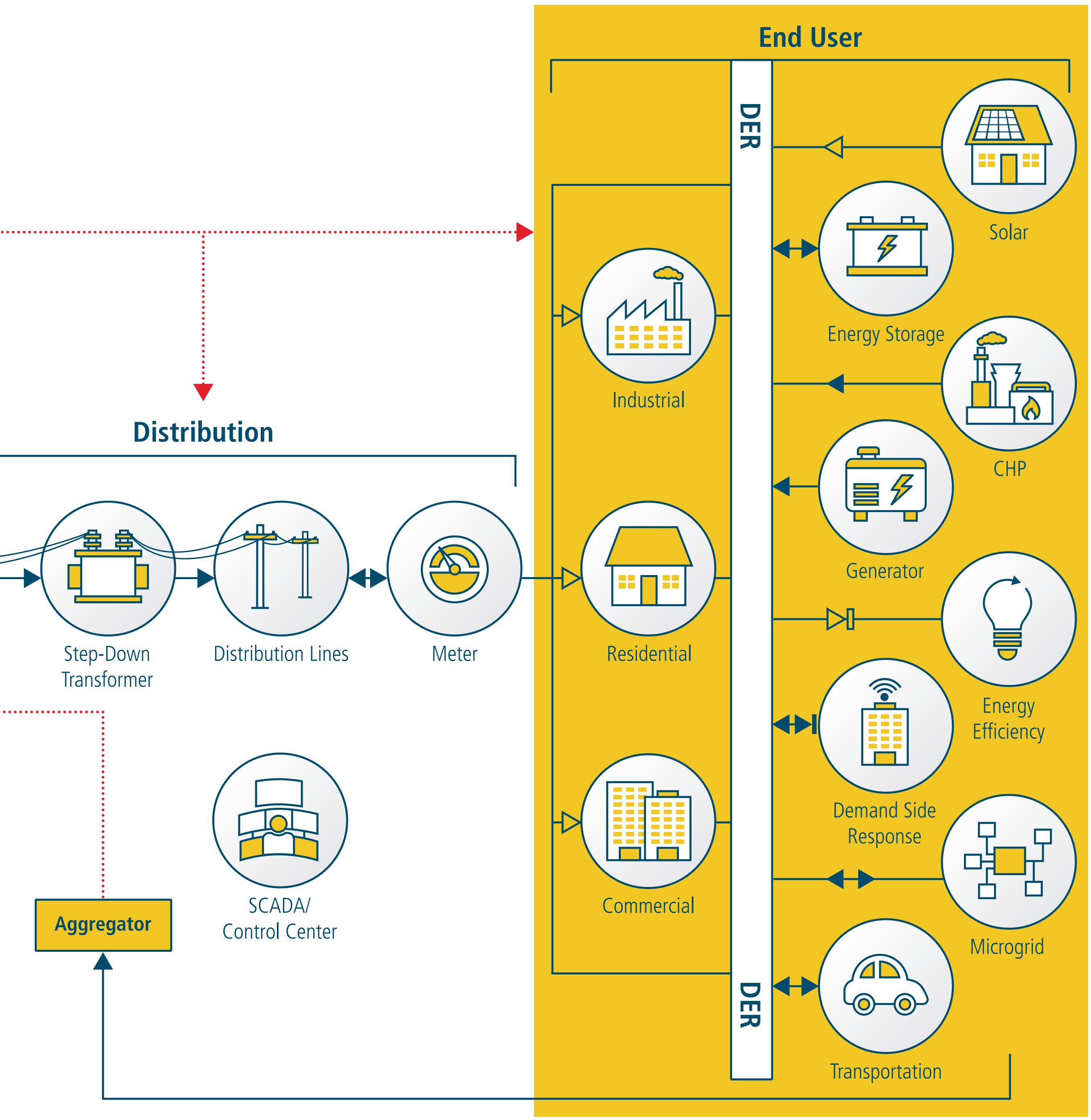
The U.S. electric power system is an immensely complex system-of-systems, comprising generation, transmission, and distribution subsystems and myriad institutions involved in its planning, operation, and oversight (Figure A-1). End use and distributed energy resources (DER) are also important parts of the electric power system.

Figure A-1. Schematic Representation of the U.S. Electric Power System



The electric power system comprises the following broad sets of systems: bulk generation, transmission, distribution, and end use (including DER).

Acronyms: combined heat and power (CHP), distributed energy resources (DER), kilovolts (kV), supervisory control and data acquisition (SCADA).


End User
DER
Solar
Energy Storage
Industrial
CHP
Generator
Residential
Energy Efficiency
Demand Side Response
Commercial
Microgrid
Transportation
DER
Distribution
Step-Down Transformer
Distribution Lines
Meter
SCADA/ Control Center
Aggregator

Generation

Electricity generation accounts for the largest portion of U.S. primary energy use, using 80 percent of the Nation's domestically produced coal,[1] one-third of its natural gas, and nearly all of its nuclear and non-biomass renewable resource production. In 2014, 39 percent of the Nation's primary energy use was devoted to electricity generation, and electricity accounted for 18 percent of U.S. delivered energy.[2]

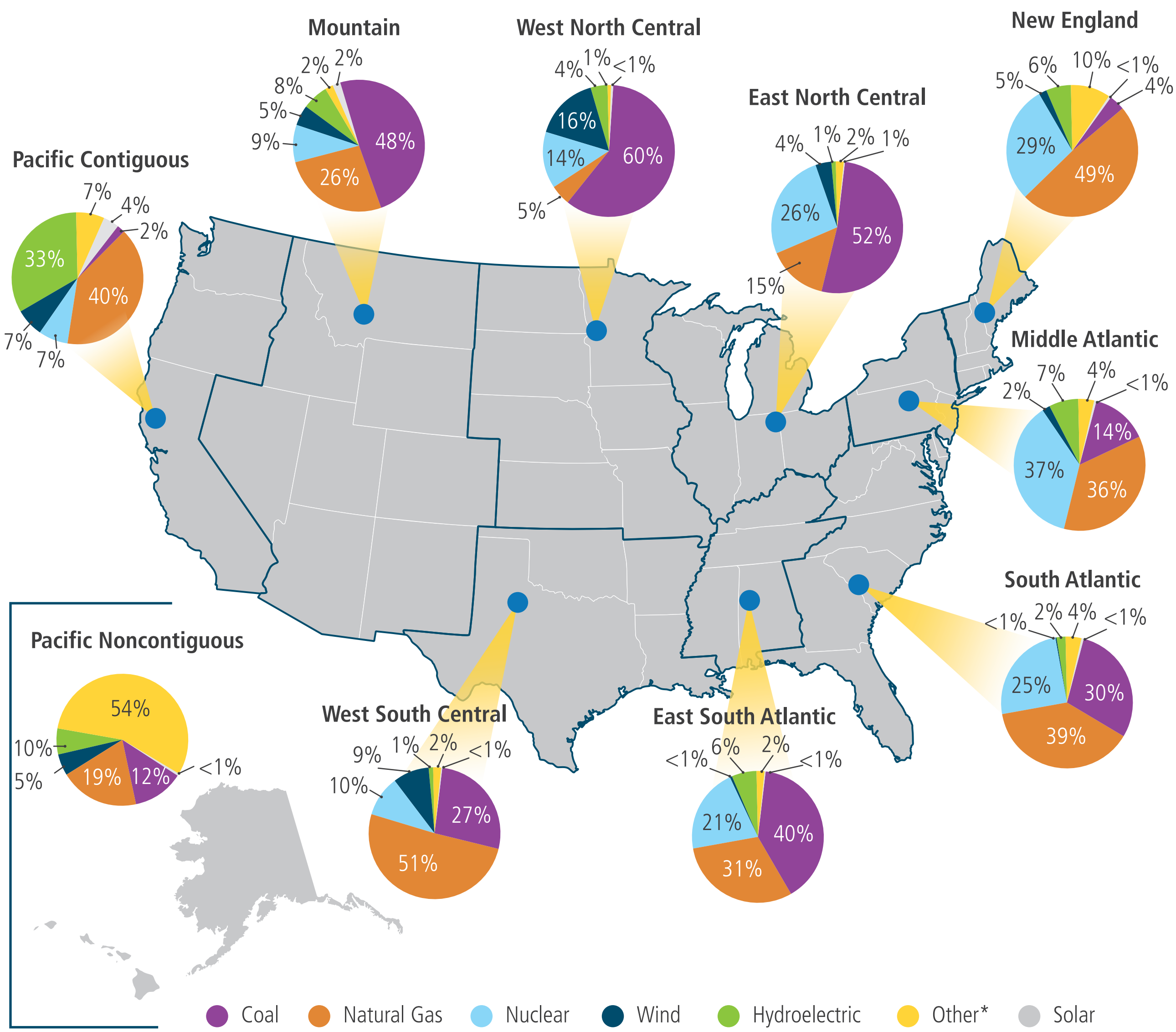
In 2014, there were over 6,500 operational power plants of at least 1 megawatt in the U.S. electric power system.[a, 3, 4] These power plants delivered nearly 3,764 billion kilowatt-hours (kWh) of power in 2014, supplying electricity to over 147 million residential, commercial, and industrial customers at an average price of $0.104/kWh for a total revenue from electricity sales of more than $393 billion.[5, 6, 7, 8]

The U.S. electricity generation portfolio is diverse and changes over time through the commercial market growth of specific generation technologies—often due to a confluence of policies, historic events, fuel cost, and technology advancement. Today, coal and natural gas each provide roughly one-third of total U.S. generation; nuclear provides 20 percent; hydroelectric and wind provide roughly 5 percent each; and other resources, including solar and biomass, contribute less than 2 percent each.[9] However, there are major generation mix differences between regions (Figure A-2).[10]

The availability of primary energy resources, like coal and natural gas, and renewable energy resources, like wind and solar, differs widely across the country (Figure A-3). This dispersed resource availability influences the regional generation mixes.

[a] A megawatt is a thousand kilowatts. A kilowatt is a unit of power output commonly used in the electricity industry. A kilowatt-hour (kWh) is a related unit of energy (the amount of power provided times the number of hours that it is provided). Electricity is usually billed by the kWh. An average American home uses roughly 11,000 kWh per year. Source: "How Much Electricity Does an American Home Use?" Energy Information Administration, Frequently Asked Questions, last modified October 18, 2016, https://www.eia.gov/tools/faqs/faq.cfm?id=97&t=3.

Figure A-2. Electric Power Regional Fuel Mixes, 2015[11, 12]

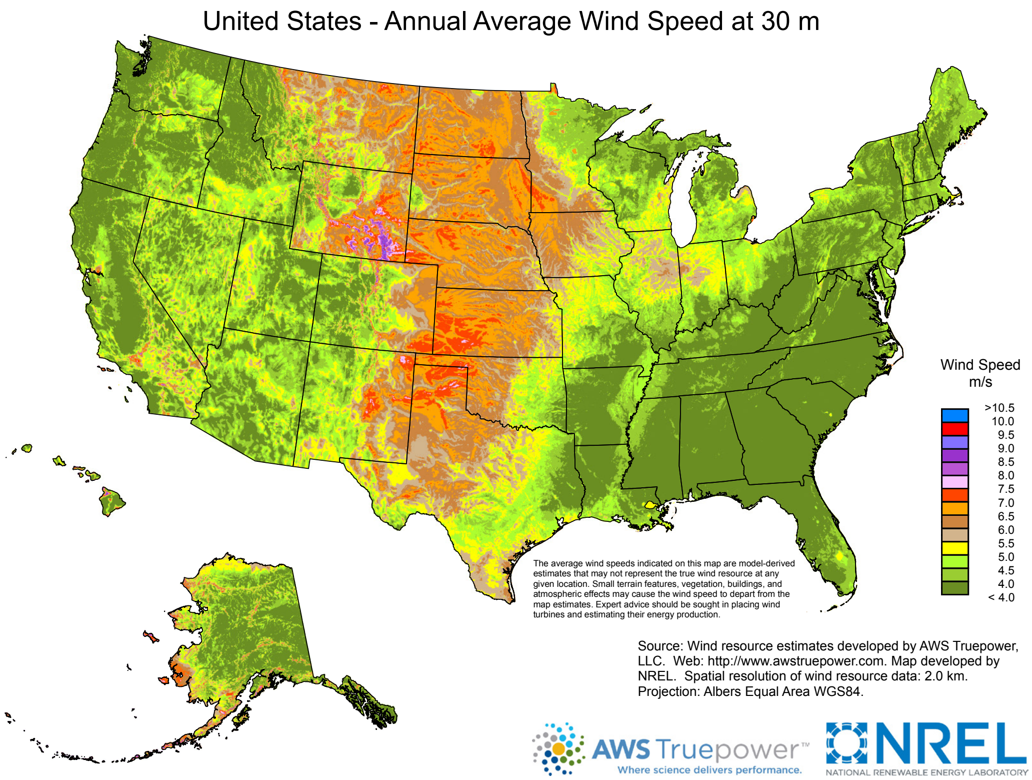


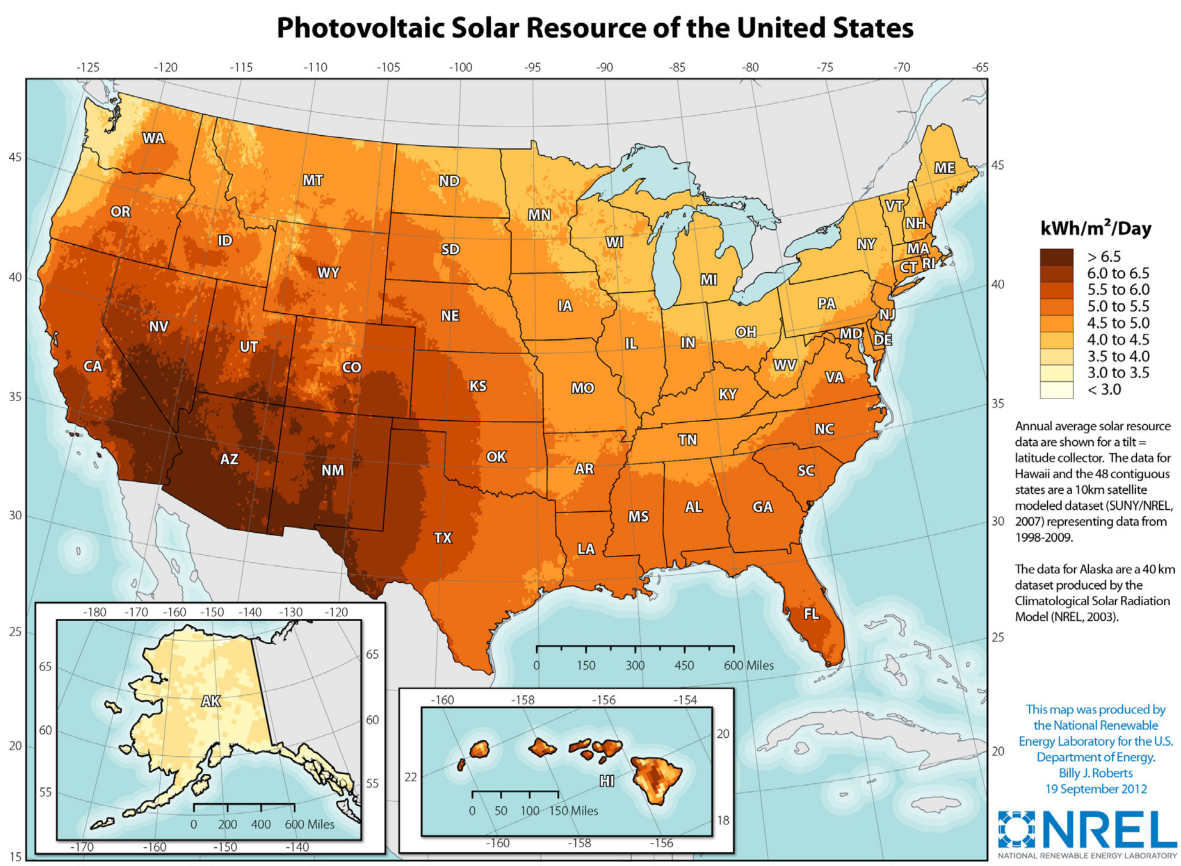
*Includes the following Energy Information Administration fuel type designations: Distillate Petroleum, Geothermal, Biogenic Municipal Solid Waste and Landfill Gas, Other Gases, Other Renewables, Other (including nonbiogenic municipal solid waste), Petroleum Coke, Residual Petroleum, Waste Coal, Waste Oil, and Wood and Wood Waste.

Note: Sum of components may not add to 100% due to independent rounding.

The U.S. electricity industry relies on a diverse set of generation resources with strong regional variations. As of 2015, coal fuels the majority of electricity generation in the Mountain, West North Central, East North Central, and East South Central regions. Coal is also a significant resource for the South Atlantic and West South Central regions, though both have sizable natural gas generation as well, and the South Atlantic region includes substantial shares of nuclear. The Pacific Contiguous and New England regions are predominately natural gas, with significant contributions of hydroelectric and nuclear, respectively. The Middle Atlantic is the only region that is predominately nuclear, and the Pacific Noncontiguous region is the only region in which fuel oil represents more than a few percentage points of total generation, where it constitutes nearly half of all generation.

Figure A-3. Wind and Solar Energy Resource Maps for the United States[13,14]





Energy resource availability varies widely across the United States. Wind and solar energy resources are concentrated in the Midwest and Southwest regions of the United States.

Transmission

The U.S. transmission network includes the power lines that link electric power generators to each other and to local electric companies. The transmission network in the 48 contiguous states is composed of approximately 697,000 circuit-miles[b] of power lines and 21,500 substations operating at voltages of 100 kilovolts (kV)[c] and above.[15] Of this, 240,000 circuit-miles are considered high voltage, operating at or above 230 kV (Figure A-4).[16] A substation is a critical node within the electric power system and is composed of transformers, circuit breakers, and other control equipment. Distribution substations are located at the intersection of the bulk electric system and local distribution systems.

The vast majority of transmission lines operate with alternating current (AC). With commonly used technology, system operators cannot specifically control the flow of electricity over the AC grid; electricity flows from generation to demand through many paths simultaneously, following the path of least electrical resistance. A limited number of transmission lines are operated using direct current (DC). Unlike AC transmission lines, the power flows on DC lines are controllable. However, their physical characteristics make them cost-effective only for special purposes, such as moving large amounts of power over very long distances.[17]

Electricity moved through transmission and distribution systems faces electrical resistance and other conversion losses. Losses from resistance and conversion amount to 5 to 6 percent of the total electricity that enters the system at the power plant.[18]

Each transmission line has a physical limit to the amount of power that can be moved at any time, which depends on the conditions of the power system. Within one market or utility control area, physical limits of system assets are the primary drivers of power price differences in different parts of the system.

Distribution System

The role of the large generators and transmission lines that comprise the bulk electric system is to reliably provide sufficient power to distribution substations. In turn, the distribution system is responsible for delivering power when and where customers need it while meeting minimum standards for reliability and power quality.[19] Power quality refers to the absence of perturbations in the voltage and flow of electricity that could damage end-use equipment or reduce the quality of end-use services.[20]

Before delivery to a customer, electric power travels over the high-voltage transmission network (at hundreds of kilovolts) to a distribution substation where a transformer reduces the voltage before the electricity moves along the distribution system (at tens of kilovolts). Several primary distribution feeder circuits, connected by an array of switches at the distribution bus, emanate from the substation and pass through one or more additional transformers before reaching the secondary circuit that ultimately serves the customer. One or more additional transformers reduce the voltage further to an appropriate level before arriving at the end-use customer's meter.[d, 21]

An emerging role of the distribution system is to host a wide array of distributed energy generation, storage, and demand-management technologies. Though some distributed energy technologies—like campus-sized combined heat and power—have existed for decades, rapid cost declines in solar, energy storage, and power electronic technologies, coupled with supportive policies, have led to a rapid proliferation of new devices and, at times, new challenges and opportunities for the planning and operation of distribution systems.

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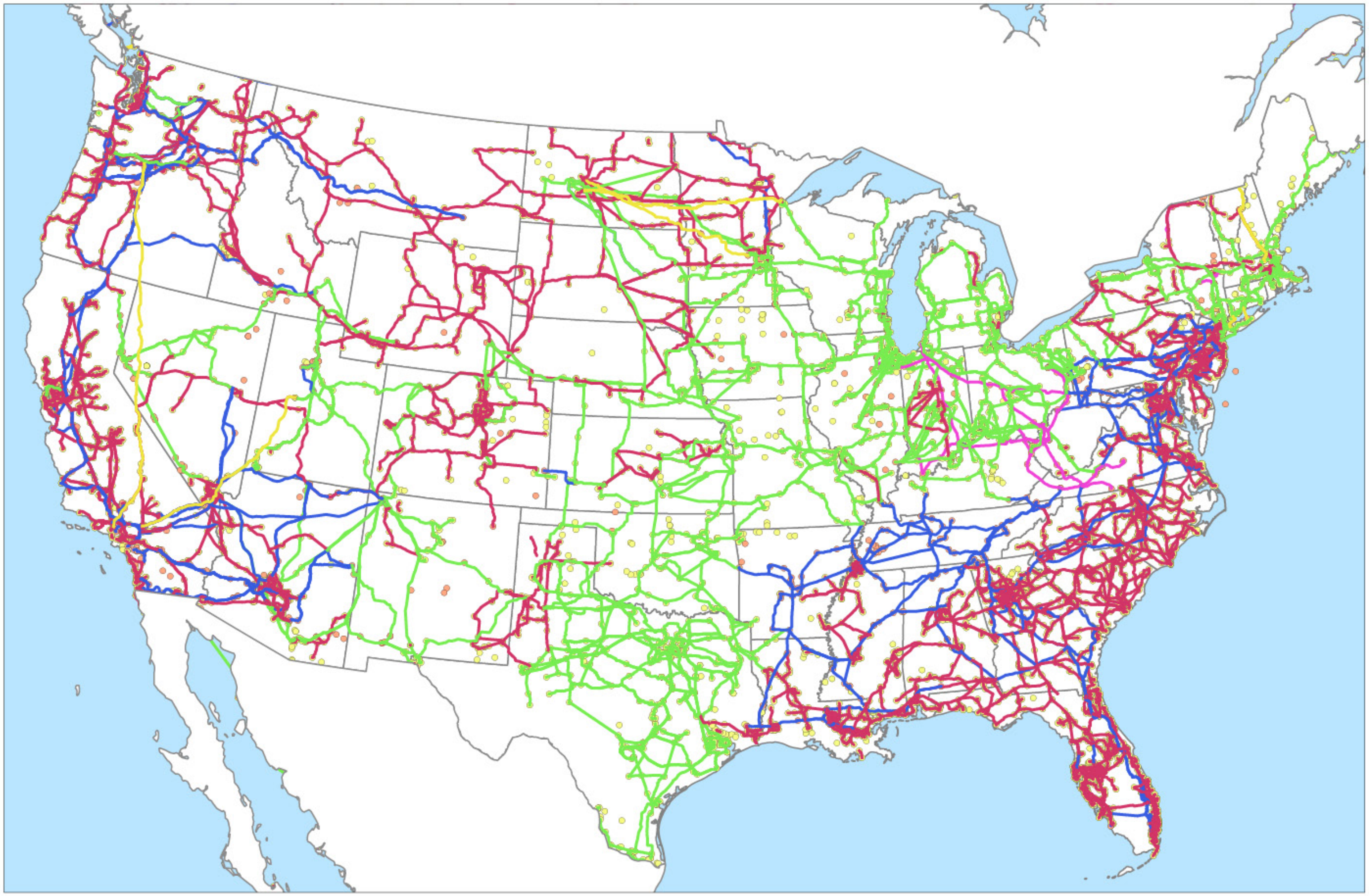
[b] A circuit-mile is 1 mile of one circuit of transmission line. Two individual 20-mile lines would be equivalent to 40 circuit-miles. One 20-mile double-circuit section would also be equivalent to 40 circuit-miles.

[c] A kilovolt (kV) is a commonly used unit of electrical "force" in the electricity industry. Electricity at higher voltages moves with less loss; however, system components able to manage high voltage are costly, and high voltages can be dangerous. Lower voltage is used in distribution systems to manage costs on system equipment and for safety.

[d] Most residential and commercial customers in the United States receive two 120-volt (V) connections. Most household plugs provide 120 V, while large appliances like dryers and ovens often combine the two 120-V connections into a single 240-V supply.

Figure A-4. High-Voltage Transmission Network and Substations of the 48 Contiguous States, 2015[22]



Electric Substations
Color by Minimum Volatage kV
- 450 to 1,000
- 300 to 450
- 230 to 300

Electric Transmission Lines (by voltage class)
Color by Volatage Class kV
- 230–300
- 345
- 500
- 735 and Above
- DC Line

The transmission network comprises approximately 697,000 circuit-miles—of which roughly 240,000 miles operate at or above 230 kV—and 21,500 substations operating at voltages of 100 kV and above.[23, 24, 25]

Distributed Energy Resources (DER)

DER constitute a broad range of technologies that can significantly impact how much, and when, electricity is demanded from the grid. Though definitions of DER vary widely, the term is used in the Quadrennial Energy Review (QER) to refer to technologies such as distributed generation (DG), distributed storage, and demand-side management resources, including energy efficiency. Given the multiple definitions and understandings of the term DER, the QER will use DER to refer to the full range of these technologies and will delineate specific technologies where only some are relevant. Current and projected market penetration of DG is shown in Table A-1.

DER technologies can be located on a utility's distribution system or at the premises of an end-use customer. They differ with respect to several attributes, though a key differentiator is their level of controllability from a grid management perspective. Certain DER, such as energy efficiency or rooftop solar photovoltaic, impact total load but may not be directly controlled by grid operators. Other DER, such as DR or controllable distributed energy storage, can be more directly managed and called upon by grid operators when needed.

Table A-1. Current and Projected Distributed Generation Market Penetration, 2015 and 2040[26]

Resource	Total Generation (GWh)		% of Total Utility Generation	
	2015	2040	2015	2040
Combined Heat and Power (CHP)	166,946	246,896	4.2%	5.2%
Rooftop Solar PV	13,453	64,485	0.3%	1.4%
Distributed Wind	637	1,643	0.0%	0.0%
Other DG	4,298	4,298	0.1%	0.1%
Total Distributed Generation	185,334	317,323	4.7%	6.7%
Total Utility-Scale Generation	**3,947,520**	**4,745,441**		

Other DG includes small-scale hydropower; biomass combustion or co-firing in combustion systems; solid waste incineration or waste-to-energy; and fuel cells fired by natural gas, biogas, or biomass. Backup generators (for emergency power) are not included here because generation data are limited, and these generators are not used in normal grid operation.

Acronyms: distributed generation (DG); gigawatt-hours (GWh); photovoltaic (PV).

End Use

Electricity end-use infrastructure includes physical components that use, require, or convert electricity to provide products or services to consumers. Since the first time the electric light bulb lit up New York City, nearly all parts of the United States have gained access to electricity.[e] In that time, the proliferation of novel and unanticipated uses of electricity has placed electricity at the center of everyday life and established it as the engine for the modern economy.

Today, the residential and commercial sectors each consume about the same share of total electricity—38 percent and 36 percent, respectively—with the industrial sector accounting for an additional 26 percent of electricity demand.[27, 28] Cumulatively, electricity sales to end-use customers in the United States generated approximately $393 billion in 2014.[29, 30] Moving forward, new technologies, from automated thermostats to electric vehicles, are changing the way consumers use electricity.

[e] There are thousands of households in Indian lands that still do not have access to electricity.

Electricity is a high-quality energy source available at a relatively low price. However, many low-income Americans struggle to afford their monthly electricity bills.[31] Nationally, average monthly residential bills in 2015 were $114.[32]

Brief History of the U.S. Electricity Industry

The U.S. electricity system represents one of the greatest technological achievements in the modern era. The complexity of the modern electricity industry is the result of a complicated history.

The Beginning of the Electricity Industry

The U.S. electricity industry began in 1882 when Thomas Edison developed the first electricity distribution system. Edison designed Pearl Street Station to produce and distribute electricity to multiple customers in the New York Financial District and to sell lighting services provided by his newly invented light bulbs.[33]

Early utilities distributed power over low-voltage DC lines. These lines could not move electricity far from where it was produced, which limited utility service to areas only about a mile from the generator. Multiple generators and dedicated distribution lines were required to serve a larger area. The limited reach of distribution lines and the lack of regulation of utilities resulted in the co-location of multiple independent utilities and competition for customers where multiple distribution lines overlapped.[34, 35]

In 1896, AC generation emerged as a competitor to DC when Westinghouse Electric developed a hydropower generation station at Niagara Falls, New York, and transmitted power 20 miles to Buffalo, New York.[36] At the voltage levels used at that time, AC has better electrical characteristics for moving power over long distances. This technological development—and related business models—allowed a single utility to broaden the geographic extent of its customers and sources of revenue. A wave of consolidation followed, where small, isolated DC systems were converted to AC and interconnected with larger systems. Interconnecting with other systems and serving more customers allowed operators to take advantage of the diversity of customer demand, deliver better economies of scale, and provide lower prices than competitors.[37]

A move toward today's system of regulatory oversight occurred around the turn of the century. With the industry consolidation of the late 1890s came public concern over lack of competition and the potential for large utilities to exert a monopoly power over prices.[38] In 1898, a prominent electricity industry leader and Thomas Edison's former chief financial strategist, Samuel Insull, called for utility regulation that granted exclusive franchises in exchange for regulated rates and profits in order to create a stable financial environment that would foster increased investments and electricity access.[39] Insull claimed that such regulation was needed because utilities are natural monopolies, meaning that a single firm can deliver a service at a lower total cost than multiple firms through economies of scale and avoidance of wasteful duplication (e.g., multiple distribution substations and circuits belonging to different companies serving a single area).

In 1907, Wisconsin became the first state to regulate electric utilities, and by 1914, 43 states had followed.[40, 41] The general form of utility regulation that was established by the Wisconsin legislature in 1907 endures today and is called the "state regulatory compact."

This compact allowed electric utilities to operate as distribution monopolies with the sole right to provide retail service to all customers within a given franchise area—as well as an obligation to do so. Those monopolies were allowed an opportunity to earn a fair rate of return on their investments. Some municipal governments across the country created their own utilities, owned and governed by the local government, as an alternative to investor-owned, regulated utilities.[42, f]

[f] Other types of publicly owned electric utilities, besides those owned by municipal governments, include utilities organized around states, public utility districts, and irrigation districts. The term "public power" is often used to refer to electricity utilities operated by any of these political subdivisions.

The State Regulatory Compact

The "state regulatory compact" evolved as a concept "to characterize the set of mutual rights, obligations, and benefits that exist between the utility and society."[g] It is not a binding agreement. Under this "compact," a utility typically is given exclusive access to a designated—or franchised—service territory and is allowed to recover its prudent costs (as determined by the regulator) plus a reasonable rate of return on its investments. In return, the utility must fulfill its service obligation of providing universal access within its territory. The "regulatory compact" applies to for-profit, monopoly investor-owned utilities that are regulated by the government. The compact is less relevant to public power and cooperative utilities, which are nonprofit entities governed by a locally elected or appointed governing body and are assumed to inherently have their customers' best interests in mind. Regulators strive to set rates such that the utility has the opportunity to be fully compensated for fulfilling its service obligation. While not technically part of the "compact," customers also have a role to play in this arrangement: they give up their freedom of choice over service providers and agree to pay a rate that, at times, may be higher than the market rate in exchange for government protection from monopoly pricing. In effect, utilities have the opportunity to recover their costs, and, if successful, their investors are provided a level of earnings; customers are provided non-discriminatory, affordable service; and the regulator ensures that rates are adequately set such that the aforementioned benefits materialize.

[g] Karl McDermott, *Cost-of-Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation* (Washington, DC: Edison Electric Institute, 2012), http://www.eei.org/issuesandpolicy/stateregulation/Documents/COSR_history_final.pdf.

In the early 1900s, states regulated nearly all of the activities of electric utilities—generation, transmission, and distribution.[43] However, a 1927 Supreme Court case[44] held that state regulation of wholesale power sales by a utility in one state to a utility in a neighboring state was precluded by the commerce clause of the U.S. Constitution.[45] These transactions were left unregulated as Congress had the authority to regulate, but no Federal agency existed to do so.[46]

The 1935 Federal Power Act (FPA) addressed the regulatory gap by providing the Federal Power Commission (FPC, eventually renamed the Federal Energy Regulatory Commission, or FERC)[h] with authority to regulate "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce."[47, 48] The FPA left regulation of generation, distribution, and intrastate commerce to states and localities.[49] Federal regulation was to extend "only to those matters which are not subject to regulation by the States."[50] FERC was given jurisdiction over all facilities used for the transmission or wholesale trade of electricity in interstate commerce and was charged with ensuring that corresponding rates are "just and reasonable, and not unduly discriminatory or preferential."[51, 52]

Federal Investments in Rural Electrification

Urban areas were the first areas to attract utility investment. The higher density of potential customers in urban areas made these areas more cost-effective to serve. By the 1930s, most urban areas were electrified, while sparsely populated rural areas generally lagged far behind. The Great Depression and widespread floods and drought in the Great Plains during the 1930s led to a wave of significant Federal initiatives to develop the power potential of the Nation's water resources.

[h] The Federal Power Commission was created in 1920 by the Federal Water Power Act to encourage the development of hydroelectric generation facilities.

One example of Federal efforts to capture the benefits of the Nation's water resources is the Tennessee Valley Authority (TVA). TVA was created in 1933 as a federally owned corporation to provide economic development through provision of electricity, flood control, and other programs to the rural Tennessee Valley area. To this day, TVA maintains a portfolio of generation and transmission assets to sell wholesale electricity to public power and cooperatives within its territory. Federal law grants first preference for this electricity to public power and cooperative utilities.

Congress passed the Rural Electrification Act in 1936, which encouraged electrification of areas unserved by investor-owned utilities (IOUs) and public power utilities. The act authorized rural electric cooperatives to receive Federal financing support and preferential sales from federally owned generation. The Bonneville Power Administration was created in 1937 to deliver and sell electric power from federally owned dams in the Pacific Northwest.[53] Increased Federal investment in hydropower followed through the 1940s, and by the 1960s, rural electrification was largely complete.[54]

Federally Owned Utilities

There are five Federal electric utilities: Tennessee Valley Authority (TVA), Bonneville Power Administration (BPA), Southeastern Power Administration (SEPA), Southwestern Power Administration (SWPA), and Western Area Power Administration (WAPA). TVA is an independent government corporation, while BPA, SEPA, SWPA, and WAPA are separate and distinct entities within the Department of Energy. Starting with BPA in 1937, followed by SEPA, SWPA, and WAPA, Congress established the Power Marketing Administrations (PMAs) to distribute and sell electricity from a network of more than 130 federally built hydroelectric dams.

The PMAs don't own or manage the power they sell but, in many cases, maintain the transmission infrastructure to distribute the low-cost electricity to public power and rural cooperative utilities, in addition to some direct sales to large industrial customers. The electricity-generating facilities are primarily owned and operated by the Department of the Interior's Bureau of Reclamation, the Army Corps of Engineers, and the International Boundary and Water Commission.

BPA, WAPA, and SWPA collectively own and operate 33,700 miles of transmission lines, which are integrally linked with the transmission and distribution systems of utilities in 20 states. Millions of consumers get electricity from the PMAs (usually indirectly, via their local utility), but a much larger number of consumers benefit from—and have a stake in—the continued efficient, effective operation of the PMAs and the transmission infrastructure they are building and maintaining.

TVA is a corporate agency of the United States that provides electricity for business customers and local power distributors, serving 9 million people in parts of seven southeastern states. TVA receives no taxpayer funding, deriving virtually all of its revenues from sales of electricity. In addition to operating and investing its revenues in its electric system, TVA provides flood control, navigation, and land management for the Tennessee River system and assists local power companies and state and local governments with economic development and job creation.

Electricity Industry Restructuring and Markets

As early as the 1920s, utilities sought operational efficiencies by coordinating generation dispatch and transmission planning across multiple utility territories. Coordination through cooperative power pools provided economies of scale and scope that ultimately lowered costs for all participant utilities. The principles of coordination pioneered in power pools later became the basis for the centrally organized electricity markets that exist today.[55]

Over time, economists and industry observers came to believe that the natural monopoly status that was the basis of so much of electricity industry regulation no longer applied to generation and instead only applied to the "wires" part of the system. While it would be economically wasteful for multiple companies to install overlapping and competing distribution and transmission lines, the generation and sale of electricity to retail customers could be organized as competitive activities.[56] To encourage fair and open competition, several states eventually restructured individual IOUs into separate companies that invested in either regulated or competitive parts of the industry.

Restructuring actions vary by region and by state, but they are typically characterized by the "unbundling" of ownership and regulation of electricity generation, transmission, distribution, and sales, with large variations in how restructuring is implemented across regions and states.

Congress took an early step toward reintroducing market competition in the generation sector in 1978 when it enacted the Public Utilities Regulatory Policies Act (PURPA).[57] PURPA required utilities to purchase power from qualifying non-utility generators at the utility's avoided cost. This led to a wave of investment in generation by non-utility companies.

A major step toward creating electric markets was Congress' enactment of the Energy Policy Act of 1992 (EPAct 1992), which provided FERC with limited authority to order transmission access for wholesale buyers in procuring wholesale electric supplies.[58, 59, 60] Subsequent FERC actions, including Order No. 888 and Order No. 889, created greater transmission access and facilitated the creation of competitive wholesale electricity markets. These FERC orders increased access to electricity supplies from other utilities for wholesale buyers, including public power and rural cooperative utilities.

Also in the 1990s, several states made regulatory changes introducing retail electric choice programs to allow some customers to choose an electricity provider other than their local utility, and to have electricity delivered over the wires of their local utility.[61] States that allow customer choice are sometimes called "deregulated states," a misnomer, as retail electricity providers and other parts of the industry remain highly regulated. By 1996, at least 41 states, including California, New York, and Texas, had or were considering ending utility monopolies and providing electricity service through retail competition.[62] Some states, notably in the Southeast and in western states besides California, did not embrace this wave of restructuring. In 2000 and 2001, California and the Pacific Northwest experienced severe electricity shortages and price spikes. This California electricity crisis left many states that had not yet implemented restructuring wary of pursuing such reforms. Today, 15 states allow retail electric choice for some or all customers, while 8 states have suspended it, including California, which suspended retail choice for residential customers after the energy crisis.[63]

The net result of these changes to jurisdictions, industry structure, and competitive markets is that the United States today has a patchwork of mechanisms governing the electricity industry and a diverse set of industry participants. Regulation of the industry continues to evolve as new technologies, policies, and business realities emerge.

Laws and Jurisdictions

Government oversight and regulation of the electricity industry centers on the concurrent needs to

- Ensure that safe and adequate electricity service is provided at just and reasonable rates
- Protect the public interest
- Enable the financial health of the system, such as ensuring that service providers can attract the investments needed to continue providing this essential public service
- Play a beneficial role in diminishing the impact of negative externalities, such as ensuring that industry activities are not inadvertently causing hardship to neighboring communities or the environment.

Governmental Actors

The responsibility for regulating and overseeing the numerous actors that encompass the electricity industry and the activities they carry out is vested in multiple government officials. These authorities span Federal, state, local, and tribal governments. The jurisdictional relationship between the actors is shown in Figure A-5 and is explained further on the following page.

Figure A-5. Broad Overview of Jurisdictional Roles in the Electricity Industry[64]

Federal Jurisdiction (FERC, DOI, DOE, EPA, NRC, others)	**State Jurisdiction** (PUC, policymakers, enviro/energy agencies)	**Local Jurisdiction** (Local governing bodies)	**Tribal Jurisdiction** (Tribal utility authorities)
Generation siting (DOI, EPA)	Generation siting (PUC, policymakers, enviro agencies)	Generation siting	Generation siting
Limited interstate transmission siting (DOE, FERC, DOI)	Interstate transmission siting (PUC, policymakers, enviro agencies)	Interstate transmission siting	Interstate transmission siting
Environmental impacts (DOE, EPA, USDA, DOI, others)	Environmental impacts (enviro agencies)	Environmental impacts	Environmental impacts
M&A for regulated utilities (FERC, DOJ, SEC, FTC)	M&A for regulated utilities (PUC, policymakers)	Zoning approval	Govern operational market, planning activities of tribal utilities and have a say in the majority of activities that occur on tribal lands
Resource adequacy in RTO/ISO markets	Resource adequacy & generation mix (PUC, legisilatures)	Local elected or appointed boards govern public power and cooperatives. These boards typically oversee the majority of public power/ coop activities	
Managing system operation and planning challenges arising from an increase in devices that can participate at both the wholesale and retail level	Managing system operation and planning challenges arising from an increase in devices that can participate at both the wholesale and retail level		
Interstate transmission commerce (FERC)	Retail sales to end users (PUC)		
Interstate wholesale commerce (FERC)	Utility planning (PUC, policymakers)		
Hydro licensing and safety (FERC)	State energy goals/policies (policymakers)		
Nuclear plant oversight (NRC)	Power plant safety standards (OSHA)		
Bulk system reliability (FERC/ NERC)			
Power plant safety standards (OSHA)			

Indicates Federal–State–Local–Tribal Jurisdictional Ambiguity

Indicates Federal–State Jurisdictional Ambiguity

Jurisdictional responsibility of the electricity industry is divided between Federal, state, local, and tribal jurisdictions. Several issues, such as generation siting, transmission siting, and environmental planning, span all of the four jurisdictions. Federal and state jurisdictions overlap in planning, resource adequacy, and mergers and acquisitions for regulated utilities. Other areas, such as interstate transmission commerce and retail sale to end users, are regulated by the Federal Government (FERC) or the states (public utility commissions), respectively.

Acronyms: Department of Agriculture (USDA); Department of Energy (DOE); Department of the Interior (DOI); Department of Justice (DOJ); Environmental Protection Agency (EPA); Federal Trade Commission (FTC); independent system operator (ISO); North American Electric Reliability Corporation (NERC); Nuclear Regulatory Commission (NRC); Occupational Safety and Health Administration (OSHA); public utility commission (PUC); regional transmission organization (RTO); Securities and Exchange Commission (SEC).

Federal Actors

At the Federal level, FERC carries out the vast majority of the economic Federal regulatory responsibilities pertaining to the electricity industry, primarily regulating transmission and wholesale sales in interstate commerce. In addition, other Federal authorities are involved with various aspects of regulation or oversight; their responsibilities are wide ranging and relate to environmental protection, land use, anti-trust protection, and transmission siting.

Federal Ratemaking

The Federal Energy Regulatory Commission (FERC) is the Federal Government agency responsible for overseeing rates for wholesale sales of electricity and transmission in interstate commerce. Sections 205 and 206 of the Federal Power Act require FERC to assure that the rates charged for transmission and wholesale sales are "just and reasonable" and do not unduly discriminate against any customers or provide preferential treatment. Initially, all FERC rate regulation was based on the cost of service, but that policy has evolved. FERC continues to employ the cost-of-service approach for transmission service. For wholesale power sales, the primary means for setting "just and reasonable" wholesale electricity rates are through competitive mechanisms, subject to market rules to address market power.

State, Local, and Tribal Actors

At the state level, the electricity industry is regulated by state public utility commissions (PUCs), state environmental agencies, and other parts of state government, such as governors, legislatures, and state energy offices.

State governors and legislatures establish laws or standards that impact the electricity industry, such as renewable portfolio standards, and state environmental agencies implement state and some Federal environmental laws and regulations and thus have jurisdiction on electricity.

PUCs in the states, territories, and the District of Columbia regulate IOUs. State laws in a handful of states also give PUCs jurisdiction over public power and cooperatives.[65] PUCs regulate all matters of IOU distribution (rates, capital expenditures, cyber security, reliability, demand-side resources, and the wholesale purchase process) and usually site transmission and generation projects; they also oversee generation choices in non–regional transmission organization (RTO)/independent system operator (ISO) states and oversee retail competition in those states that allow it.

State Retail Rate Setting

State public utility commissions (PUCs) review and set retail rates for investor-owned utilities (IOUs). In states with retail competition, rates only include the costs of the distribution of electricity, while prices for electricity generation are determined competitively. In states that have not restructured their utility industry, retail rates set by PUCs include the recovery of generation, transmission, and distribution costs that utilities incurred to serve their ratepayers.

The underlying mandate of the PUC rate-setting process is to provide affordable and reliable electricity to consumers while ensuring that IOUs are given the opportunity to recoup their costs and earn a reasonable return on their investment. Under cost-of-service regulation, PUCs calculate utility revenue requirements as the sum of (1) rate base times allowed rate of return plus (2) utility operating expenses. The rate base consists of the depreciated cost of a utility's assets. Based on the revenue requirement, rates for each consumer class are determined.[i]

A few states also grant PUCs the authority to regulate rates for public power utilities, but in most cases rates for public power utilities are set by the utility's governing body, for example, a city council or other local authority. Rates for members of rural cooperatives are set by the cooperative's governing board.[j]

[i] A more detailed discussion on different charges for consumers is included in Chapter II (*Maximizing Economic Value and Consumer Equity*).

[j] M. J. Bradley & Associates LLC, *Public Utility Commission Study* (Charlottesville, VA: SRA International, Inc., and Environmental Protection Agency, March 2011), https://www3.epa.gov/airtoxics/utility/puc_study_march2011.pdf.

Federal and State Jurisdictional Responsibilities

The current jurisdictional division of regulatory authority in the electricity sector between the Federal Government and the states, codified in the FPA and interpreted by subsequent Supreme Court and lower court decisions, is the result of the evolution of a regulatory scheme that was originally governed predominantly by state and local agencies. The FPA established an affirmative grant of authority to the Federal Government to regulate wholesale sales and transmissions of electricity in interstate commerce, but the FPA also attempts to draw a "bright line" where that exclusive authority ends and the state's authority to regulate other matters (principally facilities used in the generation and distribution of electric power, as well as retail sales of electricity) begins.

The "bright line" in the FPA uses factors such as transaction and customer type (wholesale v. retail), facility type (generation v. transmission v. distribution), geography (interstate commerce v. intrastate commerce), and regulatory action (e.g., rate regulation v. facility permitting) to divide exclusive regulatory responsibilities between Federal and state regulators. Congress has chosen different approaches for defining Federal regulatory responsibilities and the role of the states in other energy and energy-related statutes, however. The principal differences in approach include the following: (1) while the FPA contemplates exclusive authority for each regulator, with implicit opportunities for cooperative federalism, other Federal statutes explicitly provide for shared authority (sometimes called "cooperative federalism"); and (2) while the FPA provides the Federal Government with limited authority over energy facility siting or generation facilities in general (FERC has jurisdiction over siting hydro), leaving such matters mostly to the states, other Federal statutes, such as the Natural Gas Act, provide for Federal authority over facility siting.[66]

However, new and emerging technologies that are gaining an increasing presence throughout the electricity system today have significantly different operational characteristics and attributes than those that existed when the FPA and its jurisdictional "bright line" were written, and different characteristics than those that existed as that jurisdictional line developed over the ensuing decades. For DG, no clear delineation exists between wholesale and retail jurisdiction as power flows from generation through delivery to ultimate consumption. Instead, new DER (including energy storage) can be interconnected to either the FERC-jurisdictional, high-voltage transmission grid or the state-jurisdictional, low-voltage local distribution system (or behind the customer's meter). In addition, these resources, along with the other new and advanced technologies noted above, can provide (or enable DR that can provide) several kinds of wholesale and retail grid services, with benefits that extend across the traditional generation, transmission, and distribution classifications.

Tensions between Federal and state regulatory jurisdiction over the electricity system have played out in the courts recently. From the October Term of 2014 to the October Term of 2015, the Supreme Court heard three cases involving FERC jurisdictional issues, an atypical number for a single year. The Court's decisions to hear these cases reflect, in part, the growing complexity of regulating the electricity industry, but also point to uncertainty about statutes that regulate services that are increasingly converging with the electricity industry, like natural gas and telecommunications. Two of these cases, the recent *FERC v. Electric Power Supply Association*[67] and *Hughes v. Talen Energy Marketing*[68] decisions, provide examples of the courts applying the FPA's jurisdictional division to new sets of technology and market challenges. In both of those cases, the Court decided generally in favor of the broader view of the Federal role. *FERC v. Electric Power Supply Association*—relating to FERC's Order No. 745—confirmed FERC's authority under the FPA to determine compensation for DR that is bid into the organized wholesale market.

Major Federal Laws Pertaining to the Electricity Industry

While the FPA is the enabling legislation providing the FPC (and now FERC) its authority over portions of the electricity industry, additional laws and rules have further defined the legal landscape governing the electricity system. Overall, these laws and regulations can be broken into two separate categories: electricity industry–related and environmental.

The Federal Water Power Act, enacted in 1920, created the FPC (now FERC) to encourage the development of hydroelectric generation facilities by non-Federal entities. The 1935 FPA expanded the Commission's regulatory jurisdiction to include rates, terms, and conditions of service for interstate electricity transmission and wholesale electricity sales, but left regulation of generation, distribution, and intrastate commerce to state and local governments.[69] This set up the "bright line"[k] between Federal authority over wholesale rates and state and local authority over retail rates.

The utility industry of the early 1900s often relied on holding companies—a financial structure where a parent company would hold the financial stocks and bonds of subsidiary utilities—to improve financial performance and seek economies of scale. Though these companies provided cost savings that contributed to the growth of the utility industry, their complex financial structures enabled companies to subsidize their unregulated business activities with earnings from regulated activities. In response, Congress passed the Public Utility Holding Company Act in 1935, which reduced the role of holding companies in the industry and allowed closer regulatory scrutiny of utilities.[70]

PURPA (1978), passed as part of the National Energy Act, was one of the major reformations of the governance of the electricity industry. Utilities were required to purchase power from qualifying facilities at the utilities' incremental cost of producing or purchasing alternative electricity, which is now known as "avoided cost."[71] The right to sell the power at avoided cost, combined with the exemption from several state and Federal regulations, "created a new and rapidly expanding nonutility generation sector of the electric power industry."[72] Qualifying facilities fall into two categories: (1) cogeneration facilities without any size limitations and (2) small power production facilities, which use biomass, waste, or renewable resources and which have a

[k] The term "bright line" was coined by the Supreme Court in *Federal Power Commission v. Southern California Edison Co.* in 1964.

generating capacity of no more than 80 megawatts. PURPA also required states (and utilities not regulated by states, such as public power and rural cooperative utilities) to conduct proceedings to consider charging cost-of-service rates for different customer classes; eliminating declining block pricing;[l] using time-of-day, seasonal, or interruptible rates; and implementing other retail utility policies.

The Energy Policy Act of 1992 (EPAct 1992) implements many of the provisions of the National Energy Strategy proposed by the Department of Energy (DOE) in February 1991.[73] EPAct 1992 authorized FERC to order transmission-owning utilities to provide transmission services to third parties on a case-by-case basis and adopted reforms to the Public Utility Holding Company Act of 1935, both of which supported increased competition in wholesale electricity markets. EPAct 1992 also included a wide variety of energy efficiency measures, such as requiring states to establish minimum commercial building energy codes and consider voluntary minimum residential codes and equipment standards for commercial heating and air-conditioning equipment, electric motors, and lamps. As a result of the incentives offered through EPAct 1992, several Native Nations developed alternative energy projects on their lands. The Renewable Electricity Production Tax Credit for wind, biomass, landfill gas, and other renewable sources was also first passed in EPAct 1992, and has been renewed several times since then.[74] As of May 2016, the Production Tax Credit provided an inflation-adjusted tax credit worth \$0.023/kWh to qualifying electricity production from wind, closed-loop biomass, and geothermal, as well as a \$0.012/kWh credit for open-loop biomass, landfill gas, municipal solid waste, qualified hydro, and marine and hydrokinetic.[75]

The Energy Policy Act of 2005 (EPAct 2005) addressed several major areas of the electricity industry.[76] EPAct 2005 pared back the must-purchase clause contained in PURPA by giving FERC the authority to allow utilities in regions with competition not to use the avoided-cost principle. The legislation also gave FERC responsibility for mandatory reliability standards and allowed the agency to certify an electric reliability organization to develop and enforce those standards. The North American Electric Reliability Corporation (NERC) is the designated electric reliability organization for North America and oversees eight regional reliability entities in the United States, Canada, and Baja California (Mexico). NERC is a not-for-profit corporation that, through a stakeholder process, develops and enforces mandatory electric reliability standards under FERC oversight in the United States.

EPAct 2005 also tasked DOE with issuing periodic studies of transmission congestion, and following the appropriate evaluation of transmission congestion and alternatives, authorizes DOE to designate National Interest Electric Transmission Corridors where there are electricity transmission capacity constraints or congestion. For projects located in these corridors, FERC has "backstop authority" to authorize transmission siting.[77] FERC was also given responsibility to provide rate incentives to promote transmission investment.

EPAct 2005 also increased the Investment Tax Credit, which has been renewed several times, including in the Omnibus Appropriations Act of 2015.[78] Currently, the Investment Tax Credit is 30 percent for solar, fuel cells, and small wind and 10 percent for geothermal, microturbines, and combined heat and power.[79] Additionally, EPAct 2005 provided grants for nuclear energy research and development and also implemented a \$0.018/kWh production credit for modern nuclear energy plants (1) whose design was approved by the Nuclear Regulatory Commission after December 1, 1993, (2) that started construction by January 2014, and (3) that are placed in commercial operation by 2021. EPAct 2005 also created the Title XVII Loan Program, which allows DOE to provide "guarantee loans that support early commercial use of advanced technologies, if there is reasonable prospect of repayment by the borrower."[80]

Other key laws and orders in the electricity industry are included in Table A-2, and key electricity industry–related environmental laws and regulations are included in Table A-3.

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[l] Effectively a bulk-purchase discount for large electricity consumers, making marginal increments of electricity cheaper as consumption rises.

Table A-2. Additional Key Electricity Industry Laws and Orders

Name	Year	Major Provisions
Atomic Energy Act	1954	• Established Federal regulatory authority over civilian uses of nuclear materials and facilities exercised through the Nuclear Regulatory Commission • Delineated Federal/state jurisdiction for nuclear material and facilities: licensing of nuclear plant construction and operation as well as waste disposal are exclusively in the Federal domain. States retain oversight of generation planning by vertically integrated utilities (e.g., questions of whether or not to construct nuclear facilities in the first place).
Price Anderson Act	1957	• Facilitated the development of nuclear-powered generating capacity by establishing a program for covering claims of members of the public if a major accident occurred at a nuclear power plant and providing a ceiling on the total amount of liability for nuclear accidents.
National Energy Act	1978	• Passed in response to oil shortages in the 1970s and the increased reliance on imported oil, which was seen as a threat to national security[m] • Legislation included the Natural Gas Policy Act of 1978, the Public Utility Regulatory Policies Act (PURPA), the Energy Tax Act, the Powerplant and Industrial Fuel Use Act, and the National Energy Conservation Policy Act.[n]
Energy Independence and Security Act	2007	• Strengthened lighting energy-efficiency standards • Added Section 1705 to the loan guarantee program, allowing subsidized loans to commercial facilities • Called for coordination to develop a framework for smart grid interoperability standards (National Institute of Standards and Technology).
American Recovery and Reinvestment Act	2009	• Funded $31 billion in energy efficiency and renewable energy, energy infrastructure, and made other major investments in energy administered by DOE.[o]
FERC Order 1000	2011	• Requires regional and interregional transmission planning; mandates that the planning process consider transmission needs driven by public policy requirements • Requires regional and interregional cost allocation methods that satisfy six allocation principles • Eliminates the Federal right of first refusal in FERC jurisdictional tariffs and agreements.[p]

In addition to the FPA, the Federal Water Power Act, the Public Utility Holding Company Act of 1935, PURPA, EPAct 1992, and EPAct 2005, which are discussed in the above section, these laws and orders have played key roles in shaping the electricity industry.

[m] Julia Richardson and Robert Nordhaus, "The National Energy Act of 1978," *Natural Resources & Environment* 10, no. 1 (1995): 62, http://www.jstor.org/stable/40923435.

[n] Julia Richardson and Robert Nordhaus, "The National Energy Act of 1978," *Natural Resources & Environment* 10, no. 1 (1995): 62–86, http://www.jstor.org/stable/40923435.

[o] "Recovery Act," Department of Energy, accessed July 29, 2016, http://www.energy.gov/recovery-act.

[p] EPSA Analysis: ICF International, *Impacts of the Power Sector Transformation on Jurisdictional Boundaries, Planning, and Rate Design* (Fairfax, VA: ICF International, July 2016), 11.

Table A-3. Key Electricity Industry-Related Environmental Laws and Regulations

Name	Year	Major Provisions
Clean Air Act	1970	• Authorized comprehensive Federal and state regulation of stationary pollution sources, including power plants[q] • Provided for National Ambient Air Quality Standards, State Implementation Plans, New Source Performance Standards, and National Emission Standards for Hazardous Air Pollutants[r] • Requires states to decide what pollution reductions will be required from particular sources to address National Ambient Air Quality Standards, and requires states to submit State Implementation Plans.[s]
National Environmental Policy Act	1970	• Requires Federal agencies to review the environmental consequences of a proposed project before granting approval.[t] Agencies prepare statements on the environmental impact of a proposed project (Environmental Impact Statement or Environmental Assessment), considering the views of the public and of other Federal, state, and local agencies, and make the report publicly available.[u]
Clean Water Act	1972	• Established regulations for discharging pollutants into water,[v] which includes wastewater discharges from the power sector (such as cooling water, wastewater from coal ash handling, and wastewater from pollution control equipment) • The Steam Electric Effluent Limitations Guidelines—promulgated under the Clean Water Act—were updated in 2015.
Resource Conservation and Recovery Act	1976	• Provides EPA with the authority to regulate hazardous waste,[w] including management of power sector waste, such as coal ash • The Coal Combustion Residuals rule—promulgated under the Resource Conservation and Recovery Act—was finalized in 2015.
New Source Performance Standards	1979	• EPA rule governing sulfur dioxide emissions from coal power plants[x] • Effectively required flue gas desulfurization on all new coal plants.

Beginning with the Clean Air Act in 1970, major environmental laws and regulations have impacted the electric industry in key ways.

[q] "Evolution of the Clean Air Act," Environmental Protection Agency, accessed July 28, 2016, https://www.epa.gov/clean-air-act-overview/evolution-clean-air-act.

[r] "Evolution of the Clean Air Act," Environmental Protection Agency, accessed July 28, 2016, https://www.epa.gov/clean-air-act-overview/evolution-clean-air-act.

[s] "Summary of the Clean Air Act," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/laws-regulations/summary-clean-air-act.

[t] "Summary of the National Environmental Policy Act," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/laws-regulations/summary-national-environmental-policy-act.

[u] Executive Office of the President, Council on Environmental Quality (CEQ), *A Citizen's Guide to the NEPA: Having Your Voice Heard* (Washington, DC: Executive Office of the President, CEQ, December 2007), http://www.blm.gov/style/medialib/blm/nm/programs/planning/planning_docs.Par.53208.File.dat/A_Citizens_Guide_to_NEPA.pdf.

[v] "Summary of the Clean Water Act," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/laws-regulations/summary-clean-water-act.

[w] "Summary of the Resource Conservation and Recovery Act," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/laws-regulations/summary-resource-conservation-and-recovery-act.

[x] D. Hercher, "New Source Performance Standards for Coal-Fired Electric Power Plants," *Ecology Law Quarterly* 8, no. 4 (March 1980): 748–61, http://scholarship.law.berkeley.edu/cgi/viewcontent.cgi?article=1174&context=elq.

Name	Year	Major Provisions
Clean Air Act Amendments	1990	• Encouraged market-based principles to pollution control, such as emissions trading[y] • Requires EPA to regulate more than 180 specified hazardous air pollutants[z] and set up specific procedures to determine whether the air pollution regulations would apply to power plants that run on fossil fuels[aa] • Established the U.S. Acid Rain Program, the world's first large-scale emissions cap-and-trade system to reduce air pollution. The program set a permanent cap on annual sulfur dioxide emissions from the power sector.
Cross-State Air Pollution Rule	2011	• Replaced the Clean Air Interstate Rule starting on January 1, 2015 • Requires states to reduce power plant emissions that contribute to ozone and fine particle pollution in downwind states.[ab]
Mercury and Air Toxics Standard	2011	• EPA rule limiting mercury and other toxic pollution from power pants.[ac]
Carbon Pollution Standards and Clean Power Plan	2015	• In 2015, EPA finalized the Carbon Pollution Standards rule establishing carbon dioxide emission standards for new fossil fuel-fired generators under Clean Air Act section 111(b). • Also in 2015, EPA finalized the Clean Power Plan, a rule to reduce carbon dioxide emissions from existing fossil fuel-fired generators under Clean Air Act section 111(d)[ad] The rule establishes final emission guidelines for states to follow in developing plans to reduce greenhouse gas emissions from existing fossil fuel–fired electric generating units, leaving states with considerable discretion to choose the approach.[ae] • As of January 2016, implementation of the Clean Power Plan has been stayed by the Supreme Court pending the outcome of litigation.[af] • EPA regulation of greenhouse gas emissions followed from the 2007 Supreme Court decision in Massachusetts v. EPA that greenhouse gases are air pollutants under the Clean Air Act, and the 2009 EPA finding that the current and projected concentrations of six key greenhouse gases in the atmosphere endanger the public health and welfare, a prerequisite for implementing greenhouse gas emissions standards.[ag]

[y] "1990 Clean Air Act Amendment Summary," Environmental Protection Agency, accessed July 28, 2016, https://www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary.

[z] Michigan v. EPA., 135 S. Ct. 2699, 2704, 192 L. Ed. 2d 674 (2015) (citing 42 U.S.C. § 7412(b)).

[aa] Michigan v. EPA., 135 S. Ct. 2699, 2705, 192 L. Ed. 2d 674 (2015).

[ab] "Cross-State Air Pollution Rule (CSAPR) Basics," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-basics.

[ac] "EPA Announces Mercury and Air Toxics Standards (MATS) for Power Plants – Technical Information," Environmental Protection Agency, December 21, 2011, https://www.epa.gov/mats/epa-announces-mercury-and-air-toxics-standards-mats-power-plants-technical-information.

[ad] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64662 (Oct. 23, 2015).

[ae] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64662 (Oct. 23, 2015).

[af] Order in Pending Case, Chamber of Commerce, et al. v. EPA, et al., 577 U.S. (February 9, 2016), http://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf.

[ag] "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Section 202(a) of the Clean Air Act," Environmental Protection Agency, accessed January 4, 2017, https://www.epa.gov/climatechange/endangerment-and-cause-or-contribute-findings-greenhouse-gases-under-section-202a.

Federal Authorities, Policies, and Frameworks for Electric Grid Resilience and Security

The Federal Government plays a key role in enhancing the resilience and security of the grid through diverse efforts, including research and development, information sharing, the establishment and enforcement of utility performance standards, and the coordination of response resources. Presidential policy directives and congressional legislation have outlined specific authorities for the Federal Government in recognition of the importance of the electricity sector—and supporting energy sectors—for national and economic security. This section describes select Federal policies and frameworks guiding national resilience and security efforts, as well as selected challenges in fulfilling Federal roles to protect critical electricity infrastructure.

Selected Authorities for the Energy Sector

Defense Production Act: Ensures timely availability of resources for national defense and civil emergency preparedness and response, including energy-related assets. (1950)

Energy Policy and Conservation Act: Directs the Secretary of Energy to establish, operate, and maintain the Strategic Petroleum Reserve (1975), which includes the Northeast Gasoline Supply Reserve, and provides for the Presidentially-directed drawdown of those reserves. Also authorizes the Secretary to establish and manage the Northeast Home Heating Oil Reserve. (2000 as amended)

Federal Energy Administration Act: Grants the Department of Energy (DOE) the authority to collect, evaluate, and analyze energy information from facilities or businesses operating in any phase of energy supply or major energy consumption. (1974)

Federal Power Act: Provides the Secretary of Energy authority in time of emergency to order temporary interconnections of facilities and the generation, delivery, interchange, or transmission of electric energy necessary to meet an emergency. (1935, 2015 as amended by FAST Act, as defined below) The Federal Power Act also gives FERC the authority to order compliance with reliability standards. (1935, 2005 as amended by Energy Policy Act [EPAct]) In addition, the **Fixing America's Surface Transportation Act (FAST) Act** amended the Federal Power Act empowering the President to declare a grid security emergency in the face of an electromagnetic pulse, cyber or geomagnetic disturbances, and physical threats and, in doing so, enabling the Secretary of Energy to (1) direct users and operators of electricity assets to undertake such actions as are necessary to ensure the reliability of critical electric infrastructure, and (2) share classified information as necessary to mitigate effects of the grid security emergency. It also allows the Federal Energy Regulatory Commission to provide a mechanism for any affected entities to recover related costs. (2015)

Natural Gas Policy Act: Authorizes DOE to allocate supplies of natural gas to help alleviate an existing or imminent, Presidentially-declared, severe natural gas shortage that would endanger the supply of gas for high-priority uses. (1978)

Selected Authorities for the Energy Sector (continued)

Stafford Disaster Relief and Emergency Assistance Act: The Stafford Act[ah] gives the Federal Government its authority to provide response and recovery assistance in a major disaster. (1988). The Stafford Act identifies and defines the types of occurrences and conditions under which disaster assistance may be provided. Under the law, the declaration process[ai] remains a flexible tool for providing relief where it is needed. Designates the Federal Emergency Management Agency (FEMA) as the lead for Federal emergency response; FEMA may require other Federal agencies to provide resources and personnel to support emergency and disaster assistance efforts. DOE is the sector-specific agency for energy under this framework.

Executive Order 12656—Assignment of Emergency Preparedness Responsibilities: Assigns preparedness responsibilities to Federal agencies and requires agencies to be prepared to respond adequately to all national security emergencies, including developing emergency plans. (1988)

Homeland Security Presidential Directive 5 (HSPD-5): Establishes a single, comprehensive National Incident Management System under the purview of the Department of Homeland Security, under which all other Federal agencies provide their cooperation, resources, and support. The directive also provides direction for Federal assistance to state and local authorities. (2003)

Presidential Policy Directive 8 (PPD-8)—National Preparedness: Replaces prior national planning directives and takes an "all-of-Nation" approach to prepare for a wide range of threats and emergencies. National Planning Frameworks—coordinating structures of key Federal agencies and other stakeholders—have been established around five mission areas: prevention, protection, mitigation, response, and recovery. (2011)

Presidential Policy Directive 21 (PPD-21)—Critical Infrastructure Security and Resilience: Establishes shared responsibility for strengthening critical infrastructure security across the Federal Government. PPD-21 highlights the role of the national physical and cyber coordinating centers in enabling successful critical infrastructure security and resilience outcomes.[aj] Designates critical infrastructure sectors and sector-specific agencies, notably DOE as the sector-specific agency for the energy sector. (2013)

[ah] Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. § 5121 (2007).

[ai] "The Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. §§ 5121-5207 (the Stafford Act) §401 states in part that: 'All requests for a declaration by the President that a major disaster exists shall be made by the Governor of the affected State.' A State also includes the District of Columbia, Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands. The Republic of Marshall Islands and the Federated States of Micronesia are also eligible to request a declaration and receive assistance through the Compacts of Free Association." See "The Disaster Declaration Process," Federal Emergency Management Agency, accessed September 23, 2016, https://www.fema.gov/disaster-declaration-process.

[aj] Department of Homeland Security (DHS), *Supplemental Tool: Connecting to the NICC and NCCIC* (Washington, DC: DHS, 2013), 1, https://www.dhs.gov/sites/default/files/publications/NIPP-2013-Supplement-Connecting-to-the-NICC-and-NCCIC-508.pdf.

Planning and Coordination Frameworks

Federal policy directives and legislation address the evolving threats and institutional vulnerabilities of the Nation's critical infrastructure by defining roles and responsibilities for national grid *resilience* and security. Homeland Security Presidential Directive (HSPD)-7, Presidential Policy Directive (PPD)-8, and PPD-21 laid the groundwork for the key coordinating bodies and a national approach to plan for events.

Joint United States–Canada Electric Grid Security and Resilience Strategy

In December 2016, the Federal Governments of the United States and Canada released the "Joint United States-Canada Electric Grid Security and Resilience Strategy," a collaborative effort between the two nations intended to strengthen the security and resilience of the U.S. and Canadian electric grids from all adversarial, technological, and natural hazards and threats. The Strategy addresses the vulnerabilities of the two countries' respective and shared electric grid infrastructure, not only as an energy security concern, but for reasons of national security. Because the electric grid is complex, vital to the functioning of modern society, and dependent on other infrastructure for its function, the United States and Canada developed the Strategy under the shared principle that security and resilience require increasingly collaborative efforts and shared approaches to risk management.

The Strategy organizes joint approaches to protect today's grid, manage contingencies by enhancing response and recovery capabilities, and cultivate a more secure and resilient future grid. As an expression of shared intent and approach, the Strategy organizes joint efforts to manage current and future security challenges. Three strategic goals underpin the effort to strengthen the security and resilience of the electric grid:

Protect Today's Electric Grid and Enhance Preparedness: A secure and resilient electric grid that protects system assets and critical functions and is able to withstand and recover rapidly from disruptions is a priority for the governments of both the United States and Canada.

Manage Contingencies and Enhance Response and Recovery Efforts: The Strategy sets out a shared approach for enhancing continuity and response capabilities, supporting mutual aid arrangements, such as cyber mutual assistance across a diverse set of stakeholders, understanding interdependencies, and expanding available tools for recovery and rebuilding.

Build a More Secure and Resilient Future Electric Grid: The United States and Canada are working to build a more secure and resilient electric grid that is responsive to a variety of threats, hazards, and vulnerabilities. To achieve this, the electric grid will need to be more flexible and agile, with an architecture into which new technologies may be readily incorporated.[ak]

The Strategy will be implemented through the U.S. and Canadian Action Plans, which detail specific steps and milestones for achieving the Strategy's goals within their respective countries.[al] These documents are intended to guide future activity within areas of Federal jurisdiction, with full respect for the different jurisdictional authorities in both countries.

[ak] Governments of the United States and Canada, *Joint United States-Canada Electric Grid Security and Resilience Strategy* (Washington, DC: Executive Office of the President of the United States and Government of Canada, December 2016), https://obamawhitehouse.archives.gov/sites/whitehouse.gov/files/images/Joint_US_Canada_Grid_Strategy_06Dec2016.pdf.

[al] Executive Office of the President, *National Electric Grid Security and Resilience Action Plan* (Washington, DC: Executive Office of the President, December 2016), https://obamawhitehouse.archives.gov/sites/whitehouse.gov/files/images/National_Electric_Grid_Action_Plan_06Dec2016.pdf.

Under HSPD-7 and then PPD-21, the National Infrastructure Protection Plan set out a number of partnership structures for coordination and information sharing within and across sectors, including electricity. Some of the formal coordination and information-sharing councils available to the electricity subsector include the following:

- **Electricity Subsector Coordinating Council:** Represents the interests of the industry and is composed of electric utility industry executives. It is the principal mechanism for private-sector owners and operators to work collaboratively with the government under a structured and protected framework that allows open dialogue. There is a counterpart subsector coordinating council for the oil and natural gas subsector. Numerous task forces and subcommittees have worked on supply-chain concerns, interdependencies, and coordination with other sectors. The Electricity Subsector Coordinating Council is also a critical coordination mechanism for information sharing during and after incidents.
- **Energy Government Coordinating Council:** This government counterpart to the Electricity Subsector Coordinating Council is jointly led by DOE and the Department of Homeland Security (DHS), with membership from all levels of government and international partners.

These structures collectively serve as a means of sharing information, best practices, research needs, and other critical infrastructure security information, such as information about interdependencies, across sectors.

Additionally, PPD-8 calls for the development of a National Planning System to integrate planning across all levels of government and the private sector. The intent is to provide a flexible approach to prevent, protect, mitigate, respond, and recover from an event. The National Planning System includes the following:[81, 82]

- National planning frameworks describing the key roles and responsibilities to deliver the core capabilities required for the key mission areas: prevent, protect, mitigate, respond, and recover
- Federal Interagency Operational Plans for each mission area to provide further details regarding roles and responsibilities, specify critical tasks, and identify requirements for delivering core capabilities
- Federal department and agency operational plans to implement the Federal Interagency Operational Plans
- Comprehensive planning guidance to support planning by local, state, tribal, and territorial governments; the private sector; and others.

PPD-8 also outlines five frameworks to maintain proper support from the Federal Government by working through states to assist affected local jurisdictions or organizations. The five frameworks divide efforts into rational disciplines of competence—prevention, protection, mitigation, response, and recovery. The combined frameworks shape efforts to prepare our Nation for emergencies stemming from all hazards.

The National Response Framework and its Emergency Support Function (ESF)-12 Annex outline much of the joint Federal, state, and private-sector responsibility for response and recovery to energy service disruptions. The ESF-12 Annex characterizes the Federal response as the facilitation of restoration of damaged energy systems and components. For example, DOE may exercise its emergency powers depending on the conditions of certain respective declarations and findings to facilitate restoration and to meet the needs of industry. After an incident, the National Disaster Recovery Framework[83] provides guidance for an expeditious return to a normal way of life. Like the National Response Framework's ESFs, the National Disaster Recovery Framework has Recovery Support Functions. DOE is named as a primary agency in the Recovery Support Function–Infrastructure Systems.

Tools and Technical Assistance

The Federal Government also provides numerous tools and technical assistance to enhance states' and the electric industry's capabilities to operate electricity systems in a secure and resilient manner. Many of these resources help stakeholders understand risks, assess their systems, analyze vulnerabilities, and prioritize mitigation strategies. Below are a few examples:

- DOE's Electricity Subsector Cybersecurity Capability Maturity Model helps entities evaluate, prioritize, and improve their cybersecurity capabilities and allows for a better overall assessment of the cybersecurity posture of the energy sector.[84]
- DHS's Cyber Security Evaluation Tool[85] and the Cyber Resilience Review are complementary and voluntary tools for evaluating industrial control system (ICS) and information technology network practices, and operational resilience and cybersecurity capabilities, respectively.[86]
- DHS's ICS Cyber Emergency Response Team provides resources to critical infrastructure sectors to prevent and recover from cyber attacks. This includes working onsite to help resolve spear phishing campaigns that seem to target ICS/supervisory control and data acquisition (or SCADA) data, including data that could facilitate remote access and control of systems.[87]
- DHS Regional Resiliency Assessment Program conducts regional assessments of the Nation's critical infrastructure, addressing a range of hazards that could have regionally and nationally significant consequences. Argonne National Laboratory completed 56 Regional Resiliency Assessment Program projects during 2009–2014, which addressed a variety of postulated hazards, including tornadoes, ice storms, earthquakes, hurricanes, solar storms, and other threats to the electric sector.
- The National Oceanic and Atmospheric Administration supports Regional Climate Centers, which are able to provide technical assistance and climate data to support risk assessment and decision making by utilities and governments.[88]
- DOE's Office of Energy Policy and Systems Analysis convenes the Partnership for Energy Sector Climate Resilience, through which DOE provides technical assistance for 18 electric utilities that are demonstrating leadership in developing vulnerability assessments and pursuing strategies for investing in climate resilience.

Continued support for tools development and expanding technical assistance resources is increasingly important as changing risks from human-induced actions and natural hazards make risk-based planning more challenging. For example, to credibly account for projected changes in climate, utility planners and regulators need technical assistance in accessing and correctly interpreting climate data at the appropriate time and geographic scales.

Standards and Guidance

As previously discussed, FERC has regulatory authority over the reliability of the bulk power system, overseeing the development and approval of standards set by NERC. FERC can also proactively direct NERC to develop a new or modified reliability standard to address reliability issues identified by FERC. While these standards cover the reliability and security of bulk power assets, NERC has typically designed them with the benefit of the system as a whole in mind, balancing the interests of its stakeholders. In addition to standards, the Federal Government works with stakeholders to develop additional guidance to support risk mitigation strategies across the electric sector.

It is worth noting that NERC's planning standards for electric reliability (e.g., TPL-001-4) and facility ratings standards (e.g., FAC-008-3) require consideration of a broad range of risks to the system. However, assumptions within these standards regarding the frequency and intensity of extreme weather events, for example, do not account for projected changes in climate. Furthermore, transmission planning efforts routinely consider system-wide costs associated with average weather-related loads, rather than accounting for extreme conditions.[89] The practice of using historical data and average conditions undercuts efforts to plan and prepare for threats, such as extreme weather, cyber attacks, or hostile actions, that may have different characteristics in the future.

Within the Commerce Department, the National Institute of Standards and Technology (NIST) develops frameworks, voluntary standards, and other guidance documents to assist electric sector efforts in reliability, resiliency, and security.[90] NIST conveys unique technical requirements for authorizing, monitoring, and managing all methods of remote access to the smart grid information system.[91, 92] The NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 3.0, is one example of these resources.[93, 94] In addition, in 2014, the NIST released the Framework for Improving Critical Infrastructure Cybersecurity, which includes a set of standards, methodologies, procedures, and processes that align policy, business, and technological approaches to address cyber risks, and incorporates voluntary consensus standards and industry best practices.[95] In 2015, DOE released guidance to help the energy sector establish or align existing cybersecurity risk management programs to meet the objectives of the framework released by NIST.

Several organizations are also actively revising interconnection standards—the rules that prescribe capabilities that technologies like DG must possesses as a precondition to connecting to the electricity system—to better support the reliability, safety, and cost effectiveness of the grid. As technologies subject to interconnection standards increase in number and potential impact on the grid, enhanced Federal support is critical to the timely and robust completion of these standards.

Information Sharing and Threat Analysis

Federal agencies have institutions and programs in place to enhance information sharing and the dissemination of threat analysis to government and industry partners. DHS is responsible for several key infrastructure security programs. The National Infrastructure Coordinating Center and the National Cybersecurity and Communications Integration Center are the national focal points for industry partners to obtain 24/7 situational awareness and integrated actionable information to secure the Nation's physical and cyber critical infrastructure, respectively.[96] During major incidents, the National Infrastructure Coordinating Center and the National Cybersecurity and Communications Integration Center closely coordinate with the Federal Emergency Management Agency to ensure that overall critical infrastructure status and impacts on life and safety are understood throughout the Federal incident response community.[97]

Below are additional examples of government programs available to electric sector participants:

- **DHS Fusion Centers** are information-sharing hubs for Federal, state, local, tribal and territorial agencies and industry to maintain situational awareness at the state and local levels. Fusion centers receive, analyze, and disseminate threat information, providing local perspectives to their partners.[98]
- **DHS Automated Indicator Sharing** is a free program that facilitates the exchange of cyber threat indicators between the Federal Government and parties that opt in to the program through machine-to-machine sharing.[99]
- **DOE's Cybersecurity Risk Information Sharing Program** facilitates the exchange of detailed cybersecurity threat information among electric utilities, the Electricity Information Sharing and Analysis Center, DOE, and several National Laboratories. The program was designed to facilitate the timely bidirectional sharing of unclassified and classified threat information, and to develop situational awareness tools to enhance the sector's ability to identify, prioritize, and coordinate the protection of their critical infrastructure and key resources.
- **Information Sharing and Analysis Organizations** encourage exchange of information to protect critical infrastructure and are supported by sector-specific agencies and DHS in accordance with Executive Order 13691 and PPD-63.

Electricity System Operations, Business Models, and Markets

System Operation

The electricity system of the continental United States does not function as a single, unified grid, but rather is split into three interconnections that each function as independent power systems with limited power flows between them, enabled by DC interconnections between the regional systems. Hawaii and parts of Alaska also operate as independent systems. The goal in operating each of these power systems is to deliver low-cost and reliable electricity. A complex set of institutions, defined by geographic boundaries, accomplishes this goal.

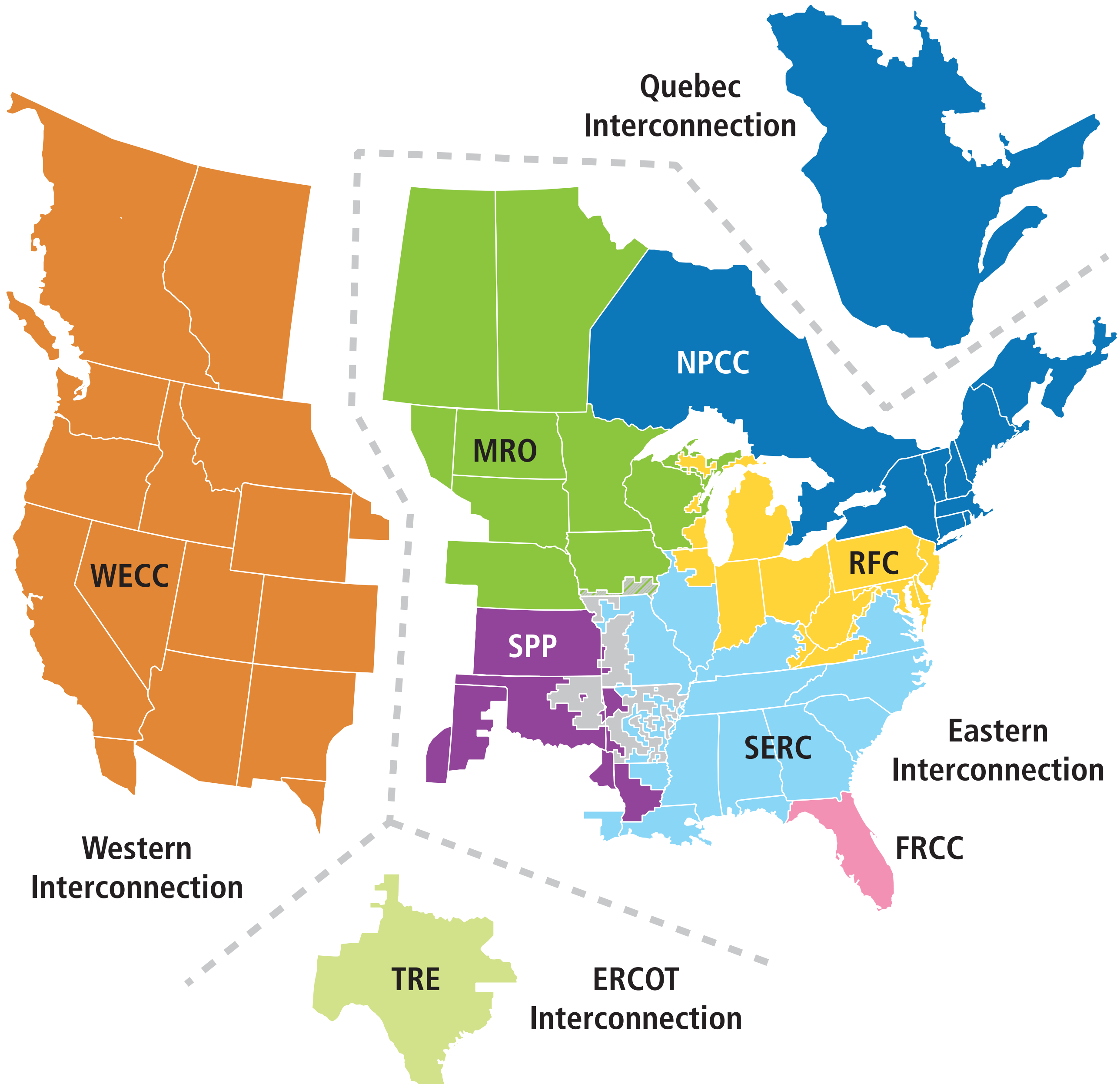
One of the broadest geographic divisions is the regional reliability entity,[am] which develops and enforces standards on behalf of NERC.[an, 100] Figure A-6 shows the three interconnections of the continental United States and the NERC reliability regions.

Providing electricity when and where it is needed is an incredibly complicated engineering process. Unlike most other consumer goods and energy sources, electricity is not stored in large quantities and must be produced at the instant it is needed. It is the job of power system planners and operators to ensure that electricity is produced when and delivered to where it is needed at every moment of every day.

[am] Instead of *entity*, the terms *council* and *organization* are sometimes used to refer to these entities as a group. Individually, their names include entities (e.g., Texas Reliability Entity), councils (e.g., Florida Reliability Coordinating Council), organizations (e.g., Midwest Reliability Organization), corporations (e.g., SERC Reliability Corporation), and pools (e.g., Southwest Power Pool, Inc.).

[an] NERC sets standards for the reliability of the bulk power system. The jurisdiction and authority of NERC is discussed in greater detail in the "Federal Actors" section of this appendix.

Figure A-6. North American Interconnections and Reliability Regions[ao, 101]

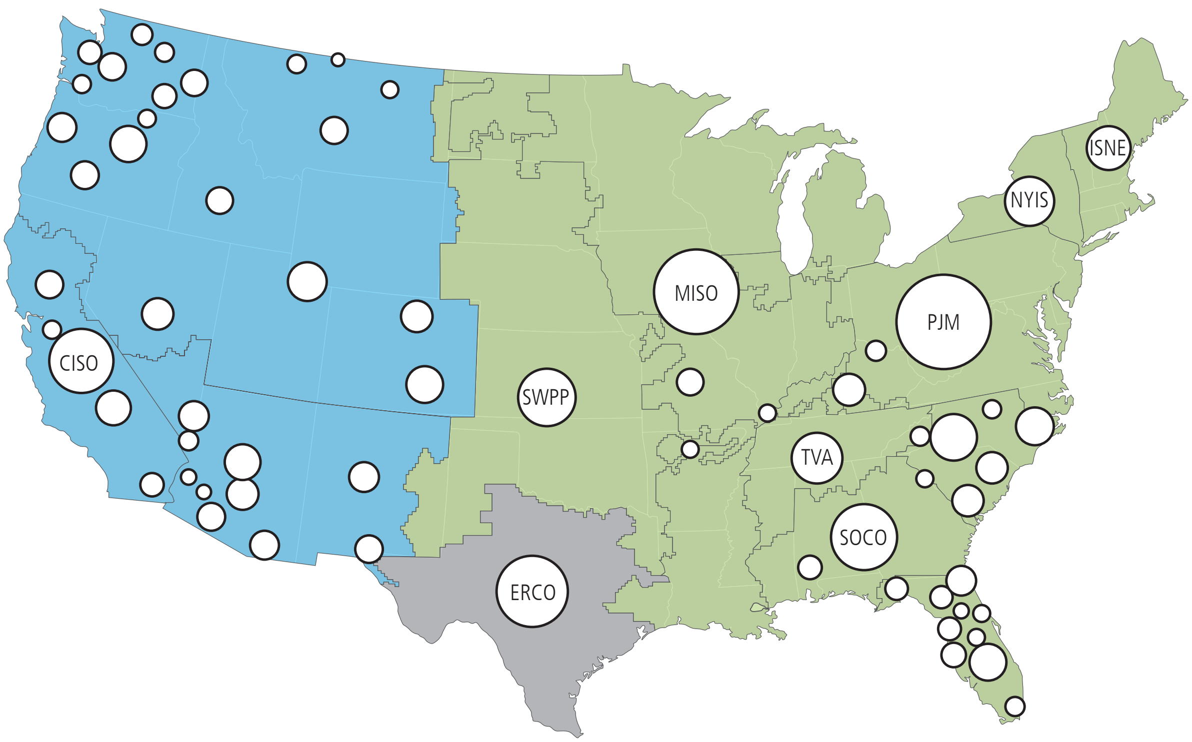


This map shows four North American interconnections, three of which include the United States, and eight NERC reliability regions. The four interconnections include Eastern, Western, Quebec, and the Electric Reliability Council of Texas (ERCOT). The NERC regions include: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

[ao] This figure is based on information from the North American Electric Reliability Corporation's website, which is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC_Interconnections_Color_072512.jpg. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation.

The Nation is regionally subdivided into balancing areas, shown in Figure A-7, where balancing authorities operate regions of the grid on a day-to-day basis. Some of these regions overlap precisely with NERC reliability regions, while many others are smaller in geographic extent. On a daily basis, balancing authorities forecast demand, schedule generation supply, and schedule exchanges with neighboring regions. These decisions are generally guided by software-optimization systems that minimize the total cost of meeting demand, subject to operating constraints and reliability criteria. Scheduling generation supply occurs on multiple time horizons, the most important of which include unit commitment (scheduling the availability of a generator days or hours ahead of time) and economic dispatch (providing operating instructions in near real time).

Figure A-7. Electricity System Interconnections and Balancing Areas[102]



The electricity industry includes the three continental United States electricity system interconnections (Eastern, Western, and the Electric Reliability Council of Texas [ERCOT]), and the 66 balancing authorities that are responsible for maintaining a balance between supply and demand within their areas. The location of the balancing area bubbles is approximate, and the size represents a rough indication of the size of the system managed in each area.

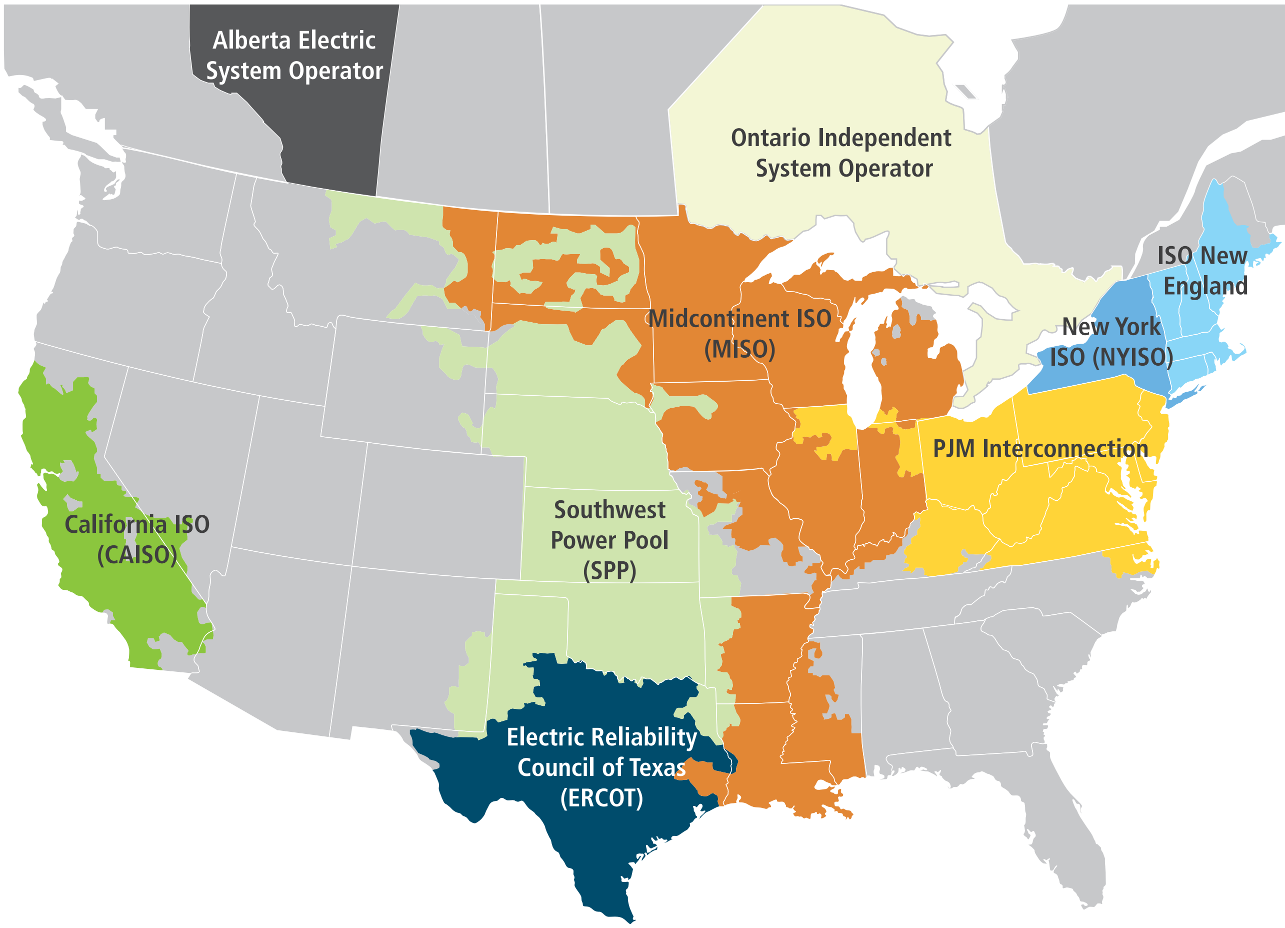
Different operating approaches are used throughout the country, though all focus on minimizing costs and maintaining reliability. In some areas, utilities operate their own systems based on their costs for resource options and operating decisions. Other regions operate based on organized markets, where market participants place supply and demand bids into a centralized market, and a market operator determines the least-cost mix of bids.[ap] Market participants then pay and earn money based on market prices for electricity and ancillary services. System operators in these areas are called ISOs or RTOs,[aq] and their markets—except for Electric Reliability Council of Texas (ERCOT), which covers most of Texas—are overseen by FERC.[ar]

[ap] The operations of markets are discussed in greater detail in the "Electric Power Markets" section of this appendix.

[aq] There are small distinctions between ISOs and RTOs, though they are insignificant for the level of discussion in the QER. Throughout, the terms will be used synonymously.

[ar] The jurisdiction and authority of FERC is discussed in greater detail in the "Federal Actors" section of this appendix.

Figure A-8. Regional Transmission Organizations, 2015[103]



FERC encouraged voluntary formation of ISOs and RTOs through a series of landmark orders that paved the way for open access to transmission and created large, centrally organized power markets in the United States. There are currently seven ISO/RTOs in the United States, and their geographic extent changes periodically.

aintaining operational reliability of the power system requires focusing on a set of essential reliability services, called ancillary services, provided by generation and load that aid in maintaining frequency and voltage of the system within acceptable bounds during normal operations and immediately after minor system disturbances.[as] Examples of these services include frequency response (automatic generator response to grid frequency deviations) and spinning reserves (generators that remain running and able to increase or decrease their output when instructed). Some ISO/RTO market regions procure ancillary services through markets that mirror their energy markets. Additional services are procured in these regions through cost-of-service payments. In non-ISO/RTO regions, many ancillary services are provided under a cost-of-service basis. The evolving composition of the electricity generation fleet has implications for long-term availability of these system-essential reliability services.[104]

[as] The term Essential Reliability Services is used by NERC to describe a set of necessary operating characteristics of resources on the bulk power system required to reliably operate the bulk power system in North America. For voltage support, it includes reactive power/power factor control, voltage control, and voltage disturbance performance. For frequency management, it includes inertia, frequency disturbance performance, operating reserves, and active power control (which includes frequency control and ramping capability). Ancillary services are a subset of Essential Reliability Services. Source: North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability* (Atlanta, GA: NERC, October 2014), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

Reliability and the Role of the North American Electric Reliability Corporation (NERC)

Over the past 50 years, Federal oversight of the reliability of the bulk power system has increased. The 1965 Northeast power blackout precipitated the formation of NERC, but bulk power system reliability standards were voluntary and subject only to industry oversight.[at] A 2003 blackout that affected more than 50 million customers led to the inclusion in the Energy Policy Act of 2005 of requirements for mandatory bulk power reliability standards and enforcement, including designation of an electric reliability organization.[au] The Federal Energy Regulatory Commission oversees NERC in its development and enforcement of mandatory reliability standards for the bulk power system. States retain oversight of local reliability, which includes lower voltage transmission lines and distribution systems. NERC mandatory reliability standards address weaknesses in the prior voluntary system that were identified in the 2003 blackout investigation.

[at] North American Electric Reliability Corporation (NERC), *NERC Operating Manual* (Atlanta, GA: NERC, June 15, 2004), HIST-1, http://www.nerc.com/comm/oc/operating%20manual%20dl/opman_june_15_2004.pdf.

[au] David W. Hilt, *August 14, 2003, Northeast Blackout Impacts and Actions and the Energy Policy Act of 2005* (Princeton, NJ: North American Electric Reliability Corporation, August 14, 2003), 10–11, http://www.nerc.com/docs/docs/blackout/ISPE%20Annual%20Conf%20-%20August%2014%20Blackout%20EPA%20of%202005.pdf.

Business Models

Electricity in the United States is produced and delivered by a diverse set of actors using a range of business models. Depending on the operating model in question, these actors can be subject to regulation and oversight by different combinations of local, state, and Federal agencies. A key factor for differentiating between actors is ownership: companies can be investor-owned, publicly owned, or cooperatively owned. Within each of these three ownership models there are significant variations in purpose, regulatory oversight, prevalence, and size. Table A-4 provides overview statistics for the most common types of utility ownership. In addition to these primary ownership models, there are a number of businesses that provide distributed resources like DR aggregation and distributed solar. Table A-5 provides a taxonomy of utility business models by ownership and asset types.

Table A-4. Characteristics of Major Utility Types[105, 106]

Utility Type	Number of Utilities	Number of Customers	Miles of Power Lines	
			Transmission	Distribution
Investor-Owned Utilities	169	107,600,000	3,467,000	459,500
Municipal Utilities	1,834	15,150,000	321,000	27,590
Rural Electric Cooperative Utilities	814	19,230,000	2,400,000	116,600
Federal and Publicly-Owned Utilities	124	5,280,000	333,700	95,960
Total	**2,941**	**147,200,000**	**6,408,000**	**699,700**

Municipal utilities are the most numerous of the various utility types, though IOUs serve far more customers. Rural electric cooperatives have a higher proportion of distribution miles per customer served than investor-owned or municipal utilities.

IOUs are privately owned, for-profit utilities whose retail service is regulated by state PUCs that may be either vertically integrated or restructured to only own transmission and distribution. IOUs earn a regulated rate of return based on investments made to serve their ratepayers.

Rural electric cooperatives include nonprofit, member-owned distribution utilities and generation and transmission utilities. The cooperative business model is predicated on providing its customers with reliable, affordable energy that is locally owned and operated. The model is unique in that customers are "members" of the cooperative and, as such, hold ownership and voting stakes. Management is democratically elected by the membership, and the prevailing methodology is one meter, one vote.[107] Cooperatives receive a significant portion of their financing both directly and indirectly from the Federal Government, through both the Department of Agriculture's Rural Utility Service and cooperative banks like the National Rural Utilities Cooperative Finance Corporation. Electric cooperatives are not subject to Federal income tax, and thus must collaborate with a third party to monetize tax credits available for utility and generation investments.

Public power utilities are owned by a governmental entity, such as municipalities, states, public utility districts, or irrigation districts, and vary in size and scope from small distribution utilities to large, vertically integrated utilities. Public power also includes joint-action agencies that may own generation and transmission and provide power purchasing services for their member utilities, such as the Lower Colorado River Authority and Missouri River Energy Services. Joint action agencies allow small distribution-only public power utilities to aggregate their demand and contract for and/or build generation, transmission, and other common services.

Federally owned utilities operate in the generation and transmission segments of the power system in several parts of the country. Four Power Marketing Administrations market hydropower generation at dams operated by the Bureau of Reclamation or the Army Corps of Engineers. TVA has a portfolio of generation and transmission to sell wholesale electricity to public power and cooperatives in its footprint. Federal law grants preference for electricity marketed by Federal utilities to public power and cooperative utilities.[av] Federally owned generation resources produce approximately 7 percent of all power in the United States, and they own approximately 14 percent of all transmission lines.[108, 109]

Merchant/independent power producers (IPPs) sell power through markets and bilateral contracts with utilities and other customers. IPPs typically have market-based—rather than cost-based—rates and do not have captive customers. They may or may not be affiliated with an IOU through a holding company. In 2014, IPPs produced approximately 40 percent of the Nation's electricity.[110] IPPs are often subject to hard-to-predict market conditions and can experience volatile cash flows and returns.

Competitive retail energy suppliers are companies that sell power to end users in states with competitive retail markets. As such, they do not earn a regulated rate of return. Although distribution utilities are the only entities that can *deliver* power directly to retail customers, in certain states customers can choose the *suppliers* of that power. In practice, this "retail choice" means that a consumer can sign a contract with a qualified third-party electric service provider who could, in turn, contract with a generator (on a bilateral basis), self-generate, or purchase power in the wholesale market, and pay the necessary tariffs to the transmission owner and distribution utility.

Energy service companies (ESCOs) were traditionally providers of turnkey energy efficiency retrofits, but ESCOs are now offering biomass, geothermal, wind, and solar generation, bill management, energy monitoring, and energy procurement.[111] ESCOs explicitly guarantee energy savings for the consumer and charge a fee below that savings, known as an energy savings performance contract.[112]

Demand-response aggregators contract with large groups of end users to curtail their load if called upon to do so by the local utility or balancing authority. This flexibility is useful for reliability and economic reasons. There are many different providers of demand-response aggregation, including existing utilities and third-party providers.[113] The terms and conditions of third-party access to wholesale markets differ between ISOs and RTOs, but, generally,

[av] Preference clauses for Federal power sales originate from a series of congressional acts regarding Federal land reclamation and hydropower development, beginning with the Reclamation Act of 1906. See GAO-01-373 for further details.

aggregators can participate in both energy and capacity markets to provide energy and ancillary services (including synchronized reserves).[114] Of 9.3 million participants registered in DR in 2014, by count, over 90 percent are residential customers. However, over 75 percent of actual peak-demand savings came from commercial and industrial customers in 2014.[115]

Table A-5. Taxonomy (Ownership/Scope) of Utility Business Models with Representative Firms[116]

	State-Regulated IOU	Rural Electric Cooperative	Publicly Owned	Federally Owned	Merchant	Competitive Retail Energy Supplier*
Vertically Integrated**	Oklahoma Gas & Electric	–	Los Angeles Department of Water & Power	–	–	–
Transmission and Distribution	Pepco	Southern Maryland Electric Cooperative	Clallam County Public Utility District	–	–	–
Generation and Transmission	–	Basin Electric G&T	New York Power Authority	Tennessee Valley Authority	LS Power	–
Generation and Distribution	DTE Energy; Consumers Energy	Fox Island Electric	Lansing Board of Water & Light	–	NRG	–
Transmission Only	–	Upper Missouri Power Cooperative	Transmission Agency of Northern California	Western Area and Southwestern Power Administrations	ITC; Hudson Transmission; Transource Energy; Clean Lines Energy Partners	–
Distribution Only	Mt. Carmel Public Utility Co.	Kenergy	Nashville Electric Service	–	–	–
Generation Only	–	–	Wyoming Municipal Power Agency	Bureau of Reclamation	Calpine; BP Energy; Tenaska	–
Retail Sales Only***	–	–	–	–	–	Direct Energy; Veteran Energy

* Competitive retail energy suppliers are a special category of market participants that buy and sell electricity, but do not own any generation or infrastructure. Some ESCOs are retailers.

** Vertically integrated entities integrate generation, transmission, and distribution.

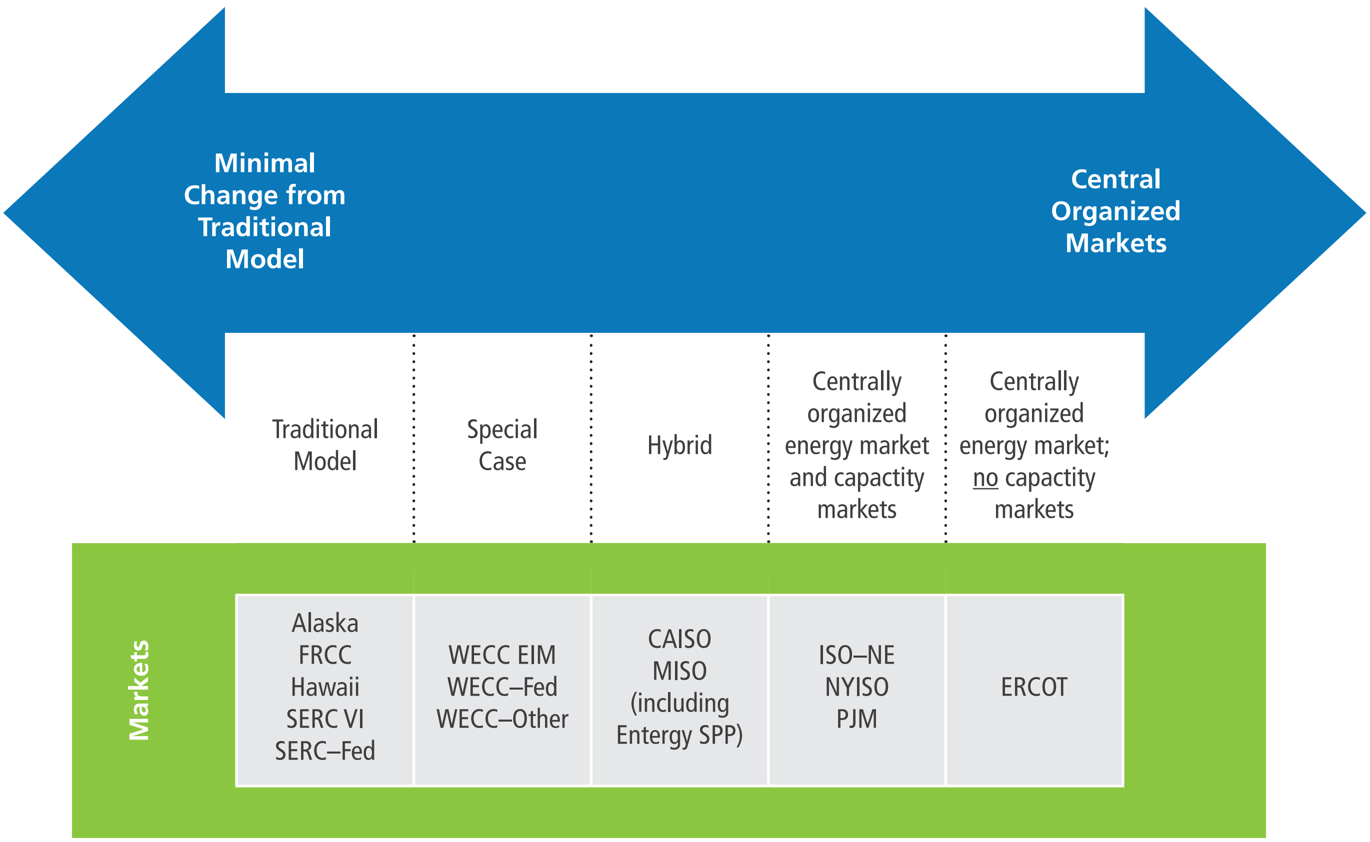
*** All business model categories in this table may include retail sales in addition to other services.

Utilities in the U.S. electricity sector have a variety of ownership and asset structures. They range from being fully vertically integrated to selling only one service, and they can be owned by government or public entities, cooperatives, or independent companies.

Electric Power Markets

Rather than consisting of a single overarching market, the U.S. electricity industry can instead be considered something of a patchwork, with different regional markets pursuing different mechanisms to provide electricity service to end users. The simplest characteristic differentiating these markets is whether resources are scheduled, dispatched, and compensated by a centrally organized RTO/ISO, or if they operate under the more traditional model wherein vertically integrated utilities operate within their franchise areas and receive revenues based on the cost of service. From this bifurcation, the organized markets can be further classified according to the types of resource adequacy constructs they use. These two attributes form a useful framework for analyzing the degrees to which the various markets differ from one another, and also underscore the diversity of approaches to electricity policy amongst the states.

Figure A-9. Spectrum of Electricity Markets[117]



This graphic illustrates the degree to which various U.S. regions have changed from the traditional market model. The two primary characteristics measured here are resource adequacy constructs and whether the market is centrally organized. Markets include: ERCOT, ISO New England (ISO-NE), New York ISO (NYISO), the PJM Interconnection (PJM), California ISO (CAISO), Midcontinent ISO (MISO), SERC Reliability Corporation (SERC), Southwest Power Pool (SPP), and the Energy Imbalance Market (EIM) in the Western Electricity Coordinating Council (WECC) region. The markets listed under "special case" and "traditional model" are classified by NERC region and are not standardized designations.

Regions Address Resource Adequacy with a Variety of Mechanisms

Resource adequacy is "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[aw] Planning for adequate investment in generation and transmission capacity to ensure resource adequacy is a critical component of ensuring a reliable electricity system.

Traditional, vertically integrated regions and some utilities in hybrid markets conduct an integrated resource planning process to plan for necessary capacity investments. Some centrally organized markets have implemented capacity markets as a mechanism for ensuring future resource adequacy. In these markets, the system operator conducts an auction process, and retail service providers procure resources to meet the electricity demands of their customers. These markets can be mandatory (PJM Interconnection and Independent System Operator [ISO]–New England); voluntary, where utilities can choose to operate under an integrated resource planning process (Midcontinent ISO); or voluntary backstopped by a mandatory process (New York ISO).[ax] Other regions (California ISO and the Southwest Power Pool) have capacity obligations where market operators require utilities to procure necessary generation reserves, either through ownership or through contracts with third-party providers. Another market-based approach, used in the Electric Reliability Council of Texas, relies on energy prices alone and does not have formal requirements or markets for capacity. In this approach, market scarcity pricing, or relatively high energy prices during high-demand periods reflecting the lack of ample additional resources, provides necessary financial incentives for investment in generation capacity.

[aw] North American Electric Reliability Corporation, "Glossary of Terms Used in NERC Reliability Standards," last modified November 28, 2016, http://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf.

[ax] K. Spees, S. Newell, and J. Pfeifenberger, "Capacity Markets—Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy* 2, no. 2 (2013): 10, doi:10.5547/2160-5890.2.2.1.

"Traditional" markets (the Southeast of the United States, for example) are dominated by vertically integrated IOUs that operate under a regulated cost-of-service model, serving customers in a defined franchise area. Public power and rural cooperative utilities also have a significant presence in some regions, and their utility asset ownership models can vary from vertically integrated to distribution-only. IPPs can also operate within these regions to some degree. However, the majority of power is produced and delivered by the integrated utilities.

Power purchases between these various entities are generally limited to bilateral trades. These can be made to take advantage of price discrepancies or cover shortfalls in supply. These bilateral transactions represent a small portion of the total generation in traditional markets and are typically in the form of long-term power purchase agreements instead of short-term trades. For example, in 2015 FERC estimated that short-term trades, called spot transactions, in the Southeast region accounted for less than 1 percent of overall supply.[118]

Centrally organized markets (ERCOT and New York ISO, for example) are markets where utilities were required to sell their power generation assets and keep only the "wires" component of the business. Generation assets were sold to IPPs who now operate these assets and build new generation based on expected market earnings. These assets work in a competitive fashion, with the IPP owners either (1) looking to sell power under bilateral contracts to utilities or other off-takers, such as industrial users, or (2) dispatching their power into wholesale energy markets.

In wholesale "energy-only" markets, units bid in on a day-ahead basis what price they are willing to produce power at, based on an assessment of their operating costs, fuel costs, and return expectations. The system operator (RTO/ISO) then pools these bids in a centralized fashion and determines a clearing price that matches supply, demand, and congestion forecasts for a given period. Notably, all units receive that marginal clearing price for that period, even if their bid prices are significantly lower than the clearing price determined by the ISO. In addition, the typical markets maintain price caps that limit what can be charged in any particular hour in order to limit the potential for market manipulation.

"Hybrid" centrally organized markets (for example, California ISO and the Southwest Power Pool) combine elements of centrally organized energy markets and traditional resource adequacy mechanisms. In fact, several of these markets had moved toward more of a pure restructured model before moving back to elements of the more traditional regulated approach.

Transmission Access, Competition, and Planning

While Congress has found that generation can be provided through competitive mechanisms and therefore encouraged restructuring in that segment of the industry in the 1990s, increasing competition among transmission owners and reducing barriers to using transmission have been more incremental processes.

Originally, incumbent transmission owners largely controlled third-party access to transmission lines, effectively precluding competition at the wholesale level. Buyers and sellers of wholesale power that did not own the transmission connecting them had difficulty reaching each other over another's transmission lines at reasonable cost. EPAct 1992 resolves this issue by providing FERC with greater authority to provide transmission access for wholesale buyers in procuring wholesale electric supplies. Since 1992, FERC has taken multiple actions to increase operational and economic efficiency and equity of transmission operations and pricing.

FERC adopted Order No. 888 and Order No. 889, which require electricity utilities that own transmission lines used in interstate commerce to offer transmission service on a nondiscriminatory basis to all eligible customers, including non-jurisdictional entities such as public power, rural cooperatives, and Federal utilities. Order No. 2000 further encouraged utilities to join RTOs to improve the efficiency and equity of the transmission systems. FERC Order No. 890 built upon Order No. 888 to encourage more transparent planning and use of the transmission system and to reduce opportunities for undue discrimination.

FERC Order No. 1000 covers concepts such as (1) precluding, in most circumstances, incumbent transmission owners from having Federal rights of first refusal to build transmission within their service territories, (2) the opportunity for entities not previously recognized as transmission owners in the region (non-incumbents) to compete to develop transmission facilities and allocate the costs of those facilities, and (3) the requirement that project costs be allocated in a manner that is at least roughly commensurate with expected benefits from the projects.

Transmission owners, operators, and regional coordinators implement structured transmission planning processes to identify solutions that can more efficiently or cost-effectively maintain system reliability and accommodate changes in generation capacity and demand. Meeting the transmission planning goal requires both technical (engineering) analysis of different power systems configurations and economic analysis of projects proposed to meet the identified needs. In the United States, the transmission planning process generally falls into three geographic categories: local, regional, and interregional coordination.

Local transmission planning activities are carried out by incumbent transmission owners. These transmission owners assess their system and implement local solutions within their own service territory. Regional transmission planning includes assessment of solutions within a given planning region that spans several transmission owner service territories. Regional transmission planning relies on extensive stakeholder engagement, power system simulation modeling, and long-term economic impact analysis of alternative transmission projects. Interregional coordination is implemented for solutions that involve more than one ISO/RTO or planning entity. Interregional coordination activities are mostly guided by the principles outlined in FERC Order No. 1000.

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